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COMPARING DIFFERENT APPROACHES TO MANAGING CO_2 STORAGE RESOURCES IN MATURE CCS FUTURES

Report: 2014/01

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COMPARING DIFFERENT APPROACHES TO MANAGING CO_2 STORAGE RESOURCES IN MATURE CCS FUTURES

Key Messages

- There are many potential competing users of the surface and subsurface in both onshore and offshore environments
- There are various different approaches to storage management, all of which are highly dependent on the jurisdiction involved
- Most jurisdictions currently work under a 'first-come, first-served' approach
- Management of storage on a first-come, first-served basis is likely to be sustainable in the short to medium term
- Pressure increases do not always result in detrimental effects, but pressure responses in *open* storage sites should be the focus of a detailed assessment in all cases
- The operator and regulator must understand the consequences of a pressure increase over an area much larger than the extent of the CO_2 plume itself
- The main benefit of a first-come, first-served approach is that the operator has the final decision on where to develop CO_2 storage
- The first-come, first-served approach should work for multiple-stacked sites
- Potential disadvantages of the first-come, first-served approach include possible reduced storage capacities, difficulties for monitoring and a lack of regional storage optimisation with stranded sources.

Background to the Study

Current regulations concerned with carbon dioxide capture and storage (CCS) mean that the licensing of CO_2 storage sites is likely to be undertaken to follow a first-come, first-served basis. Applications for licences (for 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. This assessment will be subject to certain region-specific exclusions, designed to protect the interests of pre-existing users of the subsurface, ground surface and seabed.

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. A recent (2013) IEAGHG study, '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 (see figure 1, overleaf, for a conceptual view of spatial and subsurface interactions which may limit storage site selection). 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 cost, minimising risk, access to a range of uses of the basin, ground surface and seabed, and the value of the resource. Such factors would 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.

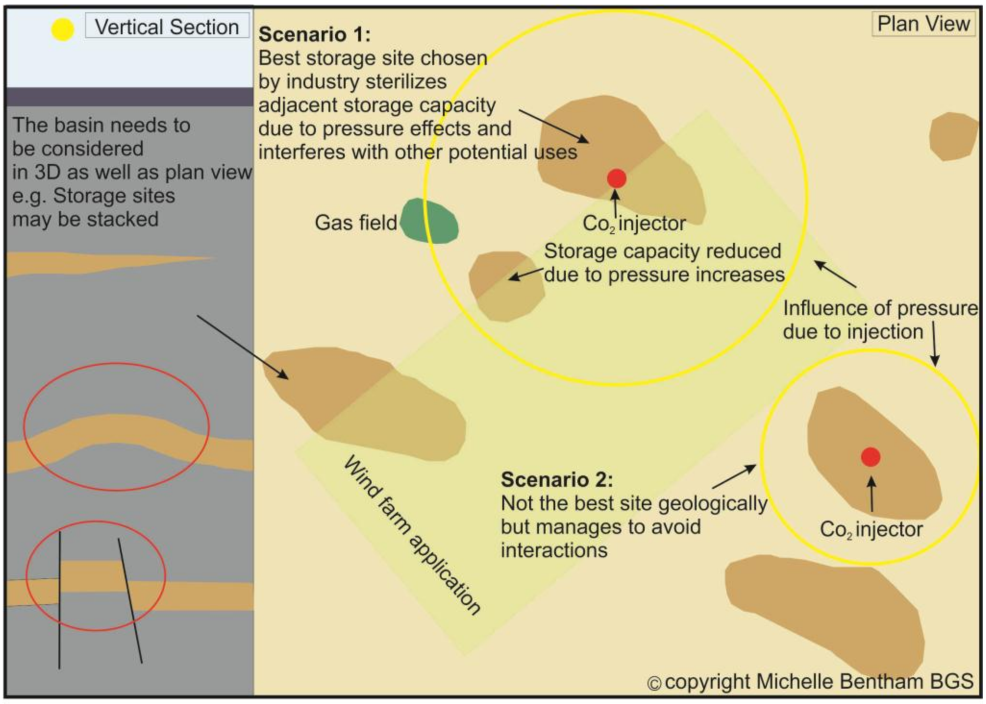

FIGURE 1. Conceptual view of spatial and subsurface interactions which might limit storage site selection, using a hypothetical example of gas fields and two storage site scenarios in the UK Southern North Sea

Scope of Work

This report develops scenarios for CO_2 storage development in the Southern North Sea Basin to compare first-come, first-served and managed approaches to CO_2 storage site licensing. The report describes the benefits and consequences of these broad strategies for the pore space owner and the operator, and considers current approached to managing offshore and onshore storage resources (in a range of jurisdictions).

A workshop was held in the early stages of the report process, which helped to evaluate approaches to the management of pore space in different jurisdictions. The following general issues were discussed at the workshop and are looked at further in the report:

- The availability of storage capacity
- Other uses and users of the pore space

- Priorities on different uses in different jurisdictions
- Potential routes to wider storage deployment
- Technical regulatory challenges for storage in areas of multiple stacked storage opportunities
- Risks that may arise from site interactions
- Examples of pore space conflict resolution
- Strategic initiatives for storage deployment.

The report details potential subsurface interactions, UK policy for CO_2 storage development (including a UK Southern North Sea case study), potential interactions between two case studies in the Southern North Sea, CO_2 storage permitting in the Netherlands, CO_2 storage in Australia, the role of CO_2 enhanced oil recovery (EOR) in Texas, USA and managing the pore space in Alberta, Canada.

Findings of the Study

Pressure as a result of CO_2 injection

Subsurface interactions may occur when a storage project operates within a geological formation and such interactions are well-documented. The most significant potential interactions are likely to be the pressure effects of CO_2 injection and the associated brine displacement. This reservoir pressure increase is a prime risk to other resources (including other storage sites) which are in pressure communication. Figure 2 shows a simulation of the relationship between CO_2 plume extent and the extent of the pressure rise from this injection.

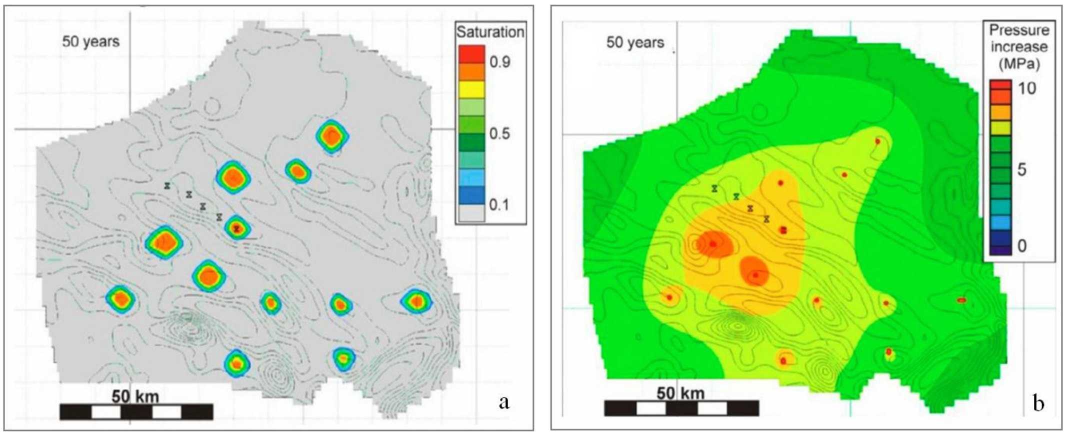

FIGURE 2. A TOUGH2 simulation showing the relationship between CO_2 plume extent and pressure rise, over a 50 year period.

UK Policy and Regulation for Storage Development

The UK has several strategies and policies to reduce greenhouse gas emissions, including a legally binding target to reduce emissions by at least 80% below base year levels by 2050. The 2012 CCS Roadmap notes 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. The Department for Energy and Climate Change (DECC) has recognised the potential for CCS clusters to develop across several regions and their storage strategy identifies the challenge of future storage deployment, included the scale of possible future storage needed. The storage roadmap sets out specific activities that the UK government will focus on in these efforts and other activities (by organisations like the Crown Estate and the Storage Cost Reduction Task Force) will support such efforts. The UK government have undertaken several significant activities for storage research and demonstration (R&D) including a commercialisation competition and a coordinated research, development and innovation programme.

The UK Southern North Sea has a vast amount of storage potential, including in gas fields (the majority of which occur within the Rotliegend Leman Sandstone formation) and saline aquifers (including the Bunter Sandstone, thought to have the best potential for aquifer storage, with good pressure communication across the reservoir).

UK Southern North Sea Case Study

The report undertakes a UK-specific case study to 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 carboniferous limestones. Potential users or conflicts identified 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 (first-come, first-served (FCFS) and managed storage resource) to run from 2020 to 2050, to illustrate the interactions that may occur as a result of CO_2 injection.

Two potential storage sites were chosen to undergo the scenario simulations, with assumptions made that all storage capacity could be used and no pressure management wells are used. No cost assessment was carried out, so differences will arise due to varying site characterisation and commissioning costs. Even in areas with large potential storage resources, surface and subsurface interactions may arise – and early projects will benefit from being able to choose the best sites for a minimal chance of interactions, and the likelihood of interactions will increase as the number of storage sites increase. The managed storage resource scenario demonstrates that CCS could face competition from other nearby CCS projects, 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.

Underground Storage Permitting for CO_2 in the Netherlands

The implementation of CCS in the Netherlands is being driven not only by climate change concerns, but also by potential economic benefits of being a front-runner in this technology. 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. At present, this country is in the start-up phase of large-scale demonstration projects, aiming to store around 1 MT per year. 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. Figures 3 and 4, below, show the theoretical storage capacity in the Netherlands.

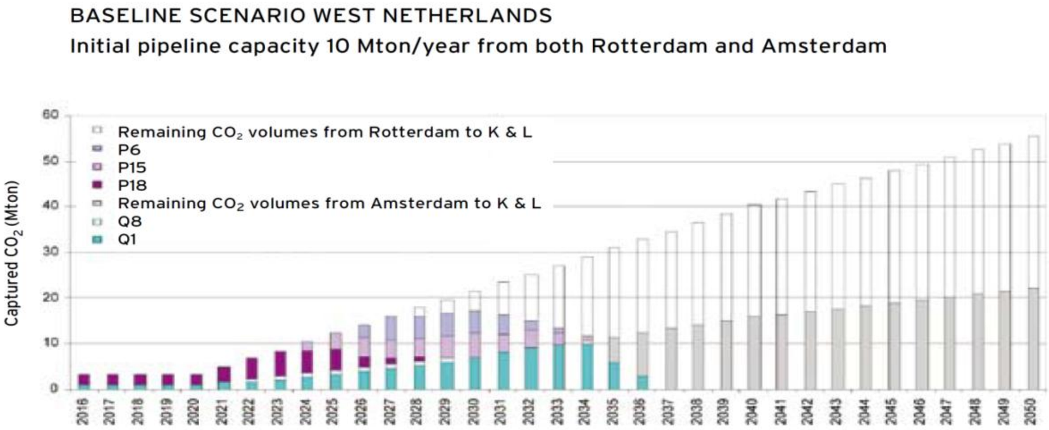

FIGURE 3. Available theoretical offshore CO_2 storage capacity based on expected end of field

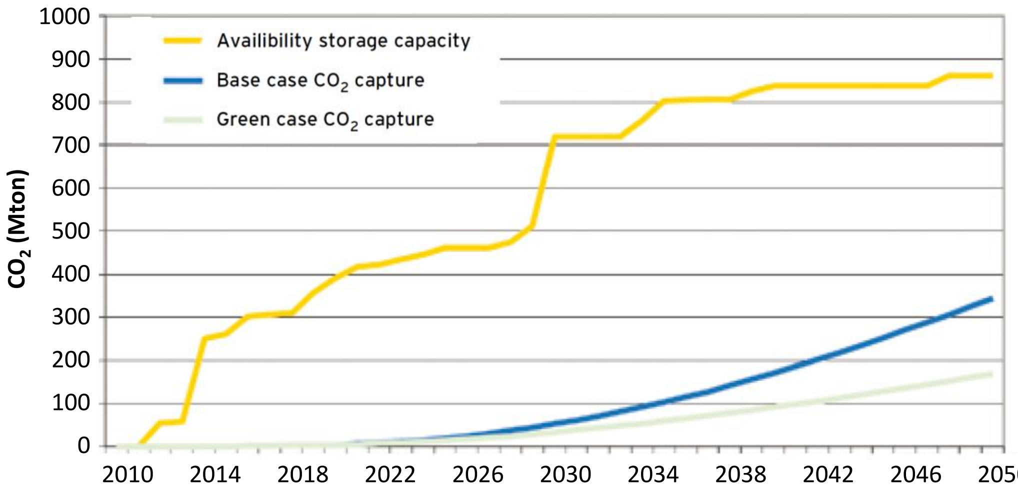

FIGURE 4. Development of cumulative theoretical onshore storage capacity in northern Netherlands versus the base case scenario and the green scenario for CO_2

There is the potential for competition within the surface and subsurface in the Netherlands, identified in the report. 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, most competition between users would arise in an onshore environment, where the storage of CO_2 may prevent gas fields from being used for other storage (e.g. potential UGS sites), but UGS only puts a temporary claim on the rights. Other potential competition may arise from nearby geothermal producer and injector pairs, or salt production activities from layers directly above the storage reservoir. A key potential offshore conflict includes the issue of connectivity and pressure communication with adjacent fields under development or production.

Australia

In Australia, different jurisdictions follow different approaches to the design of CCS regulatory frameworks. The majority of Australia's storage potential is located offshore (with the most potential residing in North West Western Australia), but 'areas assessed to have greatest storage potential are not well-aligned with key electricity demand/load centres'. There is a limited scope for CO_2 storage in depleted oil and gas fields, as the majority remain in production (and will do for many years) and high recovery rates mean there is little potential for CO_2 EOR.

When discussing potential users and conflicts, it must be noted (as in all locations) that this will be highly site-specific. Offshore conflicts in Australia could include issues with other users, such as fisheries, shipping routes, infrastructure etc., but the greatest potential conflict is with the petroleum industry itself, who is concerned about compromising production. Onshore conflicts may arise from similar users as offshore, but one must consider additional uses such as agriculture. The subsurface issues raise the most concern. Groundwater impacts (an important community-wide issue) are a huge potential conflict, as are the usage conflicts with coal bead methane (CBM) operations – there is a strong coincidence between the CBM resource and potential CO_2 storage sites.

The Australian government have adapted a range of onshore and offshore specific policy and regulatory responses to address storage management. Offshore CO_2 storage is primarily governed by provisions of the government's '*Offshore Petroleum & Greenhouse Gas Storage Act 2006*' and its associated regulations. This Act provides for clear security of title for CO_2 operators and also clarifies long term liability issues. The government has also developed detailed guidelines to help CO_2 titleholders and there are clear legislative distinctions between the petroleum industry requirements and those for other users. It is interesting to note that the approach only considers that the projected stored plume must be contained within the injection licence title, but does not consider the potential extent of the pressure front. State governments are active in working to facilitate the onshore storage of CO_2; Victoria, Queensland and South Australia have all enacted legislation. New South Wales and Western Australia have legislation currently under consideration. The regulatory and policy regimes adopted by state governments have addressed the issues of overlapping tenure and competing/conflicting use in detail.

The Role of CO_2 EOR in Texas, USA

The 'management of CO_2 storage and EOR in the same footprint is generally beneficial to both processes', perhaps why a large amount of recent work has looked further into CO_2 EOR. Pressure elevation (see figure 5, overleaf, for a diagram of increased pressure when closely spaced injector and producer wells are used to 'force seep' the residual oil) is a benefit to a connected EOR reservoir (but a risk factor for CO_2 storage), and EOR may assist in the management of pressure in the storage area. Another benefit is that in EOR-rich areas, there will be a wealth of data which could be used in site characterisation and pre-existing infrastructure, which could be used by other projects.

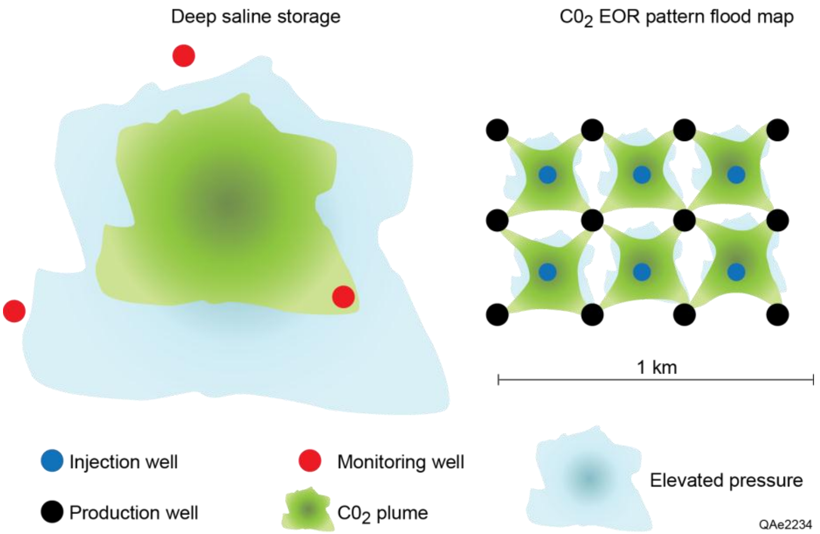

FIGURE 5. Sketch comparing the area of the CO2 plume and significantly elevated pressure at deep saline injection with an EOR flood, showing the role on injection and production well patterns in managing and monitoring the flood

CO_2 EOR has a fairly high success rate, but despite the strong technical background with this technology, it is often not economically viable (i.e. the availability of CO_2, capital to construct a delivery pipeline, available financing etc.) and there is competition with other technologies, although there is uncertainty about the extent to which the sale of CO_2 could offset capture costs (the sale of CO_2 could lower this barrier for CCS projects). Other limits of CO_2 EOR may be the nature of recycle; greenhouse gas emissions generated by compression and pressure lifting; well integrity; oil production; and size of the EOR market.

It was recognised that in most cases, the majority of storage capacity is stacked, overlapping and sometimes dynamically connected. There is great potential for CO_2 EOR in such vertically stacked, multiple systems (stacked depleted oil and gas fields and deep saline aquifers) and in such systems, monitoring programmes could be integrated. However, projects undertaking this must be mindful of different risks/uncertainties needed to be considered for the different processes taking place. Potential issues with the joint use of EOR and CO_2 storage could be that there may be documentation and investment in retention, subsurface trespass issues for EOR; and managing conflicts between the EOR and CO_2 storage technologies and processes.

Managing the Pore Space in Alberta, Canada

Alberta's 2008 Climate Change Strategy recognised CCS as a key mitigation technology to address greenhouse gas emissions and in 2009, the Carbon Capture and Storage Act was created to encourage the development of CCS projects in the province.

There are various activities and legislations to enable CCS and the storage of CO_2. The Alberta government assumed 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 government has to 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 part 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.

Expert Review Comments

The study was sent out for a peer review, and detailed comments were received from five expert reviewers in total. The reviewers were overall, very impressed with this study, and many felt that this report will be a valuable resource for operators, regulators and academics.

A few general comments on grammar were received and acted upon throughout the study, and suggestions to rephrase some sentences at various points throughout the report were taken into account, to minimise the chance of misunderstanding of the text by the reader. Specifics and further detail was added to various explanations of terms to ensure proper explanation of certain technological aspects, and further site-specific information has been added where requested and necessary. Several updated references and an updated figure were added as per the request of one reviewer.

Some suggestions were made to add information on the economics of the management scenarios, but this was considered out of scope for the study and therefore no action was taken. It was suggested that more detail and analysis should be added to the various case studies – unfortunately due to time constraints this wasn't able to be done, but is potentially a path for future research.

The final report reflects the comments of IEAGHG and the expert reviewers. The contractors have provided a detailed tabulated summary of the comments received and their actions taken to address these comments, which can be made available to interested parties.

Conclusions & Recommendations

There are many potential competing users of the surface and subsurface in onshore and offshore environments, and this study has demonstrated the potential for interactions between the possibly multiple pore space users.

There are various different approaches to storage management, which are highly dependent on the jurisdiction involved. All jurisdictions looked at in this report manage their pore space on a first-come, first-served (FCFS) basis, in which operators will be able to identify their preferred CO_2 storage site. The operators' decision on the 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. There will, however, be competition for the pore space in all regions; an issue likely to become more pronounced as CCS develops and matures. 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.

Scale and impacts of subsurface interactions during CO_2 storage

The main interaction that must be evaluated is the area, amount, rate and maximum reservoir pressure the storage formation will experience. The consequences of the increase in pressure with injection will vary site to site, depending on the characteristics of the area, the areas past history and other uses in the area – specifically the types of use and proximity to these uses. Pressure increases do not always result in detrimental effects, but pressure responses in *open* storage sites should be the focus of a detailed assessment in every potential CO_2 storage case.

The scale and impact of a pressure rise will be site-specific. Although many simulations of CO_2 injection into saline aquifers show a pressure response will occur through the connected pore volume, these simulations are often simplified representations of various factors (such as the local geology) and therefore aren't always accurate.

The maximum pressures are experienced around injection wells and this dissipates (with distance) toward the formation boundaries of the connected pore volume. Permeability baffles will limit the amount and extent of the pressure footprint. Simulations suggest that after injection, pressures often dissipate quickly, hence the highest pressures will be observed during injection operations. A number of pressure management strategies are available and may be required to optimise the storage efficiency of a site (whilst maintaining pressures below a defined threshold).

Approaches to strategic management of the storage resource

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.

Pressure increases resulting from CO_2 injection/storage are likely to become an issue when there are multiple CO_2 storage sites within a connected geological formation, injecting at the same time. The combined pressure response will limit the total capacity of the sites. This will decrease the injectivity and increase the need for pressure relief in the formation.

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.

This study by BGS, on behalf of IEAGHG and GCCSI, looked into scenarios for storage development; the development of clusters; knowledge requirements; defining lease areas; and resolving conflicts.

Knowledge, experience and research gaps

Developing strategic plans for efficient storage use

Consequences of a rise in pressure within a CO_2 storage formation will be very site-specific. In the past, such recognised consequences have been specifically focussed on the geomechanical responses in the reservoir. However, the impacts of pressure increase in non-reservoir rocks should be looked into further. This would help to address the issue of the degree of communication between reservoir rocks in stacked systems.

This report demonstrates that 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. These clusters of storage sites could be developed where regions have multiple, connected storage options. However, a current knowledge gap is the amount of pre-competitive characterisation needed to help develop policy for leasing. Along with this, a detailed techno-economic evaluation of storage clusters would also be required. The UK case study detailed in the 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 sufficient 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).

A potential option to mitigate many of the possible interactions is the ‘active reduction of pressure through production of water’. Many studies have looked into this but not evaluated the different approaches to pressure management onshore/offshore, or how pressure could be managed in regions of multiple, sequential CO_2 injection. The optimisation of CO_2 injection and timing (to maximise storage capacity and reduce costs) is required, especially in deep saline aquifers.

Issues of competition (for example in the Netherlands) show that consistent planning is required to ensure an optimal/sustainable use of subsurface space and resources. Australia has competitive legislation on the storage of CO_2 in offshore sites. A key short term objective in all jurisdictions in Australia is to realise early demonstration projects. The government of Alberta has established ownership of the subsurface space/resources and the ability to issue rights to the pore space to potential CCS projects. The government of Alberta’s Regulatory Framework Assessment has identified several gaps relating to the management of pore space and this report provides recommendations to address these gaps.

A key challenge in all regions is to ensure regulators from different jurisdictions work together. A range of issues that would benefit from further regulatory guidance have been identified, including as examples: experience in the application of the SROSAI (‘significant risk of a significant adverse impact) test in Australia, including development of guidance notes to inform on the use of these tests; the development of a guidance on what constitutes ‘good CO_2 storage practice’; and better understanding of the interactions that may occur in the subsurface with CO_2 injection and storage.

EOR as a step towards wider CCS

CO_2 EOR as part of a storage programme can be considered as ‘one response to a GHG-driven need to lower barriers to capture’. A review of the benefits/ difficulties experienced by current CO_2 EOR projects with other operations can be used to provide information on how future CO_2 storage projects may interact with other uses. The potential for using CO_2 EOR as a method of geological storage is high, and has been demonstrated by early deployments in the USA.

EOR sites have favourable attributes toward the long-term storage of CO_2, including known top seals, well-quantified injectivity and storage potential. Such favourable aspects were identified within the report, including the high quality of storage, good site characterisation and dense monitoring potential, a positive economic signal (from additional oil production), well-known regulatory and liability aspects, and well-known public acceptance (in many areas). Limits to the potential use of EOR as storage include that the whole system response is perhaps weak in terms of emissions and the energy consumption required by EOR operations reduces storage efficiency. In addition to this, there are numerous well penetrations in EOR areas which could potentially lead to lowered storage effectiveness (but this is an area identified as needing further research). The impact of different types of well failure mechanisms were looked at and such types include acute, high volume, short duration events; the migration of CO_2 into unintended areas, which could occur quickly or over a long period; and low-rate leakage through flawed well construction.

Uncertainties arise with EOR for CO_2 storage for various reasons, one major issue being economics – there are unknown cost curves (of CO_2 and future oil) and uncertainty with capital markets. Other uncertainties with CO_2 EOR include the regulatory environments and public acceptance. Uncertainty is elevated for potentially 'unconventional EOR', so in offshore reservoirs, residual oil zones, fractured reservoirs and gravity-stable floods.

Adjustments are required when using CO_2 for EOR (as opposed to water or other substances); the 'hydrogeologically-connected reservoir must be unitized and operated together'. Any interference between EOR and injection operations could be problematic in that increased pressure is beneficial for the enhanced recovery of oil, but injection operations benefit from decreased pressure. CO_2 EOR for the storage of CO_2 is an interesting and attainable strategy, but would need much legal and regulatory management.

British Geological Survey
NATURAL ENVIRONMENT RESEARCH COUNCIL

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ENERGY and Marine Geoscience Directorate PROGRAMME

EXTERNAL REPORT CR/13/110

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Foreword

This report *"Comparing different approaches to managing storage resources in mature CCS futures"* summarises the potential for surface and subsurface interactions which might occur during CO_2 storage operations. It reviews the regulatory approaches in jurisdictions active in carbon capture and storage (CCS) to managing such interactions and the consequent potential adverse impacts. We discuss possible options for managing these interactions to provide timely storage capacity, illustrated with a regional case study from the Southern North Sea. The report has been written by contributors from US, Australia, Netherlands and Canada, under the lead of the British Geological Survey, United Kingdom.

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Summary

Under current arrangements and regulations, licensing of CO_2 storage sites is likely to follow an approach in which potential sites are selected by their operators on a "most economically advantageous" basis, to match the needs of individual, or clusters of, carbon capture and storage (CCS) projects. Broadly speaking, providing these sites do not adversely impact on other existing legitimate users of the subsurface, ground surface, seabed or marine area, and they are deemed by the relevant Regulator to be suitable for CO_2 storage, the expectation is that they will be licensed. One benefit of this approach is that the operator can decide where to develop CO_2 storage and, as a result, the State will likely have to share less risk than if it took a more active role in managing options for storage development.

Sedimentary basins have multiple potential uses and hence there is potential for CO_2 storage projects to conflict with other uses of the subsurface and the overlying ground surface, seabed or sea. Moreover, increased pore fluid pressure in any reservoir formation resulting from CO_2 injection may reduce storage capacity and increase costs in adjacent sites, potentially reducing efficient use of the storage resource.

In all CO_2 injection sites, the magnitude and the physical and temporal variation of the pressure footprint generated by CO_2 injection is one of the most important interactions that must be evaluated. The consequences of this pressure rise will vary, depending on the site's specific characteristics, past history, and types of and proximity to, other users. In some circumstances, pressure increases are not expected to result in significant detrimental impacts, but pressure responses in hydraulically-connected storage sites would be expected to be the focus of detailed assessment.

The maximum pressures will be experienced around the injection point and, during the injection period, will reduce with distance to the boundaries of the connected pore volume. At the end of injection, simulations suggest that pressure anomalies often dissipate relatively quickly as pressure equalises throughout the connected pore space. Hence, the highest pressures will be felt during injection operations. Pressure management may be required to optimise the storage efficiency in some sites. This may significantly reduce the scale of pressure footprints in the reservoir and hence the potential for interactions with other users.

Therefore it is considered that a more strategic approach to the exploitation of resources in sedimentary basins *might* be required to ensure that basins realise their full resource potential. This raises important questions:

> How can CO_2 storage capacity be fully utilised in the presence of potentially competing uses of the subsurface and overlying ground surface, seabed or sea?
>
> 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?

In reality, these questions reflect a complex problem because the metrics by which the "optimum" development of a basin's resources would be judged would likely depend on a perceived optimisation of several interacting criteria, considered within the framework of government energy (and other) policies. It may also be necessary to consider the far less tangible but potentially significant future uses of the basin as well.

This study considers current approaches to managing both offshore and onshore storage resources in the UK, the Netherlands, Texas, Alberta and Australia. The jurisdictions reviewed here have adopted different approaches to storage management, depending upon their particular circumstances, which include the availability or otherwise of the storage resource, the number and type of competing users of the surface and subsurface, and the influence of other existing relevant legislation such as the different approaches to ownership of the pore space. However, all the jurisdictions reviewed in this study currently manage their pore space on a first-come, first-served basis, in which, subject to some region-specific exclusions designed to protect the interests of pre-existing users and prioritised natural resources, operators will be able to identify their preferred storage site based on their geological, technical and financial criteria. Their chosen sites are likely to be the best sites geologically which are available at the time of selection.

A case study of the Southern North Sea highlights the relevant interactions in a scenario looking outward as far as 2050, which assumes CO_2 storage development will be needed to contribute to reductions in UK emissions. The case study compares first-come, first-served and more strategically managed approaches to the basin resource development to determine the benefits and consequences of these broad strategies for both the pore-space owner and storage operator. It is concluded that management of storage on a first-come, first-served basis is likely to be sustainable in the short to medium term, especially in an area with abundant storage potential, though relative costs have not been considered in this study, it is recognised that this approach may not necessarily lead to development at least cost. Nevertheless, it is clear that in the UK at least, the current economics of CCS are driving potential project developers to consider project clustering as a means of cost sharing. This in itself is likely to lead to a more economically efficient development of basin resources. However, in many basins there could be competition for pore space, ground or seabed space and use of areas of the sea, which would likely become more pronounced as CCS and other industries develop. Therefore a more strategic approach to storage resource management could be required in the future to minimise these interactions and to maximise the efficient use of the storage resource.

The specific issues found in the Netherlands, Australia and Alberta regarding managing potential spatial and subsurface resource conflicts are also reviewed. A description of how current oil production in Texas could be used to develop future CO_2 storage (by developing fields using CO_2 Enhanced Oil Recovery into CO_2 storage sites) and the issues this might raise in accommodating both, in a mature hydrocarbon province, is also provided.

Possible conceptual routes to storage development have been considered to examine the issues described above. Storage development will be initiated from early catalyst projects that are likely to select the most geologically suitable sites. Clusters of storage sites could be developed where regions have multiple storage options which are connected. Management and infrastructure could be integrated in such clusters to provide more flexible operation and cost savings through economies of scale. Also, the experience obtained in the catalyst project could benefit follow-on projects in the same cluster. Such clustered development might occur without strong intervention except that transport (pipeline) over-sizing might be necessary. Follow-on storage permits might be encouraged from regions centred on these first projects. As expertise and experience in storage operations increase, additional sites will be exploited, which might include smaller sites near early catalyst projects, rather than commissioning larger storage sites in virgin areas at greater distances. That said, we have shown here that under one scenario for the Southern North Sea, targeting fewer but larger storage sites could meet future storage requirements as an alternative to developments of clusters. These larger sites are more geographically dispersed and would not require development of multiple sites in close proximity to provide the same amounts of storage capacity. This could reduce the potential for development of groups of more closely integrated and connected stores. Development of large sites could provide sufficient storage capacity for multiple capture plants. In the USA, private pore space ownership may inhibit the development of clusters if a lack of strategic policy occurs, as current agreements are private commercial contracts. However the mature CO_2-based enhanced oil recovery industry has already provided a considerable knowledge and experience base from which CO_2 storage might develop, for example by providing shared trunk lines and distribution of CO_2 to multiple users, which is analogous to a shared storage infrastructure.

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1 Introduction

1.1 RATIONALE FOR THE STUDY

Under current arrangements and regulations, licensing of CO_2 storage sites is likely to follow a first-come, first-served approach. In such an approach, applications for licences for individual projects are submitted to regulators and the basis of the regulator's assessment will predominantly be to consider whether they are fit for purpose as a storage site - subject to certain region-specific exclusions designed to protect the interests of pre-existing users of the subsurface, ground surface, seabed or sea, and to protect prioritised resources such as hydrocarbons, minerals and groundwaters. These storage sites will have been selected by their operators on a "most economically advantageous" basis, to match the needs of individual, or clusters of, carbon capture and storage (CCS) projects. However, as highlighted in the recent IEAGHG report, "*Interaction of CO_2 storage with subsurface resources*" (IEAGHG 2013), sedimentary basins have multiple potential uses and hence there is potential for CO_2 storage projects to conflict with other uses of the subsurface and the overlying ground surface or seabed. Moreover, increased pore fluid pressure in any reservoir formation resulting from CO_2 injection may reduce storage capacity and increase costs in adjacent sites, potentially reducing efficient use of the storage resource (Figure 1).

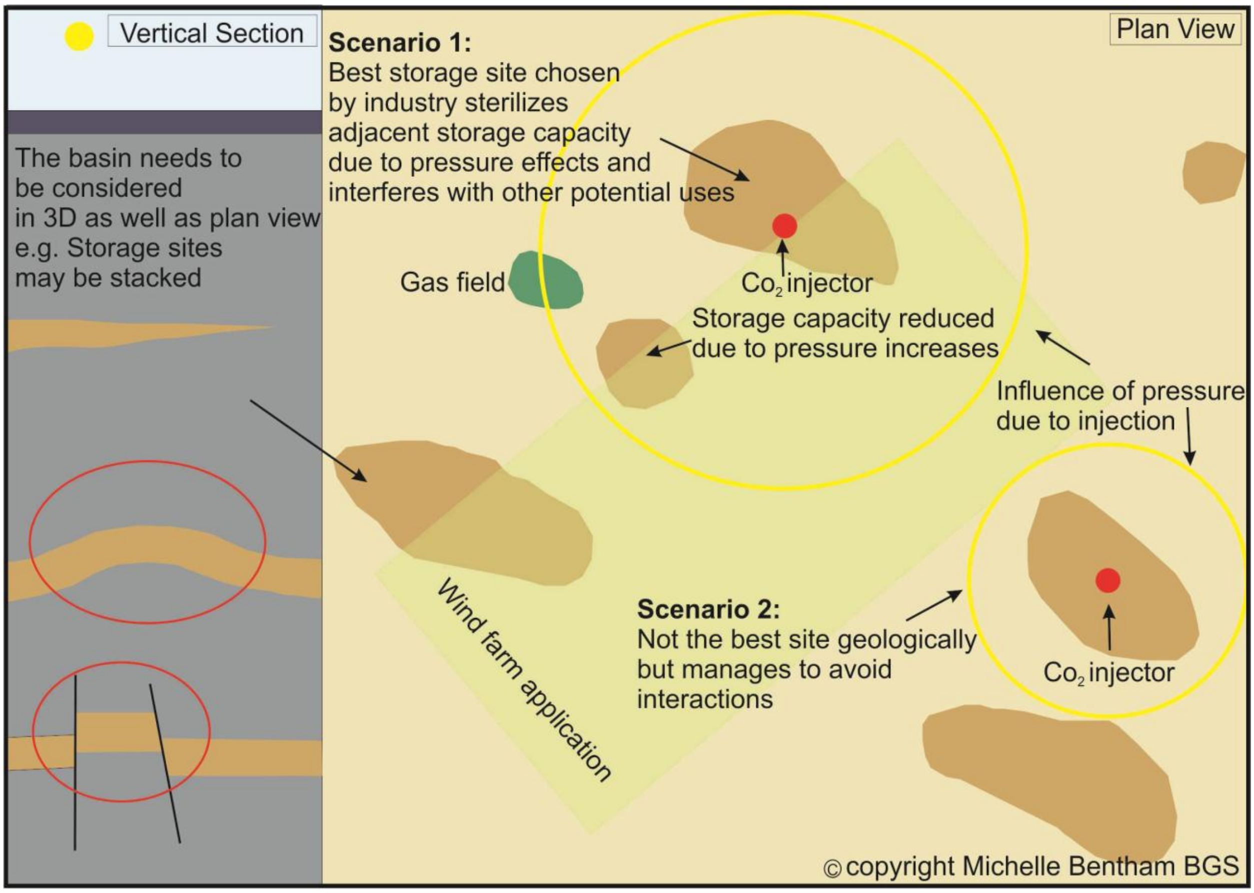

Figure 1: Conceptual view of spatial and subsurface interactions which might limit storage site selection, using a hypothetical example of gas fields and two storage site scenarios in the UK Southern North Sea (inset map).

Therefore it is considered that a more strategic approach to the exploitation of resources in sedimentary basins might be required to ensure that basins realise their full resource potential (see for example Van der Meer, 1993; Gunter et al., 1996; Nicot and Duncan, 2008; Birkholzer and Zhou, 2009; Schaefer et al., 2011). This raises important questions:

> 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?

In reality, these questions are facets of the same complex problem because the metrics by which the "optimum" development would be judged would likely depend on a perceived optimisation of several interacting criteria. Factors that would influence this optimisation might include cost which could be balanced against maximising storage, minimising risk, providing access to a range of existing and future uses of the basin, ground surface or seabed and the value of any resource at the time. This would be considered within the framework of government energy (and other) policies. It may also be necessary to consider the, far less tangible, potential future uses of the basin as well.

1.2 PROJECT SCOPE AND OBJECTIVES

This study develops scenarios for CO_2 storage development in the Southern North Sea Basin to compare first-come, first-served and managed approaches to CO_2 storage site licensing and describes the benefits and consequences of these broad strategies for both the pore-space owner and storage operator. It also considers current approaches to managing both offshore and onshore storage resources in a range of jurisdictions. A workshop was convened to evaluate approaches to the management of the pore space in different jurisdictions. Experts from twelve organisations, representing ten jurisdictions attended. The following generic issues were discussed and illustrated by specific examples from different jurisdictions (see Appendix 1 for more details):

- The availability of storage capacity,
- Other uses of, and sources of potential competition for, pore space,
- The priorities placed on different uses in different jurisdictions,
- Possible routes to wider storage deployment,
- Technical and related regulatory challenges for storage in areas of multiple stacked storage opportunities,
- Risks that might arise from interactions between nearby sites,
- Examples of pore space conflict resolution,
- Strategic initiatives for storage deployment.

1.3 REPORT STRUCTURE

Chapter 1 (this introduction) describes the scope of the study and introduces the concepts which have been addressed.

Chapter 2 reviews the principal types of spatial and potential subsurface interactions that might occur as a result of CO_2 storage.

Chapter 3 describes a specific case study of the Southern North Sea, in which the interactions identified in Chapter 2 are highlighted through development of a scenario which assumes CO_2 storage development is needed to meet capture rates necessary to achieve UK emissions reductions to 2050.

Chapters 4, 5 and 6 summarise the specific issues found in the Netherlands, Australia and Alberta, Canada, regarding managing potential spatial and subsurface resource conflicts.

Chapter 7 provides a description of how current oil production in Texas can be used to develop future CO_2 storage and the issues this might raise in accommodating both in a mature hydrocarbon province.

Chapter 8 summarises the findings of preceding chapters and concludes with proposals for managing these interactions to ensure CO_2 storage can meet expected future injection requirements, whilst still accommodating other users.

A full list of references cited is included at the end of the report.

Appendix 1 comprises the minutes from the launch workshop which defined the issues and approaches taken in a range of jurisdictions.

Appendix 2 tabulates results from the assessment of potential storage sites in the Southern North Sea.

1.4 SUMMARY OF INTERNATIONAL WORKSHOP

The workshop identified the most relevant issues for longer term storage resource management that might be required when follow-on projects develop from initial demonstration projects. In most regions represented in the workshop, the subsurface and surface have multiple users (Table 1);

Table 1: Users of the surface and subsurface

User	Ground surface	Seabed	Sea	Subsurface
Hydrocarbon production		X		X
Natural gas storage		X		X
CCS		X		X
Mining		X		X
Water production		X		X
Shale gas production		X		X
Geothermal energy		X		X
Hydrogen storage		X		X
Protected areas	X	X		
Tidal energy		X	X	
Wind energy		X	X	
Farming	X		X	
Existing infrastructure	X	X		X
Sand and gravel extraction		X		X
Urban areas	X			X

The workshop participants came to the following conclusions. Early CO_2 storage projects are likely to influence the location of follow-on projects, and act as catalysts in a region. For example, in the UK the early storage sites are likely to be the winners of the DECC commercialisation competition. Sharing of infrastructure within clusters is likely to bring benefits such as cost sharing. Acceptance of the use of oversized infrastructure has not yet been adopted globally. In the USA, private ownership of the pore space could be a barrier to facilitating the sharing of information that would allow natural clusters to form.

It was recognised that in most regions storage capacity is stacked, overlapping and sometimes dynamically connected. If the geological formations used for storage are not dynamically connected, stacked storage can limit pressure rises from multiple injection sites (Figure 2). If the stacked CO_2 storage sites are managed correctly, i.e. in an integrated joint development, then co-monitoring techniques are used, it may reduce operation costs. Use of stacked storage could also reduce the volume to be characterised during the site assessment phase as more capacity could be exploited within a smaller area. In spatially restricted areas, stacked storage could reduce the storage complex size where this stacked storage is managed as an integrated storage unit. Overlapping storage complexes that are operated independently would be more difficult to manage and regulate. However, stacked storage has some potential disadvantages including; potential tensions with oil production from within the stack, operational interference between storage projects, monitoring interference and in the case of leakage there may be problems identifying which storage site is responsible for the leaking CO_2. Multiple operators of stacked storage systems would therefore likely have to agree a way of sharing liabilities.

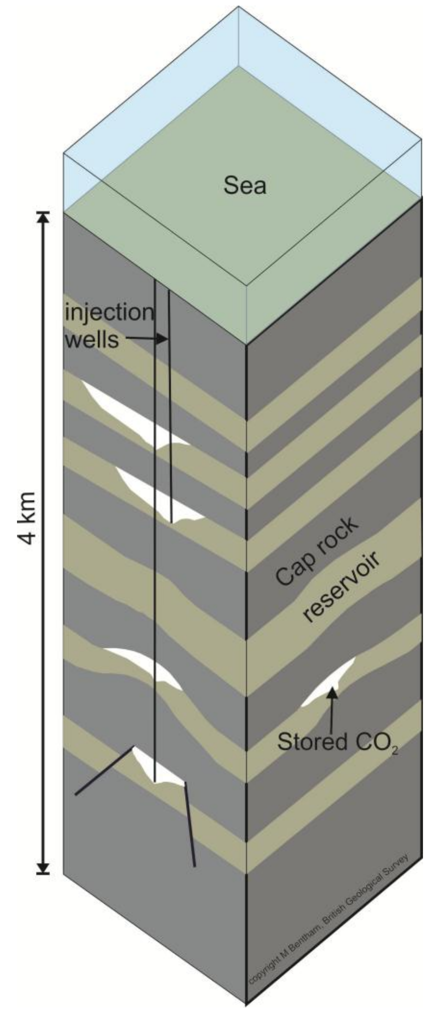

Figure 2: Conceptual cross-reference of stacked storage

Where storage sites are connected, the impacts of CO_2 injection potentially include interaction of pressure footprints induced by injection and mobilisation of brine beyond the injected plume. If not monitored and managed, these processes could affect other subsurface operations. Depending on the boundary conditions, injection of CO_2 will cause pressures to rise in the storage site and in the surrounding geological formation. The maximum pressure rise is restricted to the injection phase, after which the pressure is likely to equilibrate over the region. Pressure management wells or optimised well spacing could control excessive pressure rises, thus minimising the impact of pressure affecting other subsurface users. In regions such as the UK where storage is offshore, the produced water from such pressure management wells could be treated and discharged into the sea. However, management of large amounts of produced saline water could prove more challenging particularly in regions where storage is onshore.

Interactions beyond the storage complex, such as pressure rises, are managed differently in different jurisdictions. In Australia storage conflict between CO_2 storage and hydrocarbon production is avoided by prohibiting CO_2 storage in regions where there is active hydrocarbon production. The storage licence and storage plan in the Netherlands includes sustainable use of the subsurface by 'best possible means', following the example of the oil industry. In the USA, the surface owner usually owns the pore space, and the threat of litigation from interactions may result in self-regulation in the management of the subsurface. Here, most agreements reached by this process are private and as a result understanding how the resolution is achieved is not in the public domain. In Alberta, any impact from CO_2 injection should not affect the incumbent users of the surface or subsurface and the storage lease includes the area of pressure rise to avoid pressure trespass. In the UK it is clear that CO_2 storage will be prohibited if it adversely affects hydrocarbon production. Interactions which cross national or international boundaries may also need to be considered and managed, though this has not been explicitly addressed in detail in storage regulations.

Site modelling and prediction, which helps inform and develop a good monitoring plan, will be essential to keep track of potential interactions, and will need to be combined with plans to manage adverse interactions. The plan would need clear objectives agreed with the regulator which have to be meaningful and quantifiable. This would require consensus between the regulator and the operator as well as assigning a party responsible for mediating between parties involved in identified potential interactions.

Jurisdictions could improve storage planning and incentivise storage by providing proven bankable storage options. The workshop discussed the potential of Enhanced Oil Recovery (EOR) to act as the pathway to conventional storage, which could be included by jurisdictions as part of a CCS adoption plan. If strategic resource management is adopted, it needs to ensure that the pore space is used in the best way to maximise storage capacity, minimise conflict and protect the rights of other users of the subsurface and protect pre-existing resources, whilst allowing each jurisdiction to meet its climate change targets. Considering future storage development now, means that the industry will be ready to react when CCS market improves.

2 Sub-surface pressure increases and brine displacement as a result of CO_2 injection.

The subsurface interactions that might occur when a storage project operates within a geological formation have already been reviewed in detail (IEAGHG 2013). Resources commonly found in the sedimentary basins in which CO_2 storage is likely to occur are numerous and are summarised in Table 2.

Table 2: Summary of mineral resources and other uses of the pore space that might interact with CO_2 storage operations.

Mineral resources	Other uses for the pore space
Conventional oil and gas, bitumen and oil sands	Groundwaters
Coal, including underground coal gasification and coal bed methane production	Geothermal energy
Shale gas	Gas storage
Sedimentary mineral deposits	Liquid waste disposal
	Acid gas disposal
	Produced water disposal from oil and gas production
	Energy storage

Many of the potential uses of pore space listed in Table 2 are unlikely to be involved in detrimental interactions with CO_2 storage projects, for the following reasons (IEAGHG, 2013):

- The depths at which certain operations are most likely to occur would preclude detrimental interactions. This may apply to coal bed methane, oil shale, many shale gas operations, and potable groundwater abstraction.
- Where direct interactions occur, case studies indicate that, in many jurisdictions, protection of known hydrocarbon and mineral resources are likely to take priority over CO_2 storage operations.

The most significant potential interactions are likely to be the pressure effects of CO_2 injection and associated brine displacement. The reservoir pressure increase induced by CO_2 injection is therefore one of the prime risks to other resources, including other storage sites, which are in pressure communication (early reviews of these phenomena and their consequences include: van der Meer, 1992; Bergman and Winter, 1995; Gunter et al., 1996). As such it is the principal risk considered in this study.

A number of generic risks may also pertain to a storage site and these may also affect other uses of the subsurface. These have been summarised in IEAGHG (2013) and include ground movements, and the potential for CO_2 'contamination' of another resource by unintended migration either directly by the presence of increased CO_2 concentrations or the indirect mobilisation of minerals and other substances.

2.1 SCALES OF PRESSURE BUILD-UP IN THE SUBSURFACE

Storage sites are likely to fall into three categories these are:

- Open or unconfined, where the boundaries of the storage sites are open to hydrodynamic flow.
- Semi open or semi-unconfined, where the boundaries of the storage site are a mixture of closed and open to hydrodynamic flow.
- Closed or confined, where the boundaries of the site are closed to hydrodynamic flow.

Increased pressures are likely to be experienced in a number of CO_2 storage situations where injection of CO_2 occurs into a closed structure trap in a saline aquifer, into an 'open' dipping saline aquifer, or into a depleted (where hydrocarbons have been fully commercially exploited) hydrocarbon field that has undergone pressure maintenance during production (through, for example, re-injection of produced water) or has undergone aquifer recharge, whereby the formation water flows into areas of low pressure caused by the removal of the hydrocarbon. In some cases, where reservoir seals are locally absent, thin, or breached by permeable fault zones, pressure responses could be observed in overlying formations.

The concept of a region that is affected by CO_2 storage, that includes both the expected extent of the CO_2 plume and associated CO_2-saturated formation water was introduced by van der Meer and Yavuz, 2008 and van der Meer and Egberts, 2008. In storage sites that have closed boundaries, the storage capacity will be limited by a pressure threshold which is deemed likely, through detailed site geomechanical assessments, to prevent cap rock damage.

The region surrounding a storage site is less likely to experience increased pressures where injection occurs in depleted hydrocarbon fields in which pressures have not been maintained close to original reservoir pressures, and which are at low pressures relative to hydrostatic pressures, or where injection occurs in an isolated structure which is not in pressure communication with the rest of the formation.

The size and rate of the pressure response is dependent on a number of factors (e.g. Van der Meer, 1993; Cavanagh et al., 2010; Cavanagh and Wildgust, 2011; Zhou and Birkholzer, 2011). The geometry of the reservoir, the presence of pressure baffles which may limit pressure communication, the reservoir permeability and geometry will all influence the scale of the pressure response. The nature of the formation boundaries is a fundamental control on the expected pressure response and subsequent dissipation. Where boundaries restrict pressure dissipation, pressure responses in the formation will be expected to be higher (e.g. Chadwick et al., 2009; Morris et al., 2011 and Noy et al., 2012). Lateral or vertical changes in the geology, which could include stratigraphic boundaries with adjacent lower permeability formations or structural boundaries such as faults, will allow pressure to dissipate and the rate of this dissipation will be controlled by the degree of hydraulic confinement of the storage site, i.e. permeability of, and the distance to, these boundaries. Many systems are likely, at least at the regional scale, to be considered as having semi-closed boundaries (Oruganti and Bryant, 2009; Cavanagh and Wildgust, 2011). Oruganti and Bryant (2009) summarise the differences in pressure response between closed and open aquifers:

> "*Pressure build-up in aquifers bounded by sealing faults is larger than in unbounded aquifers, because the no-flow boundary causes the flow-field to become linear (parallel to the sealing fault) rather than radial (relative to injection well). Consequently the fluid pressure decreases linearly with distance from the injection well, rather than logarithmically. Thus any contour of pressure build-up (fluid pressure during injection less*

initial pressure in aquifer) extends farther into the aquifer. The presence of sealing fault(s) also restricts the movement of brine displaced by the injection of CO_2."

Highest reservoir pressures are likely to be experienced around the injection well (Mathias et al., 2011) where pressure build-up will be controlled by rate of injection, the permeability and permeability anisotropy (differences in vertical and lateral permeabilities), porosity,thickness of storage formation, and the perforated interval thickness (e.g. Mukhopadhyay et al., 2012) as well as the reservoir boundaries discussed above.

Simulating industrial-scale injection in the Mt Simon Sandstone in the Illinois Basin, Zhou and Birkholzer (2011) estimate a pressure response of up to 3.6 MPa over an area of approximately 160 km in diameter, and a pressure increase of 0.1 MPa over an area up to 380 km in diameter, for a total of 5 Gt CO_2 injected over 50 years. The size and maximum pressure response depends in this case on the assumed permeability of the overlying seal, with higher permeabilities allowing more pressure dissipation and consequently a smaller extent of measureable pressure perturbation. These pressure footprints contrast with plume footprints of 12-14 km extent. The average fractional pressure build-up (ratio of pressure build-up to pre-injection pressure) is 0.18 which is slightly higher than the 0.13 level commonly used for natural gas storage in Illinois and Indiana and is also below the regulated value of 0.65 which is the threshold above which geomechanical damage may start to occur). Contrasting the Mt Simon case with simulated injection of 5 Mt CO_2 per year into the Vedder Sand of the San Joaquin Basin, a partially closed system, indicates that pressure build-up is confined by the low-permeability boundaries. The permeability of these boundaries, including faults, controls the pressure build-up in the Vedder Sand. Where the storage formation is not sealed towards the northern boundary, pressure dissipates through connection to overlying aquifers, indicating the importance of water outflow in allowing pressure attenuation.

A related study by Birkholzer and Zhou (2009) simulated injection into the Mt Simon Sandstone in the Illinois Basin to estimate pressure responses at a regional scale from multiple injections from 20 sites. Each of these sites injected 5 Mt per year for 50 years. CO_2 plume extent for each site was of the order of 6-8 km with each site being separated by approximately 30 km. Pressure interferences were inferred by pressure increases of more than 1 MPa over the central injection area after 10 years. At the end of injection this area, of approximately 100 km diameter, experienced pressure increases of typically 3-4 MPa with peak values of more than 4 MPa, which is less than the regulated value, above which fracturing of the cap rock might be expected (Birkholzer and Zhou, 2009). Lower pressure increases of up to 1 MPa are experienced over most of the basin, a distance of approximately 500 km. Other studies by Person et al. (2010) using 726 injection wells injecting 80 Mt per year from 42 power plants across the Illinois Basin resulted in maximum pressures of between 5.6 and 18 MPa across the central and southern parts of the basin, and pressure disturbances (>0.03 MPa) being 'observed' in the simulation 10-25 km from the injection wells (Person et al., 2010 and related studies e.g. Leetaru et al., 2009).

Zhao et al., (2012) simulated pressure responses in the Yaojia Formation of the Sanzhao Depression during injection of 750 Mt CO_2 over 50 years via five wells spaced approximately 10-15 km apart. The maximum plume extent at the top of the Yaojia Formation ranges from 1.4 km at 19 years to 4 km at 50 years, and to 5.8 km at 100 years for the model parameters used. Increasing dissolution results in decreasing CO_2 gas saturation over 500 years of the simulation. Pressure increases during injection, with pressure rising around each well due to pressure interference from neighbouring wells. At the end of injection at 50 years the maximum pressure is between 7.8 MPa and 10.5 MPa, depending on the permeabilities used (lower permeabilities lead to higher pressures), in the region around the central injection point. Simple estimates of the maximum formation pressures suggest values which are not likely to lead to fault reactivation or fracture development in the cap rock, though detailed geomechanical analysis would be needed to determine this accurately. The pressure gradient decreases laterally away from the injection wells, reaching background values at distances of very approximately 25 km from the nearest injection well. Once injection stops, pressures decrease rapidly.

Similar results have been obtained (Noy et al., 2012) for the Bunter Sandstone Formation of the Southern North Sea which is a promising target formation for CO_2 storage. Leak-off test data allowed Noy et al., (2012) to define a pressure gradient at 75% of lithostatic pressures, below which it has been assumed that geomechanical stability would be maintained. This limit formed a pressure constraint to assess the storage capacity of the Bunter to the east of Dowsing Fault Zone. It was concluded that 15-20 Mt CO_2 per year could be stored over a 50 year period, whilst maintaining pressures below 75% of the lithostatic pressure. Pressure increases of less than 7 MPa were simulated, in the area immediately around the injection zone, though pressure responses were predicted at significant distances from the injection points (Figure 3).

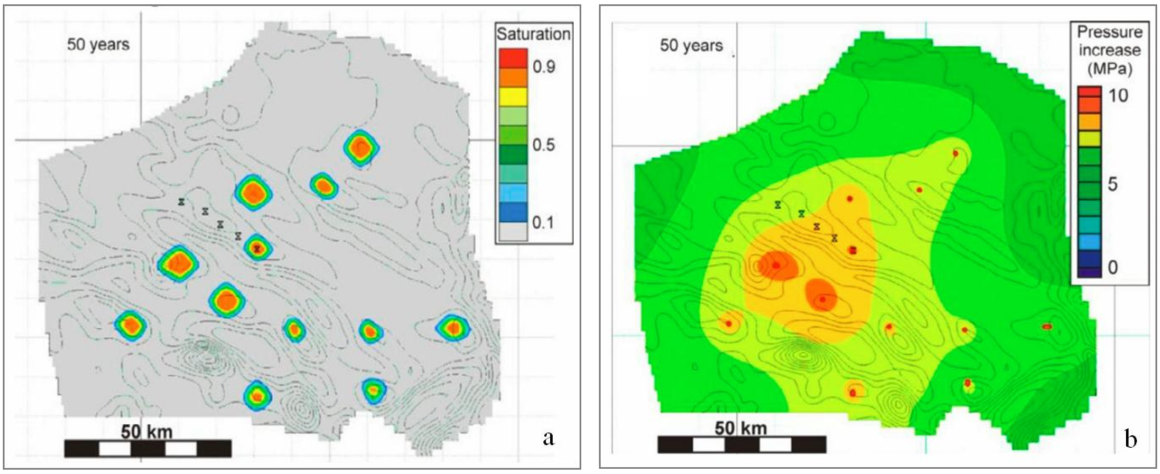

Figure 3: **Relationship between CO_2 plume extent and extent of pressure rise after 50 years of injectiing 33 Mt of CO_2 into multiple clsoures within a sandstone reservoir unit in a closed system (simulated in TOUGH2). The reservoir properties are assumed to be homogenus. (a) Shows the CO_2 saturation footprint, (b) shows the pressure footprint (Adapted from Noy et al., 2012).**

Initial transient pressure increases could be avoided by increasing injection rates slowly. Up to 360 Mt of pore water were estimated to be displaced at the seabed. Pressures decrease rapidly at the end of injection as the pressures equilibrate and brines continue to be displaced at the seabed.

In summary, pressure increases from injection into some storage types may be observed across the connected pore volume into which the CO_2 is being injected, up to significant distances beyond the area directly affected by the CO_2 plume itself. The absolute increases in pressure will be specific to each site and will be controlled by the permeability and thickness of the reservoir, the permeability of overlying and underlying seals, and the nature of confining or open lateral boundaries. Largest pressures will be experienced close to the injection wells and will decrease with increasing distance away from these points.

2.2 CONSEQUENCES OF PRESSURE BUILD-UP IN THE SUBSURFACE

Possible consequences of pressure build-up are listed below (see for example, Zhou and Birkholzer, 2011). However, it is worth emphasising that these generic risks may not pertain at any specific site; each site would require a detailed geomechanical assessment to determine its geomechanical risks.

- Limits to dynamic storage capacity in active or planned neighbouring storage sites which would be limited by acceptable pressure limits to prevent geomechanical damage to cap rocks, faults or reservoir (Schaefer et al., 2011; van der Meer and Yavuz, 2008; Zhou et al., 2008; Thibeau and Mucha, 2011; Mathias et al., 2009; Cappa and Rutqvist, 2011; Pooladi-Darvish et al., 2011; Jin et al., 2012). Pressure build-up can also reduce injection rates (Oruganti and Bryant, 2009) and will directly influence the number of wells required for injection at a desired rate. However, associated reductions in effective stresses within the reservoir may, in certain circumstances, lead to the formation of deformation bands which can lead to localised increases in permeability if plastic strain occurs (Alonso et al., 2012).
- Over-pressurisation of reservoir formation leading to fault reactivation (e.g. Streit and Hillis, 2004; Rutqvist et al., 2008; Rutqvist et al., 2010; Cappa and Rutqvist, 2011; Rinaldi and Rutqvist, 2013; Verdon et al., 2013) which might be limited to the lower parts of the cap rock where it is thick (Rutqvist and Tsang, 2002).
- Brine and/or CO_2 displacement in adjacent or overlying formations or at outcrop to the seabed or onshore (e.g. Noy et al., 2012; Walter et al., 2012; Cavanagh and Wildgust, 2011; Cihan et al., 2013). Brine displacement is not considered to be a significant issue in open systems (e.g. Birkholzer et al., 2009) and brine leakage through thick low-permeability seals is considered unlikely (Zhou and Birkholzer, 2011) in open systems but will be more important in semi- to fully-closed storage sites. However, brine displacement can occur where high permeability conduits (faults or poorly completed wells) allow the low-permeability cap rock to be bypassed (Oldenburg and Rinaldi, 2011). Where such short cuts exist, the amount of brine displacement depends on permeabilities, relative salinities and pressure gradients between over-pressured reservoir and overlying aquifer.
- Changes to the pressure regime in neighbouring hydrocarbon fields which could lead to increased water production through changes to the local oil- or gas-water contact
- Changes in pressure regime may cause changes in long-term plume migration in adjacent storage projects, which may in turn lead to a need to reassess long-term containment and lease areas.
- Ground movements (e.g. Rinaldi and Rutqvist, 2013) and induced seismicity.

2.2.1 Depleted hydrocarbon fields

A compilation of data for pore pressure/stress coupling indicates that, during depletion of pore pressures for hydrocarbon production, the minimum horizontal stress typically decreases at 50–80% of the rate of pore pressure depletion (Hillis, 2000). Stress changes induced by pressure depletion in hydrocarbon reservoirs and fields can result from both poro-elastic compaction of the rock and from pore collapse, which in turn may cause risks of subsidence, fault reactivation, wellbore casing failure and formation of new fractures (e.g. Hawkes et al., 2005). A study of potential geomechanical risks associated with CO_2 storage into a depleted North Sea hydrocarbon reservoir indicates that under expected conditions the fracturing pressure of cap rock is significantly higher than the planned CO_2 injection and storage pressures. However more conservative simulations, using more pessimistic values for key parameters and assuming the total horizontal stresses staying the same over the CO_2 injection, faulting could be reactivated on a fault with the least favourable geometry once the reservoir pressure reaches approximately 7.7 MPa. In addition, the initial CO_2 injection could lead to a high risk that a fault with a cohesion of less than 5.1 MPa could be activated due to the significant effect of reduced temperature on the field stresses around the injection site (Fang and Khaksar, 2013). Hydrocarbon production can produce subsidence as described above and can be used to constrain predictions of future geomechanical behaviour when storing CO_2 in depleted gas fields. Such a study of gas production followed by CO_2 storage in the Po river plain of northern Italy, suggests that activation of sealing faults is more likely in the production phase rather than subsequent injection (Ferronato et al., 2010). Furthermore, damage to well casings might occur due to plastic deformation in the vicinity of the production/injection wells. Injection was predicted to cause minor land surface uplift.

2.2.2 Brine displacement

Pressure rise in a CO_2 storage reservoir may result in brine displacement along the pressure gradient from injection sites in deep saline formations e.g. to outcrop. Such brine displacement may theoretically cause contamination of aquifers that are used as a drinking water supply (Nicot et al., 2009; Yamamoto et al., 2009; Lemieux, 2011 and references therein; Bricker et al., 2012; Walter et al., 2012) but has also been proposed as a potential resource for recovered heat, water and minerals (Breunig et al., 2013).

Nicot, 2008 investigated the conditions under which shallow unconfined groundwater would be impacted by up-dip displacement of brines in the Texas Gulf Coast Basin in the USA. Their simulations indicated that injection of water, equivalent to 50 Mt CO_2 per year for 50 years, may cause an average water table rise of approximately 1m, which was considered to be within natural variations in the region. Other impacts identified included a minor increase in stream baseflow and an increase in groundwater “evapo-transpiration” but no change in salinity. Other specific impacts, for example on springs along flow-focussing fault-lines, were not assessed.

Cihan et al., (2013) present the application of an analytical solution for pressure build-up and leakage rates in a multi-layered aquitard system with focused and diffuse brine leakage. Their scenario involved multiple injection wells, injecting 5 million tons of CO_2 via five wells and a leaky fault at 20 km from the injection well field. They demonstrate that brine migration beyond the CO_2 plume, can be described by single phase flow models only and that two phase flow has only a negligible impact on far field conditions.

2.2.3 Summary of impacts from increased pressure

In summary, increases in reservoir pressures *could* potentially result in the following consequences, which may affect a specific storage site to variable extents either in isolation or in combination:

- Reduced storage capacity
- Reduced injectivity which may require additional pressure management
- Increased potential for fault reactivation, which may lead to increased permeability, either within the reservoir or caprock
- Displacement of formation water and brines to higher aquifers or outcrops.

The potential impact of increases in reservoir pressure on other subsurface users is an area for future research.

3 UK Policy and Regulation for Storage Development

3.1 UK EMISSIONS TARGETS AND OPTIONS FOR ACHIEVING THEM

The United Kingdom's (UK) strategy for reducing carbon emissions is set out in the 2011 Carbon Plan (UK Government, 2011). The Climate Change Act (2008)[1] established a legally binding target to reduce the UK's greenhouse gas emissions by at least 80% below base year levels by 2050. The Act introduced a system of carbon budgets which provide legally binding limits on the amount of emissions that may be produced in successive five-year periods, beginning in 2008. The first three carbon budgets were set in law in May 2009 and require emissions to be reduced by at least 34% below base year levels in 2020. The fourth carbon budget, covering the period 2023–27, was set in law in June 2011 and requires emissions to be reduced by 50% below 1990 levels. Projections made for The Carbon Plan in October 2011 suggest that the UK will more than achieve reductions in its carbon budgets up to the end of the third budget in 2022. However, the same projections also indicate that current policies are unlikely to meet emissions reduction targets on their own, requiring increased support for energy decarbonisation.

The UK power sector accounts for 27% of total emissions (150 Mt CO_2 in 2009) and the UK's objective to meet 2050 targets is to reduce these emissions to near to zero. The 'dash for gas' saw reductions in emissions from power generation reduce by around 25% between 1990 and 2010. Demand for electricity generation is likely to increase over coming decades as heat, power and transport are increasingly electrified, by between 30% and 60% (UK Government, 2011). Three major sources of electricity generation are likely to be on- and offshore wind, nuclear and fossil fuel-based (mainly gas) with CCS. No single option has been selected by UK Government as described below.

Electricity market reforms have been introduced by UK Government to support the development and deployment of low-carbon technologies, with the introduction of feed-in tariffs with contracts for difference from 2014 to "provide stable financial incentives for investment in all forms of low carbon generation". It is estimated that between 40-70 GW of new capacity will be required by 2030 with the above technologies competing to deliver low-carbon energy at lowest costs. Fossil fuel-based generation could contribute around 10 GW by 2030 and MARKAL base case modelling suggests 28 GW of fossil fuelled power with CCS in 2050 (UK Government, 2011), rising to 40 GW in a scenario assuming wide scale CCS deployment including bio-CCS or reduced to 2 GW if CCS is not deployed at commercial scales.

Recent energy system modelling, undertaken by researchers at the UK Energy Research Centre (UKERC) using the updated MARKAL model of the UK energy system indicates that large reductions in energy demand can be achieved more cheaply through increased efficiency and conservation technologies than an equivalent level of supply (Ekins et al., 2013). However, beyond that, to meet the UK's target for greenhouse gas emissions reductions in 2050, UKERC modelling indicates that the UK electricity system must be decarbonised by at least 80% by the year 2030, which equates to a reduction to less than 100 g CO_2/KWh, compared to a value in the year 2000 of 500 g CO_2/KWh. Four main options for achieving this decarbonisation in the UK are increased generation from nuclear power stations, large-scale renewable schemes, fossil-fuel power stations with CCS and small-scale, distributed renewable sources. Ekins et al. (2013) concluded that none of these options can currently be identified as the best, cheapest route to decarbonisation for a variety of reasons including challenges of wide scale onshore wind

[1] Available at www.legislation.gov.uk/ukpga/2008/27/contents (accessed 14 October 2013)

deployment, uncertainty on costs for new nuclear power stations and the uncertainty of commercial viability of CCS at scale, high costs for offshore wind and for distributed solar PV. These uncertainties result in outcomes of MARKAL modelling being very sensitive to relatively small changes to underlying assumptions and therefore Ekins et al. (2013) recommended continued development of all options until uncertainties can be reduced. Biofuels may increase their contribution to the primary fuel mix and, when combined with bio-CCS, offers an attractive option for power generation with negative emissions. CCS plays a significant role in all decarbonisation pathways to achieving the 2050 emissions reductions targets investigated by UKERC and reported by Ekins et al. (2013), with CCS providing an opportunity to reduce CO_2 emissions by 40% in 2050, since fossil-fuelled power plants (mainly gas-fired) will be required as reserve capacity (about 20 GW) in support of offshore wind and nuclear.

In November 2012, The Secretary of State for Energy and Climate Change (SoSECC) introduced the Energy Bill 2012-2013 to 2013-2014, which is currently going through due process in parliament[2]. The Energy Bill proposes, inter alia, that the SoSECC can set a 2030 decarbonisation target for electricity for 2030, and electricity market reform which will introduce contracts for difference to enable ageing infrastructure such as coal-fired power stations, to be replaced over the next decade, requiring an estimated £110 billion capital expenditure (covering renewable, nuclear and CCS). A Carbon Floor Price will be set together with Emissions Performance Standards specifically for any new coal-fired power station to be equipped with CCS. The stated ambition is for the Carbon Floor Price to reach £30 per tonne of CO_2 by 2020, rising to £70/tCO_2 in 2030[3]. It is also proposed that both demonstration projects and commercial CCS plants will receive relief from carbon price support rates equivalent to the proportion of CO_2 captured and stored.

3.2 CO_2 STORAGE POLICY IN THE UK

In 2012, the UK's Department of Energy and Climate Change (DECC) produced a CCS Roadmap[4] which recognised the future role that CCS could play in decarbonising the UK's electricity generation. The roadmap noted that the UK has extensive storage capacity in the North Sea, clusters of power stations and industrial plants that could share infrastructure, expertise that could be transferred from the oil and gas industries and academic excellence in CCS research. The storage roadmap covers the research and development activities described below, the electricity market reforms described above and specific interventions to address key barriers to the deployment of CCS, which are described in this section.

DECC's vision for CCS in the UK is for tens of gigawatts of installed electricity generating capacity and a range of industrial sources all fitted with CCS. Due to the happenstance of industrial development over the past 200 years, including the development of the UK's oil and gas industry, there exists potential for CCS clusters to develop in several regions which have been identified in the CCS Roadmap: the east coast of Scotland, Yorkshire & Humber, Teesside, and around the East Irish Sea, where there are large concentrations of industry close to potential storage capacity. These clusters of sources could utilise common transport networks and exploit

[2] Status as of 14 October 2013: http://services.parliament.uk/bills/2013-14/energy.html

[3] See the following published in March 2011: www.gov.uk/government/uploads/system/uploads/attachment_data/file/190279/carbon_price_floor_consultation_govt_response.pdf

[4] Available here: https://www.gov.uk/government/uploads/.../4899-the-ccs-roadmap.pdf

clusters of CO_2 storage sites, including sites that could potentially use CO_2 in enhanced oil recovery, in the North Sea and Irish Sea.

In addition to the electricity market reform and Research and Development (R&D) actions described elsewhere, the following development needs for CCS deployment were identified in the 2012 CCS Roadmap:

- An appropriate regulatory framework that enables and incentivises CCS projects while protecting the environment.
- Development of a storage strategy to ensure that issues around the development of storage capacity on the scale that will be required are addressed in good time.
- Ensuring industry has appropriate skills and supply chains.
- Availability of incentives to ensure transport and storage infrastructures are deployed.

One example of regulatory changes made is giving SoSECC powers to designate an offshore installation or pipeline to remove the potential for operators who previously used the facility for hydrocarbon production to remain liable for its decommissioning.

The CCS Roadmap recognises the need for effective planning to develop CCS, e.g. by "*aiming toward an orderly sequencing of North Sea operations and investment*". A long-term programme of validating saline aquifers is being considered (but not implemented) to ensure that the availability of suitable storage sites does not impede deployment. This programme would "*reach a point by the 2020s whereby a company would be prepared to take a final investment decision to utilise the site to store CO_2, and that the regulators would have enough information to inform their decision on whether to licence such a site.*"4

Alongside the CCS Roadmap, an accompanying short note was published on DECC's Storage Strategy[5]. This strategy recognises the challenge of future storage deployment including the scale of possible storage needed including the uncertainties associated with predicting likely amounts of CO_2 that might need to be stored and the current lack of validation for saline aquifers. Assessment of saline aquifers should begin soon to avoid a pinch point in the late 2020s since the availability of individual hydrocarbon fields is difficult to predict due to the close links between close of production dates and oil prices, taken together with an element of competition from gas storage, and the long lead times for the assessment (quoted as 6-10 years).

The Storage Roadmap therefore sets out specific activities on which the UK Government will focus:

- Providing support for reducing the level of technical uncertainties – including work on phase behaviour in CO_2 fluid flow; development of time- and cost-effective aquifer appraisal methodology; confirmation of the economics of CO_2 enhanced hydrocarbon recovery offshore; and optimisation of post-injection monitoring, measurement and verification.
- Regulatory issues – including facilitating the reuse of offshore assets and geological features and defining the leasing/ licensing approach for CO_2 enhanced hydrocarbon recovery.
- Commercial/ policy issues – including terms for new parties to secure rights to investigate offshore storage locations in order to demonstrate their suitability for storage, and to develop the Government's approach to the use of the UK offshore area to store CO_2 from other countries.

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[5] Available here: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48320/4904-ccs-roadmap--storage-strategy.pdf

3.2.1 Other actions supporting UK Policy

The Crown Estate and the Storage Cost Reduction Task Force undertake activities that directly support government policy on CO_2 storage development. The pore space in the UK is owned by The Crown Estate which can issue leases to storage operators. The Storage Strategy also described the activities that The Crown Estate is, or possibly could, become involved with over time:

- The Crown Estate will develop the framework agreements and processes to be used post-demonstration, when it is anticipated that The Crown Estate would take over the responsibility for selecting storage projects from the EU and UK governments;
- Designing storage site leasing competitions and conducting competitions if required. Investigating subdivision/unitisation of large scale saline aquifer complexes;
- Identifying and leading selection of a portfolio of suitable storage sites for the period beyond the CCS Commercialisation Programme;
- Managing co-location and overlapping uses of the seabed, planning interactions between offshore renewable energy projects and infrastructure and CO_2 transport and storage infrastructure, and cooperating with agencies such as the Marine Management Organisation for implementing government policies in the management of the marine environment; and
- Facilitating leasing of CO_2 enhanced hydrocarbon recovery opportunities in conjunction with DECC EDU.

The Cost Reduction Task Force is a joint industry and government initiative that advises UK Government and industry on the potential for reducing costs and cost uncertainty so that CCS becomes financeable and competitive with other low carbon industries. Their recent report (CRTF, 2013) drew many conclusions and made a number of recommendations. Here we highlight those of relevance to this study. Of the seven key recommendations made in the CRTF's final report, the following are most relevant to this study and have been paraphrased from the original text:

> The future UK CCS transport and storage network configuration should be optimised to minimise long-run costs and take into account likely future development of CO_2 storage hubs.
>
> A vision of how CCS projects which follow on from the first demonstration project(s) through to widespread adoption can be developed and financed is required. The aim is to encourage and guide developers who are bringing the next UK CCS projects forward, which will get a Contract for Difference but no government grant.
>
> Options for characterisation of both storage areas and also specific sites for CO_2 storage in the UKCS should be examined, to reduce the 'exploration risk' premium, thereby making storage sites bankable both commercially and technically.

The CRTF emphasises the potential to build out from the transport and storage networks created from the commercialisation program. However, uncertainty around the geological and operating behaviour of CO_2 storage sites means that operators are likely to require access to more than one proven store, and to be capable of flexible operation for back-up storage within integrated 'storage hubs'. This option is explored further in this report in Section 5.4.3.3. Furthermore, the CRTF highlight that, as a large part of the storage development cost is associated with infrastructure construction and does not vary significantly with storage rate, there is potential benefit in scaling storage operations to enable development costs to be shared across large volumes of stored CO_2.

3.3 CO_2 STORAGE RESEARCH AND DEVELOPMENT

The most significant activities undertaken in the UK are the 'Commercialisation Competition' and a coordinated research, development and innovation programme, in addition to the broader energy policy measures described above. The Commercialisation Programme was launched in April 2012, and followed a previous competition to identify a suitable project to demonstrate full-scale full-chain carbon capture, transport and storage from a UK coal-fired power station to an offshore storage site. Two consortia were supported by UK Government, as part of the first competition, to undertake detailed front end engineering design (FEED) studies for their proposed projects, including characterisation of the potential storage sites; the Goldeneye depleted gas field in the Outer Moray Firth, northern North Sea and the depleted Hewett gas field in the southern North Sea. Results from both FEED studies concluded that storage was feasible at both sites, and detailed plans were prepared for the project design and subsequent operational phases to comply with UK legislation. Outputs from the FEED studies were published in detail to facilitate greater knowledge sharing[6].

The current competition opened in April 2012 and closed in July 2012[7]. Four full chain (capture, transport and storage) projects were shortlisted in October 2012. On 14 January 2013, all the shortlisted bids submitted revised proposals. On 20 March 2013 the government announced two preferred bidders:

- Peterhead Project in Aberdeenshire, Scotland – a project which involves capturing around 90% of the carbon dioxide from part of the existing gas-fired power station at Peterhead before transporting it and storing it in a depleted gas field beneath the North Sea. The project involves Shell and SSE.
- White Rose Project[8] in Yorkshire, England – a project which involves capturing 90% of the carbon dioxide from a new coal-fired power station at the Drax site in North Yorkshire, before transporting and storing it in a saline aquifer beneath the southern North Sea. It will capture approximately 2 million tonnes of CO_2 per year (90% of emissions from the new plant). The project involves Alstom, Drax Power, BOC and National Grid.

The UK Office of Carbon Capture and Storage expects a final investment decision to be taken by the Government in early 2015 on the construction of up to two projects7. However the two FEED contracts, due to last approximately 18 months, have yet to be announced despite an anticipated agreement in the summer of 2013.

The White Rose Project in Yorkshire, England is a project which involves capturing CO_2 from a new oxyfuel coal-fired power station at the Drax site in North Yorkshire, before transporting and storing it in a saline aquifer beneath the southern North Sea. The first demonstration projects may act as catalysts for the development of future storage hubs, utilising, to the extent possible, the infrastructure (essentially oversized pipelines, if these were to be installed) available in the area and taking benefit from experiences obtained during site characterisation of the first permitted stores.

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[6] Available here: http://webarchive.nationalarchives.gov.uk/20121217150422/http://decc.gov.uk/en/content/cms/emissions/ccs/ukccscomm_prog/feed/feed.aspx

[7] Available here: https://www.gov.uk/uk-carbon-capture-and-storage-government-funding-and-support#ccs-commercialisation-competition

[8] Available here: http://www.whiteroseccs.co.uk/about-white-rose

The UK has a four-year (2011-2015) £125 million research, development and innovation programme which supports fundamental research (£55m), development and demonstration of specific engineering components (£27m) and pilot-scale projects (£43m), mainly for capture technologies.

3.4 REGULATIONS FOR CO_2 STORAGE IN THE UK

3.4.1 The European Storage Directive

In 2009, the European Directive 2009/31/EC[9] on the Geological Storage of CO_2 was implemented (the 'Storage Directive'). The Storage Directive provides a framework for a site selection and characterisation workflow aimed at demonstrating that, for a particular site, CO_2 can be stored safely and permanently. It requires operators wishing to store CO_2 to apply for a storage permit in which it must be shown that for the storage operation proposed, there is no significant risk of leakage or damage to human health or the environment. No geological storage is possible without a storage permit.

In order to demonstrate the expected safe and permanent storage, an operator must assess the specific risks or uncertainties relevant to the site and, through a combination of site investigations, predictive simulations of possible future performance and project design, reduce these risks and uncertainties to an acceptable level. The operator must also develop a monitoring plan that will be capable of appropriately observing the performance of the storage operation during both the injection phase and the post-injection phase. In addition, a provisional closure plan must be developed which describes when and how a site will be closed. A corrective measures plan will specify the range of possible responses in the event that site performance significantly deviates from the expected performance. Corrective measures may range from new and increased monitoring through to large-scale interventions to prevent and remediate leakage. Specific issues of the transfer of liability are addressed in the Storage Directive such that a designated Competent Authority within a Member State may assume responsibility for a site following successful site closure.

Each Member State is free to decide if they wish to allow CCS in their territory.

3.4.2 UK Implementation of the Storage Directive

The following is a summary of UCL's 2011 review of the UK's implementation of the Storage Directive (Armeni, 2011). Armeni's review provides an in-depth description of how the Storage Directive was implemented in the UK and the following summary highlights those aspects of most relevance to the current study.

Since 2009, the UK requires that all new commercial-scale power plants greater than 300 MW must be Carbon Capture Ready (CCR). The definition of CCR is:

- sufficient space is available on or near the site to accommodate carbon capture equipment in the future;
- it is technically feasible to retrofit carbon capture technologies;
- a suitable offshore storage site exists;
- it is technically feasible to transport the captured CO_2 to the storage site; and
- it is economically feasible to link the plant to a full CCS chain within its operational life.

[9] Available here: http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=CELEX:32009L0031:EN:NOT

The Energy Act 2008 established the UK's licensing framework for CCS and although it was implemented prior to the Directive, it anticipated many of the specific requirements within the Directive which was being negotiated when British legislation was passed, including the need for a storage licence. The Act extended sovereign rights to explore and exploit the UK continental shelf for the purposes of CO_2 storage. Between 2010 and 2011 secondary legislation defined the licensing regime for offshore storage. Legislation was largely enacted through adaptation of existing oil and gas legislation.

Exploitation rights of the offshore pore space up to 200 nautical miles within the Gas Import and Storage Zone are vested with The Crown Estate and the Energy Act 2008 requires operators to obtain a lease from the Crown Estate to undertake geological storage. The Agreement for Lease (AfL) which provides prospective tenants with exclusivity and the option to take up a Lease at a certain point in time under certain conditions. The Lease is provided at the same time as the AfL so that the tenant (and TCE) knows what they are signing up to. Under the AfL the operator has the right to conduct exploration activities in order to develop a storage plan to support his/her application for a lease.

The full lease provides the operator with the right to undertake CO_2 storage and also covers site closure, decommissioning and post-closure monitoring obligations. The Crown Estate is also responsible for issuing pipeline leases for CO_2 pipelines within territorial waters (12 nautical miles). Granting of any AfL or lease is conditional upon an applicant obtaining a storage licence.

A storage licence can be granted for an area which already has a petroleum licence, as long as the storage does not prejudice pre-existing rights of the petroleum licence holder. DECC clarified that the co-existence of such uses will only be permitted when "there is evidence that suitable liability and operational liability arrangements are in place" (Energy Act, 2008). Furthermore, a licence will be granted only if DECC "is satisfied that there is a technically feasible and safe way forward which will allow both developments to co-exist without material disadvantage to the activities already authorised" which seeks to protect pre-existing petroleum activities. This is in compliance with the Directive which requires that no conflicting uses of storage sites are permitted.

DECC also has the right to require an operator to provide access to a store by a third party, and can indicate any costs that the third party should pay to the initial permit holder. However it is expected that the third party would approach the permit holder initially and if a dispute arises this can be brought to the attention of the Competent Authority (DECC). Access rights can be granted as long as the existing rights of the permit holder are not compromised. Operators are required to publish information once per year to ensure access to third parties.

3.5 UK SOUTHERN NORTH SEA CO_2 STORAGE POTENTIAL

3.5.1 Gas Fields

In the UK Southern North Sea the majority of gas fields occur within the Rotliegend Leman Sandstone Formation which is of Permian age. Most of these fields are pressure depletion-drive (where the reservoir naturally depletes under the original reservoir drive energy) which means there is little water encroachment into the field from the surrounding reservoir rocks during production. This is ideal for CO_2 storage because once depleted, the pore space in a gas field is at low pressure. Filling the reservoir with CO_2 will re-pressurise the field and the initial reservoir pressure may never be exceeded, although this has yet to be demonstrated. Some of the Rotliegend gas fields are however highly compartmentalised which may complicate injection. The compartments are typically bounded laterally by faults with very low permeability; it is likely that an injection well would be required to fill each of the compartments which, if existing wells cannot be re-used, will add to the cost of storage.

There are also several fields in Carboniferous sandstone reservoirs and in the Triassic Bunter Sandstone Formation. Some of the Carboniferous and Triassic fields have significant water drive i.e. water encroaches into the field from the surrounding reservoir during hydrocarbon production. This will make it more difficult to manage pressure increase during CO_2 injection as the water will need to be displaced.

3.5.2 Saline Aquifers

In the Southern North Sea the Bunter Sandstone Formation is thought to have the best potential for aquifer storage (Figure 4). One reason for this is evidence suggesting that there appears to be good pressure communication across the reservoir e.g. in the Esmond, Forbes and Gordon fields and between the Hewett and Little Dotty fields. This indicates that there is probably little compartmentalisation and that it may be possible to displace water from the pore space by CO_2 injection. There is however evidence of faulting (imaged on seismic survey data) that may form permeability barriers in parts of the reservoir.

There are some very large natural domes within the Bunter Sandstone in the Southern North Sea Basin which may have the potential to store large amounts of CO_2. Relatively little is known about the storage capacity or storage security of many of these structures, however, as the majority of them haven’t been characterised in detail. The Bunter Sandstone is regionally sealed by the overlying mudstone and halite of the Haisborough Group but seismic images reveal that some of the domes have faulted crests.

The Leman Sandstone Formation is the main gas-bearing reservoir in the Southern North Sea (Figure 4). It is heavily compartmentalised by impermeable or very low permeability faults in the gas fields and, by extension in the aquifer parts too. Compartmentalisation could prevent fluid flow through the reservoir and cause rapid pressure rises within water-bearing compartments. Injection wells would probably need to be drilled in each compartment, so the Leman Sandstone Formation is not considered to have the best potential for aquifer storage of CO_2 in the UK sector of the Southern North Sea.

The Spilsby Sandstone has good reservoir properties. It occurs in the western part of the basin and is split into three isolated sand bodies. The sandstone unit located nearest to shore (labelled A, (Figure 4) is too shallow in the areas that overlie the salt structures in the basin which form the major traps/structures in the area. The unit labelled B (Figure 4) is also too shallow to be considered for CO_2 storage. The smallest of the three sandstone units (labelled C in Figure 4) is however at depths more suitable for storage (greater than 1000 m). This sandstone is sealed by the Speeton Clay Formation which forms the cap rock to the nearby Orwell gas field.

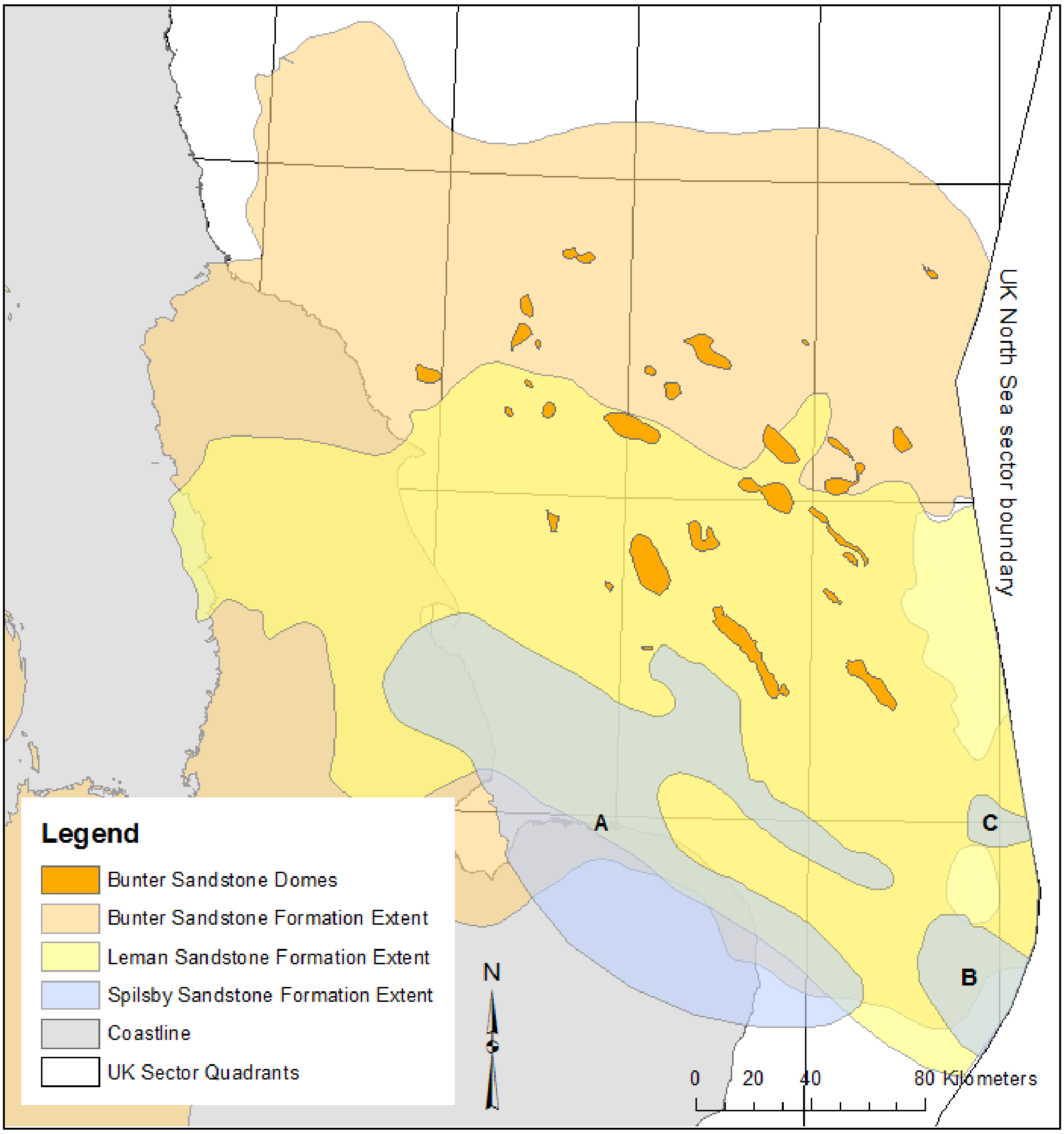

Figure 4: Map showing the location of the Bunter Sandstone Formation, Leman Sandstone Formation, Spilsby Sandstone Formation (areas A, B and C) and domes in the Bunter Sandstone Formation

3.5.3 Previous storage capacity studies

The EU GeoCapacity project (Assessing European Capacity for the Geological storage of Carbon Dioxide) funded by the European Commission Framework 6 programme provided an update of the UK CO_2 storage capacity in 2009. Capacities were estimated for the gas fields and mapped closed structures (domes) in the Bunter Sandstone Formation (Southern North Sea). The capacities in the gas fields were calculated by replacement of the Ultimately Recoverable Reserves (URR) and then efficiency factors were applied according to the reservoir drive. In the saline aquifer domes the net pore volume was calculated and an efficiency factor of 40% applied. The theoretical capacity of all potential sites in the NS was estimated at 24 Gt (billion tonnes) (Vangkilde-Pedersen, 2009).

The CO2Stored (CO_2 **Stor**age **E**valuation **D**atabase) database and GIS, hosted and under development by the British Geological Survey and The Crown Estate, is available under licence. It lists all the potential storage units on the UK continental shelf. The database was developed as part of the UK Storage Appraisal Project (commissioned and funded by the Energy Technologies

Institute). This study was more extensive than the GeoCapacity project and included additional reservoir units in the Southern, Central and Northern North Sea and in the western English Channel. Dynamic simulation was used to estimate the storage capacity of domes in aquifers and the highest modelled storage efficiency was found to be 27.6%. The storage capacity of hydrocarbon fields was calculated using mass balance methodology which accounted for fluid production and injection. The study estimates that there is a 50% probability CO_2 storage capacity of the UK offshore area is at least 78 Gt (Bentham & Pearce, *In Press*).

4 UK Southern North Sea case study

In this chapter, a case study of the Southern North Sea is used to illustrate the range of potential conflicts, both in terms of spatial planning and subsurface interactions, which could be anticipated as more storage sites are developed in the next two to three decades. Whilst this case study is of a specific basin with particular characteristics, at least some of the interactions highlighted are likely to be encountered in many areas of CO_2 storage worldwide.

4.1 POTENTIAL USERS AND CONFLICTS OF INTEREST IN THE UK SECTOR OF THE SOUTHERN NORTH SEA

All of the estimated CO_2 storage potential in the UK is located offshore on the UK continental shelf. The SNS has a number of existing and potential users both on the surface and the subsurface. These include, *inter alia*:

Subsurface users:

- Hydrocarbon operations
- Gas storage
- Other CCS sites within the same geological formations

Surface users:

- Wind farms
- Dredging areas
- Pipelines
- Hydrocarbon and gas storage operations
- Environmental protection zones
- Shipping routes
- Fishing

4.1.1 Subsurface users

4.1.1.1 HYDROCARBON OPERATIONS

The geology in which hydrocarbons form, are trapped and exploited is also the geological setting which is suitable for CO_2 storage. As a result hydrocarbon fields are often found within the same sedimentary basin, sedimentary column or geological formation as potential CO_2 storage sites. In addition, depleted hydrocarbon fields are often cited as suitable candidates for CO_2 storage sites for both pure storage and or enhanced hydrocarbon production using CO_2.

Inevitably, there could be conflicts of interest between hydrocarbon exploration and production interests and CCS. Accurate close of production dates are essential in order to understand when depleted hydrocarbon fields which can potentially be turned into CO_2 storage sites are likely to be available. In the UK the estimated close of production dates are confidential. The figures are highly sensitive to oil and gas prices and reflect economic factors rather than just the state of depletion of the fields and so it is difficult for independent bodies to gain much insight as to when individual fields will have reached a point at which the operator feels that selling them to a CO_2 storage developer is the best option.

CO_2 storage sites, hydrocarbon fields and natural gas storage sites can all be located within the same geological formation, and two or more operations in the same formation may be dynamically connected, i.e. injection into a CO_2 storage site could have some impact on a e.g. hydrocarbon field in the same formation. This could impact positively or negatively on the hydrocarbon field. The resultant pressure rise in the formation could provide active pressure support to the hydrocarbon field, increasing production. Conversely, mobilised pore fluid from the saline aquifer CO_2 storage site may increase the water produced in the hydrocarbon fields thereby reducing production and increasing costs. These scenarios are entirely dependent on the geological setting.

In the SNS, the Bunter Sandstone Formation contains both potential aquifer CO_2 storage sites and gas fields. Research to investigate the potential interaction between CO_2 storage sites and hydrocarbon fields within the same geological unit has been undertaken in the UK central North Sea. Min et al. (2012) showed, through dynamic modelling of CO_2 injection into the saline aquifer portion of the Captain Sandstone Member in the Central North Sea, that the resultant pressure rise in the formation could provide active pressure support to hydrocarbon fields, potentially increasing production.

4.1.1.2 Gas storage

As security of natural gas supply becomes an increasing concern both in terms of strategic storage and seasonal storage it is possible that small potential CO_2 storage sites in the SNS could be in competition for use of the pore space with natural gas storage. There are two operational gas storage facilities in the SNS, the Rough and Sean North and South gas fields. Further such schemes are being considered[10], some of which have been licensed (Figure 5).

[10] www.bgs.ac.uk/research/energy/undergroundGasStorage.html

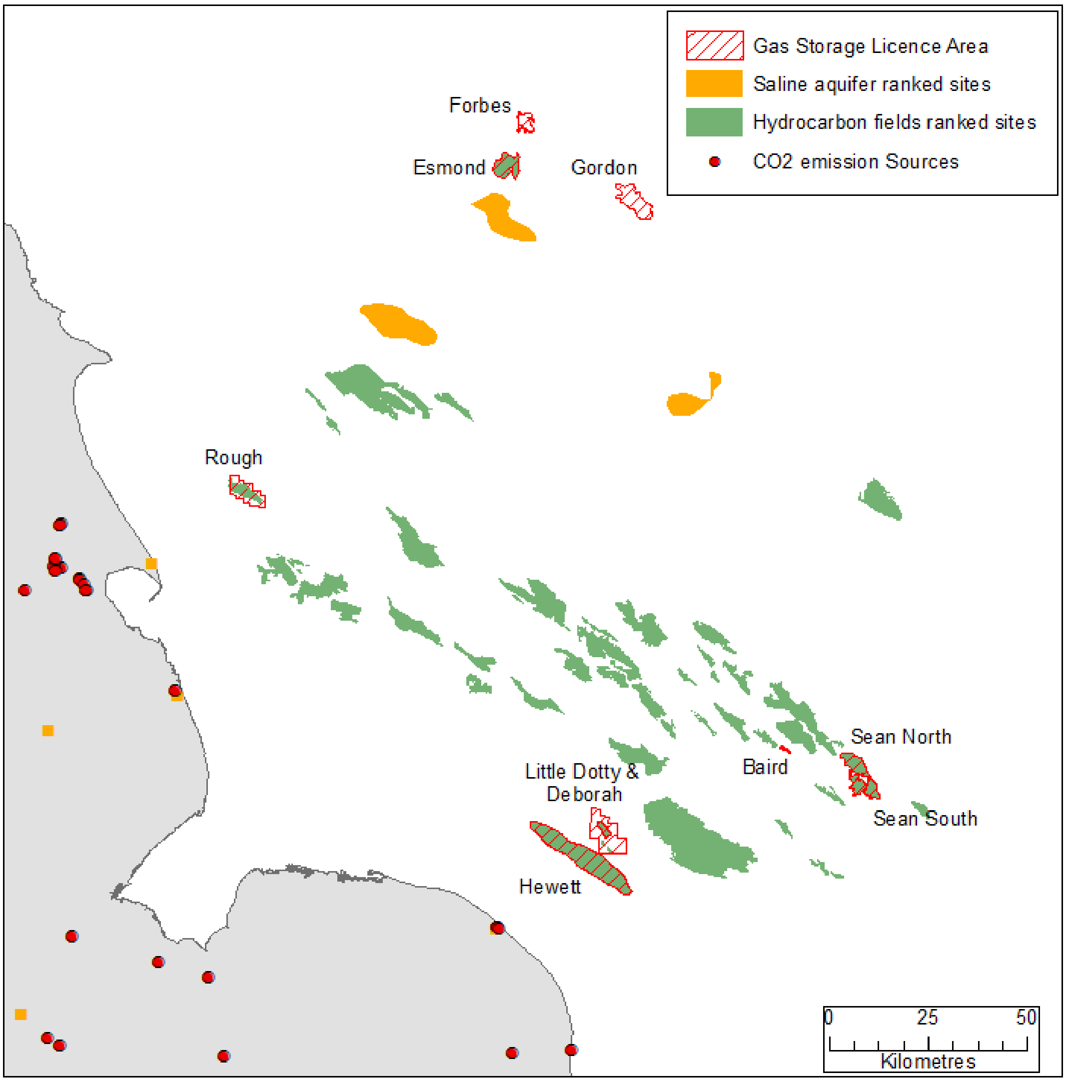

Figure 5: Gas storage licence areas and suitable saline aquifer and hydrocarbon field sites in the Southern North Sea Basin

4.1.1.3 Other CCS sites within the same geological formations

Pressure interactions between CO_2 storage sites in well-connected reservoir formations could cause conflicts of interest. These could require regulation, e.g. limits on injection rates or active pressure management by formation brine production, to ensure optimum development.

During CO_2 injection into a reservoir formation without active pressure management, the pressure perturbation extends much further than the CO_2 plume (e.g. Doughty, 2010; Zhou et al., 2010; Buscheck et al., 2012; Min et al., 2012; Noy et al., 2012). Simulations of CO_2 injection have also shown that the increased pressure rise during CO_2 injection decays rapidly immediately after the cessation of CO_2 injection as the pressure equilibrates within the model as a whole and a longer term decline also takes place due to pore water leaving the system, as pressure bleeds off through low permeability cap rocks (Chadwick et al., 2009; Doughty, 2010; Zhou et al., 2010).

In addition to increasing the pressure in the region surrounding a storage site, injection of CO_2 into a formation may mobilise the native pore fluid. In the case of saline aquifer formations, the saline pore fluid or brine will be pushed out of the pore spaces around the injection well by the injected CO_2. The mobilised brine could potentially interact with other subsurface operations, displace pore fluid to the sea bed (relieving pressure) (Noy et al., 2012; Hannis et al., In press), cross international boundaries or migrate into other geological storage sites. In areas where potable water is produced from the same or connected formations the mobilisation of brine may risk adversely affecting potable water supply.

4.1.2 Surface users

4.1.2.1 Wind farms

Wind farms present a physical barrier to accessing any potential storage sites in terms of laying down infrastructure (pipelines, platforms etc.) as well as monitoring above a site using survey ships as there is a potential risk of snagging the surface gear used from ships on the wind turbines. Therefore, safety zones may be imposed around the turbines; the Greater Gabbard wind farm has a temporary safety zone of 500 m around its 32 turbines with all other structures having an operational safety zone of 50 m[11]. Patterns of construction at wind farms because of e.g. prevailing wind direction and existing infrastructure, e.g. Kentish Flats wind farm 700 m between turbines[12]; Barrow wind farm 500 m between turbines; 700 m between rows[13] and CO_2 storage site monitoring plans would have to be adapted accordingly. In the Southern North Sea there are seven gas fields and parts of one aquifer storage site that lie within wind farm areas (Figure 6).

[11] Available here: www.sse.com/uploadedFiles/Z_Microsites/Greater_Gabbard/Controls/Lists/Resources/Guidelines%20for%20Sailing%20and%20Fishing%20activities%20within%20the%20Greater%20Gabbard%20Wind%20Farm.pdf
[12] Available here: http://www.vattenfall.co.uk/en/kentish-flats.htm
[13] Available here: http://www.stateofgreen.com/en/Profiles/DONG-Energy/Solutions/Barrow-Offshore-Wind

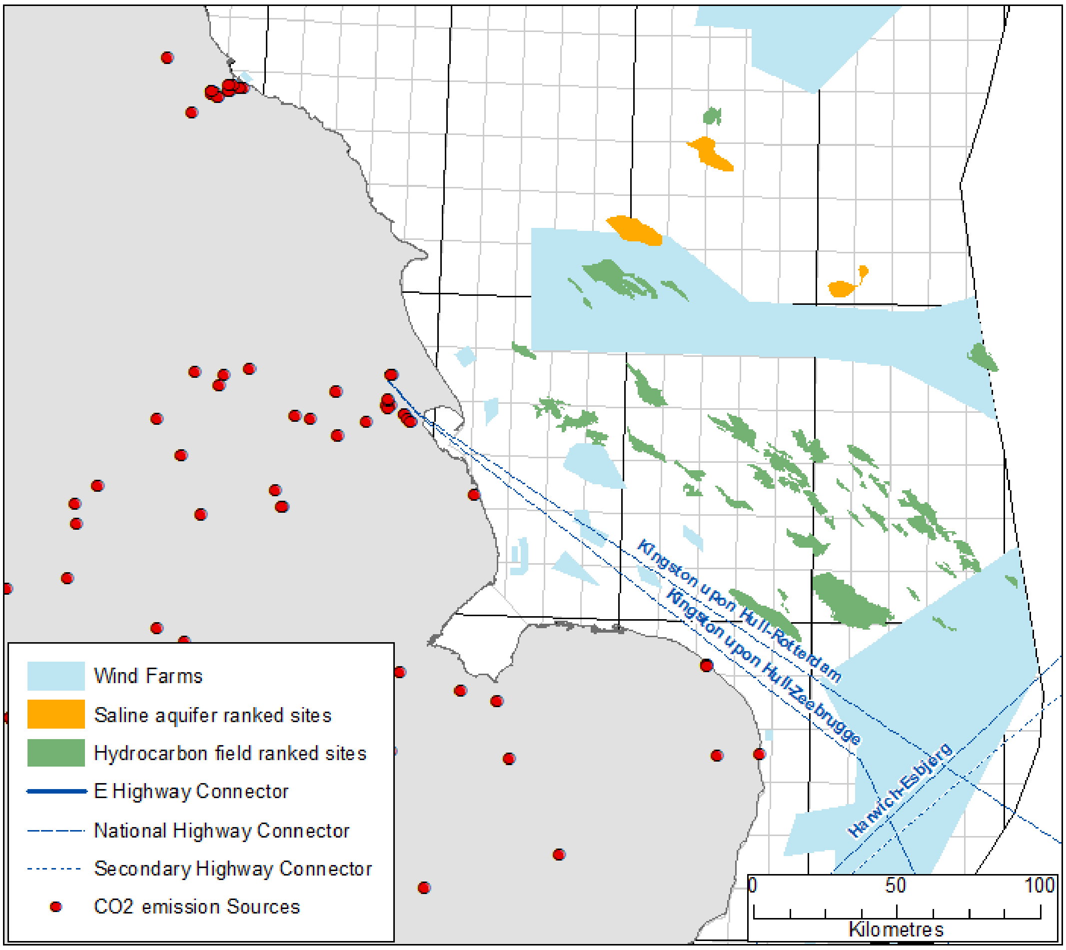

Figure 6: Map showing location of wind farms in the Southern North Sea

4.1.2.2 Dredging areas

Dredging of the seabed may be carried out to create or maintain channels or berths for shipping, level the sea-bed or for other commercial reasons such as sand and gravel extraction for the building industry[14]. It is likely that it would be impractical to install the necessary infrastructure required for CCS if a potential storage site lies within an area with a high amount of dredging activity. Dredging may also be too disruptive in terms of monitoring a site; some monitoring equipment would be too sensitive to the amounts of disturbance and excavation of surface sediments would prevent observation from imagery and monitoring of environmental features over the site.

There are currently approximately 70 production licences for dredging for marine aggregates in the offshore UK. These licences cover about 106 km^2 of the UK continental shelf[15].

Only two of the gas fields from the prospective depleted hydrocarbon field CO_2 storage sites in the Southern North Sea have a small overlap with dredging licence areas (Figure 7).

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[14] Available here: http://www.marinemanagement.org.uk/licensing/marine/activities/dredging.htm

[15] Available here: http://www.thecrownestate.co.uk/energy-infrastructure/aggregates/our-portfolio/

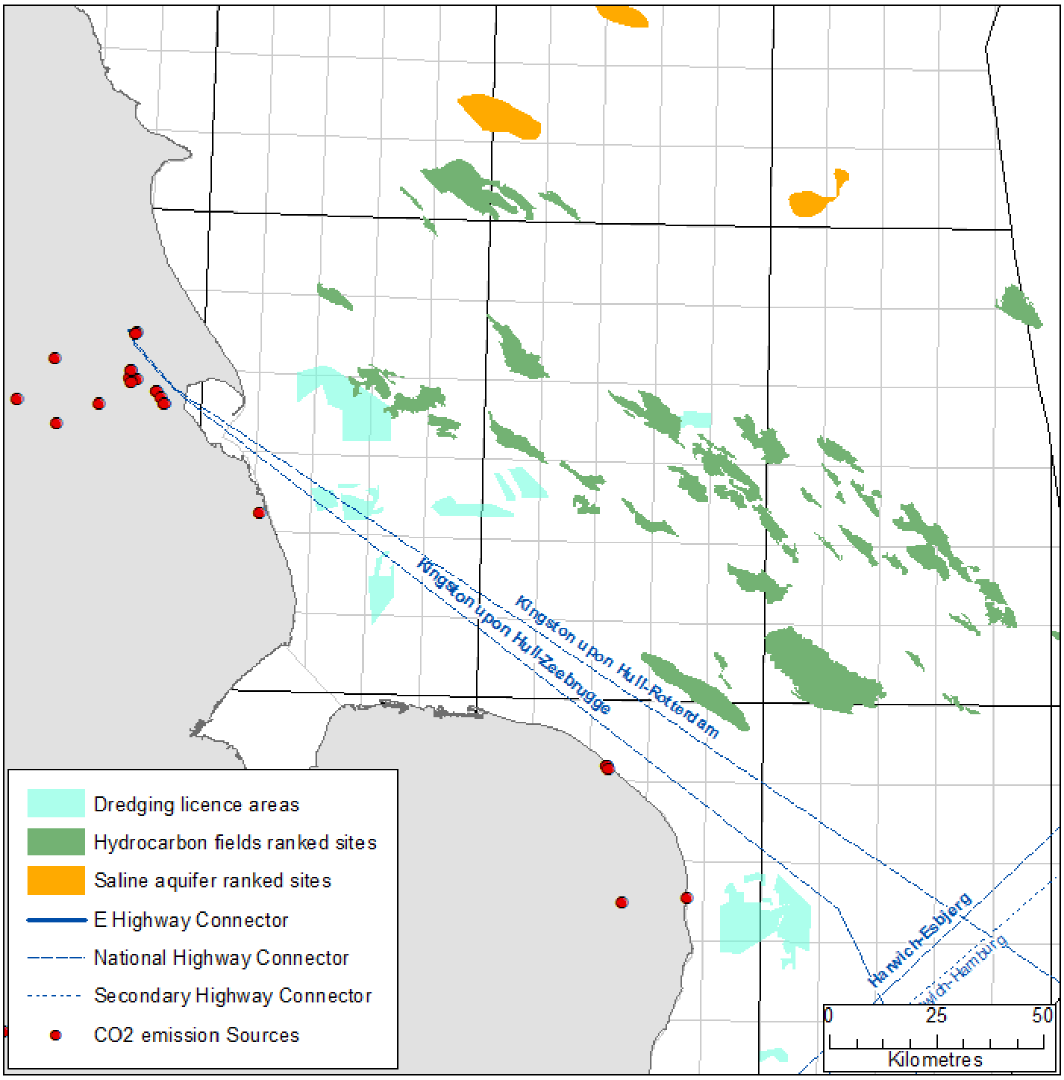


Figure 7: Map showing location of dredging licence areas in the Southern North Sea

4.1.2.3 PIPELINES

Existing pipelines (Figure 8) could be used for transporting CO_2 to prospective storage sites as long as they have a high enough specification, are in good condition, have CO_2-proof seals, have not reached the end of their design lifetime and are not currently being used to transport hydrocarbons to shore. If however existing pipelines cannot be reused for CCS then new pipelines will need to be installed. In this instance adding additional pipelines may not be too difficult, often pipelines can be laid in a 'piggyback' fashion where one pipeline overlies and is attached to another, though if however this is not possible the existing network of pipelines may make installation more difficult as there is a complex existing network in the Southern North Sea.

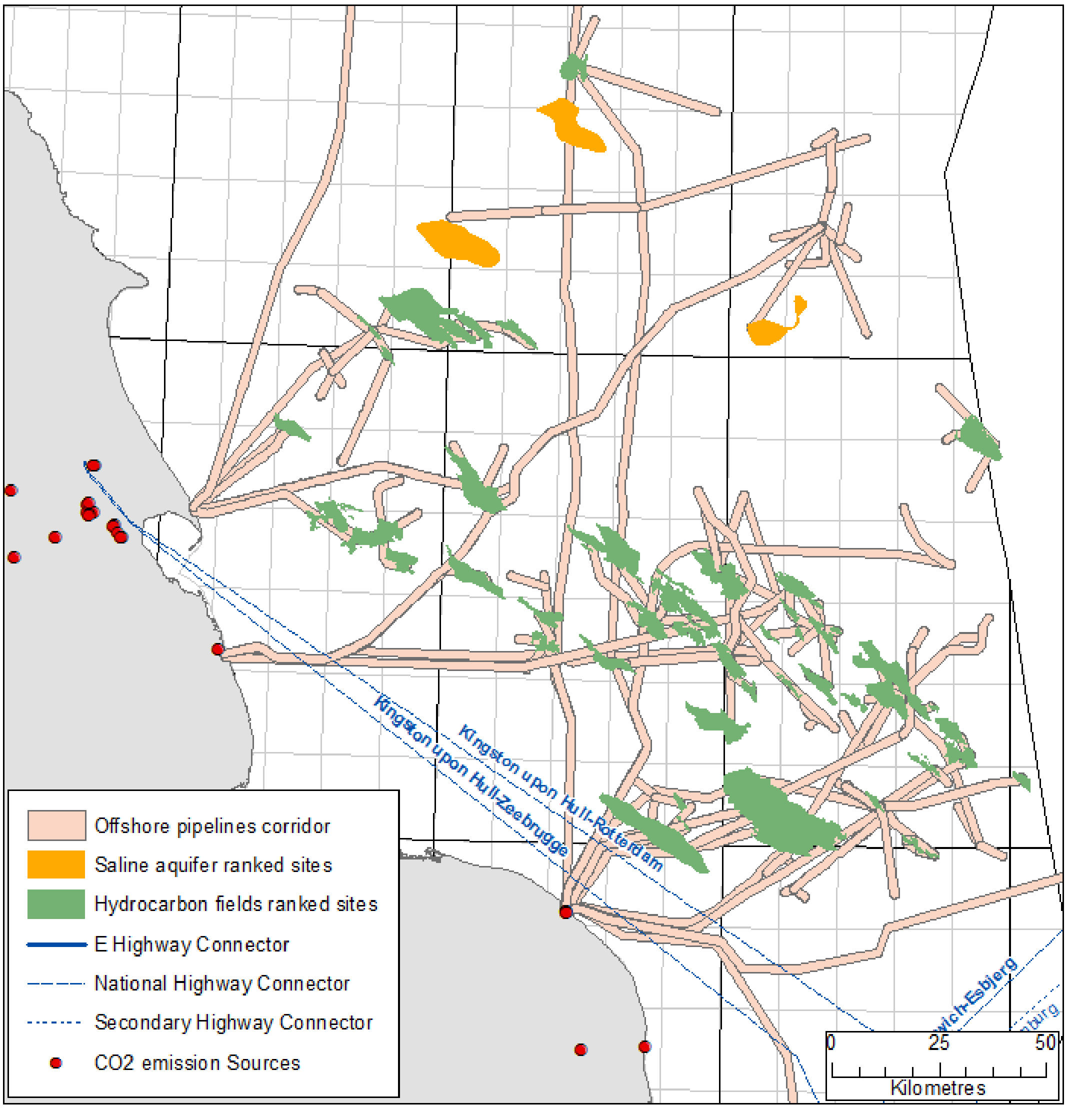


Figure 8: Map showing location of existing pipeline corridors in the Southern North Sea

4.1.2.4 Hydrocarbon and gas storage operations

Hydrocarbon fields have above sea, below sea and sea bed structures associated with their operation and production. There may be several types of infrastructure in place; some fields may have a platform or floating platform installed above where the production wells are situated; some (satellite) fields have wells tied-back to neighbouring platforms and some fields may be linked by pipeline to take advantage of common processing or export facilities. Infrastructure issues could prevent a gas field or a saline aquifer site being accessed in a set of stacked reservoirs from one of which hydrocarbons are being extracted. Existing production platforms could potentially be adapted to CO_2 injection once a field is depleted but this will need to be evaluated on a case by case basis especially as some platforms in the Southern North Sea are around 40 years old.

The condition of wells used for injection and production during hydrocarbon extraction is also uncertain and would need to be investigated before they could be re-used for CO_2 injection, as would the question of whether a platform will be able to accommodate new wells. It might be possible to drill subsea wells a few kilometres from a platform and tie them back (i.e. connect them via a short pipeline) to the platform – in fact this could be an advantageous way to develop saline aquifer storage sites because a large well spacing has advantages in terms of limiting the interaction between the pressure footprints created by each injection well. If there is no existing infrastructure near the potential storage site because it is in a saline aquifer then new platforms (or subsea facilities) and wells will be required.

4.1.2.5 Environmental protection zones

In planning for any new infrastructure required for a storage project it may be that development would be preferred to take place outside areas that have a protection order. The map in Figure 9 shows the areas of special protection located in and around the Southern North Sea. None of the protected areas overlap with any of the potential storage sites used in the case study.

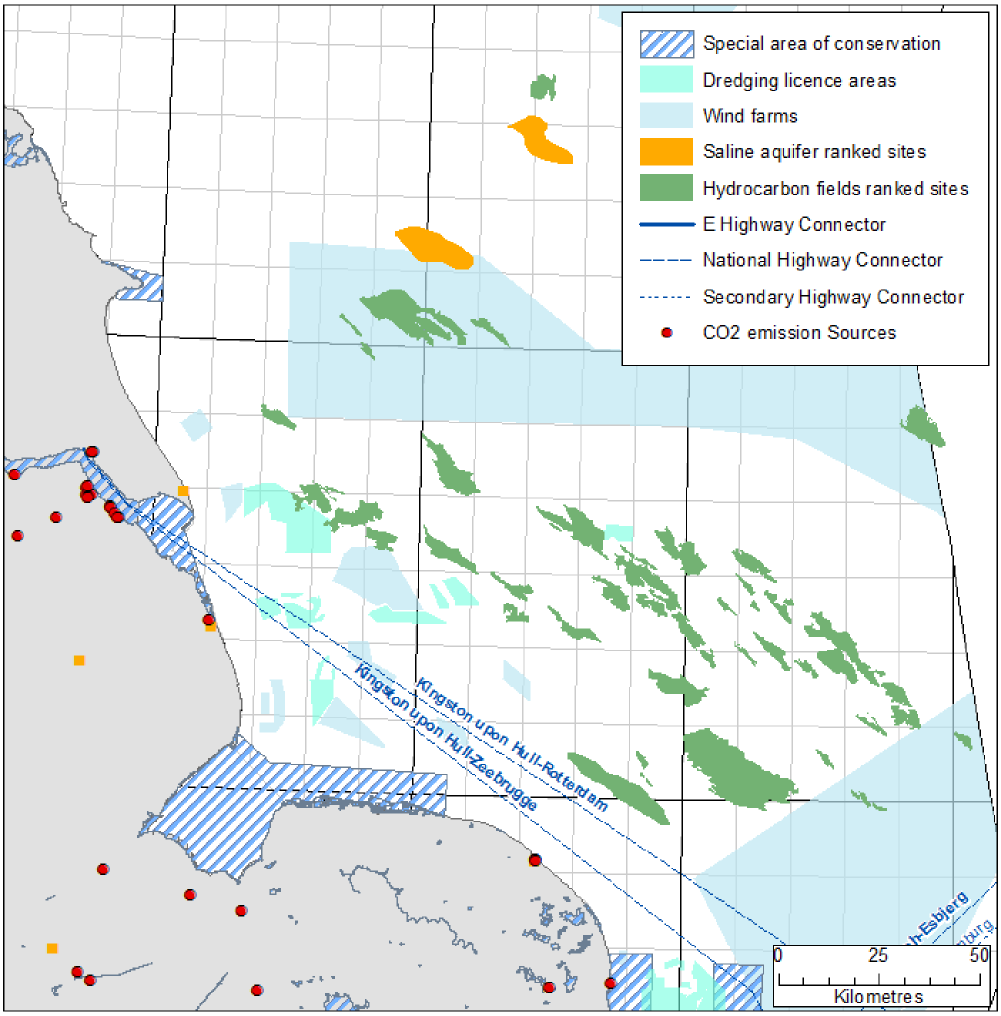


Figure 9: Map showing the location of special areas of conservation and marine protection areas [(© Natural England copyright 2013)] ranked sites, dredging areas and wind farms

4.1.2.6 Shipping routes

The development of a potential storage site (infrastructure, baseline studies and monitoring) may be restricted by the presence of heavily used shipping lanes. Figure 10 shows the ferry routes which are only a small proportion of the existing shipping lanes in the UK waters but gives an idea of where the main ports are situated. The activity in UK waters includes shipping for fisheries, dredging, oil and gas developments, cargo vessels, tankers, tugs and leisure boats among others.

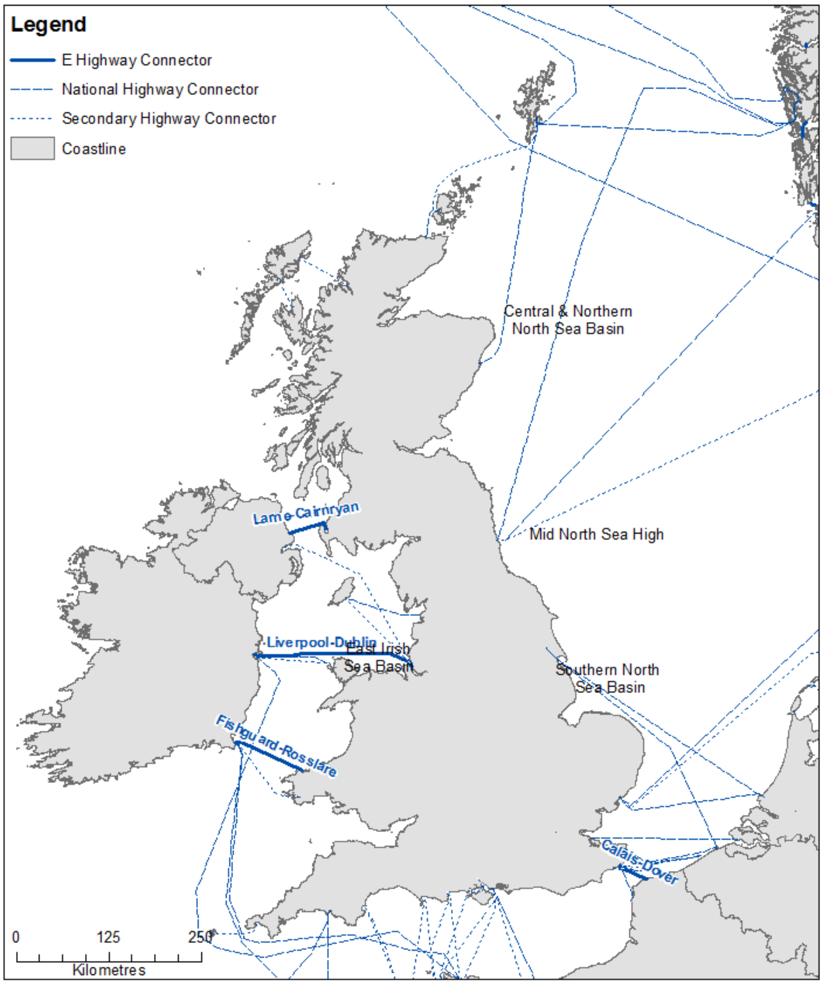


Figure 10: Map showing Ferry Routes to and from the UK

5 Possible interactions associated with two case studies showing development of CO_2 storage in the UK sector Southern North Sea

The UK sector of the Southern North Sea (SNS) has been chosen as a case study area to highlight the advantages and disadvantages of different approaches to CCS development.

NB// Scenarios have been developed to help illustrate some of the potential interactions in the subsurface and on the surface that might occur as a result of CO_2 storage development in the SNS. These scenarios are based on realistic potential storage sites in order to ground the scenario in some reality. Nonetheless they are entirely hypothetical and serve only to illustrate types of interactions that might occur in the SNS region. Moreover, this report in no way is suggesting a pathway for development of CCS within the SNS, or suggesting that any of the storage sites used in this report are suitable or otherwise for CO_2 storage. The CO_2 targets and the storage sites used in the scenario are to only illustrate the concepts discussed in this report.

The main classes of potential CO_2 storage sites in the UK SNS are: Saline water-bearing domes in the [Triassic] Bunter Sandstone Formation, gas fields in the Bunter Sandstone Formation, gas fields in the [Permian] Leman Sandstone Formation and gas fields in Carboniferous sandstones (Holloway et al., 2006). A schematic cross section showing the two major potential CO_2 storage reservoirs (the Bunter and Leman Sandstone Formations) is shown in Figure 11.

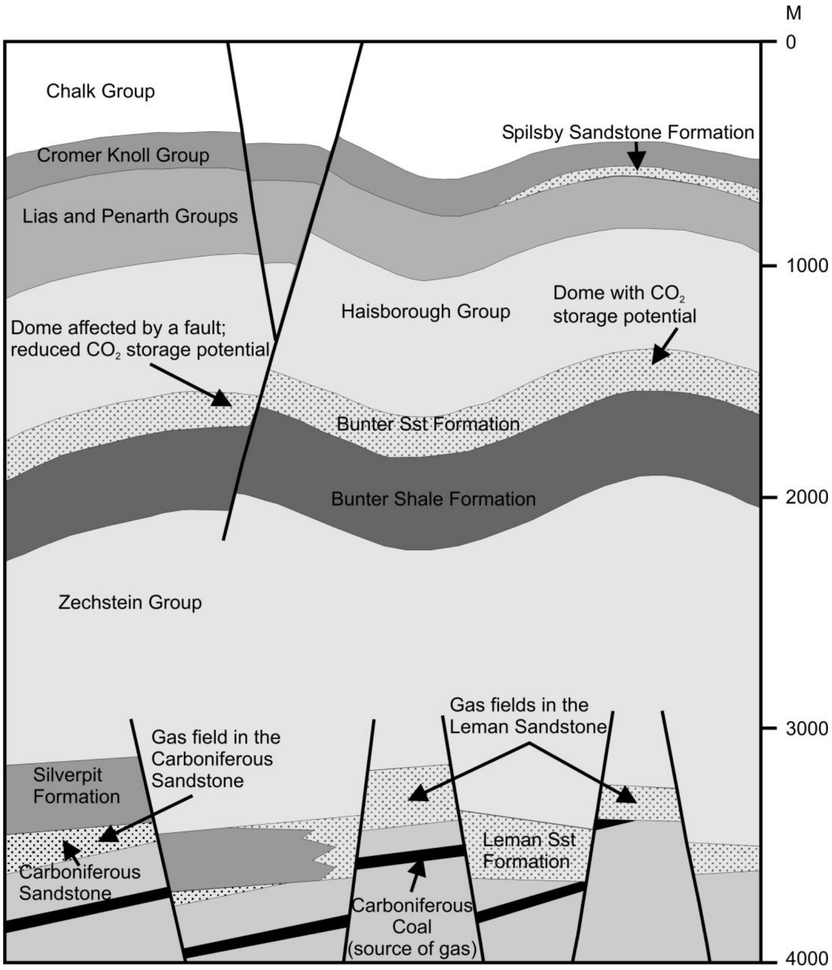


Figure 11: Schematic cross section in the Southern North Sea showing the Bunter and Leman Sandstone Formations and the Carboniferous sandstone reservoirs.

The SNS is ideally placed to accept CO_2 emissions from point sources in the East of England. In addition to being a prospective region for CO_2 storage, the SNS has many other users of the seabed and the subsurface. Some of the types of infrastructure and activities occurring in the SNS are listed in Table 3 and shown in Figure 11.

Table 3: Surface and subsurface uses of the Southern North Sea

Surface uses	Subsurface uses
Pipelines	Gas fields
Cables	Gas storage
Oil and gas infrastructure including natural gas storage	Hydrocarbon licence areas
Shipping	Gas storage licence areas
Dredging	CCS licence areas
Fishing	
Wind farms	
Tidal energy	
Conservation areas	

Any CO_2 storage development will be required to 'fit in' with the existing users of the subsurface and seabed. The SNS is a busy space and planning of CCS infrastructure will be essential to ensure it can be accommodated alongside existing and potential future users of the seabed and subsurface.

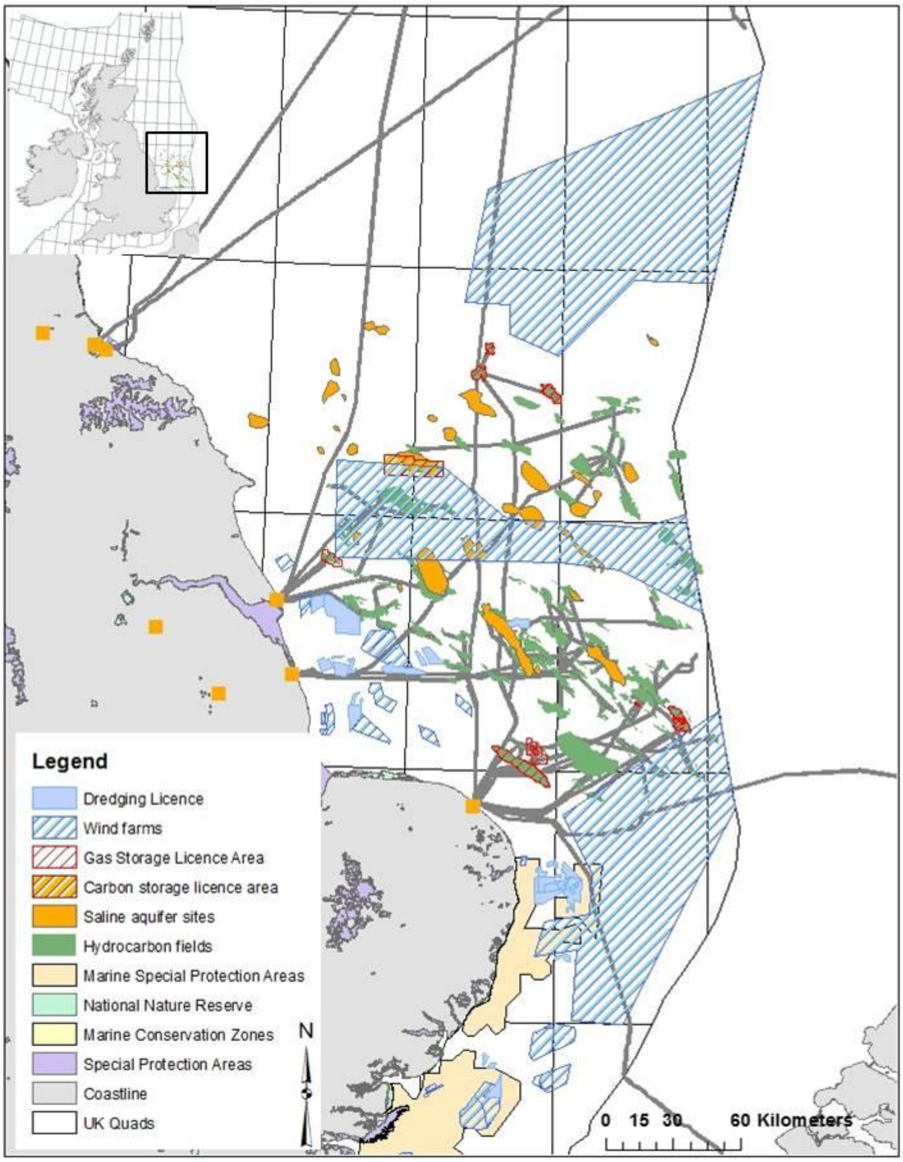


Figure 12: Activity map of the Southern North Sea

5.1 UK SOUTHERN NORTH SEA CASE STUDY - SCENARIO DEVELOPMENT

The basic methodology for the scenario development was:

1. Decide on the scenarios to be evaluated and their time spans.
2. Estimate the amount of CO_2 that might have to be stored in the SNS at two points in the scenario timeframe.
3. Evaluate and rank each potential storage site in the perceived order that they might be selected by project developers.

4. Assume the storage sites will be utilised in rank order unless the scenario applies constraints that preclude their use.
5. Observe potential interactions between utilised sites and other present (and in some cases potential future) legitimate uses of the surface and subsurface as CO_2 storage proceeds.

The scenarios to be evaluated are:

1. The ‘First-Come, First-Served’ (FCFS) Scenario in which the project developer is assumed to choose the ‘best’ sites based on geotechnical criteria on a first-come, first-served basis. It would be the responsibility of later project developers or users of the subsurface to deal with any implications of any licensed or legitimate preceding operations, and to demonstrate no negative interactions with existing users.
2. The ‘Managed Storage Resource’ (MSR) Scenario. In this scenario, site selection is restricted by adding criteria that must be met before a site can be developed, in a way which minimises the surface and subsurface impact whist maximising the amount of CO_2 that can be ultimately stored.

Both scenarios run from 2020 to 2050. “Snapshots” of CO_2 storage and interactions were taken at 2030 and 2050.

The methodology used to estimate the mass of CO_2 that needs to be stored by 2030 and 2050 (Figure 13), and the methodology used to rank the storage sites (Figure 14) is given in Appendix 2.

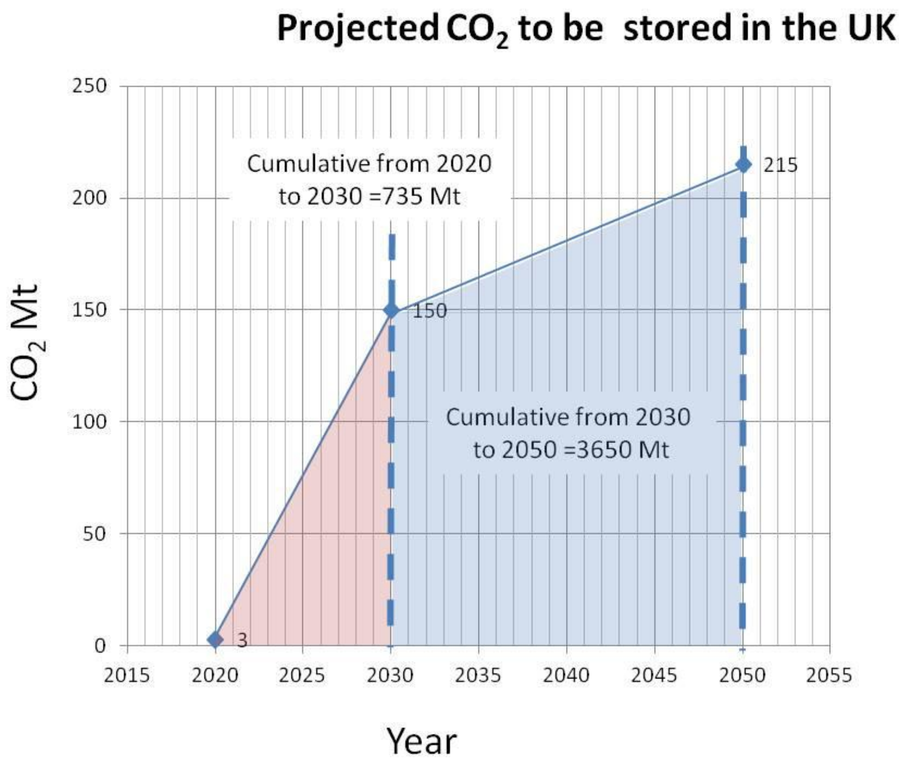


Figure 13: Projected volumes of CO_2 captured and to be stored in the UK from 2020 to 2050, based on data from DECC, 2011 & 2012). Area of pink shading shows the area of cumulative emissions from 2020 until 2030, area of blue shading shows the cumulative emissions from 2030 until 2050.

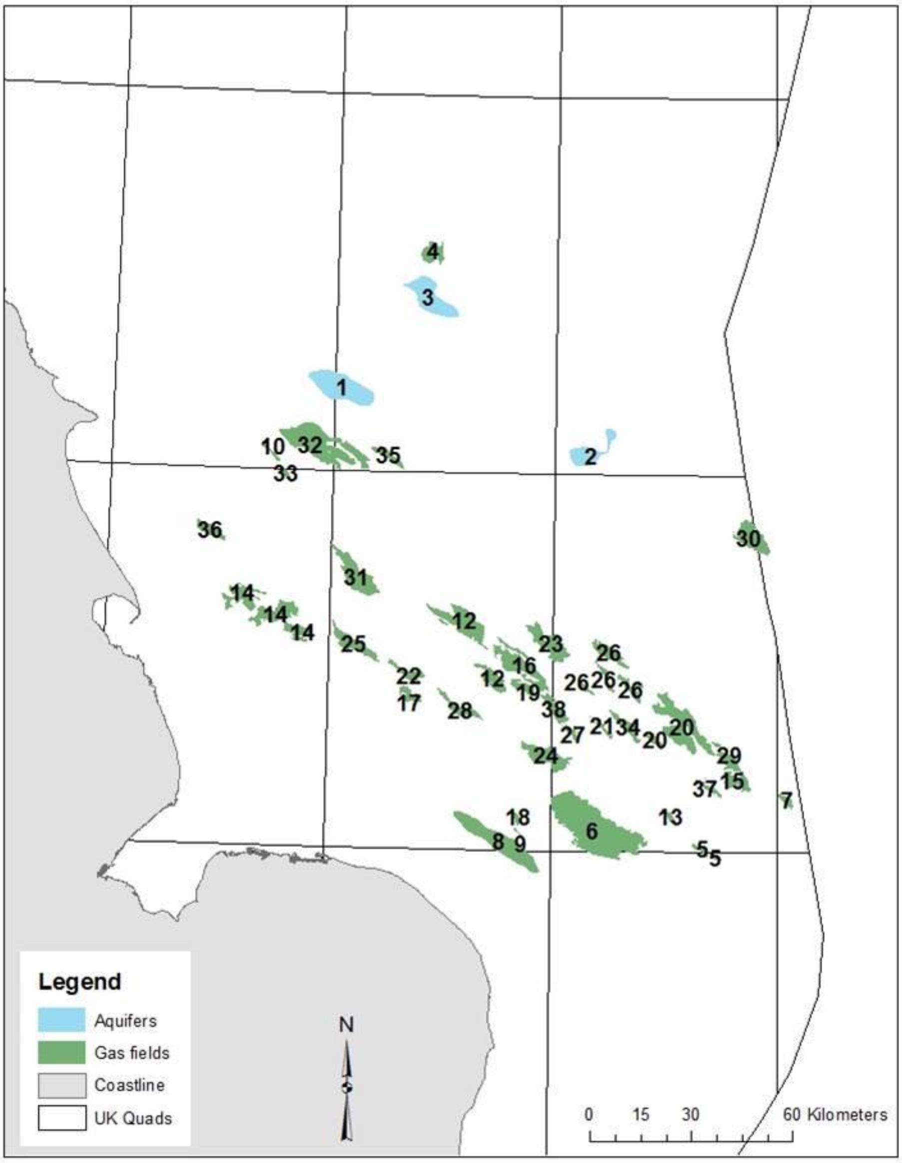


Figure 14: Storage sites remaining after site selection criteria were applied. The rank order is indicated by the number on the diagram (smallest number is highest rank – see Appendix 2).

5.2 UK SOUTHERN NORTH SEA - FIRST COME FIRST SERVED SCENARIO (FCFS)

In this scenario the storage sites are used in order of rank starting with the highest and working down the list until utilising the storage capacity in each site until the storage needs are met. This simulates a market driven approach where the market selects the storage units which are the 'best' geologically (in this case based on the limited selected criteria) that are available at the time required.

It is assumed that all the storage capacity of each site could be used, and that no pressure management wells would be used. The cumulative total storage capacity was calculated until all the CO_2 emissions for the snapshot years 2030 and 2050 could be accommodated. The storage sites required to meet the CCS targets in 2030 and 2050 are listed in Table 4.

Table 4: Storage units required to meet projected storage demands in 2030 and 2050.

Site number and ranking	Name of unit	Unit designate	Units contributing to CO_2 stored by 2030	Units contributing to CO_2 stored by 2050
1	AQ01	Saline Aquifer		
2	AQ02	Saline Aquifer		
3	AQ03	Saline Aquifer		
4	Esmond	Gas field		
5	Welland	Gas field		
6	Leman	Gas field		
7	Orwell	Gas field		
8	Hewett (Zechsteinkalk)	Gas field		
9	Little Dotty (Bunter)	Gas field		
10	Cleeton	Gas field		
11	Clipper North	Gas field		
12	Barque & Barque South	Gas field		
13	Thames	Gas field		

Figure 15 shows the location and rank of the sites used. In 2030 only one storage site is required to fulfil the storage targets set out in chapter 5.1. By 2050 an additional 12 separate storage sites (2 aquifer sites and 10 gas fields) are in operation.

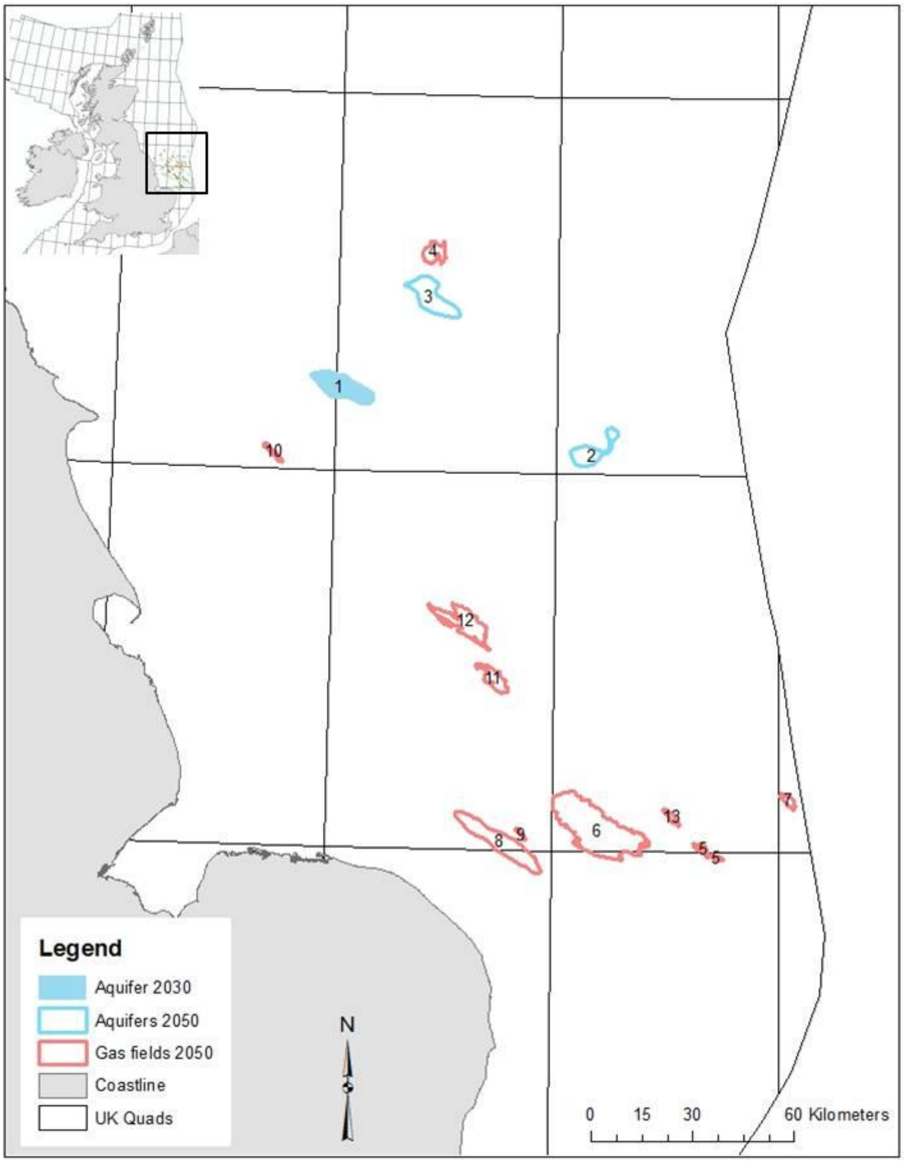


Figure 15: Location of storage sites used in the FCFS scenario. The order of utilisation is indicated by the number within the storage site.

Using a Geographical Information System (GIS) the 13 highest ranked storage sites were overlain by layers which describe sites or areas required or reserved for other uses of the surface and subsurface, in order to identify potential conflicts between them and the potential storage developments.

5.2.1 Subsurface interactions

By 2030, only one storage site in the SNS is in operation, Site 1 (Figure 16). This is a large saline aquifer site in the Bunter Sandstone Formation.

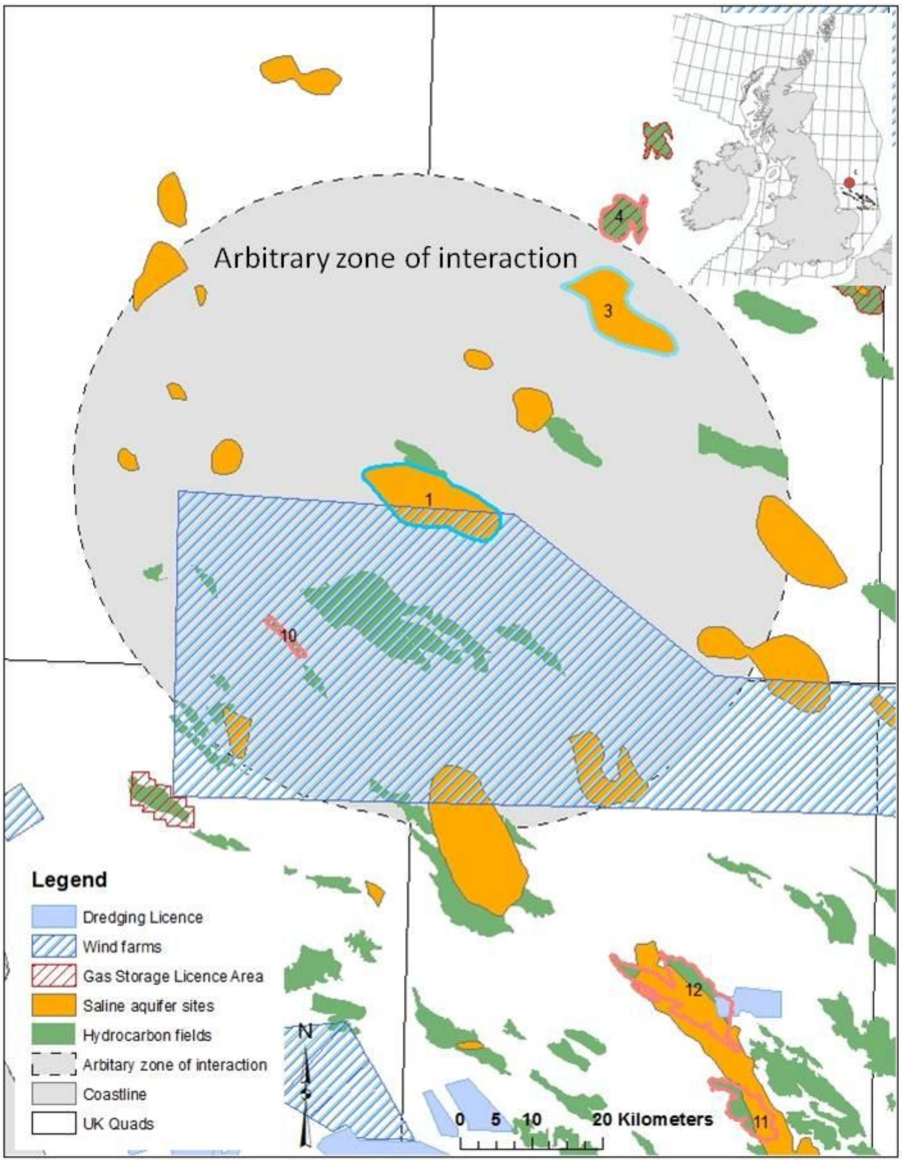


Figure 16: Map showing the location of site 1.

All potential interactions within an arbitrary radius of 40 km of Site 1 were examined. The spatial and subsurface interactions which may require planning decisions are listed in Table 5.

Table 5: Interaction on the surface and in the subsurface associated with site 1

		Planning interaction								
		Subsurface				Surface and spatial planning				
No	**Site name**	**Nearby hydrocarbon fields in a connected unit**	**Potential CCS fields within a connected unit**	**Overlying storage formation**	**Underlying storage formation**	**Wind farm licence area**	**Dredging licence area**	**Carbon storage licence area**	**Gas storage licence are or likely completion with gas storage**	**Existing hydrocarbon licence area**
1	AQ01	X	X					X		X

Site 1 in the scenario is a dome structure within the Bunter Sandstone Formation. Consequently the CO_2 plume will be retained within the dome and will not interact with any other uses of the subsurface, seabed or maritime area. However, it seems possible that the pressure footprint could reach depleted gas fields and other potential CO_2 storage sites included in the scenario. This is conjecture, and in reality depends greatly on the local geology.

Site 1 is close to other domes within the Bunter Sandstone Formation which, although not used in this scenario, may need to be considered for CO_2 storage potential in the future.

5.2.1.1 HYDROCARBON FIELDS

There are no producing hydrocarbon fields in the Bunter Sandstone within 40 km of Site 1.

It is unlikely that a storage site will be given a permit to operate if it might reduce or complicate hydrocarbon production (through increased water cut as a result of brine migration or migration of CO_2 into the hydrocarbon field). In this scenario CO_2 is stored in structural closures and unless the site is filled beyond the structural spill point (which is highly unlikely) CO_2 will be contained within the sites and will not interact with other sites. In the UK it may be that the storage operators will be expected to obtain the agreement of other nearby users of the subsurface prior to permit application. The Garrow gas field is adjacent and underlying Site 1, this has not prevented the award of a Carbon storage licence for Site 1.

5.2.1.2 DISCUSSION OF POTENTIAL SUBSURFACE INTERACTIONS

One principle of the FCFS scenario is that it would be the responsibility of later project developers or users of the subsurface to deal with any implications of any licensed preceding operations, and to demonstrate no negative interactions with existing users of the subsurface. Therefore, it would be up to the Regulator to determine the allowable pressure footprint and identify this in the licence requirements. In the scenario the Esmond gas field (Site 4), for example, will be utilised for CO_2 storage by 2050 and as a result the putative developer of Esmond would need to plan, study and potentially manage any interactions with preceding developments.

5.2.1.3 SURFACE INTERACTIONS

Site 1 (AQ01) lies beneath a designated wind farm licence area (Figure 16), and any potential conflicts must be resolved.

5.2.2 Snapshot 2050

To achieve the FCFS scenario's CO_2 storage targets, site 1 (AQ01) will continue to operate post 2030 and a further 12 storage sites will need to be developed and operating by 2050 (Table 4). The potential surface and subsurface interactions were examined using the GIS for all sites operating in 2050 and a summary of the potential interactions is provided in Table 6.

Table 6: Surface and subsurface interactions associated with storage site in snapshot 2050

		Planning interaction							
		Subsurface			Surface and spatial planning				
No	Site name	Hydrocarbon field or storage sites in a connected unit	CCS/HC field in overlying storage formation	CCS/HC field in underlying storage formation	Wind farm licence area	Dredging licence area	Carbon storage licence area	Gas storage licence are or likely completion with gas storage	Existing hydrocarbon licence area
2	AQ02	x		x					x
3	AQ03	x							x
4	Esmond	x						x	x
5	Welland				x				x
6	Leman								x
7	Orwell				x				x
8	Hewett (Zechsteink alk)			x				x?	x
9	Little Dotty (Bunter)	x		x				x	x
10	Cleeton				x				x
11	Clipper North		x						x
12	Barque and Barque South		x			x			x
13	Thames								x

5.2.2.1 INTERACTIONS IN THE SUBSURFACE

According to the scenario, Sites 2 (AQ02), 3 (AQ03), 4 (Esmond) and 9 (Little Dotty) operate in the period between 2030 and 2050, all of which are within the Bunter Sandstone Formation. CO_2 injection into these sites may potentially cause interactions (such as pressure increases or brine migration) with other subsurface operations within the same geological formation. The potential interactions are discussed in Chapter 2. Table 7 shows all the potential storage sites and hydrocarbon fields within a 40 km radius of the sites.

The other potential storage sites in operation in the 2050 snapshot are gas fields within the Leman Sandstone Formation, with the exception of the Hewett Zechsteinkalk gas reservoir (Site 8)[16]. The gas fields within the Leman are usually highly compartmentalised by sealing faults and is unlikely that CO_2 injection into Sites 5 (Welland), 6 (Leman), 7 (Orwell), 10 (Cleeton), 11 (Clipper North), 12 (Barque and Barque South) and 13 (Thames) will result in pressure and brine interactions beyond the storage complex.

All of the gas field storage sites in snapshots 2030 and 2050 could still be covered by active hydrocarbon licences and therefore have been considered in the interaction analysis.

[16] The Hewett gas field also has reservoirs in the Bunter Sandstone Formation and the Hewett Sandstone Formation, which were considered as separate storage sites by the GeoCapacity project.

Table 7: Hydrocarbon fields and potential storage sites within a 40 km radius of snapshot 2050 storage sites within the Bunter Sandstone Formation.

Name	Km to Site 2 (AQ02)	Km to Site 3 (AQ03)	Km to Site 4 (Esmond)	Km to Site 9 (Little Dotty)
AQ01 (Site 1)		30		
AQ03 (Unit 3)			4	
Esmond (Unit 4)		4		
Forbes		19	9	
Gordon		26	25	
Caister B & C	14			
Hunter	23			
Hewett (Bunter)				2
AQ04		14	12	
AQ05	12	24		
AQ06		16	24	
AQ07				36
AQ08	13			
AQ09	11			
AQ010	20			
AQ011	36			
AQ012	2			
AQ013	12			

5.2.2.2 ORDER OF STORAGE DEVELOPMENT

Storage site 2 (AQ02) is underlain by the Schooner gas field located in the Leman Sandstone Formation. It is unlikely site 2 (AQ02) would be granted a storage licence whilst the Schooner gas field is in operation unless an agreement could be reached between the operator of the Schooner field and the potential operator of site 2 (AQ02).

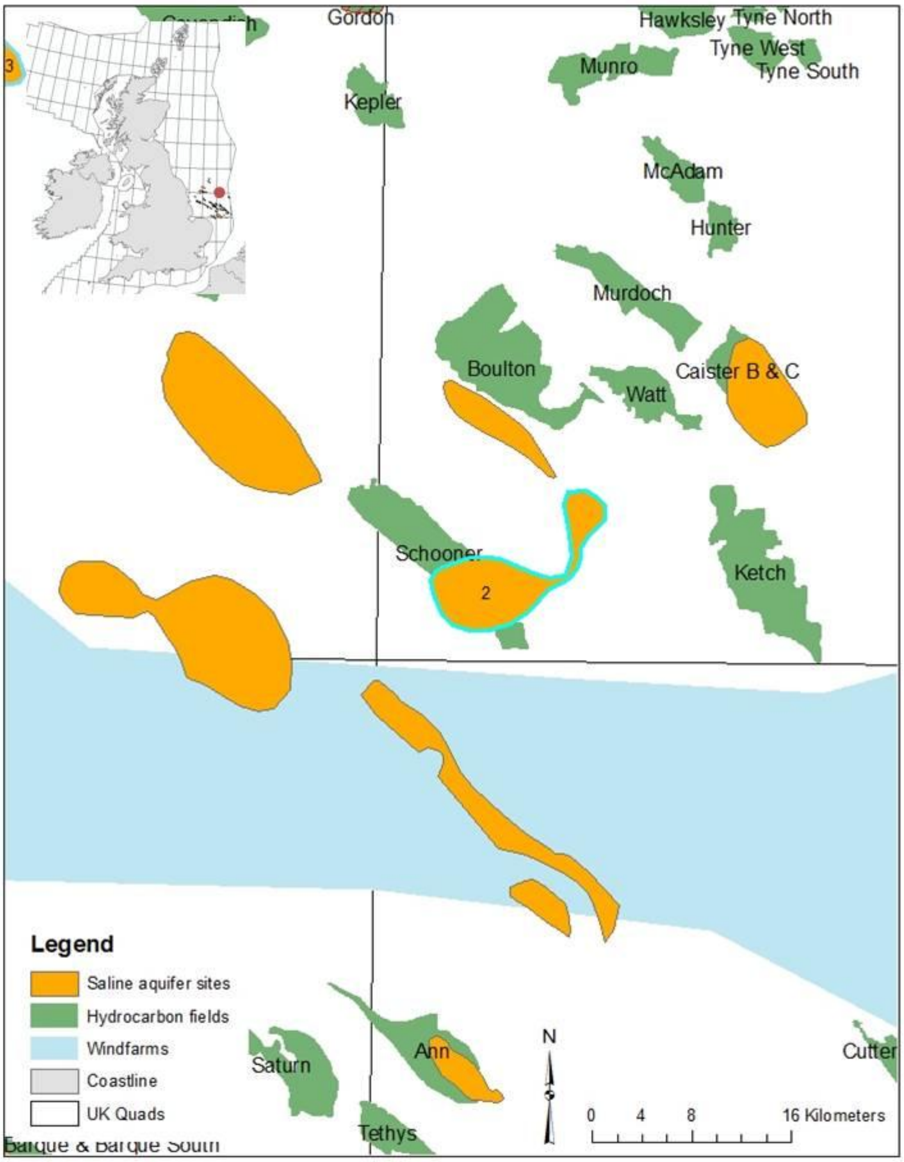


Figure 17: Location of site 2 (AQ02) showing the underlying Schooner gas field.

Although the Schooner gas field is not a site chosen as part of this scenario it is considered by the GeoCapacity project and CO2Stored database to have some storage potential. Development and operation of the overlying Site 2 (AQ02) as a CO_2 storage site could make any eventual development of the Schooner field as a CO_2 storage site at a later date more challenging because;

- Monitoring of the CO_2 within the underlying Schooner field using seismic techniques would be difficult due to acoustic blanking by the overlying CO_2 plume.
- Monitoring of the CO_2 in the Schooner field using wells may require accessing the storage site through the overlying plume in site 2 (AQ02) and might require expensive materials to be selected, e.g. chrome steel casing joints.
- Drilling thorough a pressurised CO_2 site may be technically challenging.
- It may be difficult to attribute any potential leakage from either storage site to the correct operator.

Some of these issues could be resolved by choosing to develop the underlying storage site first and, following closure of the Schooner storage site, develop site 2 (AQ02) which lies higher in the geological column. This would only be a suitable approach if other factors did not make Schooner less favourable for development, including the additional costs of developing a deeper storage site.

Sites 11 (Clipper North) and 12 (Barque), have a saline aquifer potential storage site overlying them (Figure 18). It is possible that wells used both for gas production and CO_2 operations could compromise the seal of the overlying storage formation if not completed properly. If the storage capacity in this area is to be fully utilised then the well completion as well as appraisal of abandoned wells should be sensitive to this.

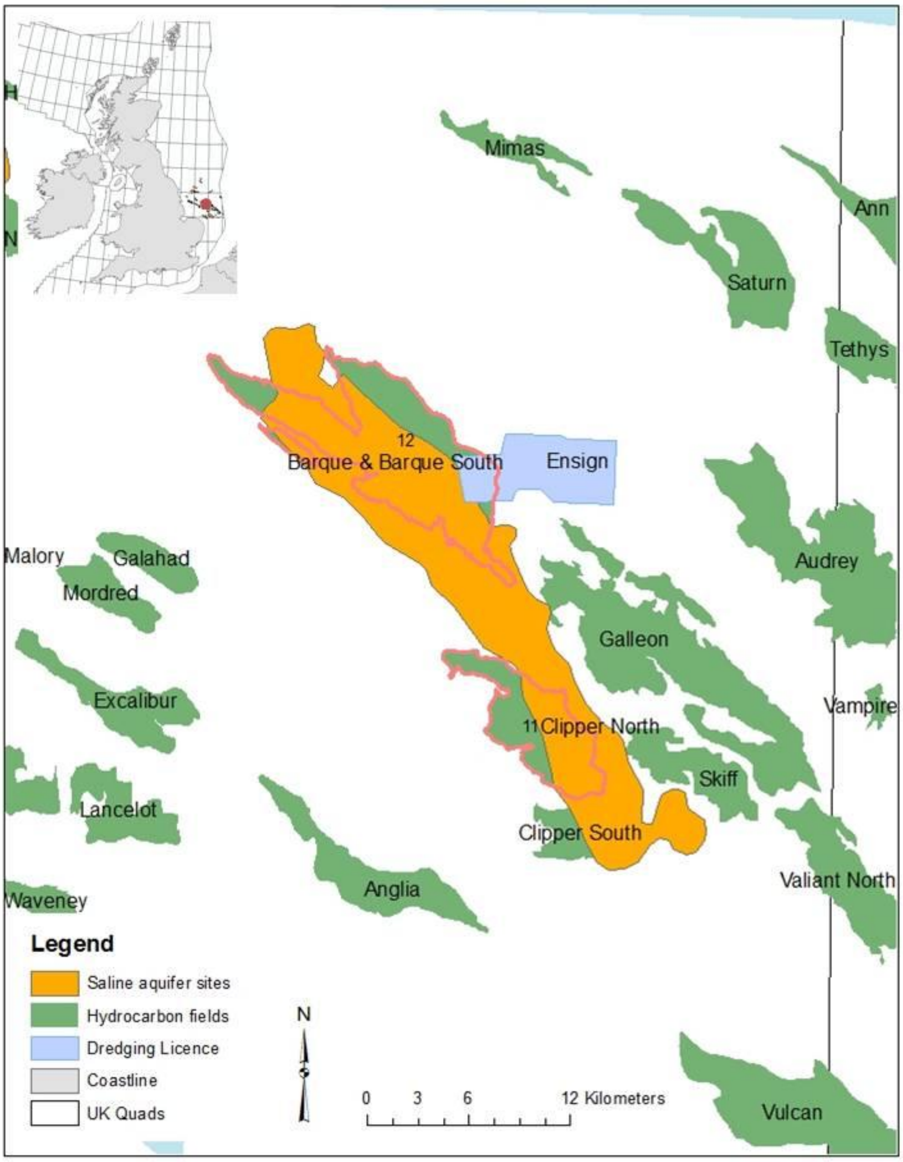


Figure 18: Location of sites 11 and 12 showing the overlying potetnial stroage site.

Both of these scenarios offer the potential for stacked storage systems. The advantages of stacked storage are discussed in section 10.2.1.

5.2.2.3 CONFLICTS WITH GAS STORAGE

Sites 4 (Esmond gas field), 8 (Hewett Zechsteinkalk gas reservoir) and 9 (the Little Dotty gas field) are located within gas storage licence areas. In these cases CO_2 storage could be in direct competition with gas storage.

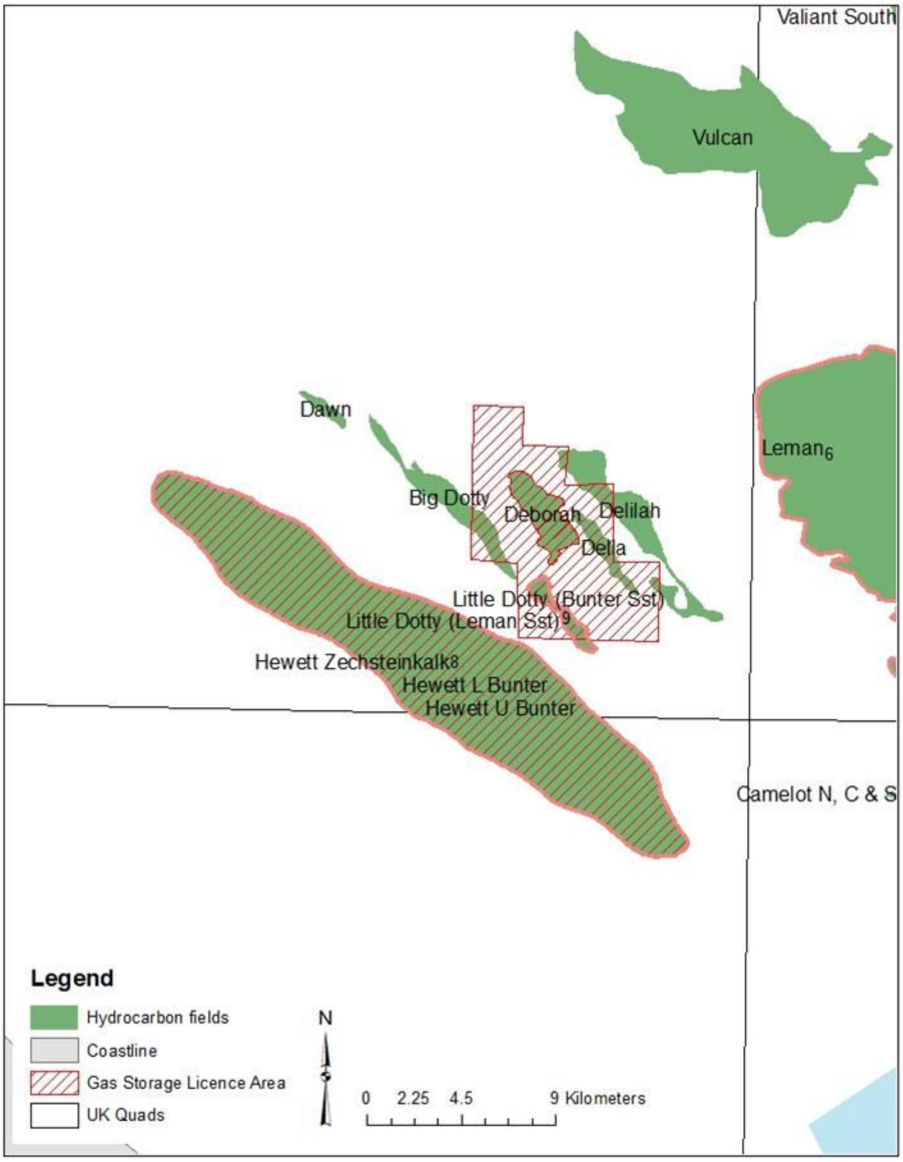


Figure 19: Location of site 9 showing it is within an existing gas storage licence area.

5.2.3 Surface conflicts

5.2.3.1 WIND FARMS

Sites 5 (Welland gas field), 7 (Orwell gas field) and 10 (Cleeton gas field) have spatial planning constraints. They are all in a designated wind farm licence area. If the storage sites were to be developed, surface injection and monitoring facilities will need to fit in with the existing wind farm infrastructure. For certain monitoring activities this could introduce challenges. Acquiring repeat seismic surveys for 4D seismic monitoring (recognised as one of the best ways of monitoring CO_2 storage sites), using boats and streamers would difficult between wind turbines.

Passive seismic techniques may potentially be disrupted by the ambient 'noise' caused by the wind turbines. On the other hand, ambient noise at storage sites to assist passive seismic monitoring has been proposed (Arts et al., 2013). Existing surface infrastructure associated with hydrocarbon production at these fields will already exist, and will have been accommodated during the planning of the wind farm, this may make 'fitting in' CCS injection infrastructure or re-using existing infrastructure possible. The extent to which potential ground movement from CO_2 injection could affect overlying wind farms may also need to be assessed.

5.2.3.2 DREDGING LICENCE AREA

Site 12 (the Barque gas fields) also has planning constraints. It is located in a dredging licence area. This could result in planning restrictions in terms of surface infrastructure during the duration of the dredging licence.

5.2.3.3 SITES WITHOUT IDENTIFIED CONFLICT

In this scenario, site 6 (Leman) and site 13 (Thames), appear to have no likely conflicts or interactions associated with them. As they are both still producing hydrocarbons the only potential conflict identified is availability of the sites for storage. However, once gas production has ceased they are likely to be good candidates for storage in terms of the minimal interactions associated with them.

5.3 FIRST COME FIRST SERVED (FCFS) CONCLUDING REMARKS

The FCFS sites were ranked based on a limited set of criteria, then deployed in ranked order until the storage targets for 2030 and 2050 were met. In the snapshot 2030 only one site (site 1, AQ01) is required to meet the storage targets. Site 1 already has a CCS exploration licence, despite overlap with a wind farm licence area. Site 1 (AQ01) lies within a connected aquifer unit and this could lead to potential pressure and brine interactions in the subsurface with a number of other potential storage sites and active gas fields, if this is not assessed and managed.

In the 2050 snapshot, Site 1 (AQ01) will still be in operation. To meet the target storage needs by 2050 a further 12 sites will be operating (2 aquifers and 10 gas fields). Many of these sites have potential conflicts on the surface and subsurface, with only 2 gas fields (site 6 (Leman) and site 13 (Thames)) showing minimal potential for interaction.

Most of the depleted gas field potential CO_2 storage sites in the FCFS scenario have potential conflicts associated with them, some of which may be difficult to overcome.

Site 2 (AQ02) lies above a producing gas field. It may be more difficult to use this site as a CO_2 storage site if this field is still operating. It is possible that CO_2 storage in the Bunter Sandstone could take place at the same time as gas production from the underlying Leman Sandstone gas reservoir, but it would involve complex negotiation with the operator of the field. This could increase the lead time and cost of storage development.

Site 9 (Little Dotty) and site 4 (Esmond) sit within a gas storage licence area. The market value of natural gas and the need for seasonal delivery and security of supply means that is more likely that site 9 (Little Dotty) and site 4 (Esmond) will have more value as natural gas storage sites than as CO_2 storage sites. As a result they are unlikely to be available for storage during the timeframe covered by this scenario. Esmond site 4 will not be considered in further scenarios as a CO_2 storage site due to this potential conflict.

Site 5 (Welland), site 7 (Orwell) and site 10 (Cleeton) are all located in wind farm licence areas. A wind farm licence area does not mean that there are necessarily any wind turbines present, only that the area is prospective for wind energy. Should there be a wind farm or planned wind farm developed in these locations, monitoring of CO_2 storage could be problematic for the reasons described in chapter 4.1. Therefore, these sites are considered to be unavailable for CO_2 storage for this scenario.

We are not aware of any current UK policy that would prioritise between wind farms or CO_2 storage should the choice be one or the other. Current high level UK government policy encourages wind energy, nuclear energy and CCS.

Sites 3 (AQ03) and 4 (Esmond) are in very close proximity and in the first-come, first-served scenario are likely to be in operation at the same time with Esmond possibly being used for gas storage. As a result the pressure rise from injection of CO_2 into site 3 could reduce the storage capacity or increase the need for pressure management wells. In this scenario this interaction could be avoided, either by using site which are further apart, by changing the order of utilisation or by accepting the use of pressure management wells.

The 13 storage sites chosen in the FCFS are geographically spread throughout the SNS. This could mean that pipeline infrastructure will not be optimised compared to a strategic storage resource management scenario (see below).

5.4 UK SOUTHERN NORTH SEA - STRATEGIC MANAGEMENT STORAGE RESOURCE SCENARIO (MSR)

This section describes the development of a Managed Storage Resource scenario within which three options were developed in order to explore how storage in the Southern North Sea could be managed to fulfil different needs.

5.4.1 Scenario Development

One challenge that the FCFS approach creates is that the storage sites are geographically spread across the southern North Sea and therefore pipeline sizes and lengths would be designed to connect only these specific storage sites to shore terminals or capture plants, unless the project developers were sufficiently confident that an economic benefit would accrue to them from oversizing their pipelines.

In order to examine if the detrimental interactions and potential impacts identified above in the FCFS scenario can be successfully mitigated, a Managed Storage Resource (MSR) scenario has been developed, within which three broad options are discussed. The aims of the MSR Scenario are the following:

- Reduce conflict with other uses of the subsurface, seabed and sea
- Reduce the length of pipelines needed
- Maximise storage capacity

This has been achieved by considering the interactions identified in the FCFS Scenario and determining if the interactions require the removal of a specific site and its replacement by another site, or if the interactions can be mitigated by other means. Each site in the FCFS Scenario has been considered in turn, starting with the highest ranked site. It is assumed that where possible, sites will still be developed broadly in rank order. However, in contrast to the FCFS Scenario, which applied this rank in strict order, in the MSR Scenario substitution of sites is allowed if it leads to a more optimised development of the necessary storage capacity.

As is currently the case in most regions globally, the MSR scenario assumes that hydrocarbon, groundwater or mineral resources will always be protected and that protection and exploitation of these resources will be given priority over storage rights. It is also assumed that storage will only take place where evidence is provided that indicates it is likely to be safe to store CO_2. The extent of strategic planning may depend on the relative weights placed on storage capacity, resource protection and exploitation, and cost minimisation.

5.4.2 Sites with potential detrimental interactions

Most of the higher ranked sites in the FCFS Scenario have some form of potential conflict associated with them, related to either spatial planning conflicts or interactions with other users. In many cases such interactions can be readily resolved through careful planning, discussions with affected stakeholders and, where necessary, agreements with affected parties and/or project redesign to mitigate the degree of detrimental interaction.

However, there are some fields with potential conflicts that may be more difficult to overcome and these are highlighted here. Site 2, discussed in Section 5.2.2.2, AQ02 lies above a producing gas field (the Schooner gas field). Hence, for the purposes of this MSR scenario, we assume Site 2 (AQ02) to be unavailable for storage during the timeframe considered. As a result, the corresponding storage capacity of Site 2 (AQ02) must be provided by an alternative storage site or sites, which have been ranked lower in this study. It should be noted, however, that it is possible that CO_2 storage development could take place during production.

Site 9 (Little Dotty), Site 4 (Esmond) and Site 8 (Hewett) are located within a gas storage licence area. The market value of natural gas and the need for intermittent gas storage for seasonal delivery, which are supported by policies encouraging security of supply and favouring hydrocarbon supply over CO_2 storage, will favour gas storage over CO_2 storage. We therefore assume that Site 9 (Little Dotty) and Site 4 (Esmond) are likely to have more value as natural gas storage sites than as CO_2 storage sites. As a result, their CO_2 storage capacity is replaced by that of lower ranked sites in the strategic resource management scenario.

Site 5 (Welland), Site 7 (Orwell) and Site 10 (Cleeton) are all located in wind farm licence areas. Given that wind farm licence areas have been designated for these areas already and leases for CO_2 storage have not been granted, these sites are considered to be unavailable for CO_2 storage for this MSR scenario.

Where a potential conflict was foreseen between an excellent CO_2 storage site and a prospective wind farm, it could be possible to design the wind farms to allow access to the CO_2 storage site for access to the storage infrastructure and for monitoring purposes. This would need a Competent Authority to recognise and plan for future storage development at such sites and to require such accommodations to be made during construction of the wind farm (or indeed other surface infrastructure such as pipelines and cables).

In summary, a total of seven sites from the FCFS Scenario may have conflicts associated with their location. This MSR Scenario considers options for planned approaches to avoid conflicts during the deployment of CCS to meet the UK emissions targets to 2050 set out in chapter 3.1. Therefore, to provide sufficient capacity to store the masses of CO_2 implied by the scenarios' emission targets, sites with a lower ranking will need to be included in the MRS portfolio to replace the capacity of the five original sites which have now been discounted.

5.4.3 Approaches to reducing interactions

5.4.3.1 Option 1: Avoiding Conflicts by Developing Different Sites

Choosing sites which avoid the potential conflicts described could be one approach to manage the development of storage sites. To replace the capacity lost by removal of the discounted storage sites, the next highest ranked units were considered in turn. These units are shown in Table 8. Each site was examined for conflicts as described above, resulting in some sites being discounted (Table 8).

Table 8: New sites that have been evaluated to determine if they meet additional storage capacity following discounting of some sites identified in the FCFS portfolio.

Site	Name	Conflict	Result
14	Amethyst E & W	Slight overlap with dredging and wind farm licence areas	Accepted
15	Sean South	Gas storage licence	Rejected
16	Galleon	No conflict identified	Accepted
17	Lancelot	No conflict identified	Accepted
18	Deborah	Gas storage licence	Rejected
19	Skiff	No conflict identified	Accepted
20	Indefatigable & Indefatigable SW	No conflict identified	Accepted

The portfolios of thirteen potential storage sites that could be developed, which are ranked highest but avoid the identified conflicts, are listed in Table 9. It is assumed that Sites 3 and 4 are managed using pressure relief wells. By coincidence five new sites replace the five discounted sites from the FCFS scenario; however it should be noted that both Site 14 (Amethyst) and Site 20 (Indefatigable) are made up of more than one accumulation of natural gas (Figure 20).

This option could be implemented by allowing leases in certain areas at certain times. The advantage of this approach is that potential detrimental surface and subsurface interactions are avoided by discounting those sites where such interactions occur and replacing them with new sites. The disadvantage is that the replacement sites may not be as geologically suitable as the original sites, which is reflected here by their lower ranking when assessed against the basic criteria in this study. This may result in higher site characterisation costs and possible higher construction and operational costs. However it must be stressed that the costs associated with characterisation, design, construction and operation of storage sites have not been evaluated in this study. A further disadvantage is that sites are widely distributed over the SNS and are still assumed to be developed separately in this option, reflecting an element of independent operators within a storage market. This development may not optimise the potential for sharing pipeline infrastructure.

Table 9: Portfolio of 'best' sites selected to avoid potential conflicts with other surface or subsurface uses, which provide required storage capacity to 2050.

	Site number and ranked order	Name	Removed from FCFS ranking due to conflict	Next ranked sites not accepted due to conflict	Sites chosen which avoid conflict to meet 2030 and 2050 storage targets
Original FCFS list	1	AQ01			x
	2	AQ02	x		
	3	AQ03			x
	5	Welland	x		
	6	Leman			x
	7	Orwell	x		
	8	Hewett (Zechsteinkalk)	x		
	9	Little Dotty (Bunter)	x		
	10	Cleeton	x		
	11	Clipper North			x
	12	Barque and Barque South			x
	13	Thames			x
	14	Amethyst E & W			x
Additional sites reviewed for managed approach	15	South Sean		x	
	16	Galleon			x
	17	Lancelot			x
	18	Deborah		x	
	19	Skiff			x
	20	Indefatigable and Indefatigable SW			x

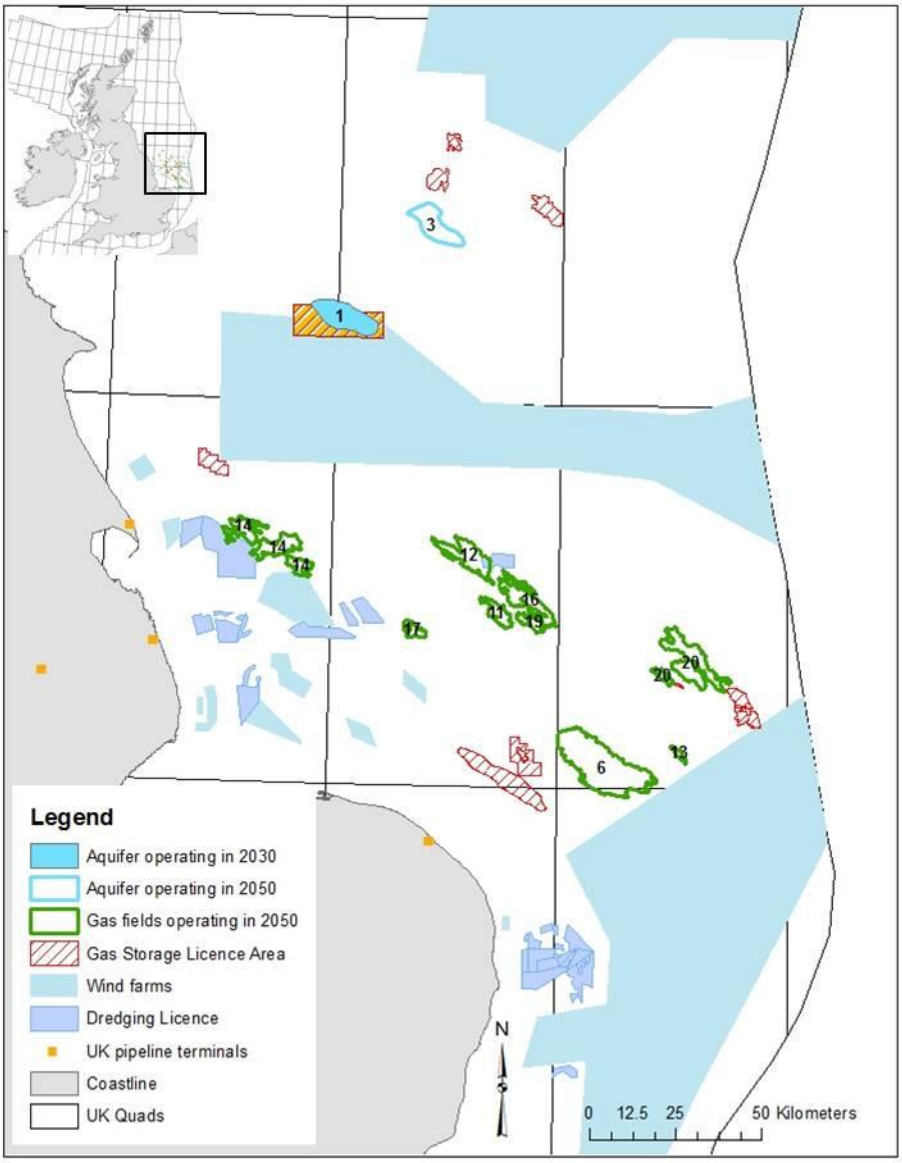


Figure 20: Map of storage sites that meet required storage capacities to 2050 for southern UK and avoid potential conflicts with other surface and subsurface uses.

5.4.3.2 Option 2: Target Sites with Larger Capacities

One option for limiting the number of storage sites and therefore reducing the potential for conflicts is to develop a smaller number of potential storage sites which have larger capacities. Here, sites were ranked according to their estimated storage capacity and were selected sequentially from the site with the highest estimated capacity first, until the predicted required storage capacity at 2050 was met. Sites with relatively high storage capacities were discounted if conflicts were identified as described in Section 5.4.2. The scores attributed to sites were not considered in this approach, since a site’s storage capacity has already been taken into account when scoring the sites initially.

Five sites were identified that would provide sufficient storage capacity to meet the estimated required capture rates in 2050 (Table 10). The portfolio comprises two saline aquifers and three gas fields.

Table 10: Portfolio of sites with largest capacity to meet predicted requirements for storage capacity, targeting the minimum number of sites with largest capacity.

ID	Name	Comments	Result
6	Leman	No conflict identified	Accepted
1	AQ01	Underlying gas field. Already a CCS licence area	Accepted
20	Indefatigable	No conflict identified	Accepted
26	Viking (A-E)	Overlying potential saline aquifer unit	Accepted
2	AQ02	In the same unit as other gas fields and potential saline aquifer storage sites	Accepted

The advantage of this option would be a smaller number of sites in operation, thereby reducing the amount of infrastructure required. Potential detrimental interactions with other users of the surface and subsurface are reduced. The close proximity of the Viking and Indefatigable fields forms a natural cluster of storage sites which could be developed via an integrated infrastructure (Figure 21).

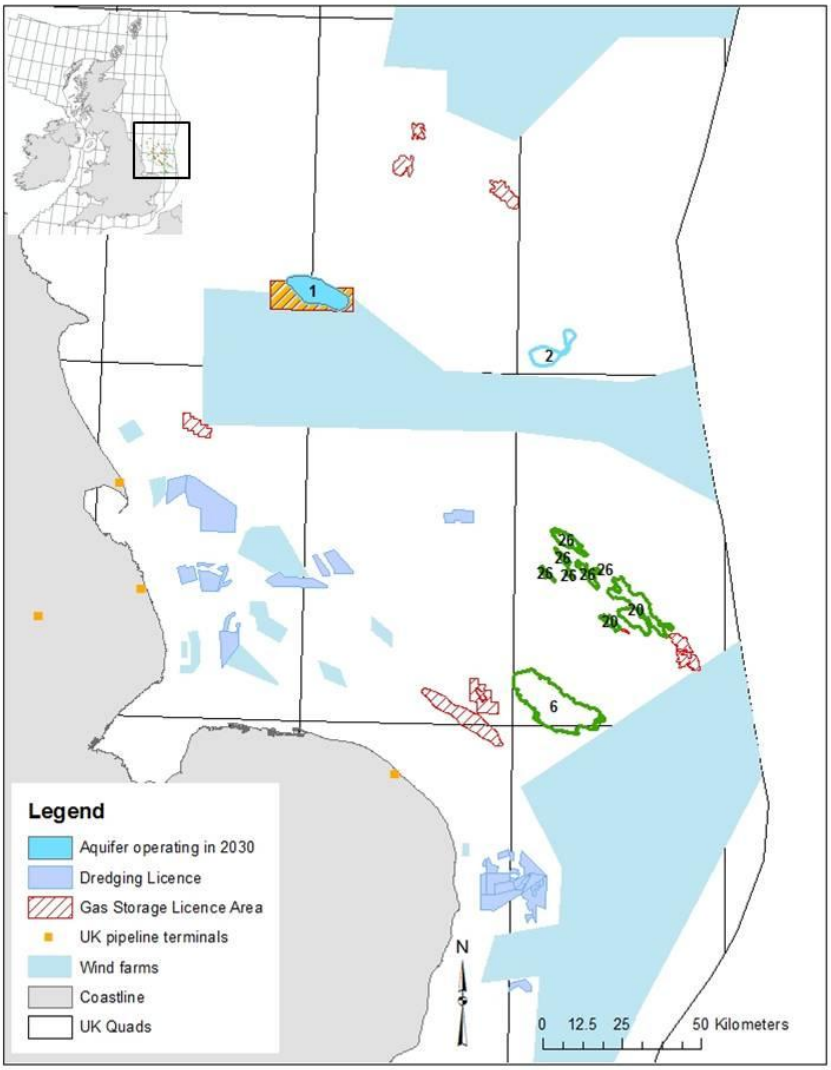


Figure 21: Map of portfolio of the minimum number of sites, regardless of their relative rank in terms of geological suitability or proximity to coast, that provide the estimated storage capacity that might be required in 2050.

A disadvantage of this method of selecting sites is that by choosing those sites with the largest estimated capacity, sites with a lower ranking will be used first. Therefore, sites that may be more suitable for early development (based on the criteria used in this study) are not selected. The sites with the largest capacity may not always be the most geologically suitable. For example, Site 20 (Indefatigable) is ranked 20th using the data available for this project. This may increase the geological risk as defined by the criteria used in this study.

5.4.3.3 Option 3: Developing clusters

It has been widely recognised, for example in the UK Government's CCS Roadmap (2012) that there could be many advantages in developing storage sites in a series of integrated clusters that can share pipeline infrastructure, balance injection with capture rates, provide flexible and more optimised storage and possibly coordinate monitoring, and thereby reduce costs (e.g. Simmonds et al., 2010; CRTF, 2013; Coulthurst et al., 2011).

To develop clusters in this option, three of the higher ranked projects, Sites 1 (AQ01), 3 (AQ03) and 6 (Leman) are used as catalyst projects, from which clusters are assumed to develop. This starting position assumes that these 'most suitable' storage sites will be initially selected, characterised and developed separately. It is further assumed that initial development of these catalyst projects would involve construction of suitably oversized infrastructure to support future expansion of the storage portfolio as capture rates increase. To identify those sites that might be included in each cluster, sites were selected and evaluated sequentially with increasing distance from each catalyst site up to 40 km distance, until the estimated storage capacity required in 2050 was reached. This maximum distance was selected as an arbitrary cut-off above which it is assumed the advantages of clustering are reduced. Again, the relative ranking of individual sites were not considered, though potential detrimental interactions were evaluated. However here it is assumed that CCS infrastructure would take precedence over wind farm development. This is because, when developing a storage cluster, it is not possible to discount nearby suitable sites due to spatial planning conflicts because replacement by more distant sites would not form a co-located cluster.

Using this approach, two distinct and natural clusters can be defined, which have been called the Easington and Bacton clusters, with reference to the closest onshore connection points for the pipeline networks.

The Easington Cluster

In this option, the first project to be developed is Site 1 (AQ01), which will be active in the 2030 snapshot. The nearest sites within a 40 km radius of Site 1 (AQ01) on the ranked list are Site 32 (Ravenspurn South Gas field), Site 35 (Johnston), Site 10 (Cleeton) and Site 33 (Neptune). All of these are in a wind farm licence area (Table 11). In this case optimisation of CCS infrastructure would need to take precedence over wind development here or CCS would need to be accommodated within the wind farm development (e.g. by developing access corridors). If compromises between CCS and other users of the surface and subsurface are not reached it will make cluster development extremely difficult.

The estimated capacity of this cluster could store approximately 34 % of the required captured CO_2 to 2050. The gas fields in this cluster are already connected by pipeline routes between themselves and the Easington terminal (Figure 22), though the extent to which these might be reused for CO_2 transport has not been evaluated. Development of this cluster would require additional infrastructure to be installed to exploit the storage capacity of the saline aquifers.

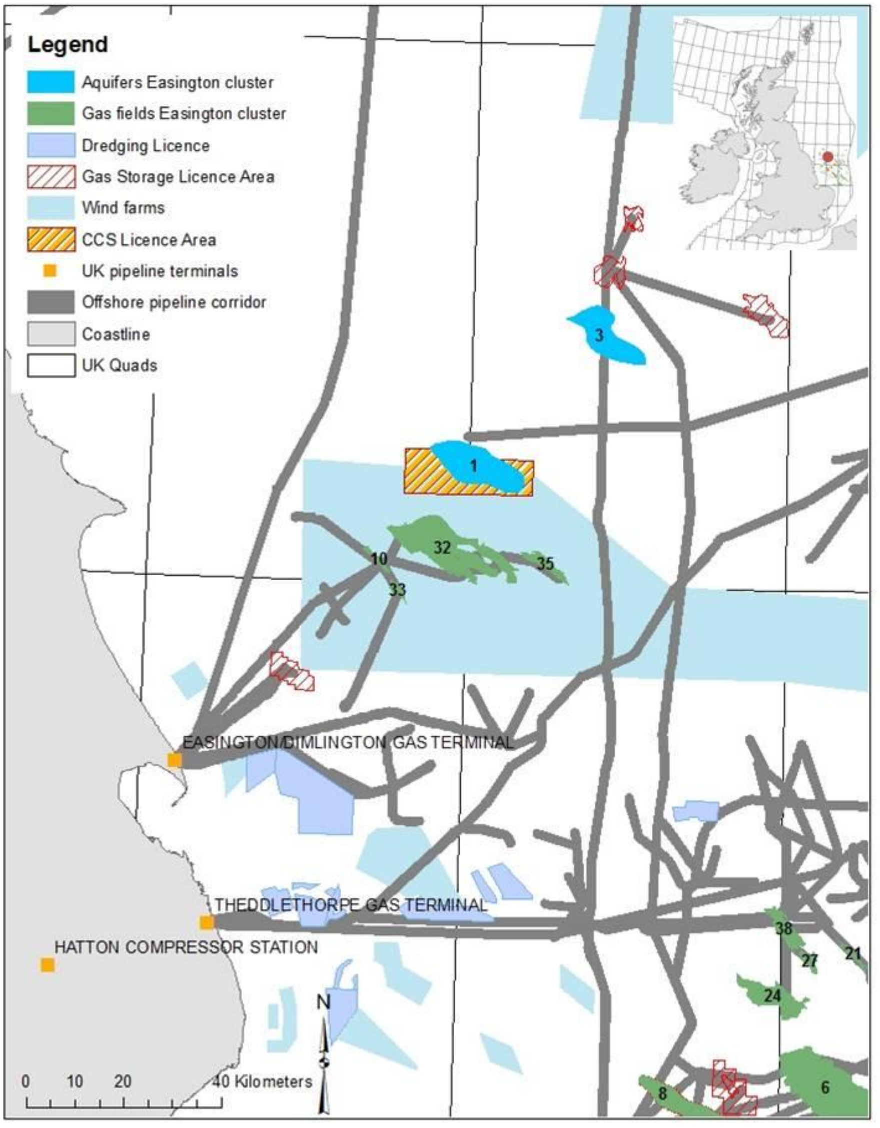


Figure 22: Portfolio of sites identified to form the 'Easington' storage cluster, assumed to form from a catalyst Site 1 (AQ01).

Table 11: Portfolio of possible storage sites identified to form the 'Easington' cluster.

ID	Name	Interaction	Comments
1	AQ01	No conflict	-
32	Ravenspurn	Wind farm licence area	Assumed appropriate arrangement could be made between the CCS operator and the wind farm licence holder or decision reached by the Competent Authority.
35	Johnston	Wind farm licence area	
10	Cleeton	Wind farm licence area	
33	Neptune	Wind farm licence area	
3	AQ03	No conflict	-

The next highest ranked site is Site 2 (AQ02), which is isolated from other nearby sites with no other ranked sites within a 40 km radius of it. As a result, Site 2 (AQ02) is not a good candidate to act as a catalyst for the development of a local cluster. In additional, the site is approximately 140 km from the nearest gas terminal onshore, which also reduces the likelihood of this site acting as a first site/catalyst for a cluster. However, it should be noted that there *are* gas fields and saline aquifer potential storage within a 40 km radius of site 2 (AQ02), but these sites did not make the ranked shortlist described in Section 5.2. This does not mean however that these sites are not suitable for CO_2 storage. Therefore for the development of this option, Site 2 (AQ02) has not been included in further 'cluster development'.

Site 3 (AQ03) would be considered next as a potential candidate to act as a catalyst for a second cluster. However, this site is located close to site 1 (AQ01) (see Figure 22) and it is therefore assumed that this site would not form an independent cluster, but would be developed as part of the Easington cluster.

Bacton cluster

In order to fully provide the required storage capacity predicted to be required a second cluster must be defined. Sites 1 to 3 are included in the Easington cluster and Site 4 has been discounted due to their locations and relatively small storage capacities. Site 5 (Welland) is also small storage site with a storage capacity just over 20 Mt, located within a wind farm licence area, and a long way from the UK coast. It is therefore considered to be unlikely to form the catalyst for a cluster though is close to the next possible site, Site 6 (Leman). This is a large gas field that is located close to the coast with many potential storage options close by. Its location does not pose any relevant conflicts that have been identified in this scenario. This cluster utilises high ranked Sites 8 (Hewett Zechsteinkalk) and 5 (Welland) (Table 12).

Table 12: Portfolio of possible sites identified to form the 'Bacton' Cluster.

ID	Name	Interaction	Comments
6	Leman	No conflicts	
8	Hewett (Zechsteinkalk)	Gas licence in overlying accumulation	Assumed appropriate arrangement could be made between the CCS operator and the gas producer or decision reached by the Competent Authority.
24	Vulcan	No conflicts	
13	Thames	No conflicts	
5	Welland	Wind farm licence area	Assumed appropriate arrangement could be made between the CCS operator and the wind farm licence holder or decision reached by the Competent Authority.
27	Valiant South	No conflicts	
38	Valiant North	No conflicts	
21	Ganymede	No conflicts	
37	Gawain	No conflicts	
20	Indefatigable	No conflicts	

These sites have been selected as a second cluster to the Easington cluster to meet the required storage capacity. This cluster is in approximate distance order from Site 6 (Leman) and therefore contains many units with relatively small capacity. There are already pipelines that could be utilised which connect many of the sites for the Bacton cluster (Figure 23).

However, another option would be to disregard the smaller sites and develop Sites 6 (Leman) and 20 (Indefatigable). This binary cluster would still provide sufficient storage capacity to meet estimated requirements in 2050 when developed in combination with the Easington cluster.

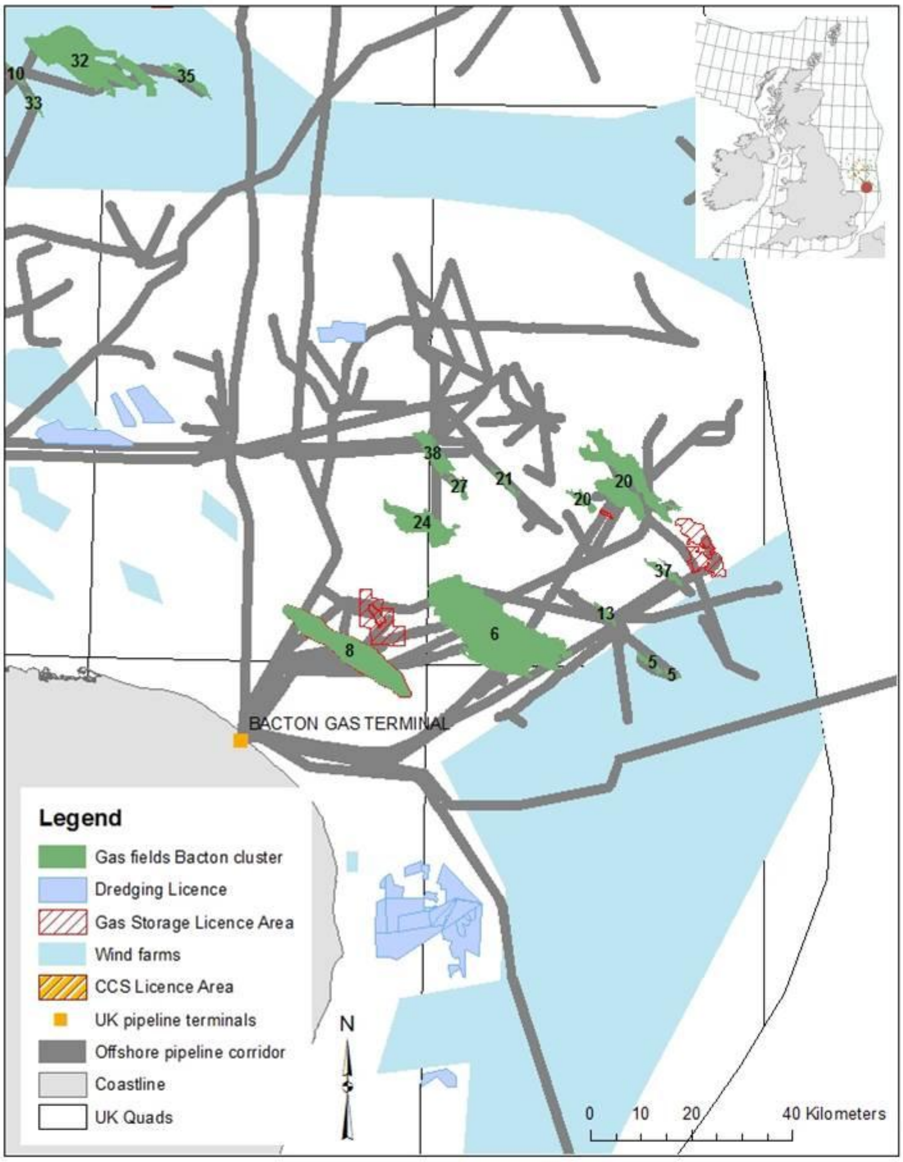


Figure 23: Map of sites that could form the proposed 'Bacton' Cluster.

5.5 MANAGED STORAGE RESOURCE (MSR) CONCLUDING REMARKS

No assessment has been made of the relative costs of implementing each option. Since site characterisation and commissioning costs may vary for each site in isolation, differences will arise due to costs of the construction of the connecting and integrating infrastructure and the discounted future value of site development costs. Development of each option could occur as demand for storage capacity increases. In the cluster option it may be assumed that initial transport connections to the catalyst project should be oversized, to the extent possible, to reduce future costs of resizing as storage capacity is commissioned. However, no evaluation of the relative benefit of this approach has been made for this study and a number of options for this would need to be evaluated, including adding additional capacity as needed compared to over sizing all components (compression and pipelines) initially.

This case study shows that even in an area with plentiful storage options there is the possibility for interactions in the surface and in the subsurface. Early projects will benefit from being able to choose the ‘best’ sites with minimum likelihood for interactions. The likelihood of potential interactions within the region will increase as the number of storage projects increase. This scenario shows that CCS could face competition from nearby CCS projects, wind energy generation, gas storage and ongoing hydrocarbon production. It is possible that only the ‘Competent Authority’ will have a sufficient overview of the whole storage region to monitor, manage and arbitrate such conflicts.

6 Underground Storage Permitting for CO_2 in the Netherlands

6.1 INTRODUCTION

The Dutch government supports the Kyoto Protocol and strives for a low CO_2 emitting industry by 2050. CCS is one of the strategies that help to accomplish the goals as agreed in the Kyoto Protocol. Other important strategies focus on energy efficiency and further development of renewable energy sources. CCS is considered a necessary intermediate step in the transition process towards a sustainable energy system that is estimated to take some 30 to 40 years.

Climate change is not the only driving force for the development and implementation of CCS. The Dutch government also expects economic benefits from a front-runner position in CCS technologies. Hence by allowing large-scale demonstration projects within the Netherlands, the Dutch government stimulates technological developments in capture and underground storage and supports dedicated research on the entire CCS chain. Since 2004, this research has been coordinated within a national research program called CATO. Some 40 participants consisting of governmental bodies, research institutes and industry are involved. The program is well embedded in international networks and programs such as the EU, IEAGHG and Zero Emission Platform European technology platform (ZEP). The CATO research program will be entering its third phase in 2014.

In June 2013 the Netherlands became the first EU country to be awarded a CO_2 storage licence compliant to the national mining act and the EU framework on CCS[17].

This chapter describes the Dutch policy, the regulatory framework for CO_2 underground storage licensing and the experience gained in the first permitting process and addresses the following topics:

- A brief outline of the current position of CCS in the Netherlands.
- The storage potential and deployment plans for CCS in the Netherlands medium to long term.
- The potential competition between CCS and other activities within the subsurface and at the surface (onshore and offshore).
- A brief outline of the current policies for managing and planning for multiple uses of the subsurface.
- An overview of gaps in research and policy that need to be considered when planning for multiple storage options in the subsurface.

6.2 CURRENT POLICY AND ORGANISATION AND ROLE OF GOVERNMENT

For the central Dutch government, two potential roles seem to be applicable within the CCS market; namely that of supervisor and that of facilitator and stimulator. This supports an organisational model of a privately run CCS market where the initiative comes from the CO_2 emitting parties themselves. This is the conclusion from an advisory study that among others

[17] Available at: http://www.rijksoverheid.nl/onderwerpen/co2-opslag/co2-opslag-in-nederland

included interviews with 30 experts (CO_2 Transport and Storage Strategy, EBN and Gasunie advice 2010, Marten W. Slagter and Edmund Wellenstein 2010).

In the Netherlands, it is preferable to leave, to the extent possible, the development of CCS to the market. The government's role may focus on the aspects that will not be filled or picked up by the market. First of all, the government in its role as supervisor must determine the conditions to operate. However, given the current market initiatives, the identified market failures and the still large uncertainties with CCS in terms of an economic market, the government should also take the role of facilitator and stimulator in the demonstration phase and the pre-commercial phase. In that role government incentives should mainly focus on capture and storage. A large investment associated with a role as a participant/owner seems to be neither necessary nor desirable.

Given the structure of the current ETS regime and the European grant programs (EERP and NER-300) it seems most appropriate to leave the initiative for CCS development to the emitting parties. This includes the demonstration phase as well as the pre-commercial phase and the commercial phase. In this model, the emitters will create the CCS chain and hire the services of the transporters and storage operators. There is, however, a possible risk of insufficient involvement of the E&P industry. Because CCS is not their current core business the industry may be reluctant to participate in the CCS chain, especially when the revenues are still uncertain. As a consequence, the development of CCS may be hampered, eventually leading to loss of technical knowhow from the current operators and abandonment of infrastructure and storage capacity. This may imply that legislation may have to be adapted; for instance, by providing the means and regulations for the adaptation of crucial infrastructure and potential storage locations by the government in order to assure its availability.

6.3 CCS PROJECTS IN THE NETHERLANDS

At present the Netherlands is still in the startup phase of large-scale demonstration projects which aim to store approximately 1 Mt per year. These projects will have to demonstrate the feasibility of the entire chain from capture and transportation to underground storage.

6.3.1 Onshore storage

Initial proposals for onshore CCS development in the Netherlands included the CCS project in Barendrecht (NAM, 2007) and a selection of possible storage sites in the northern areas of the Netherlands (TNO, 2008). These initiatives were cancelled by the Dutch Government in 2010 due to a severe lack of public acceptance. Subsequently, the government stated that development should take place in the offshore area (MEA, 2013) and that onshore development should only be reconsidered once the offshore practical capacity proves to be insufficient.

The first large-scale demonstration project in the Netherlands was planned in the town of Barendrecht in 2007. A 40 km pipeline was intended to transport pure CO_2 from a refinery in Rotterdam to the two depleted gas fields in Barendrecht. This location was selected due to the presence of an operational capture plant and the identification of a suitable sink for CO_2 within a short distance. The project’s aim was to gain experience and practical insight into the transport and storage of CCS. The project was planned to be executed in two phases. In the first three years a small field at a depth of 1700m would be filled with 0.8 Mt CO_2, followed by a second phase in which a larger field at a depth of 2700 m would be filled with 9.5 Mt CO_2. This second phase would take 25 years (NAM, 2007).

While the applicant was still proceeding with the technical work and the filing of a storage licence application the public commotion grew. The targeted gas field for storage is situated below a densely populated area and the inhabitants, many of whom have poor factual knowledge of CO_2 storage, feared for their safety and consequent economic losses due to decreasing real estate prices in Barendrecht. The communication between the project stakeholders and the public did not succeed in changing this perception. Despite efforts to inform the public about the project details and safety matters, support was not obtained from either the inhabitants or the local authorities of the town.

In its initial phase, the Barendrecht project was supported by the Dutch government with a €30 million subsidy in 2008. In 2009, the environmental impact analysis was accepted as the project met the legal safety requirements. Meanwhile the city council of Barendrecht and the commission on environmental issues of the province of Zuid-Holland voted against CCS in Barendrecht. Nevertheless, in January 2010 the Dutch Government agreed to proceed with CCS in Barendrecht. A restriction was made that only a successful execution of the first phase would lead to the permission to proceed with the second phase. However in March 2010 the government fell and consequently the authority to grant the storage licence was lost as the dossier on CCS was assumed to be politically controversial. In the period thereafter, the growing lack of (local) public acceptance induced the government to abandon the CCS project in Barendrecht as a whole. At that time CCS initiatives in the offshore, as well as in the northern parts of the Netherlands, were still being evaluated. In the spring of 2011 however, the Dutch government suspended all onshore CCS project and future focus was to be aimed at offshore projects only.

6.3.2 Offshore storage

Since 2004, small-scale CCS has been taking place in a demonstration project in the K12-B field in the North Sea. K12-B is a natural gas field in which the gas is composed of 12% CO_2. It is the first site in the world where CO_2 is being re-injected into the same reservoir from which it was produced. Investigations aim at assessing the feasibility of CO_2 injection and storage in depleted gas fields with corresponding monitoring and verification. Approximately 60 000 tons of CO_2 have been stored this way[18].

Two other demonstration projects were initiated for storage of CO_2 offshore, namely the Green Hydrogen Project (GHP) and the Rotterdam Capture and Storage Demonstration Project (ROAD). Recently the GHP was put on hold when the funding by the EC NER 300 was not granted. The ROAD project is still continuing but at a much slower pace than originally planned due to the unfavourable economic climate and uncertain status of the lack/delayed financial support by the national government and the EC. However, a significant milestone was reached by granting a storage license for CO_2 in June 2013.

Within the ROAD project a storage licence was filed by TAQA for the storage capacity in the P18-4 gas field. This gas field is situated offshore some 20 km away from the power plant that generates the CO_2. This combined setting makes it very suitable for a demonstration project. The depleted gas field is hosted by the Triassic Main Buntsandstein at a depth of 3500 meters below sea level. This field, together with a number of other fields in its direct vicinity, are fault-bounded structures sealed by mudstones. On a production time scale all gas fields are proven to be hydraulically isolated compartments (Arts et al., 2012). The storage permit was granted in 2013, with a formal start date in 2015. One restriction is that CO_2 storage must commence before 2018. The granting of this licence implies that all requirements concerning the environmental impact, the safety measures, risks management and risk mitigation plans for the storage process as well as the technical and financial capabilities of the operator were judged to be adequate. Besides this, other potential use of the subsurface was considered when judging the licence

[18] www.K12-b.nl, www.co2remove.eu/

application. At the time of application no competing activities were on-going, except for the oil and gas production. Moreover, no activities were planned in the direct vicinity of the proposed storage complex. For this reason the government decided that the large scale storage of CO_2 has priority as soon as the production of the remaining natural gas from the proposed gas reservoir has ceased.

6.4 STORAGE POTENTIAL AND DEPLOYMENT PLAN

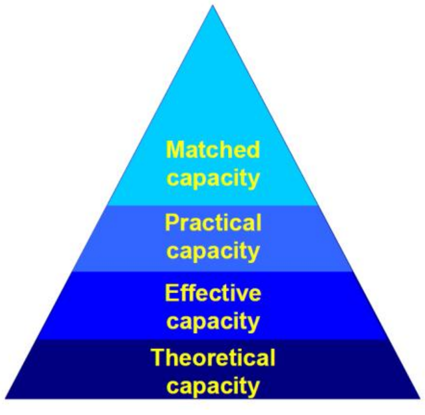
In addition to the numerous technical issues connected to the various aspects of CCS addressed within the national research program CATO, the Dutch government has investigated the practical consequences of CCS with regard to the (timely) availability of storage locations and storage potential.

The Dutch subsurface contains numerous gas fields which will become available for further use when their gas content has been depleted. The policy of the Dutch government is primarily aimed at the use of depleted gas fields as storage facilities for CO_2. These fields are preferred over aquifer storage because they are in most cases proven sealed volumes over geological time scales. Furthermore, considerable knowledge of the (dynamic) reservoir behaviour has been gained during the gas production phase, assuming that the seals have not been damaged during production. For aquifers in contrast, many of these aspects remain to be proven and require extensive research.

In order to be prepared for the take-off of large scale CCS in the Netherlands, the Dutch government is aware that large-scale subsurface storage of CO_2 will need a master plan to coordinate future activities. Which storage facilities will be available and when? If CCS is a national target then how will the Dutch government organise the process and which role does it want to play in this process? This has resulted in a number of studies on the storage capacity, the cost of transport and storage and on the organisational aspects of a national storage process. These studies provided a number of building blocks to eventually come to the desired master plan (NOGEPA, 2009; EBN/ Gasunie advice, 2010[11]). Some of the results are briefly described in this chapter.

6.4.1 Storage capacity

To investigate the opportunities for both onshore and offshore CO_2 storage in the Netherlands, the CO_2 storage capacity in depleted gas fields has been matched with the expected CO_2 supply scenarios in terms of volume and time of availability. This resulted in several scenarios that evaluate the transport capacity of the (existing) pipeline grid and the injection capacity of the reservoirs. In these scenarios the storage capacity was classified according to the scheme as introduced by the Carbon Sequestration Leadership Forum (CSLF, 2007). In analogy to the gas industry, the scheme introduces the concept of 'matched capacity' that stresses the important link between supply and demand in the CCS chain of capture, transport, injection and storage.



The theoretical storage capacity equals the total amount of CO_2 that can theoretically be stored in all the depleted gas fields based on a depth dependent CO_2 replacement volume of the ultimately recovered volume of natural gas. When filling all available pore space (theoretical capacity) only physical limits are taken into account such as volume, temperature and pressure (maximum pressure during injection may not exceed the initial pressure of the gas field).

In order to determine the effective storage capacity certain geological (reservoir) properties and engineering cut offs are applied. This includes minimum storage capacity (since small reservoirs will not be of economic interest) and minimum injectivity (as tight reservoirs will demand too much injection pressure). Practical storage capacity also involves (indirect) constraints of techno-economical or legal nature. Finally, the matched capacity combines the sources and the sinks in terms of volume and rates.

For this study, all actual production figures (both cumulative production and production forecasts) and relevant reservoir parameters (e.g. transmissivity) provided by the operators were used. This ensured an adequate calculation of available storage volumes that could not have been accomplished with data from the public domain alone.

Figure 24 shows the aggregated theoretical storage capacity for the entire offshore area against time. In these figures the capacity in gas fields only becomes available when gas production has ceased and the field is ready to be abandoned. It can be observed that most of the storage capacity will become available between 2010 and 2020.

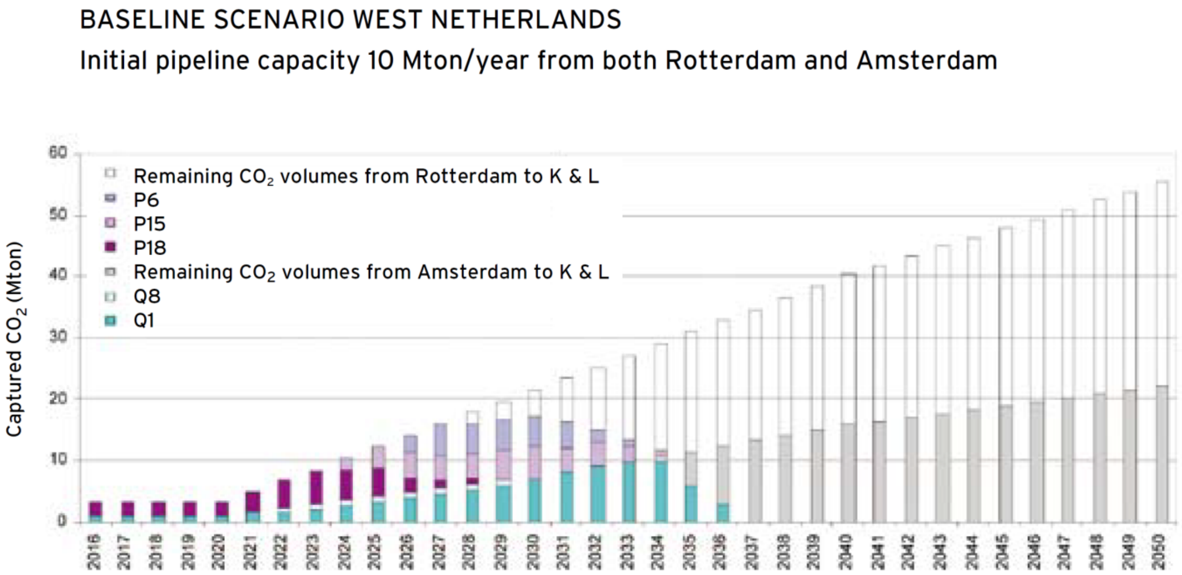


Figure 24: Available theoretical offshore CO_2 storage capacity based on expected end of field life (source: TNO 2008, Potential for CO_2 storage in depleted gas field on the Dutch Continental Shelf).

Studies by TNO (NOGEPA, 2009) illustrate the need for a master plan to manage the availability of storage capacity combined with transportation and injection capacity over a prolonged period of time in order to be able to match the supplied amount of CO_2 to possible storage sites. New storage facilities will have to be tied into the network before the injection capacity of existing facilities decreases. The order in which reservoirs will be connected depends on many parameters, including the planning and realization of trunk pipelines, end of gas production dates, and the technical condition of the existing infrastructure (e.g. costs of life time extensions). Moreover the volume of CO_2 supplied in time is an important parameter and clarity and security on the supply is essential. It is clear that direction is needed to determine the order of fields to be injected (NOGEPA, 2009).

The EBN/Gasunie report (2010)[19] considers a 'base case' CO_2 supply scenario and a 'green' CO_2 supply scenario for the main regionally delineated source areas/ CO_2 networks in the Netherlands. The 'base case' scenario assumes a continuation of the present day growth of CO_2 emissions and a 'green scenario' which assumes that the various CO_2 reducing measures will result in less emission and thus less need for storage (McKinsey, 2009). The main source areas comprise the "West Netherlands source area" including Rotterdam harbour, Amsterdam harbour and the Hoogovens steel plant on the coast in IJmuiden, and the 'North Netherlands source area' which comprises the Eems harbour. The 'West-Netherlands source area is linked to the onshore gas fields in the direct vicinity of Rotterdam and to the offshore gas fields. It is assumed that the CO_2 network would gradually be extended into the offshore with the growing demand for storage capacity. The North Netherlands source area is linked to the onshore gas fields that surround the Eems area. Offshore gas fields were considered too remote to compete with the onshore fields and the fact that many onshore storage locations would be available to accommodate the stream of CO_2 in due time (since then the government has decided not proceed with onshore storage for the time being). Other source regions such as the provinces of Zeeland and Limburg were beyond the scope of the study because of their relatively small CO_2 output.

In the baseline scenario expected CO_2 supply totals approximately 1300 Mt, 955 Mt from the West Netherlands and 345 Mt from the North Netherlands. The green scenario assumes 345 Mt from the West Netherlands and 170 Mt from the North Netherlands, totalling 515 Mt.

As an example Figure 25 shows the envisaged supply scenario from 1 to 20 Mt/year for the base case and 1 to 8 Mt/year for the green scenario for the 'North Netherlands source area'. Figure 25 also shows the availability of theoretical storage capacity in the northern onshore areas. This capacity increases with time as the gas fields will eventually be depleted. This case illustrates that there is sufficient theoretical storage capacity in comparison to the supply. It must be realised however that this scenario is not in compliance with the current government policy to limit storage to offshore gas fields for the time being. This may change when offshore pre-commercial storage and demonstration projects have proven the feasibility and safety of CO_2 storage, and onshore storage is reconsidered by the government.

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[19] CO2 transport en opslagstrategie - EBN/ Gasunie advies, 2010 available at:

http://www.nlog.nl/resources/StorageCO2/EBN_Gasunie_CO2transport_opslagstrategie.pdf

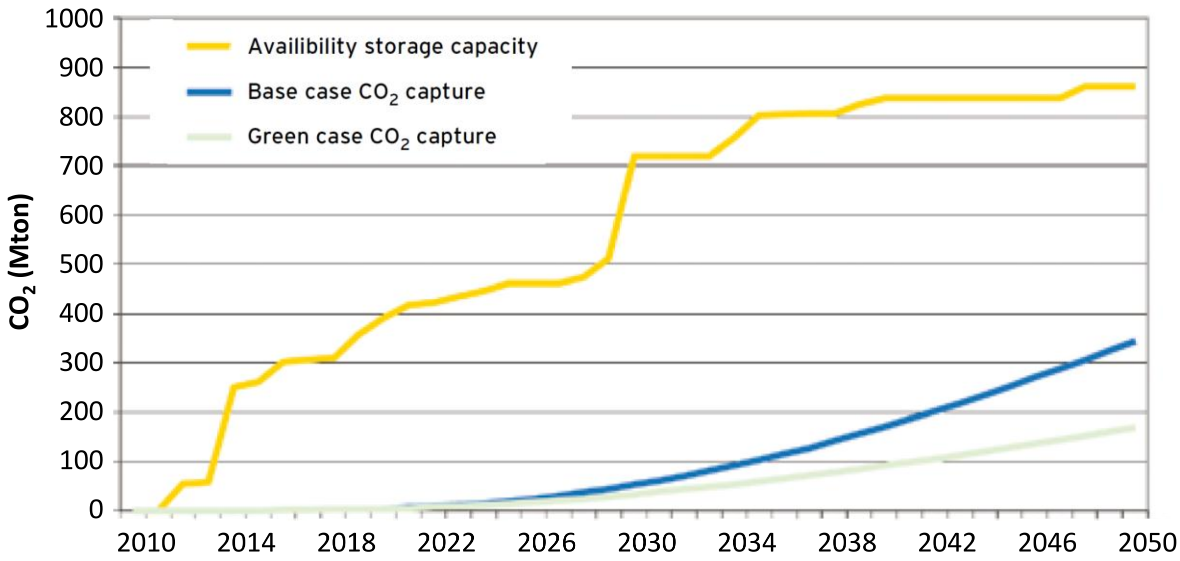


Figure 25: Development of cumulative theoretical onshore storage capacity in northern Netherlands versus the base case scenario and the green scenario for CO_2. (Source: EBN/Gasunie 2010, CO_2 Transport and Storage Strategy)

Offshore fields that could provide a CO_2 sink for the West Netherlands represent a total effective capacity of approximately 1160 Mt. Additional storage space could eventually be found in aquifers (e.g. in the Q1 block were long term water production related to the oil production has depleted the connected aquifers) or possibly onshore fields. For the western part of the Netherlands, an increasing supply of 2 Mt of CO_2 in 2015 to 55 Mt in 2050 is assumed as a base case (**Error! Reference source not found.**). Storage capacity could be found in the depleted gas fields in the directly adjacent offshore areas. After an initial period of storage it is assumed that around 2030, a major transport pipeline will have to be extended into the North Sea towards the K and L blocks to cater for the continuously growing CO_2 supply. A similar development is foreseen in the Amsterdam area. A green scenario with lower CO_2 emissions (increasing towards 24 Mt in 2050) would follow the same route but at a much slower pace. Extension into the K and L blocks would only occur in 2035. Also here the use of additional onshore fields could be reconsidered but only after the initial phase of offshore pre-commercial storage and demonstration projects and the decision to allow onshore storage by the government.

For all scenarios cost calculations were made based on industry information on dedicated cost figures for CAPEX elements such as wells, platforms (3 sizes) and pipelines and OPEX elements such as mothballing, maintenance and abandonment of wells, platforms and pipelines. For the Northern Netherlands, this would add up to €800 million for the transportation and storage of 345 Mt of CO_2 averaging to €2 to €3 per ton (onshore). Offshore cost might range from €8 to €13 per ton, approximately four times as high. Since the presentation of these studies, however, the policy of the government was amended and CCS is foreseen to start in offshore fields.

Since the publication of the NOGEPA and EBN/Gasunie studies various other TNO studies have focused on the determination of storage capacity and the further development of CCS scenarios for the offshore. These include an independent offshore storage assessment for Rotterdam (Neele et al., 2011) and an assessment of high capacity offshore CO_2 storage options including aquifer storage (Neele et al., 2012). Further assessments are currently performed for the spatial planning of deep subsurface activities in the Netherlands.

6.5 POSSIBLE COMPETITION IN THE SUBSURFACE AND SURFACE BETWEEN CCS AND OTHER USERS

6.5.1 Competition at the surface

As stated earlier the primary interest for storage locations is focussed on depleted gas fields. Converting these fields into storage locations would essentially mean that existing pipelines, production locations and offshore platforms may be reused to a great extent. It is unlikely that new well sites will be developed. Converting existing wells into CO_2 injectors is economically much more favourable compared to drilling new wells. Moreover, the licensing procedures for converting a gas production site into a CO_2 injection site is much shorter as both activities reside under the mining law.

The well heads, compressors and pumps are crucial components of the injection facilities. As the CO_2 will be injected without any further processing at the injection location, the gas treatment plants may be removed. This implies that little change in land use is expected except for the fact that the existing production infrastructure will be used over an extended period of time. The reuse of existing facilities implies that CO_2 injection will not be a new competitor for existing land uses. The prolonged mining activities may however prevent newly planned land uses. For example, onshore this may be an issue for planned development of new residential areas. Offshore and in coastal areas the extended mining activities may interfere with the development of offshore wind farms. The postponed abandonment of offshore infrastructure may however also have positive effects on hydrocarbon exploration in the far offshore areas. Due to the extension of subsurface activities new discoveries could potentially be tied into the existing platforms. Of course the evacuation of hydrocarbons will need a separate pipeline grid form the CO_2 transport grid.

As has been demonstrated by the Barendrecht project and inventories for storage locations in the northern parts of the Netherlands the public acceptance can be seen as the biggest hurdle for onshore storage. The main concern here is safety and not the use of land. For this reason storage of CO_2 is at this pre commercial and demonstration stage targeting offshore reservoirs only. Before the up scaling of CCS the Dutch government will have to develop their master plan for full scale CCS which may also consider onshore storage (e.g. due to the poor economic conditions for offshore storage development and the consequent abandonment of crucial infrastructure).

Finally the potential effects of storage in terms of ground movements should be mentioned. Many of the larger onshore gas fields have resulted in a significant subsidence due to pressure depletion and subsequent pore compaction. In several cases this has also resulted in induced seismicity. The increase of pore pressure during CO_2 injection may result in a partial reverse of this subsidence. For the onshore region, this may call for measures in order to control ground water levels in sensitive areas. Gas fields characterised by induced seismicity should be analysed for potential reoccurrences of earth tremors. For the offshore storage locations these issues are mostly irrelevant.

6.5.2 Competition and interference in the subsurface

The most prominent competition for CO_2 storage in the Dutch subsurface exists in the onshore areas. Here the permanent storage of CO_2 may mainly prevent gas fields from being used for other storage options. This mainly concerns the underground storage of natural gas (UGS) and disposal of formation water associated with hydrocarbon production. For other gasses, such as nitrogen and hydrogen, salt caverns are considered to be more appropriate because of the smaller volumes that are involved.

The giant gas field of Groningen currently accommodates a major part of the flexibility in gas production. In addition to the Groningen swing capacity there are now up to four onshore underground gas storage (UGS) sites operational or under development within depleted gas fields. A fifth UGS site is present in salt caverns in the northeast of the Netherlands. As the Groningen gas field nears its end of field life and its swing capacity decreases accordingly, the production flexibility will gradually have to be replaced by other UGS facilities. Taking the total annual gas production and its seasonal and peak variations, it is expected that the flexibility may easily be accommodated by up to five additional storage facilities (depending on size and location). The total number of producing gas fields in the Netherlands on and offshore is almost 300 (Figure 26). Only a small number of these fields will qualify for UGS site as they require the appropriate location, size and reservoir characteristics. Therefore these fields may be reserved as potential UGS sites preventing them from being used as a permanent storage location of CO_2. In contrast to the storage of CO_2, UGS only puts a temporary claim on the subsurface. UGS facilities may be reused for other purposes after their operations have ceased. As a matter of fact the expected time window of UGS operations overlaps with the time window for CCS. Therefore it is not realistic to assume that additional CO_2 storage will still be needed at a large scale after UGS has been discontinued.

The other main competition for onshore CO_2 storage may result from geothermal producer and injector pairs that are positioned nearby the storage reservoir within the same aquifer. Depending on the size, pressure, transmissivity and structure of the storage reservoir and the intended development scheme for injection, the pressure influence may extend up to several kilometres into the aquifer. In the extreme case, the placement of a geothermal production well too close to a CO_2 injector may eventually result in the undesired co-production of the injected CO_2. The presence of high permeability zones and open fractures may enhance this risk.

Other examples of potential interference and competition between onshore CO_2 storage and other subsurface activities include:

- cases were a potential geothermal prospect will not be accessible for drilling due to its positioning directly below the storage reservoir;
- gas production from shale layers directly above the storage reservoir as the hydraulic fracturing activities may lead to breach of a shale that is acting as a seal to a CO_2 storage facility;
- salt production activities from rock salt layers directly above the storage reservoir as the dissolved caverns may weaken the seal.

In the offshore the main interference and competition may result from the connectivity and pressure communication with adjacent gas fields that are under development and production. For example, this is being considered with the eventual storage of CO_2 into the P18A field. The increasing pressure during CO_2 injection and simultaneous depletion due to gas production in adjacent structures may lead to greater pressure differences and consequent leakage of CO_2 through boundary faults that were sealing before production and injection started. Currently, geothermal energy production and UGS are not considered as viable options offshore and little interference and competition is to be expected from these activities.

6.5.3 Spatial Planning Legislation

Underground storage of CO_2 is under the jurisdiction of the Mining Act. This act originates from Napoleonic times and was updated in 2003. In that version the mining act already made provisions for storage licences. Since 2011, the European directive for geological storage of CO_2 was implemented as well. The current legislation is primarily designed to ensure a safe and adequate use of the subsurface but does not incorporate a weighing of all potential options. Once an application has been submitted the principle of “first-come, first-served” applies. The Mining Act does not cater for any considerations of spatial planning.

Province (district) authorities are consulted for licence applications and permitting in connection with potential surface restrictions or interferences. The subsurface (below the direct impact on the surface activities) has hardly any role of importance at present.

The Dutch government may coordinate the decision making process with projects of national importance. In this so-called state coordination regulation (*rijkscoördinatieregeling*) the various decisions on licenses and exemptions necessary for the project will be coordinated and handled simultaneously. The ministry of economic affairs manages the process. Underground storage projects are labelled as of national importance and as such they are automatically handled under this state coordination regulation. Since July 2008 projects of national importance also qualify for a so-called “*Inpassingsplan”* under the Spatial Planning Act. This *Inpassingsplan* gives the national government the right to adapt the spatial planning by district government or local governments. In this way the national government may overrule local decisions to implement a national master plan on CO_2 storage in the subsurface.

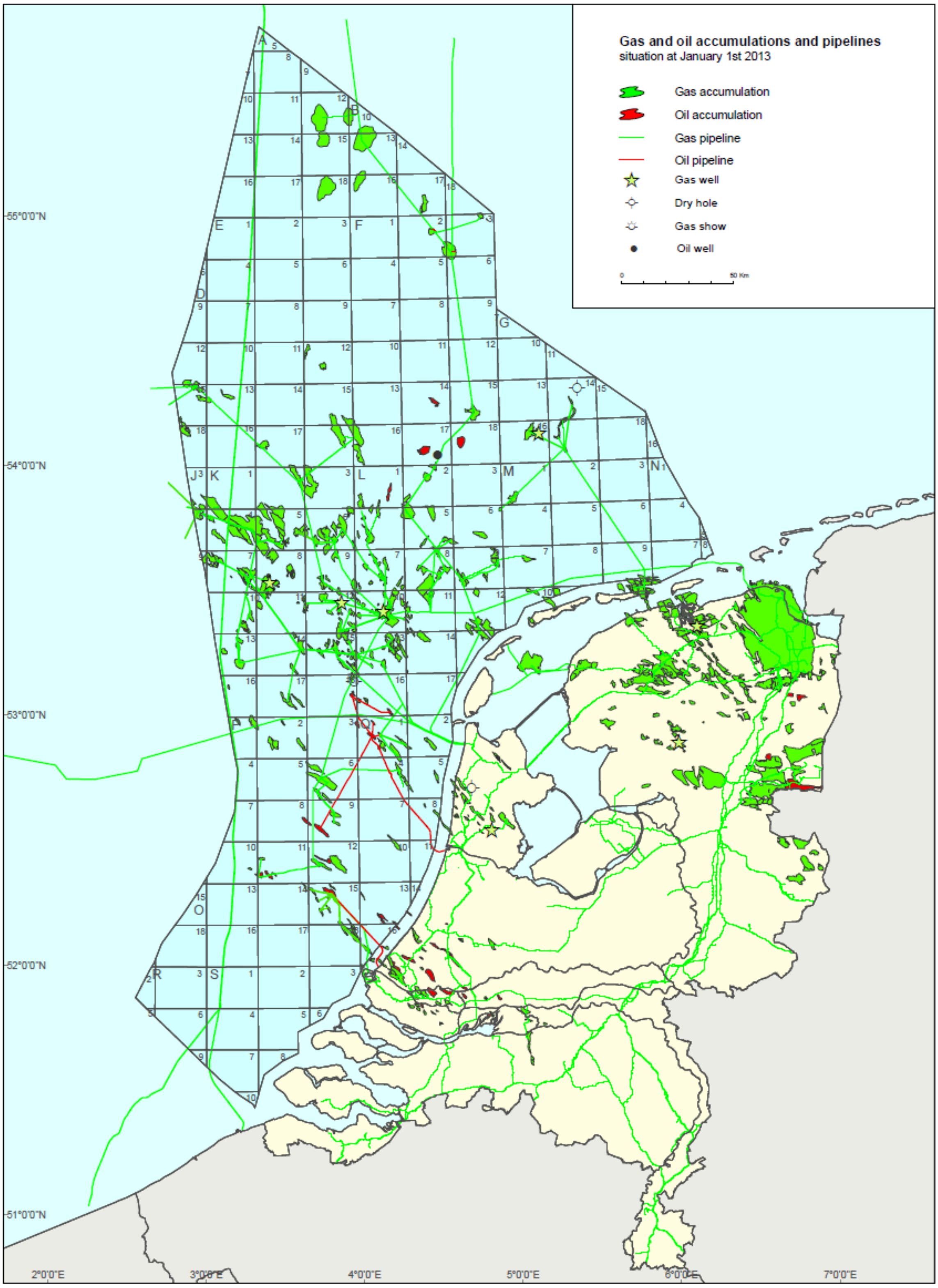


Figure 26: Outline map showing oil and gas accumulations in the Netherlands (as at 1 January 2013). New discoveries are indicated with a yellow star. (Source: Natural resources and geothermal energy in the Netherlands, Annual review 2012, TNO)

7 Australia

7.1 INTRODUCTION

Australia is richly endowed with natural resources (fossil fuels in particular) and is heavily reliant on mineral and energy exports for its economic well-being. Inexpensive domestic energy based on coal and gas is the established norm. As a result Australia has been consistently ranked amongst the top developed countries with regard to CO_2 emissions per capita since 1990. These factors have been central to the polarised and politically charged debate on climate change in Australia since the early 1990's.

While Australia was an early mover in signing the Kyoto Protocol in 1998, it took a further 10 years to move to ratification in December 2007. Nevertheless, the previous Australian Government committed to reduce emissions by 80% by 2050 (compared with 2000 levels). Following years of debate a carbon pricing mechanism was legislated into effect in November 2011 and an emissions trading scheme (ETS) similar to the European Union ETS model mooted for introduction in 2014. However, the incumbent Government is moving away from both approaches, having stated its intent to repeal the carbon tax and introduce a climate related *Direct Action plan* (a range of program initiatives – details to be announced later). CCS policy and regulatory frameworks have been developed in Australia within the broader rubric of climate and energy policy. The previous Government actively pursued CCS deployment, championing it both domestically and internationally and introduced a range of CCS support programs (i.e. the CCS Flagships Program; the National Low Emissions Coal Initiative; and the Global CCS Institute).

Under Australia's federal system of government, the Australian (national) Government has jurisdiction extending from three nautical miles offshore to the edge of Australia's continental shelf (Commonwealth waters), while the State and Territory Governments have jurisdiction onshore and in relation to coastal waters. CCS legislation has developed along these lines - the Australian Government being the key player given that the majority of highly prospective CO_2 storage sites are offshore (along with the bulk of petroleum activity). Ownership of most subsurface resources (including minerals/petroleum and use of the pore space) is vested in the crown (on behalf of the people).

CCS legislation has been developed by most jurisdictions in Australia - covering both on and offshore - details can be found in the IEA CCS Legal and Regulatory Review web site.[20] The regulatory approach has been a mix of modification to pre-existing petroleum regulations (i.e. the Australian Government's *Offshore Petroleum and Greenhouse Gas Storage Act 2006*); specific purpose legislation (i.e. Queensland's *Greenhouse Gas Storage Act 2009*); and even project specific legislation (i.e. the *Barrow Island Act 2003* and its Schedule 1 [the *Gorgon Gas Processing and Infrastructure Project Agreement 2003*], and associated Environment Protection Authority approvals in Western Australia). In general, there is a strong preference to adopt 'objectives based regulation' rather than a prescriptive approach.

7.2 STORAGE STATUS AND POTENTIAL IN AUSTRALIA

While there are compelling reasons why individual jurisdictions have chosen to follow different approaches regarding the design and form of the CCS regulatory frameworks which have been adopted, all have sought to adopt a common set of nationally agreed, overarching principles

[20] http://www.iea.org/topics/ccs/ccslegalandregulatoryissues/ccslegalregulatoryreview/

(MCMPR, 2005). The clear intent of the guiding principles is "*... the achievement of a nationally consistent approach to the implementation of this* [CCS] *technology…*" and to provide industry with a degree of certainty concerning the regulatory and operational parameters in relation to CO_2 storage which might apply across jurisdictions (The principles shown in Box 1).

BOX 1: CO_2 CAPTURE AND GEOLOGICAL STORAGE REGULATORY GUIDING PRINCIPLES (2005)

The following guiding principles facilitate a nationally consistent approach to the application of Carbon Dioxide Capture and Geological Storage (CCS).

- *ASSESSMENT AND APPROVALS PROCESS*
- *Assessment and approvals processes should be consistent with agreed national protocols and guidelines.*
- *Existing legislation and regulations relating to CCS should be identified and modified and augmented where necessary.*

- *ACCESS AND PROPERTY RIGHTS*
- *Surface and subsurface rights for CCS should provide certainty to rights-holders of their entitlements and obligations.*
- *These rights should be based on established legislative and regulatory arrangements, custom and practice and accommodate the likely evolution of multi-user CCS infrastructure and facilities.*
- *In granting rights to inject the CCS stream into subsurface formations, governments should give due consideration to land use planning issues that may arise as a consequence.*

- *TRANSPORTATION ISSUES*
- *Regulation relating to the transport of a CCS stream should be consistent where possible; using agreed national protocols and guidelines.*

- *MONITORING AND VERIFICATION*
- *Regulation should provide for appropriate monitoring and verification requirements enabling the generation of clear, comprehensive, timely, accurate and publicly accessible information that can be used to effectively and responsibly manage environmental, health, safety and economic risks.*
- *Regulation should provide a framework to establish, to an appropriate level of accuracy the quantity, composition and location of gas captured, transported, injected and stored and the net abatement of emissions. This should include identification and accounting of leakage.*

- *LIABILITY AND POST-CLOSURE RESPONSIBILITIES*
- *Current regulatory principles and common law should continue to apply to liability issues for all stages of CCS projects.*
- *Governments' overall consideration of post-closure storage of CCS streams must aim to minimise exposure to health, environmental and financial risks for project operators, governments and future generations.*

- *FINANCIAL ISSUES*
- *For all stages of a CCS project, wherever practical, established legislative, regulatory and accounting processes should be used in preference to introducing new regulations.*
- *The income from, capital and operating costs associated with a CCS project should be treated in the same way as for any other business venture for taxation purposes.*
- *Regulation should recognise the potential for post-closure liabilities for CCS activities and consider appropriate financial instruments to assist in the management of such risk.*

These principles - which have largely been adhered to by all jurisdictions in developing their CCS regulatory regimes - clearly aim to facilitate safe and effective storage operations. However, Australian Governments have not simply focussed on ensuring that there is a conducive regulatory framework in place. Considerable effort has also been undertaken to better define Australia's potential for CO_2 storage. In mid-2008 the Australian Government established the Carbon Storage Taskforce, bringing together key Government and industry players, with the specific mandate to "*... develop a roadmap to drive prioritisation of, and access to, a national geological storage capacity to accelerate the deployment of CCS technologies in Australia* (Carbon taskforce., 2009)."

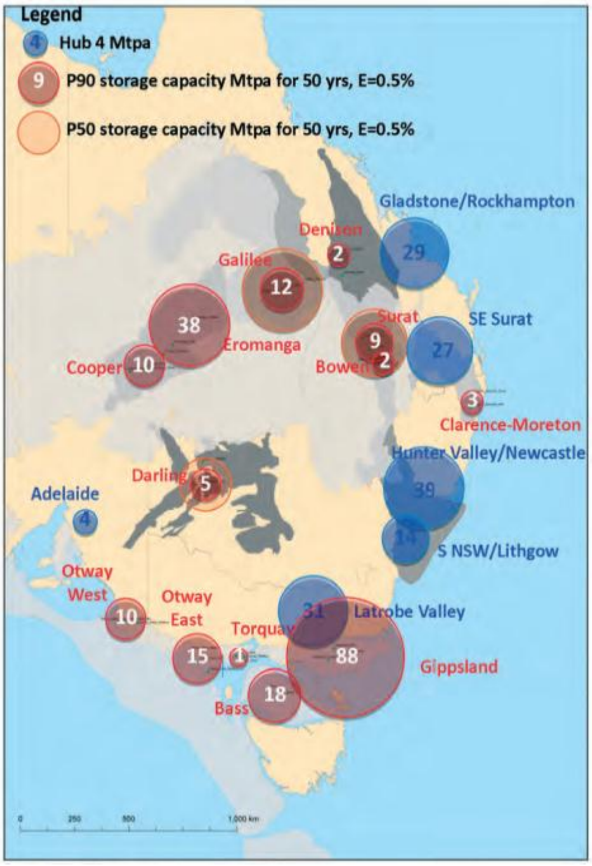


Figure 27: Eastern source-sink matching

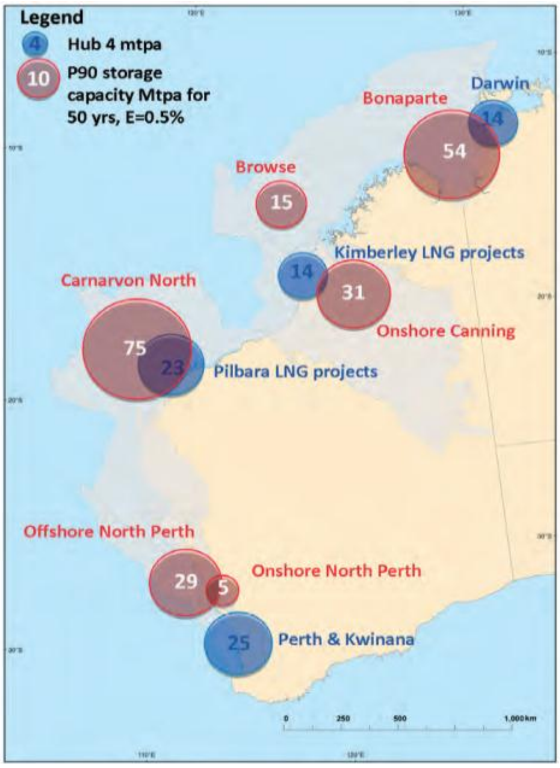


Figure 28: Western source-sink matching

Key findings of the Taskforce noted that there "… *is a high confidence that the east of Australia has aquifer storage capacity for 70 - 450 years at an injection rate of 200 Mtpa, and that the west of Australia has capacity for 260 - 1120 years at an injection rate of 100 Mtpa*"; that the "… *assumptions on storage efficiency were highly conservative*"; and that it "… *is possible that far greater capacity will be defined as basins and their CO_2 storage behaviour become better known*". The source-sink matching undertaken by the Taskforce in relation to both the east and west coasts of Australia is at Figure 27 and Figure 28 respectively.

As is clear from the work of the Taskforce, most of Australia's storage potential is located offshore - which is in accord with the available subsurface data (primarily based on petroleum industry work). Unfortunately, the areas assessed to have the greatest storage potential are not well aligned with key electricity demand/load centres. While north-west Western Australia (WA) clearly offers the most potential, demand in that region is limited to reservoir CO_2 produced in association with major LNG developments (at least until ship based transport becomes economically viable). The Gorgon project will store more than 3.5 Mtpa of CO_2 in a saline aquifer below Barrow Island. Given CO_2 storage demand is centred on the east/south-east coastline of Australia, it is here that the Taskforce recommended that initial efforts be concentrated - in particular, the Latrobe Valley and offshore Gippsland areas (Figure 27).

While Australia has a vibrant petroleum industry there is limited scope for CO_2 storage in depleted oil and gas reservoirs - the majority of fields remain in production and will do so for many years to come. Given high petroleum recovery rates there is also little potential for enhanced oil recovery operations utilising CO_2. Accordingly, the focus of CCS project development has been on aquifer storage - even in the offshore Gippsland area which has been a prolific oil and gas producing region. Nevertheless the petroleum industry has provided a wealth of highly valuable information/data of direct applicability to the CCS industry. In accordance with the provisions of Australia's petroleum legislation, all industry acquired petroleum exploration and production data must be lodged with the appropriate Government authority. The majority of this information is released as open-file data after five years - for example Geoscience Australia holds over 6,000 well/survey reports; in excess of one Petabyte of seismic data; 150 kms of cores/side wall cores; and 3,100 kms of cuttings.

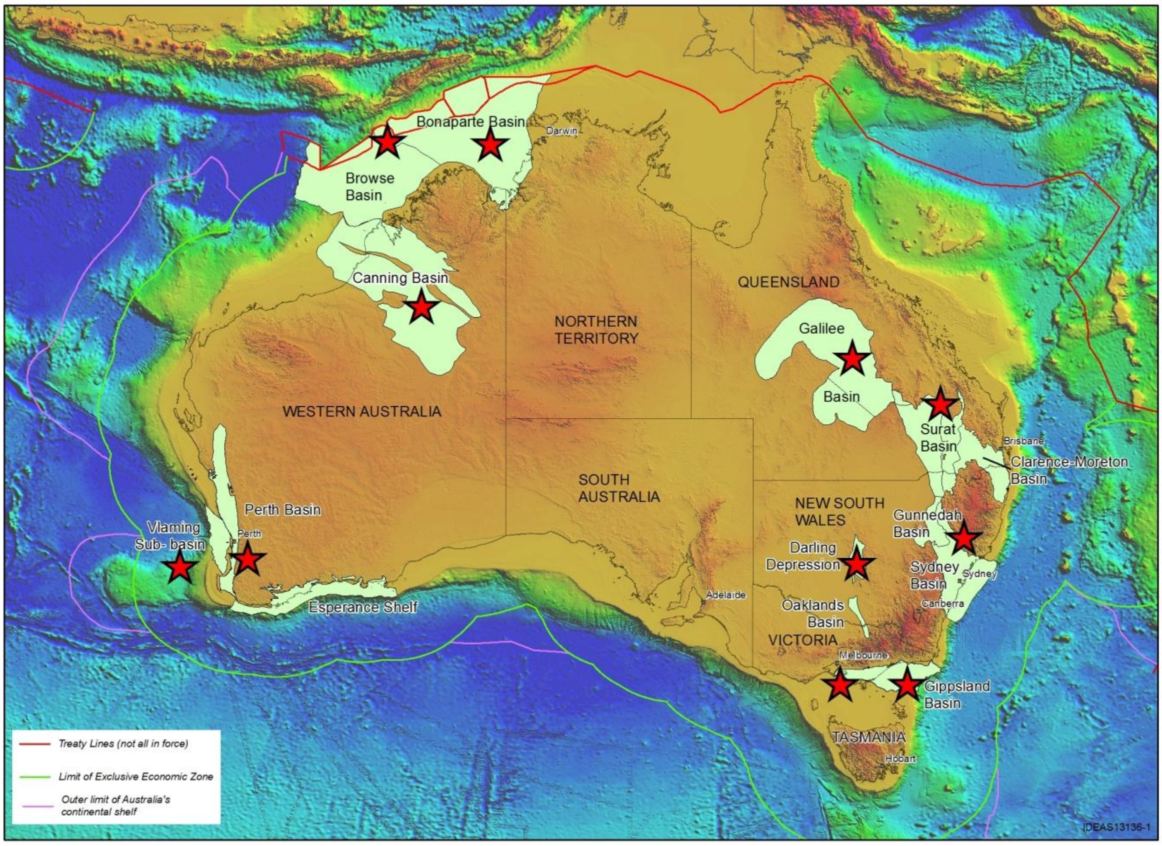


Figure 29: Pre-competitive data acquisition; Geoscience Australia

Given that this industry data is focussed on petroleum reservoirs - rather than saline aquifers - the Government has moved to implement a strategically phased, pre-competitive CO_2 storage exploration program to complement existing data sets (in line with one of the key findings of the Carbon Storage Taskforce). Geoscience Australia is undertaking a program of pre-competitive data acquisition and regional geological studies to assess selected offshore and onshore basins for their potential to store CO_2, (working in collaboration with State geoscience agencies onshore)[21]. The work is designed to accelerate the assessment of storage potential and support the uptake of exploration blocks by industry stakeholders - key focus areas are shown in Figure 29.

In effect the short term priority in Australia has been to ensure that regulatory frameworks are in place, and that there is sufficient information available to enable early demonstration projects in key localities to progress. The most intense industry interest has focussed on options for storage of CO_2 captured from electricity generation in south-east Queensland; the Latrobe Valley in Victoria; and south-west WA. However, only the Gorgon LNG project has been sanctioned and moved to the construction phase. Little real planning has been directed to basin wide CO_2 storage planning/development or to the establishment of a central CO_2 storage provider. That said the CarbonNet Project (CarbonNet) is looking to bring together multiple CO_2 capture projects in the Latrobe Valley, transporting CO_2 via a shared pipeline, and injecting it into deep underground offshore storage sites in the Gippsland region of Victoria[22] (in WA the South West CO_2 Geosequestration Hub is being developed along similar lines). However, in general

[21] http://www.ga.gov.au/ghg/ccs-program.html
[22] http://www.dpi.vic.gov.au/energy/sustainable-energy/carbon-capture-and-storage/the-carbonnet-project

governments have focussed on the realisation of ‘first mover’ demonstration projects, and seem content to allow the storage market to develop of its own accord along contemporary market lines/principles.

7.3 POTENTIAL USERS AND CONFLICTS

The possibility of CO_2 storage operations having an impact/impinging on the rights of other users is highly site dependent and varies considerably whether offshore or onshore. Given Australia’s size and relatively low population densities the possibility of conflicts with other land users is relatively low, while the nascent state of CO_2 storage development means there is very limited competition between storage operators. Nevertheless conflicts do and will arise.

7.3.1 Offshore

Most of the offshore areas with a high potential for CO_2 storage are likely to share the seabed/subsurface with other users. These include fisheries; navigation channels and infrastructure; communication cables and easements; oil/gas pipelines and easements; electricity cables and easements; and (less likely) mineral leases/recovery operations and sand winning. Furthermore, significant tracts of the sea and seafloor are set aside for defence training purposes and may have restricted access/contain live ordinance. Other areas are specifically designated as nature conservation areas (including some covered by international treaties) or may be subject to specific environmental considerations such as the protection of migratory species, cetaceans in particular. Native Title considerations may also be an issue in coastal waters.

Given the size and extent of the potential CO_2 storage province, spatial planning issues/conflict with competing users (such as offshore wind farms) are highly unlikely to arise, and storage operators should be able to readily minimise the potential impact on most other users (i.e. navigation, communications infrastructure etc.). In some cases it may be necessary to restrict the scope of operations (i.e. limitations on acquiring seismic in some areas during peak whale migration periods; management of seismic in trawl fisheries), but once again industry can accommodate these requirements as necessary. Access to some areas may be restricted (key nature conservation zones), while formal approval and consent from Native Title holders will need to be negotiated for access to aboriginal land/sea holdings.

Despite strong interest shown by some oil companies in expanding into the CO_2 storage business, the greatest potential conflict is with the petroleum industry itself. While there is considerable scope for working together on certain aspects (i.e. the acquisition of 2D and 3D seismic), the petroleum industry has been vocal regarding its concerns that CO_2 storage may compromise or sterilise oil and gas production. The petroleum industry lobbied strongly to ensure that CO_2 storage regulatory regimes included provisions to protect the rights of pre-existing title holders; to establish a framework where CO_2 storage projects only proceed if they do not impact on existing oil and gas operations; and provide for the future growth and development of the oil and gas industry. Industry considered this to be particularly important given the strong alignment between potential storage sites (adjacent to high CO_2 sources - i.e. offshore Gippsland) and key petroleum provinces of high prospectivity and significant ongoing production.

7.3.2 Onshore

Clearly, the potential for conflict is more likely onshore where spatial planning issues are often more complex. While some of these issues are effectively the same as offshore (i.e. transport, energy, communications and other forms of infrastructure; environment), a range of other land uses must also be taken into account. For example, in south-eastern Australia there is a strong alignment between many of the high potential storage sites and prime agricultural land, and the rural lobby has been strong in expressing concerns in relation to CO_2 storage (essentially a 'not in my backyard' sentiment).

However, it is the subsurface issues that give rise to most concern, in particular the possible impacts on groundwater and usage conflicts with Coal Bed Methane (CBM)/Coal Seam Methane (CSM) operations. The past decade has seen an extremely rapid expansion in the CBM business in eastern Australia with large areas given over to CBM operations (primarily in Queensland). The industry has grown rapidly with CBM now forming a major component of the domestic (east coast) gas market (around 35% in mid-2013), as well as underpinning the development of three LNG export facilities currently under construction. There is a strong coincidence between the CBM resource and potential CO_2 storage sites.

The protection of groundwater resources - in relation to both any deleterious impact on water quality arising from CO_2 storage operations, and the potential impacts from produced saline brines (to provide pressure relief) - is an equally important community wide issue. Given Australia's climate, many rural communities and agricultural operations are highly dependent on good quality groundwater resources. The incomplete understanding of basin wide groundwater dynamics only tends to exacerbate these concerns. A number of studies indicate that water quality and aquifer performance issues can be localised and widely variable in terms of the changes resulting from different actions (which could include CO_2 storage). Therefore, a precautionary approach is prudent in considering groundwater implications. Other possible land use conflicts (e.g. geothermal and mining operations) are minimal given the limited spatial overlap/footprint involved and the lack of alignment of resource potential/prospectivity.

7.4 AUSTRALIAN APPROACH TO STRATEGIC SUBSURFACE MANAGEMENT

Governments have adopted a range of policy and regulatory responses to address these potential resource management issues and conflicts. There is a strong differentiation between the approaches adopted offshore and onshore reflecting the different jurisdictions and challenges to be addressed.

7.4.1 Offshore

CO_2 storage is primarily governed by the provisions of the Australian Government's *Offshore Petroleum and Greenhouse Gas Storage Act 2006*[23] (the Act) and its associated *Offshore Petroleum and Greenhouse Gas Storage (Greenhouse Gas Injection and Storage) Regulations 2011*[24] (the Regulations). State Governments tend to mirror the provisions of the Act in coastal waters. The Act provides for clear security/tenure of title for CO_2 storage operators on a basis very similar to that enjoyed by the petroleum industry. The Act also clarifies long term liability issues. In addition, the Government has developed detailed guidelines to assist CO_2 titleholders to better understand the procedures and requirements for CO_2 storage, including the management of conflicts - *Guidelines for Injection and Storage of Greenhouse Gas Substances in Offshore Areas*[25] (the Guidelines). The strong differentiation in handling potential conflicts between CO_2 storage and the petroleum industry, and those between CO_2 storage and other uses of the seabed/subsurface is clearly outlined in the Guidelines. These are summarised below.

[23] http://www.comlaw.gov.au/Details/C2013C00302
[24] http://www.comlaw.gov.au/Details/F2011L01106
[25] http://www.ret.gov.au/energy/Documents/cei/cst/FinalGHGInjectionStorageGuidelinesDecember2011.doc

7.4.1.1 Petroleum industry requirements:

Given that the CO_2 storage and the petroleum industries both target similar geological structures, conflict between the two is always possible. In view of the national economic importance of petroleum production, the Government has put in place clear legislative provisions and approval mechanisms to ensure oil and gas resources are not compromised by CO_2 storage operations. While the Act provides for petroleum and CO_2 storage operations to coexist, there are constraints. In particular, the Responsible Commonwealth Minister (RCM) - the decision maker under the Act - must be satisfied that CO_2 injection will not have a "*significant risk of a significant adverse impact*" on pre-existing petroleum titles or operations (the SROSAI test) - that is titles which predate the introduction of the CO_2 provisions of the Act. In effect the SROSAI test is a last resort option to protect pre-existing petroleum rights. The preferred course of action is for the two parties to negotiate an agreement and for projects to work in harmony.

BOX 2: <u>Significant risk of a significant adverse impact test - key parameters</u>

- *"7.9 In the event that these procedures are required, the major parameters are:*
  - *the probability of the occurrence of an adverse impact;*
  - *the cost of the adverse impact on the project; and*
  - *the total resource value of the project."*

*(**Reference:** Guidelines for Injection and Storage of Greenhouse Gas Substances in Offshore Areas)*

In most cases it is anticipated that it will be relatively easy to demonstrate that CO_2 storage will not have an adverse impact (i.e. there is no petroleum resource in the vicinity of the operation; the probability of an adverse impact is extremely low etc.). Where a full test is considered warranted, a detailed assessment procedure (set out in the Regulations) is undertaken. The major parameters considered are set out at Box 2.

A key component of the procedure is the estimation of the cost of an adverse impact – issues to be taken into account are set out in Box 3.

BOX 3: <u>Significant risk of a significant adverse impact test - estimation of impact costs</u>

- *"7.10 In estimating the cost of an adverse impact, the RCM will take into consideration whether the adverse impact will result in:*
  - *any increase in the capital costs of the relevant petroleum operations or the relevant greenhouse gas operations;*
  - *any increase in the operating costs of the relevant petroleum operations or the relevant greenhouse gas operations;*
  - *any reduction in the rate of recovery of the petroleum or the rate of injection of the greenhouse gas substance; or*
  - *any reduction in the quantity of the petroleum that will be able to be recovered or the greenhouse gas substance that will be able to be stored."*

*(**Reference:** Guidelines for Injection and Storage of Greenhouse Gas Substances in Offshore Areas)*

Following these considerations a mathematical formula is applied to weigh up the relative impact cost and determine whether or not the impact is adverse. In accordance with the provisions of the Act (Section 25(6)), a particular event would pose a "significant risk of a significant adverse impact" only if the probability weighted costs of adverse impacts (that is, the probability of the occurrence of an event which causes an adverse impact multiplied by the cost that would be incurred if the event were to occur) exceed a threshold amount. The Regulations provide for two thresholds - one relates to a probability weighted absolute impact cost; and the other relates to a probability weighted relative impact cost (i.e. the size of the impact compared with the size of the resource value of the project being impacted upon), where:

$$\text{Probability weighted absolute impact cost} = \text{event probability x event absolute value}$$

$$\text{Probability weighted relative impact cost} = \frac{\text{event probability x event absolute value}}{\text{total resource value}}$$

The Regulations also establish absolute and relative threshold amounts at \$A5 million (2010 dollars) and 0.0015 respectively. The thresholds need to be quantifiable to ensure surety and consistency in the determinations, and to provide an objective basis for the test. The RCM makes a final determination as to whether or not the CO_2 storage project can proceed based on the outcomes of the SROSAI test.

In the situation where there are no pre-existing petroleum rights, but there is a reasonable likelihood that significant petroleum resources could be compromised by a CO_2 storage project, a "*Public interest*" test may be required. The test allows the RCM to take a decision as to which activity should proceed (recovery of petroleum or CO_2 storage) in the event that both operations cannot coexist. The considerations in determining which operation should have precedence based on 'public interest' are not prescribed, and are different to the parameters set out for the SROSAI test. In assessing 'public interest' the RCM may take into account a range of criteria including community aspirations concerning the environment; economic impacts; employment; social welfare; regional development; consumer interests; business competitiveness; and economic efficiency. These provisions are as yet untested.

BOX 4: <u>Section 460 provisions - *Offshore Petroleum and Greenhouse Gas Storage Act 2006*</u>

The following conditions apply to all holders of greenhouse gas permits; leases; licences; and authorities:

"*A person (the first person) carrying on activities in an offshore area under the permit, lease, licence, authority or consent must carry on those activities in a manner that does not interfere with:*

(a) navigation; or
(b) fishing; or
(c) the conservation of the resources of the sea and seabed; or
(d) any activities of another person being lawfully carried on by way of:
  (i) exploration for, recovery of or conveyance of a mineral (other than petroleum); or
  (ii) construction or operation of a pipeline; or
(e) the enjoyment of native title rights and interests (within the meaning of the Native Title Act 1993);

to a greater extent than is necessary for the reasonable exercise of the rights and performance of the duties of the first person."

7.4.1.2 Other user requirements

In relation to other user requirements CO_2 storage is in the same position as the petroleum industry, and in effect the obligations are mirrored in the Act. The specific requirements placed on CO_2 storage operations to minimise their impact on other uses of the marine environment are set out at Section 460 of the Act (see Box 4). While these may seem somewhat onerous initially, decades of experience with the petroleum industry show they can be effectively managed without major concerns.

While some issues require compromise and accommodation by both sides (i.e. alignment of seismic survey work with trawl fishery requirements), most can be readily resolved through consultation and dialogue between the parties (as required under the Act). In some cases the regulator may impose special conditions on the exercise of certain operations carried out by titleholders to give effect to environmental considerations - for example, restrictions on seismic operations during peak whale migration periods. Government may also seek to shape or limit the size and location of CO_2 titles (and release areas) so as to avoid key nature conservation zones - with no spatial overlap of CO_2 titles conflict is avoided (a workable solution given the size of the CO_2 storage resource). Based on petroleum industry experience there should be little call for the regulator to intervene in resolving issues between different resource users.

7.4.1.3 Strata Title issues

Issues with regard to strata titles do not arise. Under the Act, title is granted on a graticular block basis, and title holders enjoy 'rights' to all geological formations within the areal extent of the title (from the "seabed to the centre of the earth"). Thus the regulatory regime effectively rules out any potential for conflict between users of overlaying strata. However, in the longer term should the demand for available storage become intense (say in high demand regions like offshore Gippsland), the Government may need to consider alternatives to ensure optimal use of storage formations at different levels – such options could include a strata title regime. At present there are no mechanisms in place to ensure the strategic utilisation of the available storage resource, and therefore it is in the operator's interest to target the shallowest/cheapest formations for early development (even though there is a risk this may sterilise deeper strata). The current approach runs the risk of allowing a few operators to tie up the majority of the resource (in an aerial sense). Of course, any rethinking of this approach gives rise to the spectre of sovereign risk and will raise issues of compensation for the loss of pre-existing rights.

7.4.1.4 Storage plume vs. Pressure footprint

The approach adopted under the legislation is that the extent of the projected storage plume must be contained within the injection licence title. There are no considerations as to the extent of the pressure footprint and its possible impact on adjacent CO_2 storage or petroleum titleholders (even though a pre-existing petroleum titleholder could put forward a case under the SROSAI test). Given Australian titles are based on combining five minute graticular blocks, in many cases much of the pressure footprint might be contained in the title - there is also scope for buffer areas to be incorporated in the title.

The inclusion of a buffer zone of sufficient size to incorporate the pressure footprint poses a dilemma for the regulator. On one hand it would seem prudent to avoid conflict between operators, but it also presents the possibility of unnecessarily tying up potential resource. In the short term the Government has the option to strategically manage the release of storage acreage so as to avoid possible conflicts. Ultimately such conflicts, and possible loss of amenity due to pressure incursions, will be a matter for common law/litigation to resolve. This is more likely given that the Act does not contain CO_2 storage 'unitisation' clauses (along the lines of the petroleum provisions) which could at least deal with situations where a storage reservoir straddles more than one title/jurisdiction.

7.4.1.5 Good CO_2 storage practice

While the Act calls up the concept of "*Good oilfield practice*" whereby the regulator may intervene on behalf of the owner (society) to optimise long term benefits if these happen to be at odds with the short term financial objectives of the operator, there are no corresponding provisions as to 'good CO_2 storage practice'. However, the Act allows scope for specification of the origins of the CO_2; specification of gas injection sites; the period of injection; total volumes to be injected; the rate of injection; and specification of any necessary engineering enhancements to be prescribed in the injection licences. It also requires applicants to submit a detailed development plan for approval. The RCM may also issue specific directions to the operator if a "*serious situation*" arises, that is if a leak occurs; there is serious risk of leakage; or the CO_2 is behaving contrary to modelled expectations.

These combined powers appear to give the regulator scope to ensure that storage operations are undertaken in a manner which optimises use of the resource in the owner's (society's) long term interest. However, there is little guidance in the Act and the Guidelines as to how the regulator might go about doing this and at present little global 'best practice' experience to draw upon.

7.4.1.6 CO_2 STORAGE MARKET DYNAMICS

At this stage the Government has not moved to regulate the commercial development of the CO_2 market. Given the emergent state of the market this is clearly unnecessary. However, the Act does make provision for the introduction of regulations which "… *may establish a regime for third party access*" to storage operations if and when this becomes necessary. The development of the market will need to be carefully monitored to safeguard against monopolistic or oligopolistic behaviour while not fettering preliminary market growth.

7.4.2 Onshore

The State Governments have been active in working to facilitate CCS storage onshore (and in coastal waters). Victoria, Queensland and South Australia have all enacted legislation, and both New South Wales and WA have legislation under consideration (although WA has project specific legislation in place to cover the Gorgon LNG project). The complex issues of overlapping tenure and competing or conflicting use have been addressed in a reasonable degree of detail under the various regulatory and policy regimes adopted by the State Governments. In all jurisdictions projects are likely to trigger the 'standard' array of environmental approvals/environmental impact assessment and other nature conservation considerations, along with zoning and spatial land use planning deliberations. In general, those States with the most advanced CCS projects have also made the most progress with the regulatory and policy frameworks governing CO_2 storage (i.e. Victoria, Queensland and WA). The approach adopted by these three State Governments provides a solid insight into onshore storage in Australia.

7.4.2.1 VICTORIA

CarbonNet is investigating the potential for establishing a world class, large-scale CCS network based on multiple CO_2 capture projects in the Latrobe Valley. The coal-fired power stations of the Latrobe Valley generate more than 90% of the State's electricity and the Carbon Storage Taskforce assessed the Gippsland Basin as containing the best quality and largest volume of potential CO_2 reservoirs in Australia. CarbonNet aims to initially capture and store over 1.0 Mtpa of CO_2 with the possibility of scaling up from there. Intensive studies of the Gippsland storage opportunities - the *Latrobe Valley CO_2 Storage Assessment: Final Report*; Nov 2005[26] - clearly indicate that the best storage options are around 50 km offshore - thus avoiding the possibility of onshore conflicts.

[26] http://www.co2crc.com.au/dls/pubs/regional/lvcsa/lvcsa_main_05_0108.pdf

Nevertheless, the Victorian Government has also enacted onshore legislation - the *Greenhouse Gas Geological Sequestration Act 2008*[27] (GGGS Act). The GGGS Act reflects many of the principles of the State's *Petroleum Act 1988*, but also makes clear that existing petroleum (and other) interests - which could include other CO_2 storage operators as well as other subsurface users - should not be adversely affected. Where CO_2 injection plans "… *present a significant risk of contaminating or sterilising other resources in the permit area*", operators must take "… *all reasonable steps*" to obtain the consent of any resource authority holders whose resource may be affected (Part 4 of the GGGS Act). While the GGGS Act allows for compensation agreements to be reached between the competing users, these are not obligatory. The Victorian Minister may still approve a storage operation even where it may sterilise or contaminate other resources, provided that it is considered to be "… *in the public interest*" (and there is no risk to public health or the environment). While the Minister may seek the advice of an independent panel, there is no direct guidance as to what might constitute the 'public interest'.

Groundwater issues are encompassed within these broader definitions of 'health' and 'environment' and injection licences may be rejected if they could result/have resulted in a deleterious environmental impact (including impacts on groundwater resources). Part 12 of the GGGS Act provides detailed rules relating to the consent of owners of private land where storage may occur (and compensation which may be payable). Storage can only be undertaken with the consent of the land owner and occupier, and operators are also required to abide by 'native title' legislative provisions.

7.4.2.2 QUEENSLAND

A number of CCS projects have been actively pursued in Queensland - in part reflecting the State's extensive coal resources and high dependence on fossil-fired generation. High level assessments of storage options have been positive. The key challenge in Queensland is the potential conflict between CO_2 storage and other users of the subsurface, including CBM/CSM; Underground Coal Gasification (UCG); coal mining; petroleum; and geothermal. Arrangements regarding competing usage are primarily covered under the petroleum and gas; mineral resources; greenhouse gas storage; and geothermal legislation. In many cases overlapping titles do occur, even though the Queensland Government has recently moved to limit these where the usage is totally incompatible and the two operations cannot coexist (e.g. UCG operations and CBM/CSM/coal mining).

The *Greenhouse Gas Storage Act 2009*[28] (GGS Act) provides clear mechanisms for dealing with conflicts - the starting premise being that CO_2 storage titleholders "… *must consult or use reasonable endeavours to consult with each owner and occupier of private or public land*" (Section 166 of the GGS Act) where it is proposed to store CO_2. The intent of such consultation is to develop an agreement to allow for either a joint operation (with other CO_2 storage or gas production operations) or to ensure that any overlapping activities/operations proceed with negligible impact on the other. Storage operators must develop and submit "… *a proposed development plan*" to the Queensland Minister for consideration/approval, and the Minister may take submissions from other affected parties into account.

In deciding whether to approve a project the Minister must consider "… *the potential of the area*" for storage; "… *the nature and extent of the activities*"; and whether the proposed storage activities will "… *be optimised in the best interests of the State*" (Section 147 of the GGS Act).

[27] http://www.legislation.vic.gov.au/Domino/Web_Notes/LDMS/PubStatbook.nsf/51dea49770555ea6ca256da4001b90cd/7E4801FE0E8E3A55CA2574F80019A141/$FILE/08-61a.pdf
[28] https://www.legislation.qld.gov.au/LEGISLTN/CURRENT/G/GreenGasSA09.pdf

This Section also establishes criteria related to "*the nature and extent of water disposal and treatment activities*", and "… *relevant authorisation required under the Water Act*" - both of which the Minister must take into account.

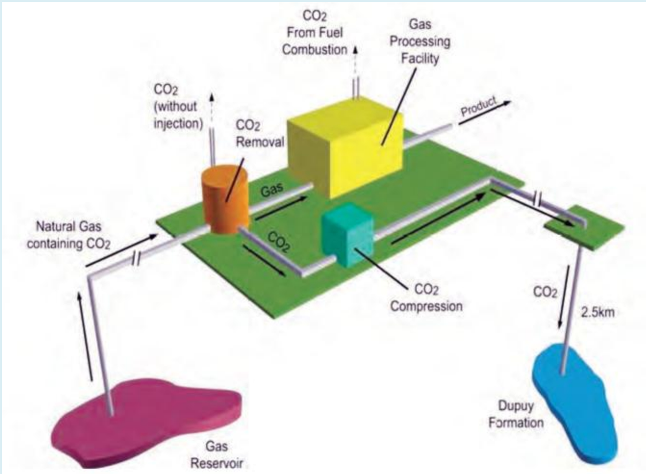
The GGS Act provides little guidance beyond the basic criteria as to how the Queensland Minister might arrive at a decision or compromise position - it is effectively undertaken on a case by case basis. Importantly it introduces the notion of 'public interest' through the "… *optimised in the best interests of the State*" provision. This allows a number of key elements to be weighed up - options between alternate land uses and subsurface users; alternate use plans for the storage resource itself; and whether or not the development plan optimises use of the storage capacity. While the provisions appear to provide a robust approach to dealing with conflicts, given that project development has not yet advanced to the stage of injection licence applications, they remain largely untested.

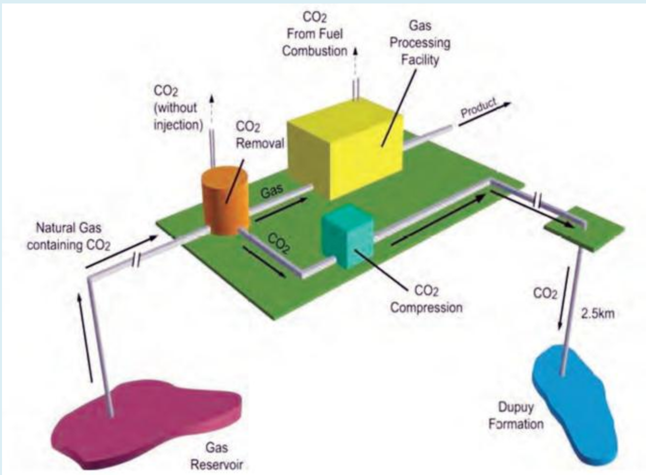
BOX 5: <u>The Gorgon LNG Project</u>

The Gorgon LNG Project in north-western Australia will be the first example of large scale greenhouse gas storage technology deployment in Australia.

The Project aims to store some 3.5 Mtpa of CO_2 in the Dupuy Formation under Barrow Island, and will be the largest storage project in the world. It was sanctioned in September 2009.

The Project represents a critical step towards demonstrating the viability of large-scale commercial storage of CO_2.





Source: Carbon Storage Taskforce report (permission of Chevron)

7.4.2.3 Western Australia

The Gorgon LNG Project (see Box 5) is being realised under project specific legislation - the *Gorgon Gas Processing and Infrastructure Project Agreement 2003*.

The Western Australia Government has tended to opt for project specific legislation (Western Australia., 2003) to cover key resource developments (from both a strategic and economic perspective) in the State. Given the major nature conservation considerations; the investment quantum; and domestic gas supply issues relating to Gorgon, project consideration/approvals clearly go beyond the ambit of the proposed CO_2 legislation which is yet to be finalised. Most issues have centred around the location of the overall LNG project (as against the storage aspects) on Barrow Island, a Class A Nature Reserve with endemic, rare and endangered species. In the area over are over 800 petroleum wells with over 60 years of petroleum production. Since Chevron operates the LNG plant with its associated CO_2 storage in addition to the ongoing oil production from shallower formations, any subsurface conflicts are resolved internally by the operator.

There is also considerable interest in the development of a South West Australian CO_2 Geosequestration Hub which would sequester CO_2 from various industrial sources and power generation, transported by a pipeline network to a preferred storage site in the southern Perth Basin. The project aims to store around 2.5 Mtpa, with the potential to scale up to 7.5 Mtpa. The WA Government is in the process of developing legislation which would cover this and other CO_2 storage operations in Western Australia.

8 Managing Storage Resources—Role of CO_2 Enhanced Oil Recovery (EOR), Texas

8.1 INTRODUCTION

Use of CO_2 to enhance oil recovery can be important in lowering barriers to carbon capture and storage. Past practices illuminate the feasibility of co-use of the sub-surface for EOR and conventional production and disposal. Introduction of low-viscosity CO_2 into a historic oilfield requires significant changes in field management. The major change is unitizing the field so that it can operate harmonically with regard to cost, profit, and management of CO_2, including effective recycling, while avoiding loss to the atmosphere through non-participating production wells. EOR also requires extensive preparation of wells for CO_2 flood and addition assessment is needed of long-term storage. In addition, a task of data collection and reporting may be needed to document storage; much but not all of the needed data may be extracted from the operator's EOR management data.

Management of storage and EOR in the same footprint is generally beneficial to both processes. Pressure elevation, a key risk factor in storage, is a benefit to an adjacent, hydrologically connected EOR project. EOR may in turn assist in management of pressure in the storage area. EOR also provides dense data to support characterization, not only in terms of imaging and rock-property data, but also a long production history, which removes many uncertainties. Production data have long been used to validate fluid-flow models and will constrain predictions of reservoir response to CO_2 injection. The need for monitoring of EOR for storage effectiveness is therefore reduced to key risk factors, and saline storage associated with EOR may benefit from this characterization. In addition, where EOR and saline projects are vertically stacked, monitoring can be integrated.

8.2 SCOPE AND SOURCES OF DATA

This chapter provides an overview of CO_2 enhanced oil recovery (EOR) from the perspective of its relationship to atmospheric greenhouse-gas (GHG) mitigation in the context of geologic storage of $CO_{2.}$ Content has been selected to provide information accessible to policy makers, with technical detail provided via citation. In addition, although CO_2 EOR is well known in the commercial environment, detailed published information on some elements is sparse, therefore examples are presented. This chapter is biased toward U.S. examples in the states of Texas, Mississippi, Louisiana, Wyoming, Michigan, and New Mexico because these are major areas of current CO_2 EOR deployment from which data are readily available.

8.3 CONVENTIONAL USE OF CO_2 FOR EOR

8.3.1 How the EOR process works

Oilfield exploitation begins with a period of natural drive, known as primary production, which is followed by a period known as secondary production, during which fluids such as water or methane are reinjected to displace oil and maintain pressure (Lake, 1989). Over time, secondary methods become ineffective in liberating economic amounts of oil, and the field is said to approach depletion. A major reason that decline occurs is that as oil in pore space decreases and is replaced by water, capillary processes limit the mobility of oil toward a limit, which is known as residual saturation. Various additives can be injected to mobilize residual oil and stimulate another phase of production, which is referred to as tertiary production (Lake, 1989; Sheng, 2013). CO_2 is one of the additives injected during tertiary production.

Under suitable reservoir conditions, CO_2 and oil are mutually soluble, or miscible. The solubility of oil in CO_2 depends strongly on pressure, temperature, and oil composition, its complexity making a large impact on the process and effectiveness of CO_2 EOR (Bath, 1989; Sheng, 2013). Therefore, CO_2 EOR is conducted using high-pressure CO_2 to increase reservoir pressure so that miscibility is increased. The target pressure may be above or below the original reservoir pressure. The miscibility of supercritical (dense-phase) CO_2 and oil is highest in the reservoir; when the fluids are produced to the surface and the pressure is decreased, they become strongly immiscible and separate by density into liquid oil and CO_2 gas.

For effective CO_2 EOR, injection must force the CO_2 to contact oil trapped at near-residual saturation in reservoir pore spaces. The major tactic used to force sweep of the reservoir is to engineer patterns of relatively closely spaced injectors and producers (Figure 30). Obtaining good sweep is a challenge the viscosity of CO_2 is much lower at typical reservoir conditions than is the viscosity of oil, which allows preferential flow of CO_2 through favourable zones. To limit fast flow, water is commonly injected before and between pulses of CO_2, a process known as water-alternating gas (WAG) (Sheng, 2013). The alternative method used by some operators, in which only CO_2 with little to no water is injected, is referred to as direct injection.

Obtaining favourable economics for EOR requires minimizing costs while maximizing oil production. A major cost is CO_2 purchase, and the recycle of CO_2 that is produced with the oil is therefore a major investment for an EOR project. Produced fluids are transported by pipeline to a central separation plant, in which pressure is dropped and oil, water, and CO_2 and other gasses are separated. Oil is effectively purged of CO_2 prior to sales by pressure drop, heating, and use of chemicals. Water is reinjected to manage reservoir pressure; CO_2 is dehydrated, compressed, and reinjected; and any methane gas produced will travel with the CO_2. Gasses mixed with CO_2 impact miscibility, density, viscosity, and, therefore, performance of the flood.

It is possible to use CO_2 to without recycling it, however, such a process is generally not economically viable. To test CO_2-oil miscibility and reservoir performance, operators will sometimes conduct a huff n'puff (Haskin and Alston, 1998). CO_2 is injected into a well, followed by a multi-day resting period, and then the same well is used to produced CO_2 and oil. For a test prior to construction of a separation facility with compression equipment, the CO_2 can be supplied as cold liquid shipped via truck. After production, CO_2 is flashed to gas and released through a flare on a portable separator.

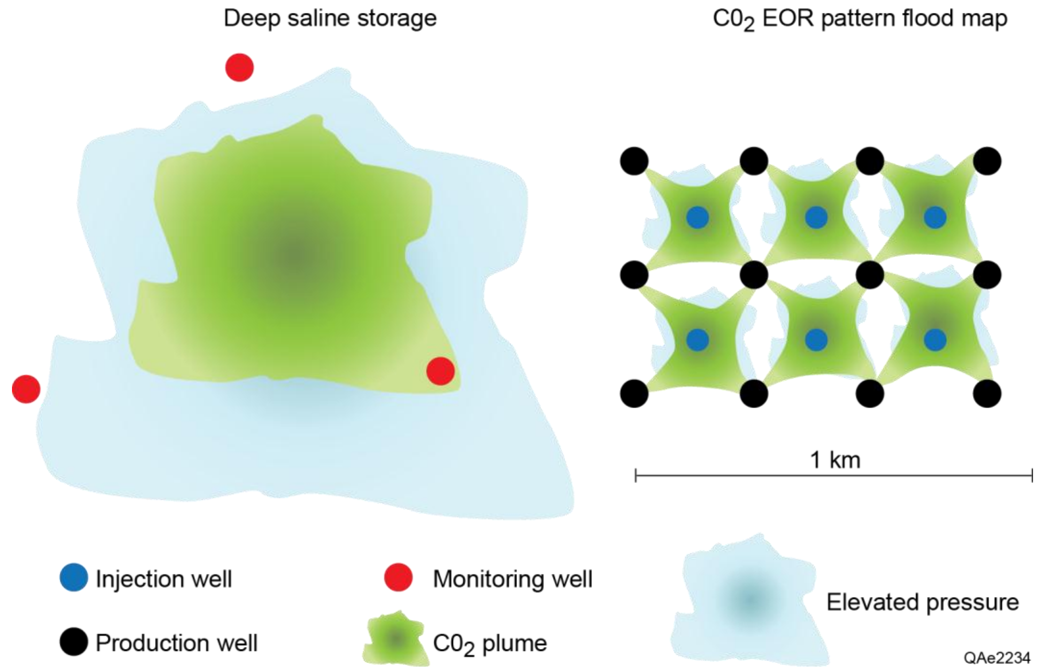


Figure 30: Sketch comparing the area of the CO_2 plume and significantly elevated pressure at deep saline injection with an EOR flood, showing the role on injection and production well patterns in managing and monitoring the flood.

8.3.2 Developing a successful CO_2 EOR project

The ingredients needed to develop a successful CO_2 EOR project include a source of CO_2, a suitable reservoir, capital investment, a good design for operation of the flood, and a market for the oil. Many sources of CO_2 have been utilized for EOR, the largest volumes of CO_2 are produced from natural geologic accumulations (Pearce et al., 1996) and transported via regional pipeline networks to EOR fields. CO_2 sourced from natural gas processing plants is also a significant source of CO_2 for EOR. Since 2010, CO_2 produced from gasification of coal to methane at the Great Plains Synfuels Plant, North Dakota, has been captured and shipped to the Weyburn oilfield for EOR (Wilson and Monea, 2004). Approximately 1 million tonnes per year of CO_2 is captured from a hydrogen plant operated by Air Products at Valero's Port Arthur refinery and shipped via pipeline for EOR to Hastings field (Products, 2013). Additional capture projects under construction, in which CO_2 is to be used for EOR, include the Kemper County gasifier and the Leucadia Lake Charles gasifier. Two more projects that will ship captured CO_2 for EOR—Summit Energy Texas Clean Energy Project and Texas Coastal Ventures Project at the J. W. Parrish Power Plant—are in advanced planning (Moniz and Tinker, 2010).

CO_2 EOR is economically viable only in suitable reservoirs. Intensive characterization and pilot testing is needed to develop a successful project (Teletzke et al., 2010). Highest oil production is obtained in situations where pressure and oil properties approach miscibility, remaining oil saturation is sufficiently high to provide a viable resource, and waterflood recovery has been successful (Lake, 1989; Holtz et al., 1999; Nuñez-López et al., 2008). More aggressive EOR resource evaluation includes immiscible floods (Advanced Resources International, 2010), which are economic under some conditions (Bath, 1989; EPA, 1998).

A less widely recognized variable in reservoir suitability is participation of mineral owners and operators. Because low-viscosity CO_2 can migrate laterally in the reservoir with relative ease, operating a field with some tracts not participating in the flood is problematic. Wells on non-participating tracts will profit from the mobilization of oil without sharing in the expense, and if they produce CO_2, it will not be returned to the separating plant but will be vented to the atmosphere. Wells that have not been prepared for the flood may be damaged by higher pressure or arrival of CO_2.

Capital investment is critical to CO_2 EOR because extensive development must be completed prior to the flood being initiated. Planning, permitting, and construction occur over several years before the start of injection. Development of the source of CO_2 (whether natural or captured) is capital intensive. In addition, construction of a pipeline and associated costs of transport for the planned volumes at the planned pressure require substantive up-front capital. Drilling and retrofitting of injection and production wells in most projects are staged because a build-out plan that balances CO_2 availability with project design will most likely initially allow only part of the field to be flooded. As the amount of recycle provides more CO_2, additional patterns of injectors and producers are prepared. Completion of construction of the separation facility is needed shortly after the onset of injection because separation and compression for CO_2 recycling are needed at the same time that production begins. After injection starts, access of CO_2 to the pore volume and interaction with oil in the reservoir require many months before the start of oil production and positive revenue generation.

Different EOR projects approach well preparation for onshore floods differently, depending on a large number of variables. The low viscosity of CO_2 and planned increase in pressure require that conditions of all wells in the flood area be reviewed and remediated as needed. Existing records for wells that were previously plugged and abandoned are reviewed, and open wells are either repaired or plugged and abandoned. State regulatory agencies conduct oversight of well preparation, with an *Area of Review* typically set at ¼ mile around the injection wells (EPA, 1998). Damaged casings are either repaired with a liner or plugged and *side tracked*, creating a new well in the injection zone but recycling the surface casing. The corrosiveness of CO_2 in water requires replacement of parts of production wellheads and production tubing and flowlines using corrosion-resistant materials. Some companies use existing wells for injection; however, replacing them with new construction is common because the increased reliability is found to be economically favourable.

CO_2 EOR projects also make substantive investments in well surveillance and maintenance. Corrosion-management programs such as the introduction of corrosion-inhibiting chemicals or cathodic protection are common. Field technicians make regular rounds to inspect well and pipeline infrastructure, and surveillance results are being increasingly reported to SCADA systems, which allow the whole system to be monitored from a central location. In addition, regulations prescribe programs of well-integrity testing (Koplos et al., 2006).

Operating an EOR flood requires both a robust, model-driven plan and considerable during-flood observation and adjustment. The basic planning and management system is the injection-withdrawal ratio. At the beginning of the flood, injection dominates; however, during operation, fluid withdrawal is generally brought into balance so that reservoir pressure is maintained at the designed and permitted optimum. The production response to injection is monitored, generally by the fluids being sent from each well to a small test facility, where oil, water, and gas are split. Well-production testing is conducted for 1 day per well and is rotated among wells so that at many fields, each well is tested monthly. Changes in ratio of CO_2:water and injection: withdrawal rates are tracked to provide feedback so that the flood can be maximized for maximum oil production and minimum costs. Other reservoir-surveillance methods are used at operator discretion and include essentially all of the sub-surface tools associated with geologic-storage monitoring. Bottom-hole pressure and cased-hole wireline logging, pulsed neutron and sonic, 3-D and time-lapse (4-D) seismic; VSP and crosswell in various modes; gravity; electrical methods; introduced partitioning and conservative tracers; and microseismic have all been used in EOR flood surveillance, generally with the goal of providing information about the sweep so that contact between CO_2 and oil can be increased.

Note that many of the surveillance data for EOR floods are for the benefit of the operator and are not reported to anyone outside the company. The abundance of professional papers on EOR flood surveillance (e.g., Cooper, 2009) is therefore not an indicator of the number of proprietary, in-company data collected. Conversely, because most surveillance is voluntary, there is no certainty that any issue is being attended to at a field or by a particular operator.

8.3.3 Limits to EOR deployment – in the past

CO_2 EOR has a fairly high success rate, in that most projects that had sufficient investment to be developed at full scale are still in operation. However, many proposed projects are evaluated as technically successful but economically not viable and have not yet been developed. One reason is availability of CO_2 or a linked reason, capital to construct a pipeline from source to field. This limitation was applicable to a number of Gulf Coast fields that were evaluated as technically successful floods in the 1980's; however, only in 2009 was a large CO_2 pipeline constructed to bring CO_2 to the Gulf Coast (Denbury Resources Inc, 2011).

Another limit on project development is available financing. Public data regarding business decisions are not easy to find; however, financing availability is often mentioned by CO_2 EOR project developers as a reason for project success or failure. EOR has a relatively slow return on investment because of the extensive infrastructure required prior to any revenue stream, although it is considered a safer investment than resource exploration because of the high certainty from past operations.

Another reason given for CO_2 EOR being limited is that technological and business expertise of the operating company does not match what is needed for EOR. Many waterflood operators work as low-capital "stripper" operators; they use and repair existing infrastructure and optimize handling large volumes of water to strip off small fractions of oil. Operators report that a change to a capital- and technology-intensive EOR does not match their optimized business model, but might be successful for another company.

Competition with other EOR technologies is a final reason noted that CO_2 EOR may not be deployed. Chemical additives or nitrogen floods can be successful over the same spectrum of reservoirs as CO_2 (Bath, 1989; Lake, 1989).

8.3.4 UNCONVENTIONAL EOR

Consideration of the impact on EOR of more abundant, more widely distributed, possibly more incentivized, and perhaps more regulated CO_2 supplies may be useful. We refer to these changes as *unconventional EOR*, which might include injection into residual oil zones, CO_2 EOR offshore, gravity-dominated floods, fractured reservoirs, or oil reservoirs with gas caps.

Residual oil zones (ROZ's) are locations where oil was formerly trapped but that have, over geologic time, spilled, leaked, or been swept by a natural waterflood so that oil saturation has been reduced to residual, capillary-trapped oil (Brown, 2001; Meltzer, 2006; Melzer et al., 2006; Trentham, 2012). Although oil is present in the pores, a well completed in an ROZ produces only water. Such accumulations have been long identified but have had no value during primary and secondary production because the oil is inaccessible. However, CO_2 flooding has been shown to be effective in producing an ROZ in the same way that CO_2 flooding is effective in producing oil after secondary flooding in tertiary-production EOR settings. Estimates of the availability of ROZ resources show a significantly potential contribution to CO_2 markets (Koperna and Kuuskraa, 2006).

Use of CO_2 in offshore, sub-seafloor reservoirs for EOR is widely thought to be technically feasible (e.g. Manrique et al., 24-28 April 2010; Alekemode, 1995; Tzimas et al., 2005; Holloway et al., 2006). Minor differences in temperature and pressure profiles created by sub-sea settings are unlikely to be detrimental, and many offshore reservoirs are reaching the stages of depletion at which tertiary recovery would be attractive for maintaining revenue. However, offshore CO_2 EOR deployments have generally not been implemented (Hallerman, 2013). Assessment of the barriers to implementation is outside the scope of this chapter; however, reasons generally given include the higher cost of infrastructure development and maintenance offshore and a typically more widely spaced well placement, which would result in a longer period between the onset of floods and oil production. These two parameters have combined to create a potentially unfavourable return on investment. No data have been identified concerning the process of retrofitting offshore wells for EOR or the impact of different construction or management offshore on cost, reliability, or retention.

Other innovative settings for CO_2 EOR include fractured reservoirs, which may be becoming important to China (Ferno, 2012), and CO_2 EOR in reservoirs that have a significant gas cap, such as the recent CO_2 EOR flood at Cranfield, Mississippi, USA. Another innovative type of EOR that has been tested and locally used is a gravity-stable flood. In a steeply dipping or vertical, reef-shaped structure, CO_2 will accumulate at the top of the structure, and mobilized oil will drain to the bottom (Nute, 1983).

8.4 CO_2 EOR AS STORAGE

8.4.1 Market for CO_2

Some assessments of geologic storage separate porous-media environments into (1) deep-saline formations and (2) depleted reservoirs. The use of CO_2 for EOR is considered a third and additional porous-media geologic-storage setting. The value of CO_2 for EOR in reaching storage objectives has been noted, principally in terms of reducing barriers. EOR combine with storage has been termed *Carbon Capture Use and Storage* (CCUS) or *EOR with incremental storage*.

The cost of capture is widely recognized as a significant barrier to widespread deployment of carbon capture and storage (CCS), but sale of CO_2 can lower this barrier. Uncertainty remains about the extent to which sale of CO_2 for EOR could cover the cost of capture, making CCUS a completely commercial operation requiring no subsidy (Holtz et al., 1999; King et al., 2013). Principal drivers of this uncertainty include the cost of CO_2 from capture and the market value of oil. An additional uncertainty is the extent to which suitable CO_2 EOR projects can be matched to supplies of CO_2 (Tzimas et al., 2005; Advanced Resources International, 2010). The extent to which CO_2 EOR projects can be fully commercial also depends on the extent to which technology improvements will allow optimization of floods in challenging reservoirs. Competition of captured CO_2 from industrial and power-plant sources, with CO_2 from natural and gas-separation facilities, will also play a role, as will competition between CO_2 EOR and other tertiary-recovery technologies.

8.4.2 Benefits of technology maturity

A second type of contribution of CO_2 EOR to advancement of storage occurs because in some jurisdictions, EOR is a mature technology with a proven track record. The first commercial CO_2 EOR flood was initiated in the Permian Basin of Texas in 1972. The regulatory environment in which EOR is conducted is therefore also mature, with a well-known and relatively short timeframe for obtaining permits. However, significant doubt remains as to how the new regime requiring accounting for CO_2 storage will intersect current regulatory regimes. The IOGCC, 2007 proposed draft rules that included EOR. The Railroad Commission of Texas, the State's oil and gas regulatory agency, has promulgated a rule providing guidance in obtaining voluntary credits for incidental storage as part of CO_2 EOR (Texas Adminstrative Code, 2011). Preparation of similar rules is under way in other states, and Mcrory, 2013 described this intersection in an EU context.

Another element of a proven track record is that methods by which liability, public acceptance, and financing barriers can be overcome are known. Public information related to liability for CO_2 EOR is sparse (discussed later). Preparation of an EOR project takes a number of years, during which representatives of the operator, known as *landmen*, negotiate with the property owners to establish a working and commercial relationship. In one-on-one discussions with property owners in areas with EOR, we have observed that discussions between the operator and landowners focus on pragmatic issues such as road maintenance and access agreements. Commercial participation by the local community in terms of fees for surface access, royalty payments, employment, and business opportunities appear to be generally effective in increasing acceptance so that projects can advance. Formal studies of public acceptance of CO_2 EOR were not found.

8.4.3 Limits and concerns about EOR as storage

8.4.3.1 Nature of recycle

Most EOR is conducted with the CO_2 in a closed loop so that atmospheric release is limited to fugitives (Figure 31). Auditing the efficiency of the surface processes can be accomplished through ordinary industrial approaches, although few of these have been conducted for input into the public domain. One audit was conducted by KinderMorgan that was related to the large volume CO_2 EOR operation at SACROC oilfield using California Climate Registry methodologies (Fox, 2009). It found that major emissions are related to electricity purchase and generation with compression, energy to lift production wells, water handling, and heating; contribution from industrial fugitives and transportation are minor.

Under current conditions, no atmospheric issues are considered; nevertheless release of CO_2 is limited. Motivation provided by operators for retention is the cost of CO_2 as an operating fluid. Another factor that may be relevant is that recycled CO_2 contains gas-phase impurities stripped from oil or water as CO_2 passes through the reservoir. Methane and H_2S are the most common impurities, and regulatory limits on release of these constituents may be drivers in maintaining a tight system. Another example of the pragmatic pressures on industry to make the surface system tight occurs in the presence of trace mercapsins in the CO_2 gas stream supplied to Weyburn oilfield (Riding and Rochelle, 2005). Minor leakage in that CO_2 supply system created a strong odour, favouring mitigation.

The major concern about the quality of storage during CO_2 EOR is the risk that CO_2 will migrate outside of the intended patterns and be produced at wells that are not attached to the recycle system. Operators are aware of this risk and take steps to reduce and monitor for negative outcomes; however, few data on the success of management and mitigation are available. Under current conditions, the operator has no obligation to limit atmospheric releases, so that, for example, a huff n'puff operation can be conducted and produced CO_2 vented.

Another issue that has been of concern to stakeholders about permanence of CO_2 storage during EOR is the availability of infrastructure such as production wells and pipelines that readily allow transfer of CO_2 from one part of the reservoir to another. As part of normal flood balancing to optimize oil recovery, operators can choose to change the injection: withdrawal ratio so that sweep is enhanced in places where high recovery is occurring. Under conditions of limited CO_2 supply, increasing injection in some patterns is accomplished by increasing withdrawal in less productive patterns. Changing the ratio of injection: withdrawal so that more CO_2 can be extracted than is being injected is referred to as *blowdown,* and it results in a decrease in the amount of CO_2 stored in the areas of extraction. Pressure can also be decreased. Alternatively, the WAG ratio can be changed to all water resulting in more CO_2 being removed than injected. The same processes could be used to transfer CO_2 that was injected into one field and place it back in the pipeline to be shipped to another field. Some operators have been concerned that new accounting or regulatory frameworks conserve access to the CO_2 that could be obtained by blowing down fields in decline and using the CO_2 to develop new fields. Advocates for reduced atmospheric emissions have expressed anxiety that such between-field recycling could result in improper accounting with regard to atmospheric benefits, decreased quality of retention, and decrease in the CO_2 market. The only past effort to extract CO_2 from one field for placement the CO_2 in the pipeline was not successful (S. Meltzer, personal communication, 2013).

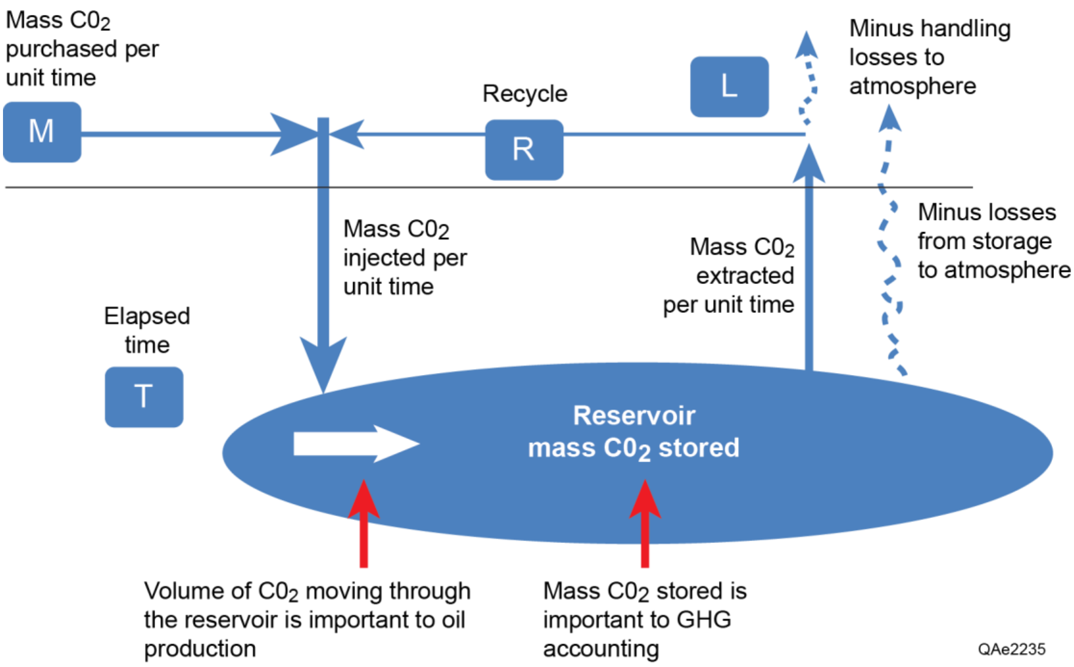


Figure 31: Components of an EOR flood are similar to a deep saline injection, with the addition of recycle and any fugitive emissions from recycle.

8.4.3.2 GHG Generated by Compression and lifting costs

One significant issue that should be considered in the whole-system evaluation of the role of EOR and GHG mitigation is energy consumption as part of the flood. To separate oil from CO_2, a drop in pressure to atmospheric is needed; to reinject the CO_2, compression back to operating pressures (>140 bar, 2000 psi) is required. Energy for compression can be bought as electricity from the grid or it can be generated on-site. Accounting for GHG emissions from this equipment could be attached to EOR operations and storage (Fox, 2009; Jaramillo et al., 2009) or could be attached to the greenhouse gas footprint of the produced oil.

In WAG floods, electricity is used to pump fluids for both production and reinjection. In direct-injection floods, the high gas content of the produced fluid causes wells to self-lift, however more energy is consumed for compression if more CO_2 is produced.

8.4.3.3 Well integrity

Current regulations recognize that maintaining the required isolation functions of wells is a critical step in both developing an EOR project and creating high-quality storage. However, the difference in motivating factors between EOR and storage could potentially result in differences in performance standards. Well reconditioning for EOR is designed to meet two goals: (1) to obtain adequate conformance so that the CO_2 is injected into, and produced fluids are extracted from, the intended zone to optimize oil recovery and (2) to comply with regulations that protect fresh groundwater resources. A goal of providing long-term isolation of CO_2 stored at depth from the atmosphere may require additional evidence that migration along wells over a long storage timeframe is minimized.

Well integrity is likely a more significant issue for an EOR project than for a deep-saline project because the well density at any EOR site is higher than in a non-producing area. However, the risk of poor performance of any individual well may be higher at a saline site because wells drilled to penetrate a saline formation would have been for exploration. Unsuccessful exploration wells, known as *dry holes*, can be plugged and abandoned to standards lower than those for production wells, and records may be more poorly curated. Also, the placement of cement plugs may not be effective in isolating saline-injection target formation because it may not have been a zone of interest for exploration.

Work is under way to understand the role of well integrity and ensuring storage permanence (for example Bachu and Bennion, 2009; Carey et al., 2010; Huerta, 2009; Kell, August 2011). Different failure mechanisms raise different types of concern. Short-term but high-volume releases to the atmosphere caused by acute well failure, known colloquially as *blowouts*, have recently elevated concern in the CCS community because of a dozen or so incidents being publicly reported. An inventory of CO_2 EOR well-control issues by Skinner, (2002) includes five case studies in which CO_2 blowouts occurred as part of EOR, mostly during operations repairing a well, which are known as *workovers*. Skinner also suggested that corrosion of equipment is a cause for concern. Reports of a few incidents involving sub-surface escape of CO_2 from wells that over a short time migrated to the surface and created visible leakage are not summarized in a citable form. Information about the frequency and rate of slow, chronic leakage to the surface that is related to flawed well construction is not available; however, because such a leak may not be detected and repaired, it may result in significant damage to storage quality; further study is needed.

8.4.3.4 Oil production

Successful CO_2 EOR has an intrinsically different whole-system GHG impact than does saline storage, in that large volumes of oil are produced. Some assessments (Jaramillo and others, 2009; see also comment in Fox, 2009) calculate the produced oil as part of the GHG impact of EOR. Note that the ratio of CO_2 injected to oil produced under current commercial conditions is minimized; strategies for changing the ratio to favour storage are discussed in a later section.

8.4.3.5 The size of the EOR market

The same question that is asked of deep-saline storage—Will there be enough capacity to provide the impact needed to reduce atmospheric emissions?—can reasonably be asked of EOR. A number of different types of assessment have obtained different answers. The U.S. storage capacity given for depleted reservoirs is less than 10 percent of that given for saline-storage capacity (NETL, 2012b). Other assessments include unconventional EOR to provide larger numbers (Tzimas et al., 2005; Advanced Resources International, 2010). King et al., 2013 conducted a U.S. regional assessment that considered the impact of assumptions about the rate at which capture projects were completed on the relative usages of EOR and saline storage during the early days of CCS. The highest value of CO_2 use for EOR is in reducing barriers to early projects; other types of GHG-emission-reduction mechanisms are needed long-term for atmospheric goals to be reached.

8.4.4 Comparing saline formation storage with EOR storage

In many ways, CO_2 storage during EOR is identical to storage in deep-saline formations, in that injection of CO_2 into pore spaces requires displacement of fluids currently present, resulting in pressure increase. This pressure elevation, as well as buoyancy of the CO_2 relative to the water, causes CO_2 to migrate; low-permeability confining systems limit vertical migration so that retention occurs. Injection processes of the rock types selected for EOR are within the range of those used for saline storage.

EOR is different from saline storage in several important ways (Wolaver et al., 2013). Deep-saline-storage sites are characterized to identify likely confining systems, however in most cases, at the time of CO_2 injection, some uncertainty in the performance of the confining system remains (Table 13). That uncertainty triggers the need for a robust monitoring program. In contrast, hydrocarbon reservoirs are proven traps for buoyant fluids over geologic time. Saline-storage sites are determined during characterization to have a capacity sufficient to accept the planned CO_2 volume at the planned rates; however, monitoring is needed to validate these predictions. In contrast, by the time the reservoir is a candidate for EOR, its response to fluid withdrawal and injection is very well known.

8.4.5 Monitoring EOR as storage

Monitoring is widely seen as an important part of a storage project, with high-level goals (1) to confirm that storage is progressing as expected and (2) to provide assurance that negative outcomes are not occurring or expected to occur (Forbes et al., 2008). Monitoring is recommended to be strongly linked to risk and to uncertainties that might have a material negative impact on the project. CO_2 EOR for oil production typically conducts a number of surveillance activities to optimize the flood for oil recovery. As previously discussed, surveillance techniques (pressure, fluid composition, geophysics, calibration of fluid flow models) substantively overlap the monitoring techniques proposed and conducted at deep-saline storage sites (Holloway et al., 2004; NETL, 2012a). However, most EOR flood-surveillance techniques are conducted privately to benefit the operation and results of surveillance and modelling are rarely publicly reported. Well management is the most regulated element of EOR; however, during collaboration with operators, we have observed that many well issues are dealt with proactively before they reach the standard of reporting to state regulators. The absence of systematic monitoring and reporting related to CO_2 EOR is seen by some researchers as why such projects should not be considered as storage and even discounted in the viability of EOR as a “stepping stone” toward storage (Dooley et al., 2010).

If CO_2 is to be counted as storage, is reasonable to expect that the same high level goals are achieved via EOR as via deep-saline-storage projects. However, because the uncertainties differ systematically at EOR fields from those at saline sites, the risk profile resulting from injection is different, and, as a result, the tailored monitoring program developed in response to risk must differ systematically as well (Table 13). The long geologic and operational history of EOR results in diminished uncertainty and risk with regard to performance in terms of capacity, seal quality, lateral-plume extent, and geomechanical response. This is not to imply that no uncertainty remains; indeed, where uncertainty is identified, a monitoring plan is needed as part of the EOR and storage program. However, reduced uncertainties at the start of injection will result in a smaller and more tailored monitoring strategy for documenting storage at an EOR site.

Table 13: Uncertainties in key storage parameters comparing saline EOR sites with implications for monitoring.

Key parameter	Uncertainty in typical deep saline site	Uncertainty in typical EOR site	Monitoring need
Storage capacity	Moderate	Low	Saline: during-injection monitoring for fluid flow model validation required. EOR: characterization using historic production data sufficient.
Adequacy of cap rock to provide confinement	Moderate	Low	Saline: during-injection monitoring for conceptual and fluid flow model validation required. EOR: strong geologic evidence sufficient, however consideration of possibility of damages during past operations is needed.
Acceptable prediction of lateral CO_2 migration	Case dependent; moderate to high	Low	Saline: during-injection monitoring for model validation required. EOR: during-operation control and surveillance at many wells and prediction based on hydrocarbon accumulation therefore little additional monitoring required.
Geomechanical response to injection	High	Low	Saline: sparse data accessed during characterization; EOR: fields have been subject to past fluid injection and withdrawal constraining geomechanical response to injection.
Existing wellbore performance	Site-dependent	High because of numerous wells	Saline sites typically have few well penetrations however the isolation of the saline zone at wells is unknown; EOR: industry and regulatory experience show that well preparation, maintenance, surveillance, and remediation are critical to good flood conformance. Additional improvement in the quality of well remediation may be needed to show long-term isolation with respect to attaining atmospheric goals.

Another reason for a different requirement for monitoring at an EOR site is that approaches and technologies that work well at a typical saline site may perform poorly at an EOR site (Wolaver et al., 2013). For example, EOR sites have complex fluids (oil, water, possibly methane gas) in the reservoir, and these fluids can interfere with many geophysical monitoring techniques (Zhang et al., 2013; Ditkof et al., in press). Shallow gas accumulations can complicate geophysical imaging of deeper reservoirs, and impact can be exacerbated during time-lapse surveys if anything changes in the shallow reservoirs because of production or groundwater interaction. The presence of natural hydrocarbon microseepage over geologic time can interfere with methodologies designed to identify out-of-reservoir-leakage (Klusman, 2003; Romanak et al., 2012). In addition, past practices have led to spilled hydrocarbon concentrations in near-surface environments of many oilfields. Hydrocarbon in near-surface environments becomes biodegraded to CO_2, and sophistication is needed to separate ambient CO_2 from the leakage signal (Romanak et al., 2012).

Pressure-based monitoring is a mature oilfield technology suitable for documenting that the reservoir is accepting the injection as planned and documenting good retention at storage sites (Sun and Nicot, 2012). However, at fields undergoing EOR, past or continuing hydrocarbon production or brine injection can limit pressure-monitoring options. Past perturbations, lingering transients, or future extraction/injection operations could mimic or obscure a pressure-based leakage signal. However, the same operational complexity corresponds to a way in which EOR has better monitoring-optimization options than do deep-saline-storage sites. By the time an onshore field is ready for EOR, it has many more well penetrations that provide high-frequency, high-relevancy data on reservoir performance. Tools such as first CO_2 arrival at producers, known as *breakthrough*, and the ratios of oil, water, and gas produced are classic reservoir-management tools that play the same roles in confirming that the flood is conforming to predictions during EOR as they do at saline sites. Well penetrations also allow diverse other types of surveillance corresponding to the tools considered for deep-saline CO_2 monitoring.

The final difference discussed between EOR and saline storage is uncertainty at site closure. Some hydrocarbons will remain at the end of economic CO_2 flooding. It is possible that additional extraction techniques (beyond those currently planned) will be deployed in the quest for remaining hydrocarbons in the future. No full-scale CO_2 EOR projects have been closed; operations have temporarily abandoned some patterns; however, the idealized view of closure, monitoring, and administrative handoff appears to be unrealistic for EOR sites (Marston and Moore, 2008).

8.5 **CO_2 EOR AND MULTIPLE USES**

8.5.1 Stacked storage

One source-rock system can provide hydrocarbon charge to multiple traps, demonstrating that fluid flow is at some rates and scales interconnected. In many settings, hydrocarbon traps occur in three-dimensional arrays, with reservoirs stacked vertically beneath different seals over the same structure and distributed laterally in different traps (Figure 32). Different reservoirs are commonly operated separately, and it is common for a CO_2 EOR flood to target only some zones while bypassing others.

A superficial review of the distribution of onshore U.S. EOR potential and deep-saline formations shows that the two storage types generally co-exist (Hovorka, 2013). Many hydrocarbon reservoirs are laterally and vertically associated with saline formations. In some structural settings, the saline formation is hydrologically well connected to the reservoir; in others, pressure depletion during production shows that the reservoir is mostly isolated from adjacent deep-saline formations.

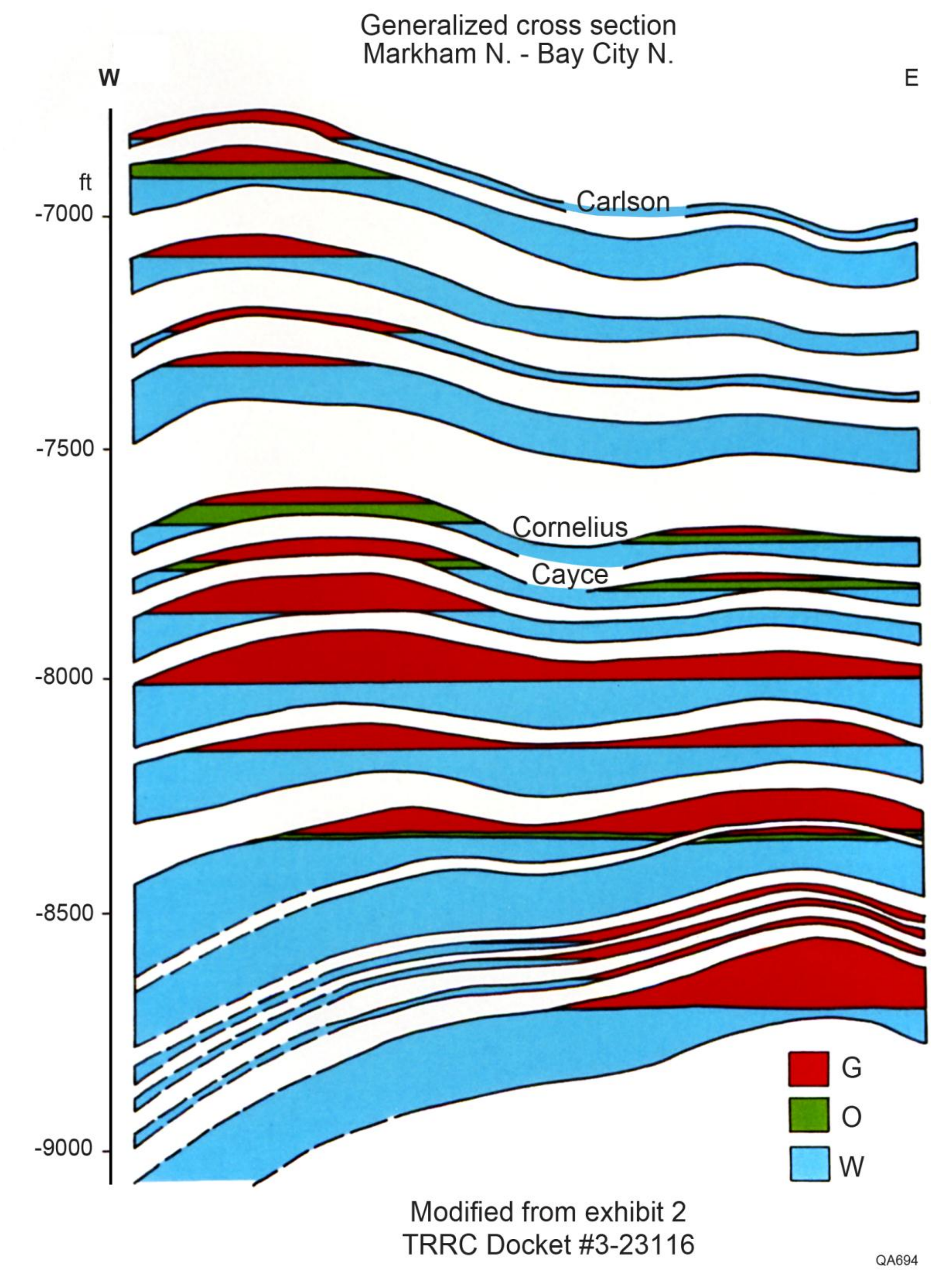


Figure 32: Stacked oil, gas, and saline reservoirs illustrate the co-use of the subsurface and the concept of staked storage. From Tyler and Ambrose, 1986.

8.6 CO_2 EOR AND NON-EOR PRODUCTION

CO_2 EOR provides a number of lessons for multiple uses of the sub-surface because it is a tertiary-recovery process conducted in locations where intense sub-surface activities are under way, and multiple uses are planned for a sustained period in the future. Little has been published on staging an EOR flood; therefore, this discussion is based on observations of operations at a number of EOR projects. EOR is typically implemented incrementally in an oilfield in secondary production under waterflood. To maintain a revenue stream, operators plan to develop the EOR flood in some areas of a field while secondary production continues in other parts of the field. Issues that are considered related to multiple uses are ownership, pressure and fluid management, well condition, and trespass.

In U.S. jurisdictions, private ownership of sub-surface resources can limit development of CO_2 EOR. This limitation may be reduced in jurisdictions where ownership of the sub-surface is retained by governments—for example, the Crown Estate in the UK, but the U.S. experience in handling multiple uses may be useful to single owners for planning. During a flood, CO_2 and oil are pushed from areas of elevated pressure where CO_2 and water injection is under way and pulled toward cones of pressure depletion around producers. If hydrologically connected parts of the reservoir under flood are in production but are not owned and operated as part of the floods, those wells may be impacted by CO_2. Operators therefore work to unitize the field, creating a legal framework such that all wells in the reservoir are handled together (unitization is discussed further later).

Any parts of the reservoir that remain outside of the CO_2 flood unit create several issues. Unitized wells can profit by receiving elevated pressure or mobilized oil; however, if CO_2 arrives at a well that has not been prepared, it can damage the casing, tubing, gathering lines, storage tanks, and other equipment. CO_2 arrival at a well not included in the flood leads to flaring of produced CO_2 because the gathering system is not connected to the separation plant. CO_2 arrival at a well that is idle or temporarily abandoned but not prepared for CO_2 flood has been a cause of leakage at several floods (e.g., Salt Creek, Wyoming; In Salah, Algeria).

Reservoirs under waterflood commonly exhibit injection-production connectivity outside of patterns (e.g., Sayarpour et al., 2011). Anecdotes of in-reservoir but out-of-injection pattern migration of CO_2 are common; however, public documentation has not been found. One technique used to control lateral migration is to rim the CO_2 flood area with wells injecting water, forming a *water curtain*. Another method is to rim the flood area with producers and trap any migrating fluids into resulting areas of low pressure *sinks*. No public-domain evaluation of the success of management methods for isolating the CO_2-flood area from adjacent areas has been found.

8.7 CO_2 EOR AND FLUID DISPOSAL

Another example of multiple uses of the sub-surface in conjunction with EOR is fluid disposal. Wastewater produced during production can be used to support a waterflood, to support WAG in an EOR flood, to create a water curtain to manage an EOR pattern or disposed of in an inactive zone. Additional water can be produced from other zones to increase pressure toward miscibility. If methane or other gas is produced with oil but is not sold to market, it is separated and locally reinjected as needed, either for pressure support or for disposal into a different zone. All these activities are managed by the same agency, in most cases the state oil and gas regulator.

Within this traditional fluid-management environment, legal disputes include issues such as inconsistencies in original map view or vertical ownership of resources, inconstancies developed during long exploitation and sales history, and conflict over issues such as unitization and trespass. Outcomes are complex and differ according to jurisdiction. Regulators work together to ensure that injection permitted by one agency does not damage resources managed by another. Intersection of the concept of geologic storage with traditional EOR has not been tested much and is the topic of some concern, which is considered in a later section on overview of evolving legal and regulatory issues.

8.8 BALANCING STORAGE OPTIMIZATION AGAINST OIL PRODUCTION

A number of workers have considered the question of optimizing storage vs. optimizing oil recovery (e.g. Jessen et al., 2005; Leach et al., 2011; Jahangiri and Zhang, 2012). This question provides an elegant modelling problem, integrating water and gas injection ratios, pattern design, and reservoir heterogeneity. However, if recycling is accepted as a closed loop, simple calculations lead to an outcome that production and storage are co-optimized by improved contact of CO_2 with reservoir volumes so that the goals are not in conflict. Only in cases where oil production and a GHG penalty for lifting cost are considered negatives against the value of storage (Jaramillo et al., 2009) does conflict arise between optimizing for oil production and whole-system GHG impact.

Pragmatic considerations lead to decisions driven by economics because the value of oil greatly outweighs the value of CO_2 storage. Trade-offs can be optimized; for example, the up-front cost of the pipeline and the size of the separation facility create a limit on how fast CO_2 can be injected and extracted. A decision about whether and at what ratio of WAG to operate requires balancing costs and benefits. Low water:gas increases lifting costs because wells must be pumped; a high ratio causes wells to flow without pumping but adds load to the separation facility.

8.9 SALINE STORAGE AND EOR IN SAME FOOTPRINT

We prefer to look at co-optimization of EOR and storage in a system using both EOR and deep-saline injection operations. In such a case, saline storage could be used as "swing" capacity in two ways—shorter and longer timeframes. Short-term energy output of power plants is varied with load to the grid, such that the CO_2 output varies with electricity demand. If CCUS were deployed extensively, it might have to manage varying output of CO_2 (Coleman, 2012). Purchase of CO_2 for EOR might be matched to average or sustained load, with higher output spillover injected into saline wells where variability had lower significance. However, varying capture with electricity usage is generally thought not to be economically viable because of the high capital investment in capture; capture facilities might be applied to base load (Cohen et al., 2010). Over long timeframes coordination of EOR with deep-saline storage is needed. The demand for CO_2 is high during the start-up of an EOR flood, when recycle is small. During early years of the flood, pipeline capacity and injection demand are balanced by the flood area being built out, such that increasing return of CO_2 from recycle allows start-up of a new set of patterns. However, after a decade or two, the entire field will have been developed, and the overall need for new CO_2 supply to the field will decrease. In a multi-field pipeline-network situation, this decrease in CO_2 demand can be accommodated with a new EOR flood in a different field; however, eventually the CO_2 market in an area will saturate, requiring a handoff to saline storage (Cohen et al., 2010). King et al., 2013 created two idealized end-member scenarios of fast increase in adoption of CO_2 capture versus slow build-out and explored the implications of balance between use of CO_2 for EOR and storage in a test area of the U.S. Gulf Coast.

8.10 OVERVIEW OF EVOLVING LEGAL AND REGULATORY ISSUES RELATED TO JOINT USE OF EOR AND STORAGE

A complete review of the legal issues involved when storage to benefit the atmosphere intersects CO_2 EOR is outside the scope of this chapter. It is also possibly premature because of a lack of guiding case law in U.S. jurisdictions where the question may first arise. This section presents a list of legal and regulatory issues in discussion. A recent summary of uncertainties and legal issues related to EOR in the EU is provided by Mcrory, 2013.

Few cases of regulator or legal action related to CO_2 EOR are available in the literature or in archive searches. One informal search was conducted for lawsuits in Texas, including litigation about CO_2 in the sub-surface; no cases were found (personal communication from E. Briggs, GCCC intern, 2009). A second search was conducted by Giacomo Bacci, Imperial College, who, on behalf of the CO_2 CARE project, went through case files and complaints at the Railroad Commission of Texas, where oil and gas are regulated, and found no records of complaints or damages related to CO_2 EOR. This paucity of cases may reflect a number of factors: (1) few incidents have occurred, (2) incidents that have occurred have been dealt with without a public record being created, or (3) public records are in different jurisdictions under different filing systems and are difficult to extract. Personal experience at experimental sites shows that many issues fall below the threshold that causes creation of a record.

8.10.1 Documentation and investment in retention

For CO_2 EOR, CO_2 is a purchased commodity, and release to the atmosphere is unrestricted. However, for geologic storage, retention of CO_2 in the sub-surface in isolation from the atmosphere is the product of value that pays for operation of the storage site. Pragmatically, the conflict between these different goals is small because most EOR is conducted with CO_2 in a closed loop so that atmospheric release is limited. Migration from the sub-surface expected in a CO_2 EOR operation is also small because the geologic characteristics of the hydrocarbon trap have been demonstrated and because wells are constructed and regulated to avoid uncontrolled fluid migration.

However, CO_2 EOR operators have strong objections to changing regulations to require that isolation is demonstrated. Concerns include which regulator is given jurisdiction (state vs. federal; oil and gas vs. environmental), cost, potential for slower permitting (a key issue in EOR project economics), and potential for unintended negative consequences (e.g., tighter rules on well construction that could preclude use of fields with existing wells). In addition, an uncertain standard as to what leakage would be considered negligible creates fear that either an intensive monitoring program will be required or a difficult and expensive mitigation program might be needed. The risk of atmospheric standards being applied to geologically sourced (natural) and captured CO_2 from gas-stripping plants is seen as a threat to CO_2 EOR business; as such, standards would likely add cost with no offsetting benefit to such projects.

Shipping CO_2 to EOR projects with no standard of retention may be problematic for anthropogenic capture where documentation of storage is part of the motivation for capture, this lack could be a barrier to development. Adding to the confusion, current EOR projects commingle natural, gas-separation, and captured-from-industrial-source CO_2 in the same pipeline system and send the commingled CO_2 to multiple fields. Commingling is reported to be planned for future capture also.

An interesting sidelight to retention is presented by residual oil zones (ROZ’s). In contrast to conventionally trapped oil, at ROZ’s, natural processes over geologic time have caused mobile oil to migrate. A question not yet answered is the value in terms of permanence of storage associated with CO_2 EOR in ROZ’s.

8.10.2 Subsurface trespass for EOR

Sub-surface trespass has long been an issue in oil and gas production because the hydrologic connectivity of the sub-surface may not be reflected by ownership of either the surface or the sub-surface. Withdrawal or injection on one property is known to have an impact on adjacent hydrologically connected reservoirs, and a large case-law literature has been developed to deal with these issues. Application to CO_2 EOR and CO_2 storage, however, is premature because cases have not dealt with trespass under conditions that provide clarity on how laws and precedent will be applied (Aldrich and Koerner, 2011). Two ideas relevant to CO_2 are being considered: *unitization* and *negative rule of capture*.

Unitization is a powerful process for management of sub-surface use in the U.S., by which the various parties who have sub-surface mineral ownership, including the leaseholders (*working interests*), the owners of mineral leases (*royalty interests*), and any unleased mineral owners, create a legal framework known as a "Unit Operating Agreement" to operate the reservoir as a *pool* (Marston and Moore, 2008). This pooling has been used since the early days of oil and gas production to manage pressure decline (Barr, 1939), later for waterflood, and now for tertiary recovery under CO_2 EOR. Rules for unitization vary by jurisdiction and include concepts of public interest through which a legally prescribed percentage of the interests can force a minority to participate. Some jurisdictions, notably the State of Texas, have no compulsory unitization; pooling a reservoir is voluntary and is accomplished through contacts and purchases. The methods by which unitization is accomplished were described in detail by Marston and Moore (2008):

> *"Another very important aspect of the compulsory unitization statutes is, that in order for such a unit to be approved by the state oil and gas agency, the operator must show that he has delineated the reservoir to such an extent that he can demonstrate that no adverse impact shall occur to offsetting properties during his enhanced recovery operation because he has included all the viable reservoir within the Unit boundaries. In order to make this showing, the production from the reservoir and the characteristics of the producing strata are studied by a team of geologists and reservoir engineers who then present evidence to the applicable state agency showing that the oil and gas reservoir is a finite area with defined boundaries. These boundaries may result from porosity and permeability pinch-outs, encroaching water tables, underground ceiling (sic) faults, or whatever other limiting factors can be geologically or operationally demonstrated. Typically, this evidence is presented at a trial-type hearing to examiners that are technical and legal, and in many states before the entire oil and gas conservation commission. The testimony must show that the reservoir is defined sufficiently to encompass the area that will undergo enhanced recovery operations, satisfy the hearing examiner(s) that oil and gas will not migrate outside the project, that no injected substance (including, for example, the CO_2 injected in a CO_2 flood) will migrate outside the unit boundary, and that no oil and gas owner within the Unit area will have oil and gas pushed off his lease, never to be recovered.*
>
> *These procedures ensure that at the time the EOR project is initially formed, there is a well-defined subsurface interval (the Unitized Formation) that is capable of containing the injected substance while increasing the production of oil and gas from the pressurized reservoir. As long as an operator can show that the moneys spent to develop the enhanced recovery project are less than the value of the additional oil and gas to be recovered, the project is usually approved by the oil and gas agency. When the unit project terminates and all commercial oil and gas production ceases, the oil and gas leases that were pooled would normally terminate as well and therefore, the compulsory pooling itself expires."*

Operation of the hydrologically connected reservoir as a unit is important for the economics of CO_2 EOR, so that all the oil that is mobilized is captured and the CO_2 is recycled through the central separation facility. However, if storage is a project goal, effective unitization becomes even more critical. As mentioned earlier, production of CO_2 through a well that is not part of the flood and therefore is not sent to be recycled can result in substantive loss to the atmosphere that would likely be problematic for a storage project. Further, segmentation of the reservoir used during the active stage of the flood by water curtains and production sinks will cease at the end of production. If CO_2 will then migrate over the intermediate or long timeframe into areas of the field that were held isolated during active production, these parts of the field must be prepared to retain CO_2—for example, in terms of well-completion reconditioning. The same ownership barriers that prevented unitization might also prevent investment in well conditioning during closure, damaging storage value.

Another issue that may emerge when storage to benefit the atmosphere intersects CO_2 EOR is migration of fluid out of the intended area into an adjacent lease. The migrating fluids could be brine, resulting in a change in pressure, or CO_2; both are considered under the negative rule of capture. Williams and Meyers (1995, quoted in Anderson, 2010) provided a definition:

> *“What may be called a “negative rule of capture” appears to be developing. Just as under the rule of capture a landowner may capture such oil or gas as will migrate from adjoining premises to a well bottomed on his own land, so also may he inject into a formation substances which may migrate through the structure to the lands of others, even if it thus results in the displacement under such land of more valuable substances.“*

A number of new discussions related to reservoir stimulation by hydraulic fracturing (Zeik, 2009 -2010; Anderson, 2010) may also provide information relevant to the handling of interference between CO_2 EOR and deep-saline storage. However, this interference maybe mutually positive. Storage in deep-saline formations without production can be limited by the ability of the subsurface to accept fluid without unacceptable pressure increase (Obdam, 2006; Jain, 2011). Conversely, CO_2 EOR is fundamentally an extraction process, with one of the limiting steps keeping reservoir pressure high enough to obtain the desired miscibility. Therefore, in most geometries, hydrologic connection of storage with EOR would be complementary, with saline storage adding pressure and EOR depleting it.

8.10.3 Duration of storage –managing conflicts between EOR and storage

Geologic storage projects are conceptualized, designed, operated, and regulated to provide storage over multi-century timescales (IPCC, 2005). Concerns about achievement of long-term storage goals are generally focused on the quality of the geologic retention. Few workers have considered issues such as later conflicts of storage with other possible uses. In general, because saline storage is placed in unused and unusable spaces, management of future conflicts is generally ranked as a low risk and is dealt with by deeds and placement of markers.

In contrast, CO_2 EOR projects are designed to be operated within a decadal window, after which an end to oilfield operation is planned. Contracts and rules that regulate operation, such as access to the reservoir via lease, are closely tied to production. When production ceases, a relatively rapid (a few years) end to the operator’s access to the surface and subsurface is triggered. In addition, in the U.S., enforcement of many rules is via permit to produce. At the end of production, the regulators’ ability to enforce can lapse. To hold or supervise the storage over longer timeframes at the end of EOR requires a new type of lease (Marston and Moore, 2008).

EOR projects are focused in areas of high-value resource, and oil that is not commercially accessible to EOR will most likely remain at the end of the project’s economic life. The presence of this resource may complicate planning for closure. Because no successful EOR projects have shut down, little case-study information about closure is available.

9 Managing the pore space for CO_2 storage and other uses, Alberta

9.1 INTRODUCTION

Located in Western Canada, Alberta is a global energy leader with a diverse resource portfolio which includes oil, coal, minerals, natural gas, bitumen, and renewables and petrochemicals. As global markets transition toward low-carbon energy sources, Alberta, like many other jurisdictions, is looking for ways to support its industries to remain competitive. Alberta's 2008 Climate Change Strategy[29] identified carbon capture and storage (CCS) as a key mitigation technology to address greenhouse gas emissions and in turn advance the responsible and sustainable development of Alberta's energy resources.

9.2 STRATEGIC MANAGEMENT OF PORE SPACE: SETTING THE STAGE

In 2009, the *Carbon Capture and Storage Funding Act* [30] was passed to encourage and expedite the design, construction, and operation of CCS projects in Alberta. Under this act, the Government of Alberta has committed over $1.3 billion to two projects, which are expected to reduce Alberta's greenhouse gas emissions by approximately 2.76 Mt per year by 2016.

Alberta also recognized the need to address regulatory and policy barriers facing the deployment of commercial-scale CCS, such as managing the pore space, and implemented legislation to address these issues. The 2010 *Carbon Capture and Storage Statutes Amendment Act*[31] amended several key pieces of legislation, including the *Mines and Minerals Act*[32] and the *Oil and Gas Conservation Act*[33]. The *Mines and Minerals Act* was amended to declare that all pore space, except that under federally owned lands, is owned by the province. The amendment also enabled the Minister of Energy to enter into agreements to grant pore space rights and allowed the provincial government to accept long-term liability for properly sequestered carbon dioxide. Lastly, the amendment created the Post-closure Stewardship Fund to ensure that money is available to cover monitoring and potential remediation costs after the Province assumes liability. The *Oil and Gas Conservation Act* was amended to specify which elements of the Act apply to CCS including definitions, the duty to abandon, regulation making authorities, notifications to the Crown when operations cease, entry and inspection authorities and emergency response measures.

One of the main barriers facing CCS worldwide is the complex nature of subsurface ownership. Before the *CCS Statues Amendment Act*, there was no legal certainty around pore space ownership. This was resolved by the legislation, and gave operators the ability to select permanent storage sites based on their technical ability to store CO_2 permanently and safely. The Act gave the province access to the pore space in freehold mineral lands, and allowed

[29] Alberta Department of Environment and Sustainable Resource Development website, http://environment.alberta.ca/0909.html [June 2013]
[30] Alberta Queen's Printer website. http://www.qp.alberta.ca/1266.cfm?page=C02P5.cfm&leg_type=Acts&isbncln=9780779742141&display=html [September 2013].
[31] Alberta Queen's Printer website. www.assembly.ab.ca/ISYS/LADDAR...27/.../20100204_bill-024.pdf [September 2013].
[32] Alberta Queen's Printer website. www.qp.alberta.ca/documents/acts/m17.pdf [September 2013].
[33] Alberta Queen's Printer website. www.qp.alberta.ca/documents/Acts/O06.pdf [September 2013]

mineral right owners to retain their rights. The amendments also added a section to the *Mines and Minerals Act* that declared historic grants of land or minerals did not include pore space, and that the Crown owned the pore space. This was critical to ensure the large scale deployment of CCS in Alberta.

The *Mines and Minerals Act* was also amended to allow the Minister of Energy to enter into contracts and agreements with project operators to permit access and use of the pore space. This enabled existing oil and gas tenure provisions to be expanded to incorporate tenure rights for sub-surface pore space. To support this amendment, the Carbon Sequestration Tenure Regulation[34] was passed in April 2011. The regulation allows CCS project operators to acquire a five-year permit to evaluate a potential storage site – investigating its geology and determining its effectiveness for carbon sequestration. Next, it allows operators to obtain renewable 15-year leases for commercial-scale carbon sequestration at suitable storage sites. Finally, the regulation specifies what criteria must be included in monitoring, measurement and verification plans as well as the closure plans that need to be approved by the provincial energy regulator[35]. Similar to Crown mineral tenure for petroleum and natural gas, pore space tenure is administered by Alberta's Department of Energy (Alberta Energy[36]). Pore space rights are granted to project operators on a first-come, first-served basis, and are subject to various requirements depending on the type of tenure agreement that they seek to acquire.

Under the Carbon Sequestration Tenure Regulation, lease applicants are required to submit a monitoring, measurement and verification (MMV) plan and an initial closure plan. The MMV plan sets out the monitoring, measurement and verification activities that a project operator will undertake for the term of the permit or carbon sequestration lease. The closure plan sets out a description of the activities that a lessee will undertake to close down sequestration operations and facilities. MMV and interim closure plans must be submitted every three years for review and renewal. Both MMV and closure plans must also contain an analysis of the likelihood that a project will interfere with other mineral recovery activities in the area. Presently, the Minister of Energy is responsible for the approval of MMV and closure plans as part of the tenure application process.

The long-term liability of CCS projects, for the period of time after project abandonment, has been identified as a significant barrier to CCS deployment. By assuming long-term liability for a sequestration site once a closure certificate has been issued, Alberta significantly improved the ability for operators to plan and execute projects, and ensured the protection of Albertans should an agreement holder cease to exist. CCS projects are long-term projects, and CO_2 sequestered during a project will remain trapped underground for hundreds, and likely thousands, of years. Due to these long timeframes, it is conceivable that sequestered CO_2 will remain in place much longer than any corporation operating a project would be expected to exist. Therefore, the Government of Alberta made a policy decision to assume long-term responsibility for sequestered CO_2 to ensure that it will be monitored and, if necessary, managed in the future. The Post-closure Stewardship Fund was also created under the Amendment Act to ensure that any

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[34]Alberta Queen's Printer website. www.qp.alberta.ca/documents/orders/orders_in.../2011_179.html [September 2013]

[35]The Alberta Energy Regulator (AER) is authorized to make decisions on applications for energy development, monitoring for compliance assurance, decommissioning of developments, and all other aspects of energy resource activities (activities that must have an approval under one of the six provincial energy statutes). More information can be found on their website http://www.aer.ca/

[36] Alberta Energy is responsible for managing the development of the province's renewable and non-renewable resources, and granting industry the rights to explore for and develop energy and mineral resources, More information can be found on their website

future monitoring or environmental costs are covered by an industry generated levy that is collected during the operational phase of a project.

In March 2011, the Alberta Government initiated the Carbon Capture and Storage Regulatory Framework Assessment. This multi-stakeholder process was guided by a steering committee, and included an expert panel of world-renowned scientists and four highly specialized working groups that examined the regulatory, environmental, technical and geotechnical issues related to CCS deployment in detail. The Assessment addressed the potential regulatory gaps that exist in the current framework for CCS in Alberta and resulted in a report[37] that contained 71 recommendations and 9 conclusions that will ensure CCS is deployed is the safest and most environmentally responsible way.

9.3 RESOLVING POTENTIAL CONFLICTS OF USE

Sedimentary basins that have high CO_2 storage potential also host fossil fuels, groundwater, minerals and geothermal energy resources. Alberta has established processes and mechanisms for preventing adverse impacts from one form of resource extraction on another, including implementation of the gas over bitumen policy. The gas over bitumen issue is unique to Alberta, and affects a number of producers of both bitumen and natural gas. The dilemma occurs when natural gas pools are found above bitumen reservoirs. Depletion of the gas pool causes lower pressure in the zone above the bitumen reservoir, making it more difficult to recover the bitumen. In 2000, a joint industry and government committee produced a Technical Solutions Roadmap[38] to assist companies to determine how to best choose which resource to develop.

This type of resource interaction is also important for CCS development, as sequestration projects have the potential to interact with the conservation, production, and protection of other hydrocarbon resources. These subsurface interactions can have negative impacts, leading to competition for pore space. The interactions can also be positive and provide the opportunity for development synergies.

The Government of Alberta has already taken steps to manage the interaction between CCS and hydrocarbon resources, by explicitly mandating in legislation[39] that CCS projects will not interfere with or negatively impact oil and gas projects in the province. As projects move through the pore space tenure review process, operators must also identify and assess any potential interactions that a proposed CCS project may have with other subsurface resources. If there is potential for a CCS project to interact with oil and gas, then Alberta Energy must decide whether to deny pore space tenure, or grant tenure and leave it to the regulator to evaluate if the potential resource interactions can be effectively managed to prevent negative impacts on mineral recovery. The provincial energy regulator has a well-developed process[40] for evaluating and managing subsurface resource interactions.

If it is determined that a potential resource interaction can be effectively managed, there may be a situation where the operator is required to monitor interactions outside the tenure area. If access to land is required for MMV activities, operators negotiate with private land owners (or Alberta Environment and Sustainable Resource Development for public land) to reach an

[37] Alberta Department of Energy website. http://www.energy.alberta.ca/Initiatives/3544.asp [October 2013]
[38] Alberta Department of Energy website. http://www.energy.alberta.ca/OilSands/578.asp [September 2013]
[39] Section 39(1.1), *Oil and Gas Conservation Act*. Alberta Queen's Printer website. www.qp.alberta.ca/documents/Acts/O06.pdf [October 2013].
[40] Draft Directive 065: Resource Applications for Oil and Gas Reservoirs. Alberta Energy Regulator website. http://www.aer.ca/rules-and-regulations/directives/directive-065 [October 2013].

agreement for land access. These agreements would also include compensation measures and address landowner concerns. If negotiations are unsuccessful, the *Surface Rights Act*[41] enables the Surface Rights Board[42] to issue a Right of Entry Order to an operator to conduct MMV activities. Currently, there is uncertainty as to whether the *Surface Rights Act* allows an operator access to land beyond the surface lease site.

The purpose of MMV activities is to address health, safety and environmental risks, evaluate sequestration performance and provide evidence for closure. Conducting MMV activities is also imperative in order to demonstrate conformance and containment of stored CO_2. Although the majority of surface access required for MMV activities will be in the areas overlying and surround the CO_2 plume, some activities could require gaining transient surface access on all areas within the sequestration lease. To manage this, the Regulatory Framework Assessment recommended the *Surface Rights Act* be amended to enable Surface Rights Board to grant an operator a Right of Entry Order for any land within the carbon sequestration lease or evaluation permit boundary in order to conduct required MMV activities.

There are also other subsurface resources that could interact with CCS development, including groundwater. Many of the potential risks to groundwater are addressed through a number of regulatory processes and approvals prior to injection that ensure proper site selection occurs and effective MMV plans are established and updated. Alberta's groundwater is protected under the *Water Act*[43] and the *Environmental Protection and Enhancement Act*[44]. The *Water Act* ensures non-saline groundwater is protected, and the *Environmental Protection and Enhancement Act* (EPEA) prohibits the release of a substance in an amount that may cause a significant adverse effect. Should such a release occur, it must be reported and remedial measures implemented to return the area to initial quality levels or comparable functions. CCS project operators are also responsible for adhering to the extensive rules, regulations and requirements[45] that ensure protection of the groundwater by addressing items such as wellbore integrity, formation suitability, and hydraulic isolation.

The pore space tenure process is the primary process to ensure that CCS development will not negatively impact the hydrocarbon development industry in the province. However, most decision makers in the private or public sector do not currently consider pore space a resource, as it is viewed as having no value and does not need to be considered when making trade-off decisions relating to resource development and planning. As a result, the RFA recommended the government and the regulator continue to evaluate potential resource and development interactions on a case-by-case basis. Development decisions will be based on resource development policies of the day. To help ensure high quality pore space for CO_2 sequestration is effectively managed, the Alberta government is working with stakeholders to develop an inventory of sequestration quality pore space in the province. This inventory will also identify potential areas of interaction between subsurface resources and sequestration quality pore space.

9.4 PORE SPACE TENURE

It is important for the Government of Alberta to ensure its pore space resources are used to their full potential. In the 2008 Climate Change Strategy, Alberta predicted that CCS will account for

[41] Alberta Queen's Printer website. www.qp.alberta.ca/documents/Acts/S24.pdf [October 2013]
[42] Government of Alberta website. http://www.surfacerights.gov.ab.ca/ [October 2013]
[43] Alberta Queen's Printer website. www.qp.alberta.ca/documents/Acts/w03.pdf [October 2013]
[44] Government of Alberta website. http://environment.alberta.ca/03147.html [October 2013]
[45] Draft Directive 065, Draft Directive 051, Directive 009. Alberta Energy Regulator website. http://www.aer.ca/rules-and-regulations/directives [October 2013]

139 Mt of CO_2 emissions reductions per year by 2050. Assuming average capture rates of one to two Mt annually, this level of CO_2 reduction would result in 80 to 100 commercial scale facilities. If each facility were to have its own sequestration site, this could result in a similar number of sequestration sites across the province. This potential proliferation of sequestration sites introduces policy challenges related to resource competition and pore space management and development.

Presently, CCS project operators submit applications for pore space tenure based on availability and project specifications. As CCS becomes a common activity in the province, demand for pore space, especially in those regions with high numbers of large industrial facilities, may compel operators to acquire pore space tenure in geological zones with close proximity to other carbon sequestration sites, including areas where the tenure is vertically stacked or overlaid. Moreover, project operators may apply for tenure adjacent to other tenure zones in order to operate as close as technically feasible and maximize pore space utilization in a particular area, which is referred to as jointly utilized.

Both of these development scenarios present opportunities to maximize pore space use in a particular zone through tenure allocation, which could become increasingly important if CCS becomes a significant activity in the province. However, both scenarios also present a number of potential technical and regulatory challenges. Competing, independently operated, CO_2 sequestration operations have the potential to affect one another in terms of injectivity, monitoring, liability and through overlapping pressure fronts. Therefore the RFA recommended that tenure applications for jointly utilized sites be considered on a case-by-case basis.

In some instances, it may be necessary for government to rescind or revoke tenure that is wholly unused. Currently, the government cannot revoke unused tenure, and instead has to choose not to renew a carbon sequestration lease at the end of its 15-year term. While it is important for government to have the flexibility to decide what period of time is appropriate for each application for pore space tenure, investors also need to have a reasonable level of certainty in their tenure. It is important for lessees to know, under what conditions and after what period of time the tenure could be revoked. To address this, the RFA recommends that the government consider restructuring carbon sequestration leases so that the Minister of Energy has the authority to revoke or rescind tenure that has not been used after a defined period of time.

9.5 PORE SPACE OPEN ACCESS

Situations may also arise where there is high demand for pore space tenure in regions where pore space tenure has already been allocated. In these situations where demand for pore space tenure outweighs the supply, it will be necessary for government to introduce policy or regulations to incentivise or compel project operators to allow third party access to their pore space for CO_2 sequestration to facilitate the development of CCS in Alberta.

There is currently no regulation in Alberta directly dealing with third party access or open access to pore space or CO_2 sequestration. There are, however, portions of the *Mines and Minerals Act* and Carbon Sequestration Tenure Regulation that allow for the transfer of tenure between parties, and that gives the Minister of Energy the authority to reduce the area of a permit or lease upon application of the permittee or lessee.

There are two primary policy drivers behind open access regulations. First, the policy could be used to mitigate market power to prevent a few operators from controlling access to sequestration sites or imposing unreasonable conditions as a result of a favourable market position. Second, the policy could be used to ensure that the public-good aspects of CCS are fully realized, including reduced environmental footprint of CCS operations in Alberta and lower costs for industry and government.

The regulator can grant a CCS operator access to another party's pore space tenure. Compelling third party access to pore space is not a preferable course of action for CCS development in the province because of the potential negative impact it could have on the original tenure holder and on the management of the sequestration complex.

Market considerations should be the primary driver behind third party access to sequestration tenure and CO_2 injection. Based on the rate of CO_2 that needs to be sequestered to meet the 2050 goals, it is important that industry make reasonable attempts to collaborate on CO_2 sequestration projects. This will allow industry to capture economies of scale, share knowledge and experience, maximize pore space utilization, and reduce the incremental environmental impact (e.g. surface infrastructure) of CCS. Though the RFA did not prescribe mandatory collaboration, it is prudent to encourage industry to adopt these practices. As a result, the RFA recommended that the Government of Alberta allow project proponents to apply for access to another operator's pipeline or sequestration site(s) if private negotiations fail.

A situation may arise where it may be necessary for the Government of Alberta to order a sequestration site operator to inject another party's CO_2 when adequate sequestration sites are scarce. Additionally, pore space open access may also be justified if high quality sequestration sites are not being used to their full potential, such as when captured CO_2 is being sold to CO_2-enhanced oil recovery (EOR) operators instead of being injected into the sequestration site. In the event that there are compelling reasons to require an operator to inject another party's CO_2, the Government of Alberta may need a mechanism in place to enable mandated access. If this is to occur, it will be critical that the burden of proof be on the party requesting access to demonstrate that there is sufficient justification for an access order. Justification could include demonstrating that the other party is not willing to negotiate, the site has sufficient storage capacity for both projects, and the third party CO_2 sequestration will not negatively impact the other party's sequestration, among other things. Furthermore, any orders for access may include a determination of compensation to be paid to the sequestration site operator by the other party (the applicant) to ensure that the operator does not suffer economic harm, unless terms of settlement are agreed by the parties.

10 Conclusions

There are many potential competing users of the surface and subsurface area, both in onshore and offshore environments. In some areas, the number of users and types of use are increasing; for example, the development of ground waters, unconventional gas, gas storage, and geothermal resources are increasing demand for access to the subsurface in areas that may potentially also store CO_2. This study has demonstrated the potential for interactions between these multiple users of the pore space.

Jurisdictions have adopted different approaches to storage management, depending on their particular circumstances, which include the availability or otherwise of the storage resource that may become available in the future, the number and type of competing users of the surface and subsurface and the influence of other existing relevant legislation such as the different approaches to ownership of the pore space. For example in the US landowners have ownership of the pore space below their property whereas in Europe, the pore space is owned by the state.

All the jurisdictions reviewed in this study currently manage their pore space on a first-come, first-served basis (FCFS), in which, subject to some region-specific exclusions, operators will be able to identify their preferred storage site based on their geological, technical and financial criteria. Their chosen sites are likely to be the best sites geologically which are available at the time of selection. Management of storage on a first-come, first-served basis is likely to be sustainable in the short to medium term, especially in an area with abundant storage potential (such as the North Sea). However even in these regions, there will be competition for pore space which is likely to become more pronounced as CCS and other industries develop.

In some jurisdictions there is already a hierarchy of uses or constraints, e.g. future petroleum discovery and production means CCS is not being considered in parts of offshore Norway, fresh groundwater areas are not being considered in the USA, and in some countries (e.g. UK, Denmark, and Netherlands) onshore storage is not being considered because of perceived public acceptance issues. Therefore planning frameworks have already developed to some extent in many countries considering CCS.

The benefit of the FCFS approach is that the operator has the can decide on where to develop CO_2 storage, based on the knowledge that their site is fit for storage and therefore that they are willing to take on the risks associated with its operation. There are no reasons why this approach should change in areas of multiple, potentially interacting, storage.

10.1 SCALE AND IMPACTS OF SUBSURFACE INTERACTIONS DURING CO_2 STORAGE

For all CO_2 injection sites, the main interaction that must be evaluated is the area, amount, rate and ultimate maximum reservoir pressure increase that the storage formation is anticipated to experience. The consequences of this pressure rise will vary, depending on the site-specific characteristics, past history and types of and proximity to other users. In some circumstances, pressure increases are not expected to result in significant detrimental impacts, but pressure responses in open, connected storage sites would be expected to be the focus of detailed assessment.

It should not be assumed that a pressure rise is by itself detrimental to storage or other resources. The scale and impact of a pressure rise caused by CO_2 injection will be specific to each site and, although many simulations of CO_2 injection into saline aquifers indicate that a pressure response will occur throughout the connected pore volume, these simulations are often very simplified representations of the likely geology, often omitting permeability baffles, so the accuracy of pressure predictions at any specific point in the model may not be optimal. Furthermore there are relatively few studies which couple relatively low pressure responses with estimates of geomechanical response and a very limited number that considered the consequences of multiple injection sites into the same formation.

The maximum pressures will be experienced around injection wells and will dissipate with distance to the boundaries of the connected pore volume. Baffles that limit permeability and hence the connection within the pore space, will limit the amount and extent of the pressure 'footprint'. At the end of injection, simulations suggest that pressures often dissipate relatively quickly and, hence, highest pressures will be felt during injection operations. Pressure thresholds are defined at varying percentages of the lithostatic pressure with figures between 65-85% being quoted in the literature. However, the pressure limit for a given site will be specific for the petrophysical and geomechanical characteristics of that site, requiring site-specific appraisal.

Pressure management, such as producing formation water to increase the accommodation space for CO_2, may therefore be required to optimise the storage efficiency in a site, whilst maintaining pressures below a pre-defined threshold. A number of techniques have been proposed and are discussed below. These may significantly reduce the scale of pressure footprints in the reservoir and hence the potential for interactions with other users.

10.2 APPROACHES TO STRATEGIC MANAGEMENT OF THE STORAGE RESOURCE

The implication of the importance of reservoir pressure rises caused by CO_2 injection is that the operator and regulator need to understand the consequences of the pressure increase over a much larger area than the extent of the CO_2 plume. It may be difficult for individual operators to gain an overview of the region in which they want to operate and to take into consideration future uses of the subsurface. As a result it would make sense for this responsibility to be taken on by the relevant authority. The operator should be responsible for simulating the extent of the pressure footprint and the regulator should be responsible for assessing the validity of this modelling. The operator's plans and pressure footprint could be placed in the public domain and then potentially impacted users would be able to comment on the plan, within a guiding framework.

Not all pressure rises have a negative impact; for example the far field pressure rise could be quite small, and an increase in pressure may support hydrocarbon production within the same geological formation. Pressure increases as a result of CO_2 storage are likely to become an issue when there are multiple CO_2 storage sites within the same connected geological formation injecting at the same time in close proximity. The combined pressure response will limit the total storage capacity of these sites, decrease injectivity and potentially increase the need for pressure relief wells.

The benefit of the FCFS approach is that the operator has the final decision on where to develop CO_2 storage, based on the knowledge that their site is fit for storage and therefore that they are willing to take on the risks associated with its operation. There are no reasons why this approach should change in areas of multiple, potentially interacting, storage. The possible drawbacks of this approach include the potential for reduced storage capacities in adjacent future storage sites, possible difficulties for monitoring, and lack of regional storage optimisation. It is recognised that this approach may not necessarily lead to a pathway of overall least-cost development for storage.

However, in order to avoid or reduce potential detrimental interactions of the types outlined in this study, some form of strategic planned management may be necessary. The degree to which strategic management might influence site selection will reflect the geological conditions, the current and anticipated future uses, including the expected required storage capacity needed to meet targets in emissions reductions, and the policies and regulations of the region. Nevertheless, we conclude that some form of strategic management is likely to be necessary in most regions to reduce storage risks. Several approaches to strategic management are summarised above and discussed in detail in Section 5.4. Such strategic management might require prioritisation of development of sites which could, theoretically, lead to increased costs for individual projects (through longer pipelines, deeper wells etc.). However, we have not examined this sufficiently in this study to draw definitive conclusions.

10.2.1 Scenarios for storage development

The FCFS scenario approximates to an open market driven approach in which storage sites are selected on the basis of their geological merits and proximity to the coastline. In the FCFS scenario, later operations must demonstrate either no or minimal impact on incumbents and/or reach compensation agreements with operators with pre-existing rights. Hence early developers have the benefit of not being restricted by pressure increases. This might encourage earlier storage development. However, the Southern North Sea case study has shown that this approach may not necessarily result in optimised storage performance since subsequent operations may not be optimally situated. We assumed that where an impact might lead to a conflict that would infringe on pre-existing rights, then that storage site may not be used. This may not necessarily be the case however, as accommodation and agreements may be able to be reached. Furthermore we have not taken into account the economics of commissioning many independent storage sites which may make this scenario unnecessarily expensive and therefore unlikely. More likely is the sequential development of sites by extending infrastructure and by targeting similar structures in the same formations as early developers to benefit from increasing knowledge and confidence. This sequential development may also use CO_2-EOR as a step to wider storage development.

As is currently the case in most regions globally the MSR scenario assumes that hydrocarbon, groundwater or mineral resources will always be protected and that protection and exploitation of these resources will be given priority over storage rights. It is also assumed that storage will only take place where evidence is provided that indicates it is likely to be safe to store CO_2. The extent of strategic planning may depend on the relative weights placed on storage capacity, resource protection and exploitation, and cost minimisation.

In the MSR scenario options for minimising interactions of CO_2 storage sites with other users could include:

- Avoid conflicts by developing a different site,
- Target storage sites with larger storage capacities,
- Develop clusters to minimise the geographic spread of storage projects.

10.2.2 Development of clusters

Initial projects are likely to select the most geologically suitable sites. Storage development will be initiated from these early catalyst projects, from which a cluster of storage sites could be developed where regions have multiple storage options. Clustered storage with integrated infrastructure offers several potential advantages, including more flexible operation and cost savings through economies of scale, plus the experience obtained in the catalyst project could benefit follow-on projects in the same cluster. Such clustered development may occur without strong intervention except where transport over-sizing might be necessary. Initial storage permits might be encouraged from regions centred on these first projects. As expertise and experience in storage operations increase, less favourable sites could be exploited, which might include smaller sites near early catalyst projects, rather than commissioning larger storage sites in virgin areas at greater distances. Nevertheless we have shown here that under one scenario of strategic management of the storage resource for the Southern North Sea, targeting fewer but larger storage sites could potentially meet possible future requirements as an alternative to developments of clusters. The differences in costs and benefits of these approaches have not been evaluated however. The workshop participants concluded that in the US, private pore space ownership may inhibit the development of clusters.

Furthermore, clusters of sources may be focused on one very large storage site or a cluster of smaller ones. Economies of scale and cost-sharing may also encourage the development of clusters. There is also a need to sort out liability between different operators. This is likely to be through commercial agreements.

10.2.3 Knowledge requirements

The managed approaches proposed here will require more understanding by the relevant Authority of the implications of multiple, synchronous storage. This is needed to enable informed decisions to be made concerning choosing storage regions within which operators can undertake detailed site characterisation. To allow the Authority to select the regions to exploit for CCS they will need to know or do the following;

- Have an inventory of current and future users in the region
- Know future storage capacity requirements
- Understand the implications of CO_2 injection in the region
- Regional modelling
- Regional mapping
- Focus on cluster and catalyst projects
- Know the jurisdiction's current permission on primacy (e.g. CO_2 storage vs. Hydrocarbon production), and recognise that this may change in the future.

Combining this information will allow relevant authorities to develop a strategic storage plan to optimise storage and reduce costs and risks. An advantage of the Authority's undertaking regional characterisation would be that industry confidence in storage would increase and lead to more bankable storage sites. A consequence of a more managed approach, where the Authority decides which storage regions should be in operation, could cause a shift in the balance of risk sharing with increased risk for the Authority. To be clear: we are not proposing any change to existing regulations as it will still be for the operator to undertake detailed site characterisation to determine if a site is suitable for CO_2 storage.

In order to regulate and manage interactions between subsurface users, key performance metrics would need to be clearly defined and agreed between operator and regulator.

10.2.4 Defining lease areas

10.2.4.1 LARGE OPEN FORMATIONS

Approaches to defining storage lease areas have been described in several jurisdictions. However, practical implementation of this for certain open aquifers may not be straightforward and will require further consideration. In simple confined closures the licence area would be defined by the extent of the closure. In closures with a connected pore volume, the licence area would be the extent of the CO_2 plume, which may or may not include some or the entire pressure plume beyond the CO_2 complex to avoid pressure trespass issues. However, in large open formations (such as the Utsira Formation) where the extent of the CO_2 plume is defined by its migration path along the top of the storage formation, division into multiple storage complexes could be more challenging. This is an area for future research. Several approaches could be envisaged that could be used to divide such formations:

- Inverse watersheds which are defined by the likely migration pathways of CO_2 mark boundaries between discrete areas.
- Down dip regions are developed first.
- Modelled pressure responses are used to define discrete areas to avoid pressure trespass between multiple storage sites.
- Modelled CO_2 migration pathways define discrete areas.

10.2.4.2 Encouraging Exploitation

In order to maximise storage potential in stacked storage systems, the subsurface could be licensed by geological strata rather than by licensing the whole of the subsurface based on the areal extent of the storage complex. This implies that deeper storage formations should be leased first and that Authorities should encourage this to prevent sterilisation of deeper storage potential by prior development of shallower pore space.

In some jurisdictions it is likely that operators will take out large lease areas to protect their storage resource. If very large lease areas are defined, any storage potential that is not currently exploited within the lease area could be neutralised for the duration of the lease. To maximise exploitation of storage resource and minimise neutralising the pore space for any other users, regulators should ensure that the areas granted for CCS leases are fit for purpose. For example, the size of the lease could be re-evaluated during the injection period to ensure that the lease area is being fully utilised. In some cases it may be beneficial to reduce the size of the lease and open up the area for other proponents.

10.2.5 Resolving Conflicts

Currently conflicts between users are managed in different ways in different jurisdictions. In Australia conflicts are avoided by preventing CCS and hydrocarbons operations in the same area. In the Netherlands and the UK, users are only allowed to store CO_2 where it does not have a negative impact on other users. In the US, the threat of litigation from pressure trespass or other negative impacts forces users to resolve conflicts via the judicial system privately. In Alberta, current practice is for early operators to apply for large storage licences to protect their assets.

In areas where there are conflicts or competition for pore space or surface space, decisions will need to be made by regulators and operators to prioritise different activities. In most jurisdictions it is likely that a secure energy supply will take precedence over CO_2 storage and the rights of the current owner/user will be protected. As energy generation decarbonises however, the relative importance of meeting climate change targets by storing CO_2 will need to be balanced with the competing uses, which may include alternative methods of producing low carbon energy, such as wind energy.

To avoid some of the detrimental interactions and reduce infrastructure needs, it may be that larger storage sites, taking CO_2 from a number of sources, can meet anticipated storage requirements. This would reduce the number of individual licence holders within a region and may lead to a more integrated transport and storage infrastructure. However this would need to be balanced with the need to maintain a flexible storage capacity that can manage variable capture rates optimally.

It is our belief that pressure rises and brine displacement across international boundaries is not sufficiently covered in current regulations. This will require participation at an international level to reach agreements on how such conflicts will be resolved.

10.3 KNOWLEDGE, EXPERIENCE AND RESEARCH GAPS

10.3.1 Developing strategic plans for efficient storage use

Gaps that have been identified during this study are described here. Future research could take benefit from knowledge gained from early projects and this is typically a policy in many jurisdictions, facilitated by knowledge transfer agreements in several countries. Furthermore, research could be targeted in areas, centred on these early catalyst projects where clusters might form.

The specific consequence of the pressure rises will be site-specific and much research has been especially focussed on the geomechanical responses in the reservoir. However the impacts of pressure increase in non-reservoir rocks is less well defined and this should be addressed by further research and testing. This would also help to partially address a related issue of the degree of potential communication between reservoirs in stacked systems. Only a few studies have addressed this, which requires more detailed and systematic investigation.

This study has identified that a strategic managed approach to a large formation or regional area may be desirable in certain scenarios of future storage development. However the costs and benefits of such approaches have not been established. Therefore studies that evaluate the methods to optimise the infrastructure for basin or large unit exploration will become increasingly important for projects following on from initial catalysts sites.

In order to understand the potential consequences of multiple, synchronous storage in a region, regional storage characterisation is recommended. However, the amount of “pre-competitive” characterisation needed to help develop policy for leasing has not been defined and remains a current gap. Detailed techno-economic evaluation of storage clusters is required to better constrain the circumstances under which they could develop, and the barriers that might prevent integrated systems for storage.

One option that could mitigate much of the potential interactions is active reduction of pressure through production of water. A number of studies have been conducted that provide conceptual assessments of various options. These have largely focussed on reducing pressure to protect cap rocks (Buscheck et al., 2011; Birkholzer et al., 2012; Elliot et al., 2013; Kabera and Li, 2012; Elliot et al., 2013), increase injectivity (Buscheck et al., 2012) or maximise storage capacities (Han and McPherson, 2009; Bergmo et al., 2011) or combinations of these (Court et al., 2012; Court et al., 2011; Court et al., 2012; Hosseini and Nicot, 2012; Michael et al., 2011; Han and McPherson, 2009). However we are not aware of studies that have evaluated different approaches to pressure management onshore and offshore, nor considered how pressure could be managed in regions of multiple injection that would be initiated sequentially.

Furthermore, optimisation of storage injection and timing to maximise storage capacity and reduce costs in areas of multiple injection, especially in saline aquifers where pressure responses may be more significant, is required.

The issues of competition between the various uses of the subsurface in the Netherlands imply that a proper and consistent planning is required in order to ensure an optimal and sustainable use of subsurface space and resources. Currently, the Ministry of Infrastructure and Environment and the Ministry of Economic Affairs jointly develop a national structure plan on subsurface use in order to implement the weighing of potential other uses of the subsurface when licenses are applied for. This plan will incorporate an integral vision of how subsurface uses will match future goals of national concern. It will include a thorough inventory of these goals in conjunction with an assessment of subsurface potential to form the essential basis to develop scenarios on subsurface use. Eventually these scenarios will identify the locations and situations were potential conflicts may arise. In these cases a decision tree will help in making appropriate planning decisions. Elements in this decision tree would address questions such as:

- Is the activity of national concern and to what extent will the activity help in fulfilling national goals?
- What is the economic and strategic value of an activity?
- What is the current situation and what are the essential developments that will shape the future for this activity?
- Does the activity conflict or compete with other activities?
- What will be the effects of the activity on environment and society?
- What are the temporal aspects of the activity?
- Who are the stakeholders?
- In which way and to what extent does the activity influence foreign relations?

The new integral legislation on planning subsurface activities is still under construction. In the coming years it may be implemented and provide an additional set of rules in addition to the current legislation covered by the mining act.

The strategic management of pore space is an important consideration in the large scale deployment of CCS in Alberta. Through the use of regulations and legislation, the Government of Alberta has established ownership of the subsurface resource and the ability to issue rights to the pore space to potential CCS project proponents. However, the Government of Alberta's Regulatory Framework Assessment has identified several other potential gaps that exist related to pore space management, and have provided recommendations to help the Government address these gaps. The Province is committed to the development of CCS, and will spend the next three years implementing the steering committee's recommendations to ensure the safe and effective deployment of CCS in Alberta.

Australia has comprehensive legislation covering the storage of CO_2 in offshore areas which underpins the development of CCS projects by providing operators with increased clarity as to their rights and obligations. While the regulatory framework onshore varies from State to State, in key jurisdictions a legislative foundation has been/is being established. The key short term objective for all jurisdictions is to realise early demonstration projects, therefore storage work is focussed on these opportunities, often on a case by case (or 'storage by design') basis. However, at a strategic level little overall planning has been undertaken to develop 'a national strategic storage plan' to achieve optimum usage of the available storage. In part this is a reflection of the focus on a few first mover projects, coupled with what is assessed to be a relatively abundant storage resource (albeit source-sink matching is far from perfect). While such an approach is rational in terms of offshore areas it would make sense to adopt a more strategic approach and carve out or reserve areas for CO_2 storage onshore where there are potentially more significant spatial conflicts with other land uses (particularly in eastern Australia). Similarly, more attention could be focussed on developing the case for a central storage operator (perhaps underpinned by Government support) servicing the needs of multiple capture projects. The work of CarbonNet and the South West CO_2 Geosequestration Hub projects in Victoria and WA respectively is partially addressing both of these needs.

A key challenge (one not unique to Australia) is to ensure that regulators from different jurisdictions work in concert, especially where addressing/resolving cross-jurisdictional issues. There are a range of issues which would benefit from further regulatory clarification/guidance; research and development; and in some cases the development of global best practice models based on 'actual' field performance. These include:

- Actual experience in the application of the "*significant risk of a significant adverse impact*" (SROSAI) test and of the "*Public interest*" test under the Australian Government legislation and the development of guidance notes to inform the conduct of these tests (for both regulator and industry use).
    - The release of CO_2 storage acreage which overlaps with petroleum leases might precipitate such experience or at least begin to flush out key conflict considerations.
    - In addition, guidance in relation to the assessment of the 'public interest' would also be invaluable to States where similar tests are incorporated in their regulatory regimes.
- The development of guidance as to what constitutes 'good CO_2 storage practice' to realise an optimal outcome from the perspective of the resource owner.
    - While the legislation at both national and State level provides sufficient 'hooks' to enable the regulator to pursue such outcomes, there is very little detail to facilitate or inform these assessments.
- A better understanding of groundwater/CO_2 storage interactions in the Australian context and the development of best practice management guidance in this regard.
    - Management practices in relation to produced water and minimising its impact on the environment is also considered a priority.

10.3.2 EOR as a step towards wider CCS

The use of CO_2 for EOR provides two types of information for managing storage resources. CO_2 EOR as part of a storage program can be considered as one response to a GHG-driven need to lower barriers to capture. Second, review of benefits and difficulties experienced by current CO_2 EOR projects with other subsurface operations can be used to provide information about how future CO_2 storage projects may interact with other uses.

The potential for using CO_2 EOR as part of geologic storage is high, as demonstrated by early deployments in the U.S. EOR sites are known to have favourable attributes in the form of known top seals and well-quantified injectivity and storage potential. In terms of providing high-quality storage, good characterization from past production, active management of pressure-fluid flow during injection, and exceptionally dense monitoring potential because of many wells completed within the reservoir are benefits. Other favourable contributions include a positive economic signal created by additional oil production and sales and well-known regulatory, liability, and public acceptance in some jurisdictions.

A number of limits to the potential use of EOR as geologic storage are also noted. If boundary conditions are set to include combustion of produced oil, GHG emissions from a successful EOR project are increased, and the whole system response to the project may not be a strong positive with regard to atmospheric emissions. Energy consumption required by EOR operations, including pumping, compression-water handling, and other operational emissions reduces the efficiency of storage in a GHG context at any EOR site. The role of numerous well penetrations in terms of potentially diminished storage effectiveness needs more detailed assessment. The impact of different types of failure mechanisms should be assessed in future studies: (1) acute, high-volume, but relatively easily remediated, short-duration blowout events; (2) migration of CO_2 into unintended subsurface settings from which they may escape to the atmosphere quickly or seep over a long timeframe; or (3) low-rate leakage through flawed well construction, which is difficult to identify or to remediate and which therefore might continue over long timeframes and which may have different impacts on retention.

The extent to which EOR can be matched to capture geographically and temporally remains to be determined. CO_2 EOR has been developed only in favourable geographic areas; the extent to which additional supplies of CO_2 will allow expansion remains unknown. Uncertainty is introduced from the unknown cost curves of CO_2 and future oil, as well as capital markets, both subsurface and GHG-emission regulatory environments, and public acceptance. In particular, uncertainty is elevated for projects that are considered unconventional EOR, including offshore sub-sea reservoirs, residual oil zones, fractured reservoirs, and gravity-stable floods.

CO_2 EOR is considered a tertiary-recovery method, deployed after a long history of primary and waterflood production. It is commonly used in conjunction with these existing operations; however, adjustments are required when CO_2 is introduced. In particular, the entire hydrologically connected reservoir must be unitized and operated together. Oil extraction and water reinjection that formerly could be conducted separately in different parts of the field may not be feasible to operate independently during CO_2 injection for EOR. The low viscosity of CO_2, combined with the pressure elevation to obtain miscibility, may result in migration of CO_2 to other parts of the field, resulting in escape of hydrocarbon from the EOR project, escape of CO_2 from the patterns on recycle, and damage to equipment not prepared for CO_2. A number of management techniques, such as water curtains or pressure sinks, can be used to segment a hydrologically connected reservoir. Assessment of the effectiveness of these techniques that operators have found to be effective is not in the public domain and the post operational implications may be problematic.

Interference between EOR and injection operations is problematic because increased pressure is beneficial to EOR and decreased pressure is beneficial to injection operations. Ensuring that CO_2 injection as part of EOR results in long-term storage may be technically relatively straightforward, but new methods of legal and regulatory management to deal with long timeframes are needed.

Appendix 1 Summary of International Scoping Workshop

Strategic CO_2 storage resource management

IEAGHG, GCCSI and BGS workshop

Meeting Report – Michelle Bentham and Jonathan Pearce

19th – 20th June 2013

Location British Geological Survey, Keyworth, Nottingham

Participants

Name	Organisation	Date of attendance
Jonthan Pearce	British Geological Survey	19-20/06/13
Michelle Bentham	Bristsh Geological Survey	19-20/06/13
Andy Chadwick	Bristsh Geological Survey	19-20/06/13
Maxine Akhurst	Bristsh Geological Survey	19-20/06/13
Sam Neades	IEA - GHG	19-20/06/13
Tim Dixon	IEA - GHG	20/06/13
Millie Basava Reddi	IEA - GHG	19-20/06/13
Sue Horvorka	Unitversity of Texas, Austin	19-20/06/13
Mr Tom Mallows	The Crown Estate	19-20/06/13
Harsh Pershad	Element Energy	19-20/06/13
Angeline Kneppers	GCCSI	19-20/06/13
Mike Smith	Interstate Oil and Gas	19-20/06/13
Andrew Barrett	Geoscience Australia	19-20/06/13
Serge van Gessel	TNO	19-20/06/13
Brian Allison	DECC	19-20/06/13
Bob Pegler	BBB Energy Ltd	19-20/06/13
Rob Bioletti	Alberta Energy, Canada	20/06/13

A1.Introduction to workshop

Jonathan Pearce (BGS)

The specific aims of this workshop are:

- To identify, review and describe potential interactions between multiple CO_2 storage projects and between CO_2 storage projects and other, potentially competing, uses of the subsurface, seabed and ground surface – and their potential impacts;

- To develop potential case studies;
- To evaluate current relevant policy frameworks;
- Formulate generic conclusions and recommendations about how to develop appropriate management practices in a number of jurisdictions.

The main project aims are as follows:

- 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 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?

The IEAGHG strategic storage management study can be summarised as follows:

- Task 1: Scoping to identify case studies and relevant interactions
  - This workshop
  - Literature review
- Task 2: Southern North Sea case study
  - Scenario development using GIS and regional 2D modelling
- Task 3: Reporting to provide evidence of range of interactions, potential issues for strategic management (to varying extents)
  - Completed end November 2013.

A2.Presentation 1 - Is there a case for storage management in the UK

Michelle Bentham (BGS)

Summary

- UK has plentiful and diverse range of storage options (more information can be found at www.co2stored.co.uk)
- Many storage sites are in the same geographical regions (East Irish Sea, Southern, Central and Northern North Sea)
- Storage is often stacked and co-located storage
- Interactions in the subsurface
  - Pressure
  - Brine mobilisation
- Competition on surface and in the subsurface
- How do we prioritise projects (multi-site operations)?
- No one is over-sizing pipelines (except Alberta)
- Multiple site planning or bottom up approach (follow on from the DECC CCS demonstration competition)?

Discussion

There was some discussion of the current status internationally of site selection policies and processes. Currently the first projects are likely to be the projects that ‘can be done’ and at least cost. It was recognised that the early projects would have a have a lot of influence in terms of best sites, potentially the location of future storage and infrastructure. The first sites would act as catalysts.

It was asked if preferences have been expressed in terms of the order in which storage sites are picked. The only preferences in the UK are the selection process undertaken for the commercialisation competition. These first projects are the ones that can be done now and market-driven (at this stage least cost). A learning curve is needed in the USA, where keeping liability ‘private’ has not yet led to clusters, to an understanding of the value of clustering. No one had yet oversized a pipeline to provide additional capacity for future expansion of the system (except in North America where CO_2 has a commercial value). Clustering has not been planned in the US, given the generation industry is considered to be in denial about CCS and liabilities are private.

It was observed that it may be optimistic to assume pressure would always ‘bleed off’ after injection (through the cap rock or boundaries). This is site specific and the pressure is more likely to equilibrate rather than reduce to initial pressure.

The balance between the costs of producing water versus multiple injection points to reduce pressure build up was discussed. Using produced water for pressure management may raise cost/technical issues on the production wells. It was felt that the cost of a production well is cheaper than multiple injectors with one production well serving many injection wells. However, it is possible to do multiple injections from one single well which could smooth out the pressure build up. With multiple injectors the pressure is expected to be the same where injection occurs into a connected unit but it is spread over a larger area.

A3.Presentation 2 - Storage Management a global overview

Angeline Kneppers (GCCSI)

- Storage is key to successful deployment of CCS.
- Gaps/challenges that were identified include:
    - Third party access
    - Multiple user access rights
    - Integration of Enhanced Oil Recovery
    - Long lead times with upfront costs ahead of Final Investment Decisions
    - Storage characterisation is a key driver for the final project timing, needing commitments before project financing, and most likely to result in delays.
- CCS is a nascent market, but thinking about storage management now means we will be ready when CCS is ready.
- Market regulation was generally not addressed currently. Issues that require consideration include for example, third party access, multi-user storage access, regulation of monopolies and oligopolies, and transfer from EOR to CO_2 operations.
- Regulations generally do not recognise the role of regulators as having responsibility for good pore space management.
- Could we provide guideline for regulators on good pore space management? The regulation of safety is recognised but resource management is not made clear.
- Resource management needs to:
    - Ensure best use of the resource
    - Recognise the storage resource is ‘owned’ by society
    - Reasonable return on use
    - Safeguard public safety
    - Meet climate change objectives

    - Manage potential conflicts
    - Protect rights of other users of the subsurface
- Recommended outputs for the study should include:
    - A list of issues
    - Outline of best practice
    - Recommendations for further work
    - Key issues for regulators, policy makers and owners of the pore space.

Discussion

A range of issues were discussed around the approaches to issuing titles to underground pore space. In some jurisdictions it may be possible to issue strata titles to different users at different depths. Not all users will want to use all depths of the pore space which might create the challenge of management of different users at different depths. It would be interesting to consider cost reduction versus design and how you can make them work together under these circumstances.

In the US in some cases, the pore space is divided strata by strata and the licensee owns the material/value in your ‘block’. If one of these subsequently has a negative impact, legal action can then be taken. The precise approach is very state-dependant, with competing regulators in some areas. There are a whole host of users in the surface and subsurface – the regulators and policymakers decide who to allocate what to. Decisions are dependent on many factors. All materials of value tend to be owned by someone. Water is often surface owner allocated. The owner of the surface can sell rights e.g. water, minerals. It is a litigious sector where people sue if the extraction has an impact. This often means that the industry is self-regulating. In some states all licensing is under one roof which can be advantageous to some participants.

In the Netherlands, the pore space can be divided strata by strata, but the licensed volume must contain the entire area influenced. If the area of influence is not contained then a bigger licence would be needed. In NL, licences cover the blocks and they must contain all of the pressure response, so if pressure response extends out of the block, more licences must be bought.

In Australia, licensing is also by block. In Queensland there are competing users onshore; agriculture, coal mining, CSG and water disposal. Storage is not a special case.

In the UK, the oil and gas operators are in a firm position. The Crown Estate has acted as the honest broker in the past between competing users. The risks and liabilities would be considered in reaching a financial settlement.

It was recognised that there needs to be a balance between the least-cost operation and maximising storage.

A4.Presentation 3 - Multiple injections into one storage unit or stacked units.

Sue Hovorka (University of Texas Austin)

- Geology is stacked and hence so is storage. We need to be able to communicate the complexity to our stakeholders.
- There are advantages and disadvantages of stacked storage
    - Some hydrocarbon traps are barriers to oil and gas migration but not to pressure.
    - In stacked reservoirs of different pressures it would be very useful to estimate the column height of CO_2 that they each could support and their influence on the

    - potential for CO_2 to migrate between units of variable pressure regimes. How would such a system evolve in the long term, i.e. beyond oil production?
    - Well integrity is likely to be an important issue in such systems
- Advantages of stacked storage were identified as:
    - Limit plume and increase pressure
    - Reduced need for characterisation
    - Co-monitoring is possible
    - Reduces public acceptability issues
- Disadvantages of stacked storage were identified as:
    - Potential tensions with oil production
    - Operational interference
    - Monitoring interference
    - Identifying the source of small leakages

- Most of the projects that are happening worldwide are EOR projects
- EOR could enable steps up the ladder to saline storage (large volumes) with transition to pure storage from EOR (baby steps)
- Water (brine) production may be more of an option offshore than onshore due to increased processing and environmental risks, especially in the US.
- Development for hydrocarbons is commonly shallowest strata first whereas a different bottom-up approach may be considered for storage.

Discussion

It was observed that EOR in the North Sea is an option but the challenges include the need for higher well densities than currently exist and the need to deal with complex geology. At the moment there is no supply of CO_2 for EOR.

EOR is the logical first step because:

- It is a beneficial use of CO_2
- It incentivises capture
- Easier public acceptance
- Experience in monitoring
- A transition to pure storage is possible.

It was noted that EOR can be negative for CCS in some people's opinions and that the regulations for EOR and geological storage are different. The business models will be different in the North Sea to the US.

It was also noted that Sue Hovorka has recently submitted a paper to IJGCC on 'Brown sites versus green sites', which may be a useful technically minded paper.

The coal industry in the US is coming around to the idea of EOR as it provides an avenue for coal to stay in business (fitted with CCS paid for by EOR). For example, the Oklahoma Valley has a huge potential source of CO_2 if it was captured from coal-fired power stations, although the transport distances are long.

Storing CO_2 in EOR is not recognised as storage. Hence CO_2 from the coal industry would not be regulated as stored if used for EOR. However, there is a legal movement to ensure CO_2 used in EOR is classed as stored. For example, the Weyburn CO_2 EOR project have recognition for the volumes and it is added to the national register as it was felt that a storage value should be associated with EOR to take into account any stored CO_2.

A5. Presentation 4 - Managing resource conflicts and multisite multiproject planning: an Australian perspective

Andrew Barrett (Geoscience Australia)

- Access to geological data – useful for emerging CCS industry
- Best storage potential, e.g. NW Australia, not always near emission intensive areas
- There is little opportunity for CO_2 EOR due to high primary production rates
- Gippsland resource management
    - Licensing for CCS only in areas of hydrocarbon exploration not production for parallel permitting to avoid competition
    - More conflicts onshore
- Significant Risk Of Serious Adverse Impacts – adverse impacts

Discussion

From the Australian experience the licensee for storage in an oil and gas producing basin needs to advise the regulator:

- Predicted travel time for the CO_2 from the injector to a production well
- Quantity of CO_2 reaching a production well
- The predicted impact of the CO_2 at a production well
- Options to prevent an adverse event
- Measures to mitigate an adverse event

To reduce the risk of CO_2 in a hydrocarbon producing basin the project may be required to:

- Delay the start of injection
- Set a minimum horizontal and vertical separations between activities
- Limit the quantity of CO_2 injected
- Implement an innovative engineering solution.

A6. Presentation 5 - Findings from the UK cost reduction task force.

Tom Mallows The Crown Estate

- TCE have the pore space rights in the UK and is preparing for competitive commercial storage site leasing.
- Could act as ‘honest brokers’ between potentially conflicting demands on pore space and infrastructure
- Cost reduction task force next steps
    - Vision of development of CCS projects for follow on from commercialisation programme in the UK to widespread adoptions
    - Pre-competitive site characterisation
- Site access (for storage operators)
- Exploration appraisal costs of sites?
- Pipelines (capacity, corridors, coastal crossing)?
- Vision for CCS beyond the competition?
- Minimise subsurface interactions.

Next steps for CCS need to:

- Optimise a transport and storage network
- Incentivise CO_2 EOR
- Establish a funding mechanism
- Agree bankable contracts for projects
- Develop a vision for CCS from demonstrators to follow-on projects
- Promote characterisation of storage locations.

Discussion

Key questions on optimised design were considered to be:

What needs to be brought together at basin scale to put in place a transport/storage infrastructure?

What mechanisms will deliver characterisation?

How will we ensure designed infrastructure whilst realising cost reduction?

What practical actions can be taken to ensure CRTF findings are delivered?

What does flexibility to allow spatial conflict resolution look like?

A7. Break out session 1

The participants were split into two groups each with a rapporteur.

Group 1

Rapporteur Millie Basava Reddi

Group Members:
Serge van Gessel
Tom Mallows
Andrew Barrett
Mike Smith
Angeline Kneppers
Andy Chadwick

Group 2

Rapporteur Sam Neades

Group Members:
Maxine Akhurst
Brian Allison
Sue Horvorka
Harsh Pershad
Bob Pegler

The groups had 1 hr. 30 to discuss the topic below:

Storage environments

Questions considered by the breakout groups:

- What are the characteristics of the storage capacity in different regions? Aim to discuss the storage capacity in the regions represented by the group.
- What are the likely interactions as a result of different storage locations? E.g. pressure, conflicts.
- Can these issues be managed and if so how?
- Development of case studies. Thinking about which of the scenarios above could be developed as case studies to demonstrate the main points discussed.

The rapporteurs were also provided with questions designed to stimulate discussion or clarify the questions should this be required by the group. The rapporteurs were asked to keep a record of the key findings from the group in a template presentation and report back to the all the participants after the end of the break out session.

Findings of the breakout groups (combined).

It was noted that CCS has the long term intent to store CO_2, which makes it different from other industries.

- What are the characteristics of the storage capacity in different regions?
- Storage is often found in offshore regions, where the young strata exist, that have higher porosities and permeabilities and are often less fractured than older rocks. Storage potential occurs in confining zones that can accept stress (due to increased pore pressure), e.g. the North Sea.
- Where there is storage potential, it is usually stacked.
- Storage projects do have some flexibility in the operational system, and it was felt that reservoirs could cope with the flexibility in the rate of supply and provision of CO_2.

Country Specific

- Australia – Potential storage is in Saline Aquifers, typically in single formations and located mostly offshore. Some multi-formation storage occurs but in the Gippsland basin, for example, most hydrocarbons occur directly under the regional seal. There may be some possibility for deeper storage with tortuous migration pathways. Storage in the NW of Australia is possible for CO_2 from gas production. Onshore storage is dependent on adequate groundwater protection. Very little depleted field capacity is present as most of the hydrocarbon fields in Australia are still young. There is very little residual oil due to high rates of primary production. Data available are from the hydrocarbon industry, which concentrates on the producing strata.
- Netherlands – Primary storage is in depleted gas fields offshore, which have proven storage, known capacity and are depressurised. There is pressure connection between some compartments. In the short- to mid-term, the offshore gas fields have enough storage capacity for Netherlands CO_2. Groningen gas field is the largest gas field in the Netherlands. From 2070 all the gas fields will be depleted. The Netherlands are evaluating aquifer storage for storage in the long term.
- US – Large variety of storage potential, with depleted gas fields onshore (some offshore) and deep saline aquifers. Some depleted fields are above salt domes. An example of current CCS project is the Cranfield (1 Mt) site in Mississippi where initial CO_2-EOR converts to storage. State and federal regulators consider EOR capacity to be storage.
- CO_2 pipelines already in place.
- In the US storage is very EOR driven
- Need full understanding of the storage potential before we can manage multiple uses. 7-10 year characterisation (starting from scratch).
- UK – The theoretical storage capacity is quite well known with most of the capacity located in Saline Aquifers. Practical capacity estimations to plan for interactions have not yet been made. No current “off the shelf” storage. Interactions between projects would need to be managed by design. EOR and EGR is not used currently. Much of the storage in the UK has spatial complexity.
- What are the likely interactions as a result of different storage locations?

General

- CCS injection can increase pressure which may increase production in other hydrocarbon fields. It is possible that compensation may need to be paid by the CCS operator to the hydrocarbon field operator
- For access to a storage site it may be necessary to drill through a field but this can be engineered. The ambient density gradient needs to be established.

- Pressure increase could interact with other CCS site or hydrocarbon fields
- Unexpected interactions that were not predicted because pre-injection modelling did not correspond to monitored observations, e.g. Snøhvit, resolved by industry self-regulation.
- Brine mobilisation is a cause for concern onshore. It may also interfere with hydrocarbon production
- Public acceptance remains an ongoing challenge
- Mineral rights could be in competition with CCS
- Hydrocarbon activities – e.g. different cement/ casing – more expensive. Old wells properly abandoned at the time – may then have issues
- Coal Seam Methane – aquifer needs to be isolated. No cross flow between aquifers, wells
- Cross-border interactions need to be managed (there are grey areas in the legislation).
- Production of water to relieve pressure. Could there be issue in discharging large amount of brine, especially onshore where reinjection could be used. For offshore sites the issue is the regulatory requirements where the cleaned produced water is discharged.

Country specific examples

- Australia – For the offshore Gippsland basin, the only risk is the potential sterilising of hydrocarbon resource. Onshore – farming, Coal Bed Methane (CBM – which already has raised public acceptance issues), water protection and production, shale gas (but this is largely in remote areas so there is less potential for conflict). Onshore storage in saline aquifers could mobilise saline brine which is a cause for concern as it may contaminate potable water supply.
- Netherlands – interactions with hydrocarbons is a primary concern. On the sea bed cables, shipping lanes, wind farms have to be spatially managed. If in the future, CO_2 is stored onshore it could be in competition with gas storage. In addition, for onshore storage high population densities may cause public acceptability issues (e.g. Barendrecht). Tremors from gas production are common and therefore the potential for induced seismicity must be considered.
- US: best candidates for CCS are to be found in heavily populated areas. Potential conflicts arise from economic use of formations for other use, such as gas storage and waste disposal. Shale gas requires fracturing cap rocks which may be required to act as seals for storage projects. Compensation to local people may be offered for some of these activities.
- UK- it is not clear how interaction beyond the extent of the CO_2 plume will be managed/regulated
- Can these issues be managed and if so how?

General:

- How does ownership constrain the regulatory framework and decision-making process? This was considered to be different for different regions.
- Good Monitoring plan – keep track of potential interactions / avoid interactions. Plan for negative interaction. Who is responsible for the predicted interaction area?
- Monitoring plan – needs to integrate all aspects and cover areas of interactions between projects – who is responsible. Regulators need to know what is required in monitoring programme. Clear objectives for monitoring programme for regulators.
- Key Performance Indicators (e.g. pressure evolution and plume spread) need to be meaningful and defined and quantified – need consensus between the regulator and the operator

- Transparent process – helps with public acceptance. Explain why need to do CCS. Difference between storage options – can help or become a challenge to explain
- Educate politicians/ policymakers
- Pressure management (more injection wells or active brine production)
- Management of interactions may increase the cost of operation
- Brine mobilisation – need to avoid interference, environmental impacts should be considered. Are there long term issues with highly saline brines?

Who will manage conflicts?

- Industry self-regulation (would be quite narrow, to layout guidelines. Issues with incentivising this)
- Regulators (either cooperative; internalised)
    - Conflict resolution
    - Assigning priorities e.g. storage not permitted in hydrocarbon areas
    - How do we get the regulators to talk to each other and act in a coordinated, concerted way?
- System operator (common to have one organisation with power e.g. set up a UK Carbon Authority)
- Contractually (multi- or bi-lateral)
- Authorities (joint-ventures): multi-stakeholder who manage space (e.g. Norfolk Broads)

- Country specific examples
- Australia: commercial agreement with landowners and between operators (or any interests) are common
- US: The individual ownership of mineral rights, and associated financial benefits, create a different environment for regulation and management of resources.
- Initial design of transport and storage infrastructure. Consider whole system from the outset. Opportunity as new industry. Using depleted gas and saline aquifers – forward planning to avoid conflicts. Examples could include the Gippsland basin and UK North Sea where petroleum licence agreements already exist. CCS licences need to be able to exist in same area at same time, before cessation of hydrocarbon production. This raises the potential to transfer closure liabilities. In Netherlands if a licence is inactive for 2 years, then a 3rd party can apply for a licence. In Australia if the licence is inactive for 5 years, then the operator loses the licence.

Interaction between two storage projects

- It may not be easy to image under a current storage site (in a way this may lead to sterilising the ‘underlying’ column) due to the presence of CO_2 obscuring detail underneath.
- Stacked storage – leakage from one stratum to another, would require an assessment of whose CO_2 this might be. Such migration may also reduce capacity.
- Timing of interactions will be important
- How do we licence the pressure footprint? In UK, licence will be by plume extent not pressure increase. Pressure issues are dealt with by affected operators where commercial relationships might be agreed. In the US, when injecting in a Class VI well, the area of responsibility is defined by the pressure footprint.

- Which of the above scenarios could be developed as case studies to demonstrate the main points discussed?

- Characteristics that could be described in the case studies include:
- Jurisdiction type
- Storage type and nature of reservoir(s)
- Storage volumes & timing
- Relevant interactions
- Challenges and barriers to development
- Suggested Case studies
- Canada – as current large-scale storage
- US – Cranfield – transition to storage from EOR. Decatur – population.
- Netherlands – p18 field due to start injecting 2017 – interactions – shipping
- Snøhvit – pressure issues. Importance of having backup options – moved from saline aquifer then moved to gas field when pressure increase required injection to stop.
- Possible review of Carbon Sequestration Leadership Forum projects
- Hydrocarbon production case studies – conflicting pressure issues resolved.
- In UK – DECC publishes production data.
- Mineral rights and pressure in US – a few cases.
- UK – Longannet/ Goldeneye FEED studies.
- Otway – landowner issues, farming, access
- Gippsland – avoiding conflict. Maybe tested soon
- Close of hydrocarbon production timings though challenges of confidentiality recognised
- Netherlands – EBN Gasunie project, 2010 – www.nlog.nl – CCS storage reports
- Gorgon – Environmental Impact Survey is available.
- UK: CO_2 storage and hydrocarbon production are under regulated by one group
- Australia: Actively manage the release of sites to minimise conflicts (economies of scale).
- Case studies to understand the pressure perturbation in subsurface (during depletion – what is signal? Look at connectivity?). In Australia information available after 2 years, also Norway
- Capacity to correct your system (i.e. Snøhvit)
- Look at how other types of conflicts have been resolved, some are good analogues to CCS. (e.g. Permian Basin work)
- Case study on 'moving up the ladder' – what you actually do/processes you go through in different scenarios. EOR project to storage project...

A8.Presentation 6 – Multi-site planning in the northern North Sea.

Maxine Akhurst (BGS)

- Modelling based project to address the issue of multi-site operations and the possible interactions between 2 sites in saline aquifers and existing hydrocarbon fields in the vicinity
- Risk-led investigation of the interaction between two realistic sites within a regional aquifer host to hydrocarbon fields
- Interactions and mitigating measures tested by simulation of CO_2 into the Captain Sandstone, a UK offshore regional storage asset
- Risk reassessed to review and measure the impact of risk reduction activities
- Monitoring plan of unmitigated risks to include any synergies between sites

- Capture of generic knowledge relevant to all multi-user sites, key questions to be asked by regulators and technical knowledge
- Led by regulators and industry and risk (re)assessment by CCS technical experts.

A9.Presentation 7 - Regulating the pore space – examples from Alberta.

Rob Bioletti (Alberta Energy)

- Alberta has two major CCS projects
- Alberta Carbon Trunk line (pipeline construction and refinery scheduled 2013-14) with ‘over-sized’ 8 Mt/year CO_2 transport capacity. In the first 3 years it will be transporting 1-2 Mt/year.
- Quest Project. CO_2 captured at industrial sites is transported by pipeline 60 km for storage in saline aquifer sandstone. Construction scheduled 2013. 1-2 Mt CO_2 stored in saline aquifer
- Before the legal framework for CCS was implemented projects were following the acid gas injection legislation.
- Two major pieces of Legislation in Alberta
- CCS Statues Amendment Act 2010
- Carbon Sequestration Tenure Regulation
- The government can assume long term liability of the site once it is deemed closed.
- Pore space ownership has been declared by the Crown (Mines and Minerals Act)
- Formation of a post-closure stewardship fund for long term liabilities e.g. monitoring (rate based on tonnes of CO_2 injected).
- Leases for CCS are 15 years.
- Includes oil and gas in the shallow subsurface. There are 3 zones above the basal Cambrian and their lease is zoned for a 3D-site.
- The Shell lease for the Quest site is very large, (100 x 100 km), to allow surface access so that they don’t transgress on any other lease and can protect their own project. For sequestration it must be at least 1000 m deep and consideration of other projects coming in must be remembered.
- May give up areas of lease after 5 years (based on plume migration)
- CCS Regulatory Framework Assessment recommendations:
- Part of plan is project must spell out subsurface interaction with other minerals.
- At the time of application must consider other resources
- Will consider stacked or jointly utilized applications on a case by case basis.
- Promote/facilitate development of an inventory of pore space suitable for CCS
- Identify areas of interaction between subsurface resources.
- Pore space management, encourage collaboration to utilize pore space.
- Market considerations for third party access.

Discussion

In Alberta, pressure should be considered in multiple use formations, it should not infringe on incumbents, if it will or does the other party needs to make a decision. The area of lease encompasses the area of influence so there is no trespass by the pressure footprint. A ‘public good’ driver is followed where there is conflict between CCS and oil and gas.

A10. Presentation 8 - Deep subsurface space management in the Dutch sector.

Serge van Gessel (TNO)

- The Netherlands is a mature hydrocarbon province with production from smaller gas fields and top-up from Groningen which is the largest gas field (~2900 bcm^3)
- CCS is licensed under mining law and currently only offshore since storage capacity is sufficient to meet short- to medium requirements.
- Practical capacity estimates in Netherlands includes timing and cluster development.
- Offshore subsurface users acting in the same reservoirs include geothermal, oil and gas and 2 storage proposals (K12B and P18A)
- Onshore: 4 Underground Gas Storage, (seasonal storage gas fields, salt caverns N2 and peak gas storage)
- P18A is a depleted gas field where full chain CCS is planned with storage in a Triassic reservoir. Storage is expected to be 8.1 Mt with a start date in 2015.
- Impacts from using the subsurface
- Subsidence (gas storage/salt production
- Induced seismicity (gas production/ storage)
- Groundwater (storage, shale gas, radioactive waste)
- Spatial planning (UGS, shale gas)
- Interference competition
- Geothermal, hydrocarbon and storage
- Hydraulic Fracturing “Fracking” or “fraccing” (sealing capacity, storage)
- Storage options (reservoirs, caverns)
- Offshore windmills (hydrocarbon and Storage)
- Conflicts with CO_2 storage, offshore and onshore
- Bergermeer UGS
- Pieterburen Salt Dome
- Hydrocarbon co-production with geothermal heat source
- Shale gas Exploration
- Groningen Gas Field production induced seismicity
- The Netherlands is building a vision of the subsurface and an inventory of options and solutions for the future. Transparent technical evaluation of the options will inform development of future storage scenarios.

A11. Presentation 9 - Regulating the pore space – examples from the US.

Mike Smith (Interstate Oil and Gas Compact Commission)

In the US

- Private ownership of the minerals in place
- Some states:
- Own the minerals in place
- Some have right of capture
- Some have the right to lease
- Pore space ownership is regulated by the state and springs from property law. Some state is there is oil and gas legislation.
- Who owns the pore space?
- It is owned by the surface owner (e.g. gas storage)

- The liability is with the injectors

Scenario 1 – Fee Simple Absolute

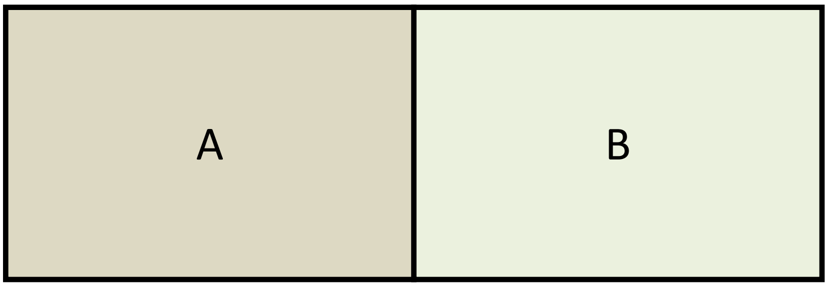

Figure 1.

A and B own surface and subsurface rights (Figure 1). A buys surface rights from B. A decides to store CO_2 in area 1. The CO_2 migrates in the subsurface under B's land. B still owns the right to the subsurface (Figure 2) so that owner A's CO_2 is trespassing. The dispute will be settled by the actors not the state (litigation, settlements). Figure 2.

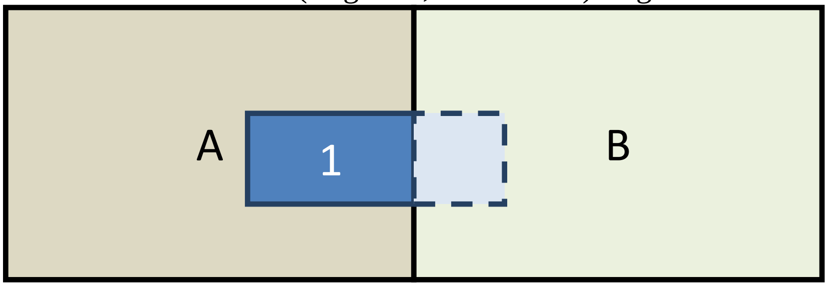

Figure 2.

Scenario 2

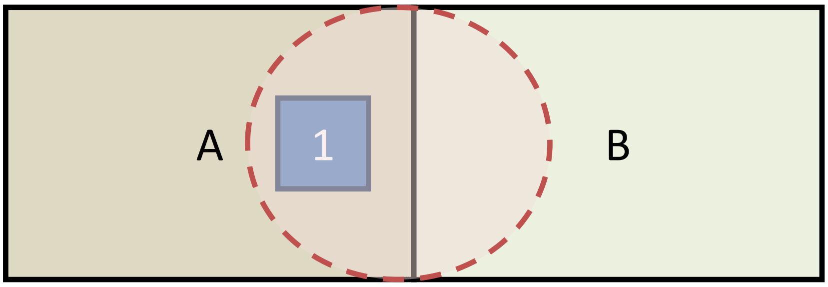

Figure 3.

Owner A stores CO_2 on their land. The plume is fully contained within the land and subsurface owned by A. B decided they want to sell their pore space rights to a company wanting to store CO_2 on their land. Site investigations reveal that the pressure has risen in the pore space beneath B's land reducing the storage capacity of the site and therefore the economic value of the pore space (Figure 3). This is pressure trespass. A dispute ensues; B will need to prove that injection at site 1 has increased the pore pressure on their land i.e. that pressure trespass has occurred.

- In the US the owners of the mineral rights have never been ruled to own the pore space.
- An action companies might take to avoid trespass could be to buy lots of pore space, therefore neutralising it for future use.
- Pore space is becoming valuable and sold e.g. Texas

- Disputes are often settled out of court in a 'no fault' agreement with a confidentiality clause. Therefore it is difficult to know how often these disputes arise and how they are resolved.

Long term liability has been a huge showstopper and could be for future projects. Insurance is very costly and there are few providers. The injector usually has the liability (primary liability during injection and for 25 year period after injection) and in Texas, for example, the state would then take over the liability after the 25 year period. Options include insure against liability but there are only two institutes large enough to underwrite the risk. Bonds are another option, the injectors could pay into a liability fund e.g. per/tonne CO_2, or could get legislator support, e.g. in Texas the state assumes the long term liability.

A12. Presentation commercial in confidence- The economics of a CCS hub in the Central North Sea (CNS).

Harsh Pershad (Element Energy)

- Work based on study for the Scottish Government (CNS storage hub)
- Improving CO_2Stored estimates from theoretical to practical capacity
- The development costs for each storage unit were treated separately by CO_2Stored without the economies of clustering.
- CNS Storage Hub calculated the percentage overlap between units in the region, e.g. the Captain Sandstone, increasing the capacity to the total from 4 overlapping sandstones.
- Cost for integrated development spread is across more than one storage unit
- Additional cost savings can be made by sharing infrastructure, wells, monitoring, administration and decommissioning.
- The analysis suggests an integrated solution for maximising reservoirs above and below the Captain would be the best value
- Clustering storage reduced the risk portfolio of a store
- Need a business model for stacked systems.

A13. Break out session 2

The participants were split into two groups each with a rapporteur.

Group 1	***Group 2***
Rapporteur Maxine Akhurst	Rapporteur Tim Dixon
Group Members:	*Group Members:*
Serge van Gessel	*Andrew Barrett*
Sam Neades	*Angeline Kneppers*
Rob Bioletti	*Sue Horvorka*
Harsh Pershad	*Tom Mallows*
Bob Pegler	*Mike Smith*
Millie Basava Reddi	*Andy Chadwick*
Brian Allison	

The groups had 1 hr. 30 to discuss the topic below:

Development of multisite storage

Questions considered by the breakout groups:

- Developing the findings from day 1, what are the issues in multisite operation that need to be considered by regulators?
- How would you consider developing multi-site storage in a region?
- What are the main issues that should be addressed?

The rapporteurs were also provided with questions designed to stimulate discussion or clarify the questions should this be required by the group. The rapporteurs were asked to keep a record of the key findings from the group in a template presentation and report back to the all the participants after the end of the break out session.

Feedback from the breakout session:

- Developing the findings from day 1, what are the issues in multi-site operation that need to be considered by regulators?

- Implications of trespass (legal aspects for each jurisdiction), as well as interactions and interference with all users of pore space.
- Pressure optimising/utilising/ambient/interactions/geomechanical conditions
- Priority of subsurface and surface operations isn't black and white or static. The broader picture should be considered by the regulator. This may include stewardship for the public good at the time, contemporary with best practise. It was recognised this may change.
- The regulator needs to know how much you 'need' for large-scale storage capacity and low demand. May be enough storage to lease by blocks, but if greater storage will be needed should consider a 'strata licence' approach. However, it may be very difficult to predict as there is generally no prescribed amount of stored CO_2. Predictions are reliant on 'scenarios' with very large ranges of possibilities.
- Discussion focussed on how to incentivise interest in storage. For example, the UK has lots of storage but not much commercial interest. Would release by blocks, as in oil and gas licensing, create demand? Offering CCS licensees has been tried in Australia and the Netherlands, but unless there is more than one applicant (offshore) for the licence there will be no competition. Licenses can co-exist onshore (geothermal and hydrocarbon exploration) restricted to particular strata. Defined 'reservations' could protect areas for known future use.
- Three aspects of trespass would need to be considered: plume migration, pressure extent and operational impacts, which should also consider future anticipated use (e.g. Pressure footprint in storage complex).
- The storage licence and storage plan in the Netherlands includes sustainable use of subsurface 'best possible means', following the example of the oil industry. Regulators should periodically review plans.
- Decisions will be made based upon imperfect or incomplete information (always) and licences must have the flexibility to respond to new information
- The cost effectiveness of multi-site storage on a basin scale needs to be considered.
- Litigation is a deterrent so regulator is seen as arbitrator of last resort

- How would you consider developing multi-site storage in a region?

- Encourage first movers (got to have one project to have a second!). Creation of an organisation with the remit to look at all regions with exclusive rights over large area to assess storage opportunities. This is not the UK approach at the moment, but is the approach taken by Gassnova in Norway, and the approach already taken in Alberta.

- If rewards are high then market will lead but could reduce storage resource. However, if rewards are not high they will 'cherry pick'. The market should lead but must be enabled by taxes/regulation. For example, royalty relief programmes for oil in Alberta encourage optimisation of rate of revenue (CO_2 EOR).
- Stimulate availability of data, by subsidy to applicant in return for data. Who pays in the first instance (industry feedback is that public availability to data is a deterrent)? Data could be confidential at first then released once a project is established.
- Cross-border issues (international agreement) may need to be addressed.
- Pre-offer regional characterisation to determine how to lease/licence may be one option to reduce risks
- Objectives of the owner and national policy – economics vs. other
- Cost-effectiveness at basin scale (transport and injection infrastructure)
- Stacked rights – avoid compromising monitoring as well as pressure etc. – allows injection into geological formations injection in sequence.
- Consider vertical as well as lateral interference between pore space users

  - What are the main issues that should be addressed?

- Research needed to inform for multi-site planning, providing the regulator and operator with guidance on what is needed for licensing (storage Monitoring Measurement and Verification, closure, corrective and preventative measures and monitoring planning). Not too prescriptive but not a blank sheet
- Monitoring of multi-site, or stacked storage: whose leak/CO_2 is it anyway?
- Access to prospective storage sites above/below an existing site.
- Techno-economic information for regions/clusters to inform the regulator
- Ambient pressures and pressure profiles in stacked storage sequences to inform injectivity of stacked stores.
- CCS is more flexible than the oil industry, options for storage i.e. oil and gas fields do not have a choice over location unlike CCS.
- Research into sterilisation of storage by 'land grab' but this may be countered by an alternative policy of 'use it or lose it'.
- Poor use of a licensed area, if don't use all the resource then it has been squandered by taking out a larger than needed licence area because don't want the liability.
- If considering releasing licence blocks as oil and gas then need to decide which blocks are to be released, requiring technical advice.
- Pressure rises in non-reservoir rocks (low permeability)
- What constitutes vertical and lateral connectivity, especially wells
- Research into design and optimisation at basin scale (transport and injection infrastructure, economics)
- 'Plan B' scenarios if the initial storage proposal cannot be effectively implemented.

A14. Summary of workshop findings

The following conclusions were defined at the end of the workshop.

- Different jurisdictions have different drivers for CCS.
- Different owners of the pore space in different jurisdictions create fundamentally different approaches to regulation and policies with different objectives.

- The nature of the geology may produce competing uses and users. A key process is the pressure constraints and management, including the consideration of impacts on other resources.
- A single, block approach to stacked storage may be significantly cheaper. A requirement for back-up storage is a point for further discussion.
- Regulators and owners have to balance competing uses and may even have competing regulators.
- Issues to be considered by multi-site operations include:
- Systemic risks
- Well integrity issues in stacked storage
- Large lease areas for operators who reduce risks but may under-utilise storage
- Potential for risk reduction
- Options and challenges of monitoring integration
- In stacked storage, it appears wise to have at least an integrated plan for storage, avoiding problems of monitoring and pressure interferences.
- Clustering of storage could reduce costs.
- CO_2-EOR could be pursued as a precursor for storage.
- Current gaps that were identified include:
- Pressure interactions in non-reservoir rocks.
- Communication in stacked reservoirs
- Design of optimal infrastructure for basin or large unit exploration
- Pre-lease characterisation to help develop policy for leasing
- Pore space inventory
- Different approaches to pressure management onshore and offshore.
- Techno-economic evaluation of storage clusters is required.

Acronyms

BGS	The British Geological Survey
CBM	Coal Bed Methane
CCS	Carbon Capture and Storage
CSM	Coal Seam Methane
COP	Close of production dates
CSLF	Carbon Sequestration Leadership Forum
CSM	Coal Seam Methane
DECC	UK Department of Energy and Climate Change
EGR	Enhanced Gas Recovery
EIS	Environmental Impact Assessment
EOR	Enhanced Oil Recovery
KPI	Key Performance Indicator
RA	Radio Active
SROSAI	Significant risk of significant adverse impact
TCE	The Crown Estate
UGS	Underground Gas Storage

Appendix 2 Site Selection, Scoring and Ranking

In order to calculate the amount of CO_2 to be stored in the SNS by 2030 and 2050, the UK National Atmosphere Emissions Inventory (NAEI) combined with government targets for emissions reduction was used.

The NAEI records CO_2 emissions from sources emitting >100 000 tonnes of CO_2 per year. In 2008 the total emissions from such sources in the UK were 250 Mt of CO_2, of which 57% occur on the eastern side of the UK and were considered potential candidates for storage in the SNS.

The UK government has a target of 10-30 GW of installed capacity to have CCS by 2030 (DECC, 2011) and this might increase to 25-43 GW by 2050 (DECC 2012). Assuming that 1 GW from a coal fired power station provides 5 Mt of CO_2 (DECC, 2012) to be stored then it could be projected that by 2030 50 – 150 Mt of CO_2 p.a. would need to be stored nationally. This might increase to 125 - 215 Mt CO_2 p.a. by 2050. Taking the upper limit from both of the projections and plotting them on a simple graph the cumulative CO_2 supply can be calculated (Figure 13).

Using the cumulative emissions to be stored in this scenario by 2030, 735 Mt of CO_2 will have been stored, of which 57 % or 420 Mt) will be transported to and stored in the SNS. By 2050 a further 2500 Mt might need to be stored in the SNS. This calculation for CO_2 emissions in 2030 and 2050 makes the following major assumptions:

- 1 GW approximately 5 Mt of CO_2 from a coal fired power station
- Assumes all point sources are coal fired power stations
- It is assumed all the emissions are abated by CCS
- The highest estimate of CO_2 to be abated for 2030 and 2050 has been used

As a result it is likely that this is an optimistic estimate of the cumulative CO_2 that will actually be stored but it is considered adequate to illustrate the likely interactions that could pertain if CCS became widely deployed.

Both scenarios were developed with the requirement that all the emissions in two ‘snapshot’ years 2030 and 2050 were required to be stored. In this study we have only considered meeting UK targets and have not considered the possibility that the SNS could act as a store for CO_2 from regions which do not have abundant storage potential.

The potential storage sites used in the scenarios were identified using data from the GeoCapacity project (Vangkilde-Pedersen, 2009). 107 potential storage sites in the SNS were identified by GeoCapacity, comprising both saline aquifers and gas field storage units (Figure 33**Error! Reference source not found.**).

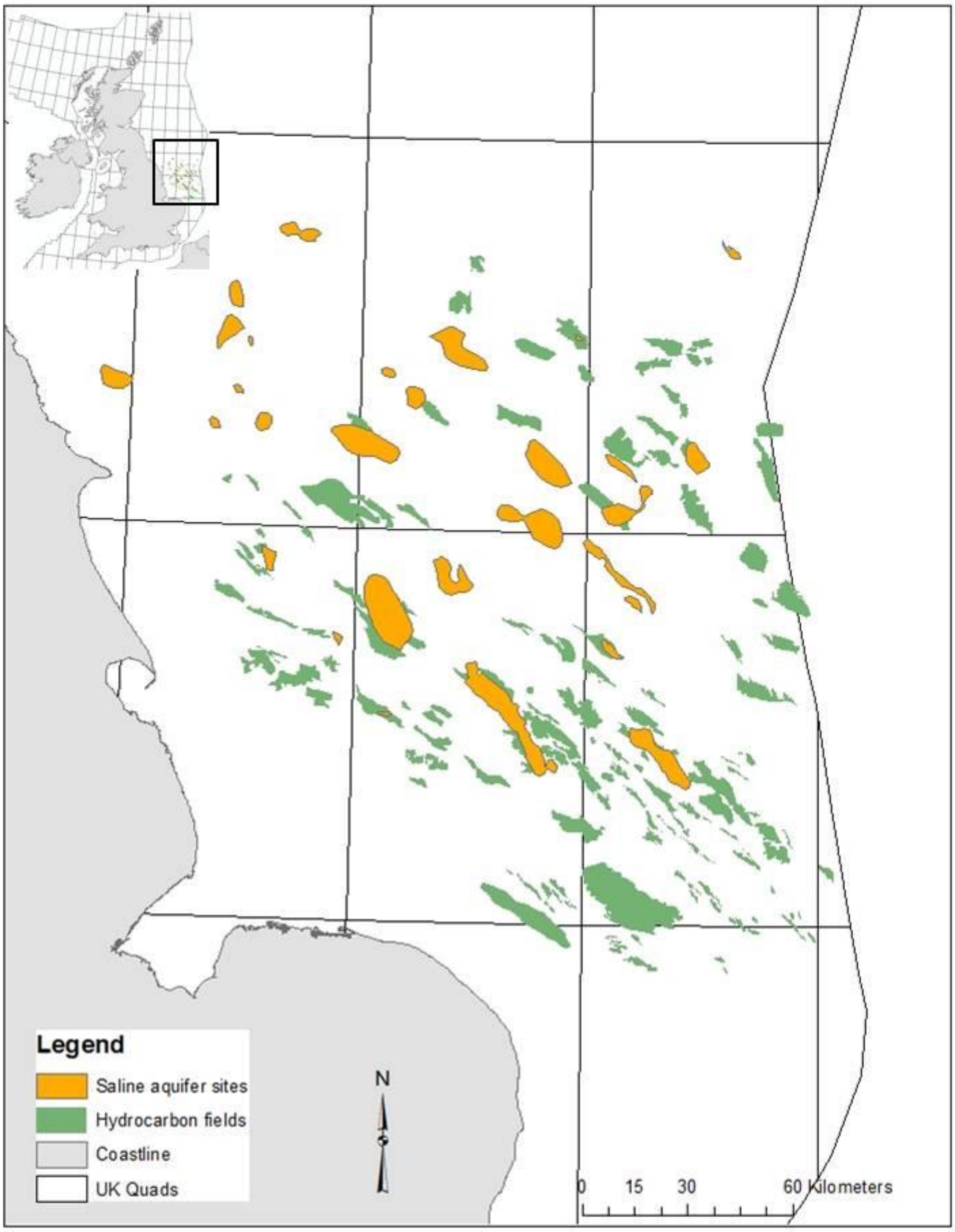

Figure 33: Location of potential storage sites in the Southern North Sea identified by the GeoCapacity project, comprising hydrocarbon fields and structural closures in the Bunter Sandstone saline aquifer.

In order to establish the order of utilisation of the storage sites in the scenarios, a basic ranking methodology was developed. The ranking uses basic site selection criteria and applies a score to each of the criteria. The sites are then listed from the highest score to the lowest score. The source data and criteria used for ranking storage sites are shown in Table 14.

Table 14: Criteria and normalised score applied to storage sites in the Southern North Sea

Criteria	Data source	Score			Notes
Distance to nearest onshore terminal (km)	GeoCapacity shapefiles, straight line distance measured in GIS	Normalised based on range of distance from terminal			
Storage capacity (Mt)	CO2Stored	Normalised based on range of capacity			Where data is unavailable the units was filtered out of the results. Additionally all units with a capacity of <20 Mt were removed from the results.
Permeability (mD)	GeoCapacity	> 500 mD	499 – 200 mD	< 200 mD	Score assigned based on values in Chadwick et al., 2008.
		1	0.5	0	
Depth to crest of storage unit (m)	GeoCapacity	< 800 m	800 – 2500 m	> 2500 mD	Score assigned based on values in Chadwick et al., 2008.
		0 and removed from results	0.5	1	
Thickness (m)	GeoCapacity	> 50 m	20 - 50 m	<20 m	Score assigned based on values in Chadwick et al., 2008.
		1	0.66666667	1	
Compartmentalisation	CO2Stored	Yes	No		
		0	1		
Availability	GeoCapacity	Available	Possibly available	Not available	
		1	0.5	0	
Faulting in seal	CO2Stored	No	Yes		
		Retained in the shortlist	Removed from shortlist		

The main aim of the ranking system was to provide a shortlist of sites on which to base the scenarios, not to produce a methodology for screening and ranking of storage sites in the UK. As a result only a small number of quantifiable criteria were used and applied and scored. This allowed some gradation between the storage sites, giving a reasonable starting point for storage scenario development.

Eight criteria were used, each criterion was scored and each score was normalised, with the exception of faulting. Where faulting was identified in the cap rock of the storage site the site was removed from the shortlist. Sites were also removed from the final list if: they didn't have storage capacity information, the storage capacity was less than 20 Mt or the depth of the storage site is less than 800 m sub-seabed. All storage capacity estimates were taken from Geocapacity

(Vangkilde Pedersen, 2009). All the scores for each site were then summed (shown in Table 16). The greater the ranking of the storage site the higher the score allocated. The scores and ranking of the potential SNS storage sites are listed in Table 15 and shown in Figure 14, in which the number refers to the ranked position of the storage site. The selection and ranking exercise resulted in choice of 38 potential storage sites in the UK SNS for use in the scenarios. Using this methodology aquifer sites rank higher than the gas fields in the SNS due to their large storage capacity and lack of compartmentalisation, the gas fields, by contrast are relatively small and tend to be highly compartmentalised.

Table 15 shows the remaining sites after the ranking process described above. Sites were chosen off this list in the First-come, first-served and the Managed Storage Resource scenarios.

Table 15: Ranking of selected sites

Site number and ranking	Name	score
1	AQ01	5.55
2	AQ02	5.01
3	AQ03	4.94
4	Esmond	4.42
5	Welland	3.87
6	Leman	3.87
7	Orwell	3.72
8	Hewett Zechsteinkalk	3.52
9	Little Dotty (Bunter Sst)	3.49
10	Cleeton	3.35
11	Clipper North	3.29
12	Barque & Barque South	3.27
13	Thames	3.24
14	Amethyst E & W	3.22
15	Sean South	3.12
16	Galleon	3.02
17	Lancelot	3.00
18	Deborah	2.99
19	Skiff	2.95
20	Indefatigable & Indefatigable SW	2.94
21	Ganymede	2.93
22	Excalibur	2.91
23	Audrey	2.88
24	Vulcan	2.87
25	Pickerill	2.86
26	Viking	2.84
27	Valiant South	2.81
28	Anglia	2.81
29	Sean North	2.60
30	Markham	2.51
31	West Sole	2.40

32	Ravenspurn South	2.36
33	Neptune	2.36
34	Victor	2.27
35	Johnston	2.19
36	Rough	2.19
37	Gawain	2.15
38	Valiant North	2.14

Table 16 shows the scoring applied to all the storage sites identified as part of the GeoCapacity project. The scores shown are normalised and then summed.

Table 16: Scoring of potential storage sites

	Normalised score								
Name	**Distance to terminal**	**Capacity**	**Permeability**	**Depth**	**Thickness**	**Compartment-alisation**	**Availability**	**Faulting**	**Summed Score**
AQ01	0.67	0.38	0.50	1.00	1.00	1	1.00	assumed no	5.55
AQ02	0.36	0.15	0.50	1.00	1.00	1	1.00	assumed no	5.01
AQ03	0.33	0.11	0.50	1.00	1.00	1	1.00	assumed no	4.94
Esmond	0.39	0.03	0.50	1.00	1.00	1	0.50	assumed no	4.42
Welland	0.69	0.02	0.50	1.00	0.67	0	1.00	assumed no	3.87
Leman	0.87	1.00	0.00	1.00	1.00	0	0.00	assumed no	3.87
Orwell	0.53	0.03	0.50	1.00	0.67	1	0.00	assumed no	3.72
Hewett Zechsteinkalk	1.00	0.02	0.50	1.00	1.00	0	0.00	assumed no	3.52
Little Dotty (Bunter Sst)	0.97	0.02	0.50	1.00	1.00	0	0.00	assumed no	3.49
Cleeton	0.83	0.02	0.00	0.50	1.00	0	1.00	assumed no	3.35
Clipper North	0.76	0.03	0.50	1.00	1.00	0	0.00	assumed no	3.29
Barque & Barque South	0.68	0.09	0.50	1.00	1.00	0	0.00	assumed no	3.27
Thames	0.72	0.02	0.50	1.00	1.00	0	0.00	assumed no	3.24
Amethyst E & W	1.00	0.05	1.00	0.50	0.67	0	0.00	assumed no	3.22
Sean South	0.59	0.03	0.50	1.00	1.00	0	0.00	assumed no	3.12
Galleon	0.73	0.12	0.50	1.00	0.67	0	0.00	assumed no	3.02
Lancelot	0.81	0.02	0.50	1.00	0.67	0	0.00	assumed no	3.00
Deborah	0.96	0.03	0.00	1.00	1.00	0	0.00	assumed no	2.99
Skiff	0.76	0.02	0.50	1.00	0.67	0	0.00	assumed no	2.95
Indefatigable &	0.64	0.30	0.00	1.00	1.00	0	0.00	assumed no	2.94

	Normalised score								
Name	**Distance to terminal**	**Capacity**	**Permeability**	**Depth**	**Thickness**	**Compartment-alisation**	**Availability**	**Faulting**	**Summed Score**
Indefatigable SW									
Ganymede	0.74	0.02	0.50	1.00	0.67	0	0.00	assumed no	2.93
Excalibur	0.72	0.02	0.50	1.00	0.67	0	0.00	assumed no	2.91
Audrey	0.67	0.05	0.50	1.00	0.67	0	0.00	assumed no	2.88
Vulcan	0.83	0.05	0.00	1.00	1.00	0	0.00	assumed no	2.87
Pickerill	0.83	0.03	0.00	1.00	1.00	0	0.00	assumed no	2.86
Viking	0.63	0.21	0.00	1.00	1.00	0	0.00	assumed no	2.84
Valiant South	0.78	0.02	0.00	1.00	1.00	0	0.00	assumed no	2.81
Anglia	0.62	0.02	0.50	1.00	0.67	0	0.00	assumed no	2.81
Sean North	0.59	0.02	0.50	0.50	1.00	0	0.00	assumed no	2.60
Markham	0.33	0.02	0.50	1.00	0.67	0	0.00	assumed no	2.51
West Sole	0.77	0.13	0.00	0.50	1.00	0	0.00	assumed no	2.40
Ravenspurn South	0.77	0.09	0.00	0.50	1.00	0	0.00	assumed no	2.36
Neptune	0.84	0.03	0.00	0.50	1.00	0	0.00	assumed no	2.36
Victor	0.70	0.06	0.00	0.50	1.00	0	0.00	assumed no	2.27
Johnston	0.67	0.02	0.00	0.50	1.00	0	0.00	assumed no	2.19
Rough	1.00	0.02	0.00	0.50	0.67	0	0.00	assumed no	2.19
Gawain	0.63	0.02	0.00	0.50	1.00	0	0.00	assumed no	2.15
Valiant North	0.12	0.02	0.00	1.00	1.00	0	0.00	assumed no	2.14
41/1	0.71		0.00	0.00	1.00	1	1.00	assumed no	3.71
42/2	0.52		0.50	1.00	1.00	1	1.00	yes	5.02
42/3	0.77		0.50	1.00	1.00	1	1.00	no	5.27
42/4	0.74		0.50	1.00	0.33	1	1.00	assumed no	4.57

	Normalised score								
Name	**Distance to terminal**	**Capacity**	**Permeability**	**Depth**	**Thickness**	**Compartment-alisation**	**Availability**	**Faulting**	**Summed Score**
42/6	0.62		0.50	1.00	1.00	1	1.00	yes	5.12
42/7	0.70		0.50	1.00	0.33	1	1.00	yes	4.54
42/8	0.70		0.50	1.00	1.00	1	1.00	yes	5.20
AQ06	0.56	0.03	0.00	1.00	1.00	1	1.00	yes	4.59
AQ04	0.56	0.06	0.50	1.00	1.00	1	1.00	yes	5.12
AQ05	0.33	0.14	0.50	1.00	1.00	1	1.00	yes	4.96
AQ08	0.48	0.27	0.50	1.00	1.00	1	1.00	yes	5.24
43/6	0.28		0.50	1.00	1.00	1	1.00	yes	4.78
44/1	0.00	0.01	0.50	1.00	0.67	1	1.00	yes	4.17
AQ13	0.22		0.50	1.00	1.00	1	1.00	yes	4.72
AQ12	0.33	0.15	0.50	1.00	1.00	1	1.00	yes	4.98
47/1	0.91	0.02	0.50	1.00	1.00	1	1.00	yes	5.42
47/2	0.86		0.50	1.00	1.00	1	1.00	assumed no	5.36
48/1	0.65		0.50	1.00	1.00	1	1.00	yes	5.15
48/2	0.74	0.46	0.50	0.00	1.00	1	1.00	yes	4.70
AQ07	0.65	0.57	0.50	1.00	1.00	1	1.00	yes	5.72
48/4	0.80	0.02	0.50	1.00	1.00	1	1.00	yes	5.31
AQ09	0.38		0.50	0.00	1.00	1	1.00	yes	3.88
AQ10	0.48	0.46	0.50	0.00	1.00	1	1.00	yes	4.43
AQ11	0.58		0.50	1.00	1.00	1	1.00	Yes	5.08
49/4	0.69		0.50	1.00	1.00	1	1.00	yes	5.19
Ann	0.57	0.01	0.50	1.00	0.67	0	0.00	assumed no	2.74
Baird	0.67	0.01	0.50	1.00	0.67	0	0.00	assumed no	2.85
Beaufort	0.70	0.00	0.00	0.50	1.00	0	0.00	assumed no	2.21

	Normalised score								
Name	**Distance to terminal**	**Capacity**	**Permeability**	**Depth**	**Thickness**	**Compartment-alisation**	**Availability**	**Faulting**	**Summed Score**
Bell	0.72	0.01	0.50	1.00	1.00	0	0.00	assumed no	3.23
Bessemer	0.72	0.01	0.00	0.50	1.00	0	0.00	assumed no	2.23
Big Dotty	0.97	0.00	0.50	1.00	1.00	0	0.50	assumed no	3.97
Boulton	0.27		0.00	0.50	1.00	0	0.00	assumed no	1.77
Brown	0.59	0.00	0.00	0.50	1.00	0	0.00	assumed no	2.09
Caister B & C	0.21	0.01	0.50	1.00	0.67	1	0.00	assumed no	3.39
Callisto	0.73	0.00	0.50	1.00	0.67	0	0.00	assumed no	2.90
Camelot N, C & S	0.90	0.00	0.00	1.00	0.67	0	0.00	assumed no	2.57
Corvette	0.66	0.01	0.50	1.00	1.00	0	0.00	assumed no	3.17
Davy	0.60	0.00	0.00	1.00	1.00	0	0.00	assumed no	2.60
Dawn	0.97	0.00	0.00	1.00	1.00	0	0.00	assumed no	2.97
Delilah	0.95	0.00	0.00	1.00	1.00	0	0.00	assumed no	2.95
Della	0.95	0.01	0.00	1.00	1.00	0	0.00	assumed no	2.96
Europa	0.77	0.00	0.50	1.00	0.67	0	0.00	assumed no	2.94
Forbes	0.33	0.00	0.50	1.00	1.00	1	0.00	assumed no	3.83
Galahad	0.71	0.01	0.50	1.00	0.67	0	0.00	assumed no	2.89
Gordon	0.28	0.01	0.50	1.00	1.00	1	0.50	assumed no	4.30
Guinevere	0.77	0.01	0.00	1.00	1.00	0	0.00	assumed no	2.77
Hewett L Bunter	1.00		1.00	1.00	0.67	0	0.00	assumed no	3.67
Hewett U Bunter	1.00	0.16	1.00	0.00	1.00	1	0.00	assumed no	4.16
Hyde	0.81	0.01	0.50	0.50	0.67	0	0.00	assumed no	2.48
Ketch	0.24		0.50	1.00	0.67	0	0.00	assumed no	2.41

	Normalised score								
Name	**Distance to terminal**	**Capacity**	**Permeability**	**Depth**	**Thickness**	**Compartment-alisation**	**Availability**	**Faulting**	**Summed Score**
Little Dotty (Leman Sst)	0.97	0.01	0.50	1.00	1.00	0	0.00	assumed no	3.49
Malory	0.76	0.01	0.00	0.50	1.00	0	0.00	assumed no	2.27
Mercury	0.96	0.01	0.00	0.50	0.67	0	0.00	assumed no	2.13
Mordred	0.73	0.00	0.50	1.00	0.67	0	0.00	assumed no	2.89
Murdoch	0.25		0.00	0.50	0.67	0	0.00	assumed no	1.42
Newsham	0.74	0.00	0.50	1.00	0.67	0	0.00	assumed no	2.91
Phoenix	0.63		0.50	1.00	0.67	0	0.00	assumed no	2.80
Ravenspurn North	0.77		0.50	0.50	1.00	0	0.00	assumed no	2.77
Schooner	0.38		0.50	0.50	1.00	0	0.00	assumed no	2.38
Sean East	0.57	0.01	0.00	1.00	1.00	0	0.00	assumed no	2.58
Sinope	0.77	0.00	0.50	1.00	0.67	0	0.00	assumed no	2.93
Trent	0.45		0.00	0.50	0.67	0	0.00	assumed no	1.61
Tristan	0.66		0.50	1.00	0.67	0	1.00	assumed no	3.82
Tyne North	0.13		0.00	0.50	1.00	0	0.00	assumed no	1.63
Tyne South	0.11		0.00	0.50	1.00	0	0.00	assumed no	1.61
Tyne West	0.13		0.00	0.50	0.67	0	0.00	assumed no	1.30
Vanguard	0.75	0.01	0.00	1.00	1.00	0	0.00	assumed no	2.76
Vixen	0.71	0.01	0.50	1.00	0.67	0	0.00	assumed no	2.89
Waveney	0.84	0.01	0.00	1.00	1.00	0	0.00	assumed no	2.85
Windermere	0.38		0.00	0.50	0.67	0	0.00	assumed no	1.54

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