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Case Studies of CO_2 Storage in Depleted Oil and Gas Fields

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CASE STUDIES OF CO_2 STORAGE IN DEPLETED OIL AND GAS FIELDS

Key messages

- The aim of this study is to highlight key factors that influence CO_2 storage in depleted oil and gas fields, drawing on four case studies.
- The use of depleted reservoirs for CO_2 storage can offer advantages because the geological characteristics that are important to CO_2 storage have been pre-determined.
- There is strong evidence for secure containment if a rigorous risk assessment and characterisation has been conducted
- Evidence from these case studies has shown that CO_2 storage does not have a detrimental impact on adjacent oil and gas fields.
- AZMI (Above Zone Monitoring Interval i.e. a formation above the reservoir and caprock) pressure monitoring has proved to be an effective tool for tracking CO_2 in heterogeneous and complex reservoirs (e.g. Cranfield). AZMI is an active area of research and development.
- Monitoring approaches should take into consideration the background geochemical reactions in aquifers that might be prone to ingress from brine or CO_2 above a storage reservoir. Simplistic approaches may not be effective and could lead to flawed inferences without an adequate understanding of natural variation in groundwater geochemistry.
- Risks associated with increasing pressure are predominantly and most commonly mitigated by keeping pressures below pre-production levels.
- Case study evidence suggests oil and CO_2 miscibility might improve storage estimates by up to 3% whereas residual gas and CO_2 miscibility could reduce capacity by up to 6%.
- At Goldeneye proprietary CO_2-resistant cements could be utilised if they can be shown as superior to 'normal' Portland cement but have not yet been thoroughly tested in terms of their compatibility.
- An in depth understanding of potential risks is essential to allow for balanced cost-benefit modifications and improved costs analysis.
- IEAGHG should review monitoring techniques for tracking CO_2 mixed with other reservoir gases. Progress with research on the use of AZMI pressure monitoring and wellbore integrity should also be regularly appraised.

Background

CO_2 storage has now been tested at a number of demonstration sites around the world, including some depleted oil and gas reservoirs. The use of depleted reservoirs can offer some advantages because the geological characteristics that are pertinent to CO_2 storage, such as the distribution of porosity and permeability, have been pre-determined. Although depleted hydrocarbon fields can show strong evidence of fluid retention, there are risks associated with existing wellbores and the possibility of caprock deterioration. The aim of this study is to highlight key factors that influence CO_2 storage in depleted oil and gas fields based on four detailed examples. Comparisons were made between storage operations in depleted fields (with or without enhanced hydrocarbon recovery) and storage in saline aquifers with the approaches required in modelling, monitoring, reporting, economics, and operational strategies. Fundamental differences in the reservoir pressure and risk profiles between the different storage sites have been explored. These studies have also allowed a comparative assessment to be made of the requirements for CO_2 storage projects from different geographic and regulatory regimes. The work was led by the British Geological Survey with support from the Gulf Coast Carbon Center based at the University of Texas at Austin.

Scope of Work

This report documents a selection of case studies where CO_2 storage has been implemented, or is planned, in depleted oil and gas fields. The case studies are focused on how the sites have overcome relevant technical issues as well as those relating to regulation, and where possible, costs and economic viability. Four main case studies were chosen; The Goldeneye (UK North Sea), Cranfield (Texas, USA), SACROC (Texas, USA) and Otway (Australia). Other less comprehensive case studies are also included to provide a more extensive comparative assessment. The specific CO_2 storage related issues addressed are: how the sites have approached risk assessment; plume monitoring; validation of capacity estimates; and how they have dealt with issues surrounding pressure changes and long-term wellbore integrity. To summarise these case studies a comparison has also been made of the following field attributes and their implications towards CO_2 storage: on versus off-shore sites; pure storage versus EOR; depleted oil versus gas fields; and deep saline aquifers versus depleted fields.

Findings of the Study

Background and Summary of Chosen Case Studies

USA Sites

The USA has been using CO_2-EOR techniques for over four decades which has had a significant impact on the development of CCS projects. The success of CO_2-EOR as a tertiary recovery method has led to fields depleted under primary and secondary methods being considered as candidate sites.

During the development period for the USA CCS Program (2000-2010) the US government had a strong focus on the use of depleted oil and gas fields for storage only. Policy and legislation regarding storage in CO_2-EOR sites in the USA has additional complexities compared to Europe:

- Firstly, subsurface ownership in the USA can be complex. The subsurface is owned by the surface owner but mineral rights and pore space can be transferred or sold. As a consequence, legal agreements have to be transacted between mineral owners, surface owners, operators and investors.

- Laws that regulate injection and greenhouse gas in the USA are historically fragmented. The motivating driver for CCS comes from the Clean Air Act but the permission for injection is under the Safe Drinking Water Act. Storage and CO_2-EOR are subject to different parts of the two acts and further complications arise from potential spatial overlap of the acts' jurisdictions.

To date no depleted field used purely for storage has tested these regulations. Site closure requirements are also different as CO_2-EOR sites are permitted under the same terms as hydrocarbon sites. This means that the operator's responsibility ends when CO_2-EOR operation ends and the wells are plugged and abandoned (i.e. no post-injection monitoring is required as it is for pure storage sites).

Cranfield, Mississippi

The Cranfield oil and gas field is located in Southern Mississippi and is an operational CO_2-EOR site, with additional injection into the water leg for research. The reservoir is a heterogeneous fluvial sandstone at 3,000m depth with a marine mudstone caprock in a salt cored simple dome structure. Since 2008, 8Mt of CO_2 have been injected and 5Mt stored. The site has a complex production history which has led to an uneven distribution of fluids in the reservoir.

SACROC, Texas

The Scurry Area Canyon Reef Operations Committee (SACROC) Unit is part of the Kelly-Snyder oil field in in West Texas. CO_2 flooding began in 1972 making it one of the oldest continuous CO_2-EOR sites in the world. By 2013 approximately 255Mt of CO_2 had been injected and 100Mt stored. The reservoir consists of a Pennsylvanian-Permian platform and slope carbonates at 2,040m depth with a mudstone/evaporate caprock. The reservoir is a bio-clastic limestone which has a heterogenic consistency including karsting, vuggy porosity, micro-fractures and detrital flows. Production of 4.5% of the oil in the reservoir lead to a 50% pressure drop in the field. This led to the need for water flooding operations which began in 1954, followed by CO_2 flooding in 1972.

Other Sites

Goldeneye, UK

Goldeneye is a gas condensate field in the North Sea operated by Shell and CO_2 capture was planned from the Peterhead gas fired power station. Gas production ceased in March 2011 and the project aimed to inject 10-20Mt of CO_2 over a 10-15yr period commencing in 2019. The primary reservoir consists of a turbiditic Cretaceous sandstone overlain by a 300m thick mudstone caprock. The reservoir is 2,600m deep with a porosity of 25% and permeability of 800mD. Pressures in the reservoir at 2,560m dropped from 26.3 to 15.2MPa during production, however the reservoir is currently being re-pressured via a regional aquifer. Goldeneye was chosen as one of the four main case studies for the report as there is information publically available on all criteria relevant to the scope for this project. **Otway, Australia**

The Naylor gas field in the Otway Basin had 65,000 tonnes of CO_2 injected from 2008-2009 as part of a pilot scale researched focused project. The reservoir consists of a Cretaceous, heterogeneous, tidally influenced stacked channel sands separated by abandoned channel fill with a mudstone seal. Local faults act as structural traps. The original production well was located at the crest of the reservoir but has been developed as a monitoring well. The CO_2 injected is obtained from a local magmatic source.

Insights into Key Criteria

1. Risk Assessment Criteria

Risk assessment criteria for CO_2 storage were shown in this study to be largely determined by their overall requirements i.e. to meet regulatory guidelines or a more research orientated focus. The case studies focused on were Goldeneye (and the bow-tie method to meet the EU Storage Directive regulations) and Cranfield (with a Certification Framework approach, for research-orientated goals).

Goldeneye was highlighted in the report as having a comprehensive and rigorous risk assessment methodology. A bowtie method was implemented, that identified potential threats and their associated consequences and then developing control measures and quantified their effectiveness summarised diagrammatically in Figure 1.

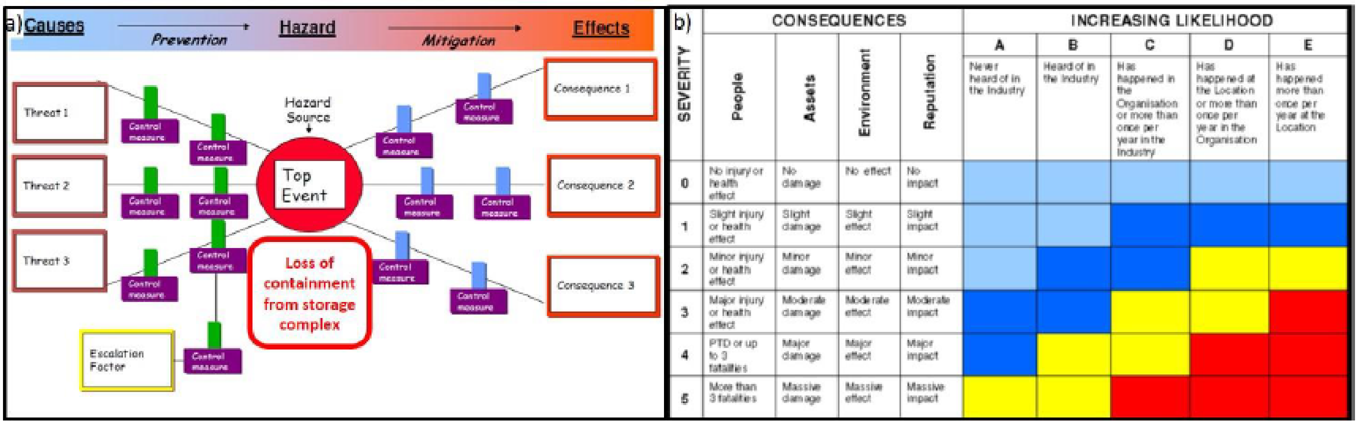

Figure 1 a) Structure of bow-tie risk assessment b) risk matrix used to quantify the assessment (after diagrams in the MMV plan) with permission from Shell UK Limited.

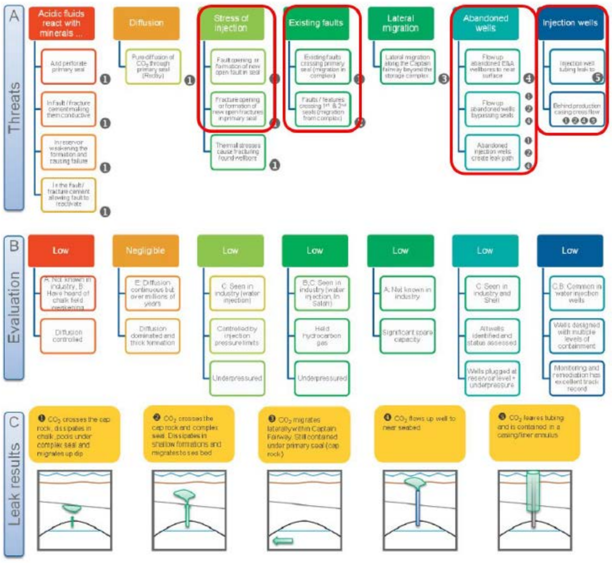

Figure 2 Schematic representation of the Goldeneye containment bow-tie risk assessment showing A: threats, B: evaluation showing that the risk of having a top level event is low, and C: potential leak scenarios that could take place if natural and engineered barriers were to fail (Tucker et al., 2013b) with permission from Elsevier.

A complex list of risks was assembled and scored relating to their probability and severity. Severity of possible consequences was then assessed in terms of harm to people, the environment, assets and reputation. The risk assessment process was developed throughout FEED and was expected to continue evolving during the lifetime of the project.

The FEED analysis showed the top risks were associated with Goldeneye being a first-of-a-kind project meaning most of these risks were likely to be dramatically reduced as CCS rollout occurs. The assessment concluded the risk of CO_2 migration out of the storage complex was 17^{th} on the list, but could be considered the top geological risk.

The initial scope for this study included focusing on what the implication of CO_2 storage was for continued oil and gas production in adjacent fields. Risk assessment at Goldeneye showed the site is hydraulically connected to neighbouring fields within the Captain Aquifer meaning CO_2 injection could raise pressure in nearby fields. Pressure and hydrocarbon composition data show that nearby fields in older strata are not connected to Goldeneye. The report concludes this is not listed as a risk as it is likely to enhance (not hinder) production elsewhere because it would raise pressure in the Captain Aquifer.

The Cranfield project also studied risk assessment criteria in depth. The assessment was research focused using the Certification Framework (CF) approach and was conducted at the start of the SECARB study of Cranfield (Nicot et al., 2013). The CF addresses the system as a source, flow conduits and compartments (including hydrocarbons and drinking water). It was a seven stage analysis process:

1. Define the storage region;
2. Identify vulnerabilities;

3. Characterize vulnerabilities;
4. Model injection, migration of CO_2, brine pressurization and fluid flow in wellbores;
5. Estimate likelihood of leakage;
6. Model impact of leakage on compartments; and
7. Discuss risk.

During the risk assessment the 'identifying vulnerabilities' stage identified wells, faults and spill points as the major vulnerabilities. Failure of wells to isolate the CO_2 from the overburden/ surface was considered the greatest risk in this assessment. Risk assessments conducted at other sites took different approaches.

Neither the Goldeneye bow-tie method nor the Cranfield CF risk assessment are designed purely for depleted hydrocarbon sites. Both methods could be adapted and applied to a variety of future storage applications.

2. Monitoring Criteria

Monitoring criteria are frequently driven by the risk assessment and demand site specific logistics e.g. offshore vs onshore techniques driven by accessibility. Monitoring required in the US for CO_2 storage falls under oil and gas not GHG regulations and hence monitoring programmes can vary from other countries.

At Goldeneye, monitoring is designed to demonstrate containment and conformance (i.e. to satisfy regulations and not for research). Monitoring tool selection was based on detecting risks at higher potential of leakage as highlighted on the risk assessment. Two plans were designed; a base plan designed to identify any irregularities and a contingency plan designed to confirm irregularities, locate the source of migration and monitor the effectiveness of any corrective measures deployed. Techniques selected for monitoring CO_2 movement within the storage reservoir are mainly mature technologies whereas migration out of the storage reservoir and quantification of emissions include both commercial and emerging R&D technologies. The monitoring programme proposed for Goldeneye is summarised below, Table 1.

Monitoring technique	Mode	Baseline	During injection	Post injection
Surface seismic - Streamer 3D	Time-lapse	✓	~5 years	1 year and 6 years
Surface / downhole seismic - OBN/VSP	Time-lapse	✓	~5 years	1 year
Surface seismic - high resolution p-cable	Contingency			
Broadband seismometer beneath platform		continuous		
GPS on platform		continuous		
Downhole pressure & temperature		✓	continuous	for 3 years
Downhole saturation and porosity logging	Time-lapse	✓	annual, years 5-10	
Well log integrity		✓	every 3 years	
Downhole fluid sampling	Time-lapse	✓	annual, years 5-10	
Seabed bathymetry and imaging	Time-lapse	✓	year 5 (targetted)	at 1 year
Sediment sampling	Time-lapse	✓	year 5 (targetted)	at 1 year
Water column sampling	Time-lapse	continuous		
Cumulative CO_2 injected (Mt)		0		10-20

Table 1 Monitoring programme proposed for Goldeneye in the Front End Engineering Design (FEED) document. (Green denotes deep-focussed techniques that operate from the surface, yellow denotes well based techniques and blue denotes shallow-focussed techniques). (From IEAGHG, 2015 with permission.)

A highlight from the report was the potential effectiveness of pulsed neutron capture (PNC) and neutron log responses for EGR (enhanced gas recovery) fields shown in the modelling of Goldeneye. The modelled PNC responses suggested that overall saturation changes would be detectable as long as the injected CO_2 replaced CH_4 and water, (i.e. not just CH_4). PNC logging would not be able to distinguish between CO_2 and CH_4 on its own but the neutron method would detect CO_2 which contains no hydrogen. Saturation logging of the recompleted injection and monitoring wells was therefore proposed. CO_2 in the reservoir was below the detection thresholds for the seafloor gravimetry and ship-towed controlled source electromagnetics (CSEM) monitoring techniques.

The SECARB early test monitoring programme at Cranfield was designed to test approaches in order to meet the US DOE's goal of improving monitoring. This study focused on the monitoring techniques relevant for CO_2-EOR sites. Cranfield is a complex site (highly heterogeneous, uncertain lateral boundary conditions, complex fluid distribution) and hence the monitoring design had to be carefully designed to allow data to be extrapolated. The study focused on AZMI (above-zone monitoring intervals) pressure monitoring undertaken at Cranfield as this was the first time this technique had been deployed at a CO_2 storage site. The proof-of-concept installation well was not able to provide any information on the location or magnitude of any leakages but it is anticipated that this will be possible with more commercial installations to come. Large deformations in the caprock were measured and proved that caprock integrity remained even given large movements. Time-lapse seismic was inconclusive. No systematic change in fluid composition was seen due to the geological complexities and the above zone signal was noisy.

Cranfield is a former EOR site and has been subject to previous gas injection to enhance production. A mixture of hydrocarbons and CO_2 further complicate CO_2 monitoring. The use of seismic is more challenging in fields like Cranfield because of the mixed fluid composition. Many wells in the north and west flooded area of the field show quite good matches, but this is not the case in the central area. The edge of the plume is also difficult to detect. One of the reasons for the difficulty in tracking a low viscosity fluid like CO_2 with geophysical techniques in this field because of the sinuosity of palaeo-channels. However, early and delayed CO_2 breakthrough is evident from U-tube sampling.

At SACROC the monitoring criteria focused on two major targets: the monitoring well and the shallow groundwater aquifer. A large number of wells are present on the site and geochemical testing was used to assess the potential leakage into a freshwater aquifer. This lead to great improvements in groundwater chemistry monitoring strategies and an understanding of geochemical aquifer systems. The initial strategy of comparing the composition of the shallow groundwater to reservoir brine was proved to be flawed given the significant natural variation in groundwater chemistryA detailed investigation of the groundwater aquifer above SACROC revealed that its chemistry is controlled by carbonate reactions, particularly de-dolomitisation. An increase in pCO_2 would increase dolomite dissolution. Simulated sensitivity analyses could result in discernible geochemical signatures above background but only if ground water chemistry is fully characterised. Three-dimensional data sets over the active CO_2 injector at SACROC and processing the AVO (Amplitude Verses Offset)[1] response was used to profile the CO_2 saturation. Different combinations of AVO coefficients were used to identify a signal that corresponded to a response to the CO_2.

As Otway is a pilot project a variety of monitoring techniques were used. High quality seismic profiles were conducted but given the low volume of CO_2 injected it was undetectable. Microseismic, pressure and temperature sensors were deployed in the monitoring well but ultimately failed and hence all pressure data was collected from the injection well. Various assurance techniques were used which did not detect CO_2 and geophysical logging techniques were unable to conclusively distinguish injected CO_2 from gases in the reservoir. One successful method deployed at Otway was the use of U-tubes and tracers to conclusively detect the presence of CO_2. This monitoring technique showed evidence of a dissolved CO_2 front ahead of the free CO_2 plume. Detailed examination of the U-tube sample's gas concentration allowed for insights into in-reservoir mixing, migration and equilibration of fluids through time.

[1] In geophysics and reflection seismology, AVO or amplitude variation with offset is the general term for referring to the dependency of the seismic attribute, amplitude, with the distance between the source and receiver (the offset). AVO analysis is a technique that geophysicists can execute on seismic data to determine a rock's fluid content, porosity, density or seismic velocity, shear wave information, fluid indicators (hydrocarbon indications).

Pressure Changes and Thresholds

This study has highlighted that CO_2-EOR fields usually have reduced reservoir pressure due to fluid extraction and have complex pressure histories from injection and production which may impact geo-mechanical properties of the caprock. The positives and negatives of EOR sites were shown in the comparison with DSF sites. Deep saline formations have no history of pressure changes or cycles and have not been thoroughly characterised. In contrast EOR sites have been extensively characterised (evidence of caprock integrity is demonstrated by the retention of hydrocarbons) but may have been compromised by previous pressure cycles. Significant modelling efforts were deployed at Goldeneye to investigate this risk and despite the long history of EOR at Cranfield and SACROC neither site has experienced any significant integrity problems.

At Goldeneye two main pressure induced risks were identified: extreme wellbore cooling due to the Joule-Thomson expansion effect; and injection fracturing of the reservoir seal. A proposal for mitigating the cooling effect was a workover of the wells to reduce tubing size which would allow a more gradual restricted flow of CO_2 (avoiding a sudden pressure drop). Operational constraints were also proposed to reduce the transient effects at the start and end of injection. Detailed simulations of “fraccing conditions” were conducted to analyse the risk of fracturing the reservoir seal. These showed fractures in the reservoir to propagate downwards, avoiding the seal and maintaining its integrity. Geomechanical modelling was also conducted to ensure pressures would not increase beyond pre-production levels. Results indicated that stress-paths were not close to replicating predicted failure cases. Goldeneye had a unique pressure profile through time due to connection with the local saline aquifer causing a water drive and pressure re-charging.

At Cranfield, the balance between having a low enough pressure to prevent leakage but high enough to allow CO_2 to be miscible with oil was carefully managed. A non-linear response of pressure change to injection rate was noted and other geomechanical performance elements are still being assessed. A fault is present within the reservoir which was the main focus of any possible risk of failure. Methane is known to have accumulated either side of the fault showing that horizontally transmissive migration is negligible. The reservoir was depleted from an initial pressure of 32MPa to 12MPa and it is possible such large changes in pore fluid pressure might affect the fault seal but this cannot be readily assessed.

At SACROC the major challenge was maintaining high enough reservoir pressure to enhance oil recovery given the very low pressures due to fluid extraction. Pressure distribution in the field was also impacted by CO_2 channelling due to compartmentalization and stratigraphic isolation. Shale zones acted as flow barriers reducing sweep efficiency of the injected CO_2 alongside other factors such as differential depletion, permeability variation and matrix dissolution. This study showed how applying controls on the injection profile, such as using foam cement, can be an effective measure to achieve a relatively uniform CO_2 front. Injection profiles were also controlled using ‘intelligent wells’ to remotely open and shut fluid flow into individual zones. Intelligent wells incorporate permanent downhole sensors and valves allowing real-time management with no well intervention required.

3. Storage Capacity Estimations and Validations

Initial storage capacity estimations at Goldeneye were calculated volume-for-volume from hydrocarbon production data. These estimations were then refined using more in depth calculations to take into account storage efficiency and sensitivity analyses. Initial theoretical capacity estimations were approximately 47 Mt of CO_2 which were revised to 34 Mt after further analysis. The final stage of the storage capacity estimation was to develop dynamic “fill to spill” models, looking at different injection scenarios. All the models tested resulted in a dynamic capacity of over 30 million tonnes of CO_2, which exceeded original requirement of the 2009-2011 former DECC competition of 20 Mt. Both the static and dynamic estimations had associated uncertainties, mainly affected by geological features of the reservoir. Relative permeability and residual saturations were identified as having the greatest potential to impact the dynamic storage estimates, as summarised in Table 2.

Factors that act to **reduce** capacity (from theoretical)	Factors that act to **increase** capacity (from theoretical)
Heterogeneities (-9.7 Mt). Part of the reservoir is likely to preferentially fill based on its favourable characteristics.	**Storage in water leg (+ 6 Mt).** CO_2 is pushed below the pre-production oil-water contact into the water leg during injection.
Residual water saturation (-9 Mt). Pore volume could be filled with up to 25% residual water during injection.	**Buoyancy filling (+1.3 Mt after 20 years).** Post injection, part of the reservoir initially bypassed by the CO_2 begins to overcome capillary forces and fill under buoyancy.
Mixing with reservoir gas (-1.7 Mt). CO_2 will mix with gas remaining in the reservoir, changing its density (and therefore compressibility).	**CO_2 dissolution in brine (+0.6 Mt).** Various published correlations were used to determine CO_2 solubility and adjusted for Goldeneye reservoir conditions to give a CO_2 solubility of 4.6% by weight.
Irreversible compaction after gas production (negligible).	**Mineralisation (negligible).** Over a long a time scale this would have an effect, but it is considered to occur over too long a time scale to count towards capacity in this instance.
Interaction with neighbouring fields or new storage sites in the vicinity could also impact on capacity (effects are currently unknown, but not considered to be potentially significant).	

Table 2 Summary of the factors that affect storage efficiency, i.e. act to increase or decrease storage capacity at Goldeneye.

The study of Cranfield highlighted what is currently unknown about flow mechanism interactions associated with injecting CO_2 into a confined structural closure. The reservoir has a low (1-2°) dip and a 76m total closure on the nearly circular structure. Near the injection well fluid velocities will be high allowing the CO_2 to migrate down-dip. Away from the well, gravitational and capillary forces will become more dominant and buoyancy driven flow will also be predominant in areas of the reservoir. It is a complex issue which has remained unresolved at Cranfield. Volume-for-volume estimates were initially undertaken but are known to be an over estimate (as field heterogeneities lead to focused CO_2 flow and low sweep efficiencies).

At Otway (Stage 1), research focused on establishing storage efficiencies rather than storage volumes as it was never intended to fill the reservoir to capacity. Pre-injection reservoir pressure was calculated and showed that significant aquifer recharge was occurring at the site. Further numerical simulations showed that by the end of injection 30-40% of the water in pore volume could be replaced by CO_2. More detailed direct monitoring of reservoir fluids during filling of the site gave an insight into the validity of the dynamic capacity estimations involving storage efficiency factors. U-tube samples were taken which allowed plume migration to be monitored. The amount of CO_2 in the pore volume suggested by U2 and U3 samples indicated that 56-84% of available space originally occupied by gas was re-occupied by CO_2. At Otway U-tube samples were the only successful in-reservoir monitoring tool that was able to determine fluid compositions.

4. Long-term Wellbore Integrity

At Goldeneye a comprehensive set of reports (regarding materials and design, abandonment plans, etc.) are available from the FEED studies under taken. Carbon steel casing in operational wells with 13% chromium were considered the most effective mitigation to the risk of corrosion. Corrosion logs from years 3 to 6 of gas production did not show any statistically significant corrosion to the casing. To understand the potential risk of degradation of the cement literature was reviewed and simulations/ experiments were run. These all suggested that the cement was fit for purpose, as long as CO_2 was injected at specified temperatures and compositions. Good cementation practice is expected to reduce risks and quality/ placement should be inspected both pre and post injection using CBLs and ultrasonic imaging tools.

Monitoring techniques were also planned at Goldeneye to assess real-time well integrity to allow possible intervention. Pressure and temperature gauges were planned to be installed during recompletion of the well alongside distributed acoustic sensors (DAS) and temperature sensors (DTS). The DTS technique is anticipated to enable rapid identification of the location of any tube leaking. The DAS is a less mature method.

Post-injection abandonment methods planned to remove necessary parts of the completions and set two cement plugs at primary seal level. Environmental monitoring was recommended but potential cement degradation rates are predicted to be such that the plugs will maintain their integrity for many thousands of years. A ‘Corrective Measures Plan’ also outlined that re-entering an abandoned well in the case of a leak would not be possible as it is standard practice to remove all top parts of the well. Instead it was suggested a relief well should be drilled, or if found unsuitable, the injection well could be re-located using magnetic detectors.

At Cranfield, the SDWA's Underground Injection Control (UIC) programme regulates the construction and operation of wells. A quarter of a mile (~402m) around each injector is considered an 'Area of Review' where the integrity of the isolation in wells is assessed. Existing wells were drilled for injection and abandoned wells were re-entered to be used as producer wells for CO_2 floods. The results are not publically available as injection activities were handled by the operator, not SECARB. Over 200 historic production wells were present on site, only 17 of which had had recorded cement bond logs (CBLs). This lead to a probabilistic approach to assessing the risk of leakage. Two wells were recorded as having poor quality cement and simulation of CO_2 leakage implied a possible 1.8t/yr. It should be noted that leakage from the injection zone does not lead to loss of fluids to shallow fresh groundwater aquifers as the under-pressured Wilcox Group is thought to act as a pressure sink that prevents further upward migration. An important note from Cranfield is a re-entered observation well, abandoned in 1966, had CBL records which implied poor-quality cement but tests showed the well was effectively sealed.

Cathodic protection was used extensively at SACROC since the 1980s to counteract corrosion and was employed for ~1600 well bores. Research on well integrity at the site focussed on one old legacy well that was used as a CO_2 injector. The impact of CO_2 on cement from a 5cm side-track core of wellbore materials was extracted from a 30 year old well. Evidenced shows some alteration but most of the cement has survived. CBLs reveal good quality bonding with the casing. Laboratory experiments suggest CO_2 saturated brine can diffuse in good quality cement but it will not necessarily damage its integrity.

None of the case studies showed any cause for concern regarding wellbore integrity. Even so, the data availablegives limited evidence that legacy wells have maintained their integrity despite the presence of poor quality cement and hence further research is required.

5. The Cost of Modifications and Storage Development

Costs have been shown to be very site specific although generally offshore operations have incurred higher costs related to logistical elements such as installing pipelines. This study showed the importance of site characterisation to allow for more realistic cost estimates relating to risk mitigation. Depleted fields and EOR sites also have reduced costs in comparison to DSFs, as expected, due to previous characterisation work.

Breakdowns of cost information for Goldeneye are published in the FEED Close Out Report. Pre-FEED costs were estimated with an accuracy of -30% to +50% which were reduced to -12% to +15% by the end of the study. The total cost for establishing the FEED work itself was £38.6m GBP; 36% of which was spent on geosciences, reservoir engineering, production chemistry and reservoir management reports. Storage costs were estimated to be £207.8 million, and decommissioning/ abandonment was estimated at £123.1 million.

Stage 1 at Otway was partially government funded and hence a majority of cost related data has been made public. Comparisons between Otway and Goldeneye show how cost elements could vary drastically between commercial and pilot projects, which required further evaluation.

Expert Review Comments

Six experts were invited to review the study, all of which returned comments. The general consensus was that the study had been well-written and deals with an important subject in a logical way, providing a useful reference document. It was noted, however, that the study had not made it clear as to why the four studies were chosen from the initial selection. The authors agreed to rectify this and include additional reasoning in the introduction. It was also highlighted that some more comparisons could be drawn from the report, possibly in tabular form, to allow the case studies to be more easily digested, these have also been incorporated into the final report. More information was added to the caprock integrity, geomechanical and pressure cycle element of the report, especially with regards to SACROC. Reviewers also highlighted some additional references which had not been included in the study and these have since been incorporated into the final report.

Conclusions

- Storage in depleted oil and gas fields is advantageous and has been shown to be viable.
- Risk assessments varied depending on the purpose of the study, e.g. to meet policy and regulations or for research. The Goldeneye bow-tie method was the most rigorous assessment carried out (of the case studies reviewed) and could be applied to a variety of sites. In depth risk assessment produced strong evidence for secure containment in these case studies.
- Risk assessments are the main driver for deciding the monitoring techniques required. These are also determined by logistical constraints such as onshore versus offshore requirements.
- Monitoring techniques for EOR sites are easier and cheaper to develop as wells are already in place and can be used for continuous monitoring. This makes the identification of irregularities in data easier which can allow for earlier leakage detection. On the other hand, EOR site data may be less easily accessed as it is proprietary whereas saline aquifers are currently likely to be more research focused.
- Saline aquifers may have higher costs associated with site characterisation and infrastructure compared to hydrocarbon sites but risks associated with caprock integrity are higher for EOR sites given the cyclical pressure history. All the sites studied aimed to keep reservoir pressures during CO_2 injection below pre-production pressure to mitigate any potential risk of exceeding fracture pressure limits.
- Modelling for deep saline formations is likely to have less complications than EOR sites given there are no residual hydrocarbons or legacy wells to account for (although new insights into natural background chemical variations need to be taken in to account). This in turn could make storage estimations quicker and therefore cheaper.

- Away from the well gravitational and capillary forces will become more dominant and buoyancy driven flow will also be predominant in some areas of the well. Different flow mechanisms have to be considered at different temporal and spatial areas.
- AZMI pressure monitoring was conducted for the first time at a CO_2 storage site at Cranfield. The proof-of-concept installation well was not able to provide any information on the location or magnitude of any leakages but it is anticipated that this will be possible with more commercial installations to come.

Knowledge Gaps

- Further work is required to better understand the implications EOR residual fluids have on imaging CO_2 plumes.
- Further cement degradation information is required to allow the risk of corrosion to be fully analysed. Especially the long-term results for CO_2-resistant cements.
- Further information on pressure cycles and the geomechanical affect and possible degradation of the caprock.

Recommendations

- Review current research on monitoring mixed CO_2, CH_4 and other reservoir fluids at pilot and demonstration sites located in depleted oil and gas fields or CO_2-EOR fields.
- Further review current research on AZMI pressure monitoring and modelling at pilot and demonstration sites.
- Further review wellbore integrity information on cement quality and bonding where there are an abundance of legacy wells and provide more evidence of proven integrity.
- In Europe time is of the essence to allow CO_2 storage before depleted fields are fully decommissioned. A consistent message needs to be sent that storage in depleted oil and gas fields is advantageous, viable and eminently suitable to fulfil climate abatement returns.

Case studies of CO_2 storage in depleted oil and gas fields: IEA CON/15/231

By the British Geological Survey (BGS) and the Gulf Coast Carbon Centre (GCCC).

Executive summary

Storing CO_2 in depleted or depleting oil and gas fields has been carried out at a number of sites worldwide. Learnings from these sites are gathered here as a set of case studies to provide a publically accessible reference document for CCS project developers, decision makers and regulators. It is hoped that this will encourage and inform discussions on CO_2 storage in depleting fields elsewhere, to allow the early consideration necessary for exploitation of existing facilities (prior to decommissioning), and ultimately fill the short-term CO_2 storage gap for quick (and relatively cheap) climate abatement returns until large-scale storage in saline aquifers can be fully implemented.

Examples of sites where CO_2 storage in depleted or depleting fields is either planned, operational or complete, include the **Goldeneye** and **Hewett** gas fields from the UK North Sea (both were proposals in the recent UK government CCS commercialisation competitions); the **K12-B** and **P18-4** gas fields from the Netherlands (the former is an enhanced gas recovery pilot, the latter is the planned commercial-scale project "ROAD" - the first project to be permitted under the EU Storage Directive); the **Rousse** gas field pilot in France; the **Cranfield** and **SACROC** enhanced oil recovery (EOR) projects in Mississippi and Texas, USA; the **Weyburn-Midale** enhanced oil recovery project in Canada; and the **Otway** gas field pilot-scale project in Australia.

Of these, the **Goldeneye, Cranfield, SACROC and Otway** sites were selected as case-studies because their publically available documentation was best able to demonstrate learnings on key topics relevant to other sites, such as risk assessment, CO_2 plume monitoring, validation of capacity estimates, pressure changes and long term storage integrity together with insights into development costs.

Goldeneye: Front End Engineering and Design (FEED) documents for the proposed CO_2 storage in the Goldeneye gas field explain the engineering, planning and financial work to finalise and de-risk aspects of the proposal, ahead of taking final investment decisions and proceeding to construction. Storage-related issues were positioned 17th on the prioritised list of overarching project risks that might prevent the project from going ahead, behind those surrounding the obtaining of appropriate consents (given that no other site had yet tested the process) and maintaining investor backing, among others. This proved well founded, as the project is now unlikely to go ahead since the UK Government withdrew (in November 2015) their promised £1 billion capital funding to support the construction and operation of any of the 'competition' projects. Storage-specific risks were addressed using the "bow tie method" of risk assessment, considered exemplary in its ability to visually and quantifiably demonstrate the management and evolution of risks throughout the project. Targeted studies, many

involving numerical modeling of various types, facilitated design and injection strategy improvements to reduce storage risks to an acceptably low level. These included assessment of risk relating to wellbore design; caprock and cement integrity; structure storage capacity; feasibility of monitoring methods for both containment and conformance monitoring (particularly with respect to in-reservoir plume monitoring in the presence of residual hydrocarbons). The studies also provided improved constraints on certain aspects of the project costs. For example, post-FEED capital cost estimates relating to storage were 35% lower than pre-FEED estimates as a result of greater understanding of over well workover requirements. Abandonment and decommissioning costs were much increased post-FEED, following the addition of both pipeline and well costs estimates.

Cranfield: CO_2 from a natural CO_2 reservoir is injected into the Cranfield oil field, in southwest Mississippi, USA, for enhanced oil recovery. CO_2 injected into the water leg forms the basis for research under the Southeast Regional Carbon Sequestration Partnership (SECARB), the source of much of the publically available documentation pertaining to the site. The field, like many undergoing tertiary production, has a complex pressure history, enhanced by the heterogeneous fluvial channel geometries and strong aquifer drive. For this reason residual hydrocarbon saturation distribution is extremely difficult to predict, and is compounded by small amounts of methane present in the injected CO_2 stream. 4D seismic monitoring of the CO_2 within the field has had very mixed success. A probabilistic approach to uncertainty was used at the site to develop optimum monitoring equipment location and sampling/surveying frequencies for in-reservoir and above-reservoir geophysical and geochemical monitoring for containment assurance. Pressure gauges were positioned both in and above the reservoir interval. Results from those in the reservoir during a pulse injection test (with an “artificial leak” created by deliberate controlled venting of CO_2 from a well) showed that leakage events could be detected. Simulation and analysis of above zone pressure monitoring results showed that measured pressure increases were the result of flexure in the caprock, and its integrity was maintained. With the appropriate spacing of simple pressure gauges, both the location and amount of CO_2 leaving the reservoir could potentially be detected. Although still in development, several site-specific set-ups have been subsequently deployed for further testing at commercial sites. A probabilistic approach was also used for analysing the integrity of abandoned wells, indicated by the Certification Framework approach risk assessment as comprising the greatest risk of leakage from the site. Numerical simulations of CO_2 migration out of the reservoir from 2 of the 17 wells with cement-bond logs was estimated at up to 0.9 tonnes (t) per year each, but this was trapped prior to reaching any fresh water aquifers or the surface by multiple permeable, and in some cases depleted pressure, horizons.

SACROC: CO_2 flooding began in the unitised SACROC field in west Texas, USA, in 1972, making it one of the oldest continuous CO_2-EOR sites in the world and also the project with the most injected CO_2 to date (about 100 Mt stored of the 255 Mt injected and recycled by 2013), i.e. around 5 times more than the Weyburn project. Considering this and the huge number of wells at the site (>1,700, with around 400 active producers and 240 active injectors), with faulty wellbores often perceived to represent the greatest risk of leakage of reservoir brine or CO_2, it is striking that the research at SACROC under the Southwest Regional Carbon Sequestration Partnership (SWP) has demonstrated no adverse environmental impacts from CO_2 injection. Groundwater monitoring, (most extensively used for containment assurance at SACROC), showed no geochemical distinction between groundwater inside and outside of the site, or (comparing with historical datasets) pre- and post-CO_2 injection, suggesting that the shallow aquifers have not been affected by the injected CO_2. The data *do* reveal that the system is dynamic with large spatial and temporal variations in chemistry and therefore that simplistic approaches such as comparisons between baseline and regional monitoring results or with the reservoir brine are not diagnostic, might be misleading and could give false alarms. Numerical models incorporating improved understanding of the geochemical processes involved at the site indicate that a leakage rate of 0.001% (for 3Mt/yr storage) would be discernible above background with dissolved inorganic carbon (DIC) displaying the highest sensitivity to leakage compared to 3 other species commonly used as leakage indicators (HCO^{3-}, pH and Ca^{2+}), which showed mixed sensitivity and unpredictable behaviours.

The duration of CO_2 exposure at SACROC provides an unsurpassed opportunity to examine longer term effects on well integrity in a CO_2 – rich environment. Cement samples from one well exposed to CO_2 for 35 years showed relatively little chemical degradation and a propensity for the cement reactions to self-heal and inhibit further degradation. SACROC also provides examples of methods successful at controlling fluid flow in a vertically compartmentalised reservoir to improve sweep efficiency. These could be transferable to storage projects which might need to prevent uneven filling by blocking undesirably fast conduits. Records of well incidents (blowouts) at both CO_2 and non-CO_2 related wells in Texas indicated well blowout frequency was extremely small and there was no evidence to show increased risk when CO_2 is involved. Where incidents occurred, it was usually related to surface component failure rather than downhole loss of isolation.

Otway: The Naylor gas field, in Victoria, Australia, (known as the Otway project) is the site of a pilot onshore storage project injecting 65 000 tonnes of CO_2. Of the research-oriented monitoring deployed, learnings from the downhole fluid sampling will be of particular interest to other projects. U-tube sampling at three levels within the reservoir was able to track the base of the CO_2 plume moving downwards past the sampling ports as the field filled. From this, the amount of CO_2 added to the pore volume during that time-frame was calculated, suggesting that 56 to 84% of the available space originally filled by gas was re-occupied by CO_2. This is comparable to the storage efficiency factors of around 75% typically used in estimates of depleted field capacity. Whilst a similar monitoring set up is unlikely to be deployed at a commercial site, the findings from directly monitoring the reservoir filling validated numerically modelled dynamic capacity estimates and lab-based storage efficiency calculations. They also improve understanding of CO_2 distribution through time as the plume stabilises - as at March 2016, six years after injection ceased, measurements are still being taken roughly every six weeks. Learnings about the sampling frequency and set up would also allow significant improvements should another research based project have the facility to investigate this further. Cost breakdowns of the operation have been published and although highly site specific provide a useful comparison of an onshore pilot site with those published from a proposed commercial-scale offshore site (Goldeneye).

Key learnings from the case studies:

Learnings from the sites show that storage in depleted fields, whether for pure storage or for EOR purposes, has been proven. Key risks have been overcome, relating to site design for dealing with reduced reservoir pressure (cited as a key challenge of storage in depleted fields by Hughes, 2009), re-using infrastructure and managing wellbore integrity risks.

- o For example, storage at the case study sites (and others) proceeded successfully regardless of the large numbers of wells. This shows that wellbore-related risks, although often the most highly rated, can be adequately managed. SACROC provides evidence of wellbore integrity and lack of cement degradation, but it would be helpful to gather more such learnings to improve understanding of these risks and possible mitigation and corrective measures at future sites. As the dataset from multiple sites grows, uncertainty over these risks and how to deal with them is expected to become clearer.
- o A vast experience from CO_2-EOR (particularly in the USA) is available to learn from. For example in history-matching models to monitoring data, in having sufficient sample size for statistically valid performance assessment, and in the effects of infrastructure exposure to CO_2.

- **Regulations-wise, large scale “pure” CO_2 storage in depleted fields remains to be tested and closure of a large scale CO_2-EOR site also has not yet occurred.** In Europe, no site has yet started operating under the EU Storage Directive. In the USA, although CO_2-EOR is becoming increasingly focused on potential anthropogenic greenhouse gas emission reduction aspirations, regulations remain segregated (with e.g. potential surface retention requirements and closure implications).

- **Storage in depleted fields can offer a “quick win” compared to saline aquifer sites.** Documented production history and proven hydrocarbon retention markedly reduces uncertainty in containment and capacity, which will almost certainly save development costs and time.

    - Costs could be further reduced or offset at depleted field sites by exploiting existing infrastructure and potentially by additional hydrocarbon recovery (i.e. CO_2-EOR).
    - Long term risks associated with well integrity, given the probable larger numbers of well penetrations at depleted field sites, as compared with many saline aquifer sites, are balanced by the overall likely lower risk relating to the pressures experienced. Although the maximum pressures that a depleted field site experiences might occur sometime after injection ceases (as a result of gradual water influx), these will nevertheless be less than the site has already withstood when it was hydrocarbon charged, whereas injection at an equivalent aquifer site will tend to increase reservoir pressures above what has been previously experienced. Although some CO_2-EOR projects may operate at above initial reservoir pressures in order to reach the minimum miscibility pressures, production of fluids effectively controls reservoir pressure within the safe range.

- **But time is of the essence**, particularly in Europe, to allow the inclusion of CO_2 storage (or CO_2-EOR) in depleted fields before they are fully decommissioned. Enabling accelerated development of depleted fields for CO_2 storage would likely involve persuading senior policy makers in government and investors of the benefits, in order to gain their backing. A consistent message needs to be sent that storage in depleted fields is not only viable, but also advantageous (i.e. relatively cheaper, potentially lower risk and able to be brought online faster than their saline aquifer counterparts) and that these sites are eminently suitable to fill the short term CO_2 storage gap for quick climate abatement returns until large-scale storage in saline aquifers can be fully implemented.

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Chapter 1 Introduction

This report documents a selection of case studies of where CO_2 storage has been implemented, or is planned in depleted oil and gas fields. This includes sites where storage in a depleting field is combined with enhanced oil or gas recovery (EOR or EGR). The case studies are focused on how the sites have overcome relevant technical issues as well as those relating to regulations and, where possible, costs and economic viability. Specific issues addressed are: how the sites have approached risk assessment, plume monitoring, validation of capacity estimates, and how they have dealt with issues surrounding pressure changes and long term integrity. These are outlined more fully in section 1.1.

This report is designed to be used as a reference document for CCS project developers, decision makers and regulators. It succinctly details our findings and conclusions within the chapters outlined below:

Chapter 1 Introduction

Chapter 2 Identification of suitable case studies

Chapter 3 Case study: Goldeneye

Chapter 4 Case study: Cranfield

Chapter 5 Case study: SACROC

Chapter 6 Case study: Otway

Chapter 7 Comparative assessment

Chapter 8 Conclusions and synthesis

In **Chapter 2**, we briefly review public domain information on a number of depleted field storage sites worldwide, to select those best able to address the scope in more detail as case studies. **Chapters 3 – 6** document the case studies from each of the selected sites, using explanation of their site-specific experiences and datasets to illustrate the key points. **Chapter 7** provides a comparative assessment between the two types of site represented by the case studies: pure storage in depleted gas fields and storage with enhanced oil recovery. They are examined in terms of their differing modelling, monitoring & reporting requirements, in addition to their economics & operational strategies. Onshore versus offshore aspects and oil versus gas comparisons are also provided. Findings are contrasted with those from CO_2 storage in aquifers. We consider factors that could be considered as either benefits or barriers to storage project development, and distil this into a list of non-prescriptive recommendations. The final chapter, **Chapter 8**, synthesises the report findings and provides conclusions.

Unit conversions are provided in the text in Chapter 2, thereafter, please refer to the conversion factors provided in the back of this report. Any cost information is shown in native currencies with 2016 pounds sterling (GBP) conversions for cross-report comparison.

1.1 Report scope

The case studies are based on well documented examples in the public domain of depleted oil and gas fields that have either been developed for CO_2 storage or have been investigated for this purpose. The sites are selected and presented based on their ability to provide insights into the following key areas (provided by IEAGHG):

#1. **Risk assessment criteria** for depleted fields.

#1a. Implications for continued oil and gas production in adjacent fields

#2. **Monitoring criteria (to quantify CO_2 storage and detect the extent of migration).** (i.e. parameters to be monitored during/post injection). Detailed descriptions/analysis of monitoring techniques are not required, but examples of how monitoring has been used to quantify CO_2 storage and detect the extent of migration. The study needs to examine recent developments on and offshore where depleted oil and gas fields have been, or are being developed, as test sites for CO_2 storage.

#2a. Implication for monitoring requirements e.g. the effects of fluid replacement. Implications for monitoring requirements that might be required including the effects of fluid replacement.

#3. **Pressures changes & thresholds and how these can be mitigated.** An assessment of the implications for changes in a pressure regime outlining the pattern of pressure build up during/post CO_2 injection. The extent of the limitations imposed by fracture pressure or low permeable barriers and how these can be or were mitigated. The assessment should include estimates of the injection and storage pressures that can be tolerated by reservoirs.

#4. **Storage capacity estimate validation.** The scale of field storage capacity and whether examples of depleted oil and gas fields can improve estimates in storage capacities. Whether fluid density change related to miscibility affects storage capacity estimation.

#5. **Long-term wellbore integrity assessment and remediation measures.** What is the evidence for long-term wellbore integrity assessment and remediation measures, for example, does well casing quality need to meet new specifications for CO_2 storage. What new techniques are available for wellbore integrity and other forms of remediation. What would be cost of compliance or rectification of leaky wellbores.

#6. **Cost of modifications and storage development.** The implications for the cost of modifications and storage development.

A comparative assessment including the differences between on and offshore CO_2 storage in depleted oil and gas reservoirs was also specified.

Chapter 2 Identification of suitable case studies

This chapter presents a range of sites from around the world where CO_2 storage has been or is being considered in depleted or depleting hydrocarbon fields (Table 1).

The geology, reservoir conditions and injection strategies for each are briefly described together with an outline of their ability to demonstrate learnings pertinent to the scope of the report (#1 - #6, section 1.1), based publically available information. Namely: how the sites have approached risk assessment, plume monitoring, validation of capacity estimates, and how they have dealt with issues surrounding pressure changes and long term integrity and any insights into costs of development.

The sites reviewed include projects planned, operational and complete represent both and onshore and offshore sites; “pure” storage in depleted oil or gas fields and where storage in a depleting field is combined with enhanced oil or gas recovery (EOR or EGR); along with a mix of geological settings and site scales (pilot, commercial) and from different geographic and regulatory contexts (Table 1).

These site-by-site summaries were used as a basis for selecting the sites to present as full case studies in the subsequent chapters (Chapters 3 to 6). The four sites selected for this (indicated by red boxes in Table 1) were selected was based firstly on their ability of to illustrate the scope issues (Table 1 indicates which issues each site was able to address) and also on the amount of publically information available to illustrate them (summarised in Table 1).

In this chapter sites in Europe are presented first in section 2.1, with a short introduction to set the regulatory context, followed by the USA sites, with a similar introduction and text on the nature of EOR sites in section 2.2. Sites from elsewhere in the world are presented in section 2.3.

	Site name:	Goldeneye	Hewett	K12-B	P18-4, ROAD	Rousse	Cranfield	SACROC	Otway	Weyburn
	Reported in section:	**2.1.2**	**2.1.3**	**2.1.4**	**2.1.5**	**2.1.6**	**2.2.3**	**2.2.4**	**2.3.1**	**2.3.2**
Site features	Location	offshore	offshore	offshore	offshore	onshore	onshore	onshore	onshore	onshore
	Field depleted of	gas	gas	gas	gas	gas	oil	oil	gas	oil
	Amount of CO_2 (Mt)	10-20	20-110	0.08	8.1	>0.051	5	100	0.065	20
	Operating status	planned storage	planned storage	operating pilot EGR	planned storage	completed storage pilot	operating EOR	operating EOR	completed storage pilot	operating EOR
	Reservoir type	sandstone	sandstone	sandstone	sandstone	carbonate	sandstone	carbonate	sandstone	carbonate
	seal type	mudstone	mixed	salt	evaporite	mudstone	mudstone	mixed	mudstone	evaporite
	Reservoir depth (m)	2600	1198	3800	3500	4500	3000	2040	2000	1-2000
Scope issues (sec.1.1)	#1. Risks criteria	x	x		x	x	x			x
	#1a. Adjacent fields	x	x							
	#2. MMV criteria	x	x	x	x	x	x	x	x	x
	#2a. Fluid replacement	x		x			x		x	
	#3. Pressure changes	x	x		x	x	x	x		
	#4. Storage capacity	x	x				x	x	x	x
	#5. Wellbore integrity	x	x	x	x	x	x	x		x
	#6. Cost of storage	x	x		x				x	
	Amount of info avail	**High**	**Medium-high**	**Medium**	**Low**	**Medium-high**	**High**	**High**	**High**	**High**

Table 1 Comparison between sites presented in Chapter 2. Those selected for case studies in Chapters 3-6 are outlined in red. Shading intends to aid differentiation of site characteristics

2.1 European sites

In Europe, the majority of large scale storage sites are located or planned for offshore. Of the European depleted field sites considered in this report (Figure 1), only the <100,000 tonne scale site at Rousse in France is onshore. The planned projects at Goldeneye, Hewett and ROAD have been developed under the EU CCS Storage Directive, which came into effect in June 2009, and although ROAD has been permitted, no sites have yet started operating under that regulatory framework. The pilot scale K12-B and Rousse sites both pre-date those regulations, although the Rousse project, permitted in 2008, incorporates recommendations from the draft EU Directive (despite falling below its 0.1 Mt threshold). Both pilots have strong research elements to their approaches. The two UK projects, Goldeneye and Hewett were proposals in the UK Government competition to assemble Front End Engineering and Design (FEED) studies, a programme of detailed engineering, planning and financial work to finalise and de-risk aspects of the proposal, ahead of taking final investment decisions and proceeding to construction. Storage in Hewett (with capture at Kingsnorth power station) and Goldeneye (with capture at Longannet power station) were part of the 2009-2011 Full Chain UK CCS Demonstration Competition. Storage at Goldeneye (with capture at Peterhead power station) was part of the follow-on 2012-2015 UKCCS Commercialisation Competition (together with an aquifer storage project). Since the UK Government announced in November 2015 that the £1 billion capital funding to support the construction and operation of one or more those projects has been withdrawn, it seems unlikely that these will now go ahead.

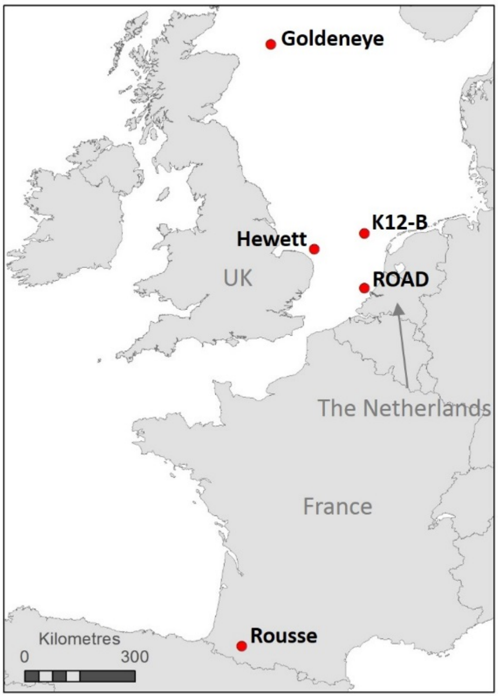

Figure 1 Map of European depleted field sites used or considered for CO_2 storage (British Geological Survey © NERC 2016).

2.1.1 EU regulatory context

A background knowledge of CO_2 regulations is assumed and only a very brief introduction to those parts discussed elsewhere in this report are specified here. A selection of the regulatory terminology, as used in this report, is also listed. A full explanation of EU regulations and their implications can be found in IEA, 2010.

Regulations

In the EU, storage greater than 100,000 tonnes of CO_2 falls under the EU Storage Directive. Gaining a storage permit requires the submission of a number of plans pertaining to storage development, including monitoring, corrective measures and post closure plans. Proof of financial security is also required, to extend until responsibility for the site is transferred to the 'Competent Authority' (CA, i.e. the state). This occurs a minimum of 20 years from when injection ceases, unless (crucially), the operator can convince the CA that "all available evidence indicates the stored CO_2 will be completely and permanently contained"[1] before that. Monitoring plans are required to be updated every 5 years and results reported at least annually (although significant irregularities or leakage should be reported immediately)[2]. The Storage Directive was brought into effect in 2009 and although 1 site (ROAD, section 2.1.5) has gained a permit (in 2011 and subject to various conditions including updating and resubmitting their plans), no site has yet started operating under these regulations. As such they remain to be tested.

Terminology

Terms relevant to storage in Europe under the EU CCS Directive are explained briefly for the benefit of readers from other jurisdictions:

1. **'storage site'** means a defined volume area within a geological formation used for the geological storage of CO_2 and associated surface and injection facilities;
2. **'storage complex'** means the storage site and surrounding geological domain which can have an effect on overall storage integrity and security; that is, secondary containment formations;
3. **'storage permit'** means a written and reasoned decision or decisions authorising the geological storage of CO_2 in a storage site by the operator, and specifying the conditions under which it may take place, issued by the competent authority pursuant to the requirements of the Directive;
4. **'closure'** of a storage site means the definitive cessation of CO_2 injection into that storage site;
5. **'post-closure'** means the period after the closure of a storage site, including the period after the transfer of responsibility to the competent authority;

[1] Article 18, 1a, European Commission (EC), 2009, Directive 2009/31/EC
[2] Article 13, 2, European Commission (EC), 2009, Directive 2009/31/EC

6. **‘migration’** means the movement of CO_2 within the storage complex and elsewhere in the subsurface;

7. **‘leakage’** relates to the unintended subsurface migration of CO_2, specifically release of CO_2 from the storage complex; *(note that this differs from the definition of leakage in the EU Emissions Trading System (ETS) regulations which define leakage as emissions to the atmosphere or water column)*

8. **‘emission’** means any release of CO_2 from the subsurface into the atmosphere or water column (note that this definition is not from the EC Directive, but is used for the purposes of this report).

9. **‘significant irregularity’** means any irregularity in the injection or storage operations or in the condition of the storage complex itself, which implies the risk of a leakage or risk to the environment or human health;

10. **‘corrective measures’** means any measures taken to correct significant irregularities or to close leakages in order to prevent or stop the release of CO_2 from the storage complex.

2.1.2 Goldeneye gas condensate field, UK (Longannet and Peterhead projects)

The Goldeneye gas condensate field lies ~2,600 m beneath the outer Moray Firth, about 100 km [62 miles] NE of St Fergus, Scotland. Two storage projects have been considered at this site. The first proposed capture from the Longannet coal-fired power-station, injecting 20 Mt of CO_2 over 14 years from 2016-2029 (as part of the 2009-2011 UK Government Demonstration Competition). The second proposed capture from the Peterhead gas-fired power-station and injection of 10 to 20 Mt of CO_2 over 10 to 15 years starting in 2019 (as part of the 2012-2015 UK Government Commercialisation Competition). Front End Engineering and Design (FEED) documents have been published from both of these proposals. However, most of the information in this report pertains to the Longannet proposal, unless otherwise stated, because at the time of writing (February 2016) the full set of Peterhead FEED documents have not yet been released by the UK Government.

Goldeneye site summary

Location: offshore UK

Depleted: gas condensate

Type: storage (10 - 20 Mt over 10 - 15 years)

Status: planned (start 2019)

Economic viability: government subsidised demonstration

Geological setting: Cretaceous sandstone reservoir at ~2,600 m [8,530 ft] depth, in well-connected sandstone aquifer fairway with mudstone caprock

Key findings from the site: (i.e. how it contributes to addressing scope, section 1.1)

- [x] #1. Risk assessment criteria
- [x] #1a. Implications for continued oil and gas production in adjacent fields
- [x] #2. Monitoring criteria (to quantify CO_2 storage and detect the extent of migration)
- [x] #2a. Implications e.g. the effects of residual hydrocarbon
- [x] #3. Pressures changes & thresholds and how these can be mitigated
- [x] #4. Storage capacity estimate validation
- [x] #5. Long-term wellbore integrity assessment and remediation measures
- [x] #6. Cost of modifications and storage development

Geology: The primary reservoir is a turbiditic sandstone of Cretaceous age (the Captain Sandstone Formation) with a porosity of around 25% and permeability around 800 mD. It forms part of a ribbon-like fairway more than 100 km long and up to 10 km wide [~62 x 6.2 miles], dipping 1 to 1.5 degrees to the south-east and outcropping at seabed some 150 km [~93 miles] to the north-east. Data from other hydrocarbon sites in the fairway suggest that it is hydraulically well-connected. In the Goldeneye area it is capped by a 300 m [984 ft] sequence of mudstones and marls. Above that are secondary sandstone reservoirs and regionally extensive mudstone seals. The CO_2 storage site is bounded by a polygon some 2 to 3 km [~1.2-1.9 miles] outside of the original Goldeneye oil-water contact (Figure 2a). The storage complex is slightly larger, and extends upwards to the top of a mudstone seal at a depth of more than 800 m [2,625 ft] (Figure 2b). Although there are faults nearby at the reservoir level, they are no large faults within the complex and none penetrate all sealing units.

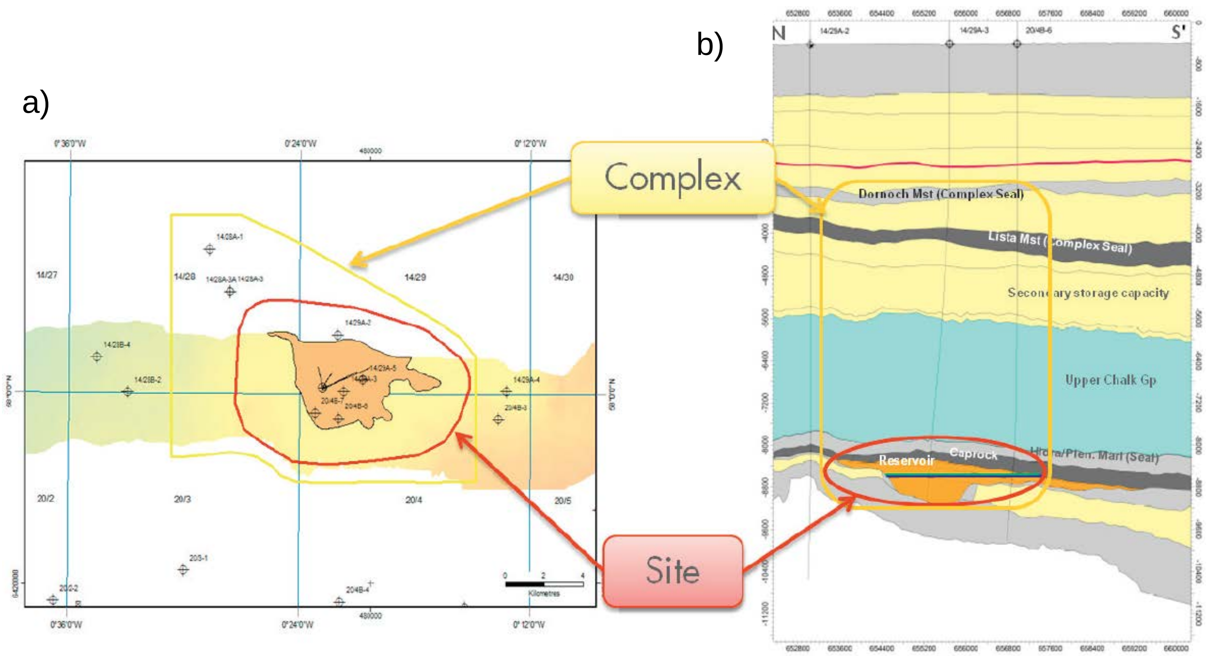

Figure 2 Goldeneye storage site and complex a) map view b) cross section view (ScottishPower CCS Consortium, 2011g).

Reservoir conditions: Production from the reservoir ceased in March 2011 and reduced reservoir pressures from 26.3 MPa at 2,560 m [~ 3,815 psia at 8,400 ft] down to ~ 15.2 MPa [~2,200 psia]. However the regional aquifer is currently re-pressurising the reservoir. It will also be affected by hydrocarbon production in neighbouring fields. Modelled expected pressures just prior to CO_2 injection (intended to start in 2016 in the Longannet proposal) were between 19.3 and 20.7 MPa. These forecasts were updated for the Peterhead proposal using an additional two years of pressure data. The reservoir pressure was reported as ~18.3 MPa in December 2013 and 18.5 MPa at the end of November 2014, (a smaller rise than initially predicted in the 2011 proposal). This subsurface dynamic parameters were revised accordingly, including a slight increase in predicted permeability and a decrease in aquifer-drive strength.

Formation temperature was 83°C at 2,560 m [181ºF] with a salinity of 53,000 ppm. A gas cap remains in the reservoir with variable amounts of residual hydrocarbon down to the pre-production contacts, the deepest of which was at 2,618 m [8,592 ft] TVDSS.

Injection strategy: Gas condensate was produced from the Goldeneye field from 2004 - 2011 via five deviated wells, until the wells watered out. These wells will be worked over and recompleted to inject dense-phase CO_2 into the storage reservoir. At any one time, three of the wells would be injecting CO_2, one would be a monitoring well and the fifth would act as a back-up. The wells could potentially be swapped to optimise injection according to CO_2 arrival flow rate, maintenance or contingency requirements. The CO_2 is sourced from power-station capture. Maximum injection rate was expected to be 2.2 Mt per year [114.4million scf/day] for the Longannet proposal. This was modified to a maximum of 1 Mt/year for the Peterhead proposal. Injection of 20 Mt of CO_2 would be expected to raise the pressure to between 24.1 MPa and 25.9 MPa at the end of injection [3,495 psia and 3,757 psia]. The pressure is then expected to fall to between 22.4 MPa and 24.5 MPa as it dissipates into the aquifer [3,249 psia and 3,553 psia]. The pressure fall-off will transition to a slow recharge, dependent on the activity of other fields in the Captain aquifer and also on the degree of extended aquifer connectivity.

Key findings from Goldeneye: (i.e. how it contributes to addressing section 1.1)

Note: these findings are described in more detail in Chapter 3.

#1. Risk assessment criteria

As a first-of-a-kind project in the UK, the majority of the overarching risks to the project related to gaining consents and permits required for it to go ahead. A comprehensive bow-tie method of risk assessment was applied for the storage aspects to allow a visualisation of the relationship between threats to and consequences of an unwanted event occurring. Possible escalation scenarios are also included. Preventative and corrective control barriers are in place either side of the event to reduce the probability and/or severity of the risks.

#1a. Implications for continued oil and gas production in adjacent fields

The Goldeneye field is known to be hydraulically connected to neighbouring fields within the same reservoir unit. This was not considered to be a risk, as the injection was expected to fill the pressure ‘hole’ resulting from earlier production and if pressure pulses resulting from this were felt in neighbouring fields these would likely be beneficial to their production.

#2. Monitoring criteria (to quantify CO_2 storage and detect the extent of migration)

A relatively limited suite of technologically mature monitoring techniques is selected for deployment in the base-case plan primarily to demonstrate containment and conformance satisfying all regulatory requirements. The technologies were selected and implemented via a risk-based Measuring, Monitoring and Verification (MMV) programme. Additional frequency and focus of surveys lie in reserve in the contingency plan, should a significant irregularity be detected.

#2a. Implications for e.g. the effects of residual hydrocarbons

The feasibility of a number of monitoring tools was explored in detail and their abilities to detect and distinguish CO_2 saturations from residual gas saturations are explored. Pulsed neutron logs, neutron porosity logs and downhole sampling are planned for deployment once CO_2 reaches the monitoring well. A number of tools were discounted due to operational constraints. Investigations suggest CO_2 plume migration monitoring using 4D seismic (for conformance monitoring) within the pre-production hydrocarbon volume will be challenging because of the small acoustic impedance differences anticipated. However, any migration beyond that would be much more readily detectable.

#3. Pressures changes & thresholds and how these can be mitigated.

The recompletion of the injection wells is designed to reduce injection risks relating to extremes of pressure and temperature on wellbore components. In addition simulations of injection conditions that could jeopardise caprock integrity resulted in changes to the injection strategy. Geomechanical modelling showed negligible risk to caprock integrity once these changes were implemented.

#4. Storage capacity estimate validation

Initial capacity estimates involved simple volume-for-volume replacement, based on the produced volume of hydrocarbon. This was updated by incorporating detailed studies into the mechanisms effecting storage efficiency and their impact on capacity. This was then compared with and verified by dynamic numerical flow simulations of the whole operation.

#5. Long-term wellbore integrity assessment and remediation measures

A comprehensive set of reports explores the selection of materials and design of the recompleted injection wellbores, including proposed post-injection abandonment plans. In addition a thorough examination of all plugged and abandoned wells in the vicinity indicates that the integrity of those wells expected to contact the plume is sufficient. Monitoring of wellbore integrity is planned during and post injection. The corrective measures plan includes options for remediation of potentially leaking wellbores.

#6. Cost of modifications and storage development

As part of the FEED studies, basic cost information was released, relating to capital, operating and abandonment expenditure should the project proceed. Estimates from both the early pre-FEED and post-FEED stages are included, allowing insight into how the improved knowledge and understanding of requirements had changed the cost forecasts.

Goldeneye key reference

ScottishPower CCS Consortium, 2011**g**. UK Carbon Capture and Storage Demonstration Competition, Longannet Goldeneye CCS Project UKCCS - KT - S7.23 - Shell – 004, **Storage Development Plan,** April 2011. Available from [at Feb 2016]: http://webarchive.nationalarchives.gov.uk/20121217150422/http://decc.gov.uk/en/content/cms/emissions/ccs/ukccscomm_prog/feed/scottish_power/scottish_power.aspx

2.1.3 *Hewett gas field, UK (Kingsnorth project)*

The Hewett gas field lies in the UK sector of the Southern North Sea approximately 16 km [~10 miles] NE of the Norfolk coast (Figure 3). It was one of the sites in the 2009-2011 UK Government Demonstration Competition, with capture proposed from Kingsnorth power station. Information in this section derives from the Front End Engineering and Design (FEED) documents published post-competition. The proposal outlines the demonstration phase involving injection of 20 Mt gaseous-phase CO_2 over 12 years, followed by a 28 year period of dense and liquid phase CO_2 injection to inject a total of 110 Mt by the end of 40 years. A subsequent target in an upper part of the structure was also considered.

Hewett site summary

Location: offshore UK

Depleted: gas

Type: storage (20 Mt over 12 years (demonstration phase), followed by 89 Mt over 28 years (commercial scale))

Status: proposed (start 2017)

Economic viability: government subsidised demonstration, followed by larger-scale storage

Geological setting: Two stacked Triassic sandstone reservoirs in a faulted anticline: Main target at @~1,300 m depth [4,265 ft] with a mudstone seal. Secondary target @ ~800 m depth [2,625 ft] with a mudstone/halite seal.

Key findings from the site: (i.e. how it contributes to addressing scope, section 1.1)

- [x] #1. Risk assessment criteria
- [x] #1a. Implications for continued oil and gas production in adjacent fields.
- [x] #2. Monitoring criteria (to quantify CO_2 storage and detect the extent of migration).
- [ ] #2a. Implications e.g. the effects of residual hydrocarbon fluids.
- [x] #3. Pressures changes & thresholds and how these can be mitigated.
- [x] #4. Storage capacity estimate validation
- [x] #5. Long-term wellbore integrity assessment and remediation measures
- [x] #6. Cost of modifications and storage development.

Geology: The Hewett gas field lies within a NW-SE trending fault bounded dome-shaped anticline. It has three reservoirs within it: the Upper Bunter Sandstone, the Lower Bunter Sandstone (aka 'Hewett', the main target proposed) and the Zechsteinkalk carbonates. The proposed storage complex proposed comprises the Lower Bunter as the main target for CO_2 storage, the Upper Bunter as a possible secondary target, and the neighbouring Little Dotty field, with its Upper Bunter reservoir (because evidence suggests that it may be in connection with the Hewett Bunter reservoirs across a fault). The sandstone of the Lower Bunter reservoir at ~1,300 m depth [4,265 ft] was deposited under fluvial, distal floodplain and playa lake conditions. It is typically around 25 m thick and has an average modelled porosity of 21% and permeability of 1,400 mD. The Upper Bunter reservoir at ~800 m depth [2,625 ft] is composed of fluvial and sheet flood sandstones, with an average modelled porosity of 19% and permeability of 240 mD. The Bunter Shale and Dowsing Dolomite Formations provide a largely mudstone caprock and lateral seal for the Lower and Upper Bunter reservoirs.

Reservoir conditions: Production from the Hewett was still ongoing when the FEED was written (2011) and is still listed as producing (Feb 2016, DECC). The initial pressure in the reservoir was 13.7 MPa in the Lower Bunter and 9.4 MPa Upper Bunter [1,987 and 1,363 psi respectively]. Pressure in the Lower Bunter reservoir has been reduced to 0.27 MPa [39.1 psi] by gas production. Temperature in the reservoir is 52°C [126°F]. Water influx from surrounding aquifer units is reported to have particularly affected production from the Upper Bunter reservoir until production started in the neighbouring Little Dotty field.

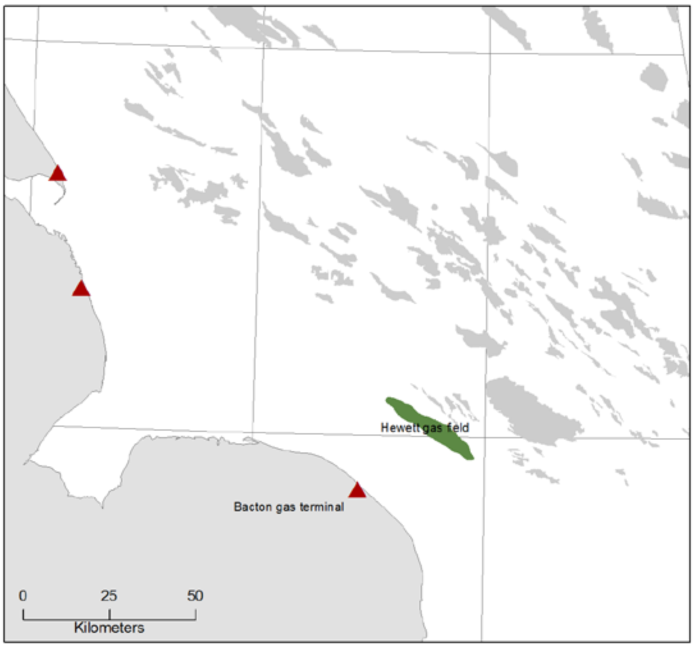

Figure 3 Map showing the location of the Hewett gas field. Contains public sector information licensed under the Open Government Licence v3.0.

Injection strategy: Gas is produced from the Hewett Lower Bunter via 28 wells. Initial plans for injection during the demonstration phase were for CO_2 to be injected in gaseous phase at a maximum rate of 6,600 t/d (~2.4 Mt/yr) via 3 wells (with an extra well for contingency) for 12 years. The 22 Mt of CO_2 injected during that period would raise reservoir pressures to 3.1 MPa [450 psi]. After the demonstration stage it was planned to supply CO_2 in its dense liquid phase (above critical pressure, but below critical temperature) at a rate of 26,400 t/d (~ 9.6 Mt/yr) via 5 additional wells (i.e. 8 plus 1 contingency). This will bring the total amount of CO_2 stored up to 110 Mt (53% of the calculated Lower Bunter capacity) after a further 28 years. At this point the pressure is estimated to be 9.1 MPa [1320 psi], i.e. well below the limits set by pre-production levels (12.2 MPa) and the capillary entry pressure threshold (estimated as 13.3 MPa) [1,769 and 1,929 psi respectively]. The total number of injection wells will be decreased to six as the reservoir pressure increases.

Key findings from Hewett: (i.e. how it contributes to addressing section 1.1)

#1. Risk assessment criteria

Hazard Identification (HAZID) sessions were conducted early in the project to ensure major risks could be considered and mitigated during site design. The main hazard was loss of containment of CO_2 outside the storage complex and the main risks to this related to wellbore integrity (both existing and abandoned wells). Material selection was identified as important to counter CO_2-related corrosion or low temperature risks (relating to the Joule – Thompson effect, explained in section 3.5.1). Risk ratings (probability multiplied by the severity of safety and/or environmental consequences) were updated after mitigating actions were considered.

#1a. Implications for continued oil and gas production in adjacent fields

Little Dotty, a small neighbouring field may be in connection with the Lower Bunter Hewett field and further work will be required to evaluate the permeability of a fault lying between them. Although the Lower Bunter reservoir was the target of the FEED study the 'CO_2 storage complex' includes the reservoirs of the Upper Bunter and Little Dotty fields.

#2. Monitoring (to quantify CO_2 storage and detect the extent of migration)

Monitoring methodology was risk-based. Objectives included the timely detection of irregularities to enable remedial actions prior to loss of containment, and monitoring to reduce uncertainty in future model predictions to allow site closure. Techniques were selected based on capabilities to detect expected property changes during different operational phases. Cost-benefits, learnings from other sites, regulatory requirements and public perception were also taken into account. 'Essential' monitoring techniques were proposed, together with 'recommended' techniques that would be beneficial in terms of early detection and location of leakage and developing more effective remediation. This included proposed consideration of a dedicated monitoring well.

#3. Implications of site pressure history

Pressure depletion has occurred during production of the Hewett field but an active aquifer has resulted in a small amount of re-pressurisation which will be taken into consideration. Thorough pressure and stress profiles are available from before and after depletion of the reservoir and can be used to simulate potential geomechanical changes that may be induced in the reservoir and overburden.

#4. Storage capacity estimate validation

The storage capacity assessment of 206 Mt for the Lower Bunter reservoir was established using dynamic full-field modelling. Key uncertainties relate to the juxtaposition of the Hewett and Little Dotty fields (from uncertainties in seismic interpretation around the field boundary fault) and also the interpretations of water saturations from the data available. Further work to address these sensitivities was proposed.

#5. Long-term wellbore integrity assessment and remediation measures

Integrity of the 5 abandoned exploration wells was assumed adequate if standard practice had been followed. Further work to understand the feasibility and costs of potential remediation and monitoring for these wells was proposed including learning from existing hydrocarbon and CO_2-EOR experiences. The 28 existing production wells were not considered suitable for reusing as injectors and would therefore need to be decommissioned to a CO_2 resistant specification. A comprehensive set of reports evaluate the new proposed injection well bores, both for operational performance and integrity.

#6. Cost of modifications and storage development

As part of the FEED studies, basic cost information was released. Only basic level post-FEED cost estimates were accessible. Of the estimated storage costs, 60% relates to wells, at almost £50 thousand pounds GBP (This includes E.ON's estimate that abandoning the 28 gas production wells to a CO_2-resistant standard would cost an additional £1.6 million GBP per well over 'standard' hydrocarbon abandonment costs, i.e. over 3 times more per well). Mobilisation costs were estimated at £13.4k, commissioning at £4.4k, with £10.2k estimated for contingency costs.

Hewett key references

E.ON, 2011. Kingsnorth Carbon Dioxide Capture and Storage Demonstration Project: **Key Knowledge Reference Book** pp66. February 2011. E.ON UK plc. Available from [at February 2016]: http://webarchive.nationalarchives.gov.uk/20121217150422/http://decc.gov.uk/en/content/cms/emissions/ccs/ukccscomm_prog/feed/e_on_feed_/e_on_feed_.aspx

E.ON, 2011. Kingsnorth Carbon Dioxide Capture and Storage Demonstration Project: **Capacity Assessment – Validation/ Assessment of Reservoir,** pp115. February 2011. E.ON UK plc. **KCP-RDS-CRE-REP-1002,** Rev.: **03.** Available from [at February 2016]: http://webarchive.nationalarchives.gov.uk/20121217150422/http://decc.gov.uk/assets/decc/11/ccs/chapter7/7.20-validation-assessment-of-reservoir.pdf

2.1.3 K12-B gas field, the Netherlands

The K12-B gas field is about 150 km [93 miles] northwest of Amsterdam in the Dutch sector of the North Sea. Since 2004, 0.09 Mt of CO_2 has been injected into a depleting gas field at 3,800 m [~12,467 ft] depth as part of a research project investigating both CO_2 storage and enhanced gas recovery (EGR).

K-12B site summary

Location: offshore Netherlands

Depleted: gas

Type: enhanced gas recovery (EGR)

Status: operational (0.09 Mt injected since 2004)

Economic viability: pilot scale, 1st ever CO_2-EGR test, research oriented

Geological setting: Heterogeneous Permian sandstone at ~3,800 m [~12,467 ft] depth, compartmentalised by faults with thick salt seal

Key findings from the site: (i.e. how it contributes to addressing scope, section 1.1)

- [ ] #1. Risk assessment criteria
- [ ] #1a. Implications for continued oil and gas production in adjacent fields
- [x] #2. Monitoring criteria (to quantify CO_2 storage and detect the extent of migration)
- [x] #2a. Implications e.g. the effects of residual hydrocarbon fluids
- [ ] #3. Pressures changes & thresholds and how these can be mitigated
- [ ] #4. Storage capacity estimate validation
- [x] #5. Long-term wellbore integrity assessment and remediation measures
- [ ] #6. Cost of modifications and storage development

Geology: The K-12B gas field reservoir is a Permian aged heterogeneous sand-shale sequence, compartmentalised into fault blocks (Figure 4). None of these faults penetrate to the top of the 500 m thick impermeable rock-salts of the Zechstein Group that form the top and lateral seal. The reservoir was deposited under mainly desert and desert lake conditions. High permeability (300 - 500 mD) aeolian sands make up about 11% of it. The remainder is lower permeability fluvial and mud flat facies (5 -30 mD), with 16% of the formation made up of shale streaks with a continuity of less than a few hundred metres which form vertical permeability barriers.

Reservoir conditions: Gas production started in 1987 and reduced reservoir pressures from 40 MPa [~5,802 psi] down to 4M Pa [~580 psi] by 2004, when CO_2 injection started. At that time the reservoir temperature was around 127 ºC [~261 ºF]. Essentially the fault compartments act as 'tanks' with no flow boundaries.

Injection strategy: Initial gas in place in 1987 was around 14.5 billion cubic metres (bcm) [~512 bcf] and as of January 2012, 13 bcm [~459 bcf] had been produced. The produced gas is relatively high in CO_2 (around 13%) and this is reduced to 2% on site in order to meet export pipeline specifications. In 2004, the extracted CO_2 started being re-injected into the field. Initially this was into compartment 4 (red in Figure 4a) for one year (over 10 000 tonnes), followed by a two-year shut-in period and gas production during 2007-2008. In 2005, CO_2 injection was switched to compartment 3 (yellow in Figure 4a) with around 70 000 tonnes injected by 2013 (Van der Meer, 2013; Vandeweijer, 2013). Injection was at a rate of up to 20 kilotonnes/year, with a number of shut-in periods for maintenance. At March 2015, 90 kt had been injected (www.k12-b.info)

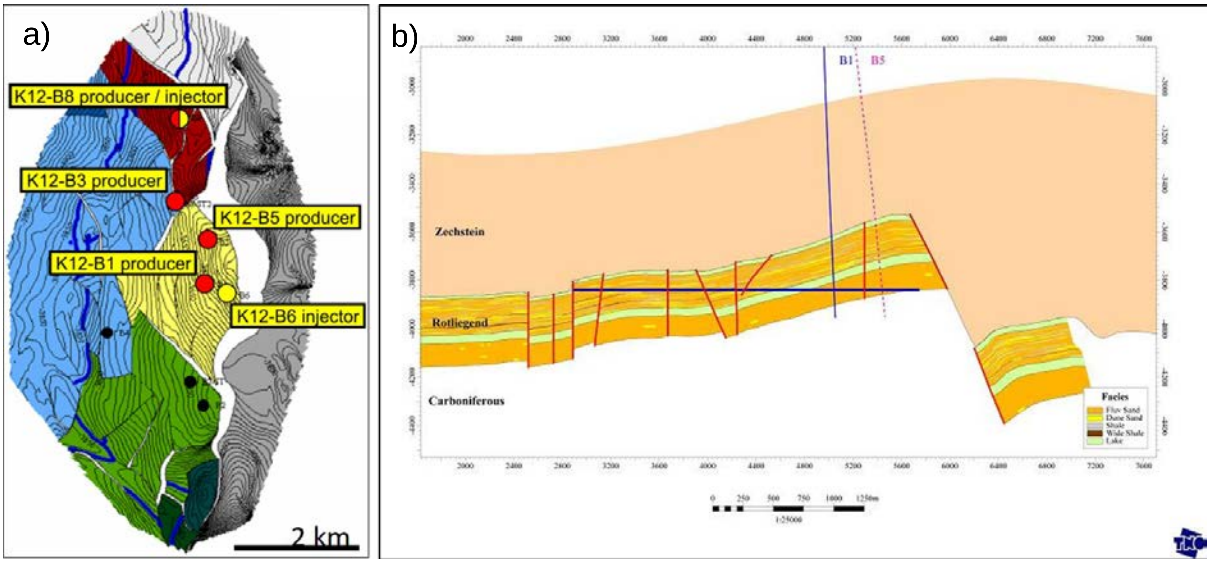

Figure 4 a) Plan view of top reservoir in the K12-B gas field. Structural compartments 1-4 are individually coloured. (Geel et al., 2005). **b) Cross section of the geological model through the K12-B gas reservoir** (Van der Meer et al., 2007).

Key findings from K12-B: (i.e. how it contributes to addressing section 1.1)

#2. Monitoring criteria (to quantify CO_2 storage and detect the extent of migration)

As the first enhanced gas recovery (EGR) storage site, monitoring to improve understanding of the behaviour of CO_2 in the wellbore and gas mixing in the reservoir was a priority. This was achieved mainly through a research programme injecting pulses of chemical tracers and analysis of produced gases, in combination with downhole pressure and temperature monitoring focussing on pressure rise and decay as CO_2 injection was switched on and off for history matching flow simulations (Van der Meer et al., 2013).

#2a. Requirements e.g. the effects of fluid replacement

The CO_2 injected is derived from the reservoir (it is produced and stripped out from the gas), so it is not isotopically distinct. Therefore, CO_2 flow behaviour and sweep efficiency was examined through analysis of produced fluid samples after injecting pulses of artificial tracers. Results were not conclusive but highlight the heterogeneous nature of the reservoir and the potential retardation of the CO_2 relative to the less water-soluble CH_4 and tracers (Van der Meer et al., 2013). In 2015 it was reported that a new innovative tracer injection programme was underway (www.k12-b.info).

#5. Long-term wellbore integrity assessment and remediation measures

The thick Zechstein evaporite at K12-B forms an excellent upper and lateral seal. The main risk of potential migration out of the site is therefore considered to be via wellbores, so multiple tools were used to assess any changes in integrity in the injection wells during the operation: Cement bond logging (CBL), imaging via downhole video, tubing and casing inner diameter using multi-fingered callipers and thicknesses using an electromagnetic tool (Vandeweijer, 2011). Numerical simulation of 'worst-case' cement degradation at the site were as much as 12.9 m over 10,000 years (Tambach et al., 2013). Numerical simulation was also used to explore novel approaches to long-term wellbore integrity: 1) intentionally clogging the wellbore completions with salt prior to abandonment by alternating brine and CO_2 injection (Wash et al., 2013) and 2) milling out a section of casing in the caprock evaporate sequence and exploiting the ductile nature of the salt caprock to creep into and naturally seal the wellbore. (Orlic & Benedictus, 2008). Shortest borehole closure rates were around 500 days (CO_2CARE, 2013).

K12-B key references

TNO, 2006. K12-B, CO_2 storage and enhanced gas recovery. Available from http://www.tno.nl/downloads/357beno1.pdf

Van der Meer, L.G.H., 2013, Chapter 13 - The K12-B CO_2 injection project in the Netherlands. In: Gluyas, J., and Mathias, S. (Eds): Geoscience of CO_2 storage: Geoscience, technologies, environmental aspects and legal frameworks. Woodhead Publishing Ltd. ISBN 978-0-85709-427-8, 68-96, p. 301–327.

2.1.4 P18-4 gas field, the Netherlands ('ROAD' project)

The ROAD[3] project aims to store CO_2 in the P18-4 depleted gas field reservoir, 20 km [~12 miles] NW of Rotterdam, in the Dutch sector of the North Sea. It is the first project to be permitted under the EU Directive (and also under the London Protocol and OSPAR Convention). In July 2013, the project was granted a permit to store up to 8.1 Mt of CO_2 at a maximum rate of 1.5 Mt/year starting in 2015 (latest January 2018), subject to conditions, which include updates to various plans and provisions. However, since mid-July 2014, the ROAD project is assumed to be "on hold" (MIT, 2016).

P18-4 (ROAD) site summary

Location: offshore Netherlands

Depleted: gas

Type: storage

Status: planned (start 2015-2018, "on hold"), 8.1 Mt at max 1.5 Mt/yr

Economic viability: industrial scale

Geological setting: Heterogeneous Triassic sandstone at ~3,500 m [~11,483 ft] with mudstone & evaporite seal

Key findings from the site: (i.e. how it contributes to addressing scope, section 1.1)

- [x] #1. Risk assessment criteria
- [ ] #1a. Implications for continued oil and gas production in adjacent fields
- [x] #2. Monitoring criteria (to quantify CO_2 storage and detect the extent of migration)
- [ ] #2a. Implications e.g. the effects of residual hydrocarbon fluids
- [x] #3. Pressures changes & thresholds and how these can be mitigated
- [ ] #4. Storage capacity estimate validation
- [x] #5. Long-term wellbore integrity assessment and remediation measures
- [x] #6. Cost of modifications and storage development

Geology: The P18-4 reservoir lies within Triassic sandstones of the Buntsandstein Subgroup (equivalent to the UK Bunter Sandstone Formation) at about 3500 m depth. The reservoir has heterogeneous porosities (5 - 13% porosity, <0.1 - 207 mD (mostly <1 mD)) and comprises ~200 m [656 ft] thick sands and clayey siltstones deposited in lacustrine, fluvial and aeolian settings. The primary seal is provided by ~ 200 m [656 ft] of siltstones, claystones, evaporites and dolostones. P18-4 is one of a number of neighbouring gas reservoirs which are bounded by a system of mainly NW-SE

[3] Rotterdam Opslag en Afvang Demonstratieproject

oriented faults. The structural compartments are hydraulically sealing on production timescales (Arts et al., 2012).

Reservoir conditions: Initial reservoir pressure, prior to gas production was 34.85 MPa [5,054 psi]. Gas production reduced this to 2 MPa [290 psi]. Reservoir temperature is 117°C [243°F]. The reservoir behaviour is assumed to be a closed system (‘tank-like’) from its production history (TAQA Offshore B.V., 2011).

Injection strategy: The P18-4 gas field is penetrated by a single well. Gas production started in 1993 and was projected to end no later than 31 December 2014. CO_2 injection was due to start between 2015 and 2018 (but note that the project is currently on hold). Maximum permitted injection rate is 47.56 kg CO_2 per second [equivalent to 1.5 Mt/yr] and the reservoir pressure may not exceed the initial pressure of 34.85 MPa [5,054 psi]. The expected operating pressure limit is 32 MPa [4,641 psi]. 8.1 Mt is the maximum that is permitted to be injected over 8 years. Closure is expected to take 1 year, with a 20-year period between closure and transfer to the competent authority (CA). For this project the operator is required to demonstrate financial security to cover a further 30 years post-transfer monitoring by the CA, to address the lack of practical experience with storing CO_2 in a depleted gas field in the Netherlands.

Key findings from P18-4 (ROAD): (i.e. how it contributes to addressing section 1.1)

[#1.] A risk management, monitoring, corrective measures and provisional closure plan was submitted in 2011. However, the storage permit granted on 13th July 2013 states that these document must be updated and resubmitted for approval no later than 6 months prior to the start of injection. The vast majority of documents relating to the site are in Dutch and so comments on all of the key findings are not included here.

[#2 & #5.] Monitoring criteria and wellbore integrity: The ROAD monitoring plan is largely risk-based with the monitoring of potential leakage via wellbores being the primary focus. Once injection starts these documents must be updated after 4 years and 9 months, and every 5 years thereafter. The key objectives are to ensure the safety and the integrity of the storage complex and to provide the necessary information to allow transfer of responsibility.

[#3.] Pressures changes & thresholds and how these can be mitigated: Following feedback from the European Commission review of the project, further study is underway to assess specific local pressure build-ups, pressure barriers and later-stage fault leakage (into the adjacent P15-9 reservoir). Results will be used to update the risk assessment which will feed into the updated monitoring plan to provide evidence for containment and to demonstrate integrity of seals, faults and wells.

[#6.] Cost information: Indicative cost information is provided in the 2011 storage proposal. This does not include capture costs or commercially sensitive information, so it is incomplete. For onshore transport and facilities (including the compressor and pipeline offshore), CAPEX is estimated at €100 million EUR [£78 m GBP], OPEX at €6.7m [£5 m GBP]. Storage CAPEX totals €65 million [£50 m GBP] although this includes a very large amount for rig mobilisation for workover and abandonment of wells in a neighbouring compartment, not only the single injection well for storage in P18 - 4 (Taqa Offshore BV, 2011). The storage permit itself lists financial securities required for the first 5 years of injection (Table 2). As a demonstration project, yearly payments to the state were waived (The Netherlands Minster for Economic Affairs, 2013).

Financial security required by the storage permit (2011 price index)		**EUR (€m)**	GBP (£m)
Monitoring during the injection and closure periods		10.0	7.8
Monitoring (by the operator) during the subsequent 20-year period		0.1	0.1
The safe abandonment of the injection well		5.5	4.3
The removal of the injection platform		7.0	5.5
Ensuring safe abandonment of the P15-9 wells (adjacent to the storage site)		10.0	7.8
Monitoring (by the competent authority) for a further 30 years post transfer.		2.0	1.6
CO_2 emission rights for years 1-5 of injection: in the event that CO_2 was unexpectedly released (calculated based on the total volume of CO_2 stored in one year and the volume of CO_2 that could escape uncontrolled through or near the well over a period of 3 months and including a 20% uncertainty factor)	Yr 1	65.9	51.3
	Yr 2	64.5	50.2
	Yr 3	64.4	50.1
	Yr 4	64.3	50.1
	Yr 5	52.1	40.6

Table 2 Financial securities required for the first 5 years of the ROAD project (as set out in the storage permit (The Netherlands Minster for Economic Affairs, 2013)).

ROAD key references

MIT, 2016. ROAD (Rotterdam Opslag en Afvang Demonstratieproject) Fact sheet: Carbon dioxide capture and storage project. Available from www.sequestration.mit.edu/tools/projects/maasvlkte.html (accessed 2.22.16).

Netherlands Minister of Economic Affairs [*Minister van Economische Zaken*] 2013. Permit for the storage of carbon dioxide in the P18-4 reservoir, filed by TAQA Offshore B.V. 19 July 2013. Available from *https://www.rvo.nl/sites/default/files/2015/06/B06%20Storage%20permit%20TAQA%20English.pdf*

TAQA Offshore B.V. 2011. Aanvulling op de Aanvraag CO_2 Opslagvergunning P18-4 (kenmerk ET/EM/10102902) - leeg geproduceerd gasvoorkomen. DM 40818 / 9W6722.40/R00001/ETH/Gron 30 juni 2011 (In Dutch). *Translation: Addendum to the Application CO_2 storage permit P18-4 (reference ET / EM / 10,102,902) - Empty produced gas presence.* Available from Netherlands Enterprise Agency (RVO.nl) http://www.rvo.nl/sites/default/files/sn_bijlagen/bep/70-Opslagprojecten/ROAD-project/Fase1/4_Aanvragen/A-06-2-Aanvulling-opslagvergunning-kl-354540.pdf

2.1.5 *Rousse gas field, France (Lacq-Rousse project)*

The Rousse gas field is the site of a completed CO_2 storage pilot. The reservoir is at a depth of 4,500 m [14,764 ft] and is located in the Lacq Basin, in Southwest France, 5 km [3.1 miles] south of Pau. More than 51,000 tonnes of CO_2 were injected between 2010 and 2013. The site permit allowed the injection of 90,000 tonnes of CO_2.

Rousse site summary

Location: onshore France

Depleted: gas

Type: storage

Status: completed. Stored >51,000 tonnes CO_2 between 2010 and 2013

Economic viability: industrial, research focused monitoring

Geological setting: Jurassic fractured dolomites and dolomite breccias at 4,500 m [14,764 ft] sealed by Cretaceous mudstones

Key findings from the site: (i.e. how it contributes to addressing scope, section 1.1)

- [x] #1. Risk assessment criteria
- [ ] #1a. Implications for continued oil and gas production in adjacent fields
- [x] #2. Monitoring criteria (to quantify CO_2 storage and detect the extent of migration)
- [ ] #2a. Implications e.g. the effects of residual hydrocarbon fluids
- [x] #3. Pressures changes & thresholds and how these can be mitigated
- [ ] #4. Storage capacity estimate validation
- [x] #5. Long-term wellbore integrity assessment and remediation measures
- [ ] #6. Cost of modifications and storage development

Geology: The Rousse field is an isolated faulted horst limited by ESE-WNW and NNW-SSE normal faults. The reservoirs are situated in the Jurassic Mano and Meillon Formations which comprise fractured dolomites and dolomite breccias. The 120 m thick Mano Formation is the target reservoir used for CO_2 storage. Average porosity was 3% with a very low average permeability of < 1 mD. However well tests estimate an effective permeability of 5 mD resulting from fractures in the reservoir. Cretaceous rocks are draped over the reservoir structure providing an effective top and lateral seal up to 2,500 m thick (Garcia, 2012).

Reservoir conditions: Pre-production pressures of 48.5 MPa [7034 psi] were reduced to an average downhole pressure of 3 MPa [435 psi] during gas production via 1 well. The initial gas in place contains a small amount of CO_2 (4.6%) and hydrogen sulphide (H_2S, 0.8%). The average downhole temperature was 150°C [302°F] (Garcia, 2012).

Injection strategy: Injection was in two phases via a single well (the worked over, 43 year old former production well). Phase 1 injection took place over 110 days followed by four months of stand-by time, phase 2 was the main injection phase over a two year period where CO_2 was injected at an average rate of 90 t/d (~0.033 Mt/yr) for 360 days and at an average rate of 65 t/d (~0.024 Mt/yr) for 110 days. The injected gas was 90-93% CO_2 and 5-7% oxygen.

Key findings from Rousse: (i.e. how it contributes to addressing section 1.1)

#1. Risk assessment criteria

A hazards and risk analysis was carried out using two main steps: 1) the identification of hazards and 2) the evaluation of risks (of the identified hazards). This process describes the environment that should be protected, identifies and characterises hazards and evaluates the potential to reduce the risks of those hazards. Impact on neighbouring fields [#1a.] is not considered to be a risk because the Rousse field is not in hydraulic connection with the neighbouring St Faust Field to the north. This was confirmed through analysis of the gas compositions (CO_2 and sulphur contents differ) in addition to pressure data.

#2. Monitoring criteria (to quantify CO_2 storage and detect the extent of migration)

Downhole pressure and temperature sensors and microseismic were the primary containment and conformance monitoring deployed. In addition, analysis of the CO_2 stream composition and flow, CO_2 atmospheric concentration at the Rousse well pad, well annulus pressure, soil gas, surface- and groundwater, fauna and flora monitoring were also deployed.

#3. Pressures changes & thresholds and how these can be mitigated

The microseismic arrays and pressure and temperature sensors were used to ensure that the integrity of the reservoir and cap rock was suitably monitored. Three small events near the injection well within the reservoir were observed but did not cause any mechanical movement and the monitoring results, supported by the geomechanical studies, indicated that the caprock integrity was maintained. Modelled pressure during production was compared to modelled pressure during injection to ensure that the field was not overpressured.

#5. Long-term wellbore integrity assessment and remediation measures

Mechanical and chemical integrity of the cement casing were investigated via laboratory experiments. Injection well cement bond logs were also examined (the original from 1967 and a 2009 repeat) to characterise risks related to loss of hydraulic isolation in the injection well. Numerical simulations of thermo-mechanical effects induced by injecting CO_2, or stress variations resulting from an earthquake in the vicinity of the well were also run. All results suggested that well integrity risks were negligible for the single well penetration into the field for the storage of the ~50 kt CO_2.

Rousse key references

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Garcia, B., Billiot, J.H., Rouchon, V., Mouronval, G., Lescanne, M., Lachet, V. and Aimard, N. 2012. A geochemical approach for monitoring a CO_2 pilot site: Rousse, France. A major gases, CO_2-carbon isotopes and noble gases combined approach. *Oil & Gas Science and Technology – Rev. IFP Energies nouvelles,* Vol. 67 (2012), No. 2, pp. 341-353. DOI: 10.2516/ogst/2011154

2.2 USA sites

More than four decades of using CO_2 for enhanced oil recovery (CO_2-EOR) in the USA has had significant impact on thought processes regarding the potential evolution of CO_2 storage and also on the actual pathways to development taken by projects. The success of CO_2-EOR as a tertiary recovery method has led to fields that are depleted under primary and secondary recovery methods being automatically considered as candidates for it when they are considered as candidate for CO_2 storage. Equivalent depleted fields elsewhere on the other hand (i.e. non-North American) would perhaps be considered for pure storage rather than CO_2-EOR. The sites selected for this study, Cranfield (section 2.2.3) and SACROC (section 2.2.4), are both CO_2-EOR sites and Figure 5 shows their location relative to other sites considered as candidates for, or with potential for CO_2-EOR in their neighbouring states in the southern USA. A brief introduction to the regulatory context is provided in section 2.2.1 and how this pertains to using CO_2-EOR as storage is explained in section 2.2.2. In the USA, regional carbon sequestration partnerships were set up to help develop large scale storage and the research results reported here were largely enabled through those. Cranfield lies within the 'south-east' region, known as SECARB and SACROC lies within the south west region, known as SWP.

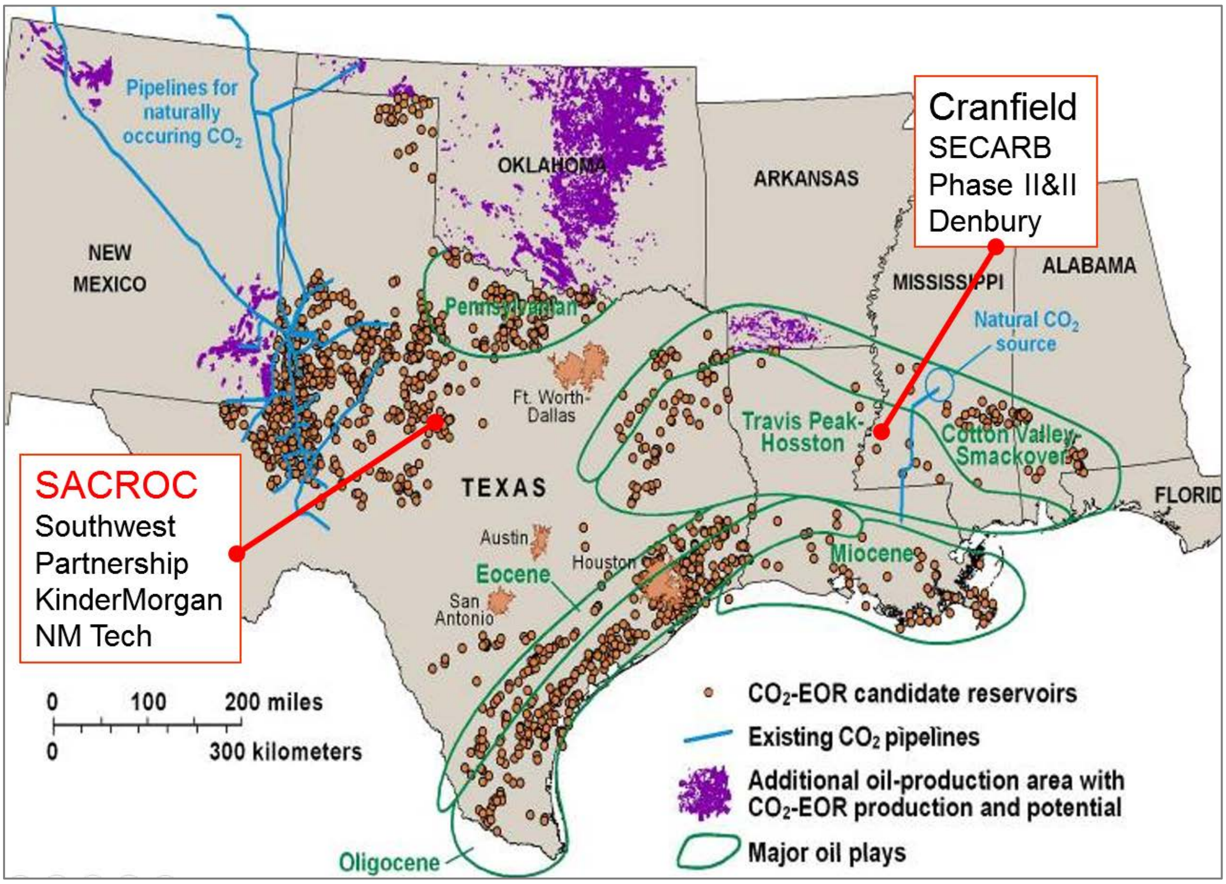


Figure 5 Map showing the relative locations of Cranfield and SACROC (Map credits: GCCC, NETL).

2.2.1 USA regulatory context

The evolution towards CO_2-EOR sites being considered as storage sites.

During the 2000-2010 period of development of the USA CCS program, Federal government (the Department of Energy, DOE) had a strong focus on the use of depleted oil and gas fields for storage-only. However in the last few years DOE and the Environmental Protection Agency (EPA) have had an increasing inclusion of CO_2-EOR as part of a storage plan. This is aligned with the approach of a number of other countries (notably China) and also industry expectations. Industries with CO_2 emissions and depleted oilfield operators are now looking at this linkage with increased interest. Our reporting of the case studies and subsequent discussion reflect this policy change.

However, currently some issues complicate the consideration of storage in CO_2-EOR sites in the USA. These are more thoroughly discussed elsewhere (e.g. IEAGHG, 2014) but to summarise the main issues:

1) The subsurface ownership in the USA has been distributed in a complex way over time. The subsurface is owned by the surface owner (not by the public as in some jurisdictions) however the rights to extract minerals (including hydrocarbons) in many places have been sold (severed) www.rrc.state.tx.us/about-us/resource-center/faqs/oil-gas-exploration-and-surface-ownership/. Further legal agreements have subsequently been transacted between mineral owners, surface owners, operators, and investors. Adding storage to these complex and long-lived legal arrangements may be problematic, as the "right" is not specifically granted and might be challenged by any party.
2) The laws that regulate injection and greenhouse gas in the US are historically fragmented. The motivating driver for CCS comes from the Clean Air Act[4] (CAA), but the permission for injection is under the Safe Drinking Water Act[5] (SDWA). Storage and CO_2-EOR are subject to different parts of the 2 Acts and further complications may arise from potential spatial overlap in the Acts' jurisdictions.
    - The SDWA's Underground Injection Control (UIC) programme adopted existing rules for managing injection that produces oil (known as 'class II' wells, i.e. applies to CO_2-EOR wells) and in 2011 developed new rules for injection of CO_2 for storage ('class VI' wells, i.e. for pure storage projects).
    - The CAA regulates emissions under the Greenhouse Gas Reporting Program (GHGRP) and this provides a framework for reporting CO_2 delivery and monitoring CO_2 injection for geologic storage. The GHGRP's Subpart UU requires CO_2-EOR operators to report the volume of CO_2 delivery and injection. The more stringent Subpart RR applies to CO_2 injected for geologic storage.

[4]U.S.A. 40 CFR, 2010a, Clean Air Act (CAA).
[5]U.S.A. 40 CFR, 2010b, Safe Drinking Water Act (SDWA).

To date [February 2016] no depleted field 'pure' storage sites in depleted fields have tested these regulations and only one saline aquifer site has been permitted as a class VI injection well. Table 3 summarises some recent North American projects that highlight the development of the shift in storage objectives towards storage for greenhouse gas (GHG) emission reduction purposes.

Site closure requirements are also different. CO_2-EOR sites are permitted under the same terms as hydrocarbon sites. This means that the operator's responsibility ends when the hydrocarbon operation ends and the wells are plugged and abandoned. No post-injection period of monitoring or modeling of stabilization is required at current CO_2-EOR sites, like there is for pure storage, although no large EOR operations have been conducted to completion yet. The operator retains liability for well failures as the "responsible party".

2.2.2 Background to EOR, site selection and motivations for retaining CO_2

What is EOR?

During primary recovery, oil and water flow, or are pumped to the surface. However, for many fields this must be augmented after a few years to maintain reservoir pressures by injection or reinjection of fluids that are native to the reservoir (brine or methane gas); this is known as secondary recovery. As secondary processes reach the end of the period in which they are effective, tertiary recovery (enhanced oil recovery, EOR) techniques may be of value in continuing production. EOR generally involves adding allochthonous constituents to oil field fluids in order to modify fluid properties such that oil that is immobile under primary and secondary process will be mobilized (Lake, 1989). Various additives and processes can be used for EOR such as surfactants, other chemicals, or steam. Dense phase (liquid and supercritical) CO_2 is the additive relevant to this paper; this subset is referred to as CO_2-EOR. The interaction of the CO_2 with the oil remaining in the reservoir is complex, but in general the mixture of CO_2 with oil phases causes increase in volume and decrease in viscosity, allowing oil formerly trapped in the pore spaces to be drawn to the producing wells (NETL, 2010). At an EOR site, injection wells are typically surrounded by production wells.

Selecting suitable fields for CO_2-EOR

Not all depleted fields are economically viable candidates for CO_2-EOR. A detailed study of the amount and value of the oil predicted to be recovered, the amount of CO_2 needed, and the cost of associated infrastructure development and modifications in terms of both capital and operational expenses is required. Consideration of other business variables such as the availability of sufficiently large amounts of CO_2 over the project duration, availability of capital for the large investment needed and the unitization of the field to a single operating unit so that the area can be effectivity flooded with CO_2 are needed as well. Even though the development of CO_2-EOR projects is technically and financially challenging, they have gradually increased since the initial project in 1972, so that currently 111 projects are conducted and 65 million tons per year of high purity CO_2 are shipped via pipeline for EOR in the USA (Melzer, 2012).

Traditional sources of CO_2 for EOR

CO_2-EOR in the past has been motivated by the value of CO_2 in mobilizing oil, and in this context CO_2 is a purchased commodity like any other additive. In North America the sources of CO_2 for EOR include:

- Production from nearly pure reservoirs of CO_2 in geologic traps (known as natural CO_2)
- CO_2 that is an impurity in produced methane that is stripped out at gas processing plants
- CO_2 produced as a bi-product from various industrial activities such as ethanol production or reformation of methane to hydrogen at a refinery.

(Note that the rise of the use of captured CO_2 sources for GHG emission reduction purposes is discussed at the end of this section and in Table 3).

Effectiveness of CO_2-EOR at retaining CO_2

This can be considered in 2 parts, the effectiveness of the CO_2-EOR at retaining CO_2 in isolation from the atmosphere in 1) the subsurface and 2) during surface processes.

1) *Subsurface retention* is required under oil and gas laws, which do not allow an operator to leak fluids into groundwater or damage other subsurface resources such as adjacent hydrocarbon operations. In effect, this triggers essentially all of the operations conducted for a CO_2 storage operation; including demonstrating that wells (new, existing, and P&A wells) are constructed and maintained to isolate fluids injected (water and gas) into the injection zone; pressure is managed to remain below regulated maximum allowable surface injection pressure (MASIP) such that reservoir, seals, and well construction integrity is preserved; the area occupied by CO_2 and elevated pressure is limited so that it does not encounter unprepared transmissive pathways such as flawed wells. A number of studies have been undertaken at various CO_2-EOR sites and to date have been unable to identify a leakage signal from the reservoir to the surface. A multi-year data-dense study of groundwater in aquifers over SACROC show that no CO_2 leakage could be detected in the overlying freshwater aquifers after 38 years of large volume commercial CO_2-EOR (section 5.1.1). Soil gas surveys were conducted for a sustained period of the commercial CO_2-EOR operation at the Weyburn field (Beaubien et al., 2004, 2013; Jones and Beaubien, 2005; Romanak et al., 2014) and over 8 years at the commercial CO_2-EOR site at Cranfield Mississippi (section 4.2.3).

2) *Surface retention* however encapsulates an element of operator choice[6] in the retention of CO_2 received from offsite, as venting of pure CO_2 is not restricted[7]. However, the cost of purchasing the CO_2 and its value in recycling where it can be used to produce more oil is a motivator for operators to conserve it and avoid losses. In addition, surface equipment in a conventional CO_2 operation will be operated to prevent losses of gasses to avoid emissions of any restricted oil-production related constituents such as benzene or H_2S. Audits of the effectiveness of retention of CO_2 by EOR operators have not been publically reported, but most normal CO_2-EOR floods have a good record of retaining CO_2 in the reservoir and recycling system, with only minor losses to atmosphere during “upsets” when equipment malfunctions require repair. For example, for the SACROC CO_2 flood, which during its 4 decades of operation has had no GHG motivation, reports CO_2 release to atmosphere as 0.5% of the CO_2 handled per year (Fox, 2013). In a GHG context, industrial audits can be conducted to add certainty to these estimates of releases from surface infrastructure.

Considering effectiveness of retention in terms of carbon lifecycle balances

The effectiveness of CO_2-EOR at retaining CO_2 in isolation from the atmosphere can also be assessed by examining the impact of the various surface activities on the carbon lifecycle and of the entire process lifecycle (including produced hydrocarbons) on carbon balance.

Significant energy is consumed for these operations[8] (Jaramillo et al., 2009). The amount of energy depends on the parameters of operation, for example, the ratio of injected water to CO_2 injected, and needs further study. However, variations in these operations are common to all oil production and all types of EOR including those that use no CO_2, so an argument can be made that the carbon footprint of surface CO_2-EOR operations should be considered part of the carbon cost of oil. Likewise various carbon emissions (refining, combustion) of the oil product must be considered in a total carbon balance but may be handed in the same way as they are for other fuels, and need not be specially credited against the storage value of CO_2 used for EOR. Examination of the role of EOR in carbon lifecycle has been debated in various ways that demonstrate the conceptualization of the elements to be put into the accounting

[6] At Weyburn-Midale CO_2-EOR operation in Canada, the CO_2 contains mercaptans as impurities which give the gas a distinctive odour. At the start of injection, residents in the area complained about the odour; in response the operator repaired small leaks in piping and the release was reduced to undetectable. (Gale and Davison, 2004).

[7] An example where an operator chose to deliberately vent CO_2 is recounted by Reid Grieg, about Chaparral's operation of the Farnsworth Unit, Anadarko Basin Texas. In an early stage the operator chose to delay start-up of an additional compression equipment, and significant amounts of produced CO_2 was vented on purpose after separation from oil.

[8] Energy is needed to lift (pump) fluids, input pressure and heat to separate CO_2, oil, and brine; pumping to reinject brine; compression of CO_2 from atmospheric pressure to dense phase suitable or injection; and handling and cleaning of oil for market. In some operations gas is further cleaned to extract condensate.

are critical in assessing the carbon balance of a CO_2-EOR project (Jaramillo et all, 2009; Nunez, 2015).

Linking CO_2-EOR to GHG emission reduction

Because CO_2-EOR provides a commercial offtake, paying the capture facility operators for the CO_2, the idea of linking sales of CO_2 to EOR operations for the purpose of decreasing GHG emissions has risen in the US and globally. The practice is still in the early phases and each project has been unique. Table 3 provides some examples of linked GHG and commercial CO_2-EOR projects. The nature of the link varies from opportunistic to an essential part of the business model.

Globally, many oilfields are in stages of depletion. Reconnaissance evaluation show that CO_2-EOR would allow significant amounts of additional oil production in many of these fields (Wallace & Kuuskraa, 2014). Increased CO_2 capture for GHG emission reduction would provide large and sustained CO_2 sources that could be used for CO_2-EOR assuming issues such as source-sink matching, stability of supply and cost could be managed. These issues have been addressed in a number of papers (Nunez et al. 2008; Kuuskraa et al., 2011).

Project name	Location	Time	Core Business	GHG reduction link
Weyburn –Midale	Saskatchewan, Canada	2000- present	Commercial CO_2-EOR from depleted oil field	IEAGHG research-oriented monitoring program added to commercial CO_2-EOR. Although Dakota gasifier captures anthropogenic CO_2 from coal, at the time of the project there was no GHG reduction requirement in either the US or Canada
West Pearl Queen study	New Mexico USA	12/20, 2002-2/11, 2003	Depleted oil field	Early monitored small scale “huff-n-puff” CO_2-EOR test with 2,090 tons of CO_2 injected
Pembina-Cardium	Alberta Canada	2005 to 2007	Commercial CO_2-EOR at depleted oil field	Research-oriented monitoring
SECARB Early test	Cranfield Field Mississippi USA	2008-present	Commercial CO_2-EOR at depleted oil field	Research-oriented monitoring
Air Products	Port Arthur, TX	2013-present	Commercial CO_2-EOR at Hastings field with CO_2 captured from Air Products’ hydrogen plant.	Monitoring commercial CO_2-EOR to meet DOE requirement. Private commercial EOR incentivised by DOE funding.
SaskPower Boundary Dam CCS project	Estevan, Saskatchewan	2014-present	Electricity production from coal with post combustion capture CO_2 sold for commercial EOR (as well as some for saline injection for research at Aquistore)	Move toward meeting Canada’s emission standards for coal fired power plants.
Mississippi Power Plant Radcliff	Kemper County, Mississippi	2016, expected	Electricity production from coal with Integrated Gasification Combined Cycle (IGCC) Capture with commercial CO_2 sales for EOR	Supported by US DOE GHG reduction via Clean Coal Power program
NRG PetraNova project	Capture at W.A Parrish Plant, Sugerland, TX	2016, expected	Electricity production from coal with post combustion capture with CO_2 sales for EOR to West Ranch field	Supported by US DOE GHG reduction Clean Coal Power program.
Summit Energy Texas Clean Energy project	Pennwell, Texas	Groundbreaking in 2016	Planned power/poly-gen IGCC project using CO_2 sales for EOR	Supported by US DOE GHG reduction Clean Coal Power program.

Table 3 Examples of projects linking CO_2-EOR and GHG emissions reduction objectives

2.2.3 *Cranfield oil and gas field, USA*

The Cranfield field is located ~20 km [~12 miles] east of Natchez in Adams and Franklin County, southwest Mississippi, USA (Figure 6). The oil field, at depths of ~3,000 m [~9,843 ft], was discovered in 1943 and produced to depletion in 1966. Strong natural water drive returned the reservoir to hydrostatic pressure prior to the start of CO_2-EOR in July 2008. CO_2 is injected into the Upper Cretaceous lower Tuscaloosa formation. Approximately 8 Mt of CO_2 has been injected and ~5 Mt stored since 2007.

Cranfield site summary

Location: onshore Mississippi, USA

Depleted: oil with a gas cap

Type: CO_2-EOR and also CO_2 injection into the water leg for research. CO_2 derived from a natural CO_2 reservoir.

Status: operational (~8 Mt injected and ~5 Mt stored since 2008)

Economic viability: industrial CO_2-EOR with DOE funding for research

Geological setting: heterogeneous fluvial sandstones at ~3,000 m [~9,843 ft] depth with marine mudstone caprock

Key findings from the site: (i.e. how it contributes to addressing scope, section 1.1)

- [x] #1. Risk assessment criteria
- [ ] #1a. Implications for continued oil and gas production in adjacent fields
- [x] #2. Monitoring criteria (to quantify CO_2 storage and detect the extent of migration)
- [x] #2a. Implications e.g. the effects of residual hydrocarbon fluids
- [x] #3. Pressures changes & thresholds and how these can be mitigated
- [x] #4. Storage capacity estimate validation
- [x] #5. Long-term wellbore integrity assessment and remediation measures
- [ ] #6. Cost of modifications and storage development

Geology: The reservoir sandstone lies within a salt-cored, simple domal structure. It comprises the so called "D-E" Sand Units of the Upper Cretaceous lower Tuscaloosa formation, a 15 to 25 m [~50 to 82 ft] thick package of porous and permeable fluvial sandstones and conglomerates over 3,000 m [~9,843 ft] deep. The reservoir is composed of crossbedded chert conglomerates, litharenite sandstones, and muddy sandstones deposited during multiple episodes of channel incision and deposition, forming an overall fining upward succession. 3-D seismic data show high-frequency lateral heterogeneity associated with incised channels, stacked point-bars, and lateral changes of facies in a fluvial system (Figure 7).

Reservoir conditions and production history: Reservoir temperature is approximately 125 °C [257 °F] and the initial pre-production reservoir pressure was approximately 32 MPa [4,641 psi]. From 1944 to 1966 the reservoir produced oil, gas condensate, and methane gas. The field was pressure depleted and water injection was tested briefly on the west side of the field in 1958–59 but was unsuccessful. Wells were plugged and abandoned in 1965-1966. (Mississippi Oil and Gas Board, 1966; Mancini and Puckett, 2005). During the prolonged idle period from 1966 to the start of CO_2 injection (in 2008), the reservoir pressure recovered to near initial pressure as a result of strong natural water drive.

Injection strategy: Since 2008 the reservoir has been under CO_2-flooding for EOR and CO_2 is injected continuously rather than using the water-alternating gas (WAG) approach. Production did not re-start until reservoir pressures had been raised by 6.9 MPa [1000 psi] (Hossieni et al., 2013) to 34 MPa [4,931 psi], i.e. above initial pressures and in this respect the pressure profile for this part of the field history would be similar to that at a saline aquifer. CO_2 injection started in the north part of the field and expanded to the southeast around the oil rim of the field, with injection wells placed at the oil-water and gas oil contacts in irregular five spot patterns. CO_2 is transported via a 160 km [~100 mile] pipeline from Jackson Dome CO_2 field in Mississippi (Hovorka et al., 2013). For research purposes, injection at a high rate into the water leg through a purpose drilled injector was initiated in 2009, monitored by two close-by monitoring wells. A rate of 1 million metric tonnes/year was attained in April 2010 and injection has continued essentially uninterrupted (Hovorka et al., 2013).

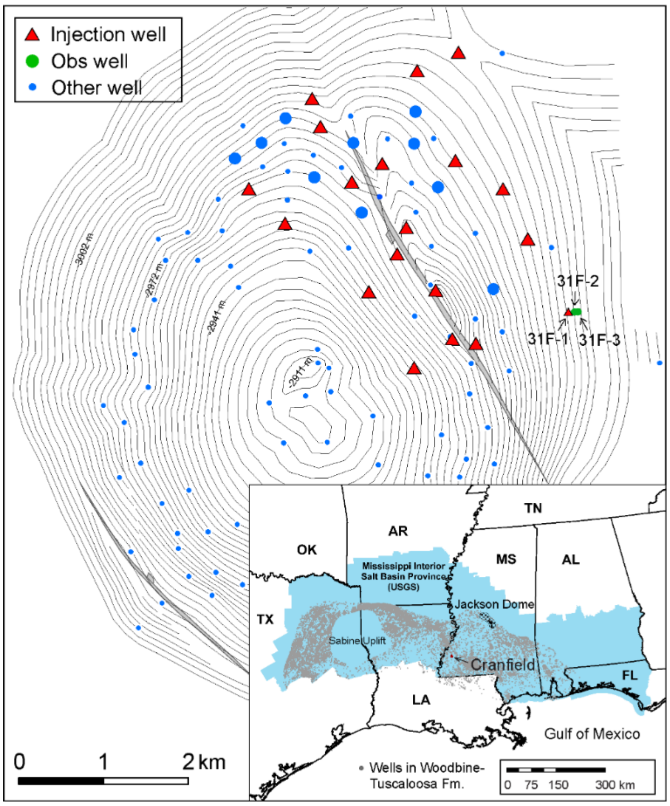


Figure 6 Location map of Cranfield showing top of reservoir (Lu et al. 2012).

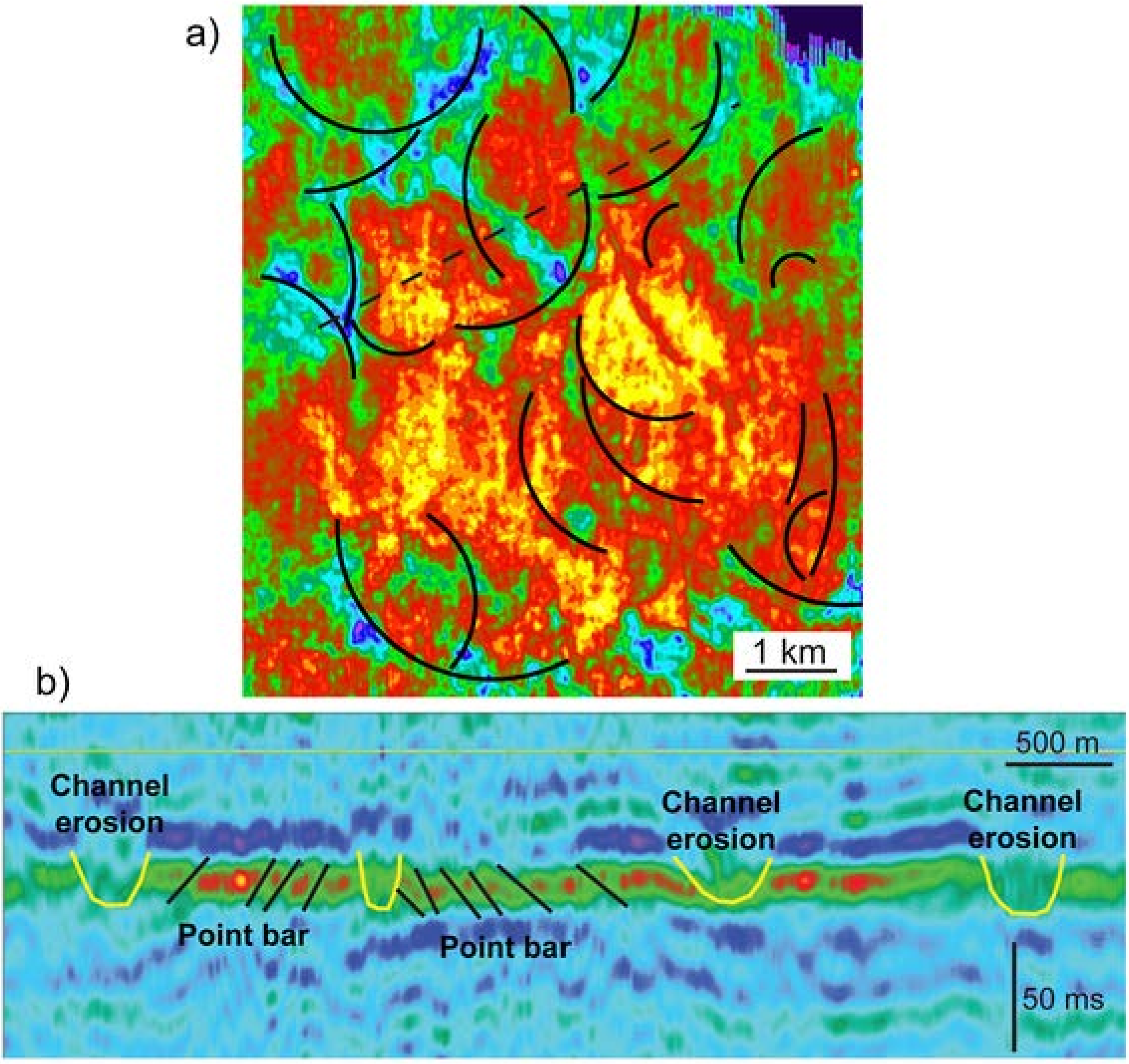


Figure 7 3D seismic data showing heterogeneity of the low Tuscaloosa formation at Cranfield. (a) Stratal slice of the 3-D seismic survey, with interpreted outlines of stacked fluvial point bars (black curves) in the lower Tuscaloosa Formation "D-E" interval showing high-amplitude (red) sinuous fluvial geometry. (b) Interpreted channel morphologies in seismic profile, showing general reservoir architecture of a fluvial point-bar plain. Sandstones (red) appear to be discontinuous laterally, suggesting sinuous deposition in 3D. Location of cross section (b) marked by dash line in (a). From Lu et al. (2012a).

Key findings from Cranfield: (i.e. how it contributes to addressing section 1.1)

Note: these findings are described in more detail in Chapter 4.

#1. Risk assessment criteria

Risk assessment was conducted using the Certification Framework (CF) method which conceptualizes a system as source, flow conduits (wells and faults), and compartments. Risks to the compartments (e.g. hydrocarbon resources, freshwater aquifer, atmosphere, etc.) from leakage through the conduits then can be identified and evaluated. At Cranfield, CO_2 leakage risk is low and brine leakage risk is even lower. Leakage risk through the fault and a nearby spill point is low. Well penetrations of the confining system are found to be the top-ranked leakage risk.

#2. Monitoring criteria (to quantify CO_2 storage and detect the extent of migration)

The SECARB early test monitoring program was designed to test monitoring approaches to increase confidence that CO_2 is being stored with high levels of retention and to improve capacity estimation by assessing how CO_2 migrates in the reservoir. Monitoring to assess storage permanence was undertaken in four zones: injection zone (IZ), above-zone monitoring interval (AZMI), the shallowest of the fresh water zones, and soil–gas stations near wells. The field studies conducted focused on testing and evaluating various technologies. The project produced series of analyses and publications on monitoring technologies.

#2a. Requirements e.g. the effects of hydrocarbon displacement

The complex production history at Cranfield has resulted in an uneven distribution of fluids within the system. Attempts at mapping the CO_2 extent using surface seismic and comparing this to the modelled plume showed only partial matches. Research is ongoing in this area. Attempts to define plume extents using downhole saturation methods including fluid sampling and pulsed neutron capture also highlighted the difficulties in matching saturation predictions to observed results. These mixed successes are largely the result of a combination of the heterogeneous nature of the reservoir and also partly the non-consistent methane content of the injected CO_2. The injected CO_2 contains increasing amounts of methane as time goes by, because it includes recycled gas (which contains CH_4 because only the oil is extracted from the CO_2 prior to reinjection).

#3. Pressures changes & thresholds and how these can be mitigated

Injection zone pressure was recorded using multiple downhole and wellhead gauges. The pressure data are used for calibration and verification of reservoir models (Nicot et al., 2009; Hosseini et al., 2013). However, the boundary conditions of the models create a major source of uncertainty that could potentially mask a leakage signal. Modeling calibrated with pressure data is an effective tool to make predictions, but a good match with measurements does not necessarily indicate a retention, nor does a mismatch suggest leakages. Hydrologic pump tests may be one way to address the uncertainty in boundary conditions.

#4. Storage capacity estimate validation

The overall hydrocarbon volume in place is well constrained from the historic production data (Mississippi Oil and Gas Board, 1966). However, using the total volume of produced fluids for storage capacity estimation probably leads to an overestimation, because hydrocarbons were accumulated over geologic time while injection of CO_2 is rapid process. Heterogeneity in the reservoir geology results in focused CO_2 flow and low sweep efficiency. Numerical modeling was performed to predict storage capacity. The models were calibrated to a large number of field measurements. Several downhole monitoring techniques were deployed to assess sweep efficiency at a Detailed Study Area, including pulsed neutron capture (PNC, to measure reservoir saturation), cross-well electrical resistivity tomography (ERT), time lapse resistivity logging, cross-well continuous active seismic source monitoring (CASSM), distributed temperature sensor (DTS), and U-tube sampling with tracer tests, etc.

#5. Long-term wellbore integrity assessment and remediation measures

There are over 200 existing production wells completed in different reservoirs prior to the CO_2-EOR operation at Cranfield field. Relying heavily on interpretation of Cement Bond Logs (CBL), the potential of CO_2 leakage through wellbores was estimated for 17 plugged and abandoned wells, 10 of which had been re-entered, recompleted, and retrofitted as production wells to reduce the cost compared to drilling new wells. High leakage potential exists for two wells with poorer-quality cements. Simulations estimated that the leakage rate through these wells could be up to 1.8 t/yr. However, two overlying sandstone formations (upper Tuscaloosa formation and the underpressured Wilcox group) form effective pressure sinks to trap leaked CO_2. However, it is possible that the hydraulic isolation may not be as poor as the CBL indicates: a re-entered 1954 production well was found to be effectively sealed behind the casing despite the new CBL having suggested questionable cement above the injection zone.

Cranfield key references

Hosseini, S. A., Lashgari, H., Choi, Jong-Won, Nicot, J.-P., Lu, Jiemin, and Hovorka, S. D., 2013, Static and dynamic reservoir modelling for geological CO_2 sequestration at Cranfield, Mississippi, U.S.A.: International Journal of Greenhouse Gas Control, v. 18, p. 449-462.

Hovorka, S. D., Meckel, Timothy, and Treviño, R. H., 2013, Monitoring a large-volume injection at Cranfield, Mississippi-Project design and recommendations: International Journal of Greenhouse Gas Control, v. 18, p. 345-360.

2.2.4 SACROC oil field, USA

The Scurry Area Canyon Reef Operators Committee (SACROC) Unit is a major portion of the Kelly-Snyder oil field located in the Midland basin, the easternmost of the Permian Basins in west Texas, USA (Figure 8a). The field, at ~2,040 m [~6,693 ft] depth, was discovered in 1948 and water flooding operations began in 1954. CO_2 flooding began in 1972, making it one of the oldest continuous CO_2-EOR sites in the world. By 2013, about 255 Mt [4.92 Tcf] of CO_2 were injected (the most CO_2 injected into a site worldwide to date) and about 155 Mt [2.99 Tcf] were recovered, which gives 100 Mt [1.93 Tcf] stored CO_2 (Kinder Morgan, 2013).

SACROC site summary

Location: onshore Texas, USA

Depleted: oil

Type: CO_2-EOR with CO_2 supply from natural CO_2 reservoir and gas treatment plants

Status: operational, **~**255 Mt injected and **~**100 Mt stored from 1972 to 2013

Economic viability: industrial EOR with U.S. DOE subsidized research

Geological setting: Pennsylvanian-Permian platform and slope carbonates at ~2,040 m [~6,693 ft] depth with mudstone/evaporite caprock.

Key findings from the site: (i.e. how it contributes to addressing scope, section 1.1)

- [ ] #1. Risk assessment criteria
- [ ] #1a. Implications for continued oil and gas production in adjacent fields
- [x] #2. Monitoring criteria (to quantify CO_2 storage and detect the extent of migration)
- [ ] #2a. Implications e.g. the effects of residual hydrocarbon fluids
- [x] #3. Pressures changes & thresholds and how these can be mitigated
- [x] #4. Storage capacity estimate validation
- [x] #5. Long-term wellbore integrity assessment and remediation measures
- [ ] #6. Cost of modifications and storage development

Geology: The SACROC unit, at around 202 km^2 [~80 square miles], is the largest of the many prolific, Late Pennsylvanian age carbonate buildups that comprise the Horseshoe Atoll (Figure 8b). The reservoir is composed of thick sections of bioclastic limestone and thin shale beds representing the Strawn, Canyon, and Cisco Groups (Vest, 1970; Raines et al, 2001) (Figure 9). The lower Permian Wolfcamp Shale Formation forms a caprock. The reservoir is located at about 2100 m depth and its thickness varies from ~230 m on the crest to ~30 m on the flanks [756 – 98 ft] (Brummett et al., 1976). Permeability of the producing zones ranges from 10 to 100 mD with a porosity near 10%, while the non-producing zones have lower permeabilities of <0.1 mD and porosities <2% (Raines and Helms, 2005). Lateral and vertical heterogeneity associated with the presence of karsting, detrital flows, vuggy porosity, and micro-fractures was caused by alternating growth of the reef and sudden exposure due to the extreme sea level fluctuations (Brnak et al., 2006). Fractures and karsts are important locally and can dominate fluid flow (Larkin, 2008).

Reservoir conditions and production history: When the field was discovered in 1948, oil was produced by solution gas drive resulting in a large pressure decrease from the original reservoir pressure of 21.5 MPa to 10.7 MPa [3,118 to 1,552 psi] by 1953 (Dicharry et al., 1973; Brummett et al., 1976). Only 4.5% of the original oil in place (OOIP) had been produced with a 50% drop of reservoir pressure. To improve recovery, the field was unitized to initiate pressure maintenance and water flooding started in 1954 through a centre-line of 53 wells along the crest of the reef (Langston et al., 1988). When water-alternating-gas (WAG) flooding started in 1972, the majority of the injection patterns were below 11.0 MPa [1,595 psi], so a pre-CO_2 water slug was injected to lift reservoir pressure above minimum miscibility pressure (15.9 MPa, [2,306 psi]). By 1974, average pressure increased above 16.5 MPa [2,393 psi] (Langston et al., 1988). The reservoir has a temperature of 54°C [~130°F].

Injection strategy: In 1972, WAG flooding for three consecutive phases (central, north, and south) began with CO_2 supply from the Ellenburger natural gas processing plants in the Val Verde basin, about 354 km [~220 miles] south of the SACROC Unit (Figure 8a). With the small CO_2 supply, the response in oil production was limited. All water produced (exceeding 1 Ml/d [1MMbbl/d] in 1984) was reinjected. In 1996, the CO_2 source was switched to McElmo Dome, a natural CO_2 reservoir in Colorado because of the inconsistent CO_2 supply from the gas power plants (Weeter and Halstead, 1982). With the new CO_2 supply, the operators started using large CO_2 slugs and high CO_2/water WAG ratios. By 2013, 100 Mt of CO_2 had been stored (Kinder Morgan, 2013). The field contains more than 1,700 wells with at least 400 active producers and 240 active injectors (Han et al., 2005) (Figure 8c).

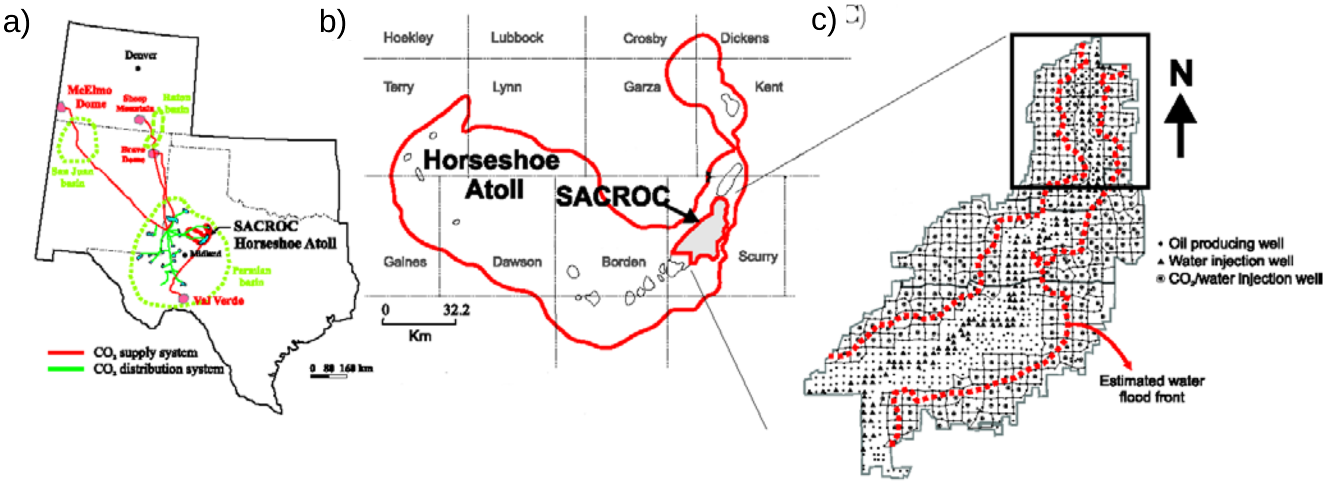


Figure 8 Map showing location of the SACROC unit. a) SACROC Unit at the Horseshoe Atoll in Midland Basin in west Texas and CO_2 pipelines from natural CO_2 reservoirs; b) Map of the SACROC unit within the Horseshoe Atoll; c) Well locations of SACROC unit with the estimated water-flooding fronts at the end of water-flooding period in 1973. From Han et al. (2010).

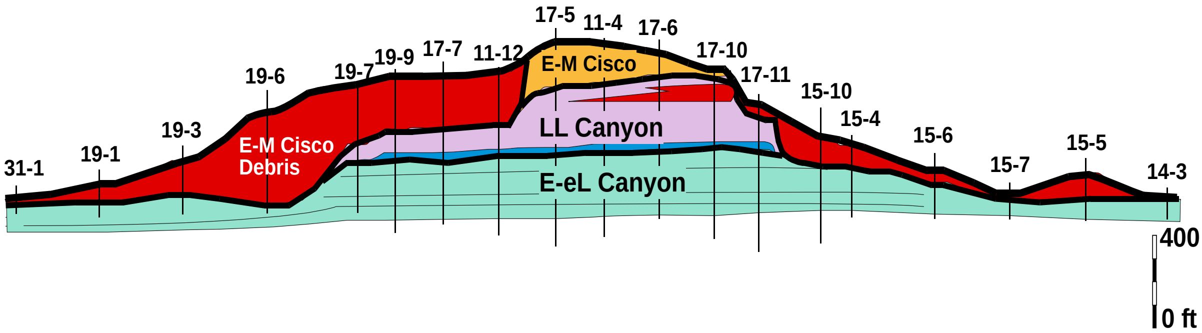


Figure 9 Simplified SACROC reservoir stratigraphic framework. From Dutton et al., (2005).

Key findings from SACROC: (i.e. how it contributes to addressing section 1.1)

Note: these findings are described in more detail in Chapter 5.

#2. Monitoring criteria (to quantify CO_2 storage and detect the extent of migration)

At the SACROC site, besides the management and monitoring of the injection and production by the operator, shallow groundwater has been the major monitoring target for detecting potential CO_2 out-of-reservoir migration. These studies showed no impact to groundwater above the SACROC field over the lifetime of this extensive operation. They also illustrate the evolution in our understanding of the complexity of the natural geochemical system of the aquifers and improvement of the monitoring approaches.: Starting with direct comparisons between the chemistry of groundwater and the reservoir brine, and then comparing groundwater chemistry both inside and outside the SACROC site, to understanding the natural geochemical processes in the shallower aquifers and the effects of potential CO_2 input. Numerical simulations were used to calculate leakage rates that would be discernible above background and to determine the parameters that have the highest sensitivity for leakage detection. The effectiveness of seismic methods is also described.

#3. Pressures changes & thresholds and how these can be mitigated

Reservoir pressure at SACROC has always been below discovery pressure due to the large amount of fluid extraction, which poses an advantage for carbon storage (in terms of capacity and leakage risk) but a disadvantage for EOR (where pressures need to be above the minimum miscibility pressure for oil and CO_2 to mix for EOR to be effective). Pressure responses and fluid injection history at the field are important for understanding production and storage behaviours. There is a large body of published information on field operations to limit CO_2 channelling and fast breakthrough at the production wells. Some of the methods of controlling CO_2 distribution can be applied in CO_2 storage to access more pore volume and control the CO_2 plume extent.

#4 Storage capacity

The specific effects of miscibility on capacity are explored using the Peng-Robinson equation of state for both the SACROC and the Cranfield oil compositions and reservoir conditions. Mixing CO_2 and oil increases the density of the resulting mixture which can lead to slight increases in capacity as a result. Miscibility effects could alter fluid densities by as much as 14.5% for SACROC and 6.2% for Cranfield if ideal mixing ratios occurred. However, given the reservoir heterogeneity the mixing ratios are likely to be less than ideal, at these sites only a small capacity change from this mechanism is anticipated. However, it is recommended that this effect is evaluated on a site-by-site basis and taken into account in capacity calculations.

#5. Long-term wellbore integrity assessment and remediation measures

The SACROC unit was the first large scale CO_2-EOR project in the world. The long history and the scale of the EOR operation provide an effective case study to assess wellbore performance in a CO_2 environment. Several studies have investigated well performance at SACROC using statistical approaches, direct observations, laboratory experiments, and numerical simulations. Records of well blowout and well control problems during the CO_2-EOR operation provide a statistical view of the risk of potential well leakage. A side-track drilling operation retrieved cores of the casing and cement which allowed direct assessment of wellbore sealing capacity in the CO_2 injection zone. Site specific laboratory experiments and numerical simulation were conducted to predict long-term well integrity.

SACROC key references

Han, W.S., McPherson, B.J., Lichtner, P.C., Wang, F.P., 2010. Evaluation of trapping mechanisms in geologic CO_2 sequestration: Case study of SACROC northern platform, a 35-year CO_2 injection site: American Journal of Science, v. 310 (4), p. 282-324.

Romanak, K.D., Smyth, R.C., Yang, C., Hovorka, S.D., Rearick, M., Lu, J., 2012, Sensitivity of groundwater systems to CO_2: application of a site-specific analysis of carbonate monitoring parameters at the SACROC CO_2-enhanced oil field: International Journal of Greenhouse Gas Control, v. 5, no. 1, p. 142-152.

2.3 Sites elsewhere

In this section the key features of the Otway site in Australia and the Weyburn site in Canada are outlined.

2.3.1 Naylor gas field, Australia (Otway project)

The Otway Basin, about 200 km [~124 km] from Melbourne in Victoria, Australia, is the site of a pilot onshore CO_2 storage site (Figure 10). Here, 65,000 tonnes of CO_2 was injected into a depleted gas field at ~ 2,000 m [~6,562 ft] depth between 2008 and 2009.

Otway site summary

Location: onshore Australia

Depleted: gas field

Type: storage

Status: completed. 0.065 Mt stored 2008-2009

Economic viability: pilot scale, research focus

Geological setting: heterogeneous stacked tidally influenced channel sands at ~2,000 m [~6,562 ft] depth, Cretaceous aged, mudstone seal.

Key findings from the site: (i.e. how it contributes to addressing scope, section 1.1)

- [ ] #1. Risk assessment criteria
- [ ] #1a. Implications for continued oil and gas production in adjacent fields
- [x] #2. Monitoring criteria (to quantify CO_2 storage and detect the extent of migration)
- [x] #2a. Implications e.g. the effects of residual hydrocarbon fluids
- [ ] #3. Pressures changes & thresholds and how these can be mitigated
- [x] #4. Storage capacity estimate validation
- [ ] #5. Long-term wellbore integrity assessment and remediation measures
- [x] #6. Cost of modifications and storage development

Geology: The depleted gas field is an approximately 0.5 km^2 [~0.2 square miles], north east dipping structural trap formed by a north-south trending fault to the west. The Cretaceous aged reservoir is 25 to 30 m [82 to 98 ft] thick and consists of stacked sandstones separated by abandoned channel fills. The average permeability is higher than one darcy. The main cap rock is a thick, laterally extensive mudstone (Cook, 2014; Vidal – Gilbert, et al., 2010).

Reservoir conditions: The gas production from the reservoir (2002-2004) reduced reservoir pressure from ~ 19.59 MPa down to about 11.86 MPa [~2,841 to 1,720 psi]. However by the time the CO_2 injection well was drilled (2007), aquifer recharge had returned reservoir pressures to 17.8 MPa [2,582 psi] and reservoir temperature was 82°C [180°F]. (Cook, 2014 and Dance, 2013). The post-production gas water contact (GWC) in the monitoring well was at 1,988.4m TVDSS with a residual gas saturation down to the pre-production GWC of 20%.

Injection strategy: The former gas production well (Naylor 1 in figures 10 and 11), near the crest of the structure, was refitted as a monitoring well. CO_2 was injected via a specifically drilled well (CRC-1 in figures 10 and 11) ~300 m [~984 ft] to the east and downdip of the monitoring well, outside the post-production gas water contact. The CO_2 was sourced from a nearby natural (magmatic) source (Buttress No. 1 in figures 10 and 11). The gas injected was about 80% CO_2 and 20% methane. Injection started in April 2008 at an average rate of 150 tonnes per day. By August 2009, 65,445 tonnes of gas containing about 58,000 tonnes of CO_2 had been injected. This operation is known as "Stage 1" of the project, subsequent stages included injection into shallower saline aquifer units and are not discussed here.

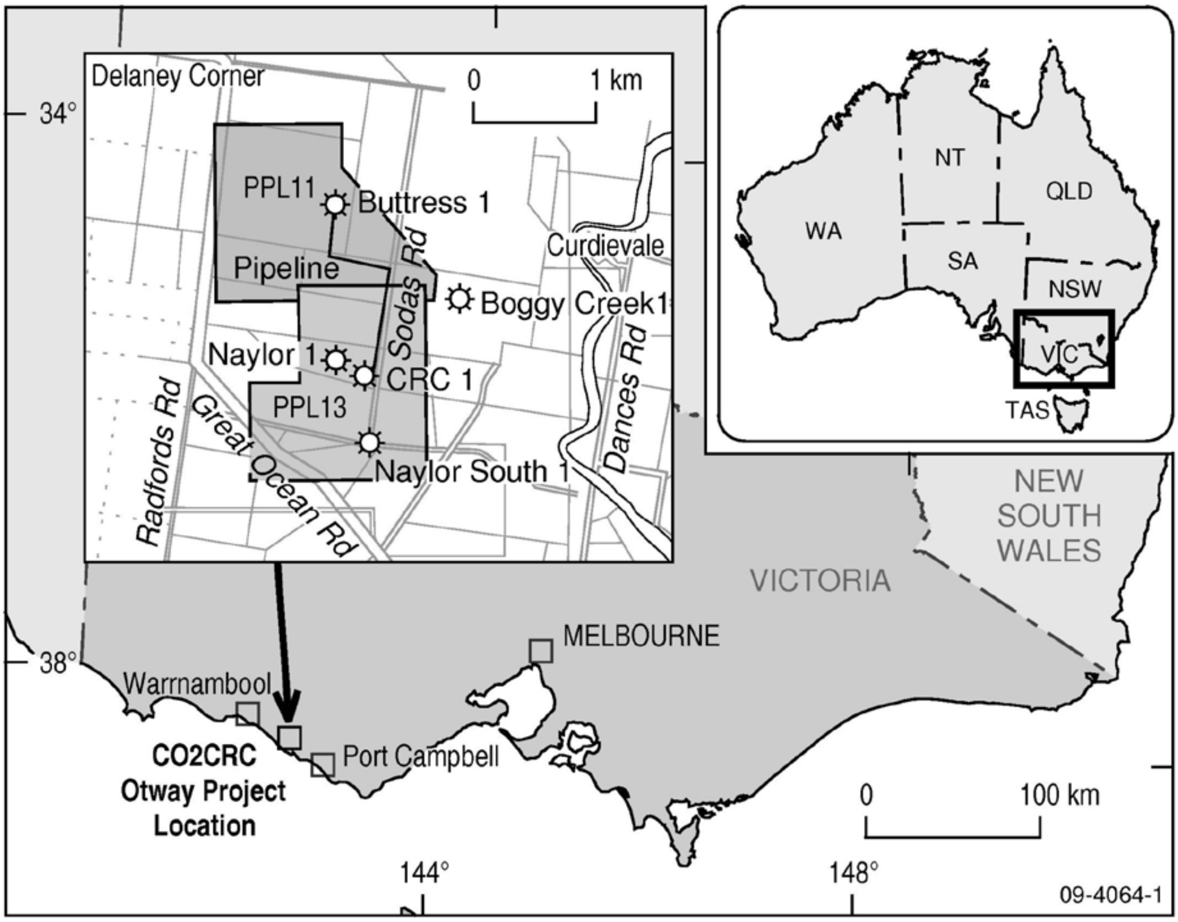


Figure 10 Map showing location of Otway basin project. Image courtesy of Dr Chris Boreham. Intellectual Property of CO2CRC Limited, reproduced with permission.

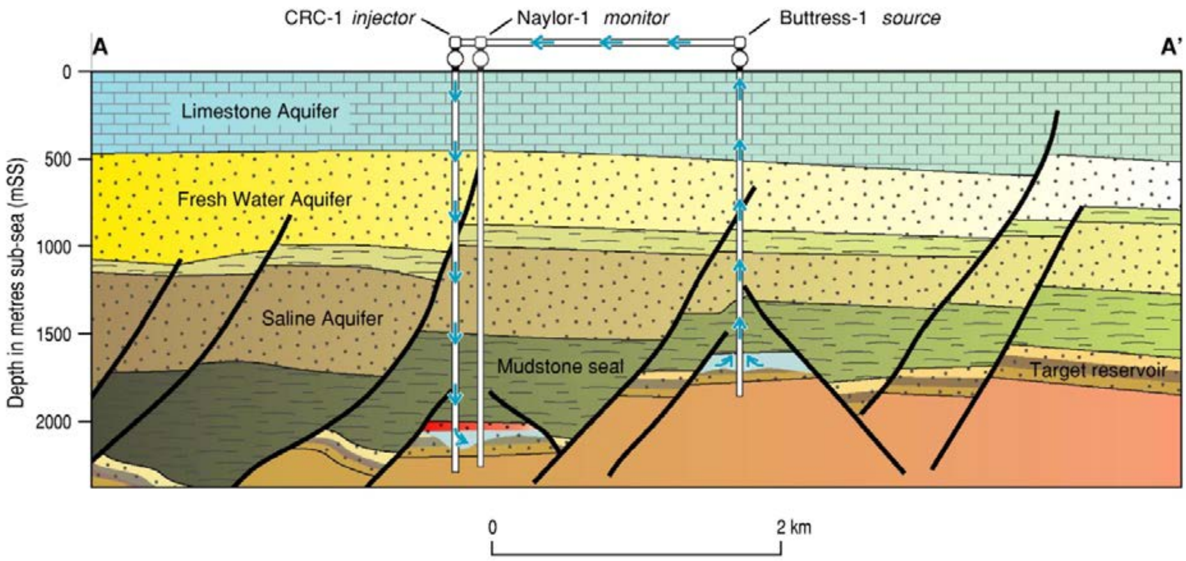


Figure 11 Otway CO_2 storage set up for "Stage 1" injection into a depleted gas field. Image courtesy of Dr Chris Boreham**.** Intellectual Property of CO2CRC Limited, reproduced with permission.

Key findings from Otway: (i.e. how it contributes to addressing section 1.1)

Note: these findings are described in more detail in Chapter 6.

#2. Monitoring criteria (to quantify CO_2 storage and detect the extent of migration) and #2a. Requirements e.g. the effects of fluid replacement

As a pilot project, many monitoring technologies were tested at the site. In particular the monitoring well was equipped with a U-tube system sampling at 3 levels, above and below the post-production GWC, and various tracers were injected in to the CO_2 stream, so this system was able directly monitor the fluid changes across those intervals in the reservoir as the structure filled with the injected CO_2.

#4. Storage capacity estimate validation

Initial pre-injection capacity estimates were made using simplistic volume-for-volume replacement, based on the volume of produced gas. However, once pre-injection reservoir pressures were established (when the CRC-1 injection well was drilled), which showed significant aquifer recharge, this was no longer deemed suitable and more complex calculations were initiated together with numerical simulations to refine this.

#6. Cost of modifications and storage development

As a part-government funded research pilot site requirement, and on the publication of Cook, 2014 ("the Otway Book"), a breakdown of the overall costs of the project have been made public.

Otway key reference

Cook, P.J. (Ed.) 2014. Geologically Storing Carbon: Learning from the Otway project Experience. CSIRO Publishing, Melbourne.

2.3.2 *Weyburn –Midale oilfield, Canada*

The Weyburn oil field located in the Williston Basin in South Saskatchewan (Figure 12), is a large-scale enhanced oil recovery (EOR) project in an onshore carbonate formation at a depth of approximately 1,450 m [~4,757 ft]. CO_2 injection commenced in 2000 and is expected to extend the life of the oil field by approximately 25 years. Ultimately 30 Mt of CO_2 is expected to be stored during the lifetime of this EOR project and an additional 25 Mt could potentially be stored if CO_2 injection continued after oil recovery ceases. CO_2-EOR commenced in 2005 at the adjacent Midale oil field which is likely to extend its production by 20-25 years and is expected to result in storage of 10 Mt of CO_2.

Weyburn-Midale site summary

Location: onshore Canada

Depleted: oil

Type: CO_2-EOR. Injected CO_2 is from anthropogenic sources (industrial & more recently, capture from a coal-fired power station)

Status: operational. (>20Mt stored over 14 yrs, since 2000)

Economic viability: industrial, research focused monitoring

Geological setting: thin fractured Carboniferous vuggy/marly carbonate reservoir at ~1,450 m [~4,757 ft] depth with an evaporite seal

Key findings from the site: **(i.e. how it contributes to addressing scope, section 1.1)**

- [x] #1. Risk assessment criteria
- [ ] #1a. Implications for continued oil and gas production in adjacent fields
- [x] #2. Monitoring criteria (to quantify CO_2 storage and detect the extent of migration)
- [ ] #2a. Implications e.g. the effects of residual hydrocarbon fluids
- [ ] #3. Pressures changes & thresholds and how these can be mitigated
- [x] #4. Storage capacity estimate validation
- [x] #5. Long-term wellbore integrity assessment and remediation measures
- [ ] #6. Cost of modifications and storage development

Geology: The Weyburn Oil Field lies within a regional structural trap and covers an area of approximately 180 km^2 [~70 square miles] (Riding & Rochelle, 2005). The carbonate reservoir of Carboniferous (Mississippian) age is part of the Charles Formation Midale beds. It is typically up to 30 m [~98 ft] thick, dipping by 1-2° towards the south-west (White, 2013) and can be divided into two units. The upper unit is a marly (mainly dolomite) and the lower unit is mostly a fractured (vuggy) limestone (Uddin et al. 2013). The marl unit has average porosities and permeabilities of 26%

and 10 mD respectively, whereas the limestone unit has variable porosities (average 10% (White, 2013)) and permeabilities (range 10 - 300 mD (White, 2013)) that are generally lower porosity and higher permeability than the marl unit (Uddin et al. 2013). Overlain by the Midale Evaporite, a dense anhydrite up to 11 m [~36 ft] thick (Wildgust et al. 2013).

Reservoir conditions: The reservoir conditions in the Midale Marly Unit are around 60 °C [140 °F] and 15 MPa [2176 psi].

Injection strategy: The Weyburn field original oil in place was estimated at 220 Mm^3 [7,063 Mcf] of oil, and since CO_2 injection started, production is around 4,500 m^3/d [~159 000 cf/d] of which approximately 65% is due to CO_2 flooding of the reservoir. CO_2-EOR in the Midale Field is expected to increase its production by 9.5 Mm^3 [~335 Mcf] during operation of the project (Hitchon, 2012).

CO_2 was initially injected at a rate of 2.69 Mm^3/d [~95 Mcf/d] but in 2002 this was increased to 3.39 Mm^3/d [~120 Mcf/d] with additional CO_2 being recycled from the oil production process (IEAGHG, Weyburn Public Summary Report) between 2003 and 2008. During phase 1 (Weyburn field only) CO_2 was injected into a total of 29 wells, 16 of which are vertical and 13 are horizontal and they form a driving line within the reservoir (Brown et al. 2001). The gas injected consists of approximately 95% CO_2 and is transported 323 km [125 miles] from an industrial plant in Beulah, North Dakota via pipeline. Recently, a proportion of the CO_2 is now also transported ~66 km by pipeline from the Boundary Dam CCS project near Estevan in Saskatchewan Canada (Figure 12). The post-combustion CO_2 capture from the coal-fired power plant started up in late 2014 (www.globalccsinstitute.com/ projects/boundary-dam-carbon-capture-and-storage-project).

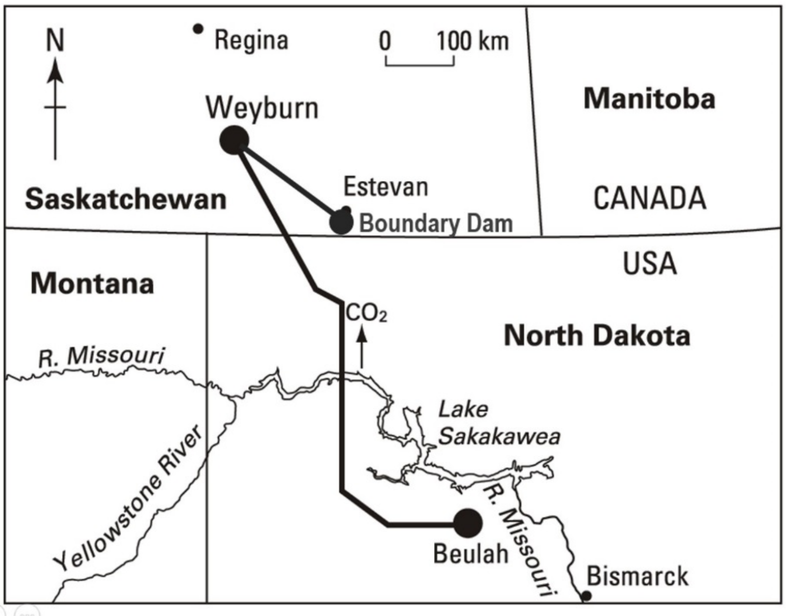


Figure 12 Location of the Weyburn oilfield. Courtesy of C. Rochelle. © BGS NERC 2016.

Key findings from Weyburn: (i.e. how it contributes to addressing section 1.1)

From the Weyburn-Midale best practices observations (Hitchon, 2012)

#1. Risk assessment criteria

At Weyburn various risk assessment methodologies were deployed and updated as the project evolved. Geosphere risks were assessed using the modelling method known as RISQUE, which involves expert judgement and is consistent with international standards (ISO) of risk management. This is a quantitative method which allows prioritisation of risk mitigation and understanding of the cost-benefits associated with mitigating strategies. Monte Carlo simulations were used to express different confidence levels in the risks to help communicate the uncertainty (50% confidence level to represent an optimistic estimate of the risk, 80% for a conservative estimate (used for planning the project) and 95% as a pessimistic view (Bowden et al., 2013).

#2. Monitoring criteria (to quantify CO_2 storage and detect the extent of migration)

Extensive monitoring has been deployed at Weyburn using geochemical, geophysical and biological methods. Many had research based objectives and showed variable ability to monitor the CO_2 extent in the subsurface including downhole seismic; InSAR (satellite imagery); Long-electrode electrical resistance tomography (LEERT), Time-lapse gravity; Vertical seismic profiling (VSP); and time-lapse seismic.

#4. Storage capacity estimate validation

Storage capacity of a site can be dependent on many key properties of the reservoir. At Weyburn two modelling scenarios were used to explore methods for estimating local CO_2 storage capacities including various trapping mechanisms. The first model considers just a fluid phase whereas the second model considers fluid-phase, mineral trapping and porosity/permeability changes resulting from chemical reactions.

#5. Long-term wellbore integrity assessment and remediation measures

At Weyburn an abandonment and well integrity monitoring plan is in place to ensure the appropriate remediation can be applied if a leak occurred. For new wells, design, execution and post drilling assessment of cementing are essential. Well trajectory has been highlighted as an important factor in integrity, to ensure high-angle trajectories through the caprock do not compromise cement isolation.

Weyburn key References

Hitchon, B. (Ed). 2012. Best practices for validating CO_2 geological storage: Observations and guidance from the IEAGHG Weyburn-Midale CO_2 monitoring and storage project. Geoscience Publishing.

Wildgust, N., Gilboy, C., Tontiwachwuthikul. P. 2013. Introduction to a decade of research by the IEAGHG Weyburn-Midale CO_2 monitoring and Storage project. International Journal of Greenhouse Gas Control 16S (2013) S1–S4. http://dx.doi.org/10.1016/j.ijggc.2013.03.014

Chapter 3 Case study: Goldeneye

This chapter describes specific aspects of the CO_2 storage proposed in the Goldeneye depleted gas field, relevant to the scope of this report (section 1.1). Context for the legislative framework and terms relevant to CO_2 storage in the EU are described in the introduction to EU sites in section 2.1 and an overview of the storage planned at Goldeneye is outlined in section 2.1.2. The box below is a copy of the summary information from that section, highlighting which elements of the scope are described in this case study. *The information for this chapter comes from the published FEED documents from the UK government competitions. The FEED close-out report (ScottishPower Consortium, 2011a) and the Storage Development Plan (ScottishPower Consortium, 2011g) contain most of the key points, but individual reports are also referred to throughout as necessary.*

Goldeneye site summary

Location: offshore UK

Depleted: gas condensate

Type: storage (10 - 20 Mt over 10 - 15 years)

Status: planned (start 2019)

Economic viability: government subsidised demonstration

Geological setting: Cretaceous sandstone reservoir at ~2,600 m [8,530 ft] depth, in well-connected sandstone aquifer fairway with mudstone caprock

Key findings from the site: (i.e. how it contributes to addressing scope, section 1.1)

- [x] #1. Risk assessment criteria
- [x] #1a. Implications for continued oil and gas production in adjacent fields
- [x] #2. Monitoring criteria (to quantify CO_2 storage and detect the extent of migration)
- [x] #2a. Implications e.g. the effects of residual hydrocarbon
- [x] #3. Pressures changes & thresholds and how these can be mitigated
- [x] #4. Storage capacity estimate validation
- [x] #5. Long-term wellbore integrity assessment and remediation measures
- [x] #6. Cost of modifications and storage development

3.1 Risk assessment criteria (#1 issue, section 1.1)

As part of the FEED process, the Scottish Power CCS consortium assessed risks relating to the overall development, execution and legacy of the demonstration project using established practices for Risk Management[9], with the purpose of balancing project benefits with risk exposure. A *high level review of these risks and the assessment process is provided in the FEED closeout report section 4.7.* The rest of this section refers specifically to the storage related risks and as such*, material is derived primarily from the Storage Development Plan and the MMV plan.*

3.1.1 Risks relating to the overall development, execution and legacy of the demonstration project.

Methodology: Initially a simple list of risks (known as a risk register) was assembled. This evolved into a scored, more complex list of linked “parent” and “child” risks, to dictate the level of response required for each risk. Each risk was assigned a score from 5 to 75 according the probability of it occurring and its severity should it occur (assessed in terms of the impacts to the project costs, schedule and reputation). Risks with a score of less than 15 were considered “tolerable”. Above this, the initial response was “treat”, whereby the project aimed to reduce the severity or probability down to a tolerable level, mostly achieved through site design. If it was not possible reduce the risk to a tolerable level it could either be “transferred” to a third party, or if this were not possible to “terminate” the project, or that particular part of it.

Results: Post FEED, the top risks[10] reflect that this is a first-of-a-kind project (in the UK) and most of them would be expected to be dramatically reduced as CCS rollout occurs. At the time of developing the Longannet methodology, no other storage site had tested the permitting process in obtaining the consents required through the UK and the EU Storage Directive regulatory system: and the OSPAR convention was not yet ratified by the necessary number of parties. As such there was significant uncertainty as to whether this would delay the project. The risk of migration of CO_2 out of the store was 17th on the list but could be considered to be the ‘top’ geological risk. To mitigate this risk a number of surveys, studies and design elements were investigated or proposed throughout the FEED, discussed throughout this chapter.

3.1.2 Risks specifically relating to storage containment and conformance

Methodology: At Goldeneye, all containment risks were assessed by a bow-tie method of risk assessment. This first involves identification of possible unwanted events, the “top” unwanted event, in this case being loss of CO_2 from the storage complex. This event forms the centre of the “bowtie”. All the threats that could lead up to this event occurring are listed on left side of the bow-tie and all the consequences should the event occur are listed on the right (Figure 13a). Two sets of control measures, preventive and corrective are set up respectively to the left and right of the event with their potential effectiveness documented (as ‘effective’, ‘partially effective’ or ‘ineffective’), along with escalation factors that could reduce their effectiveness.

[9] As defined in the HM Treasury ‘Orange Book’, ‘PRAM’

[10] Top risks: Inability to obtain the necessary consents at all stages for the full project chain (construction, operation and abandonment for capture, transport and storage elements); Complications with technology scale- up, followed by adverse public reaction that could make investor and government backing difficult to maintain.

Overall this gives a visible structure to the risk assessment. The process was made quantitative to help in prioritising the steps necessary to improve control measures until the risks were ‘as low as reasonably practicable’ (ALARP), to create a safe and economic project. This allows active and effective risk management as the project evolves and technologies and understanding of risks mature.

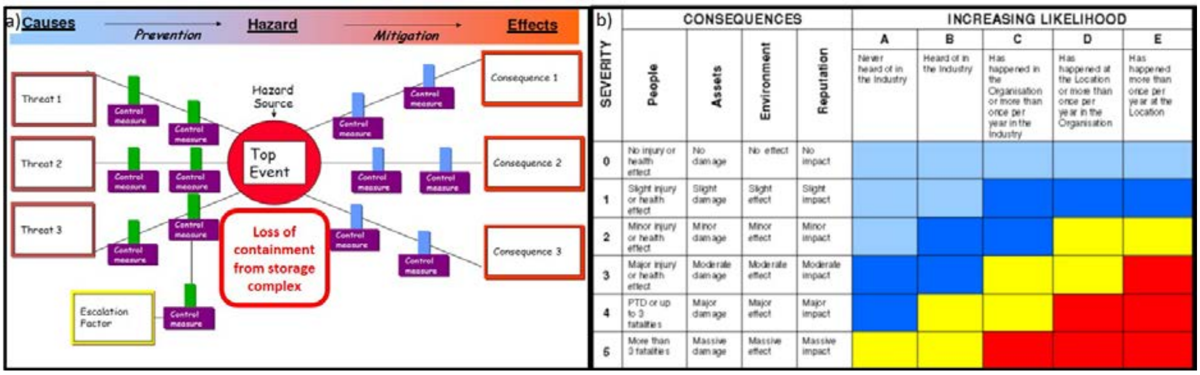
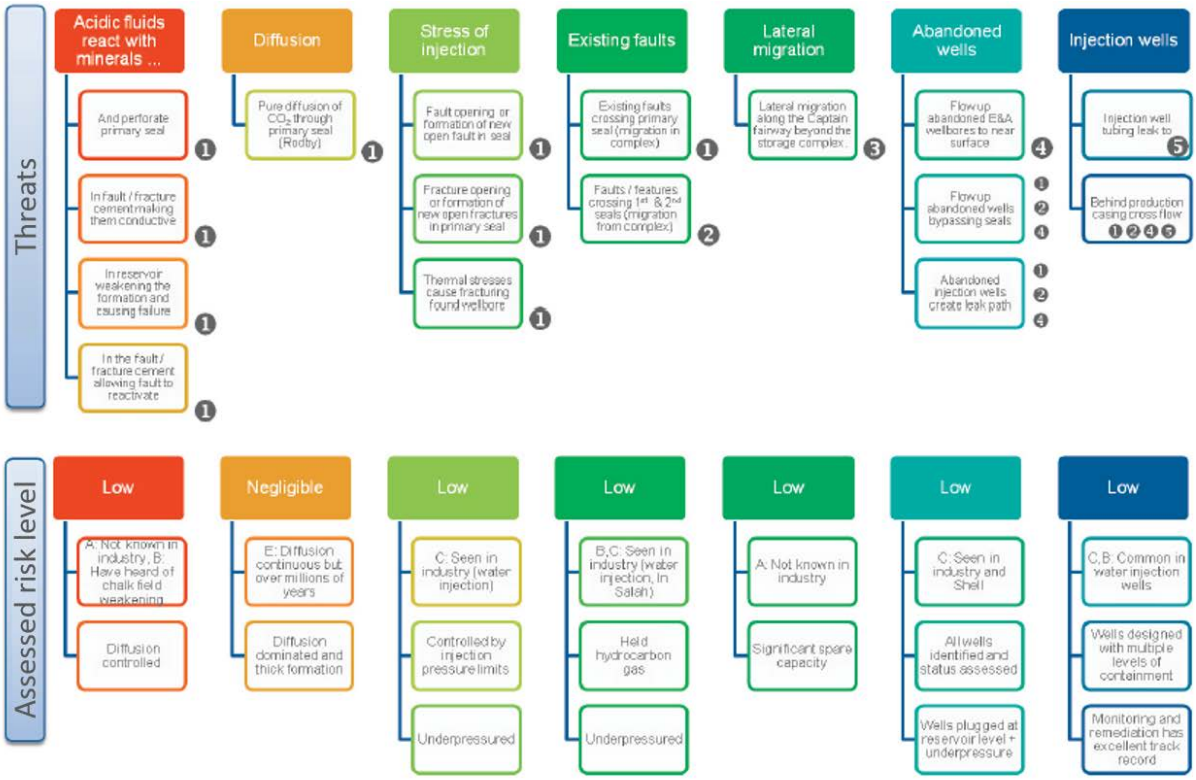


Figure 13 a) Structure of bow-tie risk assessment b) risk matrix matrix used to quantify the assessment (after diagrams in the MMV plan). (ScottishPower CCS Consortium, 2011g).

Quantification was achieved by assigning to each threat and consequence a score based on a risk matrix (Figure 13b). This was calculated by assessing the likelihood of each threat occurring and the severity of the consequences should it occur. Likelihood was assessed based on how many times similar events were known to have occurred in the industry or in analogous industries. Given that CO_2 storage is a relatively new technology, there is as yet insufficient experience from which to assess the statistical significance of the likelihood of any such events occurring. Therefore event likelihood was sometimes explored using potentially analogous industries including gas storage and CO_2-EOR. Severity of the consequences was assessed in terms of harm to people, the environment, assets and reputation. The reputation aspect is particularly important for these early demonstration projects to secure the confidence of the public and regulators that the industry is safe and economic, as required to pave the way for larger scale commercial roll out of CCS.

This risk assessment process at Goldeneye was extremely comprehensive. It developed throughout the FEED and would be expected to continue to evolve throughout the life of the project. The process involved input and interaction between many of the disciplines involved in site design and informed the monitoring and corrective measures plans. The evolution from the Longannet project FEED to the Peterhead FEED (unpublished at Feb 2016) demonstrated improvements in risk-assessment understanding, by improving the quantification (via seven linked bowties to more fully recognise the different types of unwanted events) and the demonstration of ALARP.

Results: The 2011 containment risk bow-tie contained 16 threats (Figure 14, top) and 19 consequences under seven top level categories. As mentioned previously, many of these are not specific to depleted fields. Around 50 preventative control measures (some repeated in multiple branches) were in place between the threat and the event. These included geological factors (primary and secondary seals and the fact that the system is underpressured), engineered (well plugs and well design) and monitored barriers (see section 3.3). Around 20 additional preventative control measures were also in place (mainly involving additional well recompletions, drilling and monitoring). In the unlikely event that these were unable to prevent the event from occurring, mitigation was proposed via around 25 corrective control measures (again, some repeated in multiple branches). These were categorised as either passive (requiring no intervention such as CO_2 becoming immobilised in overlying geology) detection measures (monitoring of CO_2 outside the containment) or corrective measures (e.g. changes in injection strategy, or well interventions). Risks of loss of CO_2 containment were considered to be low (Figure 14, middle).



A	B	C	D	E
Never heard of in the industry	Heard of in the industry	Has happened in the organisation or more than once per year in the industry	Has happened at the location or more than once per year in the organisation	Has happened more than once per year at the location

Figure 14 Schematic representation of the Goldeneye containment bow-tie risk assessment showing threats at the top (in seven categories), assessed risk levels in the middle (all low or negligible) and the criteria by which the likelihood was assessed (A-E). (ScottishPower CCS Consortium, 2011g).

3.2 Implications for continued oil and gas production in adjacent fields (#1a issue, section 1.1)

The Goldeneye field is known to be hydraulically connected to neighbouring fields in the Captain aquifer[11] whereas pressure and hydrocarbon composition data show that nearby fields in older strata are not connected to Goldeneye (Figure 15). So injection of CO_2 into Goldeneye could cause a pressure response in some nearby fields but this is not listed as a risk, primarily because increased aquifer pressure would tend to enhance rather than be detrimental to production elsewhere. For example, at the Blake field, water is deliberately injected to keep pressures above a certain level.

The fairway connectivity naturally affects the rate of repressurising as a result of CO_2 injection and potentially more of a concern to storage at Goldeneye would be additional injection elsewhere in the fairway that might cause pressure to rise faster than currently expected and therefore limit effective capacity.

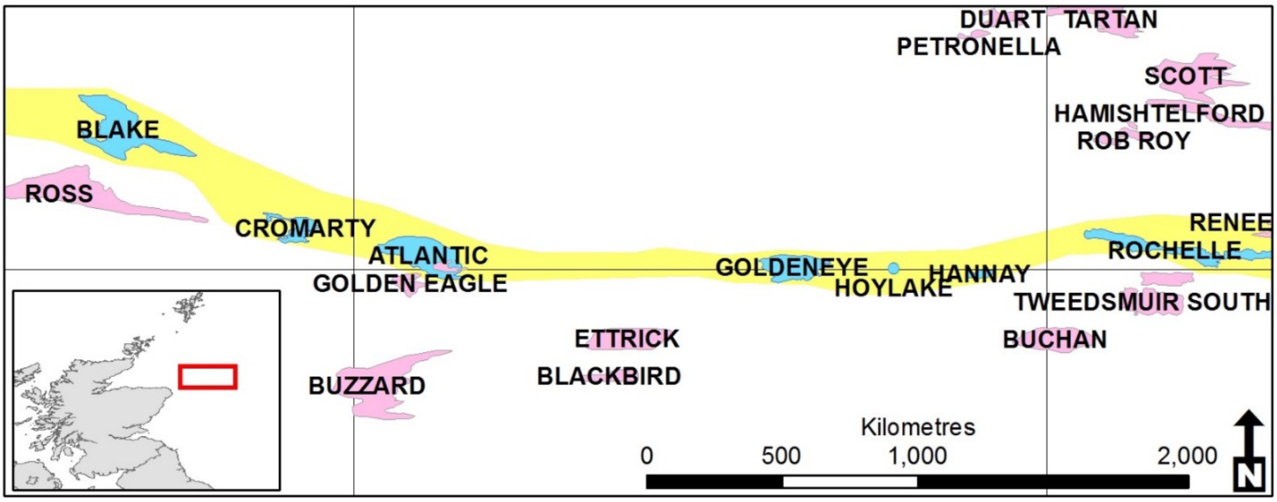


Figure 15 Fields and discoveries neighbouring Goldeneye with approximate location of Captain Fairway sketched in yellow. Fields in blue are in the hydraulically connected Captain Sandstone fairway. Fields in pink are in older strata, hydraulically unconnected to Goldeneye. (British Geological Survey © NERC 2016).

3.3 Monitoring criteria (examples of how monitoring has been used to quantify CO_2 storage and detect the extent of migration). (#2 issue, section 1.1)

Monitoring designed to verify containment and demonstrate conformance while fulfilling European offshore storage requirements is described in the *Measurement, Monitoring and Verification (MMV) Plan.* Monitoring tool selection was based on a

[11] The *Storage Development Plan* for Longannet cites connection to Cromarty, Atlantic, the Holylake discovery, Hannay and potentially to Blake and Rochelle (Figure 16). Since these documents were assembled (and at January 2016), Atlantic and Cromarty have ceased producing, the Hoylake discovery has been relinquished and the Rochelle East and West fields have come online.

comprehensive *Monitoring Feasibility Report* and is focussed on areas or features highlighted by the risk assessment as being of higher risk of potential leakage (section 3.1). This section explains how the techniques were selected in addition to outlining the principles underlying the monitoring plan.

The primary purpose of monitoring at the site is to show that the CO_2 is stored in the storage complex i.e. to ensure:

- **Conformance** to demonstrate long-term security of the storage site by establishing conformance of monitoring data with modelled predictions.
- **Containment** to demonstrate the current security of the storage operation by verifying the absence of any significant irregularities and to allow timely intervention in the case of containment loss.

Monitoring is deployed according to two plans, to allow a stepped escalation in monitoring focus (and cost) should a significant irregularity be detected:

Base-case plan: designed to monitor CO_2 migration within the storage complex and to detect any significant irregularities to ensure that the integrity of storage is maintained by allowing corrective measures to be taken (if required). It relates to the threats on the left hand side of the bow-tie risk assessment (Figure 13a, section 3.1).

Contingency plan: designed to confirm suspected irregularities detected by the base-case plan and locate the source of migration, to enable corrective measures to be implemented (*documented in the Corrective Measures Plan*) if required and to quantify any emissions. It would also be used to monitor the effectiveness of any corrective measures deployed. It relates to the consequences on the right hand side of the bow-tie risk assessment (Figure 13a, section 3.1).

Tools were selected based on the monitoring feasibility study and although feasibilities were set up specific to this site, much of the content and the approach is likely to be useful for other sites. The techniques were considered in terms of their:

- Risk relevance: How well the measurements were able to address the risks
- Measurability: Their ability to detect the predicted changes above background
- Operational constraints: whether there were site specific constraints relating to water depth, borehole access etc.
- Competitive application: selecting techniques with the least risk, least cost, best data if multiple options were available
- Proven technology: Whether the techniques were proven in CCS/EOR or analogous industries or in research and development (R&D),

45 techniques were considered and 27 were returned as suitable for monitoring. This was narrowed down to around 15 suitable techniques following a cost-benefit analysis. As a large-scale commercial demonstration site, the minimum suite of tools required to achieve the site objectives and regulatory requirements were selected to be

deployed. Those selected for monitoring CO_2 movement within the store are mainly mature technologies proven in comparable geological situations (e.g. 3D seismic and P&T downhole gauges), whereas migration out of the store and quantification of emissions (where there are less commercial analogue situations at least offshore) include both commercial and emerging (R&D) technologies. The MMV plan is flexible and able to be updated as new technologies become available. For example, at present, post-closure downhole pressure and temperature monitoring once the platform has been removed is not feasible, but could be by the time this project stage is reached.

The timing and frequency of monitoring varies from technique to technique, balancing both tool capabilities and costs with requirements dictated by the risk assessment, regulations and model validation and predictions. As the risk profile changes with time, so the monitoring intensity and duration also changes. Broadly, this is subdivided into *pre-injection* or baseline; *during injection*; and *post-injection/closure* (Table 4). Pre-injection conditions will be confirmed in the baseline surveys, monitoring will be intensive during injection to validate and update numerical models and ensure safe operations. Post-injection, monitoring intensity will be reduced, with data collection to validate predictions and make final models to check site stability for long term stability requirements for site handover to the competent authority[12]

Technologies proposed specifically with the aim of detecting the CO_2 in the reservoir and the extent of any migration within it and out of it are listed below and summarised with timings in Table 4:

- **Reservoir pressure and temperatures** (P&T) will be monitored continuously in the injection wells and in one or more dedicated monitoring wells to ensure conformance (in combination with saturation logging and reservoir fluid sampling) and for well log integrity monitoring (distributed temperature logging, casing annular pressure, in combination with downhole integrity logging).
- **Geophysical logging** includes pulsed neutron capture (PNC) to monitor gas saturation and down-hole fluid sampling. Baselines to establish fluid contacts are proposed, followed annual monitoring in years 5-10 for conformance in combination with P&T and to further characterise reservoir processes. Tubing integrity logging is also proposed.
- **Various environmental "assurance" monitoring** of the seabed & seawater to verify that CO_2 has not migrated to seabed. This includes monitoring using multi-beam echo-sounding, seabed sediment and pore-gas sampling around "high risk areas" i.e. wells, platform and any seismic anomalies, and continuous water column sampling beneath the platform. Injection of tracers to improve the ability to detect emissions is also considered.

[12] At Goldeneye (Longannet) handover to the *UK Competent Authority* is proposed to take place between six and twenty years post-closure.

- **Time-lapse 3D surface seismic** is designed to monitor plume conformance and detect any lateral and vertical irregularities. 3D coverage of the storage complex is proposed using a combination of conventional ship-towed streamers and with ocean bottom nodes (OBN) beneath the platform.
- Additional options include an **on-platform GPS** to monitor seabed uplift (maximum of 36 mm is predicted) and a **seabed seismometer** to establish baseline seismicity. High resolution **P-cable** shallow seismic is also specified for contingency monitoring in the overburden. Downhole sensors (using behind-casing or clamped-to-tubing optic fibre for **distributed acoustic sensing (DAS) for borehole seismic VSP**) are also considered, subject to the technology maturing.

Monitoring technique	Mode	Baseline	During injection	Post injection
Surface seismic - Streamer 3D	Time-lapse	✓	~5 years	1 year and 6 years
Surface / downhole seismic - OBN/VSP	Time-lapse	✓	~5 years	1 year
Surface seismic - high resolution p-cable	Contingency			
Broadband seismometer beneath platform		continuous		
GPS on platform		continuous		
Downhole pressure & temperature		✓	continuous	for 3 years
Downhole saturation and porosity logging	Time-lapse	✓	annual, years 5-10	
Well log integrity		✓	every 3 years	
Downhole fluid sampling	Time-lapse	✓	annual, years 5-10	
Seabed bathymetry and imaging	Time-lapse	✓	year 5 (targetted)	at 1 year
Sediment sampling	Time-lapse	✓	year 5 (targetted)	at 1 year
Water column sampling	Time-lapse	continuous		
Cumulative CO_2 injected (Mt)		0		10-20

Table 4 Monitoring programme proposed for Goldeneye in the Front End Engineering Design (FEED) documents. (Green denotes deep-focussed techniques that operate from the surface, yellow denotes well based techniques and blue denotes shallow-focussed techniques). (From IEAGHG, 2015**)**

3.4 Implications for monitoring requirements e.g. the effects of residual hydrocarbon fluids. (#2a issue, section 1.1)

Feasibility of various tools to determine in-reservoir saturations for conformance monitoring was studied (*Monitoring Feasibility Report*). Methods investigated included the capabilities of: geophysical logging tools to determine CO_2 saturations around the wellbore; downhole sampling for direct measurement of the fluid concentrations; and seismic monitoring for deriving saturation changes across the whole reservoir. Monitoring of CO_2 in the reservoir was below the detection thresholds for seafloor gravimetry and ship-towed controlled source electromagnetics (CSEM) techniques. Results and conclusions from the other feasibility studies mentioned are listed below:

Geophysical logs: Cased-hole resistivity logs, acoustic logs and Carbon/Oxygen logging (C/O) were discounted on operational grounds (as a result of sandscreen and gravel pack completions, borehole size constrictions and not having liquid in the wellbore respectively). However, modelling of PNC and neutron log responses[13], suggested that overall saturation changes would be detectable as long as the injected CO_2 replaced CH_4 *and* water (not just CH_4). The PNC would not be able to distinguish the CO_2 from CH_4 on its own, but the neutron method would (the neutron tool would 'see' the CO_2 as reduced pore space, because it measures the hydrogen content, and CO_2 contains no hydrogen). In the monitoring plan, saturation logging of the recompleted injection and monitoring wells is therefore proposed. This comprises a baseline (to try and avoid problems experienced by other depleted field projects of having non-easily-comparable legacy PNC logs, e.g. Otway, Chapter 6) repeating periodically in years 5 - 10 of the operation to identify breakthrough and for saturation conformance.

Downhole sampling: During the same period, annual wireline bottom-hole sampling in the monitoring well is proposed (compatible with the saturation logs, so collectable during a single operation), to obtain 2 samples from the hydrocarbon leg and one from the water leg. U-tube sampling as (deployed at Otway) was discounted as it compromised offshore well safety and integrity issues (because the U-tube would have had to run through the subsurface safety valve or bypass it).

Seismic techniques: Forward modelling of fluid substitution was used to test the ability of seismic methods to detect CO_2 in the reservoir. Experience from North Sea fields with similar geology (and a normalised route mean squared (NRMS) repeatability metric of 30%) indicated that an acoustic impedance change of >5% would be detectable using repeat surface 3D seismic. Various filling scenarios and saturations were examined which indicated that it would be difficult to monitor the CO_2 plume in the reservoir within the pre-production hydrocarbon volume because of remaining residual hydrocarbon saturations. However, any protrusion of the plume outside of the original oil-water contact and into the aquifer (such as the Dietz tongue indicated by dynamic modelling, section 3.6) would be much more readily detectable, as would CO_2 that migrated into the overburden. Options for downhole fibre-optics for acoustic sensing (4D VSP) were considered, and, by the time that the Peterhead proposal was being developed 4D VSP technology had matured sufficiently that it was included in the base case monitoring plan, still as an option, but with the expectation that it would replace the midlife OBN survey. This set up would also potentially allow

[13] Given the formation water salinity of 50 kppm, porosity ~28% and remaining gas saturations in the reservoir.

for more frequent monitoring surveys, given that only a seismic source is required rather than the additional deployment of hydrophones required for a surface 3D seismic survey.

3.5 Pressures changes & thresholds. (#3 issue, section 1.1)

The reservoir initial conditions and production history are briefly described in section 2.1.1. The investigations into recognised risks relating to pressure and/or temperature changes at the site and their proposed solutions are summarised in each subsection.

3.5.1 ***Mitigating the risk of extreme wellbore cooling*** (*Reported in Longannet FEED close out report: section 3.8.3.1)*

In the early design phases, a risk of severe cooling in the upper wellbore was identified as a result of the Joule-Thomson expansion effect. This is caused when dense-phase CO_2 flashes to vapour as a result of a sudden drop in pressure (as the fluid expands into the wellbore)[14]. This could potentially present a containment risk if wellbore integrity were adversely affected by the extreme temperature changes. As mitigation for this, workover of the wells was proposed to reduce tubing sizes[15] to constrict the flow and keep wellhead pressures within a certain threshold range[16] to provide back pressure to keep the CO_2 in its dense phase above the depth it would otherwise flash to vapour. The tubing sizes in each well would be optimized according to the order that the wells would be injecting, while incorporating a range of sizes to allow for flexibility in CO_2 arrival rate. Operational constraints were proposed to reduce transient effects at start-up and shut-down of injection (when there is low fluid velocity and hence minimal back pressure to keep the CO_2 in the dense phase). Monitoring of the downhole fluid conditions in the injection well was also proposed with distributed temperature sensing and downhole pressure and temperature gauges. This was to provide data for operational optimisation as well as data for research to allow for further improvement of transient well modelling software.

3.5.2 ***Mitigating the risk of injection fracturing the reservoir or seal*** (*Reported in Longannet FEED close out report: section 3.8.3.5)*

Interpretation of early reservoir flow models suggested the injection would initially be under “matrix conditions” and then this might change to “fraccing conditions” as the reservoir pressure increased, i.e. fracturing the reservoir rock. While fractures in the reservoir rock are not a risk to integrity, if there were propagation into the seal there would be the potential of a risk to primary seal integrity. Reservoir fractures can concentrate flow in a small area of the completion and can also pose a challenge to

[14] Modelling suggested that the temperature could drop to around -25°C [77°F] in the near surface of the well, down to a depth of around ~762 m [2,500 ft] in the wellbore (at which depth, conditions would cause the CO_2 to return to its dense phase).
[15] It was proposed to replace the existing 7” tubing with smaller diameter tapered tubing.
[16] Above 4.5 MPa and below ~ 10 MPa [653 psi and 1,450 psi]

the durability of the completion equipment (sand screens). Numerical models were therefore instigated to investigate further.

Detailed simulation of fraccing conditions showed that the fractures in the reservoir propagated downwards within the pressure depleted reservoir, or parallel to the primary seal. For the scenarios investigated, no fractures grew across or above the primary seal and seal integrity was maintained in all cases. It was proposed to limit injection rates[17] and to perform downhole tests (leak off/minifrac) to reduce uncertainty on minimum stresses and when the transition from matrix to fraccing injection conditions might occur.

In addition to this detailed risk-specific modelling, geomechanical and geochemical modelling to characterise the storage site behaviour and for more general uncertainty-reduction on injection and storage related risks was also performed, as might be expected at any site (section 3.3.3).

3.5.3 *Modelling threats of tensile or shear failure of the reservoir, or caprock, fault slip and thermal fracturing close to wellbore* (*Reported in Longannet Geomechanics Summary Report).*

Site injection strategy and design meant that the pressures would not rise above the pre-production initial pressure. Geomechanical modelling[18] was performed to define stress paths, especially during hysteresis (to examine differences in stress state on production of gas compared to injection of CO_2), and the mechanical stability of the cap rock and faults. Base case and worst case scenarios were considered. Results indicated that stress-paths were not close to replicating possible failure cases.

The geomechanical modelling did not take the aquifer re-pressurisation back to initial pre-production levels into account (estimated to occur between 300 and tens of thousands of years depending on connectivity and assuming no other injection). However, preliminary calculations indicated that this was unlikely to significantly increase the risk of failure. In addition, the detailed analysis of the near-wellbore effects was only for vertical wells with analysis for deviated wells requiring further investigation.

Coupling of dynamic flow, geomechanical and geochemical models is still at a research stage. The geochemical modelling performed at Goldeneye was therefore not coupled directly to the geomechanics, but its separate results suggested that no

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[17] To 38 million scfd per well [1 million cubic metres per day per well] if reservoir fracturing was suspected.

[18] Geomechanical simulations were run using a 364736-cell box model, 50 km by 20 km by 8km deep. The mesh was made up of hexahedral cells with a horizontal resolution of 250 m around in the central area of the production and injection volume, and 500 m cells outside. Minimum cell thickness was set to 20m. Metre-scale pressures and rock properties from the dynamic model were upscaled into the grid. Additional laboratory experiments (e.g. to derive rock strength parameters) were done on reservoir core. Caprock core was too poorly preserved for directly deriving fault stability parameters, so these were derived from proprietary correlations based on surface measurements on caprock cuttings and compared to other published values.

large-scale rock weakening (e.g. by porosity enhancements thereby increasing compressibility) would occur. This was backed up by "worse-case scenario" laboratory experiments, flushing CO_2 though reservoir core samples. The geochemical modelling results suggested that there might be a permeability decrease during injection, but it was considered to be unlikely to have significant impact on injection pressures.

3.6 Storage capacity estimate validation (#4 issue, section 1.1)

At Goldeneye the requirement for the 2009-2011 DECC competition was for the site to store 20 Mt of CO_2, so capacity estimates were made to ensure that the site had sufficient space. *The refinements in capacity estimates are documented in the CO_2 Storage Estimate report.*

As is common with depleted field storage sites, an initial estimate was made using a simple volume-for-volume replacement of produced hydrocarbon (recharging the pressure in the field back up to the initial discovery pressure). At the time of the Longannet-Goldeneye proposal (2009-2011), production had not quite ceased at Goldeneye and was therefore made using projected final volumes. This gave a **theoretical capacity of 47 Mt of CO_2**.

This value was subsequently refined to take storage efficiency factors into account (i.e. to reflect that not all the space previously occupied by hydrocarbon would be able to be refilled by CO_2). Sensitivity analysis to investigate particular elements with the greatest uncertainty was performed (summarised below) to deduce how much each of the storage efficiency factors (Figure 16, Table 5) would impact on the capacity. This gave an **effective capacity of 34 Mt** (i.e. 170% of requirements).

This was then compared to results using 3-phase dynamic "fill to spill" flow models to investigate different injection scenarios. It also enabled additional spatial storage efficiency factors (such as the areal sweep that could not easily be estimated analytically) to be taken into account and checked that the interaction between the geological and dynamic systems did not result in any unexpected capacity reductions. Three injection scenarios were investigated for three different history matched geological realisations: a 'reference case' (injecting CO_2 through 4 of the 5 wells evenly for 10 years) and two 'extreme cases' (injecting all the CO_2 through 1 well, and doubling the injection rate). These were run beyond the proposed end of injection to investigate the "fill to spill" capacity. All scenarios showed that that the site had a **dynamic capacity of over 30 million tonnes of CO_2**, corroborating the calculated effective capacity. All capacity estimates therefore showed that there was more than sufficient capacity for the 20 million tonnes required for in the UK Demonstration Competition.

a) **Geological (static) uncertainty** gave rise to uncertainty in storage volumes available and also filling efficiency factors. The static model iterations were validated within the P15-P85 range of production team's 381 stochastic models for gas-in-place-volume. Three main geological features affected the gas in place volumes and so a sensitivity analysis on each was performed:

- Internal reservoir zonation resulted in volume changes -9.6% to +4.8% from the base case
- Position of the northern stratigraphical pinchout resulted in volume changes of -5.3% to +1.2%
- Angle of structural dip of the western flank of the field gave a maximum volume reduction of 1.5%.

b) **Dynamic parameter uncertainty** gave rise to uncertainty in filling efficiency factors. Relative permeability end-points and residual saturations were identified as having the greatest potential to affect storage capacity. At the time of writing (2009-2011) little had been done to establish potential relative permeability end-points for CO_2-brine systems using rocks similar to Goldeneye that could be considered representative. Laboratory experiments on Goldeneye core, analytical solutions (Buckley–Leverett and fractional flow calculations) and numerical simulations (using Peng-Robinson EOS calibrated to Goldeneye specifics) were therefore initiated to try and establish both relative permeability end points and residual water and gas saturations that could be expected. Findings were:

- Residual gas saturation was 25-38% (based on lab experiments, corroborated by published porosity-saturation correlations). 30% was used in the numerical simulations.
- Initial, pre-production residual water saturation was 7%, but on the time scale of injection (i.e. before buoyancy and capillary forces have time to re-equilibrate the system), the effective residual water saturation could be as much as 25% (based on the analytical techniques with sensitivity in the Corey Exponent, corroborated by numerical simulation).

Simulations were run on dipping-box models (to simulate the dipping western flank of the field) to investigate the sensitivities to effective water and CO_2 relative permeability end-points (i.e. at residual gas and water saturations, respectively):

- Effective water relative permeabilities of 0.6, 0.25, 0.1 (at residual gas saturation of 30%) showed CO_2 flowing downdip, sub-parallel to the dipping reservoir caprock and out of the original hydrocarbon-water contact. This is known as a Dietz tongue and results in unstable displacement and inefficient filling of the reservoir in the short term. However once injection ceases the tongue retreats updip leaving capillary trapped CO_2 in the water leg and the CO_2 spreads out within the storage structure.
- Effective CO_2 relative permeabilities of 0.8, 0.5, 0.25 (at residual water saturation of 25%) made little difference to the distance that the plume travelled (but would have an effect on the injectivity, as at the lower end points higher differential pressures will be needed to move the CO_2).

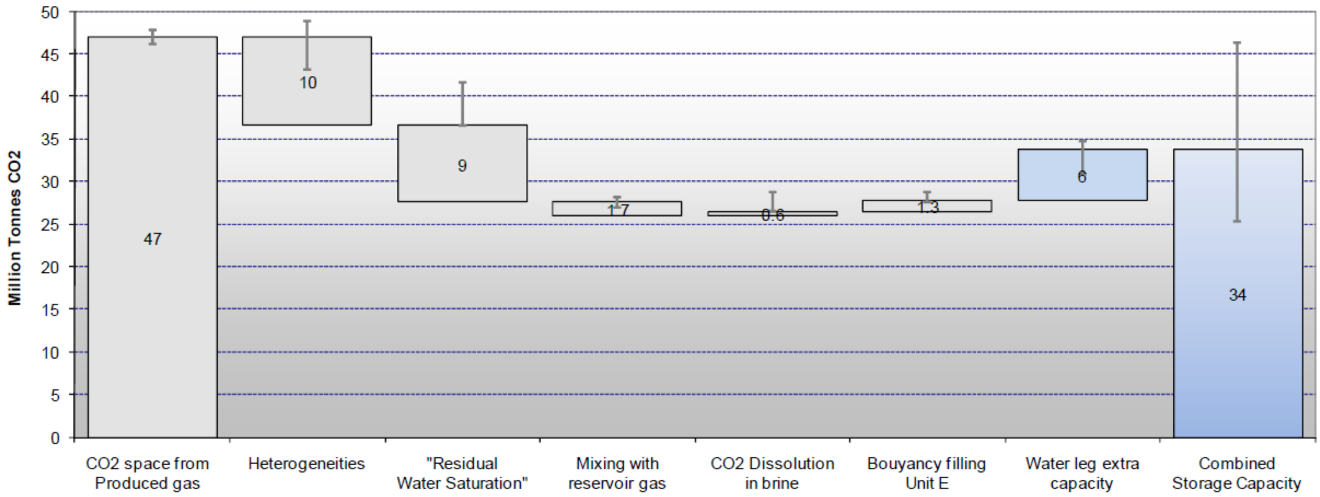

Figure 16 The factors that influence effective storage capacity at Goldeneye. Error bars represent the uncertainty on each factor. (ScottishPower CCS Consortium, 2011f).

Factors that act to <u>reduce</u> capacity (from theoretical)	Factors that act to <u>increase</u> capacity (from theoretical)
Heterogeneities (- 9.7 Mt). Part of the reservoir is likely to preferentially fill based on its favourable porosity, permeability and net to gross properties (based on evidence from gas production). *Geological uncertainty on exact volumes, particularly reservoir internal zonation. Note that aerial efficiency sweep is not taken into account analytically, only in the simulators.*	**Storage in water leg (+ 6 Mt).** CO_2 is pushed below the pre-production oil-water contact into the water leg during injection. Once injection stops this CO_2 flows back up into the field, leaving between 20 and 30% behind, capillary trapped in the water-leg. *Geological uncertainty on exact volumes depending on dip of the west flank and stratigraphic pinch out.*
Residual water saturation" (- 9 Mt). Pore volume could be filled with up to 25% residual water during injection when the CO_2 has pushed away moveable water, (rather than the initial, pre-production residual water saturation of 7%). *Dynamic uncertainty on exact values based on Corey exponent sensitivity in analytical calculations.*	**Buoyancy filling (+ 1.3 Mt after 20 years).** Post injection, part of the reservoir initially bypassed by the CO_2 (because of less favourable properties, including lower permeability) begins to overcome capillary forces and fill under buoyancy. If this was 100% efficient, 3.4 Mt of extra capacity could result, but production history suggests it is still part-filled with gas, so estimates suggest CO_2 re-filling efficiency could be 33-66%.
Mixing with reservoir gas (- 1.7 Mt). CO_2 will mix with gas remaining in the reservoir, changing its density (and therefore compressibility). The Real Gas theory equation was used to estimate that capacity would be reduced by 6% if there was perfect mixing, but simulations shows that gas is pushed ahead of the CO_2 plume, thereby reducing mixing opportunity, so the real effect on capacity is small	**CO_2 dissolution in brine (+0.6 Mt).** Various published correlations were used to determine CO_2 solubility and adjusted for Goldeneye reservoir conditions to give a CO_2 solubility of 4.6% by weight. If the CO_2 contacts with the 25% residual water saturation during injection, it is estimated that this dissolution would increase storage capacity by 2.2%. Other effects (diffusion and convective mixing) could increase this but are not included here because of the long time scales involved. (e.g. after 10,000 years, numerical simulations showed 14% of injected CO_2 could be stored in the dissolved phase).
Irreversible compaction after gas production (negligible). Experiments on core showed that the porosity change was too small to have a significant effect on capacity (porosity reduced about 0.3% (loaded 17 – 34 MPa) as a result of some calcite cement dissolution, but not sufficient weaken the grain support and make the pore space collapse irreversibly.	**Mineralisation (negligible).** Over a long a time scale this would have an effect, but it is considered to occur over too long a time scale to count towards capacity in this instance.
Interaction with neighbouring fields or new storage sites in the vicinity could also impact on capacity (unknown, but not considered to be significant for the proposed project duration and start date).	

Table 5 The factors that affect storage efficiency, i.e. act to increase or decrease storage capacity at Goldeneye (from the theoretical maximum, to give the effective capacity, Figure 16) (after information in Scottish CCS Consortium, 2011f).

3.7 Long-term wellbore integrity assessment and remediation measures (#5 issue, section 1.1)

Risk of loss of containment via wellbore-related leakage was considered to be one of the principle threats at Goldeneye. This section is based on reports from both the Longannet and Peterhead proposals as indicated below. Workshops were held during the FEED studies to ensure experts from all the required disciplines were present for discussion on wellbore material requirements and design to ensure a safe injection operation and subsequent abandonment to maintain long-term integrity.

Three types of well are considered at Goldeneye, old wells (plugged and abandoned), operational wells and potential new wells. No new wells are proposed at the site but should any be required their materials and design will be subject to the latest requirements and best practice, as would plugging and abandonment of the injection wells. Proprietary CO_2-resistant cements, might be utilised if they can be shown as superior to 'normal' Portland cement: The *Conceptual Completion & Well Intervention Design Endorsement report* for Peterhead notes that CO_2 resistant cements have not been thoroughly tested in terms of their compatibility with Portland-type cements, setting times, mechanical integrity and bonding to the required materials (formation, casings) and their long term integrity performance[19]. In addition, alternative technologies that could increase long term well bore integrity with time (rather than potentially degrading under unfavourable conditions) such as swelling packers or self-healing cement systems may become feasible.

Operational wells: The five Goldeneye production wells are cased with carbon-steel and have 13% Chromium-steel completions. These are cemented into the well using Portland Class G cement (commonly used in the hydrocarbon industry). When production ceased in 2011 the wells were suspended. All elements are expected to be suitable for CO_2 injection, once the workovers are implemented to replace the upper completion (see section 3.5.1) and some elements of the surface equipment (to improve resistance to low temperatures and explosive decompression in case of surface CO_2 release). The injected gas has specifications for temperature, water and oxygen content (to reduce corrosion and cement degradation risks). Well design and material selection were based on a combination of review of current research, detailed simulation of possible conditions and component responses, experimental and field testing and proven field experience. The next two sections are based primarily on the *Conceptual Completion & Well Intervention Design Endorsement report* with elements from the *well technical specification*

3.7.1 Mitigating risks of potential corrosion of metal casing/completion

Water plus CO_2 forms carbonic acid. The 13% Cr-steel is not expected to be affected by carbonic acid, but could be corroded by oxygen if water is also present. To mitigate

[19] Anecdotal evidence from Shell suggests that they have reverted to using Portland cement for CO_2 operations following poor experiences with CO_2-specific cements in Canada.

these risks the injected CO_2 is intended to be dry[20] with oxygen levels below a certain threshold[21].

Casing corrosion logs (using a pulsed eddy current tool) during years 3 and 6 of gas production did not show any statistically significant corrosion. However, given that the wells are currently suspended, water could have flowed into the well and the very small amount of CO_2 in the Goldeneye gas (<0.4% mol) could be causing some corrosion. Therefore pre injection well integrity logging is planned to assess baseline casing wall thickness. Integrity monitoring for tubing corrosion is planned for years 3, 7 and 11 of injection (depending on previous survey results) to give early warning of any wall thickness reductions.

Simulations of possible "worse case" corrosion rates[22] for the carbon-steel casing showed that the surface casing retained a 2.4 safety factor for loading beyond its assumed 25 year lifespan. A section of the production casing beneath the production packer is at risk from corrosion[23] if water flows back into it i.e. during periods of non-injection, although this is unlikely given the lower than hydrostatic pressure in the reservoir. In the later stages of injection, water and CO_2 will be in contact with the 13% Cr-steel completion (as will the cement). These issues are not expected to present a problem as long as oxygen content of the injected gas and the frequency of "wet events" are kept below the threshold limits (see footnote 20). Note also that this is below the production packer, so in the event that the casing were to become corroded, this would not present a CO_2 migration risk.

3.7.2 Mitigating risks of potential degradation of cement (its fabric or its bond to the formation or the casing)

There are two main risks considered here 1) that chemical degradation could occur as a result of carbonic acid forming when water contacts the cement after injection starts and 2) that mechanical degradation or de-bonding could occur as a result of the different temperatures and pressures involved in the production-injection cycle particularly in depleted fields that consider re-using production wells. This expansion and contraction could create or re-open microfractures in cement re-exposing it to water and the chemical degradation reaction. To understand the risk, the literature was reviewed, and simulations and experiments were run. These all suggested that the cement would not suffer undue damage and was fit for purpose. Literature indicated that cement degradation requires water and the rate is dependent on the pressure and temperature conditions and (the square root of) time[24]. Initial reactions would likely 'self-heal' by precipitating a film of calcium carbonate (limestone), slowing degradation, although these could be re-opened mechanically. Experiments to

[20] CO_2 injected will be dry, but corrosion tolerance allows <165 days of wet events per year over 15 years.
[21] Less than 1 ppm (by vol.) of O_2 in the CO_2, equivalent to <10 ppb (by mass) dissolved in water.
[22] 0.5 mm/year corrosion rate and a 25 year life span was modelled for the surface casing.
[23] At potential rates of up to 10 mm/year
[24] Estimates of degradation depths over 10,000 years range from 0.05 to 12.36 m, with Goldeneye conditions returning 0.5-2.5 m.

measure the expansion and shrinkage of the cement[25] showed very little of either. These were conducted at atmospheric pressure (based on recommended practice), so in addition, simulations were run to analyse the mechanical integrity of cement and its bonds to formation and casing at downhole dynamic conditions. Results from simulating a variety of operational scenarios, including production - injection but not repeated start - stop cycles, all showed a capacity for further cycling or fatigue left in system.

To reduce potential rates of any cement degradation, the CO_2 is to be injected at 0 - 5°C. This is a lower temperature than many USA CO_2-EOR wells, which often inject CO_2 at ambient temperature, but nevertheless, these show extremely small degradation rates (see SACROC Chapter 5). This, combined with good cementing practice is expected to reduce risks involving cement integrity in the injection wells. In addition, cement quality and placement will be evaluated both pre-injection and post injection by cement bond logs and ultrasonic borehole imaging tools.

3.7.3 Understanding the risks relating to currently abandoned wells

A well integrity desk study was initiated to examine the 13 plugged and abandoned (P&A) wellbores in the vicinity of Goldeneye[26] to assess their potential CO_2 leakage threat. This included determining their position relative to possible migration scenarios and the quality of barriers at both the primary and secondary seal levels within each well. All were concluded to have sufficient barriers and sealing capacity.

Scenarios were run in the dynamic flow model to examine possible plume extents after 20 Mt had been injected with a further 20 years post-injection for the plume to equilibrate and spread out within the structure. This included scenarios of spreading should the CO_2 migrate into the secondary containment units within the overburden. The amount of free CO_2 predicted to be present around each well at that time was listed for all wells[27] to understand possible leakage risks from each.

The quality of barriers was assessed by examining, for example the number and positions of the cement plugs, what the plugs were supported by (e.g. a previous cement plug or a viscous pill etc.), the thickness of the barrier, whether they had been verified at the time (tagged or pressure tested) and whether cement bond logs were available to assess the behind-casing cement integrity across the seals). The wells that were predicted to possibly come into contact with CO_2 had good barriers[28]. Those with poorer barriers (for example at the secondary seal level) were unlikely to contact

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[25] Using a mix very similar to that used at Goldeneye, unfortunately the exact match was no longer on the market, but the mix was deemed close enough to be representative

[26] Exploration and appraisal wells. The oldest is from 1979. 1 is deviated the rest are vertical.

[27] Models show that 4 P&A wells are contacted by CO_2, with 0-13 Mt beneath. For comparison, the recompleted injection wells have 9-13 Mt beneath.

[28] The 4 old wells that would be contacted by the plume in the primary reservoir had "sufficient barriers" at the primary seal level. 3 wells had potential contact via secondary seals and 6 were not expected to contact it either through not having reservoir at either level or being too far away. 1 of these is the only well in the assessment with poor abandonment quality that could potentially represent a leakage threat to seabed if CO_2 were to migrate that far.

CO_2; if it were to migrate that far it would become residually trapped prior to reaching them and so were considered relatively low risk.

3.7.4 Monitoring for potential leakage from wellbores (Described in the Well Technical Specification report for Peterhead)

During injection the recompleted wells will be operating within their design specification and so would be unlikely to leak. However, if leakage should occur the severity of impact could be high, so various monitoring technologies are planned to monitor real-time well integrity and allow early intervention if required. During the recompletion of the wells, permanent pressure and temperature (P&T) gauges will be installed along with fibre optic systems for distributed temperature sensing (DTS) and distributed acoustic sensing (DAS) in each well.

The DTS is able to take continuous measurements at 1m intervals and is anticipated to enable rapid identification and location of any tubing leak. The DAS is a less mature technology but would essentially enable collection of acoustic data in a similar manner. The feasibility of using real-time borehole stress and tubing/casing deformation imaging was also considered. It uses a fibre-optic system wrapped around the outside of casing or tubing. The cable contains strain gauge sensors every centimetre, capable of measuring less than micro millimetres of deformation. This high resolution strain data can be processed to provide a real time image of borehole stress (*Monitoring Feasibility Report*).

Four permanent gauges, routinely used in hydrocarbon production, are planned for each well, three for monitoring P&T in tubing and one in the annulus. They will require recalibrating for the CO_2 storage operation at Goldeneye as they are slightly outside their usual calibration range[29].

Other conformance monitoring will check that plume behaviour is as expected and environmental seabed monitoring around the wellbores, especially the slightly higher-risk old wells will provide additional assurance that they are not leaking. Dedicated sediment sampling to monitor the geochemistry and biology of the samples is proposed within a 500 m radius of all abandoned wells (pre-injection and 5 years in). Multibeam Echosounding (MBES) to detect seabed features and active seeps across the whole Storage Complex is proposed pre- and post-injection. Water column profiling will monitor continuously beneath the rig. Seismic monitoring of the overburden would detect build ups of CO_2 in the subsurface (see section 3.3 and Table 4). Contingency monitoring will be deployed if a significant irregularity is suspected to identify the source of any leak and verify whether it is wellbore related.

Monitoring is anticipated to continue after the end of injection, although the exact length of time will depend on when the store is anticipated to regain its initial pressure. If it is likely to be more than 20 years, the operation may be handed over to the

[29] The P&T gauges commonly in use in the hydrocarbons industry (in the North Sea) are routinely calibrated for 25-150°C [65-302°F], whereas bottom hole temperatures predicted in modelling at Goldeneye were in region of 17-35°C [63-95°F].

competent authority when it is still sub-hydrostatic. Pressure monitoring via currently available methods (i.e. requiring the wellbores to be left open and the platform remaining in place) is expected to cost potentially more than £2 million GBP per year. However it is conceivable that technology to remotely monitor pressure while abandoning the platform and wells might be available by the time this stage is reached.

3.7.5 Mitigating risks of leakage post injection well abandonment: Possible abandonment plans are laid out in *Well Technical Specification for Peterhead* but would be updated according to the legislative & industry standards at the time of abandonment.

Broadly they consist of removing necessary parts of the completions (the upper completion packer and potentially parts of the lower completion), setting two cement plugs at the primary seal level, ideally inside casing assuming that cement bond logging confirms cement top & quality is acceptable, or by milling out the casing to create a 'rock-to-rock' cement plug if not. In this case the plug across secondary seal would provide a secondary barrier to the production casing annulus. The secondary containment level will also be plugged by either a single cement plug if CO_2 shows no sign of migrating into it, or by two plugs if CO_2 saturations are suspected.

The thickness of the cement plugs and potential cement degradation rates are such that (see section 3.7.2 and footnote 24), that they will likely maintain their integrity for many thousands of years. There is a very small possibility of CO_2 leakage *around* the plugs and therefore seabed environmental monitoring is set up to assess for this (section 3.7.4).

3.7.6 Corrective measures if an abandoned well is found to be leaking

Options are reported in *the Corrective Measures Plan.* They depend on the nature and severity of impacts as determined by risk assessment and on the source and nature of the leak as determined by the contingency monitoring. Directly re-entering an abandoned well is not an option because offshore it is standard practice to remove all trace of the top parts of the well to avoid trawler obstructions. Therefore if remediation were required on a leaking well, a relief well would need to be drilled, re-entering the abandoned wellbore at a depth where it was sufficiently stable to do so. In the hydrocarbons industry relief wells have only been drilled into non-abandoned wellbores and even this is extremely uncommon, difficult and costly (requiring the use of sophisticated downhole directional steering and hole-locating tools). As such, the procedure would only be initiated once monitoring had established that re-entering the well was the most effective course of action. If the hole section requiring re-entry is cased, it can be found using magnetic detectors. Re-entering a section where the metal parts have been removed is more problematic and is likely that the cased part above it would need to be targeted. Various schematics and explanations of the types of relief wells that could be implemented are included in the corrective measures plan which estimates that the time to drill a relief well (not including rig-sourcing time) at Goldeneye would be 55 days.

3.8 Implications for the cost of modifications and storage development. (#6 issue, section 1.1)

The ScottishPower CCS Consortium have published breakdowns of cost information[30] on the CCS chain in their *FEED Close Out Report* with the aim of enabling potential developers of CCS projects to estimate up-front FEED costs. All the data in this section is derived from that document, specifically chapters 2 and 10, It includes capture from the Longannet power station (by ScottishPower), onshore transport & compression of the CO_2 at St Fergus (by National Grid), and offshore transport & storage in the Goldeneye depleted gas field (by Shell). Estimates for capital costs, operating costs and the cost of abandonment and decommissioning[31] are presented, both as early-stage estimates ("Pre-FEED" in Figure 17) and late-stage close-out costs ("Post-FEED in Figure 17), to enable to the reader to appreciate how the cost estimates were refined during the course of the FEED study. Pre-FEED costs were estimated with an accuracy of -30% to +50%. This was reduced to -12% to +15% for the some of the capital costs by the end of the study, and to -15% to +25 or 30% for the capital costs specifically associated with storage (ScottishPower CCS Consortium, 2011a).

The total cost for accomplishing the FEED work itself was £38.6m GBP (£1.4m below budget). This represented 393,544 person-hours work in total (shared between around 300 people, but otherwise equivalent to 45 years of continuous working for one person). £12.6 million GBP (or 33%) of the total cost and 20% (77,142 hrs) of the total hours were attributed to Shell. Of this time, around 36% of the hours (~28,000) were spent on geosciences, reservoir engineering, production chemistry, monitoring and reservoir management reports.

Costing methodology: Each of the three main partners (ScottishPower, National Grid and Shell) submitted costs according to their own internal methodologies (and associated accuracy estimates) and these were combined. An amount was then added to this to allow for typical development in the scope during the implementation stage. This made up the "Core Costs" i.e. those items that are mainly capital costs (for tangibles, such as equipment etc.) that can be assembled directly from quotes and estimates. On top of this is added a contingency amount (based on identified risks and also allowing for unknown events) and an amount for fees associated with managing the project, both of which are indicative, as they would be subject to later-stage commercial negotiations.

Differences in the pre- and post-FEED capital and abandonment cost estimates are shown in Figure 17b. Operating costs at not shown because costs for capture and transport were calculated differently pre-and post-FEED, involving price or energy (MWh) per tonne of CO_2 post-FEED rather than the pre-FEED annual estimates. Only

[30] All prices are in 2010 terms, with no inflation applied and assuming an operating life of 15 years (the duration of the project) after which time there would be no residual value.

[31] Post-injection monitoring and well closure have not been included as a result of uncertainties in requirements and liability at the time of writing, although these would require inclusion if the project were to proceed.

the storage elements are discussed in the text here and these include costs relating to the preparation of the offshore pipeline, infrastructure and wells at the Goldeneye site and associated surveys:

Capital cost estimates for storage were £207.8 million (Figure 17 and Table 6). This is 35% lower than the pre-FEED estimates as a result of an improved understanding of the work required once the FEED study had been done. In particular, the scope and costs of work at the wells was significantly decreased once the extent to which well-workover was required was established.

Post-FEED, the storage operating costs were £12.8 million per year (scaled up from the reported per-month estimates). This was less than the pre-FEED £15.8 million per year estimate, although it is difficult to compare directly given the different methods of estimating these (Table 6).

Decommissioning and abandonment cost estimates for storage were £123.1 million. This was an increase of 78% on pre-FEED estimates and reflects the refinement of initial rough approximations following the improved understanding achieved through the FEED (Figure 17 and Table 6). Pre-FEED no allowance had been made for pipeline decommissioning, and infrastructure and so well related estimates increased by 36% and 43% respectively.

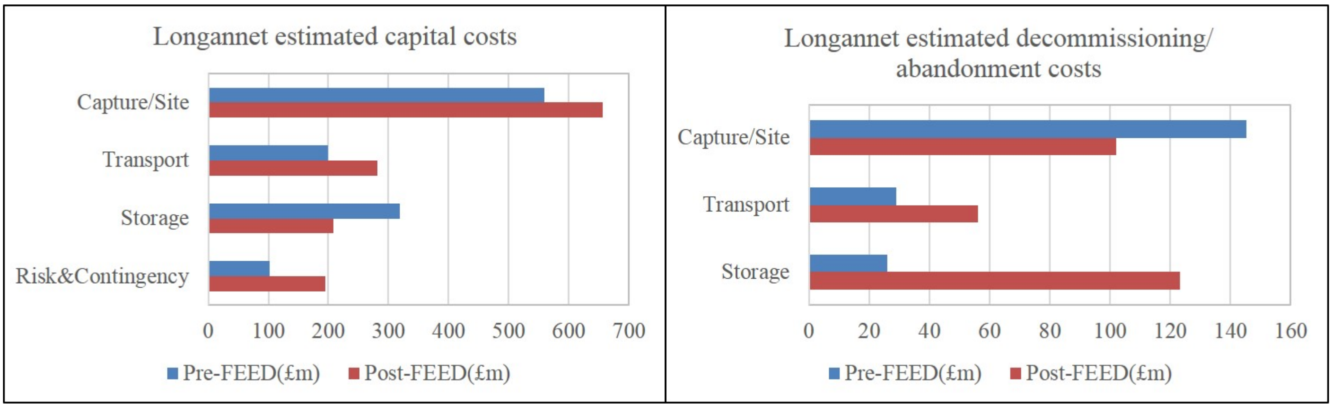


Figure 17 Comparison between cost estimates derived pre- and post-FEED study. (after information in Scottish CCS Consortium, 2011a).

	Storage cost estimates (£mil)						
	Capital		**Operating**		**Abandonment and decommissioning costs**		
	Item	**Cost**	**Item**	**Cost**	**Item**	**Cost**	
Pre-FEED	Offshore pipe	114.4	Offshore pipe	15.5	Offshore pipe	0	**Pre-FEED**
	Infrastructure at Goldeneye	32.4	Infrastructure at Goldeneye	0	Infrastructure at Goldeneye	9.3	
	Wells at Goldeneye	171.9	Wells at Goldeneye	0.3	Wells at Goldeneye	16.9	
	Pre-FEED total	**318.7**	**Pre-FEED total**	**15.8**	**Pre-FEED total**	**26.2**	
Post-FEED	Pipeline preparation	4.6	Fuel	0.05	Pipelines	31.4	**Post-FEED**
	Subsea	8.9	consumables	0.10	Offshore Topsides & Subsurface	25.7	
	Wells	37.5	Waste	0.02	Wells	39.3	
	Topsides/Platform	91.3	Maintenance	3.41			
	Pre-injection	16	Staff	2.42			
	FEED extension	12.5	Insurance	0.23			
	Surveys/Licenses	22.1	Overheads	2.14			
	St Fergus	14.9	Lease costs	0.10			
			Other fixed	4.36			
	Post-FEED total	**207.8**	**Post-FEED total**	**12.8**	**Post-FEED total**	**96.4**	

Table 6 Breakdown of the cost elements relating to storage for capital, operating and abandonment including both pre- and post-FEED cost estimates. (after information in Scottish CCS Consortium, 2011a).

Chapter 4 Case study: Cranfield

This chapter describes specific aspects of the CO_2 storage and enhanced oil recovery in the Cranfield depleting oil field, relevant to the scope of this report (section 1.1). Context for the legislative framework in the USA and the suitability sites for EOR (with or without CO_2 storage) is provided in section 2.2.1. The Cranfield site itself is described in section 2.2.3. The box below is a copy of the summary information from that section, highlighting which elements of the scope are described in this case study.

Cranfield site summary

Location: onshore Mississippi, USA

Depleted: oil with a gas cap

Type: CO_2-EOR and also injection into the water leg for research

Status: operational (~8 Mt injected and ~5 Mt stored since 2008)

Economic viability: industrial CO_2-EOR with DOE funding for research

Geological setting: heterogeneous fluvial sandstones at ~3,000 m [~9,843 ft] depth with marine mudstone caprock

Key findings from the site: (i.e. how it contributes to addressing scope, section 1.1)

x	#1. Risk assessment criteria
	#1a. Implications for continued oil and gas production in adjacent fields
x	#2. Monitoring criteria (to quantify CO_2 storage and detect the extent of migration)
x	#2a. Implications e.g. the effects of residual hydrocarbon fluids
x	#3. Pressures changes & thresholds and how these can be mitigated
x	#4. Storage capacity estimate validation
x	#5. Long-term wellbore integrity assessment and remediation measures
	#6. Cost of modifications and storage development

4.1 Risk assessment criteria (#1 issue, section 1.1)

A risk assessment using the Certification Framework (CF) approach (Oldenburg et al., 2009) was conducted at the start of the SECARB study of Cranfield (Nicot et al, 2013). The CF conceptualizes the system as source, flow conduits (wells and faults), and compartments. Five compartments can be impacted by fluid leakage through conduits: hydrocarbon and mineral resource (HMR), underground sources of drinking water (USDW), health and safety (HS), near-surface environment (NSE), and emission credits and atmosphere (ECA). The analytical process go through the following steps: 1) define the storage region; 2) Identify vulnerabilities; 3) Characterize vulnerabilities; 4) Model injection, migration of CO_2, brine pressurization, and fluid flow in wellbores;

5) Estimate likelihood of leakage; 6) Model impact of leakage on compartments; 7) Discuss risk.

During the process of identifying vulnerabilities, processes analysis showed that wells and faults as conduits and spill points of the structure were the major vulnerabilities. In this assessment the greatest risk of not retaining CO_2 was determined as failure of wells to isolate the injection zone from overburden or the surface (section 4.6). Transmissive faults (section 4.4) and lateral migration out of the structure (section 4.5) are also considered. Methods to asses these three risks were included in the monitoring program.

4.2 Monitoring criteria to quantify CO_2 storage and detect migration. (#2 issue, section 1.1)

The SECARB early monitoring program was designed to test approaches to meet DOE's goal of improving monitoring, both to increase confidence that CO_2 is being stored with high levels of retention and to improve capacity estimation by assessing how CO_2 moves in the reservoir. The experiments conducted focused on testing multiple technologies against each other. Because anthropogenic CO_2 is not being stored at the site, a full field-wide monitoring program to allow reporting of amounts stored was not required. Instead, products were a series of analyses leading to publications about monitoring technologies.

A large number of approaches and tools were assessed (
Table 7). In this review we focus on key findings that are relevant to other storage sites undergoing CO_2-EOR and storage at depleted fields. From the number of broad research goals at Cranfield, those presented in this case study include: Impact of heterogeneities on fluid flow, storage capacity and pressure effects, boundary conditions and migration of fluids out of the structure, and measuring retention in the reservoir. Reservoir heterogeneity is considered in this section and its impact on optimally locating reservoir monitoring (in time and space). Surveillance of above-zone monitoring intervals (AZMI) and monitoring of shallow intervals are also briefly described in this section. Other aspects of the monitoring programme are described in the subsequent report sections.

Monitoring methods	Location	Deployment	References
Electrical resistance tomography	through and beyond Injection zone	31 Electrodes installed behind casing in two monitoring wells	Yang et al., 2014
Pressure and temperature gauges	Injection zone, AZMI	On tubing and behind casing	Meckel et al., 2013
VSP and cross-well continuous active seismic	Injection zone	In and behind casing	(Ajo-Franklin et al. 2013)
Reservoir geochemistry	Injection zone	Wellhead, U-tube, Kuster sampling	Lu et al., 2012a, 2012b
Fibre optical distributed temperature	Throughout injection zone and overburden	Behind casing	Nuñez-López and Hovorka, 2012
Reservoir saturation tool log	Throughout injection zone and AZMI	Time-lapse logging	Butsch et al., 2013
Fluid density log in wells	Throughout wellbore	Production log to measure pressure, temperature, fluid density in tubings	Verma et al., 2013
Shallow groundwater geochemistry	Shallow aquifer	Time-lapse groundwater sampling, push-pull test	Yang et al., 2013, 2015
Tracer test	Injection zone	Noble gas, SF_6, PFTs tracers injected with CO_2 and received at monitoring wells	Lu et al., 2012a
Microseismicity	Near surface	6 seismometers installed in shallow wells	Takagishi et al., 2014

Table 7 Monitoring technologies tested at Cranfield.

4.2.1 Modelling uncertainty in reservoir heterogeneity to determine optimum downhole monitoring sampling frequency

During the characterisation of the site to determine the most effective monitoring to deploy, it became apparent that, given the complexity of the site, careful monitoring design was required to enable interpretable data to be extracted. The complexities included: the heterogeneous nature of the rock with complex fluid distribution in the pores, the perturbed fluid compositions and pressures from past operations and uncertain lateral boundary conditions, in addition to complex fluids in zones above the reservoir, and near surface complexities. Because similar complexities are likely to occur at other depleted reservoirs, details are provided:

The lower Tuscaloosa reservoir at Cranfield contains fluvial gravels and chlorite-cemented sandstones that are incised into each other in a complex way in three dimensions (Figure 7). Channels are laterally sinuous and barriers between channels are discontinuous. Interbedded finer-grained sandstones and cemented zones are not clearly distinguished from the coarser-grained zones on logs or 3D seismic so that deterministic mapping was not possible, and from the early stages of designing the project the uncertainties were approached probabilistically. For example, for the research injection into the water leg, the target injection rate of 1 Mt per year could be accomplished using four wells. However because the project team had limited ability to target the high quality parts of the reservoir, 8 wells were planned to accomplish the target rate.

Reservoir heterogeneity leads to uncertainties in how much of the pore space will be occupied by CO_2 and how connected the permeable zones are. These fluid flow uncertainties lead to uncertainties in the velocity of CO_2 migration from one measuring point to another (e.g. breakthrough at an observation well) and uncertainty as to whether the plume and CO_2 saturation will be detectable (low saturation and thin plumes may be difficult to detect with either surface or well-based geophysics, but should be detected with geochemical methods). The project team therefore modelled and planned for uncertainty. A fluid flow model was prepared after drilling and logging three wells and analysing two cores. Though the reservoir model is constrained by three close-by wells, property distribution across the whole reservoir can only be done probabilistically with relatively high uncertainty because of the heterogeneous nature of the fluvial depositional system. Consequently, model predictions at inter-well scale are highly uncertain in terms of CO_2 breakthrough time, saturation distribution, and plume fingering. For example, single phase hydrologic testing showed a range of CO_2 breakthrough times from 5 days to more than 30 days at the nearest observation well at the detailed study site, so that a sustained period of sampling for the U-tube sampler was planned.

4.2.2 Monitoring in above-zone monitoring intervals (AZMI)

SECARB researchers tested a well-known technique for surveillance of gas storage fields at Cranfield: measuring pressure in an above-zone monitoring interval (AZMI). This was the first time such techniques had been deployed at a CO_2 storage project. The optimal AZMI should be an idle zone (i.e. one not used for either injection or withdrawal), reasonably transmissive and hydrologically connected over a significant part of the field, but relatively thin (Zeidouni et al., 2014; Sun et al., 2013). The AZMI well was completed to isolate the selected monitoring zone from other zones, a pressure gauge was installed in good communication with the perforations. If any well in the area were to leak fluids from the high pressure parts of the injection zone into the AZMI, pressure would increase over a relatively large area of the AZMI. If no fluid leakage occurs, the pressure in the AZMI may respond to geomechanical deformation of the injection zones, but no sharp rises in pressure will occur. Pressure showed a measureable increase in the AZMI at Cranfield. Numerical simulation and analytical methods show that the pressure response can be accounted for by mechanical deformation of the AZMI due to the pressure increase in the injection zone without upward hydraulic flow (Kim and Hosseini, 2014). The study indicates that the caprock sustained a certain degree of deformation and retained its integrity. Multiple AZMI gauges have the potential to provide information on the location and magnitude of any leakage and such set-ups have been deployed at commercial sites.

The capabilities of geochemical AZMI monitoring was also tested to help distinguish whether elevated pressures were the result of brine ingress (no major change in geochemical signal) or CO_2 ingress into the AZMI (expected geochemical signature change). However, acquisition of uncontaminated samples suitable for geochemical analysis proved difficult because of the complex dual-completed wells and corrosion and damage of packers and tubing during prolonged idle periods. Additionally, modelling shows that a geochemical leakage signal would be much more localized that the pressure signal (Porse 2013). In an idle AZMI, to get a good probability of leakage detection using the geochemical signal a higher well density, set out in an array and a longer period of observation would be required, compared to the pressure signal in the same setting.

A novel method for detecting CO_2 leakage into an AZMI has been developed based on time-lapse compressibility using pulse injection tests (Hosseini, 2014). A similar harmonic pulse injection method was tested at Cranfield as a detection method for CO_2 leakage out of the injection zone (Sun et al., 2016). The field demonstration shows that deviation in the amplitude of the frequency response function of the pressure pulsing signal (measured by pressure gauges in the reservoir interval in the field test, but could equally the set up could be designed to be measured via gauges positioned in the AZMI, as per Hosseini, 2014) is a sensitive indicator for point leakage events occurred after the baseline tests. It shows that harmonic pulse injection can be easy to implement and cost-effective for monitoring a relatively large area. It only requires only downhole pressure gauges and no additional equipment. Detection thresholds for the potential leaking events can be estimated in advance, so the method can be readily deployed where this threshold meets the monitoring requirements.

Assessment of the time lapse change in seismic impedance shows no systematic change in fluid composition above the injection zone. However some uncertainty in this interpretation must be acknowledged because of the complexities described earlier and the above zone time lapse seismic is somewhat noisy. It is possible that minor gas in zones above the reservoir could also mask CO_2 leakage signals, but this has not yet been specifically investigated.

4.2.3 Monitoring in shallow intervals

At Cranfield, hydrocarbons occur in zones above the reservoir. This is common in many depleted reservoir settings and adds to monitoring complexity. Commercial hydrocarbon production in the Wilcox Formation above the lower Tuscaloosa formation results in decreased pressure in the shallow oil production intervals. In addition, the geochemical signals are not unique to individual zones/formations. A soil gas study at a well pad with high concentrations of CO_2 and methane (Anderson et al, in prep.) showed anomalous gas compositions and stable isotopes that could have been attributed to leakage from depth. However, their entirely modern ^{14}C isotopic composition suggests that the methane was generated from unknown modern sources, presumably at the surface, and the CO_2 was a biodegradation product from the methane. After the proof-of-concept installations at Cranfield, additional projects have used pressure gauges and fluid sampling in multiple shallow zones to better constrain such complexities (Yang et al., 2013). Complexities in fluid and gas composition can be expected in depleted reservoir settings because of vertical hydrocarbon migration, trapping hydrocarbons at multiple horizons, or spills and contamination from past hydrocarbon extraction operations (Romanak et al., 2013).

Other near surface complexities were found at Cranfield and can be expected at other depleted fields. Both construction of new facilities and clean-up and removal of old facilities such as roads, well pads, ditches and berms, pipelines, ponds, and temporary construction can create strong perturbations in soil, vegetation, and near surface groundwater that should be taken into account.

Overall, though the geology of the reservoir is complex and the long operation history of the oil field created significant difficulties for monitoring, the combination of extensive site characterization, numerical simulation, and monitoring in multiple zones suggest effective CO_2 containment and low probability of leakage at the site.

4.3 Implications for monitoring requirements: the effects of residual hydrocarbon fluids (#2a issue, section 1.1)

The complex production history at Cranfield (when combined with reservoir heterogeneity) has had significant impact on reservoir fluid distribution and therefore, on monitoring capabilities: in particular the ability to detect and distinguish injected CO_2 from the hydrocarbons. Early in the field history, oil production caused pressure decline, so produced gas from the lower Tuscaloosa formation and other reservoirs was injected into the top of the reservoir to maintain pressure. This drew an unknown amount of gas, as well as water from the down-dip brine aquifer, to the oil rim production wells. When oil production ended, the operator produced the gas-cap and associated condensate. This further reduced field pressures and further redistributed remaining fluids. During the post-production period, the reservoir pressure recovered almost to its discovery pressure. Modelling shows this resulted in the shrinking of the gas cap and invasion by brine from the water leg.

The result is that the distribution and saturation of the principal components, brine, oil, and gas have invaded the fluid zones present at discovery under disequilibrium conditions. Fluid distribution has a strong interaction with CO_2 migration, because a) oil-CO_2 miscibility traps large amounts of CO_2 dissolved in oil phases, making storage more efficient and limiting plume spread, and b) multiple fluid capillary entry pressure effects, and c) buoyancy override effects for different fluids. Some assessment of fluid distribution can be inferred from pre-injection measurements. The present distribution of fluids in the reservoir is therefore extremely difficult to predict. Distinguishing injected CO_2 from the hydrocarbons is an ongoing area of research.

4.3.1 Using seismic methods to attempt plume tracking

Time-lapse 3D surveys have been shown to be effective in tracking the expansion of CO_2 plume in a saline aquifer (e.g. Williams and Chadwick, 2013; Chadwick and Noy, 2015), but the complex fluid distributions in depleted fields are a more challenging monitoring proposition. At Cranfield a pre-CO_2-injection 3D survey was acquired in

2007 with a repeat over part of the injection area after 1 to 1 ½ years and about 1 Mt of injected CO_2. Data were analysed utilising a number of methods and different research teams (Zhang et al. 2012; Ditkof et al., 2013; Carter, 2014, Carter et al., 2014, 2015). In addition 4D VSP and 4D cross-well seismic surveys were collected (Ajo-Franklin, et al., 2013). The fluid change resulting from substitution of CO_2 for brine is detectable, although as predicted by rock physics modelling, results in only a small change in velocity (work by Sava D., reported in contract report, Hovorka et al., 2014). Most 4D seismic interpretations show reasonable partial matches with modelled CO_2 distribution as well as other measures of distribution, increasing confidence in the monitoring (Alfi and Hossieni, 2016). Many of the wells in the northern and western parts of the flooded area show quite good matches in modelling and measured spatial extent (Figure 18).

Two areas of greater uncertainty are noted: 1) In the centre of the field, no change in seismic response to injection is observed, although CO_2 was injected into wells in this area. 2) At the margins of the field, as the fold of the survey decreases, the noise increases so that the edge of the plume is difficult to map. One possible explanation for little change in seismic velocity in the centre of the field after introduction of large amounts of CO_2 is that this area might have contained significant amounts of methane prior to CO_2 injection. (The image of a stratal-slice from the pre-injection 3-D seismic survey shows systematically lower velocity at the centre of the field, which probably indicates higher methane saturation in this region, but because the reservoir properties are also variable, no map of fluids could be created). Methane impurities in the CO_2 injection stream increased from ~4% to ~12% due to gas recycling during 3 years of EOR operation, supporting the idea that methane was present in the field (Györe et al., 2015). The presence of methane prior to CO_2 injection reduced the ability of 4D seismic of detecting the increase of gas saturation.

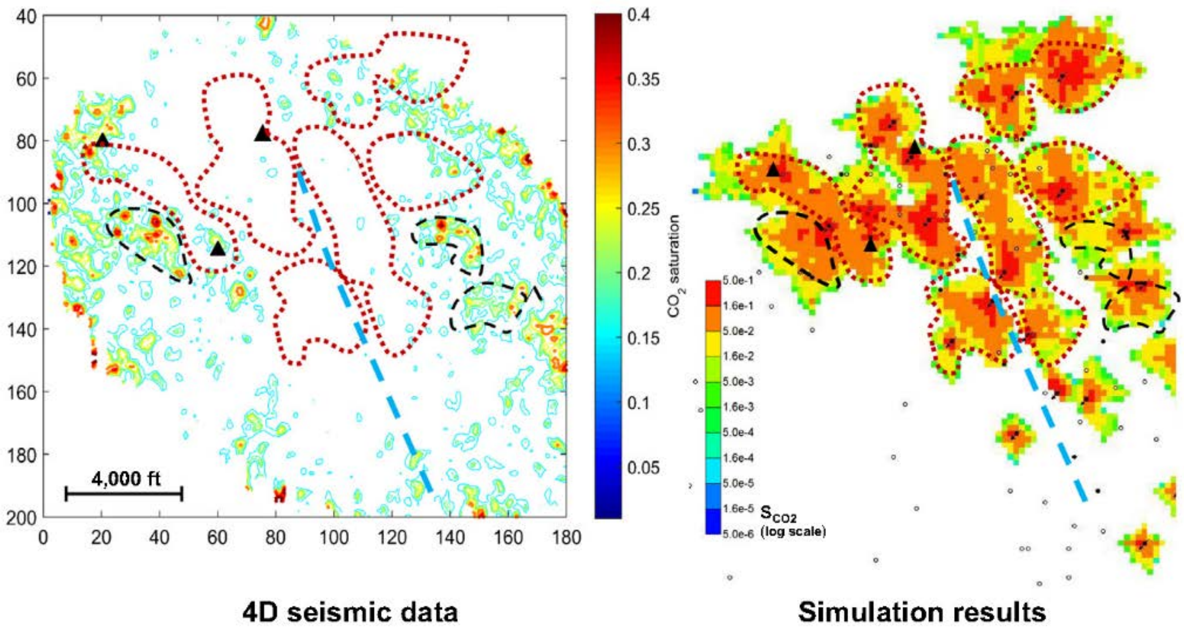


Figure 18 Comparison of CO_2 saturation distribution of seismic interpretations (Carter, 2014) **with reservoir simulation results at Cranfield. Black dashed polygons show the matches and red dotted polygons show the mismatch between the 4D seismic data and the simulation model. Blue dash line is fault.** From Alfi and Hossieni (2016).

4.3.1 Using downhole methods to attempt plume tracking

Pulsed Neutron Capture logs (the Schlumberger Reservoir Saturation Tool) were collected to measure, gas, oil and brine saturations to contribute to understanding and mapping the subsurface fluid distribution. However, logs show high vertical and lateral heterogeneity, and the number of logs that could be collected limits the viability of this method of assigning fluid compositions. The number of wells that could be logged was limited by access to the reservoir interval: In old boreholes that terminate in the reservoir, there is no rat-hole below the formation to allow the long tool to be deployed over the reservoir interval. For modelling, the fluid saturation at the start of CO_2 flooding was estimated by setting the fluid compositions at discovery and modelling production and stabilization during shut-in, an approach that worked adequately but with significant uncertainty (Choi et al., 2013; Hossieni et al. 2013).

4.4 Pressure effects, boundary conditions and CO_2 migration. (#3 issue, section 1.1)

Pressure response of the reservoir is one of the major limits on injection and is a high ranked criterion in management and regulation of an injection project. In the US, the EPA Underground Injection Control (UIC) Class II program regulates both the maximum pressure allowed and the maximum amount of fluid injected. Over-pressure during injection is recognised as a key risk in triggering fluid leakage out of the injection-zone and therefore pressure management is a key component in operation and monitoring for all injection projects. High pressure can damage the injection well construction or other wells in the area of elevated pressure and introduce buoyant fluids. Failure can result from errors in estimating the safety margins in both new well constructions, or the potentially, degraded construction of older wells.

On the other hand, for EOR it is important for the CO_2 flood to elevate pressure sufficiently so that CO_2 will be miscible with oil. This may require cessation of production and a period of injection, most typically of water, to elevate pressure to the required levels. The Cranfield unit is an anomalous case in that it almost completely repressurised during the 42 years between depletion and CO_2 flooding (Hosseini et al., 2013). The operator chose to inject at a fairly high rate, bringing pressures in the reservoir to about 6.9 MPa *above* the pre-production initial pressure. Then, as the flood evolved, pressure was moderated by production and by increased demand for CO_2. The operator chose not to inject water at Cranfield, another fairly unusual condition that increased the amount of CO_2 injected per barrel of oil produced. Many CO_2-EOR fields are water-alternating gas (WAG) operations, in which a “slug” of either field brine or fresh water is injected, followed by a period of CO_2 injection. This type of operation limits the amount of CO_2 needed as well as the amount of CO_2 produced that must be recycled, and changes the multiphase fluid interactions in ways that may benefit the flood. However, injecting large amounts of water requires pumping the production wells (Hovorka et al., 2013).

Some geomechanical effects, such as the non-linear response of pressure change to injection rate have been noted at Cranfield. Further assessment of the interaction of CO_2 and elevated pressures on the geomechanical performance of the Cranfield site are being assessed. Several possibilities are considered including the impact of cooling on rock strength and the interaction of CO_2 with rock physics, perhaps via abundant chlorite cements (White et al., 2015). In such cases, more sophisticated monitoring techniques such as multi-component and/or multi-azimuth seismics can provide information on mechanical integrity of the overburden.

4.4.1 Understanding the risk of failure of faults or fractures to isolate CO_2

One fault in the anticline’s crestal graben penetrates the lower Tuscaloosa Formation in the area of injection. The risk of vertical transmissivity along fractures associated with the fault was therefore considered in the risk assessment (Nicot et al. 2013). When the field was discovered, the fault isolated the oil-gas contact, which indicated that the central part to the fault was sealing. However, the oil-water-contact, which intersected the fault near and beyond the seismically mapped end of the offset, is continuous. This means that parts of the fault might be horizontally transmissive (i.e. across the fault). Analysis of the vertical extent of the fault shows that its seismic signature dies out in the overlying thick mudstones of the Midway Formation (T. Meckel unpublished 3D seismic interpretation). However, methane accumulated against both sides of the fault, so it is assumed that vertical transmissivity to gas is small. The impact of deformation on the fault seal integrity cannot be readily assessed.

The reservoir pressure was strongly depleted from the initial pressure of 32 MPa to 12 MPa at the end of production in 1966, and then elevated to 39 MPa in the first year of injection. It is possible that such large changes in pore fluid pressure might affect the fault seal.

4.4.2 Understanding lateral boundary conditions using pressure responses

Lateral boundary conditions have a large impact on pressure response to injection and a moderate impact on fluid flow. They also have a strong impact on rate dependent capacity (Delshad, et al., 2013; Hossieni et al., 2013). However, for the >1 Mt/yr test injection, the relevant hydraulic boundaries lie outside of the study area, kilometres away from the injection area. Regional data and structural style suggest that the Tuscaloosa sandstone is structurally continuous over large areas and the faults that offset the entire thickness are localized. However, the regional continuity of the high permeability sandstones typical of the Tuscaloosa Formation at Cranfield are not well known. Regional studies suggest that fluvial sandstones are focused in depositional belts with more discontinuous sandstones in between, and that the Cranfield field is on the margin of such a high-sandstone channel system, The expectation of relatively open boundary conditions is supported by pressure recovery following strong local pressure depletion at the end of 1966 production, however the quantification of this important parameter remains a value that is adjusted to obtain model match of pressure response.

Some depleted reservoirs have closed or nearly closed boundaries, such as the K12B reservoir studied in the Netherlands North Sea (van der Meer et al., 2005, section 2.1.4), the Mano reservoir of Rousse field in France (Thibeau et al., 2013, section 2.1.6), or the Michigan pinnacle reefs studied by Midwest Regional Carbon Sequestration partnership (Barnes et al., 2013). Closed boundaries reduce uncertainty but at the low end of the possible distribution, open boundaries lead to increased capacity but greater uncertainty.

4.5 Capacity estimations (#4 issue, section 1.1)

The theoretical CO_2 storage capacity based on produced hydrocarbon volumes at Cranfield is well constrained. However, this will be an overestimation of total storage capacity because of the much shorter timescales of injection compared to those on which hydrocarbons accumulated. The aforementioned reservoir heterogeneities (section 4.2.1) and lateral boundary conditions (section 4.4.2) will both have important impacts on storage capacity estimates. This will affect the sweep efficiency, rates of pressure rise to threshold levels and whether CO_2 might transgress beyond field boundaries (section 4.5.1, below). In addition the effects of miscibility on storage capacity at Cranfield are described in section 5.3, in conjunction with the SACROC results).

4.5.1 Understanding the risk of CO_2 migration out of the structural closure

Dips on the structural closure at Cranfield are low (1-2 °) with a total closure of 76 m on the 6.4 km wide nearly circular structure (Lu et al., 2013). One risk to be considered is the extent to which injected CO_2 will be confined to the structural closure. This is a complex issue, involving unresolved issues of interactions amongst flow mechanisms. Near an injection well where flow velocity is high, the CO_2 migration will be dominated by pressure, and even though the CO_2 is buoyant it will migrate by viscous flow process some distance down structural dip along the pressure gradient. Creation of a pressure sink at a production well will likewise increase velocity and cause flow to follow pressure gradients. In contrast, far from operating wells, where flow velocity is slow, issues of capillary entry pressure and the gravitationally induced gradient (because of lower density of CO_2 compared to brine) will cause the CO_2 to migrate upward. The third variable to be considered is how efficiently the CO_2 occupies pore volumes inside the structure. If the heterogeneity of the reservoir is high, CO_2 is slow to enter some volumes of the structure, lowing the effectiveness of the sweep and causing overflow of the structure after relatively low amounts are injected under either viscous or gravity driven flow conditions. With time, CO_2 sweep efficiency improved as the CO_2 conduits appeared to grow in size and flow velocity decreased (Lu et al., 2012a). The balance between processes has not been fully understood, but is likely dependent on a number of factors. Monitoring data was collected at Cranfield to constrain such modelling in situations where the fate of CO_2 is critical.

In the case of the EOR operation at Cranfield, injectors were set at or below the oil water contact, and CO_2 migrated in some areas more than 100 of meters down structural dip. This down dip migration was detected at down-dip observation wells (Hovorka, et al., 2013). A question remains about how far out of the structure the CO_2 migrated. In models, if high rates of CO_2 injection typical of the first years of operation for Cranfield are continued for a longer period, CO_2 would “spill” outside the structural closure (Hossieni et al., in prep).

Pragmatically out-of-structure migration is not a key risk at the study site as the wells were not drilled into the Tuscaloosa below the well-defined original OWC. Furthermore, Cranfield field is distant from other producing fields in the area, with the nearest active Tuscaloosa production 32 km to the southeast. The pressure interference at this distance is negligible for this reservoir, and the chance of CO_2 migration encountering open pathways to the surface is small. Therefore, at this site, any out-of-structure migration has little risk of leading to leakage. In addition this also means that the CO_2-EOR operation has no implications for continued oil and gas production in adjacent fields.

4.6 Long-term wellbore integrity assessment and remediation (#5 issue, section 1.1)

The performance of well completions in isolating the injection zone from other resources, groundwater, and the surface is a well-known risk. The UIC program (section 2.2.1) regulates the construction and operation of injection wells. It includes assessment of the integrity of isolation in wells within the Area of Review, which usually defaults to within a ¼ mile (~402 m) of each injector. In this field the operator chose to drill new wells for use as injectors but re-enter and re-condition existing plugged and abandoned oil production wells to serve as the producers for the CO_2 flood. Both the new wells and the retrofit[32] wells were subject to UIC permits and periodic inspection for mechanical integrity. These activities are handled by the site operator (as is conventional), rather than SECARB researchers, so the information on the well integrity of the old wells is not publically available to report here.

Risk assessment modelling shows that under the scenario at the Cranfield Unit, the injection wells have low leakage risk because they are newly constructed and the production wells have low leakage risk because they are open to production as soon as fluids can flow to the surface. The highest risk is allocated to plugged and abandoned wells that were not retrofitted as producers, because they may be subject to high pressure in the reservoir but cannot be inspected.

4.6.1 Understanding the risk of failure of historic wells to isolate CO_2

Most of the original (~100) production wells drilled into the lower Tuscaloosa were plugged and abandoned at the end of production in 1966. There are also ~130 wells drilled to the deeper Paluxy and shallower Wilcox Formations at the footprint of the field and most of them were drilled in 1950s. It was therefore difficult to evaluate the quality of the isolation over the reservoir interval for CO_2 injection. Arguably better standards of isolation are required for injection than for production, because of the importance of avoiding up-well/behind casing fluid migration.

Records of completions and abandonment procedures exist, including cement bond logs (CBL) from some wells and plug depths and cement quantities in terms of bags of cement. Only a fraction (17) of the wells were logged with cement bond logs, so the approach to understand the risk was probabilistic. The evaluation of risk of leakage defined this way is necessarily approximate. Semi-analytical solution for assessment of well leakage was conducted using permeability computed from the CBL results. Measured permeability for intact cement ($10^{-21}m^2$) and degraded cement ($10^{-15}m^2$) by Bachu and Bennion (2009) were used in the assessment. The CBLs were evaluated and used to statistically assign the risk of having poor quality cement (Nicot et al., 2013). The well permeability was estimated by averaging over the entire wellbore length and ranges from 1.3×10^{-14} to 8.7×10^{-21} m^2. Two wells with poor cement-bond quality show the highest estimated permeability. These wells do not

[32] Note that re-entering, re-conditioning and retrofitting P&A wells are common operations for re-developing older fields in North America to save costs compared to drilling new wells.

have an adequate interval of cement bond across the regional seal (the middle Tuscaloosa formation) and present significant potential for CO_2 migration along the wellbore. Simulation of CO_2 leakage through these two wells indicated that rate could be up to 1.8 t/yr (0.9 t/yr per well). The other 15 wells examined show excellent sealing capacity. Simulated average CO_2 flow rate for these wells with adequate cement bonds is negligible (5.8×10^{-6} t/yr). Furthermore, simulation results show that upward leakage along the well bores will be trapped in the upper Tuscaloosa formation and the underpressured Wilcox Group, which will serve as effective pressure sinks and prevent leaked CO_2 reaching shallower aquifers (Nicot et al., 2013).

It is strongly noted that fluid leakage out of the injection zone should not be equated with loss of the fluids to the fresh water or atmosphere. At Cranfield, multiple permeable zones above the injection would likely interact with and “blead off’ fluids rising through an unsealed casing-rock annulus, (specifically modelled by Nordbotten et. Al. (2009)). The shallower zone active production at 1,000-2,000 m depth in the Wilcox Formation could be the ultimate sink (thief zone) for a large volume of leaking fluids, however since it was operated by different producers, it was not incorporated in the SECARB project monitoring plan.

One important field observation about well quality was observed in the Ella G Lees #7 well which is a 1945 production well that was plugged and abandoned in 1969 and then re-entered in 2008 to create an idle observation well. Multiple mechanical integrity tests and CBL and casing-integrity logs were run. The permitted cement and drilling-mud plugs were located where the P&A records reported, and they had pressure integrity. A new CBL showed questionable cement above the injection zone. Since this well was to host a first experiment with AZMI pressure monitoring, a remedial circulating squeeze was carried out to cement an interval of the casing-rock annulus that appeared open on the CBL. However, the squeeze was unsuccessful because the annulus was not open, and in fact there was no pressure connection along the annulus of the selected poor quality cement bond interval. It appears that the well was effectively sealed, though the CBL indicated poor-quality cement. A recent CBL also shows discontinuous cement along depth and uneven distribution around the casing (Duguid, et al., 2014). Sidewall coring also show soft cement materials behind casing at several depths. Nevertheless, the results of well testing, coring and log that several small sections of competent cement provided adequate isolation for this well.

Chapter 5 SACROC case study

This chapter describes specific aspects of the CO_2 storage and enhanced oil recovery in the SACROC depleting oil field, relevant to the scope of this report (section 1.1). Context for the legislative framework in the USA and the suitability sites for EOR (with or without CO_2 storage) is provided in section 2.2.1. The SACROC site itself is described in section 2.2.4. The box below is a copy of the summary information from that section, highlighting which elements of the scope are described in this case study.

SACROC site summary

Location: onshore Texas, USA

Depleted: oil

Type: CO_2-EOR

Status: operational, ~255 Mt injected and ~100 Mt stored from 1972 to 2013

Economic viability: industrial EOR with U.S. DOE subsidized research

Geological setting: Pennsylvanian-Permian platform and slope carbonates at ~2,040,m [~6,693 ft] depth with mudstone/evaporite caprock.

Key findings from the site: (i.e. how it contributes to addressing scope, section 1.1)

- [ ] #1. Risk assessment criteria
- [ ] #1a. Implications for continued oil and gas production in adjacent fields
- [x] #2. Monitoring criteria (to quantify CO_2 storage and detect the extent of migration)
- [ ] #2a. Implications e.g. the effects of residual hydrocarbon fluids
- [x] #3. Pressures changes & thresholds and how these can be mitigated
- [ ] #4. Storage capacity estimate validation
- [x] #5. Long-term wellbore integrity assessment and remediation measures
- [ ] #6. Cost of modifications and storage development

5.1 Monitoring criteria to quantify CO_2 storage and detect migration (#2 issue, section 1.1)

The CO_2-EOR operation at SACROC is actively managed and monitored by Kinder Morgan, the operator. As at most of EOR operations, pressures and flowrates are monitored continuously in all active injectors at SACROC. The injection plans for each pattern are programmed into the injection WAG skid, to govern the rate, pressure, and duration of either water or CO_2 injection. Production flowrates are measured regularly at test sites. All the information is compared with the model predictions. Major deviations in well performance trigger alerts and require inspection. Besides these routine monitoring activities, research oriented monitoring studies funded by the SWP (see section 2.2) were conducted at the site. The findings of these studies are summarized below.

5.1.1 Improvements in groundwater geochemical monitoring

At SACROC, because of the large number of well penetrations, upward migration of reservoir brine or CO_2 through faulty wellbores is a major concern. If leakage of the injected CO_2 occurs, there is a risk that it could contaminate overlying hydrocarbon accumulations and eventually enter fresh-water aquifers which would compromise water quality. Geochemical reactions driven by elevated CO_2 partial pressure and/or change in water chemistry by brine input could further alter chemical composition of the groundwater.

Shallow groundwater geochemistry is widely used as a monitoring tool for evaluation of storage performance and leakage detection. To be an effective detection method geochemical signals stronger than the natural variations need to be identified and used as early leakage indicators (Romanak et al., 2012).

The monitoring strategy at SACROC started with direct comparison of groundwater chemistry and the reservoir brine. Han et al (2010) collected historic groundwater chemical data to look for signs of brine leakage by comparing the chemical compositions of shallow groundwater and reservoir brine. The aim of the study was to determine whether there is evidence for mixing between reservoir brine and shallow groundwater. Mixing was simulated using mean values of dissolved species from both reservoir brine and shallow groundwater with three mixing ratios between the reservoir brine and shallow groundwater of 1:9, 3:7, and 1:1. Most of the shallow groundwater samples show distinctly low concentrations of most of species and no evidence of contamination. However, chemistry of the groundwater displays significant variation with over 4% of the samples showing higher concentrations than the calculated value of the 10% brine mixing model. The authors suggest that surface brine pits or upward leakage through the caprock are the potential contamination sources. Later studies reveal that the aquifer system is dynamic with large temporal and spatial variations in chemistry (Romanak et al., 2012), so direct comparison between the groundwater and the reservoir brine are not diagnostic and could give false alarms.

Smyth et al. (2009) conducted a groundwater survey and compared water chemistry inside and outside of the SACROC site. This work confirms that groundwater chemistry in the Dockum and Ogallala Formations varies temporally and spatially. Comparison between the samples collected inside and outside the site shows no geochemical distinction that would suggest impact from the CO_2–EOR operations. Groundwater quality inside SACROC is not more degraded, compared against EPA drinking water standards, than that outside the unit. In addition, the data show no consistent difference from historical regional data collected by the Texas Water Development Board (TWDB). Historical data show that average CO_2 fugacity of the shallow groundwater did not change after CO_2 injection started in 1972, suggesting that the shallow aquifers were not affected by the injected CO_2 (Han et al., 2010). pH measurements around the SACROC site collected during the 1998- 2008 period show no distinct decrease from pre-1980 values (Figure 19), but there are significant regional changes in pH, suggesting a dynamic geochemical system.

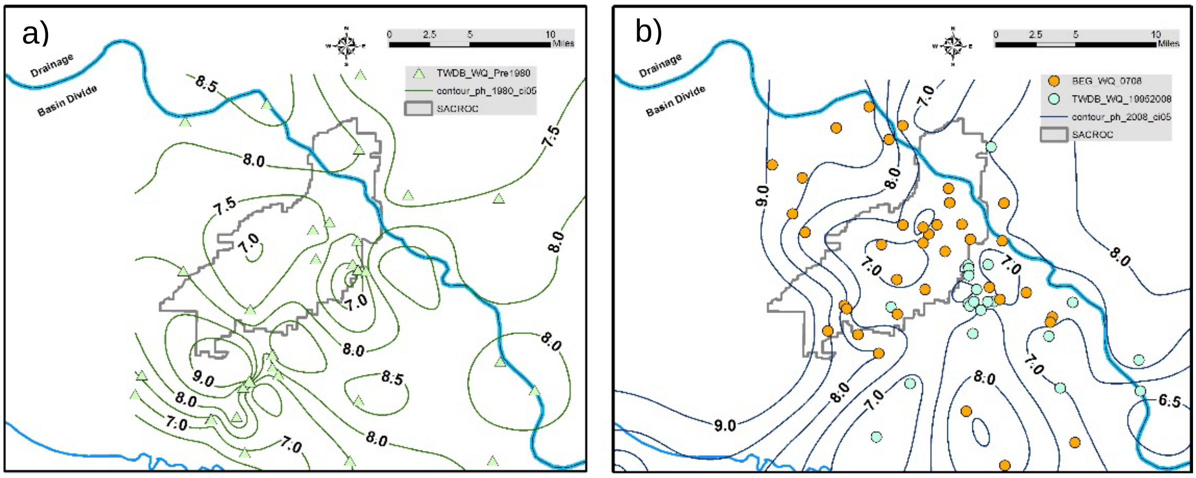


Figure 19 a) pH value contours in freshwater samples measured by TWDB before 1980. Data points denoted by green triangles. b) pH value contour measured in freshwater wells by TWDB and Bureau of Economic Geology (BEG) between 1995 and 2008. From Smyth et al., 2009.

Romanak et al. (2012) improved the monitoring methodology by taking into account the natural geochemical processes occurring in the aquifer and conducting sensitivity analyses to determine how leakage signals will show up in such a dynamic system.

By analysing groundwater chemistry around SACROC, it was found that, in spite of the dominant silicate minerals, groundwater chemistry in the Dockum aquifer is controlled by carbonate reactions, particularly, the natural process of dedolomitisation (Figure 20). Dedolomitisation at SACROC is driven by input of Ca^{2+} which replaces Mg in dolomite converting dolomite to calcite:

$$Ca^{2+} + CaMg(CO_3)_2 \leftrightarrow Mg^{2+} + 2CaCO_3 \qquad (1)$$

In this system, the kinetics of dissolution/precipitation of calcite and dolomite temporally and spatially control the concentrations of the major ions. The geochemical system responds to a higher pCO_2 by increasing dolomite dissolution and decreasing calcite precipitation, leading to an HCO_3^- increase.

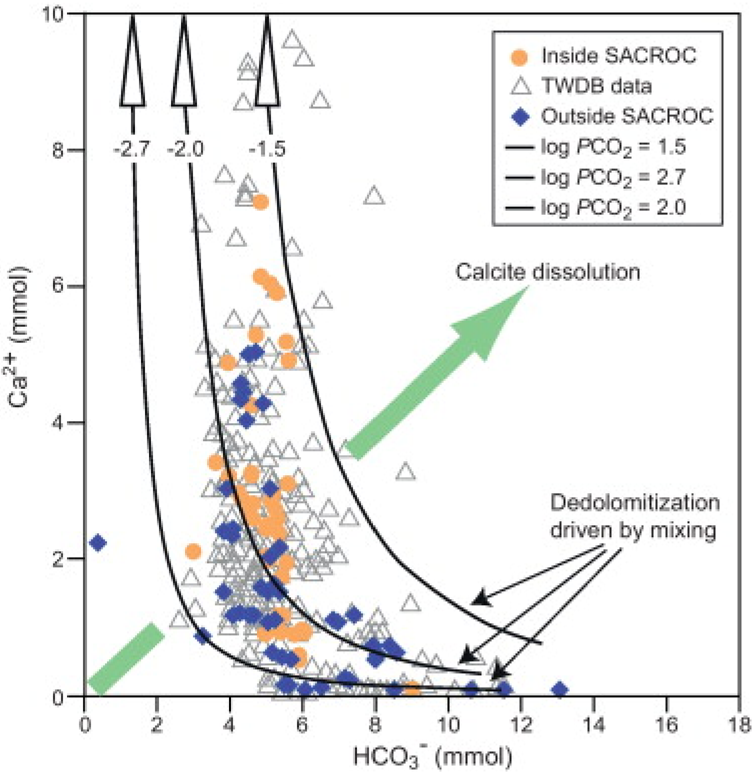


Figure 20 Concentrations of calcium and bicarbonate of groundwater at SACROC with modelled evolution trends for calcite dissolution and dedolomitisation. Solid lines are modelled curves for dedolomitisation under constant ***P*****CO2 of $10^{-1.5}$, $10^{-2.0}$, and $10^{-2.7}$. Green arrow line shows direction of calcite dissolution.** From Romanak et al. (2012).

With the geochemical process defined, the effects of the geochemical reactions driven by CO_2 input can be discerned from the background processes. Sensitivity analyses were conducted to understand how the system reacts to CO_2 and to determine the most sensitive geochemical parameters. The geochemical perturbations that would occur upon CO_2 leakage were simulated, showing that a 0.001% leakage rate for 3 Mt/yr CO_2 storage will result in discernible geochemical signatures above background concentrations.

Four parameters associated with carbonate reactions, dissolved organic carbon (DIC), HCO_3^-, pH, and Ca^{2+} were evaluated for their sensitivity to an addition of CO_2. DIC displays the highest sensitivity with the largest and most consistent changes in different geochemical systems. The other parameters (pH, HCO_3^- and Ca^{2+}), although commonly suggested as leakage indicators, show mixed sensitivity and unpredictable behaviours in a range of natural systems.

There is a need to accurately understand the natural geochemical processes occurring in the monitoring aquifers before an effective monitoring strategy can be determined. Different geochemical systems will response differently to CO_2 leakage. Effective monitoring approaches and parameters should be selected based on the background geochemical reactions in the monitored aquifers. For example, an aquifer undergoing dedolomitisation will response differently from one that experiences calcite dissolution. Simplistic approaches such as comparisons with baseline monitoring results and regional comparisons may not be effective and can be misleading.

5.1.2 Testing the efficacy of time-lapse 3D seismic and VSP

CO_2 injection into reservoirs partially saturated with brine and hydrocarbons is perceived to be less suitable for seismic monitoring due to difficult to predict changes in seismic properties that occur when CO_2 is introduced into the complex fluid system. Funded by U.S. DOE's Regional Partnership on Carbon Sequestration program, small scale time-lapse 3D seismic and vertical seismic profile (VSP) surveys were conducted at the SACROC Unit to test the effectiveness of the methods (Cheng, et al., 2010; Purcell et al., 2010; Yang et al., 2014).

Two 3D seismic datasets were collected over an active CO_2 injector as the centre of the swath (Purcell et al., 2010; Harbert et al., 2011). The amplitude versus offset (AVO) response at the top of the reservoir was first computed. Different combinations the AVO coefficients were examined to show a signal around the injector. The attribute anomaly variation proxy, ½(A+B) using the Shuey 3-term approximation, was then determined to be an excellent indicator and used to image the high CO_2 saturation area (Figure 21). For the Shuey 3-term approximation, the attribute ½(A+B), where A is the intercept and B is the slope, is an estimate of Rp-Rs (reflectivity of P and S waves). The results suggest that the proxy is a good indicator for supercritical CO_2 and can be used to map the extent of CO_2 plume. The time-lapse swaths are able to allow 4D calculations of seismic attributes and changes detectable related to the CO_2 injection. This study shows the potential of time-lapse 3D seismic swaths being a cost-effective alternative to full-field 4D seismic acquisition.

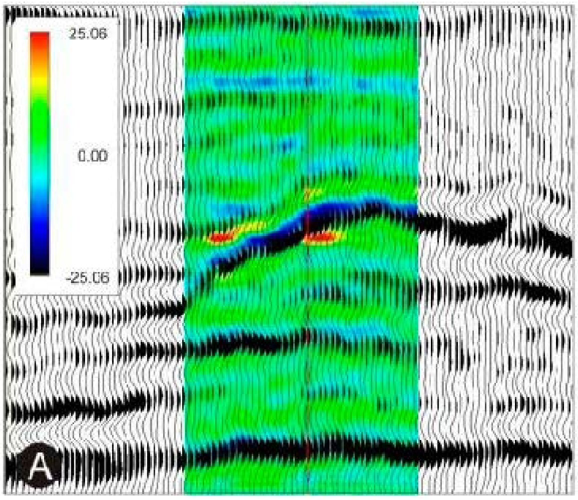


Figure 21 A reflection seismic line collected over a CO_2 injector at SACROC with ½(A+B) using the Shuey three-term approximation superimposed, showing high values representing high supercritical CO_2 saturation around the injector. The seismic line is approximately 1,800 m long.

As a part of the Southwest Regional Partnership for Carbon Sequestration project, walkaway VSP surveys were conducted before and after the start of CO_2 injection in the monitored area (Yang et al., 2014). The monitoring well is located some 350 m to the north of the two injection wells with geophones installed above the reservoir at depth from 152 – 1,737 m. A baseline dataset was collected along the north–south direction before the CO_2 injection started in July 2008. A repeat survey was completed in April 2009. Data inversion using image domain wavefield tomography (IDWT) method shows a velocity decrease beneath the reservoir top (1,900 m), indicating the presence of CO_2. However, the study did not calculate CO_2 saturation from the velocity changes and the seismic inversion results could not be calibrated because of the lack of information on pore pressure and fluid saturation. The method also suffered from a limited monitoring volume, amplitude mismatch, and the ambiguity between depth and velocity for the monitored interval below the receivers.

5.2 Pressure changes (#3issue, section 1.1)

One major challenge throughout the production at SACROC has been maintaining reservoir pressures. Whilst low pressures are advantageous for CO_2 storage capacity, they are generally disadvantageous for oil recovery mechanisms.

5.2.1 Historical pressures changes at SACROC

From the discovery in 1948 to 1954, oil was produced by the solution gas drive mechanism resulting in reduction of the reservoir pressure from 21.5 MPa to 11.4 MPa, i.e. a pressure reduction of over 50% for only 5 percent of OOIP production (Figure 22) (Dicharry et al., 1973; Brummett et al., 1976). Such a pressure response suggests that the reservoir has closed boundaries.

To improve oil production and prevent excessive pressure drop, in 1954, water flooding was implemented with wells placed along the crest of the reef (centre-line pattern). Seventy two water injection wells initiated water flooding at a rate of approximately 21,000 m^3 per day (Dicharry et al., 1973; Brummett et al., 1976). The aim of the centre-line injection design was to increase the reservoir pressure above the bubble point and displace oil from the centre of the reservoir toward producing wells on the eastern and western flanks. At the end of the secondary water flooding in 1971, the average reservoir pressure had increased from a low of 10.8 MPa to 16.2 MPa (Figure 22). A large portion of the SACROC Unit returned to pressures above the bubble point. However, the large scale water injection at the reservoir crest created a pressure gradient from the centre towards the eastern and western margins (Han et al., 2010).

At the beginning of Water-Alternating-Gas (WAG) flooding in 1972, most of the injection patterns in the Phase 1 area had not rebounded and remained below 11.0 MPa. An initial water injection was carried out to achieve the minimum miscibility pressure (MMP) of ~15.9 MPa. After 18 months of WAG injection, average pattern pressure was lifted over 16.6 MPa (Langston et al., 1988). In 1986, the Unit stopped importing water for injection and only produced water was injected. As a result, reservoir pressure declined. A 1992 pressure survey showed many CO_2 injection patterns were actually below MMP and the operator stopped injection into those areas.

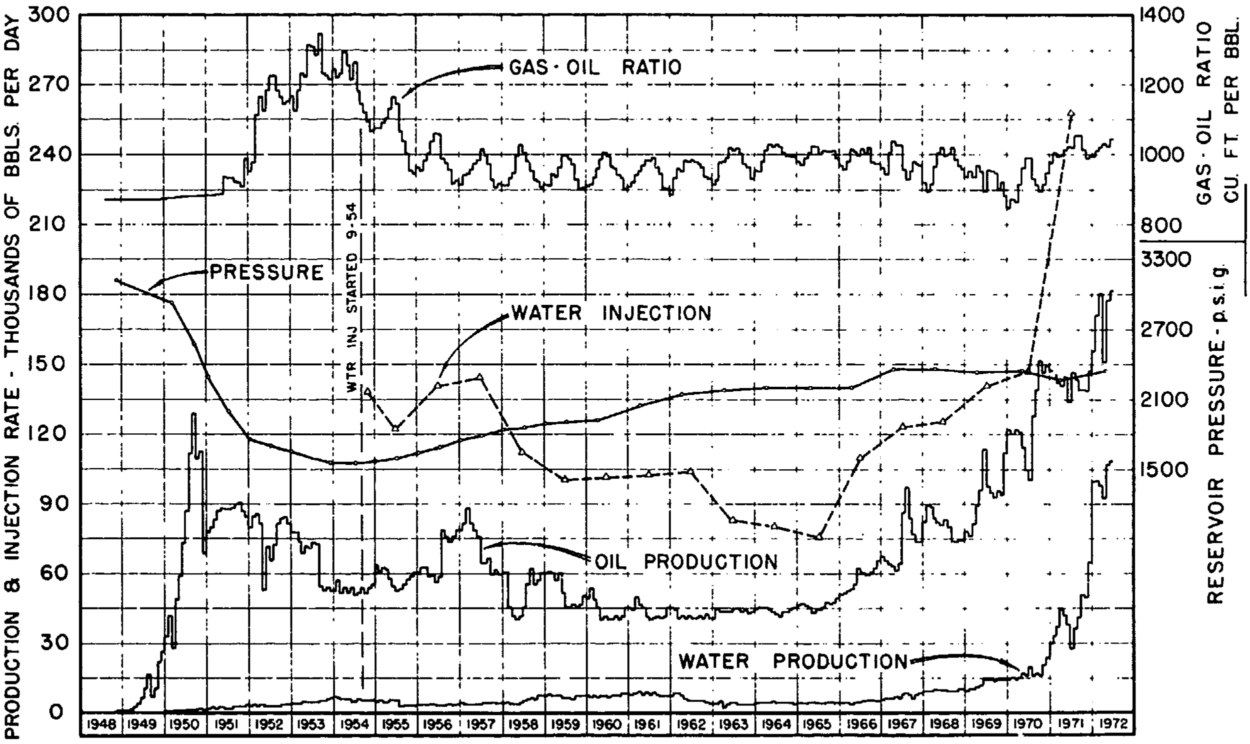


Figure 22 Pre-CO_2-EOR history of SACROC field performance. From Dicharry et al. (1973).

5.2.2 Mitigating stratigraphic isolation to improve sweep efficiency

Compartmentalization and stratigraphic isolation within the reservoir create significant effects on pressure distribution. Throughout the reservoir, a few dense, tight streaks and thin shale zones are likely to be laterally extensive and act as flow barriers. Wells drilled to -1,372 m subsea found bottomhole pressures (BHP) much higher than those in the shallower zones, indicating vertical isolation and essentially horizontal fluid flow, which leads to poor vertical conformance of injection (Hawkins et al., 1996).

Besides pressure discrepancy in the reservoir, vertical segregation also results in low CO_2 sweeping efficiency and CO_2 channelling. Thief zones existed in the reservoir as a result of several factors, including differential depletion, permeability variation, relative permeability effects, and matrix dissolution. To address these problems, injection profile surveys are routinely conducted to measure fluid flow in each zone. These surveys show that CO_2 and water were often being injected into different zones. The injection profiles provide information for conducting the conformance treatment (Larkin, 2008). For example, one survey at an injector indicated that 90% of the injected water entered a 16 m zone from 1,996 to 2,012 m and avoided other zones.

The operator squeezed the 16 m zone with foam cement and killed the thief zone. As a result, water entered the other 43 m of the pay and oil production increased quickly (Hawkins et al., 1996). Additionally, cross-well tracer tests using fluorescence dye can be used to determine the connectivity between the injection and production wells and to estimate the volume needed for conformance treatment (Larkin, 2008). Conformance treatment and the remedying of well communication problems can be done using cement squeeze, foamed slurry, or crystallized polymers. Injection profiles can also be controlled using "intelligent wells" which were used at SACROC to remotely open and shut fluid flow into individual zones (Brnak et al., 2006). Another way to control CO_2 distribution is to use a set of injectors that are completed in individual flow units. At SACROC, dual and triplet injection completions were used to direct CO_2 into to an individual reservoir zone through each of the close-by injectors (Kinder Morgen, 2013). The set of injectors serves the role of one conventional injector perforated through the whole reservoir interval, but with better control of injection volumes into different flow units.

Similar treatment can be useful to improve CO_2 sweeping efficiency and control plume extent in multi-layered storage formations. Undesirably fast conduits would make the CO_2 plume reach the lease boundary prematurely. Undesirable CO_2 injection profiles also lead to CO_2 bypassing a large portion of the storage formation. Injection profile surveys and other monitoring techniques can be used to show CO_2 distribution in different injection intervals. Based on such information, selected injection zones can be temporarily or permanently shut in by cement squeeze or preinstalled downhole valve/packer systems. CO_2 will be deliberately injected into the flow units that are not accessed before. By applying such control on the injection profile, the CO_2 distribution between the multiple flow units can be modified, early breakthrough restricted, and a relatively uniform CO_2 front achieved.

5.3 Storage capacity: the impact of miscibility effects (#4 issue, section 1.1)

Three phase numerical modelling by Han et al. (2010) showed that a significant amount of CO_2 (~4.5 million metric tons in 200 years) will dissolve in oil, which is beneficial for storage security. The presence of oil in the storage formation also leads to a lower density contrast with CO_2 than that of brine and CO_2, therefore, lower buoyancy-driven mobility of CO_2. Another process between CO_2 and oil that might benefit carbon storage is miscibility. Its effect on fluid density and storage capacity has not been fully discussed in the CCS context. When mixing occurs, the density of the miscible fluids becomes higher than the density of the individual components (CO_2 and oil) in the same conditions, increasing storage capacity.

For this review, numerical simulations using the Peng-Robinson equation-of-state (PREOS) were conducted on oils from SACROC and Cranfield to calculate the density/volume changes related to miscible reactions. CO_2 mixing with SACROC and Cranfield oil are simulated at their reservoir temperatures, 54.5 ˚C and 125 ˚C, respectively. Table 8 summarizes the composition of both hydrocarbon systems that show contrasting properties. Figure 23 shows the pressure/temperature diagram for both systems.

SACROC		Cranfield	
Component	Concentration	Component	Concentration
CO_2	0.0032	CO_2	0.0184
N_2	0.0083	C_1	0.5376
C_1	0.2865	C_2	0.0717
C_2	0.1129	C_3	0.0334
C_3	0.1239	I-C_4	0.0104
I-C_4	0.0136	N-C_4	0.0158
N-C_4	0.0646	I-C_5	0.0123
I-C_5	0.0198	N-C_5	0.0095
N-C_5	0.0251	FC_6	0.0248
FC_6	0.0406	$C_{7\text{-}1}$	0.0800
C_{7+}	0.3015	$C_{7\text{-}2}$	0.1861

Table 8 Composition of SACROC and Cranfield oils

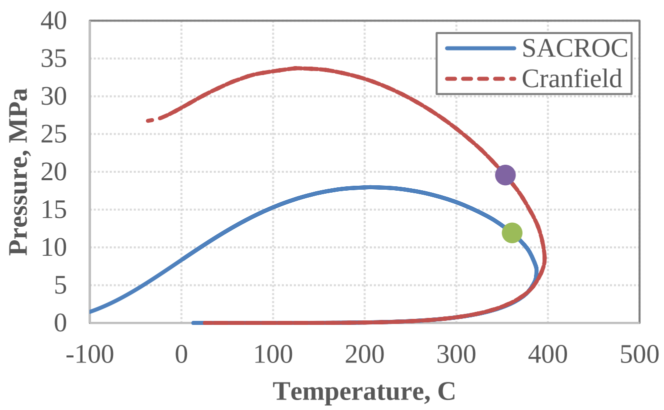
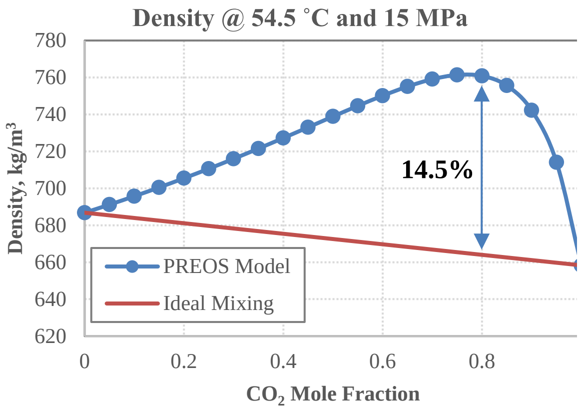
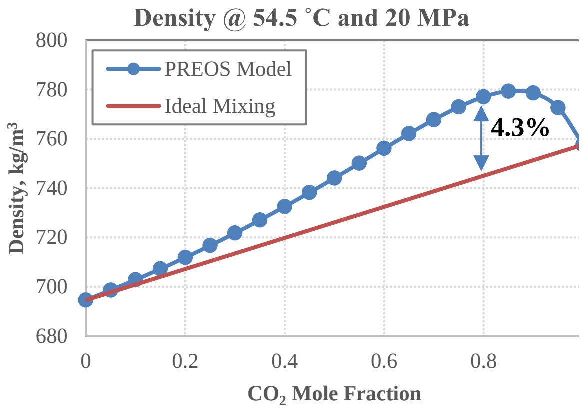


Figure 23 Pressure/temperature diagram of the SACROC and Cranfield hydrocarbon system envelope. The dot marks the critical point

The Peng-Robinson equation-of-state (PREOS) was used to model the mixture of both hydrocarbon systems with CO_2 under reservoir conditions. Figure 24 shows the density of miscible SACROC oil/CO_2 mixture versus the molar fraction of CO_2 at 54.5 ˚C and at pressures of 15, 20, and 25 MPa. Pure CO_2 density varies significantly with pressure because it is supercritical under the reservoir conditions. However, the oil density changes much less with pressure because the liquid compressibility is much smaller than gas. The supercritical CO_2 becomes denser than the oil at high pressure. The PREOS predicts that the density of oil/CO_2 mixture can significantly deviate from the ideal mixing rule. However, this deviation is pressure and composition-dependent, with higher deviation at larger fractions of CO_2. The model predicts that the deviation can be as high as 14.5 percent at 15 MPa with a 80/20 percent of CO_2/oil molar ratio.



a)



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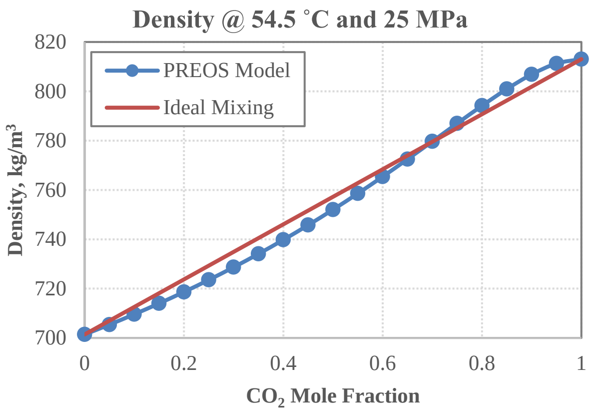
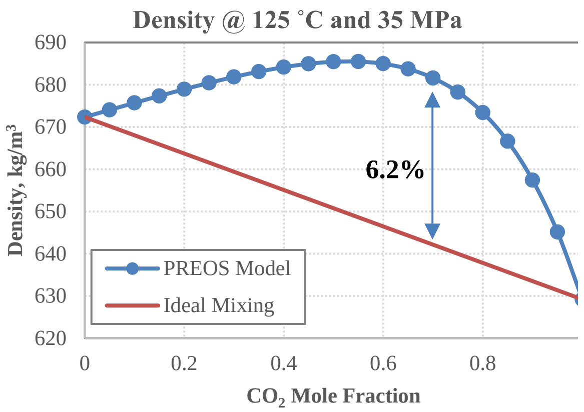


c)

Figure 24 Density of SACROC oil/CO_2 mixture at 54.5 ˚C and a) 15 MPa, b) 20 MPa, c) 25 MPa.

Figure 25 shows the density of Cranfield oil/CO_2 mixture versus the molar fraction of CO_2 at 125 ˚C for pressures of 35, 40, and 45 MPa. The trend of departure from ideal mixing is similar to the one for the SACROC case. However, the amount of departure is less for the Cranfield case. The highest mixture density increase is 6.2% at 35 MPa with a CO_2/oil ratio of 70/30.



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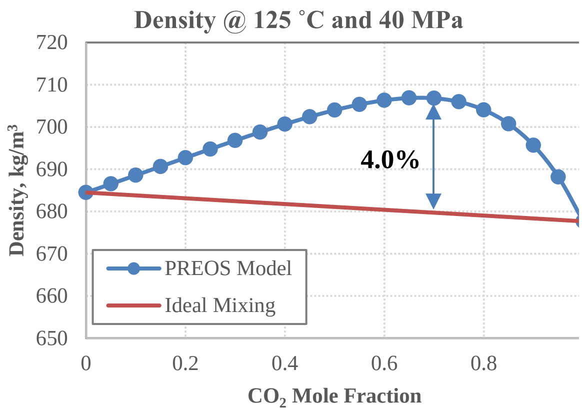

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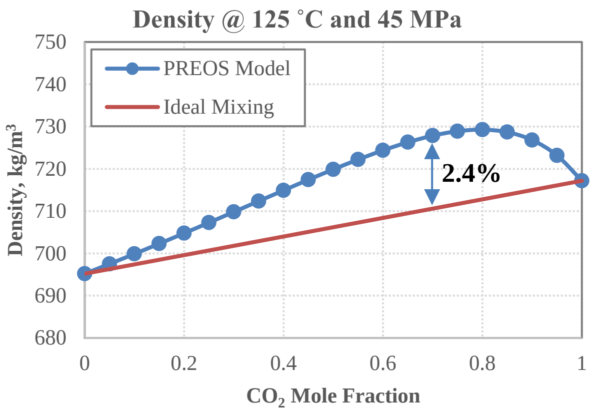

c)

Figure 25 Density of Cranfield oil/CO_2 mixture at 125 ˚C and a) 35 MPa, b) 40 MPa, c) 45 MPa.

It is concluded that the volume change of mixing of oil/CO_2 can be significant. The departure in mixture density from the ideal mixing line is larger at low temperature. The amount of deviation also depends on the composition of oil, pressure and temperature, and the ratio of oil/CO_2 mixture. Relatively lower pressure leads to a large density difference relative to the average density of CO_2 and oil, but the density of the mixture is higher with increasing pressure.

The volume decrease due to mixing of oil/CO_2 are beneficial for increasing storage capacity at most conditions. When CO_2 mixes with oil, the density of the mixture is mostly higher than the average density of the two fluids when separate, leading to extra space for CO_2 storage. However, the impact of density departure is local. The density deviates from the ideal mixing line only at those parts of formation where mixing of oil and CO_2 occurs. Therefore the density departure will be zero close to the injector, where the formation is saturated with CO_2, and also at those parts of formation which are not flooded by CO_2. The effect of density departure on CO_2 storage capacity is naturally case dependent. Therefore, fluid and reservoir modelling is needed to evaluate the effect of fluid compositions, reservoir conditions, and mixing patterns of oil and CO_2.

Additionally, mixing of CO_2 in oil and density increase of the miscible fluid would lead to enhanced storage security as the buoyancy force of the injectate is reduced.

5.4 Long-term wellbore integrity (#6 issue, section 1.1)

The potential for CO_2 leakage through existing wells represents a significant risk factor to permanence of CO_2 sequestration in depleted oil and gas fields (e.g. Nicot, 2009; Zhang and Bachu, 2011). Leakage in wells is defined as “any unwanted migration of fluids from any component of the well system” by Carey (2013) and can occur as a result of poor completion, abandonment, or well operation. CO_2 injection wells[33] are likely to be specifically built for the CO_2-EOR or sequestration projects and subject to regulations and monitoring. In a properly constructed well, the rate for CO_2-bearing fluids to chemically compromise well integrity is very low because the reaction front would have to move through 10s to 100s of meters of cement and steel by the process of diffusion (Carey, 2013).

Therefore, leakage potential through injection wells is perceived to be less than that of pre-existing wells that were not specifically designed for CO_2. Operating wells represent only a small fraction of the total number of wells in Texas, most of which have been plugged and abandoned. Wells abandoned early in Texas’s production history pose the highest risk of leakage because the regulations for drilling and abandonment were much less strict or not present at all. The integrity of the abandoned wells is largely controlled by the regulations of drilling and abandonment, the practice by the well operator, and the materials used to plug the well (Nicot, 2009). Problems related to abandoned wells include quality of annular space, unsealed boreholes, corrosion of casing, corrosion products, seal degradation and incomplete records of abandonment/sealing (Chalaturnyk et al., 2004).

The long history and the large scale of the CO_2-EOR operations at SACROC provide an effective case-study to assess the wellbore performance in a CO_2 environment. Several studies have investigated well performance using a statistical approach, direct observation, laboratory experiments, and numerical simulation.

5.4.1 Understanding well integrity risks from regional well incident frequencies

Porse et al. (2014) used a statistical analysis of well blowouts to assess the relative performance of wells for oil or gas production against those for CO_2-EOR. The study examined the official records of well blowout incidents in three oil producing regions,

[33] Note that cathodic protection was extensively implemented at SACROC since the 1980s to counteract corrosion of infrastructure following the principle of a battery to decrease oxidation of metal casing strings and pipes. As of June 2016 at SACROC, cathodic protection is employed for approximately 1,600 well bores and some 600 miles of H_2O and CO_2 injection lines with approximately 750 rectifiers (Nathan Mathis, personal communication). Thus great effort and care is taken to preserve wellbore and pipeline infrastructure.

the Texas Railroad Commission (RRC) Districts 3, 8, and 8A (Figure 26). SACROC is located within District 8A. Data is primarily collected online from the Texas Railroad Commission databases by Porse et al. (2014) and updated for this report.

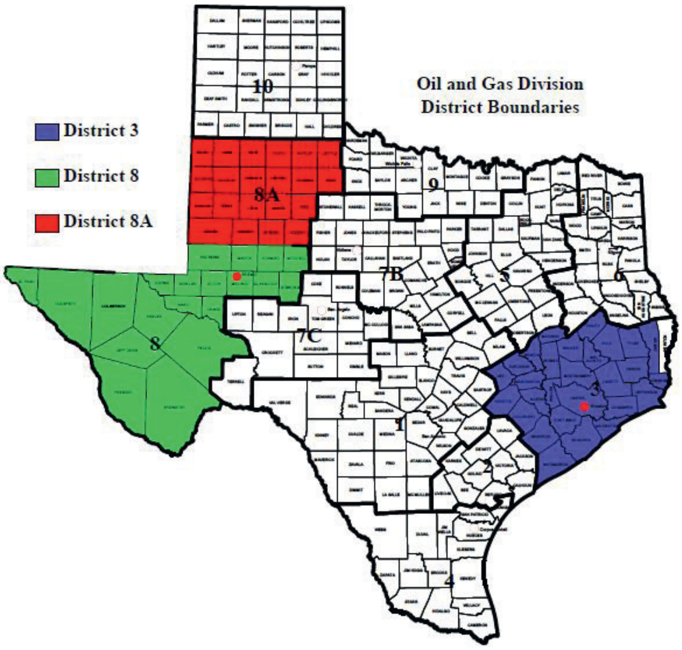

Figure 26 Texas Railroad Commission Oil and Gas Division Districts Map showing three study area. From Porse et al. (2014). **SACROC is in District 8A.**

Districts 8 and 8A host the largest numbers of active CO_2 injection wells in the state of Texas with 978 and 1,016 for the period of 1998-2013, respectively (Table 9). In contrast, District 3 has only 35 active CO_2 injection wells. These differences of activity levels can be used to determine whether CO_2 injection increases the occurrences of blowout incidents.

The survey found 616 recorded “well blowouts and well control problems” in Districts 3, 8, and 8A from 1942 to 2013. Among these, 158 occurred from 1998 to 2011. District 3 encountered the largest numbers of recorded incidents (75) (Table 10). Well incidents occurred mostly during the drilling, completion, workovers, and production stages. In particular, problems rarely occurred for injection wells; only 1 incident during injection was recorded which was in District 8.

Overall the blowout frequency is small, on the order of tenths of a percent or smaller for a given development stage. District 3, with the fewest CO_2 injection wells, had the highest overall incident frequency at 0.174% (Table 10). In District 3, the drilling stage had the highest frequency of well blowouts, while in Districts 8 and 8A, workover was the riskiest stage.

	District 3	District 8	District 8A
Wells Drilled	7,063	20,468	8,523
Well completions	9,535	26,344	9,831
Workovers	2,895	4,543	1,622
Production wells	10,968	48,897	22,622
CO_2 injection wells	35	978	1,016
Plugged wells	8,759	12,541	6,613
Orphan wells	584	394	38

Table 9 Texas RRC District number of wells, 1998-2011. From Porse et al. (2014)

	District 3		District 8		District 8A	
	Number	Frequency	Number	Frequency	Number	Frequency
Drilling	29	0.411%	28	0.137%	7	0.082%
Completion	9	0.084%	5	0.019%	6	0.061%
Workover	7	0.242%	7	0.154%	9	0.555%
Production	19	0.173%	3	0.006%	11	0.049%
Injection	0	0.000%	1	0.020%	0	0.000%
Plugging	6	0.080%	1	0.008%	0	0.000%
Abandoned	1	0.171%	0	0.000%	0	0.000%
Other	3		2		1	
Uncategorized	1		2		0	
Total (Average)	75	0.174%	29	0.038%	35	0.062%

Table 10 Texas RRC District number of well incident and frequency (1998-2011). From Porse et al., 2014.

Injuries or deaths associated with a well leakage or blowout were rare. Only District 3 documented an incident of a death associated with a well blowout during drilling, equating to a 0.014% frequency. Total worker injuries due to well blowout is 5, 11 and 3 for District 3, 8 and 8A respectively for the 3 year period.

Overall, risks for oil and gas wells are very low, but change with the operational stage. Wells have a very low risk of blowout during routine operations (mostly <0.1%). However, incident rate increases over 0.1% during well workovers, but still at low risk. Options for mitigating risk are available. There is no evidence to show increased risk with CO_2-EOR operation. In contrast, the areas with intense CO_2-EOR activities had the lowest frequency of well failure.

For this review, we further examined the RRC records of all well blowouts and control problems specific to SACROC which is in District 8A. A total of 11 incidents occurred and were reported to RRC from the start of the recording prior to 1950 to 2015. The earliest was in 1985 and the others all postdate 2004. No death or injury was reported. There was one account of fire and two H_2S detections. The most severe leakage incident was a well blowout through the tubing during a plugging operation in 2012. It was not stated how long the blowout lasted or how much fluid leaked. Seven incidents are failures of pipe nipples and valves. Three leakage incidents were caused by downhole problems: submersible pump mandrel corrosion, leaking through casing annulus, and leaking through surface casing. One incident has no description of the occurrence. It appears that only 4 incidents may be specifically related to the CO_2 operation during the last 4 decades, which suggests a low risk potential for CO_2 related incidents.

To compare with the regional blowout frequency during 1998-2011 (Porse et al., 2014), we counted a total of nine well incidents at SACROC, from more than 1700 wells by 2005. This gives a frequency of well incidents of 0.529%, higher than the regional averages of 0.174% (District 3), 0.038% (District 8) and 0.062% (District) 8A.

5.4.2 Examining risks relating to the degradation of wellbore completions

Unintended migration along wellbores can be caused by poorly bonded cement between the casing and the borehole and could possibly result in leakage or in a worst-case scenario, well blowouts. A major concern in the case of CO_2 storage in geological formations is that the reaction between supercritical CO_2 and/or CO_2-saturated brine with well cements and steel casing could potentially cause degradation. Portland cement used to seal wellbores is an alkaline substance with pH > 12.5 and is not in equilibrium with CO_2-bearing fluids (pH <6) and low-carbon steel used as well casing is subject to aggressive corrosion by carbonic acid (Carey, 2013). CO_2-EOR operations, particularly SACROC with its long history of CO_2 injection, provide a unique opportunity to investigate the medium-term (decadal) performance of wellbores. To assess wellbore integrity in the CO_2-rich environment, a focused study on one of the old CO_2 injectors at SACROC was carried out (Carey et al., 2007). This study investigated the impact of injected CO_2 on cement performance by drilling a side-track well and collecting core of wellbore materials from a thirty year old CO_2 injector, well 49-6.

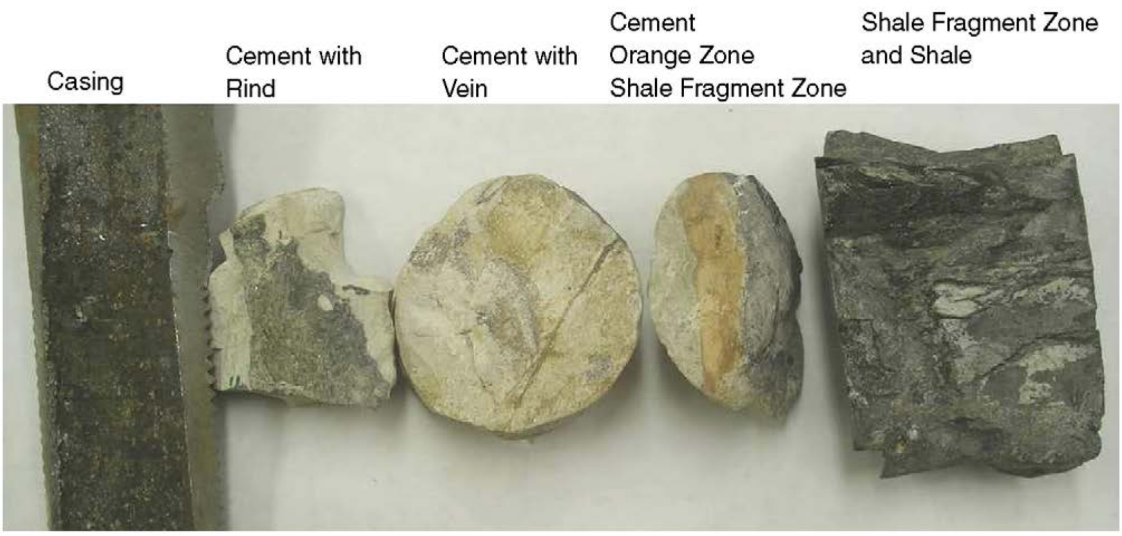

Figure 27 Cored wellbore samples from a SACROC CO_2 injection well showing the casing (left), grey cement with a dark rind adjacent to the casing, 5-cm core

of grey cement, grey cement with an orange alteration zone in contact with a zone of fragmented shale, and the shale country rock. From Carey et al. (2007).

The study well, located in the northern region of the reservoir, was drilled in 1950 to a total depth of 2,131 m, 131 m below the shale–limestone reservoir contact. It was first exposed to CO_2 in 1975 as a producer for 10 years. In 1985, the well was converted to an injector with a total of 110,000 tonnes CO_2 injected through the well during a period of 7 years. In mid-2000, after being exposed to CO_2 for 30 years, the well was re-entered and a 5 cm diameter side-track core was obtained through the casing and cement and into the caprock from a depth of 1,994 m to the caprock-reservoir contact at 2,000.1 m. The coring operation recovered samples of casing and cement at 3 – 4 m above the reservoir top.

The side-track core shows that the Portland cement survived and retained its structural integrity. A large portion of the cement sample shows properties of typical Portland cement (Figure 27). Two thin alteration zones were observed at the interfaces with casing (0.1 – 0.3 cm thickness) and shale (0.1 – 1 cm) and were produced by reactions between cements with CO_2 that travelled along the interfaces.

The position of the cement sample at only 3–4 m above the reservoir top suggests that most of the cement forming the wellbore seal has survived and would continue retaining CO_2. The cement bond log (CBL) collected by the study also shows that cement is well bonded to both casing and the shale from the reservoir top (2,000 m) to 1950 m. Between 1,950 and 1,905 m, the cement distribution and bonding is more variable and includes a 5 m interval with little bonding or presence of cement. From 1,905 m to 1,760 m, the cement is uniformly bonded to casing and formation. The CBL shows no evidence of CO_2-induced de-bonding or channel formation at or near the reservoir contact. Cement sections with potentially poor integrity are distant from the reservoir and are likely to be features of the original cement job. The thick intervals of uniform cementing are sufficient to effectively retain the buoyant fluids in the reservoir. The retrieved casing sample was in good condition and showed minimal signs of corrosion after 55-years in place, providing additional evidence that the cement retained its capacity to limit fluid circulation. These observations indicate that Portland cement based wellbore systems, if properly completed, can prevent significant migration of CO_2 from reservoirs for long periods of time (at least decades) (Carey et al., 2007).

1-D diffusion-based models were able to reproduce the observed mineralogical changes, porosity, and chemical evolution in the cement and suggest that the carbonation was caused by the diffusion of dissolved CO_2 migrated from the reservoir along the cement–shale interface (Carey et al., 2007). Carey & Lichtner (2011) confirm that the dominant CO_2 migration pathways in the SACROC well are along the contacts between cement and steel and between the cement and the caprock, rather than through the cement itself, where diffusion processes are likely to dominate.

Laboratory reaction experiments of CO_2 and Portland cement show consistent results in both the geochemical reactions and the reaction rates with the field evidence (Kutchko et al. 2007, 2008), suggesting that the diffusion of CO_2-saturated brine in good-quality cement will not significantly damage its integrity.

Chapter 6: Case study 4: Otway

This chapter describes specific aspects of the CO_2 storage at Otway in the depleted Naylor gas field, relevant to the scope of this report (section 1.1). An overview of the site is outlined in section 2.3.1. The box below is a copy of the summary information from that section, highlighting which elements of the scope are described in this case study. *The information for this chapter comes primarily from Cook, 2014 but individual publications are also referred to throughout as necessary.*

Otway site summary

Location: onshore Australia

Depleted: gas field

Type: storage

Status: Completed. 0.065 Mt stored 2008-2009

Economic viability: Pilot scale, research focus

Geological setting: heterogeneous stacked tidally influenced channel sands @~2,000 m depth, Cretaceous aged, mudstone seal.

Key findings from the site: (i.e. how it contributes to addressing scope, section 1.1)

☐	#1. Risk assessment criteria
☐	#1a. Implications for continued oil and gas production in adjacent fields.
x	#2. Monitoring criteria (to quantify CO_2 storage and detect the extent of migration).
x	#2a. Requirements e.g. the effects of residual hydrocarbon fluids.
☐	#3. Pressures changes & thresholds and how these can be mitigated.
x	#4. Storage capacity estimate validation
☐	#5. Long-term wellbore integrity assessment and remediation measures
x	#6. Cost of modifications and storage development.

6.1 Monitoring criteria (examples of how monitoring has been used to quantify CO_2 storage and detect the extent of migration). (#2 issue, section 1.1)

Material from this section is chiefly derived from Cook, 2014; specifically Chapter 9, Jenkins, 2014.

As a pilot project, many monitoring technologies were tested at the site. The monitoring programme objectives were as follows:

- To ensure safe operations, evaluate a range of monitoring methods and provide data to calibrate numerical models

- To demonstrate compliance with regulatory requirements. These were developed during the initial phases of project and were therefore “aspirational”. They specified that the monitoring results should:
  - Be clear, comprehensive, timely and accurate to effectively and responsibly manage environmental, health, safety and economic risks and meet “set” performance standards. [These were deliberately non-specified at the time]
  - Determine to an appropriate level of accuracy, the quantity, composition, and location of the gas (CO_2) captured, transported, injected and stored and the net abatement of emissions. This should include identification and accounting of fugitive emissions.

Various monitoring technologies were deployed specifically with the aim of detecting the CO_2 in the reservoir and the extent of any migration within it and out of it (listed below).

- **3D seismic & vertical seismic profiles (VSP)** were deployed. Baseline surveys were collected, followed by a repeat mid-way through injection (35 kt injected) and another at the end of injection (65.4 kt injected). Despite the use of a high fold and high quality processing (the normalised route mean squared (NRMS) repeatability metric at the target horizon was 16% i.e. very good), the methods were unable to detect the presence of injected CO_2 in reservoir. This was mainly because of the relatively small amount of CO_2 injected and the difficulties in distinguishing this from residual gas in the reservoir. However, modelling showed that accumulations of 5-10 kt in overlying aquifers would be detectable.
- **Microseismic, pressure and temperature sensors** in the monitoring well unfortunately failed. Pressure information was therefore only available from the injection well and this was used for model calibration.
- **Various “assurance” techniques** were used to verify that CO_2 had not migrated to surface. These included groundwater monitoring (surface geochemical sampling of shallow aquifers via wells), soil gas measurements and atmospheric monitoring. No injected CO_2 was detected except some deliberately released at surface to test the abilities of the equipment to detect leaks.
- **Geophysical logging** included pulsed neutron capture (PNC) to monitor gas saturation and resistivity logs. Pre-injection logging was used to confirm a 20% residual gas saturation beneath the post-production gas water contact. Post injection logging of the same tools was unable to conclusively distinguish the injected CO_2 from gases in the reservoir, explained in section 6.2.
- **Downhole reservoir fluid geochemical sampling using U-tubes** were deployed from pre-injection to post injection. Samples were analysed for CO_2 and tracers: δ13 C CO_2, CD_4, SF_6, Kr. This was the only monitoring technique that was able to conclusively detect injected CO_2 in the reservoir (explained in the next section).

The monitoring at Otway was aligned to the risk assessment, and efforts were made to state what monitoring measurement was able mitigate each risk and how and where this was expected to be achieved. The site operators also had significant experience of communicating monitoring results at various levels of detail to stakeholders including regulators and the public. Especially relevant to any project with a research element, the importance of creating a separation between monitoring required by regulations and monitoring for research purposes is highlighted. This allows regulations to be satisfied while allowing more freedom for the research into monitoring methods that could lead to unexplainable results, the nature of which could cause alarm or create controversy.

6.2 Implications for monitoring requirements e.g. the effects of fluid replacement. (#2a issue, section 1.1)

A system for measuring the downhole reservoir fluid chemistry and thereby monitoring the in-reservoir migration of injected CO_2 was installed in the monitoring well. *The content in this section is derived from Cook, 2014; specifically Chapter 12, Boreham et al.). The U-tube methodology is described in Freifeld et al. 2005.*

Three U-tubes were installed at reservoir level to enable samples at reservoir pressures to be collected from the surface (Figure 28). This is important so that dissolved CO_2 (that exsolves on depressurisation of the sample) and mobile free CO_2 in the reservoir can be distinguished. Briefly, the kit consists of a U-shaped tube, open at the reservoir level. N_2 gas is pumped down one leg of the "U", forcing the reservoir fluid sample up the other leg to the surface. Once free gas reaches the sampling depth, samples self-lift to surface. Given its position within the gas cap, U1 always self-lifted gas. The successive transition to self-lift of U-tubes 2 and then 3 marked the downward movement of the base of the CO_2 plume as the field filled. The set-up was designed to monitor the migration of the injected gas (predominantly CO_2) and its mixing with the native reservoir fluids (predominantly CH_4 and formation water) as the reservoir filled.

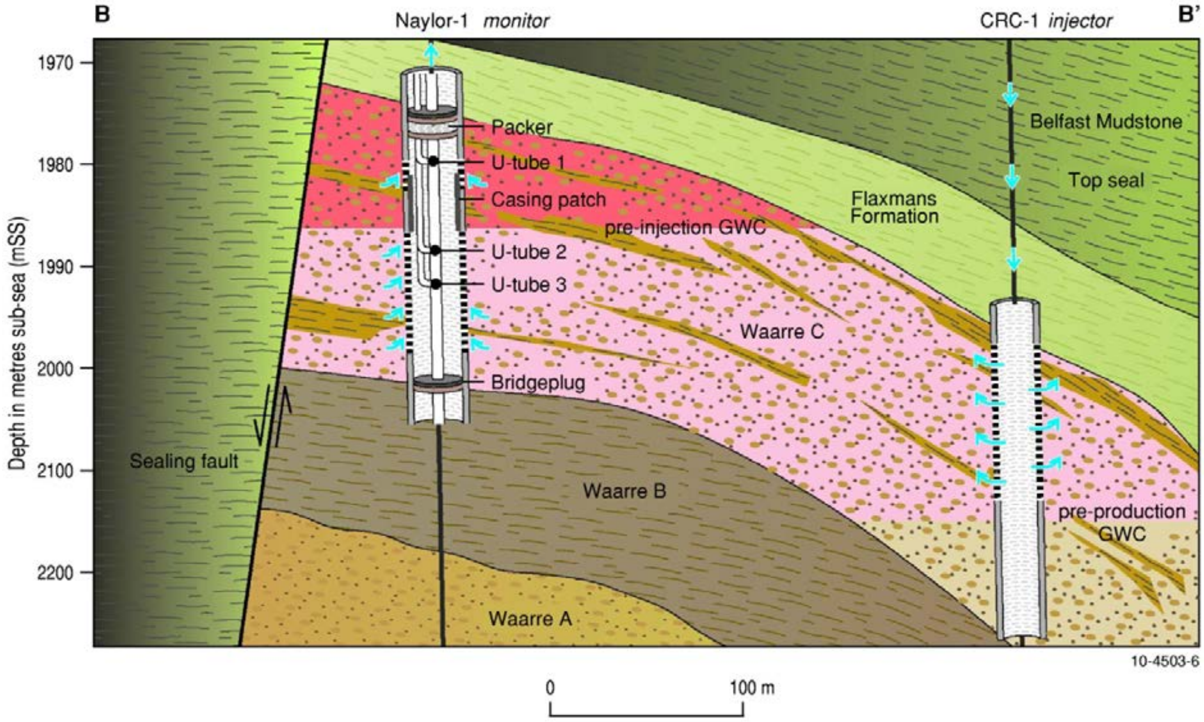

Figure 28 Set up of the 3 U-tubes in the monitoring well at Otway. Red shading represents the CH_4 post-production gas cap. The shaded orange beneath it indicates residual gas down to the pre-production gas water contact (GWC). Image courtesy of Dr Chris Boreham. Intellectual Property of CO2CRC Limited, reproduced with permission.

Samples were taken every 7 days and analysed for CO_2 and the associated tracers which had been injected early into the CO_2 stream (CD_4, Kr and SF_6). The $\delta^{13}C$ CO_2 signature of the injected CO_2 was found to be sufficiently different from the CO_2 already in the reservoir and so the isotopic composition was also used as a tracer. The arrival of the injected gas at the monitoring well (300 m away) (known as "breakthrough") was detected by an increase in dissolved CO_2 content and the presence of the tracers in the samples. The transition to self-lift marks the arrival of the free CO_2 plume at the U-tube sample inlets[34].

[34] - Breakthrough at U2 occurred abruptly between 100 and 121 days after start of injection, when CO_2 content increased above a background level of 7.5 mol %. After 177 days (when 21.1 kt had been injected), U2 transitioned to self-lift.

- Breakthrough at U3 was less clear and occurred over a longer period. The transition to self-lift started between days 212 and 226 and completed after 303 days (when 39 kt had been injected)
- Breakthrough at U1 occurred at day 247. This was detected by a rise in CO2 content above the background of 1.5 mol%. By day 261, this had risen to 20mol % and gradually increased to 30 mol% (Figure 30).

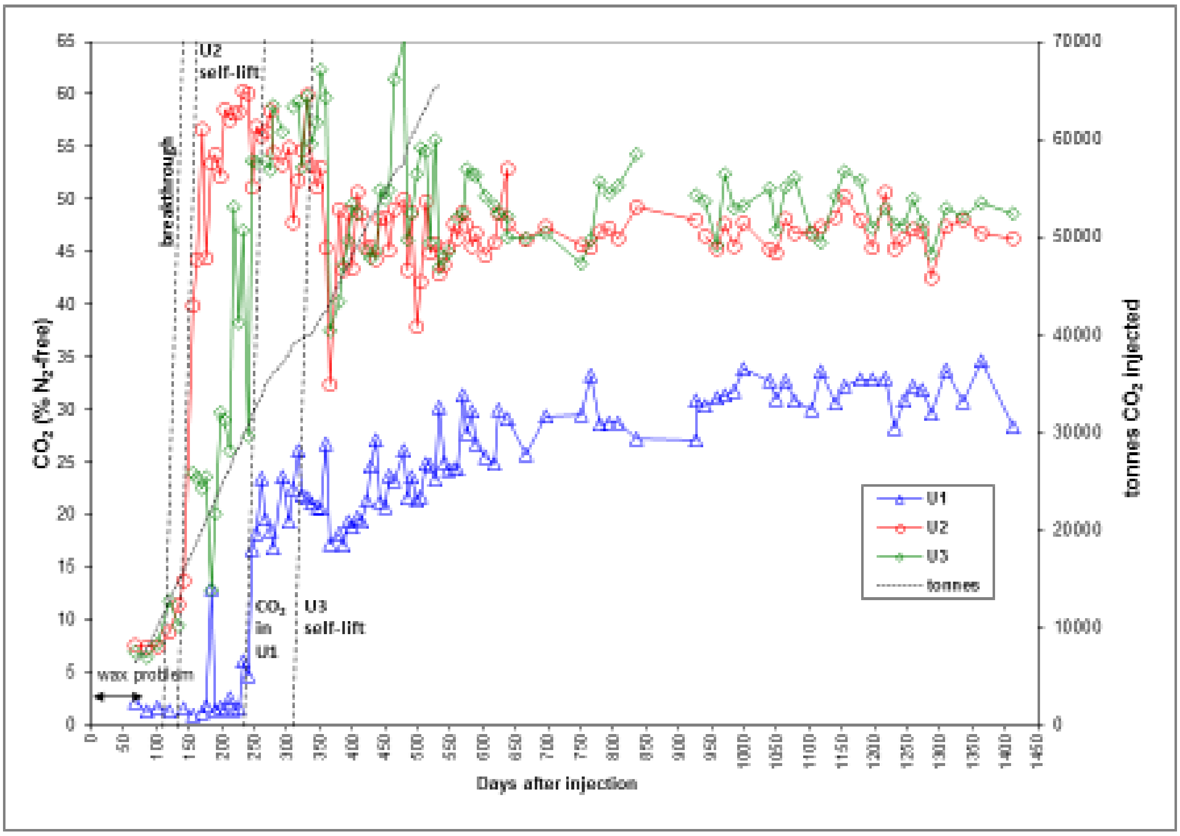

Figure 29 Time series of CO_2 content (mol% as N_2 free basis) measured in the 3 U-tubes in the monitoring well at Otway and the cummulative CO_2 injection amount. Image courtesy of Dr Chris Boreham. Intellectual Property of CO2CRC Limited, reproduced with permission.

The arrival of injected CO_2 prior to the samples self-lifting (together with various changing gas ratios not described here) is evidence that a dissolved front of CO_2 moved ahead of the free CO_2 plume. The increase in CO_2 molar content in U2 and U3 initially rose up to around 60 mol% CO_2 (Figure 29) and then this gradually dropped and appeared to stabilise at just under 50 mol% CO_2. The CO_2 content in the samples never reached the CO_2 content of the injected gas (75.4 mol% on average over the course of injection). This was interpreted to be a result of mixing between the injected gas with both residual CH_4 and formation water along the 300 m migration route from the injection well.

Once self-lift had occurred in U2 and U3, another pulse of tracers was injected which consisted of SF_6 and R-134a[35]. This was an experiment to enable continued study of the CO_2 migration and mixing and establish transit times of injected CO_2 between the injection and monitoring well. Sample collection from the reservoir is continuing at a

35 The R-134a took 141-176 days to arrive at U3 and around 231 days to arrive at U2. Elevated levels of SF_6 were not distinguishable above the background created by the 1st pulse.

reducing frequency (currently every six weeks at March 2016) to provide longer term post injection information on the stability of the CO_2 plume.

Detailed examination of the relative concentrations of the CO_2, CH_4 and tracers, both within the reservoir and those introduced, through time, has allowed development of the methodology (through improved understanding of sampling mechanisms and artefacts, for example) and, importantly, presented insights into the in-reservoir migration, mixing, and equilibration of fluids through time.

6.3 Storage capacity estimate validation (#4 issue, section 1.1)

As a research project, there was no intention at Otway to fill the storage reservoir to capacity, as might be the case at a commercial venture. Capacity calculations were performed prior to injection to ensure that there was sufficient space for the intended injection amount. However, once injection started, analysis of monitoring results and refinement of the numerical models focused on determining storage efficiencies rather than calculating capacity (as this can be dependent on external factors including economics). Although site specific, the method and results could offer insight to other potential CO_2 storage projects and allow validation of previously globally applied storage efficiency factors. *Material for this section derived from Cook, 2014; specifically, Chapters 5 (Dance) and 16 (Ennis-King & Paterson):*

Space for 100 kt of dense-phase CO_2 was required for the initial project concept. Simplistic pre-injection capacity estimates using volume-for-volume replacement of the produced gas[36] suggested that there was 150 kt of space (i.e. 150% of the required capacity) (Figure 30).

Once pre-injection reservoir pressures were determined (when the CRC-1 injection well was drilled), they showed significant aquifer recharge[37], so the previous, simplistic capacity estimation was no longer appropriate. Geocellular models were built to estimate pore volumes and these were fed into a volumetric-based capacity equation (as proposed by USA Department of Energy in 2006 (DOE, 2006)). This includes a storage efficiency term, to account for volume taken up by residual water and gas saturations. PNC saturation logging in the injection and monitoring wells confirmed that below the post-production gas cap, pore volume was occupied by 20% residual gas and 80% formation water. Numerical simulations suggested that by the end of injection, some of the water would be pushed back out of the reservoir, leaving 30-40% of the pore volume occupied by CO_2, and resulting in a calculated a capacity of 113-151 kt of CO_2; still sufficient for the intended injection amount of 100 kt (Figure 30). In fact only 65.8 kt were injected during the course of the project, as research objectives had been met by that time.

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[36] Produced volume of gas was $9.5 \times 10^7 m^3$ [~3.3 bscf], (around 64% of the initial gas in place). This was equivalent to 150 kt of gas to be injected (which was 80% CO_2, 20% CH_4) by mole fraction.

[37] Discovery pressure was 19.5 MPa. At the end of production this had reduced to 9.6 MPa. At the start of CO_2 injection, pressure had recovered to 17.8 MPa.

A wealth of data was collected during the site characterisation process that fed into these numerical models. Laboratory tests on core samples from the reservoir well and other data from the nearby fields were used to try and refine values for residual water and gas saturations and determine relative permeabilities. These returned a range of values, each with their own limitations. Throughout the operation, geological and numerical models were iterated and updated to match monitoring results. Model history-matching suggested an average residual water saturation of 24% and gas saturation of 25-30%.

The U-tube reservoir sampling (see above) offered an opportunity to test and validate the dynamic capacity and storage efficiencies indicated by the numerical modelling, at least between the depths of U2 and U3. Detailed post-injection analysis of the sampling results and relative timings between U2 and U3 transitioning to self-lift were used to establish the range of movement of the base of the CO_2 plume as the field filled and consequently, to calculate the amount of CO_2 in the pore volume between U2 and U3 within that time frame. This suggested that **between 56-84% of the available space originally occupied by gas was reoccupied by CO_2**. This is comparable to the storage efficiency factor of 75% previously applied to global estimates of storage capacity in depleted fields (Figure 30).

There were certain elements of the sampling set-up and timing of sample collection which introduced significant uncertainties into the ability to more accurately calculate the exact volume of space reoccupied by the gas. Some of these could potentially be avoided in future and included:

- The timing between sample collection affects the volumes calculated. The timing in self-lift between U-tubes 2 and 3 was 126 days, during which time injection was at a roughly constant rate. Samples were collected every 7 days, so there is therefore a 7 day window for the transition at each U tube. This results in a 10-15% uncertainty in the quantity of CO_2 between the two U-tubes, i.e. 17± 2 kt CO_2.
- Although the depths of the U-tubes are known, the depths from which the samples originated has some uncertainty and consequently, so does the depth of the base of the CO_2 plume. Each tube samples a 0.6 m interval which are not hydraulically isolated (packed off) from each other. Exactly where the flow is induced therefore depends on reservoir productivity (permeability & thickness) and also mixing of the fluids in the reservoir. Detailed modelling suggested that the base of the plume moved 3.5 ± 0.5 m.

Nevertheless, the U-tube offered unique insight into the site-specific storage efficiency factors and was the only in-reservoir monitoring tool that was able to usefully determine fluid compositions and saturations. It was hoped that post-injection (2010) resistivity and saturation logging would enable post-injection CO_2 and CH_4 saturations to be measured across the whole reservoir interval, leading to an improved understanding of storage efficiencies across the whole reservoir interval. However, interpretations were hampered by difficulties in comparing open-hole and cased-hole logs, the presence of a palaeo-gas column and the similarity in logging responses between CH_4 & CO_2 (the native gases in the reservoir and the injected gases contained both in different proportions). Given the nature of depleted gas field storage, it is likely that unless there is a step-change in tool or interpretation capabilities, other projects would experience similar difficulties.

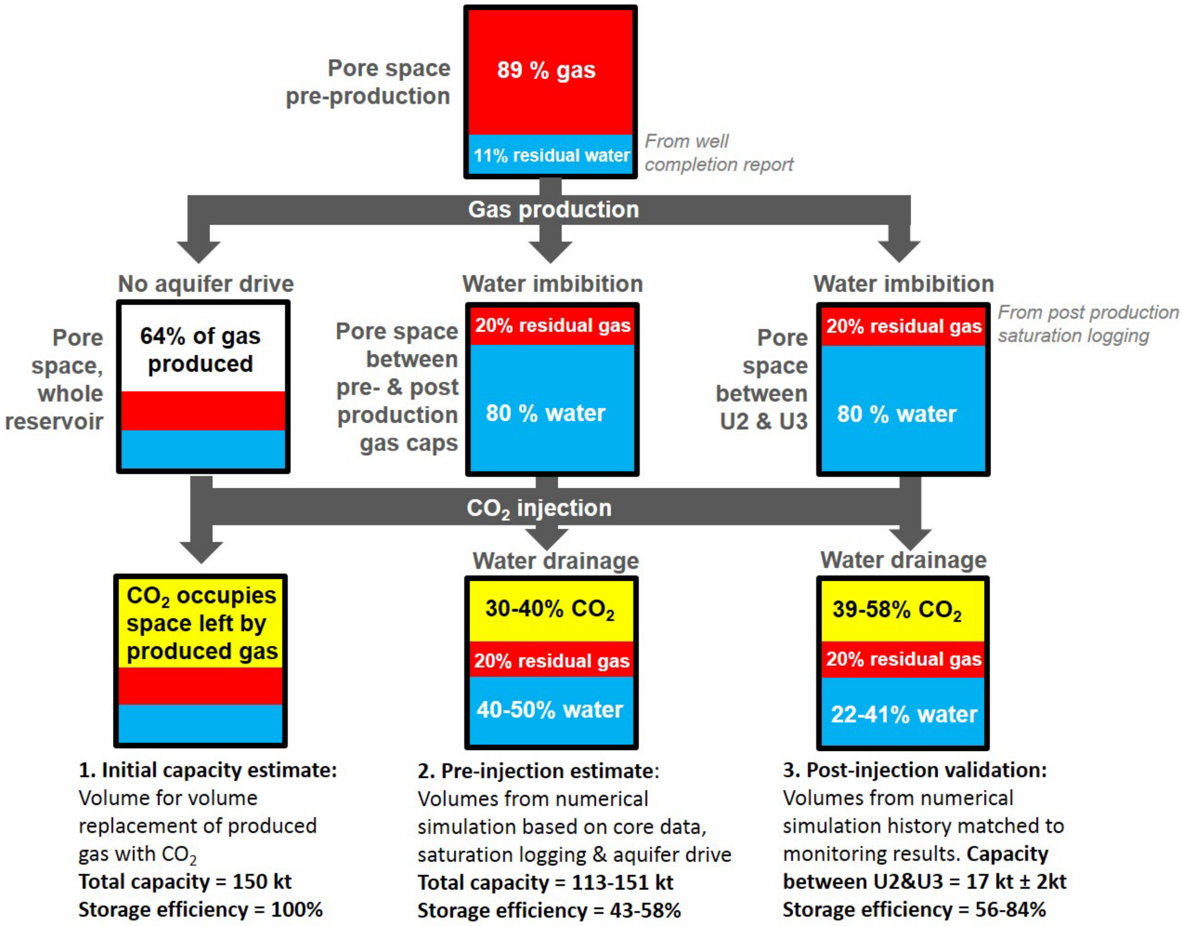

Figure 30 Simplified summary of evolution in storage capacity estimations and filling efficiency factors at Otway. Squares represent pore volumes of either the whole reservoir, the volume between the pre- and post-production gas caps, and the volume between U-tubes 2 & 3. For comparison, a generic efficiency factor used for global estimation of capacity in depleted gas fields is 75%.

6.4 Cost of modifications and storage development (#6 issue, section 1.1)

The Otway project Stage 1 was part-funded by the Australian Federal and State governments and industry, with additional top-up funds provided by the US Department of Energy and the Korean Geological Survey. *Breakdown of the overall costs of the project have been made public in the "Otway book", (Cook, 2014; specifically, Chapter 1, Cook et al.) and the cost data that follows is from that source:*

In the early stages of project planning (2004), initial estimates of project costs were around 20 million $AUD (equivalent to around 10 million £GBP or 14 million $USD at January 2016). The budget submitted prior to project start-up (2007) was closer to 30 million $AUD mainly as a result of underestimated drilling and resource-related costs, which escalated in the run up to the global financial crisis of 2008. Final forecast costs on completion (Table 11) are similar to this, although it is estimated that the actual final costs were around 40 million $AUD. Cook (2014) suggests that the science component of 7.5 million $AUD, (Table 11) could be considered to be more like 20 million $AUD, when all factors such as the in-kind contributions and difficulties in separating out research directly related to Stage 1 etc., are taken into account. The authors also note that insufficient cost provision was made for writing up results and data curation.

Financial uncertainties in research funding were perhaps less severe at Otway than experienced at similar projects elsewhere, in that funding was secured for 7 years initially, although inflation was not taken into account, which caused major budgeting difficulties leading up to the global financial crisis of 2008. Policy changes associated with the government change in 2008-2009 also added significant uncertainty. Despite this, a successful CO_2 storage pilot was delivered.

Naturally many costs are highly site specific. For example: drilling and permitting costs might be cheaper in USA than Australia. Buying the petroleum tenements necessary for the Otway project were a major outlay (~2.7 million $AUD), but buying the CO_2 itself from a commercial supplier would have cost the project 13 million $AUD. Follow-on project stages were also able to benefit from the CO_2 supply from the Buttress Field. Re-using an existing well as the monitoring well resulted in significant cost savings, but at detriment to the monitoring capabilities (see section 6.1). Provision for abandonment & remediation stands at 0.9 million $AUD in Table 11, but the authors estimate that given the follow-on stages of the project with additional wells etc., this has increased to ~3.5 million $AUD (Cook, 2014). Although such cost specifics are unlikely to be directly relevant to other projects, it is nonetheless anticipated that similar economic factors will need to be considered.

	Cost indication: Final forecast		
	$AUD	£GBP (1AUD=0.5GBP)	$USD (1AUD=0.7USD)
Naylor-1 well (recompleting for monitoring)	799,919	399,960	559,943
Monitoring and verification (M&V)	892,176	446,088	624,523
CRC-1 well (drilling new injection well)	4,822,183	2,411,092	3,375,528
Buttress-1 well (CO_2 supply well)	565,133	282,567	395,593
Pipeline	1,526,871	763,436	1,068,810
Process plant	2,928,693	1,464,347	2,050,085
Permits/licences	252,043	126,022	176,430
Process group	1,810,185	905,093	1,267,130
Project management	2,005,077	1,002,539	1,403,554
Abandonment	900,000	450,000	630,000
Opex total	1,440,000	720,000	1,008,000
Scope change	325,433	162,717	227,803
Management (legal/bank fees etc)	590,000	295,000	413,000
Operations (regulatory/landowner permits etc)	729,000	364,500	510,300
Petroleum tenements	2,655,000	1,327,500	1,858,500
Total operations	**21,906,576**	**10,953,288**	**15,334,603**
Executive	2,086,000	1,043,000	1,460,200
Geoscience	1,246,000	623,000	872,200
M&V personnel	1,496,000	748,000	1,047,200
M&V research (atmosphere, geochemistry, geophysics)	2,467,000	1,233,500	1,726,900
Outreach and risk	327,000	163,500	228,900
Total science	**7,622,000***	**3,811,000**	**5,335,400**
total ops and science	**29,528,576**	**14,764,288**	**20,670,003**

Table 11 Costs of Stage 1 of the Otway project in AUD, showing rough currency conversions (at 2016) into GBP and USD. Adapted from Cook, 2014, (Chapter 1, page 20). Intellectual Property of CO2CRC Limited. Reproduced with permission.
* it is estimated that the science amount was actually closer to $20 million AUD over the life of the project.

Chapter 7: Comparative assessment: Trends, differences, barriers or enablers to development

Naturally there are some key differences amongst the case studies presented in Chapters 3 - 6. The most striking is between offshore and onshore site location, pure storage versus CO_2-EOR and the relative ages/maturities of the fields and consequent number of well penetrations. Here the different types of project are examined in terms of their differing modelling, monitoring & reporting requirements, economics & operational strategies. Differences in storage in depleted oil fields compared with depleted gas fields are also considered, and are contrasted with CO_2 storage in aquifers (summarised in Table 12). These elements are discussed taking into account benefits or barriers to storage project development (sections 7.5.1 & 2 respectively) and distilled into a list of recommendations (section 7.5.3).

7.1 Offshore versus onshore (Goldeneye, *ROAD, K12-B, Hewett* vs SACROC, Cranfield, *Rousse, Weyburn* & Otway):

The main differences in onshore and offshore storage are not specific to depleted fields. They relate primarily to regulatory requirements and operational logistics. Onshore, the protection of drinking water aquifers is of paramount importance but this is not the case offshore where aquifers are generally saline. Amongst the selected case studies, the EU sites are largely offshore and the US sites are onshore. This is perhaps largely because of public acceptance issues in the more densely populated EU limiting onshore storage to date. Conversely, in the US their long history of onshore exploration and production has resulted in a public generally more accepting of onshore operations. It is notable that US regulations for offshore CO_2 storage are developing later than their onshore equivalents.

Given that offshore development started later (due to its relative logistical complexity) we suspect that infrastructure placement records and abandonment practices and records offshore will be superior, given the evolution of regulatory requirements in this area.

Monitoring on and offshore will naturally require different technologies and deployment methods, despite their similar objectives. Shallow-focussed monitoring approaches in particular will be very different. A thorough comparison between monitoring onshore and offshore is available in Appendix 1 of IEAGHG, 2015.

7.2 Pure storage in depleted fields versus enhanced hydrocarbon recovery and storage (Goldeneye, Otway, *ROAD, Hewett, Rousse* vs SACROC, Cranfield *Weyburn, K12-B)*

Perhaps the main difference between pure storage in depleted fields compared with storage that accompanies CO_2-EOR is the motivation (or lack of) for storage and how the regulations apply. Broadly, pure storage (both in depleted fields and saline aquifers) is motivated by the need to abate carbon emissions, whereas CO_2-EOR is motivated by hydrocarbon extraction, and in the USA at least, it is considered in the same way as “conventional” hydrocarbon production, with no carbon abatement credit. Calculating how much CO_2 is stored at CO_2-EOR projects is not a straightforward task because the CO_2 is recycled (of the CO_2 injected, some is stored, but some returns to the surface mixed with the hydrocarbon, where it is extracted, and then reinjected) and CO_2 recycling generally increases with time[38]. Possible approved methods for calculating amounts stored are in development (section 2.2.2), but in any case, are not required by regulations at this stage (Choi et al., 2013). For example, at Weyburn, the amount of CO_2 stored after 14 years of CO_2-EOR was estimated as 20 Mt but this was not included in national emissions accounting.

Regulations for pure storage are in general more stringent than those for CO_2-EOR (which often falls under oil and gas legislation). This is particularly true in the USA for example, for greenhouse gas reporting rules between the types of site. In Europe, the EU Storage Directive and associated guidance on modelling, monitoring & reporting requirements is purpose-designed, but, with the exception of granting a permit for the ROAD project, it still remains to be operationally tested. In Australia, regulations were developed in concert with the Otway project allowing learning from both sides, and finding the balance between ideal and achievable requirements (in particular at the pilot site, separating and defining the levels of monitoring required to satisfy regulations, from those that are research-based is recommended). However, in the USA, the maturity of existing regulation has in itself imparted several limits on combining storage with CO_2-EOR resulting both from the historic 1) severance of surface land owner rights from subsurface extraction rights and therefore the involvement of multiple parties and 2) fragmentation of the regulations themselves, whereby permitting and greenhouse gas reporting falls under different Acts. Offshore regulations for CO_2 storage in the USA are developing and have not been tested, but potential suffer from similar jurisdictional separations (IEAGHG, 2015). Onshore, merging these multiple mature programmes each with a different purpose has been problematic for enabling GHG-emission-reduction-recognised storage at CO_2-EOR sites. The first such merger is the EPA approved MRV plan for OXY’s Denver unit in Wasson field West Texas (Oxy, 2015).

Despite these legal complexities and the fact that historically CO_2-EOR has been conducted without any intent to “store” CO_2, these projects nevertheless effectively store CO_2 in the reservoir and avoid migration, leakage or emissions in a similar manner to pure storage operations, albeit with different high-level motivators (hydrocarbon production vs climate abatement). This is because the basic regulatory requirement in both cases is to protect the environment (drinking water, air) and thereby the population and biosphere. In the CO_2-EOR case this is supplemented by

[38] At SACROC, between 1972 and 2013, approximately 40% of total injected CO_2 was stored in the reservoir with 60% recycled. In 2013, however, the ratio of recycled CO_2 reached 90% of total injection (Kinder Morgen, 2013).

an economic driver to conserve CO_2 both because of purchase costs and because the available supply typically limits the rate at which the reservoir can be “processed”, which has an important impact on economics of the flood.

Characterisation: Both depleted field and EOR storage will have dynamic flow information from the production history as well as knowledge that the seal has been effective in retarding vertical hydrocarbon migration and is continuous over the reservoir. This strongly reduces characterisation uncertainty in comparison with saline aquifer sites (see section 7.4). EOR projects will have the further advantage of having injected fluid previously during secondary production and so will have more data on dynamic flow parameters for input into predictive performance models. On the other hand their varied production history can add local complexity to residual hydrocarbon distributions and geomechanical stresses. In addition, significant effort could be required to assimilate the potentially vast body of legacy data into the characterisation.

Modelling at a pure storage site will be based on addressing risk, demonstrating the site can be safely operated and there is sufficient capacity to store the CO_2. At EOR sites in contrast, their models would typically be more focused on compositional phase behaviour of oil or gas and therefore may not specifically represent issues such as risk of non-conformance. Both types of site will require complex multiphase modelling to take account of residual hydrocarbons remaining in the pores, compared to the relatively simpler two-phase flow of brine and CO_2 at aquifer storage sites (see section 7.4).

Monitoring will be implemented to satisfy the regulations at both types of sites and address containment risks. At a pure storage site this would include demonstrating conformance with modelled predictions, which would not necessarily be required at EOR sites. However, the latter are likely to have the additional objective of monitoring the effectiveness of the CO_2 flood to optimise the operation which is a similar aim to monitoring the plume evolution in a pure storage project, albeit, not requiring reporting. Given their relatively large numbers of well penetrations, EOR sites might often have a much more well-based monitoring programme compared to pure storage. For example, at Cranfield there are almost 300 wells and monitoring data are collected from the 55 active wells, compared to Goldeneye and Otway which have five and two wells respectively, with only one specifically assigned for monitoring. Some depleted storage sites (such as ROAD) might have no dedicated monitoring well, the cost and integrity risks outweighing any benefits (particularly offshore). In terms of reporting requirements and frequency, ratios of injected fluids to produced fluids (volumes and compositions) are typically observed monthly at EOR sites and reported to regulators along with wellhead tubing pressures. Other tools such as logging, seismic, and tracers might also be used to monitor the flood, but operators are not typically expected to provide this data to regulators, although it is published from time to time. In contrast, monitoring results at pure storage sites might require less frequent reporting (e.g. annual reporting is stipulated under the EU Storage Directive) but generally with more rigorously stated objectives - such as the aforementioned demonstration of site conformance with modelled predictions. In particular this allows flagging of deviations from expected behaviour and hence potential early warning of containment issues. This necessitates significantly more effort in designing an appropriate monitoring system to provide this. The requirements for satisfactory demonstration of a match between observed and modelled results and to detect significant deviations from expected behaviour could be regarded as areas where pure CO_2 storage regulations might be considered stricter or more onerous compared with analogous storage-EOR activities since they require significantly more effort (and cost) to be expended. Despite this, it is anticipated that as pure storage operations increase, practical implementation to meet these requirements will become clearer. From the EOR side, all the basic tools of monitoring and managing a conventional CO_2-EOR flood provide a substantive monitoring program that meets the needs of demonstration of storage. The major improvement needed is to gather the data reported and collected for operator use to provide documentation to stakeholders. A case in point is the monitoring reporting and verification plan approved by US EPA for OXY's Denver unit flood at Wasson field in West Texas.

Well penetrations and consequent containment risks will naturally be highly site specific, and the number of wells (or the ages of those wells) is not a definitive differentiator between depleted field storage and CO_2-EOR, but it is notable in the case studies presented. For example, to take the extremes, the Otway site contains only two wells, both relatively young as the field was small and discovered in 2001, compared to SACROC with >1,000 wells, back to the 1940s. Goldeneye has five production wells (~2004, also relatively young compared to SACROC), but from past hydrocarbon exploration in the area, also has 13 abandoned wellbores in its vicinity, dating back to 1979. This is still relatively few compared to the hundreds of wells at many USA CO_2-EOR sites. With large numbers of wells it is likely that storage characterisation uncertainty could be reduced, although a proportionally larger effort would be required to assimilate all the information. However, the larger number of wells would also increase well bore integrity risks, particularly if the older wells (pre-1960s-70s), were drilled using lower quality materials and under laxer standards for completing, plugging, and abandonment[39]. Despite most of the wells at SACROC and

[39] Summarised by examining the USA case: in 1919, RRC of Texas adopted the first statewide rule regulating dry or abandonment wells that they must be plugged by the use of mud laden fluid. The first specific rule for plugging was enacted in 1934 to enforce circulation of cement throughout the producing formations. The Well Plugging Statute was enacted in 1965 to clarify the duty to plug and abandoned oil and gas wells (Nico, 2009). In addition, the old wells (pre-1967) in Gulf Coast counties in Texas tend to lack the information of location and plugging, which would increase the uncertainty of the analysis of well integrity.
One issue that has led to well failure elsewhere in the USA is "lost wells" where past records are inadequate to properly locate all wells. Several approaches are used onshore to reduce this risk: Aerial photographs collected during the periods of field development can be interpreted to identify areas of past oilfield activities. Modern high resolution LIDAR has been used the same way at Bell Creek Field, Montana to identify well sites. Airborne magnetic surveys can also identify casings and was used at Cranfield to confirm that all wells had be located. More research into qualifying existing wells is needed.

Cranfield being pre-1960s there are no reports of CO_2 blowout at P&A wells during the later CO_2 flooding (see section 5.4). At Cranfield, some old wells were re-entered and used as producers, which can reduce risk while saving the cost of a new well installation. Assessment of the quality of existing wells is an important element of preparing either type of site for storage. It formed a key part of the storage development permit at Goldeneye for example (section 3.7) and the process has also been well-demonstrated by experience in preparing wells in a field for CO_2-EOR. In the USA this process is overseen by regulators. Loss of control of a well by internal or surface blowout is uncommon but has been frequent enough that the value of investment in bringing wells up to the required standard is well-recognised. The Cranfield Risk Assessment provides a case study of using cement-bond logs to assess isolation over the reservoir zone and use this to provide an index of wellbore integrity risk (Nicot et al, 2013).

Production history and pressure profile Reservoir pressure in depleted fields and EOR fields is usually reduced by extraction of hydrocarbon and potentially the coproduction of brine (Figure 31 a&b). The overall lowered reservoir pressure is an advantage for carbon storage by increasing storage capacity and lowering leakage risk. At Goldeneye, this pressure depletion is cited as an overriding mitigating factor for preventing CO_2 leakage because the sub-hydrostatic reservoir pressure would tend to suck formation water into the reservoir rather than force CO_2 out. Naturally as this type of store fills and pressures approach and ultimately exceed hydrostatic pressures, this mitigating factor no longer applies. It is possible that the pressure in the top of the reservoir could peak many years after injection ceases, depending on aquifer recharge rates (and neighbouring pore-space use). Risk levels could therefore be considered to increase up until that point (Figure 31). This delayed risk element could be potentially apply to EOR sites too, despite their very different pressure profiles. At EOR sites, pressures will have increased and decreased from injection and extraction over multiple cycles, which could put the containment of the wellbore or caprock more at risk from failure resulting from geomechanical fatigue. In contrast, pure storage in fields that have only had primary production, followed by injection will only experience one pressure cycle. Nevertheless, significant modelling efforts were deployed at Goldeneye to investigate this risk (section 3.5) and despite the long history of EOR at Cranfield and SACROC neither site has experienced any significant integrity problems (sections 4.6 and 5.4). At EOR sites, active management of fluid production and injection can be an advantage, and could be used to effectively control CO_2 distribution and plume size, which will greatly reduce the risk of out-of-zone migration during the period of production.

Site closure requirements for pure storage operations will be different to storage at EOR sites. In the EU the handover of the storage site to the state can only occur once certain criteria have been met[40]. These need to be demonstrated by the operator and a further important monitoring objective at pure storage sites is to ensure that sufficient evidence exists to meet these criteria and expedite transfer of responsibility (and liability) to the state as soon as possible after injection ceases. The EU Directive states that the operator should make financial arrangements to cover post-injection monitoring over a period of at least 30 years. EOR sites are permitted under the same terms as hydrocarbon sites, as the operator's responsibility ends when hydrocarbon operation ends and the wells are plugged and abandoned. No period of monitoring or modeling of stabilization is required at current CO_2-EOR sites (in the USA), although no large EOR operations have been conducted to completion yet. The operator retains liability for well failures as the "responsible party".

Costs of developing a storage site (be it depleted field pure storage, EOR or saline aquifer) are highly site specific and information in the public domain is not sufficient to make detailed comparisons. EOR sites naturally have an economic incentive from the sale of produced hydrocarbons, although this should be offset against the additional capital required for preparing wells for CO_2 service, flow lines, test separation facilities, and separation plant. Operating costs are also higher than storage, mostly to pay for energy for lifting at producers, separation, CO_2 compression, and fluid reinjection.

At either type of site, the presence of existing wells can provide a cost benefit, as they provide data and access to the reservoir for injection, monitoring (as at Goldeneye), and in the case of CO_2-EOR, production at low cost. However, wells of poor quality must be repaired or plugged and abandoned to prepare for storage or EOR, leading to cost increase. The cost of well repair is highly case-specific. In general onshore it might be 1/8th to half the cost of a new well, however outliers can require very expensive remediation, including operations such as drilling a new well to intersect and remediate a damaged wellbore. Offshore, a new intervention well will almost always be required to remediate a badly leaking wellbore.

40 In the EU closure of a storage site can only occur when there is:

a) The conformity of the actual behaviour of the injected CO_2 with the modelled behaviour.
b) The absence of any detectable leakage.
c) That the storage site is evolving towards a situation of long-term stability.

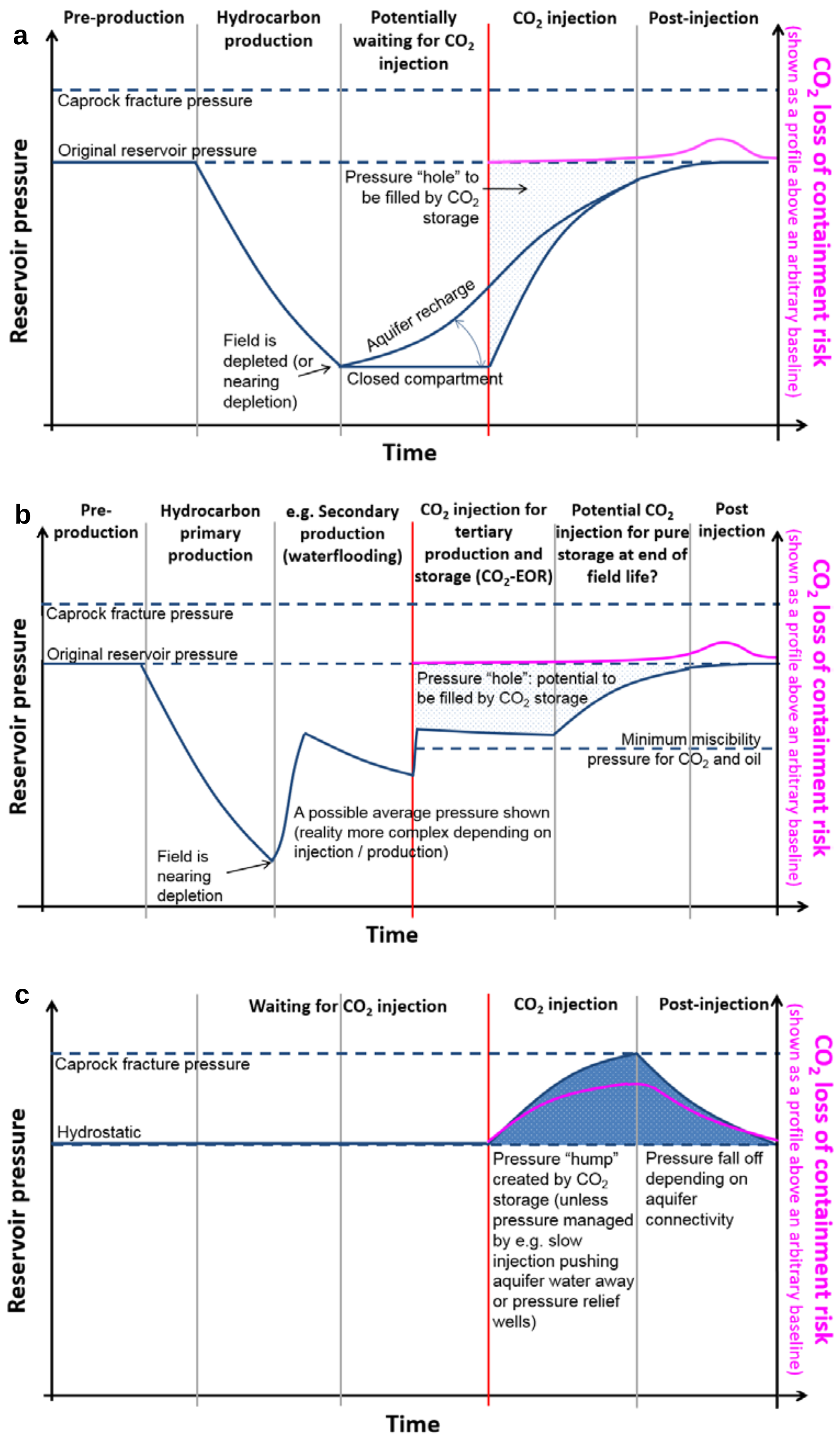

Figure 31 Schematic pressure profiles (blue) and possible risk profiles (pink) through time to highlight differences in the project types. a) Pure storage in a depleted field e.g. Goldeneye; b) CO_2-EOR storage in a depleted field e.g. SACROC; c) Pure storage in a saline aquifer. Red line indicates when CO_2

injection begins. Note that storage in a depleted field or CO_2-EOR site could theoretically inject up towards the caprock fracture pressure as per saline aquifers, but their risk profile would consequently become more similar to that of a saline aquifer during that period. Note: NOT TO SCALE. Discussed in sections 7.2 and 7.4.

7.3 Depleted oil versus gas (Goldeneye, Otway, *ROAD, Hewett, Rousse K12-B* vs SACROC, Cranfield, *Weyburn,)*

Besides the obvious difference of economic incentive between depleted oil and gas fields the impacts on storage capacity and injectivity from residual oil and gas are also different. Depleted gas reservoirs are likely to be relatively simpler to model compared to oil, because of the many hydrocarbon components making up the oil that need to be taken into account. CO_2 injection into depleted oil or condensate reservoirs with a free gas-cap will be particularly difficult to model given that most modern simulators can only handle a maximum of three phases.

The presence of residual hydrocarbon can increase dynamic storage capacity to a minor extent:

1) **Compressibility:** Gas is more compressible than oil, so the presence of residual gas will preferentially increase total reservoir compressibility and reduce pressure elevation resulting from CO_2 injection (Solano et al., 2011) and thereby increasing storage capacity. So, in a closed reservoir with a gas-cap, injection pressures beneath the gas-cap will be suppressed due to the presence of the gas column. This means that CO_2 density and viscosity is lower than it would be at the same depth in an equivalent oil reservoir (or aquifer). This results in faster upward buoyant migration of CO_2 and further lateral spreading of the CO_2 plume in a gently dipping trap compared to a case without a gas-cap (Solano et al., 2011).
2) **Miscibility:** CO_2 is miscible in both gas and oil (depending on reservoir conditions), which has the effect of increasing the density (and therefore compressibility) of the mixed fluid. This means that at the same pressure it occupies less volume, thereby slightly increasing capacity. At SACROC, numerical simulation of an optimal oil:CO_2 mixing ratio of 7:3 increased the storage capacity by less than 3%. At Goldeneye similar calculations suggested perfect mixing could decrease the storage capacity by as much as 6%. However, both studies suggest that such optimal mixing would be unlikely to occur and the effect on capacity resulting from compressibility of residual hydrocarbon would be likely to be greater.

Another important difference between depleted oil and gas fields is associated with the mobility of CO_2. The residual saturation of oil may produce three-phase relative permeability effects that reduce injectivity (mobility) of CO_2. This will further restrict CO_2 flow and might increase fingering of the CO_2 plume. Consequently, CO_2 injection into a reservoir with residual oil requires higher injection pressure to achieve the same injection rate compared with the same formation holding residual gas. With increasing volume of bypassing CO_2, the oil phase will be stripped of lighter components leaving remaining oil with a higher density, viscosity, and molecular weight and consequently even less mobile, further affecting the injectivity (Shelton and Yarborough, 1977). On the other hand, the presence of residual gas in the pore network will result in higher mobility of CO_2 because of the increased relative permeability for CO_2. This was modelled at Goldeneye and resulted in unstable displacement of the CO_2 on filling and the formation of a 'Dietz tongue' whereby the highly mobile CO_2 spreads rapidly downdip beneath the caprock in a thin plume that can extend out of the original oil-water contact. This can detrimentally affect storage filling efficiency as parts of the reservoir are initially by-passed.

7.4 Depleted field pure storage or EOR versus saline aquifer storage

Naturally the intrinsic differences in the settings of saline aquifers, depleted fields, and CO_2-EOR operations necessitate different storage operational strategies and result in different risk profiles (Figure 31). Key differences immediately apparent between aquifer storage and storage/EOR in depleted fields are the lack of residual hydrocarbons, which significantly affect modelling complexity and monitoring capabilities, and also alter the range of geochemical interactions. The quantity of information available for characterisation will generally be greatly different at the beginning of the site characterisation process, as will the pre-injection pressures relative to hydrostatic (Figure 31c) and the in situ stress state of the reservoir and its surroundings. The implications of these is discussed below:

Characterisation: Saline aquifers, will almost always have initially much less data on which to base site characterisation than depleted fields and will therefore have consequently higher uncertainty on a number of factors. They will generally have fewer well penetrations to provide model input parameters and, compared to depleted fields, the trap itself will not have been previously tested, either terms of its static or dynamic properties and migration spill-points will not be well constrained. Generally much more effort will be required to reduce uncertainties in site characterization compared with depleted fields with production history (for example, by drilling an appraisal well and performing well tests such as at the UK White Rose aquifer storage proposal, or conducting pilot injection tests upfront).

Well penetrations & consequent risks: Saline aquifers might have few or even no wells penetrating the confining system, which reduces or eliminates risk of unintended leakage through unmonitored wellbores. In contrast this is generally considered a major risk requiring significant monitoring effort for depleted fields. However, if saline aquifers do have well penetrations, they are perhaps more likely to be "wild cat dry holes" with higher levels of uncertainty in the completion and/or with variable plugging and abandonment quality across the storage interval and caprock.

Operating pressures: Saline aquifers will generally have undisturbed formation pressures usually at hydrostatic. The storage formations will therefore be operated above the hydrostatic pressure during the whole project period (Figure 31, blue lines). This is generally considered to be more risky than storage at depleted fields (Figure 31, pink lines). Depleted fields will have disturbed pressure fields, generally below hydrostatic pressure, depending on aquifer recharge or EOR operations, but for storage they will generally operate at less than the initial reservoir pressure (i.e. considered 'less risky' than saline aquifers). In terms of the effect this has on the risk profile through time, the maximum risk for open saline aquifers could be considered to be around the end of injection, when pressures reach a maximum and then start to dissipate depending on aquifer connectivity (Figure 31, pink lines). The maximum risk for depleted fields in contrast, could be expected to occur when the field reaches its maximum pressure, which could potentially be some time after injection ceases (see section 7.2) as the depleted reservoir continues to re-charge from the surrounding water-bearing reservoir. Theoretically, injection into depleted fields could continue above initial pressures and result in a pressure/risk profile similar to that for saline aquifers (Figure 31c), although this would negate the risk mitigation benefits of storing at less than initial pressure.

Another key factor to consider for storage in aquifers relates to their connectivity. If large scale aquifer storage were to proceed, then this would potentially necessitate multiple stores in the same formation. Avoidance of interacting pressure footprints (which could be very large) might therefore require some governing oversight, (IEAGHG, 2014). Storage in depleted fields of the type common in the Netherlands for example, which, on operational time-scales are effectively "closed tanks", would allow injection without impacting on the pressure fields external to the site.

Modelling: As previously mentioned (section 7.2), data for populating models with parameters, particularly dynamic models, including boundary conditions, are unlikely to be available for saline aquifers. Detailed reservoir characterisation and (possibly lengthy) pumping tests are likely to be required for evaluation of storage capacity and injectivity. Despite this, lack of residual hydrocarbon in the pore space simplifies the model prediction of CO_2 flow considerably, requiring only a two-phase system. In a depleted field setting, understanding residual hydrocarbon and water saturation distributions; the miscibility of CO_2 in the hydrocarbons and formation water; and the geomechanical effects of pressure depletion followed by inflation can be complex.

Monitoring: In depleted fields many geophysical techniques are hindered by the presence of residual hydrocarbon, especially gas, by its relative similarity in physical properties to CO_2. This contrasts with the situation in saline aquifers where the contrast in properties between brine and CO_2 significantly improves the ability of geophysical techniques to detect CO_2 (for example time-lapse seismic techniques and well-based geophysical tools to measure saturation, such as those utilising pulsed neutron capture).

Geochemical reactions: In depleted fields the presence of residual hydrocarbon in the pores will prevent some portion of the minerals from coming into contact with the CO_2 and water, consequently reducing rock-brine-CO_2 geochemical reactions which require water compared to an equivalent aquifer. In a saline aquifer, *all* the mineral components along the pores are potentially exposed to low pH solutions of brine and dissolved CO_2. The presence of hydrocarbons can significantly change the diagenetic evolution of a reservoir which may further reduce the potential for subsequent mineral reactions. However, differences in the resulting impacts on storage capacity and containment are often negligible (Lu et al., 2012b). Storage capacity and storage efficiency is improved for hydrocarbon-bearing systems over saline aquifer systems because of oil-miscibility and solubility processes. When the reservoir pressure is above the minimum miscibility pressure (MMP), miscibility between CO_2 and oil occurs. The density of the miscible fluid is higher than the weighted average density of CO_2 and oil, which leads to increased storage capacity (discussed in Section 5.3). When the reservoir pressure is below the MMP, CO_2 and oil will remain as separate phases, but CO_2 will dissolve in the oil. The solubility of CO_2 in oil is generally higher than in water for the same conditions, which results in improved storage efficiency (although the benefit is partially negated because the oil swells more than water with the same amount of dissolved CO_2).

Geomechanical responses: Hydrocarbon production, particularly where enhanced recovery methods have been applied, can result in potentially complex changes in the stress state in and around the reservoir. Characterisation and understanding the geomechanical responses to CO_2 injection at these sites, and how this relates to caprock and wellbore integrity risks may consequently require more effort to model and predict than at an 'unperturbed' saline aquifer site. Note however that in situ stresses at a saline aquifer site may, at least initially, be relatively uncharacterised, whereas there could be useful extensive datasets available for depleted field sites (as described in the 'characterisation' section). In addition, saline aquifer sites could also be impacted by nearby subsurface use, in the same way that connected hydrocarbon fields can be.

Site closure: A key difference between aquifer and depleted field storage is the fact that aquifer storage will not necessarily be in a closed structure, but rather within a relatively flat-lying or dipping reservoir that allows the CO_2 to migrate long distances, potentially well after cessation of injection. This predictive uncertainty can present difficulty in developing a longer-term safety case for large-scale aquifer storage (Goater & Chadwick 2013). Depleted fields, commonly (though not always) occupy structural closures which by definition will spatially constrain the migrating CO_2 plume and allow for much more certain future performance prediction. On the other hand future prediction could be more straightforward for aquifer storage given the relative simplicity in model physics and the ability to potentially more easily monitor the CO_2 plume migration remotely (using surface seismic, such as at Sleipner in Norway). Another issue to consider with storage in depleted fields is that some hydrocarbon remains and stabilization with CO_2 over decades post-abandonment might concentrate hydrocarbons. Extraction of the hydrocarbons could feasibly become economic in future, depending on supplies and extraction technology development. Such a benefit would not exist in a saline store. Experience from CO_2-EOR sites has been that the fields continue to be operated as technologies advance and closure might be delayed, perhaps long after the field stops accepting CO_2.

Costs: see also the cost section in section 7.2. It is possible that development costs for storage in depleted fields could be less than at saline aquifer sites. Their documented production history is likely to reduce characterisation costs and time and the proven hydrocarbon retention markedly reduces uncertainty in containment and capacity compared to at saline aquifers. In addition, costs could potentially be further reduced or offset at depleted field sites by exploiting existing infrastructure and/or by additional hydrocarbon recovery (i.e. CO_2-EOR).

	Depleted hydrocarbon site	Depleted site operated as CO_2-EOR	Saline aquifer site
Overarching motivator	Climate change abatement. Containment required by storage-specific regulations (environmental protection and emission abatement)	Hydrocarbon production. Containment required by environmental & air pollution protection regulations. And to avoid having to buy more CO_2.	Climate change abatement. Containment required by storage-specific regulations (environmental protection and emission abatement)
Regulation maturity	Purpose-designed, relatively recent (EU: 2009, USA: 2011) & not tested in EU or USA yet	Very mature, but somewhat fragmented and comparably complex in USA	Purpose-designed, relatively recent (EU: 2009, USA: 2011) & not tested in EU yet
Characterisation effort required	Low: Well(s) with production history, tested containment of CH_4	Low: Many wells with production and injection history. High effort may be required to assimilate vast historic datasets	High: Few or no wells, no production history, untested trap. Well tests likely needed to reduce uncertainty prior to permitting/injection
Modelling requirements	To predict behaviour & demonstrate site capacity & containment. Initial predictions submitted to obtain permit. Thereafter, history matched (and long term stability predictions updated) EU: reported annually, USA: no reporting schedule specified.	Typically focussed on improving understanding of sweep efficiency and compositional phase behaviour for operator internal use only.	To predict behaviour & demonstrate site capacity & containment. Initial predictions submitted to obtain permit. Thereafter, history matched (and long term stability predictions updated) EU: reported annually, USA: no reporting schedule specified.
Modelling capabilities	May be complex because of residual hydrocarbon saturations, but can be matched to production data to reduce uncertainty. Geomechanical modelling to include site history to ensure wellbore/caprock rock integrity after pressure cycling	May be complex because of residual hydrocarbon saturations. (Potential data 'overload' to match to full field history. E.g. Pressure cycling may be complex)	Less complex because no residual hydrocarbon saturations (2 phases only), but no production data to match to, to reduce uncertainty.
Monitoring requirements	Report to regulator typically annually (EU): risk-based monitoring focussing on how results demonstrate containment & conformance with models.	Report to regulator typically monthly (USA): well production and injection volumes, wellhead pressures. Other risk-based monitoring data may be collected but not reported	Report to regulator typically annually (EU): risk-based monitoring focussing on how results demonstrate containment & conformance with models.
Monitoring capabilities	Wells may allow opportunities for well-based monitoring. May be difficult to distinguish CO_2 from residual hydrocarbons using geophysical techniques	Wells almost certainly allow opportunities for well-based monitoring. May be difficult to distinguish CO_2 from residual hydrocarbons using geophysical techniques	Less opportunities for well-based monitoring. CO_2 likely to be much more readily distinguishable from brine using geophysical techniques
Irregularity detection and contingency potential	Likely to have continuous well-based monitoring for early warning irregularities, although less spatial coverage than at CO_2-EOR sites (but also consequent reduced wellbore leakage risks)	Many wells - lots of well based continuous monitoring, potential for early catching of irregularities (but also many more possible leakage paths). Potential for "plume steering" using multiple active wells away for contingency containment.	Less opportunities for continuous well-based monitoring (other than in injection well) (but could represent a lower risk of wellbore leakage). High spatial coverage monitoring (e.g. seismic) likely to be periodic (i.e. less opportunity for early detection of irregularities)
Site closure requirements	In EU operator needs to demonstrate long term stability of the site, potentially monitor for up to 30 years.	No specific requirements for CO_2-EOR compared to other EOR operations.	In EU operator needs to demonstrate long term stability of the site, potentially monitor for up to 30 years.
Costs & economics	May be savings in reusing infrastructure such as wells	Economic benefit from sale of produced hydrocarbon. Additional costs of equipment and higher operating costs for EOR. May be cost savings by reusing existing wells	Likely to be additional costs for characterisation and infrastructure installation. Long term costs for abandonment might be less (fewer wells)

Table 12 Summary of comparative assessment between storage in depleted fields, in CO_2-EOR sites and in saline aquifers.

7.5 Summary list of factors potentially aiding or hindering storage development in depleted fields

7.5.1 Factors potentially aiding projects in depleted fields

- Depleted fields could be considered as "low hanging fruit" in that they are generally already well characterised (reducing characterisation costs), have proven caprock and have lower risk profiles than saline aquifers, particularly if pressures stay below hydrostatic for a protracted period (the 'pressure-sink' effect) and subsequently remain below initial pre-production values.
- A vast experience from CO_2-EOR (particularly in the USA) is available to learn from. For example in history-matching models to monitoring data, in having sufficient sample size for statistically valid performance assessment, and in the duration of CO_2 exposure. In the EU, fragmented and different regulatory regimes, as are found in the US, could be avoided as the first CO_2-EOR projects have yet to be initiated/permitted.
- Potential storage resources in depleted fields are still significant in relation to CCS 'targets', e.g. the IEA 2DS scenario (95Gt stored by 2050, IEA, 2016).
- There is the potential for enhancing hydrocarbon recovery to offset the costs
- There is the potential to exploit existing infrastructure to reduce costs

7.5.2 Factors potentially hindering projects in depleted fields

Sara et al. (2015) examined the interaction and crucially the interdependancy of factors that contribute to hindering project deployment (whereas previous studies have tended to examine barriers independently). The specific case of ROAD in the Netherlands was used, although a number of pan-European sites that are currently delayed or cancelled are listed. Barriers considered were economic, legal, societal and technical and combined using two purpose-designed multi-criteria decision making methods. The factors listed below result from suggestions arising from our report and have not undergone any such rigorous methodology to rank them. We note that the recent (November 2015) withdrawal of government funding from the UK competition projects (including Goldeneye) has led to cancellation of these projects and caused potentially irreparable damage to investor confidence (The Energy and Climate Change Committee, 2016).

- Global and regional capacity in depleted fields is less than in saline aquifers, so there might be less opportunity for economic scale-up and with depleted fields less attractive at a national or regional scale.
- In significantly pressure depleted fields, additional surface and/or downhole equipment might be required to avoid adverse effects from Joule-Thompson cooling because of pressure reduction in the wellbore or as the CO_2 enters the reservoir. If unmitigated, this could result in thermal shrinkage effects impacting on wellbore or caprock integrity or potentially, hydrate formation affecting flow. The

low injection rates at K12-B (section 2.1.4) allowed the CO_2 to be warmed by the surrounding material, but this is not practical for larger scale projects. Mitigation options include compression and heating of the injected CO_2, (considered at the Hewett site, Section 2.1.2) or well recompletions such as the planned tapered tubing at Goldeneye.

- Uncertainty on the suitability of existing infrastructure for a straight swap to CO_2 operations (e.g. in wellbores and pipelines). Building/drilling from scratch for aquifer storage might be less risky.
- There are complications in converting CO_2-EOR to storage in the USA because of different regulation, ownership and operator mindsets.
- The maximum pressure a reservoir experiences could peak later for depleted fields than saline aquifers as the storage reservoir re-pressurises (albeit at a lower risk level). This could be many years after injection, rather than close to the cessation of injection as is the case for saline aquifers and could potentially lead to difficulties in demonstrating long term stability to allow early transfer of liability.
- Pressure cycling (i.e. pressure drop on production, followed by re-inflation on CO_2 injection) of depleted fields/CO_2-EOR sites might damage caprock or wellbore integrity, and present a storage permanence risk.
- Larger numbers of wellbores compared to saline aquifers might present a long term integrity/storage permanence risk.
- If the depleted fields are in areas where they could affect hydrocarbon production nearby their use might be restricted (e.g. Norway, UK and potentially elsewhere).
- Leakage of CO_2 with associated residual hydrocarbon might pose a larger environmental threat than pure CO_2, giving difficulty with potential environmental remediation and proving remediation to regulators.
- Transfer of liabilities between the hydrocarbon operator (particularly when joint-venture) and the storage operator could be challenging and sometimes prohibitive.
- Competition for the pore-space in depleted fields means that some good candidate sites may be used for gas storage rather than CO_2 storage.

7.5.3 List of non-prescriptive recommendations

This list includes high-level possible recommendations that might help enable and prioritise storage in depleted or depleting fields. This specific issue would potentially benefit from more targeted study to determine the best approach.

- Education at ministerial level so that governments can understand the advantages of storage in depleted fields as a “quick win” to start the CO_2 storage ball rolling. (The CLSF report, (Vincent et al., 2015) suggests that there is state-level doubt about the benefits of CO_2 storage in general). It is recommended that the best approach be investigated, but that this could take the form of, for example, summary brochures, presentations, conversations or government petitions by respected international bodies.

- Encourage governments to champion storage in depleted fields, perhaps offering financial incentives. This should also involve careful consideration of the need to facilitate change of use at the end of production, when oil and gas operators wish to rapidly decommission a site.
- Potentially consider encouraging “storage-enabling legislation” to by-pass/avoid confusion/liability with multiple regulations. This currently applies to the USA but would also be relevant elsewhere, including Europe.
- Continue to gather and publish data from existing sites to add to the body of data available for research and analysis that can contribute to reducing uncertainty on key risks. For example, observations of subsurface behaviour relating to storage permanence, such as geomechanical and geochemical effects on caprock and wellbore integrity.
- Timing, in Europe particularly, is of the essence to avoid field closure and removal of infrastructure before CO_2-EOR and CO_2 storage can be considered.

Chapter 8: Concluding synthesis

This final chapter synthesises report findings in light of the original scope (section 1.1).

#1. **Risk assessment criteria** for depleted fields

At Goldeneye the bow-tie method of risk assessment was used to assess and manage risks relating to the geological storage part of the planned project. This gives a visible structure to risk assessment which was also quantified with a scored system using a probability and severity matrix. At Cranfield the Certification Framework approach was used, which identifies vulnerabilities and characterises them using a systems modelling approach. Neither of these methods are specific to depleted fields and could be implemented at any site. Risks relating to storage in depleted fields, that would likely be less important for saline aquifer storage include containment integrity risks resulting from the larger numbers of wellbores and the effects of pressure cycling (production followed by injection). These are summarised in sections #5 and #3 below. Conformance risk relating to being unable to distinguish CO_2 from the residual hydrocarbons is also applicable (described in #2a). At both sites the approach was to investigate the risks using a combination of laboratory experiments, legacy or baseline field measurements, numerical simulations and comparison with analogous operations. This allowed improved understanding of the threat/vulnerability levels to enable effective control measures, for example, in site design and injection strategy to reduce the risks as far as possible. At Goldeneye a key risk mitigation control measure was the intention to cease injection before re-reaching the initial pressure (discussed in Chapter 7). Monitoring was closely linked to remaining risks at both sites. Continuing to collect, publish and analyse data from operational sites might contribute to further reducing uncertainty on key risks and improving understanding of the feasibility and costs of potential preventative and corrective measures. Although many aspects will be site specific, this adds to the body of evidence available to other sites.

#1a. Implications for continued oil and gas production in adjacent fields

This was assessed at Goldeneye, because the site lies within a hydraulically well connected aquifer, but impact on neighbouring fields was not eventually included as a risk. This is mainly because of the intention not to increase pressures up to the initial discovery pressure and also because the CO_2 injection would in any case tend to increase pressures at the neighbouring fields which would be beneficial to their production. At Cranfield it is noted that hydrocarbon production also occurs in rock units above the CO_2 injection zone. Although these are hydraulically unconnected it could contribute to an increased hydraulic isolation risk (resulting from pressure cycling) in the upper wellbores and also make above zone pressure monitoring more complex.

#2. Monitoring criteria (to quantify CO_2 storage and detect the extent of migration) and #2a. Implication for requirements e.g. the effects of fluid replacement.

Much of the monitoring described in the Cranfield and SACROC case studies was designed to test technique capabilities, whereas at Goldeneye the monitoring plan is focused on meeting the EU regulations. The Otway site had a mixture of both research and regulatory focussed techniques which were developed as site operations progressed. The feasibility of monitoring techniques will be site specific, but their relative successes can lend confidence to the general approaches for depleted fields. Importantly there are no specific regulatory requirements to quantify CO_2 in the store and detect the extent of migration (as mentioned in the report scope, section 1.1), rather, requirements are focused on demonstrating that the CO_2 is contained. There is also a requirement to demonstrate that the plume conforms with predictions, although the parameters are not specified. At the depleted field sites this is important because residual hydrocarbons in the reservoir can seriously hamper the abilities of monitoring technologies (particularly geophysical tools) to identify CO_2. Notable research deployments include attempts to map the CO_2 plume at Cranfield using seismic methods and match it with modelled plume extents based on known CO_2 injection well volumes. Large parts of the field where CO_2 had been injected showed no change in seismic response. Evidence suggests that this could be the result of higher methane contents in the CO_2 injected there, although modelling verification of this continues. Test deployments of small-scale 4D seismic swath surveys and VSPs at SACROC showed some potential to detect injection-related changes in the reservoir using advanced processing techniques, but they were not able to specifically distinguish CO_2 saturations.

Despite the relatively large number of accessible wellbores at Cranfield, attempts to map CO_2 flood extent using downhole pulsed-neutron tools was also unsatisfactory as many wells stop in the top part of the reservoir, providing insufficient penetration depth to allow the tools to make measurements in the reservoir itself. Saturation logs at Otway were unable to confirm CO_2 saturation distributions partly for a different operational reason: there were difficulties in differencing the time-lapse surveys when borehole infrastructure had changed (i.e. between open and cased-hole deployments). For this reason Goldeneye proposed a running a baseline survey *after* the wells had been recompleted. In addition, the PNC technique was to be combined with neutron logging to enable the CO_2 to be distinguished from residual gas.

The U-tube method was successful at Otway for directly measuring reservoir saturations at the wellbore at weekly intervals, which was useful for verifying storage efficiency factors (section 6.3) as well as calibrating the dynamic models. However, this method is perhaps less likely to be deployed outside of a research environment. It was not selected for use at Goldeneye for example, rather, they proposed downhole wireline sampling from the base of the wellbore which would be much more episodic.

The CO_2-EOR sites in particular focused on demonstrating containment by monitoring for leakage in zones above the reservoir, where injected CO_2 can be more easily distinguished from the formation water background. For example using 'AZMI' above zone pressure monitoring at Cranfield (which includes promising pressure pulsing field tests to help locate point source leaks) and sampling at SACROC which showed no impact to groundwater above the field over the lifetime of this extensive operation. Numerical simulations taking into account likely geochemical attenuation processes suggested that a 0.001% leakage rate for 3 million tonnes/year CO_2 injection would result in a discernible geochemical signature above the background concentrations.

#3. Pressure changes & thresholds and how these can be mitigated.

Schematic pressure profiles through time for each type of site are included together with their associated risk profiles. Depleted fields generally have the advantage of being pressure depleted, so that CO_2 can be injected without subjecting the reservoir, caprock and wellbores to pressures above the initial discovery pressure. Saline aquifer sites, on the other hand, will be injecting above hydrostatic pressure, certainly around the injection wells, even with pressure management. It is likely that early projects for pure storage in depleted fields will cease injection below pre-production pressures in order to ensure containment i.e. they will act cautiously given uncertainties in capacity. This means that pressures in the water leg, beneath the CO_2-water contact, will likely be below hydrostatic, with fluids tending to flow into rather than out of the store. This scenario is exemplified by Goldeneye, where the 'pressure-sink' effect is cited as a major risk-mitigating factor. As water flows back in to the pressure anomaly, so the reservoir re-pressurises. This means that the maximum pressures a store could experience might materialise some considerable time after injection ceases (estimated to be tens to hundreds of years or more at Goldeneye). It is therefore possible that demonstrating a site is tending towards long-term stability (a condition for site closure in the EU), might be challenging if this re-pressurisation is still occurring. Nevertheless, given that the field has likely experienced higher pressures in the past (pre-production), means that the overall risk level from pressure effects would still be considered lower than for saline aquifers.

Reservoir evolution during depletion is reasonably well understood, with field data collected over decades of hydrocarbon production providing valuable evidence for system behaviour (e.g. Goulty, 2003). However, the long-term mechanical response of the caprock, and implications for seal integrity under these conditions, is less well understood, and there is a paucity of material properties data available to populate and validate numerical models of this process (Graham et al., 2015). The effects of 're-inflation' of a previously depleted reservoir, and especially of repeated pressure cycling (for example, when there are repeated periods of injection and/or production, such as might occur in secondary or tertiary hydrocarbon production or episodic CO_2 injection), are currently also much less well documented. For example, there is a lack of data on the effects on physical properties of the reservoir and the caprock (i.e. will the permeability change, will it be damaged, will the damage lead to dilation or compaction, etc.) and what impacts that might have on flow and integrity. Such responses are likely to be very site specific, being heavily dependent on the composition, grain-size and porosity of the rocks. However, knowledge about these potential impacts (on the mechanical behaviour and transport properties of the affected subsurface) are crucial to designing injection strategies and making long-term predictions of field behaviour. In addition, consideration of the hydraulic and mechanical interactions will be important to understand the potential for fault reactivation (Cappa & Rutqvist, 2011), and whether any faults could act as flow barriers within a reservoir which might increase overpressure locally (Rutqvist et al., 2007; Rinaldi et al., 2015) or act as conduits, and create an open migration pathway for CO_2 out of the reservoir (Zoback & Gorelick, 2012). Fault reactivation has not been observed at any CO_2 storage sites (Verdon et al., 2013), although microseismicity was observed at some (Total, 2015; Stork et al., 2015). Experimental work on fracture transmissivity in shale (e.g. Cuss et al., 2011, 2014) and clay gouge (Sathar et al., 2012) showed that hydraulic flow is a complex, focused, transient property that is dependent upon stress history, normal stress, shear displacement, fracture topology, fluid composition, and clay swelling characteristics. The influence of pore pressure cycling on fault behaviour must therefore be carefully considered during assessments of caprock behaviour. In the four case studies examined, reservoir, caprock and wellbore integrity risks were assessed and injection and monitoring strategies were designed accordingly. There is no evidence that the site integrity was compromised during CO_2 injection and storage operations.

#4. Storage capacity estimate validation.

U-tube reservoir sampling at Otway offered an opportunity to test and validate dynamic capacity and storage efficiencies based on numerical modelling, at least between two of the sampling depths. Fluid samples taken as the field filled, as the base of the CO_2 plume moved downwards past the sampling ports, were used to calculate the amount of CO_2 in the pore volume during that time-frame. This suggested that 56 to 84% of the available space originally filled by gas was re-occupied by CO_2. This is comparable to typical storage efficiency factors of around 75% applied to global estimates of storage capacity in depleted fields. It was also in line with storage efficiency estimates at Goldeneye calculated by two methods (although not field-validated). These comprised detailed analytical solutions and numerical models investigating a range of injection scenarios, both giving efficiency factors of around 70%. Based on evidence from gas production, heterogeneities were judged to have the largest effect on storage efficiency with parts of the reservoir preferentially filling due to more favourable porosity, permeability and net-to-gross properties. The effect of heterogeneity were also explored at Cranfield, (probably more geologically complex than Goldeneye) where a dynamic model incorporating reservoir heterogeneity uncertainty attempted to predict CO_2 breakthrough times at various wells. Both early and delayed breakthroughs were observed compared to those predicted, although this could be largely due to uncertainties in the complex fluid and pressure distribution from earlier EOR operations rather than geological uncertainty.

Miscibility of the CO_2 in the hydrocarbon and its impact on storage capacity was explored at both Goldeneye (gas) and at Cranfield and SACROC (both oil). With “perfect mixing” which would be unlikely to occur at any field (given the presence of residual water) simulation results suggest that a density increase of the resulting mix of up to 14.5% could occur at SACROC and 6.2% at Cranfield. This effectively allows the pore space to accept more CO_2 and at SACROC was estimated to potentially increase capacity by up to 3%. At Goldeneye the same process but with a CO_2 and gas mixture was calculated to potentially reduce capacity by 6%, although given the imperfect mixing the actual effect was expected to be much less, giving a capacity reduction of 1.7 Mt.

#5. Long-term wellbore integrity assessment and remediation measures.

As depleted fields will have at least one and potentially tens or even hundreds of wells, wellbore integrity is often one of the top threats. More specific to depleted fields is the risk that pressure cycling resulting from production followed by injection mechanically degrades the wellbore seal interfaces. However at the sites that investigated this with numerical simulation did not find undue cause for concern. Analysis of records of well incidents from CO_2-EOR sites suggest that any failures are usually related to surface component failure rather than downhole loss of isolation. Samples of cement exposed to CO_2 at SACROC for 35 years showed relatively little chemical degradation and an ability of the cement reactions to self-heal and inhibit further degradation. Specific issues relating to cement and casing at Goldeneye were thoroughly investigated, including re-examining the casing and re-running cement bond logs in the production wells to determine their status before numerically simulating the effects of CO_2 injection. Any degradation or corrosion risks were overcome by controlling the plume water and oxygen content, injection strategy, and replacement of a few components. At SACROC corrosion protection of subsurface metal infrastructure by extensive cathodic arrays undoubtedly reduced risks of infrastructure corrosion and thereby aided the outcome of no adverse environmental impacts. Both from the SACROC sample exposure and Shell’s investigations, ordinary Portland cement was considered to be adequate for CO_2 given the lack of quality comparison between the mixing, bonding and setting times of newer CO_2-resistant alternatives. Cranfield and Goldeneye examined well integrity of old wells by examining legacy data to assess the risk. Wellbore risks would be monitored during injection using various techniques and long term, Shell speculated that systems might be developed to allow pressure monitoring in wells offshore without the need for the rig to be left in place, post injection. Surface and seabed monitoring around wells was also planned for or deployed at all sites to provide assurance that the wellbores were not leaking. Shell outlined possible remediation measures for leaking wellbores in their corrective measures plan, including various options for drilling relief wells into abandoned wells if contingency monitoring indicated that this was the most cost-effective solution. The minimum time it was estimated it would take to drill the offshore relief well (not including rig sourcing time) was 55 days.

#6. Cost of modifications and storage development.

Costs are presented for Goldeneye and Otway (permit-specified financial securities required are also listed for ROAD, section 2.1.5 and basic storage costs at Hewett, section 2.1.3). Naturally these are very different given the offshore, commercial nature of Goldeneye versus the onshore, pilot-scale research status of Otway. Costs are likely to be highly site specific, although logistical costs for offshore projects, such as drilling or maintaining wells and installing pipelines, would almost certainly be higher than onshore. Both site present early cost forecasts and then later updates (post FEED in the Goldeneye case and post-injection for Otway). Learnings from this show the importance of site characterisation for understanding risks and making the necessary cost-benefit balanced modifications to allow more realistic cost estimates. In general characterisation costs should be lower for depleted fields/EOR than for saline aquifer storage due to the plethora of legacy information.

#7 Comparative assessment

The comparative assessment examined and explains, where possible, key differences between the types of site. These are summarised in Table 12 and sketches of the pressure and risk profiles are shown in Figure 31. On and offshore differences and differences between storage in oil and gas fields is also explored. Section 7.5 contains the distilled list of factors perceived to be aiding or hindering projects and the consequent non-prescriptive recommendations.

8.1 Concluding comments

Learnings from the sites presented show that storage in depleted fields, whether for pure storage or for EOR purposes, has been proven. Key risks have been overcome, relating to site design for dealing with reduced reservoir pressure (cited as a key challenge of storage in depleted fields by Hughes, 2009), re-using infrastructure and managing wellbore integrity risks. In addition, there would likely be cost savings over saline aquifer sites, particularly in the characterisation stages (where there is the advantage of production history and proved hydrocarbon retention to reduce uncertainty in containment and capacity), but also at the operational stages if existing wells can be reused for injection and monitoring. Long term risks associated with well integrity, given the probable larger numbers of well penetrations, are balanced by the overall lower risk relating to the pressures experienced. Although the maximum pressures that a depleted field site experiences might occur sometime after injection ceases (as a result of gradual water influx), these will nevertheless be less than the site has already withstood when it was hydrocarbon charged, whereas injection at an equivalent aquifer site will need to increase reservoir pressures above what has been previously experienced.

Enabling accelerated development of depleted fields for CO_2 storage would likely involve persuading senior policy makers in government and investors of these benefits, in order to gain their backing. Time is of the essence, particularly in Europe, to allow the inclusion of CO_2 storage in depleted fields before they are fully decommissioned. A consistent message needs to be sent that storage in depleted fields is not only viable, but also advantageous (i.e. relatively cheaper, potentially lower risk and able to be brought online faster than their saline aquifer counterparts) and that these sites are eminently suitable to fill the short term CO_2 storage gap for quick climate abatement returns until large-scale storage in saline aquifers can be fully implemented.

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Reference unit conversion table

Note that ‘Mt’ means million metric tonnes

	Metric unit				Imperial unit		
		full name	abbreviation			full name	abbreviation
Length	1	centimetre	cm	=	0.39	inches	"
	1	metre	m	=	3.28	feet	ft
	1	kilometre	km	=	0.62	miles	miles
Area	1	square kilometre	km^2	=	0.39	square miles	
	1	square meter	m^2	=	10.76	square feet	ft^2
Volume	1	cubic metre	m^3	=	35.31	cubic feet	ft^3
Pressure	1	mega pascal	MPa	=	10.00	bars	bar
	1	mega pascal	MPa	=	145.04	pounds per square inch	psi
Temperature	25	Celsius	°C		77.00	Fahrenheit	°F

Table 13 Unit conversion table

Evaluating technology options to mitigate greenhouse gas emissions

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