Programme Area: Carbon Capture and Storage

Project: MMV FRP

Title: Measurement, Monitoring & Verification of CO2 Storage: UK Requirements: Final Report - Vol 1

Abstract:

This report was prepared for a study commissioned by the Energy Technologies Institute on: Measurement, Monitoring and Verification (MMV) of CO2storage: UK requirements. The project was led by the British Geological Survey (BGS) and involved the Nederlandse Organisatie voor Toegepast-Natuurwetenschappelijk Onderzoek (TNO) and Quintessa Limited. The report consists of two volumes. Chapters 1 to 9 form the first volume, whilst Chapter 10, a review of existing technologies, is presented in Volume 2. The main aim of the study was to identify priority technologies and methodologies which ETI could consider funding to enable effective MMV programmes to be implemented in the UK. A secondary objective was to improve understanding of MMV strategies relevant to UK offshore storage. The approach taken was to review existing monitoring methods and examine potential developments. This was done in the light of developing legislation and in the context of the range of offshore storage options available for the UK.

Context:

This desk-based survey of UK requirements for Measurement, Monitoring and Verification (MMV) of offshore CO2 storage sites was designed to provide a clear view of the developing legislation, state of the art of MMV technologies and field experience in UK offshore applications. The study reviewed UK legislative requirements, features of likely UK storage sites and potential MMV technologies. From this, MMV technology development requirements were identified to give an understanding of the main technology gaps and to establish where ETI resources should be focused to deliver future technology development. The Project provided valuable and focused information about the technology and developing regulatory environment and identified priorities for the development of MMV technologies to meet UK requirements.

British Geological Survey
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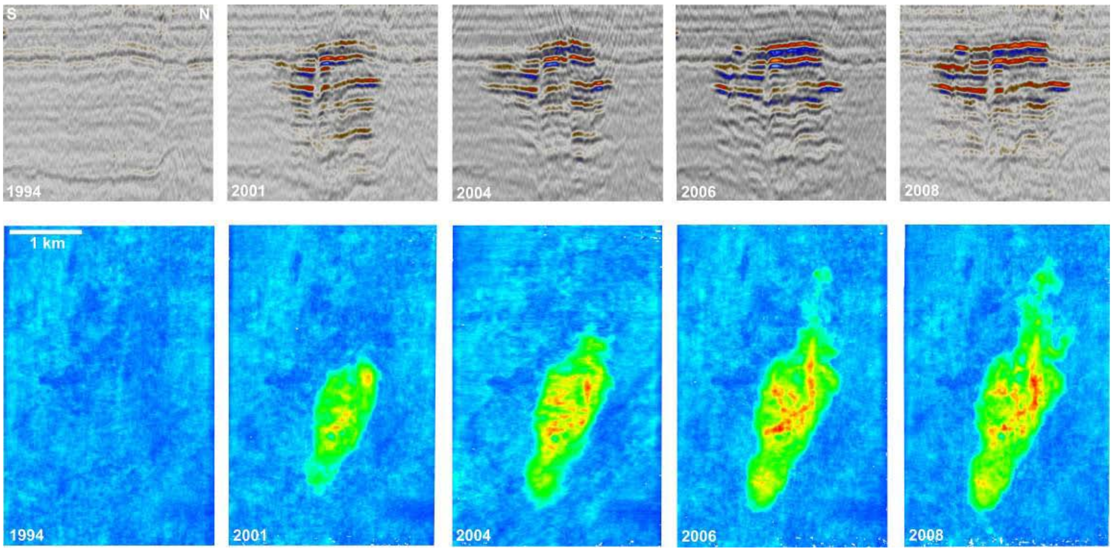
Measurement, Monitoring & Verification of CO_2 Storage: UK Requirements - Final Report: Volume 1

Energy Programme

Commercial Report CR/10/030



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BRITISH GEOLOGICAL SURVEY

ENERGY PROGRAMME

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Measurement, Monitoring & Verification of CO_2 Storage: UK Requirements - Final Report: Volume 1

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CO_2, Carbon dioxide, monitoring.

Front cover

Repeated 3D seismic surveys across the CO_2 plume in the Utsira Formation, Sleipner. Courtesy BGS

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Executive summary

This report was prepared for a study commissioned by the Energy Technologies Institute on: Measurement, Monitoring and Verification (MMV) of CO_2 storage: UK requirements. The project was led by the British Geological Survey (BGS) and involved the Nederlandse Organisatie voor Toegepast-Natuurwetenschappelijk Onderzoek (TNO) and Quintessa Limited. The report consists of two volumes. Chapters 1 to 9 form the first volume, whilst Chapter 10, a review of existing technologies, is presented in Volume 2.

The main aim of the study was to identify priority technologies and methodologies which ETI could consider funding to enable effective MMV programmes to be implemented in the UK. A secondary objective was to improve understanding of MMV strategies relevant to UK offshore storage. The approach taken was to review existing monitoring methods and examine potential developments. This was done in the light of developing legislation and in the context of the range of offshore storage options available for the UK.

Chapter 2 presents an overview of the status of the regulatory requirements for monitoring storage sites in the UK. The most relevant documents are the OSPAR Guidelines, the European Commission Storage and Emissions Trading Scheme (ETS) Directives, and two Consultation Documents from the Department of Energy and Climate Change (DECC).

The OSPAR Guidelines for Risk Assessment and Management of Storage of CO_2 in Geological Formations**,** published in 2007, place emphasis on monitoring through all stages of a storage project from collation of baseline data to long-term post injection monitoring, for the dual purposes of detecting potential leakages and verifying that such leakage does not occur. Central to the guidelines is a Framework for Risk Assessment and Management (FRAM) which is progressively updated as new information becomes available to reduce uncertainty in site performance. Several performance criteria are also defined, largely focussed on environmental protection. OSPAR states that no storage may take place without a licence and that this requires a risk management plan. The plan should include monitoring and reporting requirements, mitigation and remediation options and a site closure plan. In terms of site closure, the guidelines also stipulate that monitoring shall continue 'until there is confirmation that the probability of any future adverse environmental effects have been reduced to an insignificant level'. Ongoing review of monitoring results is central to continued permitting.

The EC Directive on the geological storage of CO_2, published in 2009, provides a regulatory framework for permanent CO_2 storage where the intended storage is more than 100 kilotonnes. It develops the principles defined by OSPAR and provides more detail on the practical implementation of a licensing regime. The EC storage directive specifically addresses monitoring for the purposes of assessing whether injected CO_2 is behaving as expected, whether any migration or leakage occurs and if this is damaging the environment or human health.

We follow the EC Directives in defining migration as movement of CO_2 within the 'storage complex' i.e. the primary storage reservoir (the storage site) plus any surrounding secondary geological containment. Leakage is defined as the release of CO_2 from the storage complex. The ultimate expression of leakage is, therefore, emission to seawater or the atmosphere.

In the EC Storage Directive a designated 'Competent Authority' is responsible for ensuring that the operator monitors the site according to the approved monitoring plan. The monitoring plan must include continuous or intermittent monitoring for certain specified items. Monitoring results should be reported to the Competent Authority at least once a year and routine inspections are also required at least annually. To enable site closure and transfer of responsibilities, the operator should submit a post closure plan for approval by the Competent Authority. This must include a demonstration that the actual behaviour of the injected CO_2 conforms to the modelled behaviour, the absence of any detectable leakage and that the storage site is evolving towards a situation of long-term stability.

The EC Monitoring and Reporting Guidelines (MRG) (in the draft amendment to the EC directive on the ETS) cover greenhouse gas emissions from the capture, transport and geological storage of carbon dioxide. The MRG state that a monitoring plan should be established, which should include detailed documentation of the monitoring methodology for a specific installation, including the data acquisition and data handling activities, and quality control. Emissions are taken as zero if there is no evidence for release of CO_2 to the seabed or seawater on the basis of monitoring results. However, if leakage from storage is detected, monitoring techniques should be deployed which are capable of quantifying the leakage to a specified level of uncertainty. This is the only case where the MRG demands monitoring additional to that already required by the Directive and OSPAR.

Following the publication of the EC Directive on CO_2 storage, the UK government has issued two consultations documents. The first of these was ‘Towards Carbon Capture and Storage’ for which responses were published in April 2009. They indicate that monitoring would be required to cover the subsurface volume affected by the CO_2 storage, rather than just the volume occupied by the CO_2 plume itself. The period before transfer of responsibility will be determined for each project individually, depending on the behaviour of the store during operation, (based on evidence from the monitoring programme). The monitoring programme will be used as the evidence base for deciding on the duration and type of post-transfer monitoring, for which a ‘transfer fee’ may be imposed.

The second UK consultation document, ‘Consultation on the proposed offshore carbon dioxide storage licensing regime’, was released in September 2009. It presents a description of how the UK CO_2 storage licensing scheme is intended to work, and seeks views on a draft of the proposed regulations for implementing the EU storage Directive and a draft licence. The Consultation proposed that the applicant must provide a proposed monitoring plan and that responsibility for the site remains with the operator during the post-closure phase of the licence until DECC is satisfied, on the basis of the monitoring reports and inspection, that the carbon dioxide within the storage site has stabilised as predicted and that permanent containment has been achieved. This suggests that closure of the site, with removal of infrastructure and sealing of the wells, would occur before handover to the authorities. Such action would restrict subsequent monitoring as wells would no longer be accessible. However, recent discussions with DECC indicate that they are considering an option to maintain monitoring wells if appropriate. Following this consultation, guidance on applications for storage licences will be issued by DECC. It is expected that this will provide further detail on the kind of information required, including plans for monitoring.

Significant gaps remain in understanding how the high-level principles set out in the regulations will be implemented at real sites, particularly involving transfer of liability following site closure.

Chapter 3 comprises a detailed examination of three actual or proposed offshore CO_2 storage sites most relevant to the development of storage in the UK offshore area. Confidential information on the proposed monitoring plan for Miller was also considered. Although details of the Miller plan are not included in the report, some aspects are reflected in the generic plans presented in Chapter 8. There is a comprehensive description of each storage site, providing:

- Background information on the site history and reasons for its selection and development.
- A description of the geological setting, the properties of the reservoir, seal and overburden and the baseline surveys carried out or proposed.
- An analysis of the risk profile, considering migration through the seal, migration into well bores, migration outside the site’s licence block, and the public relations aspects of the work.

- A description of the monitoring programme put in place or proposed, covering all the monitoring methods used and highlighting any site-specific requirements.

The monitoring programme is then assessed in terms of how well it addressed the identified risks, the overall effectiveness of the methods employed in meeting other monitoring objectives, such as management of the reservoir and the injection process, and finally how well the monitoring programme would stand up in the context of current and planned regulatory requirements. Finally, consideration is given to any additional work that could have been undertaken with the benefit of hindsight.

The Sleipner storage site is located in the Norwegian sector of the North Sea and is the oldest production-scale test CO_2 storage site. Operation began in 1996 and is still active with over 11 Mt of CO_2 injected into a saline aquifer. Because operations began well before the current regulations were developed, much of the monitoring and verification framework grew out of the research experience of operating the site. The geology is well-understood from the development of the Sleipner West gas field, which provided extensive details of the reservoir properties and baseline surveys. Monitoring was designed primarily to meet a risk profile based on understanding the subsurface migration of injected CO_2. The monitoring programme uses non-invasive technologies: 2D and 3D surface seismic, seabed imaging and gravimetry, electromagnetic surveys and pressure measurement. 3D seismic and gravimetry surveys were repeated to provide time-lapse data, and pressure is monitored continuously at the wellhead. The seismic and gravity surveys were particularly effective and provide useful research insights for storage site monitoring elsewhere. It is concluded that the monitoring objectives and programme would be largely compliant with current regulatory requirements apart from explicit emissions accounting. However, as there are no indications of leakage, such monitoring would not be needed under the regulations, although it would have to form part of a monitoring plan.

The Miller Oilfield lies in the UK sector of the North Sea about 240 km north east of Peterhead and was proposed as a storage site with the injected CO_2 also providing for enhanced oil recovery (CO_2–EOR). The geological setting is well-understood from exploration and development of the oilfield. Some baseline surveys were available; however, it was proposed to carry out additional work to characterise the seabed to provide a basis for leakage and environmental monitoring. As the site did not progress beyond the proposal stage the risk profile and monitoring plans remained incomplete. The main risks considered were vertical migration and leakage around existing wells, and lateral migration into adjacent oilfields. It was intended to use reservoir simulations of injection, with the monitoring programme, to address risk mitigation and to manage the EOR. An important factor was to be co-operation with the operators of adjacent fields. The planned monitoring was more extensive than at Sleipner, with use of invasive (downhole) methods including geophysical logging, downhole pressure measurement, well fluid and geochemical logging (with tracers).

The first CO_2 storage test site in the Netherlands is at the K12-B natural gas field, in the Dutch sector of the southern North Sea. Injection tests started in 2004, and injection continues at about 20 kt per year into a depleted reservoir. The sandstone reservoir is capped by mudstone and salt – a geological setting characteristic of this part of the North Sea. Good baseline data is available and reservoir modelling has been undertaken. The risk profile acknowledges the effectiveness of the cap rock and considers upward migration to be a low risk, with any leakage restricted to loss of well integrity. The research-oriented monitoring programme was designed on this basis, with the additional objective of providing information on CO_2 flow and mixing (with methane) within the reservoir. Integrity monitoring was based on well imaging technologies and well pressure and temperature gradient profiling. Gas migration and mixing were monitored using gas and water analysis, chemical tracers and pressure profiling, with further reservoir modelling based on this data. A significant difference with other monitoring regimes was the omission of seismic surveys for reservoir imaging. These were deemed unlikely to be effective due to the small quantities of CO_2being injected into a deep reservoir below a salt caprock. The monitoring regime was assessed as good for research purposes, with a useful test of the application of reservoir modelling in the context of regulatory requirements to predict future site behaviour.

Finally the P-18 (and P-15) sites are also gas fields in the Dutch sector of the southern North Sea. They are located a few tens of kilometres offshore, are nearly depleted and could thus represent a cost-effective option for production-scale CO_2 storage. The geological setting has some similarities with K12-B, with a sandstone reservoir capped and sealed by mudstones, although here there may be more faulting. The caprock is known to be gas-tight for methane and the risk of upward migration of injected CO_2 through it is regarded as very low. Existing wellbores are however a leakage risk and there is also a possibility of fault reactivation providing leakage pathways. Unwanted lateral migration is regarded as low-risk as the structure seems to be well constrained. Monitoring plans are at a very early stage, but are being designed using current best-practice around the risk profile and within the regulatory framework. Some of the existing wells will be converted to observation wells, using a variety of downhole physical and chemical measurement methods to monitor both migration within the reservoir and to detect leakage; the observation wellbores themselves will also be monitored for leakage. Similar measurements will be made at the injection wells, as far as injection operations permit. Seismic surveys will be used to monitor migration and image the injection plume. Seabed imaging, with geochemical sampling backup, will be used to detect any subsea leakage.

Chapter 4 presents modelling work examining CO_2 leakage parameters at four different generic North Sea sites and a review of CO_2 leakage parameters from the literature.

Modelling work examined CO_2 scenarios for migration out of the main storage container at four hypothetical sites designed to cover the range of likely storage options in the UK North Sea. The site types are similar to those considered in Chapter 3 and form the basis for preparing monitoring schemes in Chapter 8. The study provided estimates of the limits and ranges of parameters that could be monitored at future CO_2 storage sites, using the results from simplified systems-level models. Parameters derived from modelling plausible scenarios can help to prioritise suitable monitoring tools and determine monitoring strategies. The sites were specified to represent the key Features, Events and Processes (FEPs), including potential migration paths likely to be encountered.

Scenarios were investigated for each site type using Quintessa's QPAC-CO_2 computer code. Important processes that can be modelled with this code include the advection of groundwater and CO_2 due to pressure and density variations, state changes caused by pressure and temperature variations, and CO_2 dissolution in groundwater. Rapid simulations at the full system scale were possible which allowed different parameter sensitivities to be explored. Values for formation water pH were calculated separately using the geochemical modelling code PHREEQC. In each case, the hypothetical leakage paths were specified to occur at the same distance from the injection well, in order to allow comparison of the results. The simulations were run for 500 years in order to cover any likely period for which monitoring might be required. The results suggested that if the leakage pathway is reached by the CO_2 during injection then leakage will be more significant than if it arrives after injection has ceased. However, while breakthrough times to the leakage pathway can be relatively short, simulations showed that peak CO_2 fluxes may not have had sufficient time to develop over the simulation run period in under-pressured or hydrostatic scenarios.

Simulation results suggest that initial reservoir pressure conditions influence where and when monitoring is appropriate. Underpressured sites present significantly lower leakage risks. For all site types wells were the main CO_2 leakage pathway considered, although leakage through a fault or through a zone of overburden with enhanced permeability was also considered. Results suggested that chemical monitoring of a typical cap rock would be unnecessary because of the small amount of CO_2 involved and the very long timescales. Leakage that occurs via a fault or through enhanced-permeability overburden was found to discharge much more significant volumes of CO_2, for the cases studied, than when it occurs via a borehole, despite the time for the borehole to leak being typically much shorter. Seawater pH changes above a leakage pathway were found to be extremely small if only CO_2-charged water discharges, but much more significant (1 pH unit or more) if free CO_2 discharges. However, these changes are very much controlled by the rate of mixing of seawater at the discharge point. The aquifer scenario simulation results suggested that if migration occurred along a wellbore, additional storage might be found in unbounded aquifers above the main storage reservoir and these aquifers would be the most appropriate monitoring target to assess whether the borehole was providing a leakage pathway.

Leakage parameters assessed by the literature review included CO_2 flux, concentration, distribution and duration both from observations and simulations. Leakage parameters were calculated from a variety of methods, including direct field measurements. Scenarios were divided into the following categories; natural CO_2 releases; CO_2 injection sites; CO_2-EOR sites; experimental sites and numerical models.

Natural CO_2 releases exist mainly in volcanic or hydrothermal areas, where deep sourced CO_2 is released to the surface. This allows investigation of potential CO_2 pathways, fluxes and environmental impacts. Flux rates range typically from background values (10^{-3} tonnes/m^2/year) up to a few tonnes/m^2/year. CO_2 injection sites at both the pilot and commercial-scale have, in almost all cases, not detected leakage, as they were chosen carefully as secure containers. Methods including tracers and isotopic CO_2 signatures have been used to determine if any CO_2 detected originates from the stored CO_2 or comes from unrelated biogenic sources. A low flux rate leak was detected from West Pearl Queen, a small-scale storage test in a depleted oil field. CO_2-EOR sites have been operating in some cases since the 1970s and as such data on gas releases experienced at these sites can aid estimation of CO_2 leakage parameters. Expected leakage rates are very low; for example, at Weyburn, only about 0.001 % of the predicted total CO_2 stored at cessation of injection is expected to leak over 5000 years. Research at these sites indicates that old wells not designed for CO_2 contact present the most likely risk of leakage. Experimental sites have been specifically designed to monitor leakage parameters from CO_2 injection into the shallow subsurface to assess the effects and rate of leakage. Release rate and location can be controlled to mimic, for example, potential diffuse leakage or sudden leakage from a point source such as a fault. These experiments also suggest that CO_2 releases become concentrated into 'hot spots' which incidentally may aid detection of low level releases. Numerical models have been developed to investigate CO_2 migration and leakage from a variety of storage scenarios and over a variety of timescales.

Chapter 5 synthesises the findings of earlier chapters in order to assess the measurement requirements for UK offshore MMV and to outline the efficacy of existing measurement technologies. By examining the capabilities of existing tools, used individually or in combination, key technological and methodological gaps are identified. These are assessed further in subsequent chapters.

The regulatory requirements for monitoring at CO_2 storage sites define high-level objectives. Consideration is made of more specific requirements, and how those might be met, when large-scale storage takes place in future. This is weighed against the MMV schemes proposed or deployed at actual North Sea sites and the likely range of leakage parameters.

The efficacy of existing monitoring tools (fully documented in Volume 2) is then examined in the light of regulatory requirements and actual or proposed practice.

The purpose of this chapter is to identify where existing MMV technologies are likely to fall short of what is needed to satisfy the requirements for demonstrating storage performance and detecting and quantifying leakage. This leads to a definition of the extent to which improvement is needed to help focus investigation of technological developments in the following chapters of the report.

With some specific exceptions (discussed in later chapters) deep focussed monitoring techniques, based on decades of continuing development in the oil and gas industry, are largely considered relatively mature and adequate to meet requirements. While leakage is not expected at any storage site that has been suitably characterised and designed, regulations place significant emphasis on monitoring leakage and its impact. Our review indicates that current technologies for assessing and quantifying leakage require more development.

Chapter 6 complements Chapter 5 by presenting gaps in monitoring technologies as identified by service companies, R&D teams and those involved in CCS projects, and indicates how such organisations see developments addressing these gaps.

Some sixty organisations were canvassed for their views. Most CO_2 monitoring is carried out using existing tried-and-tested oil and gas field monitoring technologies, but there are some methods or adaptations specific to CO_2 monitoring either newly available or in development.

Joint interpretation methods represent a gap, which is also a major focus of the oil and gas industry for its reservoir monitoring, modelling and reservoir simulation programmes.

The lack of a robust strategy for dealing with abandoned wells was identified as an important gap. It was felt that technologies existed to address the monitoring issues, but there were significant risks in deployment (e.g. damage to a well completion during installation subsequently forming a CO_2 migration pathway).

The gaps identified from discussions with third parties were then cross-referenced to the gaps identified previously in Chapter 5. A full catalogue of gaps is presented in Appendix 5 (Volume 2) under six themes: monitoring strategy; monitoring large areas with non-invasive techniques; monitoring in and around wells; leakage and shallow monitoring; monitoring injection at the well head; environmental impact assessment. Within each theme the gaps have been prioritised according their importance for production-scale CCS.

This analysis allowed collation of an inventory of novel technologies. For each, we present a summary of the developments identified followed by more detailed descriptions. These are grouped according to the basis of the technology and the drivers for development. Descriptions are cross-referenced to relevant material elsewhere in this report, mainly in Chapter 10 (Volume 2), which can be regarded as providing essential background on technologies and their application. The methods and developments included in the inventory can be summarised as:

Seismic methods: there is potential for permanent installations for example using Ocean Bottom Cables (OBCs) and scope for multi-component monitoring system data. Improvements are also foreseen in: hardware (wireless, improved sensitivity, Micro Electro Mechanical System (MEMS), optical sensors, continuous recording, improved sources); processing (improved imaging, joint inversion); interpretation (data assimilation, visualisation). Inversion of pressure and saturation are envisaged from Amplitude Versus Offset (AVO) or multi-component data.

High-resolution sea-bottom imaging and bubble detection: forward-looking sonar instruments, can survey over 100 m ahead of the survey ship, and downward looking systems (e.g. sidescan sonar and multibeam echo sounding) can map seabed features with increasing resolution and detect bubbles. However, most experience is with methane or water and not with CO_2. Development is needed to establish detection limits for bubble streams, quantification potential, whether bubble composition can be determined and development of permanent detectors for critical locations (e.g. near old wellbores).

Geophysical logs: this is a mature technology, but more experience with CO_2 is needed. New concepts for well integrity logs include electro-chemical techniques. Integrity logs need more testing to establish threshold values for detectable leakage in wellbores. Custom completions for monitoring at different levels, such as the Westbay System, need further evaluation.

Downhole P/T: distributed temperature sensors seem to be a mature technology.

Chemical methods: developments are needed for downhole fluid chemistry and for new sampling devices. Permanent and robust downhole pH sensors are not yet available. Improved sampling devices and CO_2 detectors are under development. Microbial monitoring and developments in biogeochemical methods are also ongoing.

EM or resistivity based methods: there is potential for joint inversion with seismics for CO_2 monitoring.

Gravimetry: developments in gravity gradiometry have not been considered for CO_2. Borehole applications have not yet been explored sufficiently.

Other techniques: ecosystem impacts are being examined in new European and UK projects, including the use of a benthic chamber, and progress in developing biomarkers has been made by Statoil. No real development in tiltmeters is foreseen. New tracers are being tested. Drill cores which maintain the pressure of seabed samples could potentially be used to sample shallow (up to 500 m below seabed) sediments for CO_2. The acoustic signal (sound) of CO_2 bubbles in the water could also be detected at short range (up to 15 m) from a fixed monitoring position or an ROV, using directional microphones. Noise logging in boreholes is experimental for CO_2. Fixed underwater cameras may have the potential to detect bubbles.

Each novel technology identified in the inventory has been assessed in terms of its maturity, limitations and the improvements foreseen from current developments. Many developments are incremental and the main need is for more testing with CO_2. Shallow-focussed monitoring is, in general, in need of more developmental effort than deep-focussed techniques.

Chapter 7 describes the potential for integrating two or more monitoring technologies. Here we consider the integration potential from two aspects: the potential for joint interpretation of the outputs from a range of technologies, and/or the joint acquisition of monitoring data via simultaneous deployment, for example in a borehole or on a ship. The benefits of integrating monitoring technologies include: optimising detection and quantification of CO_2 migration and leakage, reducing deployment costs and improving understanding of reservoir processes such as dissolution. Typical monitoring techniques suitable for joint interpretation are injection well and monitoring well data and geophysical measurements such as seismic (including vertical seismic profiling - VSP), microseismic, gravity and controlled source electromagnetic (CSEM). Joint interpretation leads to better constrained models of the storage system. Improved understanding of the reservoir over time will reduce uncertainties in the future behaviour of CO_2 in the reservoir. Combinations of methods covering wide areas for detection, with local methods for measurement can be used to detect and characterise migration or leakage.

Selection of tools to be integrated will be based on providing complementary monitoring capabilities which improve detection and measurement both spatially and temporally. For example, geophysical methods providing detection of migration and leakage over large areas may be integrated with more direct measurement techniques deployed in wells or at the seabed which are more spatially constrained but provide higher measurement frequency and/or resolution. Further integration could include more detailed analysis to quantify rates of movement (especially flux to seabed if leakage is occurring), composition and source of CO_2. One example described in this chapter is the integration of multibeam echo sounder imaging to detect a potential leakage feature on the seabed combined with subsequent analysis of headspace gas taken from sediment cores to confirm the composition of the gas (in this case naturally-occurring methane). Similar integrated approaches with 2D seismic have been successfully used to explore for shallow gas fields in the Southern North Sea. Joint interpretation of a range of shallow geophysical technologies has showed their potential to monitor shallow CO_2 movement onshore whilst individual techniques were not able to provide a definitive interpretation in isolation.

Joint interpretation of seismic and gravity data has been demonstrated at Sleipner. The combined use of gravity with seismics (as partially tested at Sleipner) could, in specific circumstances, reduce the cost of monitoring. For example borehole-gravity measurements could be used in conjunction with pressure-test data and/or surface seismic data to enable a statistical interpolation of predicted changes in the saturation of CO_2 at a lower cost than simply using 4D seismic. Specific examples of joint acquisition are provided to illustrate the benefits for integration. Permanent well and seabed geophone installation has high installation costs but provides significant benefits in terms of continuous passive microseismic monitoring and for regular or periodic active seismic surveys. Similarly, down-hole receivers can be integrated with conventional 2D/3D surface seismics to significantly reduce costs. Downhole permanent sensors can now include geophones, temperature and pressure sensors, with noise sensors becoming available to provide more continuous real-time monitoring of events. Assessing well integrity requires the joint deployment of a number of technologies, such as multifinger callipers and electromagnetic tools, to confirm that results from individual technologies are indicative of material degradation.

Monitoring plans for UK offshore storage sites are a regulatory requirement. They will need to demonstrate appropriate site performance, to monitor and evaluate deviations from expected performance and to measure CO_2 emissions should leakage occur. In Chapter 8 we consider monitoring methodologies for four generic storage site types, which cover the likely range of storage scenarios in the North Sea. They comprise: depleted gas fields beneath the Zechstein Salt in the southern North Sea; saline aquifers and depleted gas fields above the Zechstein Salt in the southern North Sea; depleted hydrocarbon fields in the central and northern North Sea and saline aquifers in the central and northern North Sea. The generic monitoring methodology comprises two distinct elements: a core monitoring programme designed to meet the regulatory requirements of a conforming site (i.e. one that behaves as expected during its lifetime) and an additional monitoring programme designed to address the requirements of a storage site that does not perform as expected. The core monitoring programme will be defined as part of the storage licence. It is aimed at performance verification, the monitoring and management of any site-specific containment risks identified in the Framework for Risk Assessment and Management (FRAM) and the detection and evaluation of performance irregularities including early warning of potential leakage. The additional monitoring programme is contingent upon the development of a significant performance irregularity. It comprises a portfolio of targeted monitoring tools held in reserve to evaluate and manage the range of possible irregularities and meet the needs of any associated remediation. The additional monitoring programme includes any requirement for emissions measurement under the ETS.

Specific methodologies for the core monitoring programme depend on storage site type. Depleted hydrocarbon fields are assumed to have secure geological seals, so monitoring emphasis is on possible migration and leakage along wellbores. Saline aquifers have geological seals whose properties are less well understood and there will be a greater emphasis on non-invasive monitoring tools providing wide spatial coverage. For all site types, the priority is to deploy pre-emptive deep-focussed monitoring systems targeted on the primary storage reservoir and its immediate surroundings, with the aim of identifying irregularities as soon as possible, and before they become too serious to be remediable. Shallow-focussed systems, deployed at the seabed or in the seawater column, aim to provide additional assurance that leakage is not occurring. Fit-for-purpose baseline data is essential and, for shallow-focussed systems, must be sufficiently robust to allow quantitative measurement of emissions should the need arise.

Key technologies for deep-focussed monitoring include downhole pressure and temperature (P, T) measurement on the injection well and 3D (in some cases 2D) surface seismic. If suitable wellbore infrastructure is available, remote (from the injection wells) P, T monitoring, saturation logging and downhole fluid sampling may be appropriate. With the exception of CO_2 saturation logging these are generally mature technologies with ongoing improvements driven by the oil industry. Key technologies for shallow-focussed monitoring include multibeam echo sounding, sidescan sonar, bubble stream detection and seabed measurements and/or sampling. These technologies are less mature than the deep focussed tools particularly in terms of accepted practice for effective integrated deployment.

Methodologies for the additional monitoring programme depend very specifically on the nature of the irregularity. They may require further deployment of tools already used in the core programme or the use of specific new tools such as seawater chemistry or cross hole seismic. Such tools may however be relatively developmentally immature, have unproven longer-term reliability or have stringent wellbore infrastructure requirements. For emissions quantification the ability to integrate spatially extensive information from non-invasive surveys (e.g. sonar imaging) with local detailed sample measurements will be required.

Chapter 9 identifies where gaps exist in current monitoring technologies that should be addressed to meet the anticipated monitoring requirements for UK offshore storage. It builds on the findings and conclusions of previous chapters: summarising the regulatory requirements for monitoring, defining the likely monitoring needs for four generic offshore storage types and reviewing existing monitoring technologies and future developments including a review of new technologies that might offer increased or improved monitoring capabilities

We conclude that current technologies are likely to meet most expected monitoring requirements, especially in the areas of deep-focussed monitoring since this will largely utilise mature technologies widely developed and tested in the hydrocarbon industry. No significant gaps have been identified that require the development of completely new technologies. Further, no completely new technologies are expected to be developed in the near future that will either supersede any current technologies or address the gaps identified. It is expected that incremental advances in current technologies, driven largely by market demands in the hydrocarbon and marine surveying industries, will provide beneficial improvements in monitoring capabilities for CO_2 storage.

Nevertheless, some monitoring requirements have been identified for which current technologies have yet to be demonstrated as providing the necessary capability. These requirements are in the following areas:

1. Leakage detection and measurement (emissions quantification) technologies including both spatially extensive survey and continuous data collection. This may be achieved through finding and measuring bubbles acoustically and by measurement of gas concentration and flux. Testing of the latter could provide much needed natural background values for offshore environments
2. Continuous monitoring technologies, primarily monitoring geochemical processes, in boreholes.
3. High resolution time-lapse monitoring for detailed assessment of plume migration via borehole instrumentation
4. Well integrity monitoring using noise logs and establishing detection thresholds for well bore leakage using existing or refined techniques

A range of needs has therefore been identified to address these requirements, which mainly involve development and testing of existing technologies to establish their efficacy.

We recommend that consideration be given to developing UK test facilities for permanent and continuous borehole monitoring and for developing and testing CO_2 geological emission detection and measurement technologies. Alternative approaches would be to establish partnerships with existing international facilities and to work in collaboration with European and UK projects.

We also recommend dialogue with service companies and projects to help foster development in assessing well integrity, especially in plugged and abandoned wells.

Further assessment is suggested of the potential for integrated permanent monitoring technologies for specific UK offshore requirements.

Consideration should also be given to joint development with planned UK CCS demonstration projects, through discussion with DECC and project participants.

The second volume of this report (Chapter 10) presents a review of existing technologies with examples of their application and serves as a resource on the range of available techniques, which can be referred to when reading other parts of the report. Appendices related to all chapters are also to be found in Volume 2.

1 Introduction

This report is the main output from a project selected to meet the Energy Technologies Institute's request for proposals on: 'Measurement, monitoring and verification (MMV) of CO_2 storage: UK requirements study'. The project was led by the British Geological Survey (BGS) in collaboration with Nederlandse Organisatie voor Toegepast-Natuurwetenschappelijk Onderzoek (TNO) and Quintessa Limited.

Carbon capture and storage (CCS) is a means of mitigating the effects of climate change by reducing greenhouse gas emissions. The UK Department of Energy and Climate Change (DECC) sees fossil fuels as a vital part of a diverse and secure low-carbon energy mix. However, they recognise the need to substantially reduce carbon dioxide emissions from these sources. Development and deployment of CCS is critical to this. It has the potential to reduce CO_2 emissions from power stations by around 90%, and would make a significant contribution towards meeting UK and international targets for emissions reductions. The Climate Change Act 2008 sets legally binding targets of at least a 34 % cut in greenhouse gas emissions by 2020 and at least 80 % by 2050, against a 1990 baseline.

In 2007 the UK Government launched a competition to build one of the world's first commercial scale CCS power plants in the UK. The project aims to demonstrate post-combustion CCS on a coal-fired power station with CO_2 stored offshore, capturing CO_2 from 300MW (net) of the power station's capacity. On 12 March 2010 funding was awarded to E.ON and Scottish Power for design and development studies as part of the competition. These studies will be completed within twelve months, after which the final competition winner will be selected. This will lead to the commissioning of a licensed CO_2 storage site under the North Sea - a key part of the licence application will be a monitoring plan that fully meets the regulatory requirements currently being developed. The stated aim is to have a full-chain demonstration operational by 2015. This provides a clear momentum to this review of MMV requirements for the UK offshore storage industry.

MMV of CO_2 storage sites will be required by legislation for a number of purposes. These include verification of storage integrity, evaluating the movement of CO_2 and demonstrating that injected CO_2 is behaving as predicted. In the event of leakage any CO_2 emitted has to be quantified. Monitoring is therefore a key element of CO_2 storage site operations. It is needed to show that CO_2 is being stored safely and that any risks to resources and the environment are being properly managed.

Measurements will start before injection, as part of site characterisation, and to define baseline conditions. They would then continue throughout the injection of CO_2 and into the post-injection period until cessation of monitoring was acceptable to the regulators. The nature of monitoring is expected to change over time, and in response to the behaviour of the CO_2, in both type and frequency. Techniques will be required for different purposes, such as tracking migration of CO_2 or verification of predictive models, and certain methods would be held largely in reserve to deal with potential leakage; some of these might never be deployed but would have to be available to cover that eventuality.

MMV has been identified by the ETI as a key technology area in support of the roll out of CCS in the UK. It is anticipated that ETI technology projects in this area would involve development of MMV tools and strategies to meet both UK legislative requirements and the technical demands of offshore operations.

The current review is seen by the ETI as a necessary step in assessing UK needs for MMV in the light of current technologies and MMV experience prior to defining technology development projects. The results provide the foundation to help ensure that the ETI will be in a position to develop research into novel MMV technologies for UK offshore applications that address key gaps and requirements.

This report documents the findings of the study, which was carried out in two separate but overlapping work packages (WPs). WP1 reviewed the developing regulatory requirements which will affect CO_2 storage and benchmarked current MMV technologies and field experience relevant to UK offshore application. It aimed to identify key requirements for technologies and methodologies to meet the UK's CO_2 MMV needs. WP1 was essentially completed in February 2010 and presented as a draft report. That report covered Chapters 2 to 5 and Volume 2 of the present document, which have been revised during the second stage of the project in the light of comments and to encompass the latest technological and regulatory developments.

WP2 examined the potential for technological improvements. This included developments to existing MMV techniques, identification of methods that have not yet been demonstrated fully for CCS and the scope for improved performance through integration of techniques.

This report presents the combined results of the work from the two WPs and represents the main deliverable from the project.

Chapter 2 describes the regulatory requirements with particular reference to the developing UK legislation being prepared by DECC to implement EU directives on geological storage of CO_2 and the Emissions Trading Scheme. This will also encompass the OSPAR Guidelines and support the proposed UK CCS demonstrations.

Chapter 3 reviews monitoring strategies for three case studies relevant to offshore storage in the UK North Sea. Sleipner is the worlds' longest operating industrial scale storage site and provides an example of storage in a saline aquifer. K12-B and P18 are depleted gas fields in the Dutch sector of the southern North Sea and representative of sub-salt and above salt storage in this sector. K12-B is an active site, whilst storage at P18 is planned in future. The Miller Oilfield in the Viking Graben, was proposed as a storage site, although plans for this were shelved. It provides an example of a depleted oilfield from the central or northern North Sea. Confidential documents from BP on the approach to monitoring for the Miller project were studied during the project. They were used to inform the generic monitoring plan considered for this type of site in Chapter 8 but are not presented in detail in Chapter 3.

Chapter 4 describes systems modelling work undertaken for this project examining potential changes to measurable parameters arising from the movement of CO_2 in four hypothetical simplified sites which cover a range of typical storage scenarios in the UK North Sea. This chapter also provides a literature review of CO_2 leakage parameters from natural analogue sites, experimental work, and modelling as well as consideration of leakage from enhanced oil recovery and CCS demonstration projects. These indicate the range of realistic flux rates, potential migration pathways, local environmental impacts and other relevant parameters.

Chapter 5 synthesises the findings of earlier chapters, at the end of WP1, in order to assess the measurement requirements for UK offshore MMV and to outline the efficacy of existing measurement technologies. The capabilities of existing tools, individually or in combination, were assessed to identify key technological and methodological gaps. These were assessed further in WP2 of the project and form the content of the subsequent chapters.

Chapter 6 looks at each of the types of monitoring techniques in turn and assesses their state of development in terms of CCS deployment. It considers the practicalities of the methods for offshore UK use. The different techniques are then ranked and prioritised and recommendations made as to their potential for further development. This takes account of costs (in broad terms) and the time likely to be required. This is followed up in Chapter 7, which considers the opportunities for integration of technologies to add value from both cost and data quality perspectives.

MMV methodologies for different types of UK offshore storage sites are considered in Chapter 8. The four types of site considered are broadly those reviewed in Chapter 3, but are more generic rather than specific. The monitoring regime for each site type is examined in relation to regulatory requirements and the specific geological conditions that give rise to different risks and thus require variations in monitoring strategy.

Chapter 9 draws together the outcomes of the preceding chapters into recommendations for key tool development needs in a UK offshore context. This section discusses not only those methods with scope for development but also identifies suppliers/institutes that might have the potential to carry out the required technical innovation.

The current monitoring technologies relevant to the UK offshore environment, covering both shallow- and deep-focussed techniques, are reviewed in Volume 2 (Chapter 10). This builds on earlier reviews and makes use of our continued development of the IEA Greenhouse Gas R&D Programme Monitoring Selection Tool and links with CCS projects and networks. Case studies are presented to illustrate the use of the different techniques. Where possible, these cover CO_2 storage projects. However, many of the shallow techniques have not been tested with CO_2, and so other appropriate case studies are presented.

Key definitions

Definitions of the terms ‘migration’ and ‘leakage’ are not always consistent in regulatory/policy documents worldwide. In this report we follow the EC Storage and ETS Directives, which define ***migration*** as movement of CO_2 within the ‘storage complex’ i.e. the primary storage reservoir (the storage site) plus any surrounding secondary geological containment. ***Leakage*** is defined as the release of CO_2 from the storage complex. The ultimate expression of leakage is emission to seawater or to the atmosphere.

Section A

Monitoring requirements for UK North Sea

2 Regulatory requirements for monitoring storage sites in the UK offshore area.

2.1 EXECUTIVE SUMMARY

This chapter presents an overview of the status of the regulatory requirements for monitoring storage sites in the UK offshore area. The documents considered most relevant to CO_2 storage are the OSPAR Guidelines, the European Commission Storage and Emissions Trading Scheme (ETS) Directives, and two UK Consultation Documents from the Department of Energy and Climate Change (DECC). This chapter summarises how these regulations contribute to the definition of monitoring requirements including both deep focussed (subsurface) and shallow focussed (sediment, seawater and atmosphere) monitoring objectives, for which specific applicable technologies are reviewed in Volume 2.

The **OSPAR Guidelines for Risk Assessment and Management of Storage of CO_2 in Geological Formations,** published in 2007, place emphasis on monitoring through all stages of a storage project from collation of baseline data to long-term post injection monitoring, for the dual purposes of detecting potential leakages and verifying that such leakage does not occur. Central to the guidelines is a **Framework for Risk Assessment and Management (FRAM)** which is progressively updated as new information becomes available to reduce uncertainty in site performance. Several performance criteria are also defined, largely focussed on environmental protection. OSPAR states that no storage may take place without a licence and that this requires a risk management plan. The plan should include monitoring and reporting requirements, mitigation and remediation options and a site closure plan. In terms of site closure, the guidelines also stipulate that monitoring shall continue ‘until there is confirmation that the probability of any future adverse environmental effects have been reduced to an insignificant level’. Ongoing review of monitoring results is central to continued permitting.

The **EC Directive on the geological storage of CO_2**, published in 2009, provides a regulatory framework for permanent CO_2 storage where the intended storage is above 100 kilotonnes. It develops the principles defined by OSPAR and provides more detail of the practical implementation of a licensing regime. The EC storage directive specifically addresses monitoring for the purposes of assessing whether injected CO_2 is behaving as expected, whether any migration or leakage occurs and if this is damaging the environment or human health. A designated Competent Authority is responsible for ensuring that the operator monitors the site according to the approved monitoring plan. Among other things, the monitoring plan must include continuous or intermittent monitoring for certain specified items. Monitoring results should be reported to the Competent Authority at least once a year and routine inspections are also required at least annually. To enable site closure and transfer of responsibilities, the operator should submit a post closure plan approved by the Competent Authority. This must include a demonstration that actual behaviour of the injected CO_2 conforms to the modelled behaviour, the absence of any detectable leakage and that the storage site is evolving towards a situation of long-term stability.

The **EC Monitoring and Reporting Guidelines (MRG)** (in the draft amendment to the EC directive on the **ETS**) cover greenhouse gas emissions from the capture, transport and geological storage of carbon dioxide. The MRG state that a monitoring plan should be established, which should include detailed documentation of the monitoring methodology for a specific installation, including the data acquisition and data handling activities, and quality control. Emissions are taken as zero if there is no evidence for release of CO_2 to the seabed or seawater on the basis of monitoring results. However, if leakage from storage is detected, monitoring techniques should be deployed which are capable of quantifying the leakage to a specified level of uncertainty. This is the only case where the MRG demands additional monitoring to that already required by the

Directive and OSPAR. The **IPCC (Intergovernmental Panel on Climate Change)** Guidelines have a similar objective to those of the MRG in quantifying emissions to the seawater.

Following the publication of the EC Directive on CO_2 storage, the UK government has issued two consultations documents. The first of these was '**Towards Carbon Capture and Storage**' for which responses were published in April 2009. They indicate that monitoring would be required to cover the subsurface volume affected by the CO_2 storage, rather than just the volume occupied by the CO_2 plume itself. The period before transfer of responsibility will be determined for each project individually, depending on the behaviour of the store during operation, (based on evidence from the monitoring programme). The monitoring programme will be used as the evidence base for deciding on the duration and type of post-transfer monitoring, for which a 'transfer fee' may be imposed.

The second UK consultation document entitled '**Consultation on the proposed offshore carbon dioxide storage licensing regime**' was released in September 2009. It presents a description of how the UK CO_2 storage licensing scheme is intended to work, and seeks views on a draft of the proposed regulations for implementing the EU storage Directive and a draft licence. The Consultation proposed that the applicant must provide a proposed monitoring plan and that responsibility for the site remains with the operator during the post closure phase of the licence until DECC is satisfied, on the basis of the monitoring reports and inspection, that the carbon dioxide within the storage site has stabilised as predicted and that permanent containment has been achieved. This suggests that closure of the site, with removal of infrastructure and sealing of the wells, would occur before handover to the authorities. This would restrict any subsequent monitoring as there would no longer be access to the wells. However, recent discussions with DECC have indicated they are considering retaining the option to maintain monitoring wells if appropriate. Following this consultation, guidance on applications for storage licences will be issued by DECC. It is expected that this will provide further detail on the kind of information required, including plans for monitoring.

Significant gaps remain in understanding how the high-level principles set out in the regulations will be implemented at real sites, particularly involving transfer of liability following site closure.

2.2 INTRODUCTION

In this section we provide a brief overview of the regulations that are most relevant to CO_2 storage and identify how these regulations contribute to the definition of monitoring requirements for offshore storage sites in the UK. The scope of this review of the regulatory monitoring requirements for offshore CO_2 storage includes key aspects of the geological storage, largely from the point of injection outwards into the storage formation. As such it focusses on monitoring the geosphere and overlying seawater and atmosphere. It formally excludes monitoring of infrastructure associated with operational safety and any onshore monitoring.

We aim to provide an overview of the technical monitoring requirements, as they are currently understood, that existing regulations indicate might be required at an offshore storage site. It is only intended to set the scene and does not purport to provide legal guidance on likely future requirements.

The key regulations and publications that are considered relevant to defining requirements for monitoring the performance of CO_2 storage projects in the UK offshore area are listed below:

OSPAR Guidelines

EC Directive on Storage

EC Directive on the ETS – as amended to meet the Storage Directive

UK Consultation Document

UK Storage licence consultation

North Sea Basin Task Force: Monitoring Verification Accrediting and Reporting paper

2.3 OSPAR GUIDELINES FOR RISK ASSESSMENT AND MANAGEMENT OF STORAGE OF CO_2 IN GEOLOGICAL FORMATIONS

These guidelines were published following the meeting of the OSPAR Commission in June 2007 (OSPAR 07/241/1-E, Annex 7). Central to the guidelines is a Framework for Risk Assessment and Management (FRAM) which was developed from that produced for the London Convention/Protocol. The Guidelines cover both the process of CO_2 injection and also post-injection risks of leakage. Publication of the Guidelines was significant as it provided an indication that CO_2 storage could be undertaken legally in the marine environment once the amendment to the treaty is ratified. Elements from the Guidelines were subsequently incorporated within the EC Directive on Storage.

The objective of CO_2 storage is defined in the Guidelines as the permanent containment of CO_2. OSPAR indicated that this objective should be underpinned by developing and operating a Framework for Risk Assessment and Management, which is described generically in the Guidelines.

2.3.1 Framework for Risk Assessment and Management

Operating the FRAM is an iterative process whereby the FRAM is progressively updated as new information is collected and analysed to reduce uncertainty in site performance. Six stages are defined within a FRAM:

a. *Problem formulation*: critical scoping step, describing the boundaries of the assessment (i.e. defining the storage area/volume and the scope of the assessment e.g. environmental impact or security of storage).

b. *Site selection and characterisation*: collection and evaluation of data concerning the site, including the establishment of baseline datasets.

c. *Exposure assessment*: characterisation and movement of the CO_2 stream, which may include an assessment of additional substances present within, or mobilised by, the CO_2 stream.

d. *Effects assessment*: assembly of information to describe the response of receptors (e.g. possible consequences of CO_2 storage on the environment, such as on species, communities, habitats, marine resources and other users);

e. *Risk characterisation*: integration of exposure and effect data to estimate the likely impact. This characterisation may need to be revised in the light of new information obtained from monitoring activities, and;

f. *Risk management*: including monitoring, mitigation and remediation measures. The risk management should demonstrate how risks of leakage will be managed to avoid significant adverse consequences for the marine environment, human health and other legitimate uses of the maritime area.

Monitoring is seen to be an integral part of all phases of a CO_2 storage project. The life cycle of a CO_2 storage project, as defined by OSPAR, consists of the following phases:

- Planning
- Construction
- Operation
- Site-closure

- Post-closure

Monitoring is seen to be applicable at all stages of the project and forms an integral part of FRAM operation and development.

The following performance criteria are proposed by OSPAR and this review indicates which of these criteria are relevant to this study:

	Monitoring required	Within scope of this study
a. characterisation of the CO_2 stream (including composition);	Yes	No
b. characterisation of the proposed storage-site(s);	Yes	Yes
c. preventive and/or mitigating measures (with appropriate performance standards);	Yes	Yes
d. injection rates and techniques;	Yes	Yes
e. potential leakage rates and exposure pathways;	Yes	Yes
f. the potential impacts on amenities, sensitive areas, habitat, migratory patterns, biological communities and marketability of resources, including fishing, navigation, engineering uses, areas of special concern and value and other legitimate uses of the maritime area;	Yes	No
g. the nature, temporal and spatial scales and duration of observed and expected impacts;	Yes	Yes
h. cumulative number of permits issued;	No	No
i. whether guidelines are implemented;	No	No
j. amount CO_2 stored (tonnes);	Yes	No
k. net amount of CO_2 stored (tonnes);	Yes	No
l. chemical composition of the CO_2 stream;	Yes	No
m. any observed leakage rates and exposure pathways;	Yes	Yes
n. any expected impacts from this leakage;	Yes	Yes
o. any observed impacts on the marine environment and other legitimate uses of the maritime area; and	Yes	Yes
p. any (mitigative) measures taken.	Yes	Yes

These performance criteria should form part of the risk assessment and management reports. OSPAR recognises that the assessment of hazards and risks related to storage of CO_2 streams in geological formations may include a significant level of uncertainty. This uncertainty should be identified and, wherever possible, quantified in the reports. This information should be used to identify areas for which further research or monitoring is required.

2.3.2 Permit and permit conditions

In accordance with paragraph 3 of OSPAR 07/241/1-E, Annex 7, no storage may take place without a licence. The licence must contain, *inter alia*, a risk management plan (Para. 18b) that includes:

- Monitoring and reporting requirements
- Mitigation and remediation options
- A site closure plan including a description of post-closure monitoring and mitigation and remediation options; the guidelines also stipulate that monitoring shall continue 'until there is confirmation that the probability of any future adverse environmental effects has been reduced to an insignificant level'.

The review of monitoring results should also provide evidence of whether monitoring programmes need to be continued, revised or terminated and underpins decisions concerning the continuation, modification or revocation of permits.

2.3.3 Risk Management

Monitoring programmes should be linked to putative impact hypotheses of the storage project, via the performance criteria and to verify predictions and review the adequacy of management measures applied.

The risk characterisation should lead to the development of an 'Impact Hypothesis'. This is a concise statement of the expected consequences of disposal. It provides the basis for deciding whether to approve or reject the proposed disposal option and for defining the monitoring requirements. Data collected during site selection and characterisation would form the baseline for management and monitoring of the injection and storage of CO_2. The baseline data should be used in the development of a monitoring strategy.

The impact hypothesis should be linked to an effects assessment. Part of this will be a concise statement of the expected consequences of storage of a CO_2 stream in geological formations. It provides input for deciding whether to approve or reject a CO_2 storage proposal, site selection, and monitoring, both to verify the impact hypothesis and to determine what additional preventative and/or mitigating measures are required. It therefore provides a basis for management measures and for defining environmental monitoring requirements.

Key issues identified by OSPAR include well integrity, fluid flow and prediction of any fracture development or reactivation.

Monitoring during injection

OSPAR identifies two main purposes of monitoring:

- Detection of potential leakages
- Verification that such leakage does not occur.

A monitoring programme should include:

a. Monitoring for performance confirmation.
b. Monitoring to detect possible leakages.
c. Monitoring of local environmental impacts on ecosystems.
d. Monitoring of the effectiveness of CO_2 storage as a greenhouse gas mitigation technology.

The following essential elements of process monitoring and control have been listed:

a. The injection rate.
b. Continuous pressure monitoring.
c. Injectivity and fall-off testing. (although this is arguably not process monitoring)
d. The properties of the injected fluid (including temperature and solid content, the presence of incidental associated substances and the phase of the CO_2 stream).

e. Mechanical integrity of seals and (abandoned) wells.

f. Containment of the CO_2 stream including performance monitoring and monitoring in overlying formations to detect leakage.

g. Control measures, overpressure, emergency shut down system.

While not essential, the OSPAR guidelines state that if observation wells are available they can provide useful information.

The evaluation of the results of the monitoring may be used to update the strategy and any other operational practices.

Long term, post injection, monitoring of migration of CO_2 streams and mobilised substances

Long-term monitoring can generally be accomplished with a sub-set of the technologies used during the injection phase. Moreover, new efficient monitoring technologies are likely to evolve. Methods chosen for monitoring should not compromise the integrity of the sealed formation, or the marine environment. In addition, records should be kept of the authorisation, licensing and site closure processes, together with data on long-term monitoring and management capabilities.

2.3.4 OSPAR Key issues

Monitoring should be undertaken throughout all stages. This includes collection of baseline data necessary to demonstrate acceptable site performance and monitoring following site closure (note that the site closure is not specifically defined).

OSPAR define several performance criteria, largely focussed on environmental protection, and we can identify that monitoring is required to measure many of these.

Ongoing review of monitoring results is central to continued permitting.

It may be necessary to monitor additional substances that are already present or mobilised by the CO_2 stream.

Stakeholder involvement is an important part of the FRAM and monitoring activities and planning can be assumed to be included in any stakeholder consultation.

Monitoring data must be maintained for much longer periods than those associated with other authorised practices and most other human activities (although precisely how long is not defined).

2.4 EC DIRECTIVE ON THE GEOLOGICAL STORAGE OF CO_2

The EC Directive on storage (2009/31/EC), published on 23 April 2009, further develops the principles defined by OSPAR for CO_2 storage and provides more detail of the practical implementation of a licensing regime. The Directive provides a regulatory framework for permanent CO_2 storage. The Directive does not apply to geological storage of CO_2 with a total intended storage of less than 100 kilotonnes, undertaken for research and development or testing new products and processes.

The Directive recognises that monitoring is essential to assess whether:

- Injected CO_2 is behaving as expected.
- Whether any migration or leakage occurs.
- Whether any identified leakage is damaging the environment or human health.

Member States are therefore required to ensure that during the operational phase, the operator monitors the storage complex and the injection facilities on the basis of an approved monitoring plan designed to address specific monitoring objectives. The Competent Authority is the regulatory organization designated within the Member State responsible for applying the regulations. The operator should report the results of the monitoring, including information on the monitoring technology employed, to the Competent Authority at least once a year. Routine inspections are required to be carried out at least once a year. The inspection will examine relevant monitoring facilities. If a Competent Authority withdraws a permit it will temporarily take over all legal obligations related to acceptance criteria, including monitoring, until a new permit has been issued.

During the closure of a storage site, the operator should remain responsible for monitoring until a post closure plan has been submitted and approved by the competent authority. Part of the approval process and transfer of responsibilities (Article 18) is provision of a report, which includes a demonstration that all available evidence indicates that the stored CO_2 will be completely and permanently contained and:

(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.

These crucial closure-related criteria are critically dependent on the monitoring plan and its efficacy.

Once a project is completed and the storage site closed to the satisfaction of the Competent Authority, any liabilities (termed responsibilities in the Directive) associated with the site are transferred to the Competent Authority. At this point, monitoring may be reduced to a level which still allows identification of leakage or significant irregularities. If any leakages or significant irregularities are detected, monitoring should be intensified as required to assess the scale of the problem and the effectiveness of corrective measures. The Directive indicates that monitoring costs would be covered by a financial contribution from an operator (before site closure and revocation of the storage licence) and that these costs should cover anticipated monitoring over a period of at least 30 years.

Article 13 of the Directive specifically addresses monitoring:

> 1. Member States shall ensure that the operator carries out monitoring of the injection facilities, the storage complex (including where possible the CO_2 plume), and where appropriate the surrounding environment for the purpose of:
>
> (a) Comparison between the actual and modelled behaviour of CO_2 and formation water, in the storage site.
>
> (b) Detecting significant irregularities.
>
> (c) Detecting migration of CO_2.
>
> (d) Detecting leakage of CO_2.
>
> (e) Detecting significant adverse effects for the surrounding environment, including in particular on drinking water, for human populations, or for users of the surrounding biosphere.
>
> (f) Assessing the effectiveness of any corrective measures taken… [in case of leakage].
>
> (g) Updating the assessment of the safety and integrity of the storage complex in the short and long term, including the assessment of whether the stored CO_2 will be completely and permanently contained.
>
> 2. The monitoring shall be based on a monitoring plan designed by the operator …submitted to and approved by the Competent Authority…. The plan shall be updated pursuant to the requirements laid down in Annex II and in any case every five years to take

account of changes to the assessed risk of leakage, changes to the assessed risks to the environment and human health, new scientific knowledge, and improvements in best available technology. Updated plans shall be re-submitted for approval to the Competent Authority.

Annex II of the Directive sets out the criteria for establishing and updating the monitoring plan and for post-closure monitoring and the most pertinent parts are:

1.1. Establishing the plan

The monitoring plan shall provide details of the monitoring to be deployed at the main stages of the project, including baseline, operational and post-closure monitoring. The following shall be specified for each phase:

(a) Parameters monitored.

(b) Monitoring technology employed and justification for technology choice.

(c) Monitoring locations and spatial sampling rationale.

(d) Frequency of application and temporal sampling rationale.

The parameters to be monitored are identified so as to fulfil the purposes of monitoring. However, the plan shall in any case include continuous or intermittent monitoring of the following items:

(e) Fugitive emissions of CO_2 at the injection facility.

(f) CO_2 volumetric flow at injection wellheads.

(g) CO_2 pressure and temperature at injection wellheads (to determine mass flow).

(h) Chemical analysis of the injected material.

(i) Reservoir temperature and pressure (to determine CO_2 phase behaviour and state).

The choice of monitoring technology shall be based on best practice available at the time of design. The following options shall be considered and used as appropriate:

(j) Technologies that can detect the presence, location and migration paths of CO_2 in the subsurface and at surface.

(k) Technologies that provide information about pressure-volume behaviour and areal/vertical distribution of CO_2 plume to refine numerical 3-D simulation to the 3-D-geological models of the storage formation.

(l) Technologies that can provide a wide areal spread in order to capture information on any previously undetected potential leakage pathways across the areal dimensions of the complete storage complex and beyond, in the event of significant irregularities or migration of CO_2 out of the storage complex.

1.2. Updating the plan

The data collected from the monitoring shall be collated and interpreted. The observed results shall be compared with the behaviour predicted in dynamic simulation of the 3-D-pressure-volume and saturation behaviour undertaken in the context of the security characterisation ….

Where there is a significant deviation between the observed and the predicted behaviour, the 3-D model shall be recalibrated to reflect the observed behaviour. The recalibration shall be based on the data observations from the monitoring plan, and where necessary to provide confidence in the recalibration assumptions, additional data shall be obtained.

Where new CO_2 sources, pathways and flux rates or observed significant deviations from previous assessments are identified as a result of history matching and model recalibration, the monitoring plan shall be updated accordingly.

2.5 MONITORING AND REPORTING GUIDELINES IN THE ETS

The following is based around the recent North Sea Basin Task Force report 'Monitoring Verification Accrediting and Reporting (MVAR) Report for CO_2 storage deep under the seabed of the North Sea: Final Version – 4 October 2009', which summarises the content of the EC Monitoring and Reporting Guidelines.

Monitoring and Reporting Guidelines (MRG) are laid down in the draft amendment (2009/xx/EC) of Decision 2007/589/EC. They address monitoring and reporting guidelines for greenhouse gas emissions from the capture, transport and geological storage of carbon dioxide

N.B. If there is no evidence for release of CO_2 to the seabed or seawater on the basis of monitoring applied in accordance with the Storage Directive, emissions are taken to be zero. If on the other hand there is an indication, or potential, that CO_2 is being emitted or released to the seawater, appropriate monitoring must be undertaken to enable the quantification of the leakage. This is in addition to any monitoring requirements under the Storage Directive. Monitoring of emissions from a leakage shall continue until emissions from that leakage can no longer be detected. The document, in particular Annexes I (e.g. Section 4.3) and XVIII, specifies how emissions from the CO_2 storage activity have to be reported.

The MRG (Section 4.3 of Annex I) states that a monitoring plan should be established. This should include a detailed, complete and transparent documentation of the monitoring methodology for a specific installation, including documentation of the data acquisition and data handling activities, and quality control. It should include the following specific items:

- Quantification approaches for emissions or CO_2 release to the seawater from *potential* leakages as well as the applied and possibly adapted approaches for *actual* emissions or CO_2 release to the seawater.
- Description of the installation.
- List of emission sources.
- Description of the calculation- or measurement-based method for quantifying emissions.
- If applicable, a description of continuous emission measurement systems.
- Compliance with the *uncertainty* threshold for activity data.

Furthermore the operator must demonstrate a credible understanding of the main sources of uncertainty when measuring and calculating emissions (Chapter 7 of Annex I).

Potential CO_2 emission sources from the storage which should be quantified are:

- Fuel use at booster stations and other combustion activities such as on-site power plants.
- Venting at injection or at enhanced hydrocarbon recovery operations.
- Fugitive emissions[1] at injection.
- Breakthrough CO_2 from enhanced hydrocarbon recovery operations.

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[1] Fugitive emissions = Irregular or unintended emissions from sources which are not localised, or too diverse or too small to be monitored individually, such as emissions from otherwise intact seals, valves, intermediate compressor stations and intermediate storage facilities.

- Leakage from the storage complex.

The Monitoring and Reporting Guidelines for CCS under the ETS describe the procedure for quantifying potential CO_2 emissions from a storage project. Quantitative monitoring will be triggered by evidence that migration has led to leakage resulting in emissions or release to the water column. Emissions resulting from such a release of CO_2 into the water column shall be deemed equal to the amount released to the water column.

Quantitative monitoring shall continue until corrective measures pursuant to the Storage Directive (Article 16) have been taken and emissions or release into the water column can no longer be detected.

Emissions and release to the water column shall be quantified as follows:

$CO_{2emitted}\ [t\ CO_2] = \sum L\ CO_2\ [t\ CO_2\ /d]$

With summation from T_{start} to T_{end}, where:

$L\ CO_2$ = Mass of CO_2 emitted or released per calendar day due to the leakage.

For each calendar day in which leakage is monitored it shall be calculated as the average of the mass leaked per hour [t CO_2/h] multiplied by 24. The mass leaked per hour shall be determined according to the provisions in the approved plan for quantitative monitoring. For each calendar day prior to commencement of monitoring, the mass leaked per day shall be taken as equal the mass on the first day of monitoring.

T_{start} = The latest of:

a. the last date when no emissions or release to the water column from the source under consideration were reported;
b. the date the CO_2 injection started;
c. another date such that there is evidence demonstrating to the satisfaction of the competent authority that the emission or release to the water column cannot have started before that date.

T_{end} = The date by which corrective measures have been taken and emissions or release to the water column can no longer be detected.

Other methods for quantification of emissions or release into the water column from leakages can be applied if approved by the competent authority on the basis of providing a higher accuracy than the above approach.

The amount of emissions leaked from the storage complex shall be quantified for each of the leakage events *with a maximum overall uncertainty over the reporting period of ±7.5%*. However, if the overall uncertainty of the applied quantification approach exceeds the value of ±7.5%, an adjustment shall be applied, as follows:

$CO_{2,Reported}\ [t\ CO_2] = CO_{2,Quantified}\ [t\ CO_2] * (1 + (Uncertainty_{System}\ /100) - 0.075)$

Where:

$CO_{2,Reported}$ = Amount of CO_2 to be included in the annual emission report with regards to the leakage event in question

$CO_{2,Quantified}$ = Amount of CO_2 determined through the used quantification method for the leakage event in question

$Uncertainty_{System}$ = The level of uncertainty (%) which is associated with the quantification method used for the leakage event in question.

2.6 REGULATORY DEVELOPMENT IN THE UK

Following the publication of the EC Directive on CO_2 storage, the UK government has issued two consultations:

'Towards Carbon Capture and Storage' (URN 08/992), issued on 30 June 2008, and a response (URN 09D/532) to that consultation published in April 2009.

'Consultation on the proposed offshore carbon dioxide storage licensing regime' (URN 09D/753), published on 25th September 2009. The closing date for responses to this latest consultation was 30 December 2009.

2.6.1 UK Government's position as indicated in responses to the 'Towards Carbon Capture and Storage' Consultation

The responses to the June 2008 consultation indicated that monitoring would be required to cover the subsurface volume affected by the CO_2 storage, rather than just the volume occupied by the CO_2 plume itself. This recognised also that further review might be needed in the light of practical experience and improved understanding of the behaviour of injected CO_2. It was therefore suggested that, at least initially, permits may be easier to grant for relatively confined geological structures.

Although the EC Directive suggests that a minimum period of 20 years after the end of injection should elapse before the Competent Authority is able to accept responsibility, unless all available evidence indicates that the stored CO_2 will be completely and permanently contained before the end of that period, the UK Government has indicated that, in practice, the UK intends to assess the risks on a case by case basis. The period before transfer of responsibility will therefore be determined for each project individually, depending on the behaviour of the store during operation. It is clearly stated that the monitoring programme will provide the evidence to determine if the objective of permanent containment has been met.

The duration and type of post-transfer monitoring will be determined by the nature and behaviour of the store during operation. A 'transfer fee' may be imposed to cover the costs of this monitoring.

2.6.2 UK Government's position as indicated in the "Offshore Carbon Dioxide Storage Licensing Regime" Consultation.

Broadly speaking, this consultation presents a description of how the UK CO_2 storage licensing scheme is intended to work, and seeks views on a draft of the proposed regulations [for implementing the EU Directive on CCS] and a draft licence. Following the consultation, DECC is planning to issue guidance on applications for storage licences, which will provide further detail on the kind of information required, including plans for monitoring.

Key highlights of relevance are:

- The applicant must provide a proposed monitoring plan.
- Responsibility for the site remains with the operator during the post closure phase of the licence until DECC is satisfied on the basis of the monitoring reports and inspection that the carbon dioxide within the storage site has stabilised as predicted and that permanent containment has been achieved.

According to this, closure of the site, with removal of infrastructure and sealing of the wells, would occur before handover to the authorities. However, this would restrict any subsequent monitoring as there would no longer be access to the wells.

The following description of the monitoring plan is taken from the consultation:

> The proposed monitoring plan which is to be submitted with the application should detail monitoring of:

- The injection facilities;
- The storage complex (including where possible the CO_2 plume) ; and, where appropriate;
- The potential impact of the operations on the surrounding environment;

for the purpose of:

(a) Comparison between the actual and modelled behaviour of CO_2 and formation water, in the storage site.

(b) Detecting significant irregularities.

(c) Detecting migration of CO_2.

(d) Detecting leakage of CO_2.

(e) Detecting significant adverse effects for the surrounding environment, including in particular on drinking water, for human populations, or for users of the surrounding biosphere.

(f) Assessing the effectiveness of any corrective measures taken pursuant to Article 16.

(g) Updating the assessment of the safety and integrity of the storage complex in the short- and long-term, including the assessment of whether the stored CO_2 will be completely and permanently contained.

The applicant must submit a report at a frequency of not less than one per year that includes the results on monitoring during the reporting period.

After a storage site has been closed according to the conditions stated in the permit, the operator will remain responsible for maintenance, monitoring, control, reporting, and corrective measures until the responsibility for the storage site is transferred to a competent authority. The operator will also be responsible for sealing the storage site and removing the injection facilities.

2.6.3 Recent discussion on site closure and monitoring requirements

There is a certain lack of clarity currently on the exact timing of the closure and transfer of a storage site. Once a storage site has been closed the operator remains "responsible for maintenance, monitoring, control, reporting, and corrective measures until the responsibility for the storage site is transferred to a competent authority"[2]. It is likely however, that once injection has finished, the operator will wish to abandon the injection and monitoring wells and remove any pipeline and platform or subsea template infrastructure as quickly as possible to reduce risks (of leakage) and maintenance costs. It is not clear therefore whether the operator will be required to maintain this infrastructure to enable continued post-injection monitoring or whether DECC EDU will accept a more reduced (non-invasive) form of monitoring. For example, monitoring of reservoir pressures, storage efficiencies (dissolution and residual trapping processes) and observing CO_2 breakthrough would no longer be possible if well access was removed. We have asked DECC EDU about this and they have indicated that: (i) they recognise the interest of operators in reducing costs and uncertainty (though DECC EDU question whether this will point to earlier or later decommissioning); (ii) they might wish, depending on the particular site circumstances, to retain some wells and other relevant monitoring facilities for some period after the cessation of injection, possibly including throughout the post-closure period; (iii) they note that when applying for a storage permit, the operator must also submit a draft post-closure plan, including decommissioning proposals and their proposed monitoring

[2] A consultation on the proposed offshore carbon dioxide storage licensing regime, published by DECC URN 09D/.753, 25th September 2009.

programme for the post-closure period – this will require detailed discussions during which DECC EDU intend to provide as much clarity as possible; and (iv) that the post-closure plan is required by the Directive to be regularly updated in the light of relevant new information obtained from monitoring during injection and therefore complete certainty is only likely to be obtained when the final decommissioning and post-closure monitoring plans are approved, after cessation of injection (Kiff, R., pers. comm., March 2010).

2.7 SUMMARY AND REMARKS ON MONITORING REQUIREMENTS FOR STORAGE SITES IN THE UK OFFSHORE AREA

The full monitoring philosophy of the Storage Directive and the OSPAR Guidelines are well represented by one single statement, from the Storage Directive:

"Monitoring is essential in order to assess whether injected CO_2 is behaving as expected, whether any migration or leakage occurs, and whether any identified leakage is damaging the environment or human health.…In the case of geological storage under-the seabed-, monitoring should further be adapted to the specific conditions for the management CCS in the marine environment."

The MRG do not require monitoring additional to that required by the Directive and OSPAR unless there is indication of leakage or potential leakage to the seawater. If this is the case, monitoring techniques should be deployed which are capable of quantifying the leakage/emissions to a specified level of uncertainty.

The IPCC Guidelines have a similar objective to those of the MRG in quantifying emissions to the seawater.

The monitoring requirements of the three main regulatory instruments are set out in Table 2-1.

2.7.1 Acceptance Criteria

Significant gaps remain in understanding how the high-level principles set out in the regulations will be implemented at real sites. A good example would be the requirements for transfer of liability following site closure. The Directive sets out three minimum geological criteria for transfer of liability:

- Actual (observed) behaviour of the injected CO_2 is conformable with the modelled behaviour.
- No detectable leakage
- Site is evolving towards a situation of long-term stability.

The challenge we face is to define specific technical acceptance criteria, based on real site performance data, to demonstrate that a given site meets these requirements. The main issues are illustrated below:

Actual behaviour conformable with predicted

All current storage sites show mismatches of varying degree between the predictive modelled behaviour and actual observed performance (e.g. 4D seismic from Sleipner, well breakthrough times at Ketzin, pressure behaviour at K12-B, etc). The key to regulatory conformance is to distinguish between mismatches which just reflect minor inaccuracies of model parameters and those which arise from significant misunderstanding of site processes. The former are compatible with closure and transfer of responsibility, the latter are not.

No detectable leakage

Leakage monitoring at a site, whether under the requirements of the Directive, or whether triggered by more stringent ETS requirements, will nevertheless be subject to limitations and uncertainty in leakage detection and measurement. A key issue therefore is whether the leakage detection and measurement uncertainty arising from whatever monitoring strategy is deployed at the site is sufficient to allow transfer. This involves an integrated assessment of the whole (deep and shallow) site monitoring system as well as the site characterisation. Initial acceptance criteria for the demonstration of satisfactory leakage monitoring will need to be set at the time of site licensing, but may be subject to adjustment thereafter as site understanding evolves.

Table 2-1: Summary monitoring objectives as set out in the OSPAR, Directive and EU MRG regulations. * Reporting of leakage rates is mentioned in OSPAR but we assume any such requirement would be subsumed within the MRG requirements.

	OSPAR	Directive	MRG (ETS)	Remarks
Deep focussed monitoring objectives				
Migration in reservoir				Required
Migration in overburden				Required
Performance testing and calibration and identification of irregularities				Required
Containment integrity				Required
Testing remedial actions				Required
Calibration for long-term prediction				Required
Shallow focussed monitoring objectives				
Verification of no leakage				Required
Leakage detection				Required
Environmental impacts				Required
Emission quantification*				Contingent

Site is evolving towards a situation of long-term stability

This criterion is perhaps the most challenging of all to demonstrate. Our experience of testing predictive simulations is largely restricted to ongoing injection projects, and analogous research results from oil and gas production. The longest post-injection projects are at Nagaoka in Japan (4 years since injection ceased) and Frio in Texas (over 5 years since injection ceased). Time-lapse well logging at Nagaoka (Section 10.4, Volume 2) has given important insights into post-injection processes, but robust verification of medium to very long-term storage performance prediction is missing.

Legal implementation of these technically-based guidelines may be challenging It is possible that site-specific transfer conditions could be written into the licence requiring the government to take back the site when they are met. This provision could help in encouraging operators to take on the risk, whilst maintaining protection for the authorities e.g. if the monitoring results do not exactly match the modelling.

With regard to the requirements of the ETS for quantification of CO_2 emissions, there is clearly a balance to be struck by an operator between highly sensitive, but expensive methods, that incur little penalty in loss of storage credits, and cheaper, less sensitive techniques, which result in a larger penalty.

3 Review of four sites most relevant to the UK offshore

3.1 EXECUTIVE SUMMARY

This chapter presents a detailed examination of three experimental offshore CO_2 storage sites most relevant to the development of storage in the UK offshore area. There is a comprehensive description of each storage site, providing:

- Background information on the site's history and reasons for its selection and development.
- A description of the site's geological setting, including information on its stratigraphy and structure, the properties of the reservoir, cap rock and overburden and the baseline surveys carried out or proposed.
- A review of the site's risk profile, considering migration through the cap rock, migration into well bores, migration to strata or structures outside the site's licence block, and the public relations aspects of the work.
- A description of the monitoring programme put in place or proposed, covering all the monitoring methods used and highlighting any site-specific requirements addressed.
- An assessment of how well the monitoring programme addressed the identified risks, the overall effectiveness of the methods employed in meeting other monitoring objectives, such as management of the reservoir and the injection process, and finally how well the monitoring programme would stand up in the context of current and planned regulatory requirements (such as the EU Storage Directive, OSPAR and emissions accounting under the ETS).
- Lastly, consideration is given to any additional work that could have been undertaken with the benefit of hindsight.

A fourth site, Miller, was also studied, on the basis of confidential information provided by BP as described below.

The **Sleipner** storage site is located in the Norwegian sector of the North Sea and is the oldest production-scale test CO_2 storage site. Operation began in 1996 and is still active with over 11 Mt of CO_2 injected into a saline aquifer. The geological structure is well-understood due to the development of the Sleipner West gas field, from which extensive details of the reservoir properties were obtained along with baseline surveys. Monitoring was designed to meet a risk profile based on understanding the subsurface migration of injected CO_2. The monitoring programme uses non-invasive technologies: 2D and 3D surface seismic, seabed imaging and gravimetry, electromagnetic surveys and pressure measurement. 3D seismic and gravimetry surveys have been repeated to provide time-lapse data, and pressure is monitored continuously at the wellhead. The seismic and gravity surveys have been particularly effective. It is concluded that the monitoring objectives and programme would be largely compliant with current regulatory requirements apart from emissions accounting. However, as there are no indications of leakage, such monitoring would not be needed under the regulations, although it would have to form part of a monitoring plan.

The **Miller** Oilfield lies in the UK sector of the North Sea about 240 km north east of Peterhead and was proposed as a storage site in which the injected CO_2 would provide a drive for enhanced oil recovery (CO_2–EOR) from a depleted reservoir. The geological setting is well-understood from exploration and development of the oilfield. Some baseline surveys were available from legacy data sets; however it was proposed to carry out additional work to characterise the seabed and to provide a basis for the type of leakage and environmental monitoring not undertaken at Sleipner. As the site did not progress beyond the proposal stage the risk profile and monitoring plans remained incomplete. The main risks considered were vertical migration and leakage around existing wells, and lateral migration into adjacent oilfields. It was intended to use reservoir simulations of injection with the monitoring programme to address risk mitigation and to manage the EOR. An important factor would be co-operation with the operators of adjacent fields. The planned monitoring was much more extensive than that at Sleipner, with use of invasive (downhole) methods, including geophysical logging, downhole pressure measurement, well fluid and geochemical logging (with tracers) and use of some observation wells. Confidential information on the proposed monitoring plan for Miller was provided by BP to assist the project team with understanding requirements for MMV for such a site. Details of the Miller plan are not therefore included in this report, although some of the learnings from Miller are reflected in the generic plans presented in Chapter 8.

The first CO_2 storage test site in the Netherlands is at the **K12-B** natural gas field, in the Dutch sector of the southern North Sea. The first injection tests were in 2004, and injection now continues at about 20 kt per year into a depleted reservoir. The sandstone reservoir is capped by claystone and evaporites – a geological setting characteristic of this part of the North Sea. Good baseline data is available and reservoir modelling has been undertaken of this producing gas field. The risk profile notes the effectiveness of the cap rock and rates upward migration as a low risk, with any leakage likely to be from loss of well integrity. The monitoring programme was designed on this basis, with the additional objective of providing information on CO_2 flow and mixing (with methane) within the reservoir. Integrity monitoring was based on well imaging technologies and well pressure and temperature gradient profiling. Gas migration and mixing were monitored using gas and water analysis, comparing injection with production, chemical tracers and pressure profiling, with further reservoir modelling based on this data. A significant difference with other monitoring regimes was the omission of seismic surveys, which were deemed unlikely to be effective due to the small quantities being injected into a deep reservoir below a salt caprock. Otherwise, the monitoring regime was assessed as good, with a useful test of the application of reservoir modelling in the context of regulatory requirements to predict future site behaviour.

Finally the **P-18** (and **P-15**) sites are also gas fields in the Dutch sector of the southern North Sea. They are located a few tens of kilometres offshore, are nearly depleted, and could thus be a cost-effective site for production-scale CO_2 storage. The geological setting has some similarities with K12-B, with a sandstone reservoir capped and sealed by claystones, although here there may be more faulting. The caprock is known to be gas-tight for methane and the risk of upward migration of injected CO_2 through it is regarded as very low; however there is some risk of reactivation of faults providing leakage pathways. Existing wellbores are also a leakage risk. Lateral migration is regarded as low-risk as the structure seems to be well constrained. Monitoring plans are at a very early stage, but are being designed using current best-practice around the risk profile and within the regulatory framework. Some of the existing wells will be converted to observation wells, utilising a variety of downhole physical and chemical measurement methods to monitor both migration within the reservoir and to detect leakage; leakage from the observation wellbores themselves will also be monitored. Similar measurements will be made at the injection wells, as permitted by injection operations. Seismic surveys will be used to monitor migration and image the injection plume. Seabed imaging, with geochemical sampling backup, will be used to detect any subsea leakage.

3.2 INTRODUCTION

Four sites representative of the range of offshore storage operations in the North Sea were selected (Table 3-1). Two of these, Sleipner and K12-B are active injection sites, and P-18 is earmarked for storage in the future. Miller was selected for injection but the project was subsequently shelved. Because the plans for Miller have not been published we are unable to present the details here, although they have been used to inform the generic monitoring plans for this type of site in Chapter 8.

Table 3-1: Summary of four sites typical of UK North Sea storage sites.

	Water depth	Storage type	Storage depth	Relevance for UK storage
Sleipner	80 m	Saline aquifer	~ 800 m	Typical regional saline aquifer in Central / Northern North Sea
Miller	100 m	Depleted oil field	~ 4000 m	Typical depleted oil field in Central / Northern North Sea
K12-B	30 m	Depleted gas field	~ 3800 m	Analogue for sub-salt UK depleted gas field
P-18	30 m	Depleted gas field	~ 3200 m	Analogue for above-salt UK depleted gas field and southern North Sea aquifer

The selected sites cover a range of storage types and environmental conditions. The Sleipner reservoir is a major offshore saline aquifer, the Utsira Sand, Miller a depleted oilfield, K12-B a depleted gas field beneath the Zechstein salt and P-18 a depleted gas field above the Zechstein salt.

In addition to geological differences, the high-level monitoring objectives at the sites also differ significantly. Figure 3-1 shows the monitoring objectives for Sleipner, K12-B and P18.

	Sleipner	K12-B	P18
Plume location	✓	✓	✓
Test predicitive models	✓	✓	✓
Migration in storage complex	✓		✓
Early warning of leakage			✓
Leakage measurement			✓
Public perception	✓		
Well integrity		✓	✓

Performance monitoring

Leakage monitoring

Figure 3-1 High-level monitoring objectives at Sleipner, K12-B and P18

Sleipner is an operating site which commenced prior to the monitoring guidelines set out in the Storage Directive. Sleipner also has a high research / demonstration component, based around a number of major EU/industry research projects. Monitoring objectives at Sleipner are focussed on imaging plume migration with respect to identified project risks and also to demonstrate understanding of storage processes. Monitoring at Miller and P-18 was focussed on operational aspects and meeting the regulatory requirements. K12-B is a small research project in a secure site, so monitoring is designed to address specific research objectives.

As a consequence of the range of site types and monitoring objectives, the monitoring programmes differ significantly between the sites. Figure 3-2 shows the monitoring programmes for the Sleipner, K12-B and P18 sites.

Existing monitoring tools are described in Chapter 10, Volume 2, which builds on earlier reviews in the literature. Tools can be subdivided into ‘deep-focussed’, for reservoir surveillance and tracking of CO_2 in the subsurface, and ‘shallow-focussed’, for detection and measurement of CO_2 migration or leakage, at or close to the surface. The deep-focussed tools are mainly mature oil industry technologies, tested at a number of sites for CO_2 monitoring whereas the shallow monitoring methodologies are more commonly novel and / or under development and relatively untested for CO_2.

	Sleipner	K12-B	P18				
Deep-focussed							
3D surface seismic	✔		✔				
2D surface seismic	✔						
Seabed gravimetry	✔						
Seabed CSEM	✔						
Wellhead P,T	✔	✔	✔		M	M	M
Downhole P,T		✔	✔				
Geophysical logs		✔	✔				
Downhole fluid chemistry		✔	✔				
Passive seismics			✔				
Shallow-focussed							
Multibeam echosounding	✔						
Sidescan sonar	✔		✔				
Bubble-stream detection			✔				
Bubble-stream chemistry			✔				
Infrastructure							
Well integrity		✔	✔				

Figure 3-2: Monitoring tools deployed or planned for the three sites. Note wellhead P,T monitoring is a mandatory requirement (M).

The key deep-focussed tools are surface seismic (3D or 2D), downhole pressure and temperature, downhole logging and downhole fluid chemistry. The key shallow-focussed tools are some form of seabed imaging, plus bubble-stream detection and analysis. Establishing well integrity is also of major importance.

3.3 SLEIPNER

3.3.1 Background to the Sleipner storage operation

The CO_2 injection operation at Sleipner commenced in 1996. It is the world's longest-running industrial-scale storage project, and so far is the only example of underground CO_2 storage arising as a direct response to environmental legislation (Baklid et al., 1996). CO_2 separated from natural gas produced from the Sleipner west gas field is injected into the much shallower Utsira Sand, a regional-scale saline aquifer. The injection point is at a depth of about 1012 m below sea level, some 200 m below the reservoir top, with over eleven million tonnes (Mt) of CO_2 currently stored.

3.3.2 Geological Setting

The geological setting of Sleipner is relatively simple. Details are set out in a number of publications (e.g. Zweigel et al., 2004; Chadwick et al., 2004b). A brief summary will be given here, setting out the key points.

3.3.2.1 Structure

The Utsira Sand forms the Sleipner storage reservoir and comprises a basinally-restricted deposit of Mio-Pliocene age extending for more than 400 km north to south and between 50 and 100 km east to west (Figure 3-3 and Figure 3-4). Its eastern and western limits are defined stratigraphically; to the southwest it passes laterally into finer-grained sediments, and to the north it occupies a narrow, deepening channel. Locally, particularly in the north, depositional patterns are quite complex with some isolated depocentres, and lesser areas of non-deposition within the main depocentre. The top Utsira Sand surface generally varies quite smoothly in the depth range 550 to 1500 m, and is around 800 – 900 m near Sleipner. Isopachs of the reservoir sand define two main depocentres (Figure 3-3), one in the south, around Sleipner, where thicknesses locally exceed 300 m, and another some 200 km to the north with thicknesses approaching 200m.

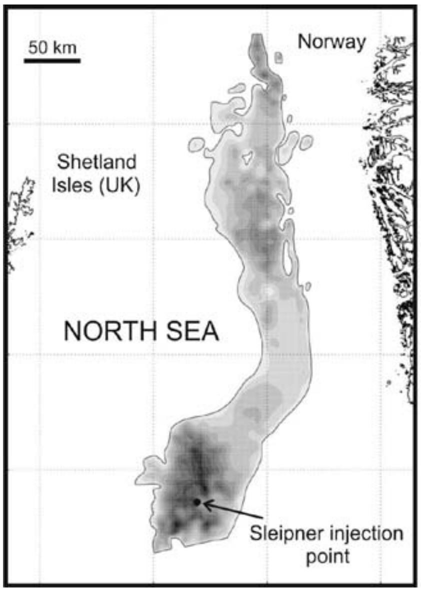

Figure 3-3: Thickness map of the Utsira Sand showing the location of Sleipner (image courtesy British Geological Survey).

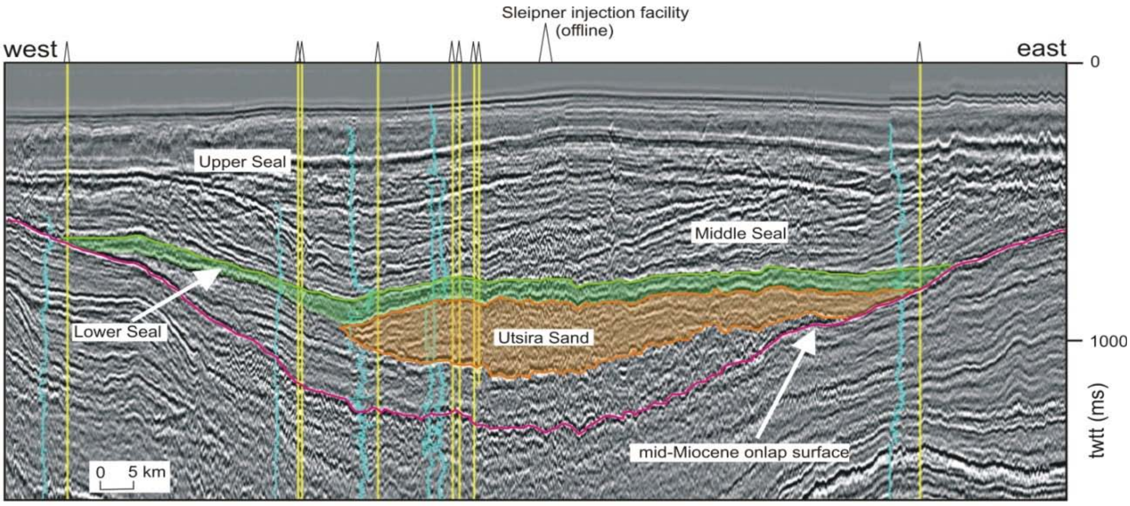

Figure 3-4: Regional 2D seismic line through the Utsira Sand (note very strong vertical exaggeration). From CO_2STORE, 2008

In the immediate vicinity of Sleipner the detailed structure was mapped using some 770 km^2 of 3D seismic data. The top of the Utsira Sand dips generally to the south, but in detail it is gently undulatory with small domes and valleys. The Sleipner CO_2 injection point is located beneath a small domal feature that rises about 12 m above the surrounding area (Figure 3-5). The base of the Utsira Sand is structurally more complex, and is characterised by the presence of numerous mounds, interpreted as mud diapirs. These are commonly about 100 m high and are mapped as isolated, circular domes typically 1 – 2 km in diameter, or irregular, elongate bodies with varying orientations, up to 10 km long. The mud diapirism is associated with local, predominantly reverse, faulting that cuts the base of the Utsira Sand, but does not appear to affect the upper parts of the reservoir or its caprock.

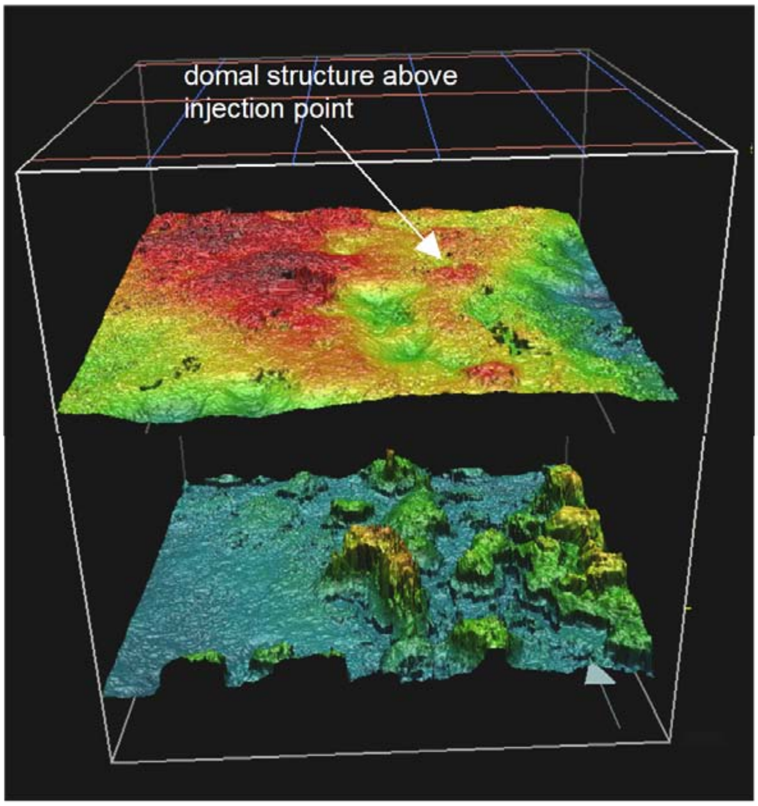

Figure 3-5: Perspective view of the top and base of the Utsira Sand around the injection point, based on 3D seismic. Note the small domal structure above the injection point. Image adapted from CO_2STORE, 2008

3.3.2.2 RESERVOIR PROPERTIES

Internally the Utsira Sand comprises stacked overlapping 'mounds' of very low relief, interpreted as individual fan-lobes and commonly separated by thin intra-reservoir mudstone beds. It is interpreted as a composite low-stand fan, deposited by mass flows in a marine environment with water-depths of 100 m or more.

On geophysical logs the Utsira Sand characteristically shows a sharp top and base (Figure 3-6), with the proportion of clean sand in the reservoir unit varying generally between 70 and 100 %. The non-sand fraction corresponds mostly to the thin mudstones (typically about 1m thick), which show as peaks on the gamma-ray and resistivity logs. In the Sleipner area, a thicker mudstone, some 5m thick (here termed the 'five-metre mudstone' separates the uppermost sand unit from the main reservoir beneath (Figure 3-6). The mudstone layers constitute important permeability barriers within the reservoir sand, and have proved to have a significant effect on CO_2 migration through the reservoir.

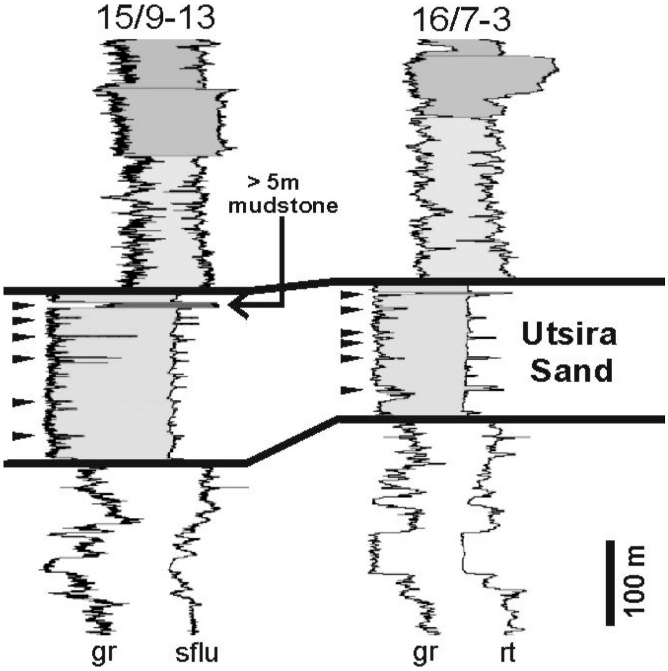

Figure 3-6: Sample geophysical logs through the Utsira Sand from two wells in the Sleipner area. Note the low γ-ray signature of the Utsira Sand, with peaks denoting the intra-reservoir mudstones (adapted from CO_2STORE, 2008).

Macroscopic and microscopic analysis of core and cuttings samples of the Utsira Sand show it to be mostly fine-grained and largely uncemented. Porosity estimates of core based on microscopy range generally from 27% to 31%, locally up to 42%. Laboratory experiments on the core give porosities from 35 - 42.5%. These results are broadly consistent with regional porosity estimates, based on geophysical logs, which are quite uniform, in the range 35 to 40% over much of the reservoir. Permeabilities are correspondingly high with measured values (from both core testing and water-production testing) ranging from around 1 to 8 Darcies).

3.3.2.3 Overburden properties

The overburden of the Utsira reservoir around Sleipner is about seven hundred metres thick, and can be divided into three main units (Figure 3-4). The Lower Seal is the primary reservoir caprock and forms a basin-restricted mudstone some 50 to 100 m thick, extending more than 50 km west and 40 km east beyond the area currently occupied by the CO_2 injected at Sleipner. This is well beyond the predicted final migration distance of the total volume of injected CO_2 (Zweigel et al., 2001). The Middle Seal mostly comprises prograding sediment wedges of Pliocene age, dominantly muddy in the basin centre, but coarsening into a sandier facies both upwards and towards the basin margins. The Upper Seal is of Quaternary age, mostly glacio-marine clays and glacial tills.

The seismic, geophysical log and cuttings data enable many overburden properties to be characterized and mapped on a broad scale. Cuttings samples from wells in the vicinity of Sleipner comprise dominantly grey clayey silts or silty clays, classified as non-organic mudshales and mudstones (Krushin, 1997). Although the presence of small quantities of smectite may invalidate the approach, XRD-determined quartz contents suggest displacement pore throat diameters in the range 14 to 40 nm, consistent with capillary entry pressures of between about 2 and 5.5 MPa (Krushin, 1997). In addition, the predominant clay fabric with limited grain support resembles type 'A' or type 'B' seals (Sneider et al., 1997), stated to be capable of supporting a column of 35º API oil greater than 150 m in height.

A core sample was obtained from the lower seal in 2002 (Figure 3-7). The core material is typically a grey to dark grey silty mudstone, uncemented and quite plastic, and generally homogeneous with only weak indications of bedding. It contains occasional mica flakes, individual rock grains up to three mm in diameter and a few shell fragments. XRD-determined quartz contents suggest displacement pore throat diameters in the range 2.2 to 21 nm (Kemp et al., 2002), similar values to those of the cuttings samples from other wells, and suggesting capillary entry pressures to supercritical CO_2 of between 3.4 and 37 MPa .

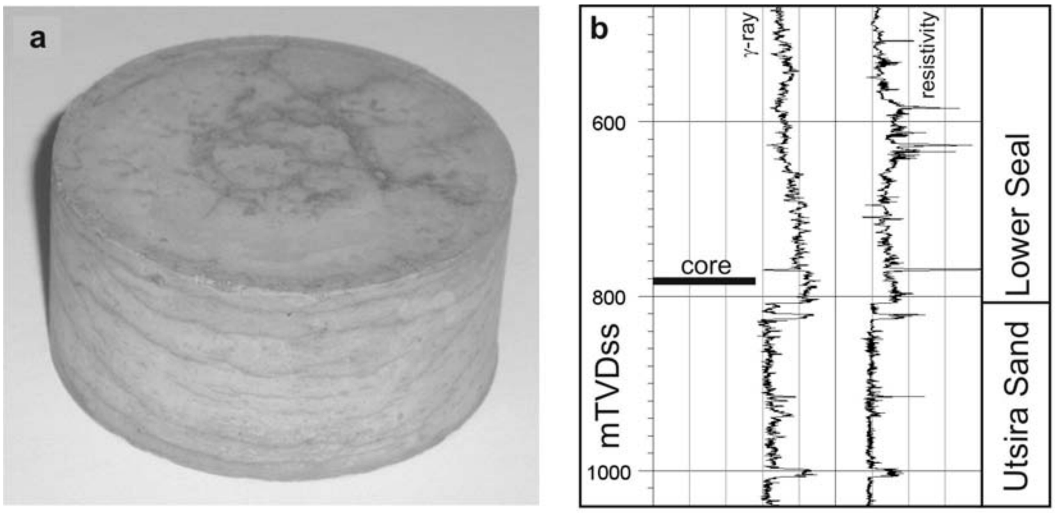

Figure 3-7: Core sample from the Lower Seal (a) with its location indicated on well logs (b), some 20 m above the Utsira Sand (image courtesy British Geological Survey).

The core has been subjected to a number of testing procedures including geomechanics (Pillitteri et al., 2003) and flow transport testing with nitrogen and supercritical CO_2. Long-term hydraulic and nitrogen gas transport testing (Harrington et al., 2006: in press) on the caprock core at reservoir P,T conditions, indicates porosities in the range 32% to 38%, intrinsic permeabilities ranging from 4×10^{-19} m^2 vertical to 1×10^{-18} m^2 horizontal, and a capillary entry pressure to nitrogen of around 3 MPa. A parallel study on the core (Springer et al., 2005) showed in situ porosity of ~35% and vertical intrinsic permeability e in the range 7.5 - 15 x 10^{-19} m^2, slightly higher than in the study by Harrington et al., presumably due to a lower clay content in the samples used in the second study. Capillary entry pressure was 3 - 3.5 MPa to both nitrogen and gaseous CO_2, and ~1.7 MPa to supercritical CO_2. This is consistent with a suggested tendency of supercritical CO_2 to exhibit a degree of wetting behaviour.

Induced adverse geomechanical effects on topseal integrity are likely to be small, as predicted injection pressures are considered unlikely to induce either dilation of incipient fractures or induce microseismicity (Fabriol, 2001; Zweigel & Heill, 2003).

3.3.3 Risk profile

The risk profile discussed here includes all significant issues associated with the subsurface migration of CO_2. It does not include environmental impacts, such as might form part of an EIA, nor health and safety issues associated with failure of surface/underwater infrastructure.

The risk profile at Sleipner is relatively straightforward, and reflects the simple geological setting. Key risks are listed below:

3.3.3.1 MIGRATION THROUGH THE CAPROCK SEAL INTO THE OVERBURDEN AND ULTIMATELY TO THE SEABED.

This risk can be subdivided into four elements:

Migration through intact rocks: This is considered to be very unlikely given the high capillary entry pressures of water-saturated caprock strata (see above).

Migration through intact rocks with impaired capillary sealing capacity: Such a situation could arise if the caprocks were not water saturated, such as within a pre-existing gas-chimney. However even if this were the case, the low intrinsic permeability of the caprock strata (see above) should result in very slow rates of migration.

Migration through pre-existing fractures or faults: Migration of CO_2 along faults, particularly those in a state of near critical stress, is generically perceived as a significant storage risk. However at Sleipner, characterisation of the overburden from 3D seismic data shows that faults with throws of more than a few metres are not present. Small faults beneath the seismic detection threshold may be present but well-established scaling relationships indicate that such faults would have very limited lateral and vertical extent, far from sufficient to penetrate to the seabed.

Migration through induced fractures: New fracture pathways may be induced in the overburden if reservoir pressures increase beyond a critical threshold. At Sleipner this is considered unlikely due to the large size and high permeability of the reservoir, and the relatively modest amounts of CO_2 to be injected (see above).

Risk management

Monitor for changes in the overburden. Monitor CO_2 migration in the reservoir. Monitor reservoir pressures.

3.3.3.2 Migration into wellbores resulting in leakage pathways to the seabed

This is considered unlikely in the short-term due to the topography of the topseal which tends to keep the buoyantly-trapped CO_2 away from the nearer wells. In the longer term as more CO_2 accumulates towards the reservoir top and lateral migration continues, some abandoned wells may be reached by the plume.

Risk management

Make predictive models of lateral spread of CO_2 with time. Monitor CO_2 migration in the reservoir to identify developing situations with respect to the wells.

3.3.3.3 Migration of CO_2 outside of the Sleipner licence

The plume could impact on third party wellbores and may also compromise future external activities (such as by making drilling through the Utsira reservoir more costly, or by blanking seismic signals beneath the plume).

Risk Management

Make predictive models of lateral spread of CO_2 with time. Monitor CO_2 migration in the reservoir to identify developing situations with respect to the wells.

3.3.3.4 4. Generic public relations issues

Imperfect understanding of storage could result in inaccurate or poorly – informed criticism of the site from external parties.

Risk Management

Monitor site performance to demonstrate a thorough understanding of storage processes. Monitor for leakage.

3.3.4 Monitoring Programme at Sleipner

A major time-lapse monitoring programme has been carried out at Sleipner, with a strong emphasis on deep-focussed tools monitoring the CO_2 in the reservoir (Table 3-2). All the monitoring is non-invasive, with no downhole monitoring deployments. The time-lapse monitoring frequency is very high for some of the tools (notably 3D surface seismic). This reflects the fact that the Sleipner injection project has a large research component with significant additional funding for acquiring monitoring datasets. The strict operational requirements for monitoring the CO_2 storage project would be much less stringent.

Table 3-2: Monitoring at Sleipner

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
3D surface seismic	✓					✓		✓	✓		✓		✓		✓	
2D surface seismic (hi-res)													✓			
Seabed imaging (ss sonar, multibeam)													✓			
Seabed gravity									✓			✓				✓
CSEM															✓	
Wellhead pressure			continuous													
Cumulative CO_2 injected at TL surveys (Mt)	0.00		injection starts			2.35		4.25	4.97(s) 5.19(g)		6.84	7.74	8.40		10.15 (s) 10.38 (em)	11.05

3.3.4.1 3D SURFACE SEISMIC

Time-lapse surface 3D seismic surveys have been acquired in 1994 (baseline), 1999, 2001, 2002, 2004, 2006 and 2008. Results from a subset of the full time-lapse ensemble are shown in Figure 3-8. Details of the CO_2 distribution in the reservoir are clearly evident. In cross-section the CO_2 plume is seen to be roughly 200 m high, imaged as a number of bright sub-horizontal reflections within the reservoir, growing with time. These are interpreted as tuned wavelets arising from thin (mostly < 8 m thick) layers of CO_2 trapped beneath thin intra-reservoir mudstones and the reservoir caprock. In plan view the plume is elliptical, with a major axis increasing to over 3000 m by 2006, accompanied by development of a prominent northerly extension since 2004.

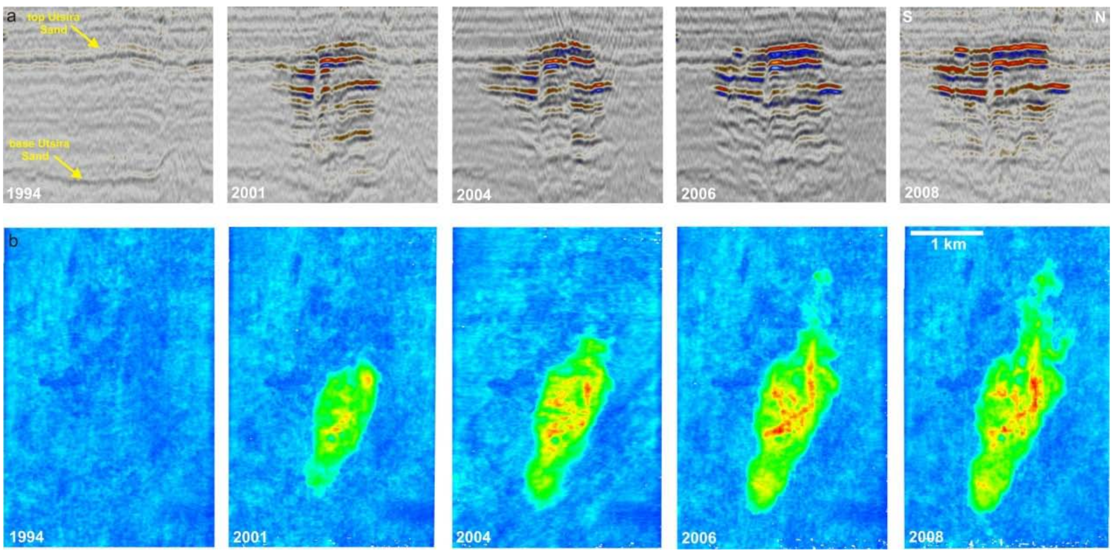

Figure 3-8: Time-lapse images of the CO_2 plume at Sleipner a) N-S inline through the plume b) map of total plume reflectivity (Courtesy British Geological Survey))

A number of publications deal with the analysis of the Sleipner datasets. Early papers concentrated on quantification of the seismic signal with the aim of independently verifying the measured injected amount of CO_2 (Arts et al., 2004, Chadwick et al., 2004a; 2005). A satisfactory match was obtained; a saturation model for the 1999 dataset was derived which contained around 85% of the known injected CO_2 whilst maintaining a satisfactory match with the seismic data (Figure 3-9). Given that reservoir flow simulations suggest up to 10 % of the free CO_2 would have dissolved into the aqueous phase (thereby becoming seismically invisible), this may be considered a remarkably accurate result. It is fair to say though that significant uncertainties render a unique verification very challenging, most notably the differing seismic responses of uniform and 'patchy' mixing of the CO_2 and aqueous phases in the reservoir and the effects of signal attenuation in the deeper parts of the plume.

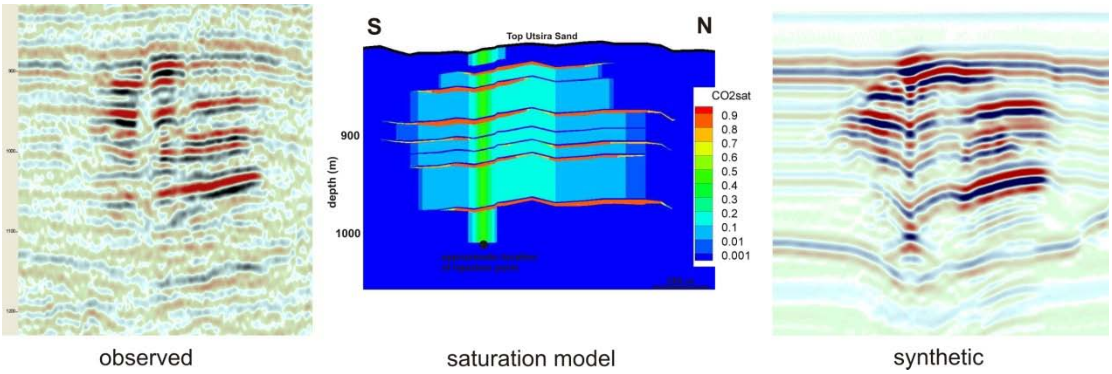

Figure 3-9: Seismic quantification of the 1999 dataset a) E-W seismic section through the 1999 plume b) same section extracted from 3D CO_2 saturation model c) synthetic seismogram generated from the CO_2 saturations (courtesy British Geological Survey).

Other publications concentrated on history-matching flow simulations of plume development with the observed datasets (Lindeberg and Bergmo, 2003, Van der Meer, 2001). A general match of plume development and flow simulations is readily obtainable (Figure 3-10). However a key issue is understanding how the CO_2 is transported through the intra-reservoir mudstones. One group of models assumes that the mudstones are semi-permeable, another group of models assumes that they are impermeable but with holes. Well logs (Figure 3-6) suggest that they have similar properties to the caprock, so they should be more or less impermeable. Both models are capable of reproducing the general morphology and rate of development of the plume.

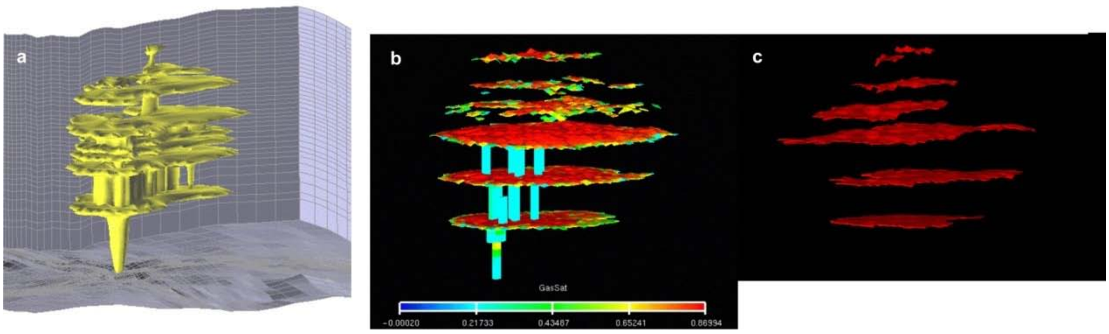

Figure 3-10: Flow simulations of the Sleipner plume a) Plume simulation 1999 using 8 semi-permeable intra-reservoir mudstones b) Plume simulation 2001 using 5 impermeable intra-reservoir mudstones with discrete holes c) interpreted seismic horizons corresponding to CO_2 layers in (b). Diagrams courtesy of Bert van der Meer and CO_2STORE, 2008.

The most recent publications on Sleipner (e.g. Chadwick et al., 2009b) have concentrated on detailed quantitative analysis of the topmost layer of CO_2 (Figure 3-11). This is for two main reasons. Firstly the lower layers in the plume are becoming progressively less distinct with time (so full plume history-matching is becoming less practicable. Secondly, the lateral spread beneath the caprock of the topmost layer is the key pointer to the longer-term behaviour of the storage site (see below).

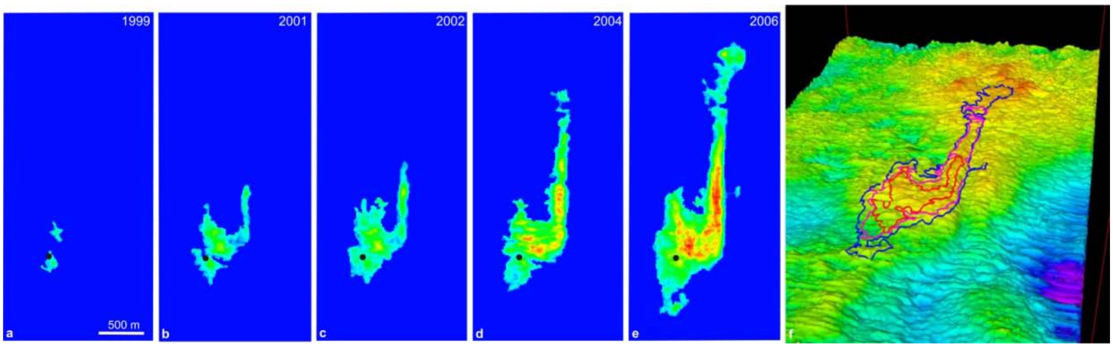

Figure 3-11: Growth of the topmost layer at Sleipner a) – e) plan views of the layer spreading from 1999 to 2006. Perspective view of the topography of the top reservoir, showing the gas (CO_2) – water contacts in 2001 (red), 2004 (purple) and 2006 (blue) (courtesy British Geological Survey).

Detailed quantitative analysis of the layer has been history-matched against numerical flow simulations (Figure 3-12). There are significant mismatches, most notably arising from the difficulty in modelling the very rapid northward migration of the plume between 2001 and 2006. Assessment of parameter variability and uncertainties suggests that the main cause of this mismatch is very small errors in the depth imaging of the reservoir top topography, rather than any significant misunderstanding of the physical processes controlling lateral migration (Chadwick & Noy, in press).

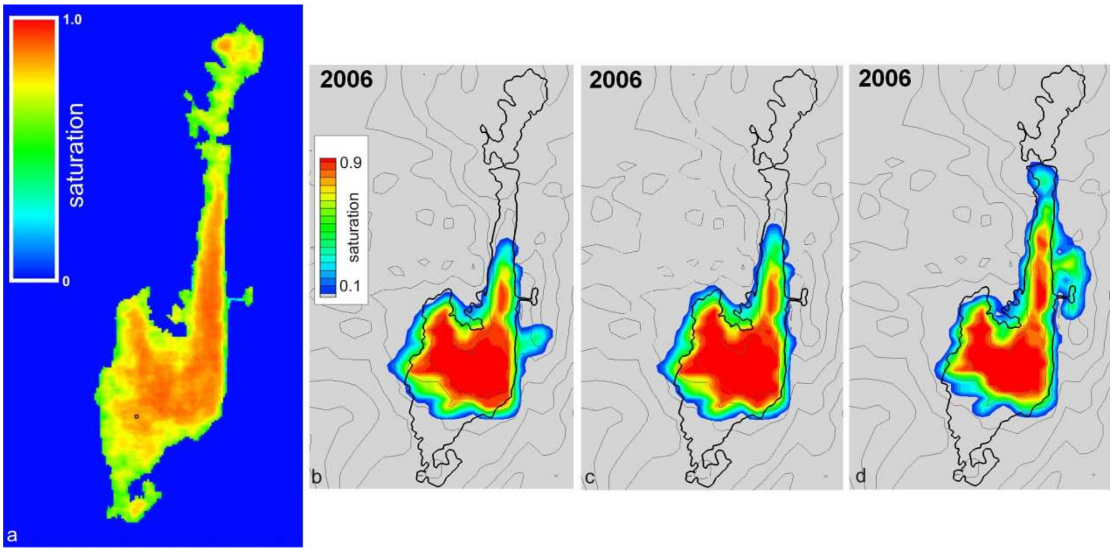

Figure 3-12: Topmost layer in 2006 a) observed b) to d) flow simulations using variable reservoir flow parameters (courtesy British Geological Survey).

Alternative approaches have been used to obtain additional quantitative information from the 3D datasets, including pre- and post-stack trace inversion and more recent model-based inversion described in Delepine et al. (2009). The inversion approaches all suffer from the difficulty in accounting for tuning effects from very thin layers of CO_2. Ongoing work on the Sleipner datasets is using spectral decomposition to further constrain layer thicknesses and velocity, and is also looking in more detail at amplitude – offset changes to extract elastic parameters as well as acoustic information from the plume reflectivity.

In general terms it appears that the more recent Sleipner datasets are becoming more difficult to model. With time, reflectivity in the deeper plume is fading and velocity pushdown is becoming more difficult to map (Figure 3-8). These may be seismic imaging effects arising from generally increasing CO_2 saturations within the plume envelope, or may signify real and significant changes in CO_2 distribution in the deeper part of the plume.

In addition to imaging the CO_2 plume within the reservoir, a key objective of the time-lapse seismic is to indicate whether any detectable migration of CO_2 into the caprock has occurred (in other words, whether CO_2 is being contained within the primary reservoir). The most straightforward way of assessing this is to look at difference datasets, obtained by subtracting the baseline cube from a time-lapse cube. Close examination of the difference cubes in the overburden succession can reveal whether any systematic changes have occurred which may be indicative of CO_2 migration. Examples of difference time-slices in the caprock succession (Figure 3-13) typically show a rather random difference signal with a characteristic mottled appearance. This difference signal is referred to as repeatability noise and is due to unavoidable mismatches between the baseline and the repeat survey, with a number of causes including different source/receiver properties and positioning, different ambient noise conditions, different tidal states etc. Repeatability noise is weakly correlated with reflectivity arising from the geological succession, as survey positioning mismatches will tend to adumbrate this.

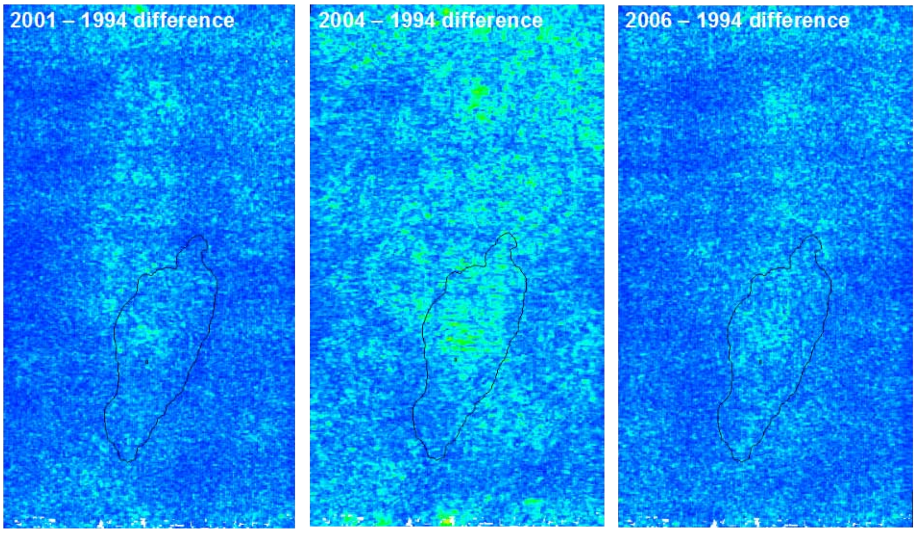

Figure 3-13: Time-slices through successive difference cubes, located in the overburden above the Utsira reservoir. The mottled signal is composed of repeatability noise which shows no systematic correlation with the location of the CO_2 plume (black polygon). The 2004 survey was acquired with ship lines perpendicular to the other surveys, so ray paths are completely different and the intrinsic mismatch is much higher, giving a much higher level of repeatability noise (courtesy British Geological Survey).

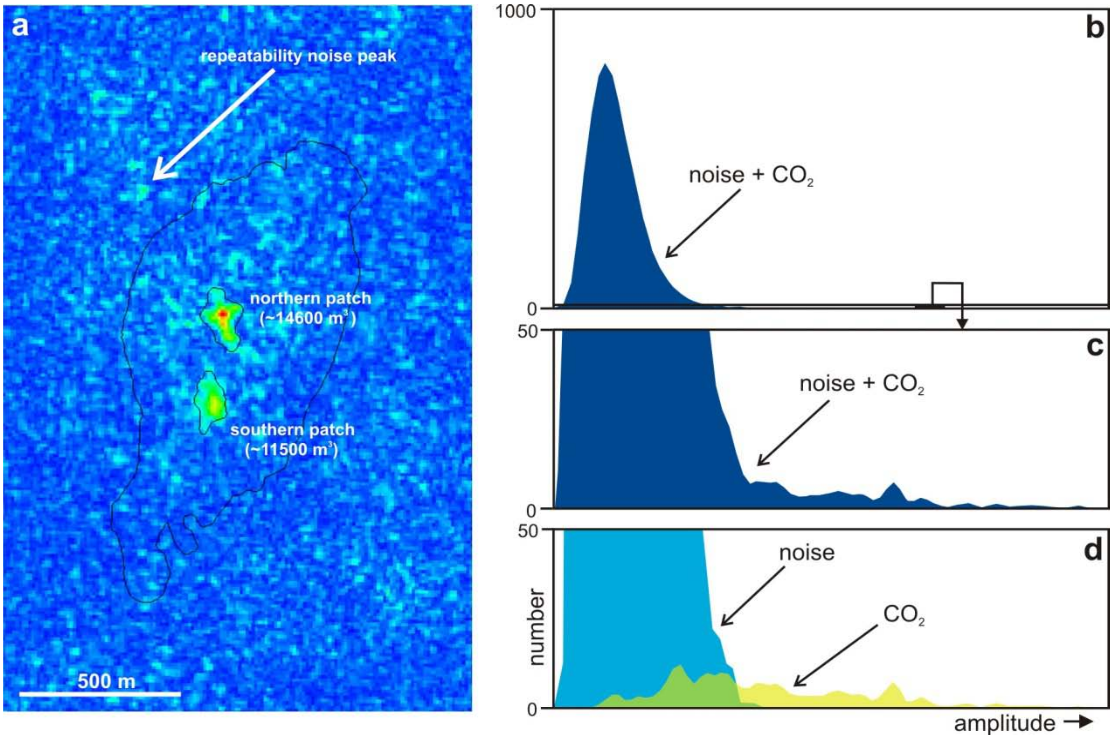

Figure 3-14: Detection limits for small amounts of CO_2 at Sleipner a) Time-slice map of the 1999-94 difference data showing reflection amplitude changes at the top Utsira Sand. High amplitudes (paler greys) correspond to two small CO_2 accumulations. Other scattered amplitudes are due to repeatability noise. b) to d) Histograms plotting number of seismic traces against reflection amplitude (courtesy British Geological Survey).

The potential detection capability of the Sleipner data can be illustrated by examining differences in time-lapse data between the 1994 baseline survey and the first repeat in 1999 when two small lenses of CO_2 had just started to accumulate beneath the caprock seal (Figure 3-14). From the reflection amplitudes, the volumes of the two accumulations can be estimated at about 14000 and 11500 m^3 respectively. Other seismic features on the difference map are down to repeatability noise. It is clear that repeatability plays a key role in determining detectability, so for a patch of CO_2 to be identifiable it must be distinguishable from the largest noise peaks. Preliminary analysis of the difference signal from CO_2 compared with repeatability noise (Figure 3-14) suggests that accumulations larger than about 4000 m^3 should fulfil this criterion.

3.3.4.2 2D SURFACE SEISMIC

A single survey of 2D surface seismic was acquired at Sleipner in 2006. Configuration was in the form of a number of parallel profiles oriented NNE over the CO_2 plume with additional lines arranged in a star arrangement centred on the plume (Figure 3-15).

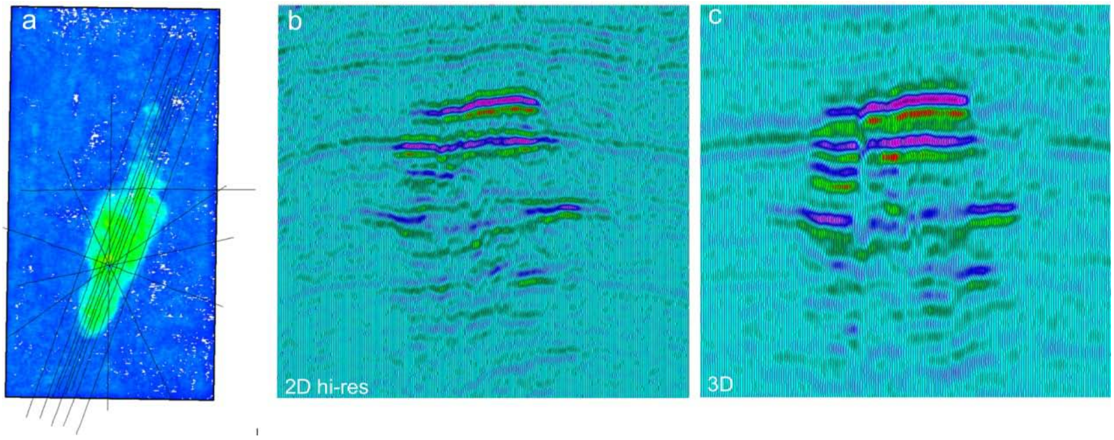

Figure 3-15: 2D surface seismic data a) location of 2D survey compared to 3D survey (main rectangle), footprint of 2006 plume showed in green b) 2D line through the plume c) equivalent section extracted from the 3D cube (courtesy British Geological Survey).

Acquisition of the 2D survey was with a relatively inexpensive vessel acquiring high resolution ‘site survey’ data, rather than a full 2D exploration setup. The dominant frequency of the 2D data is 55Hz, rather than the 30 Hz of the 3D data (Figure 3-16).

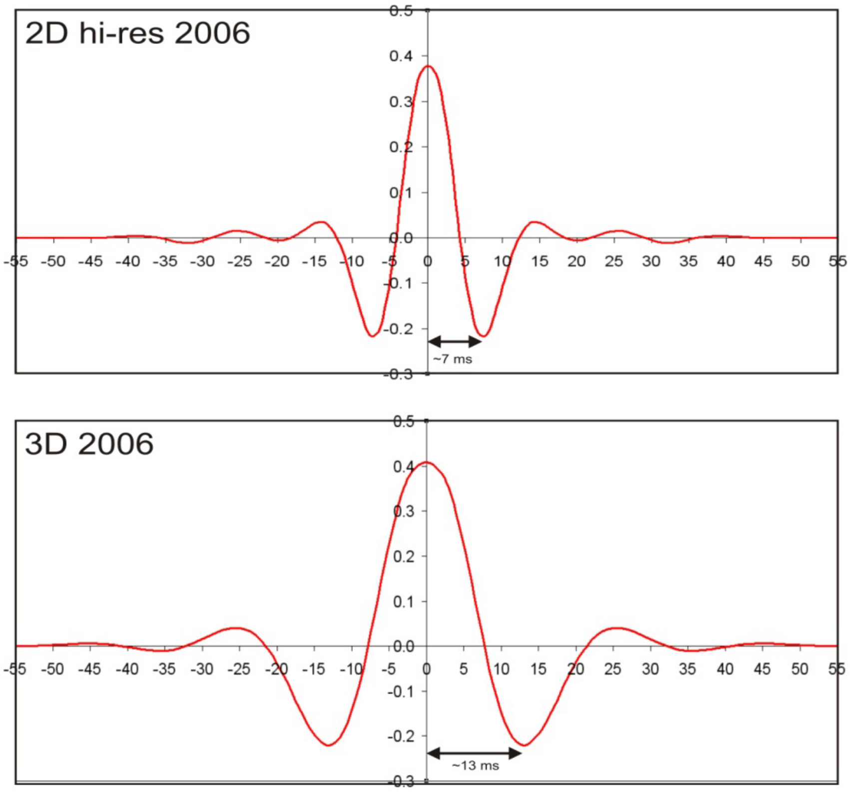

Figure 3-16: Seismic wavelets derived from the 2006 seismic surveys (courtesy British Geological Survey).

Data quality was good, with superior resolution of the uppermost parts of the plume compared to the 3D datasets (Figure 3-15b, c). Imaging of the deeper plume on the 2D data however is not as good as with the 3D data, due to poorer signal penetration and less effective rejection of multiples. The 2D data has cast some light on detailed structure in the uppermost plume layers, including explicit imaging of the base of the topmost layer; the 3D data is mostly characterised by tuning wavelets from the CO_2 layer.

3.3.4.3 SEABOTTOM GRAVITY

An initial seabed gravity survey was acquired at Sleipner in 2002 (Nooner et al., 2006), with 5.19 Mt of CO_2 injected. Repeat surveys were then acquired in 2005 with 7.74 Mt of CO_2 injected and in 2009 with 11.05 Mt of CO_2 injected. The surveys were based around pre-positioned concrete benchmarks on the seafloor that served as reference locations for the (repeated) gravity measurements. Relative gravity and water pressure readings were taken at each benchmark by a customised gravimetry and pressure measurement module mounted on a Remotely Operated Vehicle (Figure 3-17). Thirty concrete benchmarked survey stations were deployed in two perpendicular lines, spanning an area of about 7 km east-west and 3 km north-south and overlapping the subsurface footprint of the CO_2 plume (Figure 3-17), a number of additional stations were added for the 2009 survey to allow for the increased plume footprint. Each survey station was visited at least three times to better constrain instrument drift and other errors, resulting in a single station repeatability of about 4 µGal. For time-lapse measurements an additional uncertainty of 1–2 µGal is associated with the reference null level. The final detection threshold for Sleipner is therefore estimated at about 5 µGal.

For the 2002 and 2005 datasets the gravimetric response due to the additional CO_2 was obtained by calculating the gravimetric time-lapse response from the Sleipner East field (the deeper gas reservoir currently in production) and removing this from the measured gravity changes between 2002 and 2005. So far, gravity modelling has focussed on constraining the *in situ* density of CO_2, which has constituted a significant uncertainty in the quantitative seismic analysis (see section below on temperature measurements). Initial modelling (Nooner et al., 2006) concluded that the average CO_2 density in the plume was around 530 kgm^{-3}. However, more recent modelling, based on optimising several parameters simultaneously and with improved application of the various data corrections (Alnes et al., 2008), has derived a preferred CO_2 density of 760 kgm^{-3} (Figure 3-18). The 2009 dataset will likely show a much more significant time-lapse signal than the 2005 dataset, so hopefully modelling results will be more accurate. Analysis is ongoing.

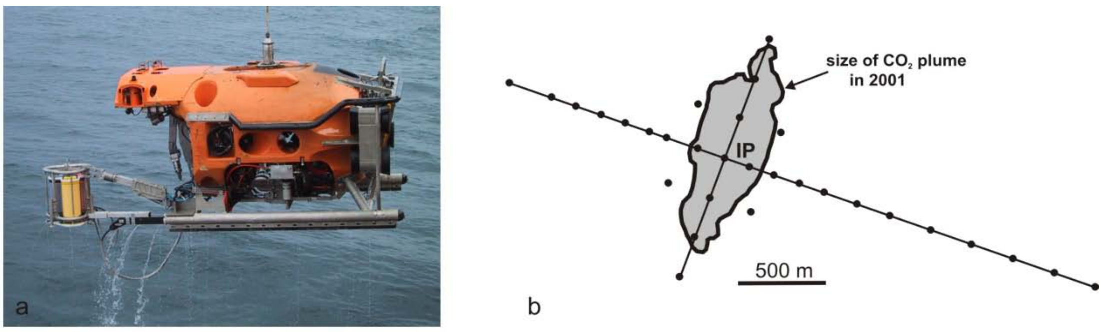

Figure 3-17: a) ROV and seabed gravimeter deployed at Sleipner b) location of the gravimetry benchmarks with respect to the CO_2 plume footprint. Image courtesy of Ola Eiken (Statoil).

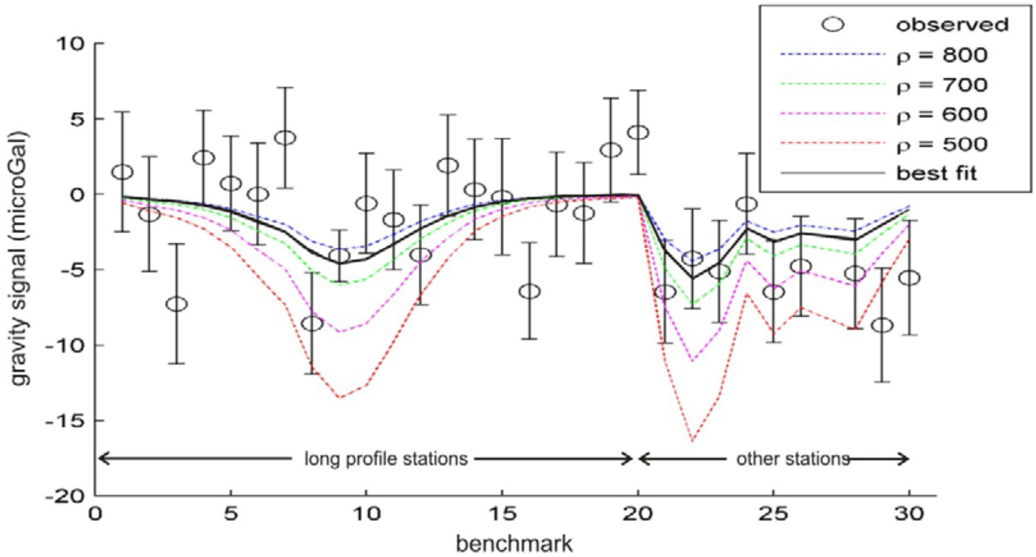

Figure 3-18: Observed gravity changes at Sleipner from 2002 to 2005 and modelling results. Dashed lines indicate modelled gravity with CO_2 densities from 500 to 800 kgm^{-3}. Solid lines shows best fit for a CO_2 density of 760 kgm^{-3} (adapted from Alnes et al., 2008, image reproduced with permission of the Society of Exploration Geophysicists).

3.3.4.4 Seabottom EM

Electromagnetic wave propagation depends on resistivity of the subsurface so in principle, in a brine-filled reservoir, Controlled Source Electro Magnetic (CSEM) data can map out changes in the distribution of (low conductivity) CO_2, albeit at much lower resolutions than seismic.

A seabottom CSEM survey was acquired at Sleipner in 2008. A 2D profile was recorded roughly along the long axis of the CO_2 plume (Figure 3-19), comprising 20 stations 500m apart, in places shifted slightly to avoid seafloor infrastructure (pipelines, gravity benchmarks etc). Two tows were carried out, one at frequencies from 0.5 to 7 Hz, the second at frequencies of 0.25 to 3.5 Hz.

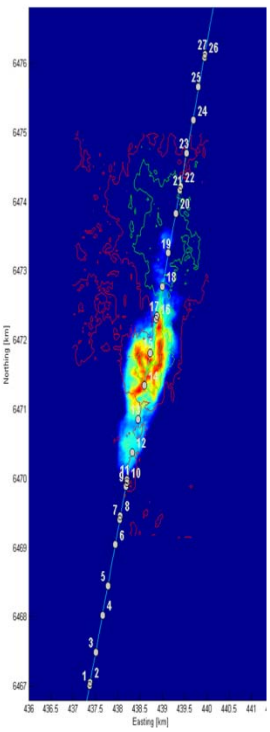

Figure 3-19: Location of the seabottom CSEM survey profile with respect to the CO_2 plume (in colour). Image courtesy of Havard Alnes

The data quality is good with no indication of interference/noise from seafloor infrastructure. Initial processing of the data however shows equivocal results and it is too early to say whether the CO_2 plume has been detected by the survey.

3.3.4.5 Pressure and temperature

Although no reservoir pressure readings have been taken at Sleipner, wellhead pressures have been measured since the start of injection in 1996 (Figure 3-20).

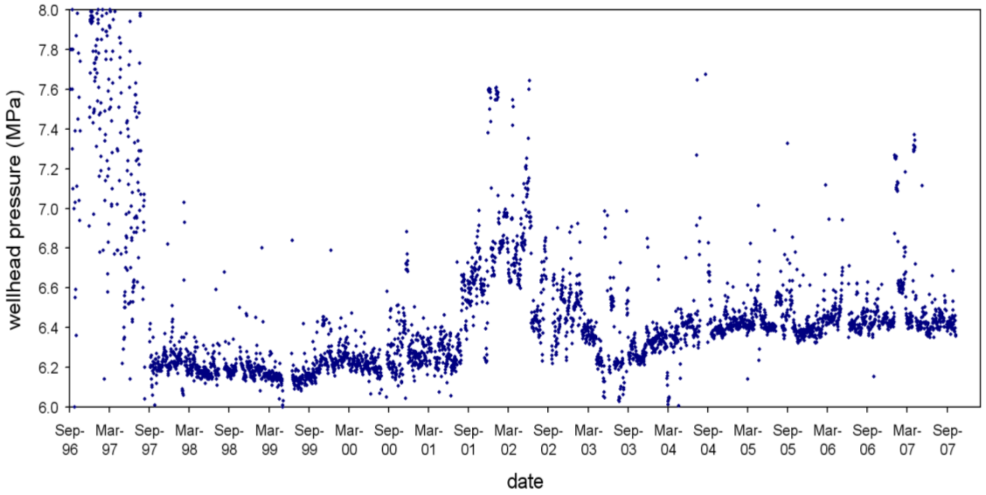

Figure 3-20: Wellhead pressures measured at Sleipner, 1996 to 2007. Image courtesy of Ola Eiken (Statoil).

Two prominent features in the measured data are irregularly high pressures for the first few months and a high pressure excursion from late 2001 to early 2003. These were caused by specific technical problems related to the injection infrastructure: the former due to sand blocking the perforation screens, an issue that was subsequently remediated, and the latter due to irregular wellhead thermostatic temperature control (see below). Setting aside these anomalous readings, the wellhead data indicate early wellhead pressures of around 6.2 MPa (1997 to 2001) with rather higher pressures of around 6.4 MPa from about 2005 onwards.

Neglecting frictional effects associated with fluid transport down the well, downhole pressure at the injection point (approximating to near-wellbore formation pressure) is a function of the wellhead pressure and the weight of the CO_2 column in the wellbore:

$$P_{IP} = P_{WH} + g\int_0^Z \rho(z)dz$$

Where:

P_{IP} = downhole pressure at the injection point (depth Z)

P_{WH} = wellhead pressure (measured)

g = acceleration due to gravity

$\rho\,(z)$ = density of the injected CO_2 in the wellbore at depth z

Downhole pressure therefore depends on the density of the CO_2 column in the wellbore, which varies with temperature. Early in the injection history, CO_2 temperatures at the wellhead were held around 23 ºC (Korbøl & Kaddour, 1994), but from early 2005, measurements show accurate thermostatic control at 25 ºC (Figure 3-20). Downhole temperature measurements are not available, but calculations assuming adiabatic compression indicate that the CO_2 would be heated by about 32 ºC adiabatically as it moves down the wellbore to the injection point (Ola Eiken, Statoil, personal communication).

Looking first at the most recent pressure measurements where wellhead temperatures have been tightly controlled (Figure 3-20), it is clear that from early 2005 onwards there has been negligible systematic increase in wellhead pressure. It follows that downhole (and by implication reservoir) pressures have not increased significantly either.

To assess the longer-term observed wellhead pressure increase from 6.2 to 6.4 MPa, it is instructive to examine the effect of temperature changes on the CO_2 column in the wellbore. Assuming that the measured wellhead temperature increase, from 23 ºC to 25 ºC, is propagated down the temperature profile in the wellbore, CO_2 properties can be calculated using an equation-of-state. Densities calculated for a wellbore fluid column comprising 98% CO_2 and 2% CH_4 (approximating the average injectant composition at Sleipner) indicate that a 2 ºC increase in wellhead temperature would reduce average density in the CO_2 column by about 9 kgm^{-3}, thereby reducing the pressure due to the column by about 0.1 MPa. Thus, to maintain pressure at the injection point, wellhead pressures would have to be increased by the same amount. This can explain about half of the observed change in wellhead pressure, possibly more, acknowledging parameter uncertainty.

In addition to wellhead temperature changes, a longer-term effect concerns heat loss from the wellbore to the surrounding (cooler) rock formations. Heat loss would have been greatest at the start of injection, with a wellbore wallrock temperature profile rather cooler than the adiabatic. Since then, as the wellbore rock walls have gradually warmed, the temperature profile within the wellbore will also have increased, to progressively approach adiabatic. This would have the effect of decreasing column densities with time, reducing the pressure due to the wellbore column and increasing the wellhead pressure necessary to maintain downhole pressure. This effect would augment the effects of wellhead temperature change described above.

To conclude, it is likely that the wellhead pressure measurements at Sleipner are consistent with negligible pressure increase in the reservoir. In recent times, with wellhead temperatures closely controlled, wellhead pressures have remained roughly constant. The measured small increase in wellhead pressure in the longer term is explicable in terms of temperature changes of the CO_2 column in the wellbore. Very little, if any, increase in downhole pressure can be inferred from the wellhead measurements. This is consistent with the results of flow simulations which indicate that the Utsira Sand is behaving as a very large aquifer with negligible internal flow barriers (Chadwick et al., 2009a).

There is no active temperature monitoring in the Utsira reservoir. Prior to injection a single downhole measurement of 36 ºC was obtained from a depth of 1056 m. Subsequent to this Statoil carried out thermal modelling based on better constrained temperature measurements from the much deeper Sleipner gas reservoir. These indicated significantly higher temperatures with a best estimate of the temperature at the injection depth (1012 m bsl) of around 41 °C (Statoil personal communication 2005). Still more recently however, in late 2007, large scale water production commenced from the Utsira Sand at the Volve field, a few kilometres to the north of Sleipner. A near-equilibrium temperature of 27.7°C was recorded at a depth of 768m, with a dynamic temperature reading of 32.2°C in water produced from a reservoir interval of between 886 and 1009 m. These figures strongly support the initial downhole measurement.

3.3.4.6 Seabed imaging

Seabed imaging profiles (sidescan sonar, single beam and multibeam echo sounding and pinger seabottom profiler) were acquired along the lines of the high resolution 2D profiles. A seabed bathymetry image from multibeam echo sounding is shown in Figure 3-21. Highest resolution was obtained from the sidescan sonar, which was able to detect the benchmarks set for the seabed gravimetry survey (about 1.5 meters in diameter). A simple interpretation has been carried out by the contractor who states that no evidence of gas leakage was detected.

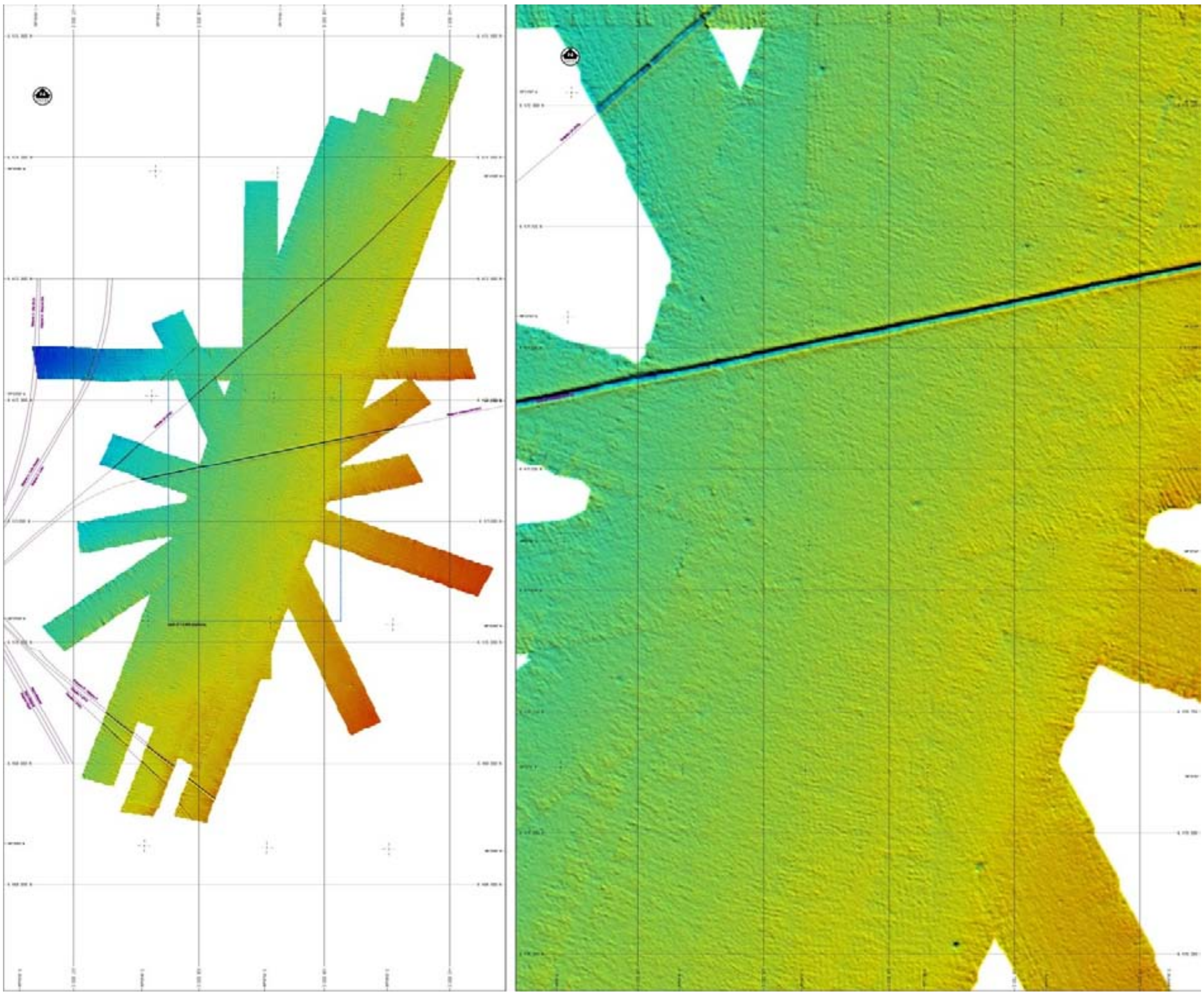

Figure 3-21: Multibeam echo sounding image of the seafloor above Sleipner (the echo sounding swaths were acquired along the same lines as the 2D seismic survey (Figure 4-19). a) whole survey b) zooming in on the area above the injection point, showing small seabed features. Image courtesy of Ola Eiken (Statoil).

3.3.4.7 Underwater video

Comprehensive video footage has been taken from the ROV used to deploy the gravity meter. This has not been analysed in detail, but anecdotal evidence suggests that nothing untoward (bubble streams etc) has been noticed.

3.3.5 The extent to which the monitoring programme addresses the key risks at Sleipner

The monitoring programme at Sleipner has addressed all of the identified risks to varying degrees, discussed below.

3.3.5.1 Migration through the caprock seal into the overburden and ultimately to the seabed.

The 3D surface seismic (Figure 3-22), combined with the site characterisation data, provide the key evidence for demonstrating caprock and overburden integrity.

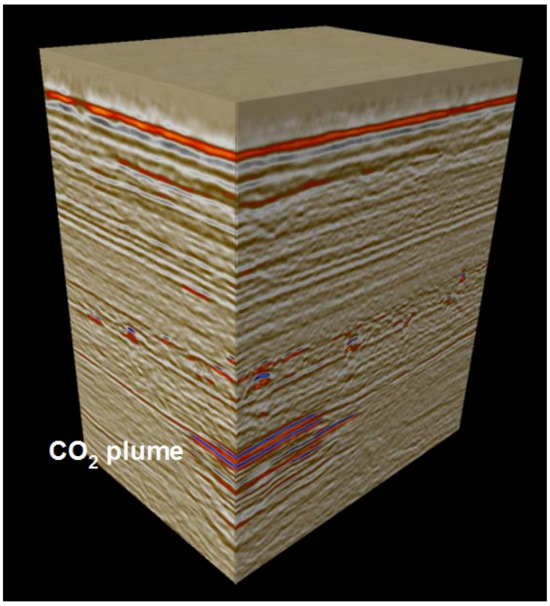

Figure 3-22: Subset of the 2006 3D seismic cube showing the plume in the reservoir and imaging of the overburden (courtesy British Geological Survey).

The surface seismic provides continuous and uniform 3D coverage of the reservoir and overburden albeit with a finite resolution and detection capability (see above). At the current time, no changes have been seen in the overburden which would suggest upward migration of CO_2 from the reservoir. Site characterisation data indicate that the topseal (Lower Seal) is laterally uniform (from seismic, well logs and well cuttings), and laboratory determinations on core indicate that it forms a capillary seal. Taken together, the monitoring and characterisation data are strongly indicative of secure containment.

Secondary evidence of containment, that CO_2 has not migrated to seabed, is provided by the seabed imaging datasets which show no unusual features. Only one vintage of surveys has been acquired so far however. Acquiring repeat seabottom datasets may provide stronger evidence, particularly from the public perception viewpoint. However, experience from the repeat seabed gravity surveys (notably changing benchmark elevations) suggest that the seabed sediments are quite mobile in the Sleipner area, due to significant bottom currents. This would weaken the time-lapse potential of seabed imaging.

A third, albeit somewhat circumstantial, line of evidence pointing to a secure topseal lies in the motion of the CO_2 within the reservoir itself. The observed rapid lateral migration of CO_2 beneath the topseal (around 1 m /day between 2001 and 2006) is not consistent with migration of CO_2 into the topseal, but rather suggests a sharp, impermeable flow barrier (Chadwick & Noy, in press).

3.3.5.2 Migration into wellbores resulting in leakage pathways to the seabed

The approach for ensuring that CO_2 is not impinging on wellbores is based around predictive simulations supported by monitoring. Migration modelling carried out in the SACS project was used to investigate whether or when CO_2 would be expected to approach existing wellbores (Figure 3-23). Predictions used SEMI, a simple buoyancy migration simulator (Zweigel et al., 2001). SEMI does not include migration retarding effects such as capillary trapping or dissolution, so migration estimates can be considered to be intrinsically conservative from a risk assessment viewpoint.

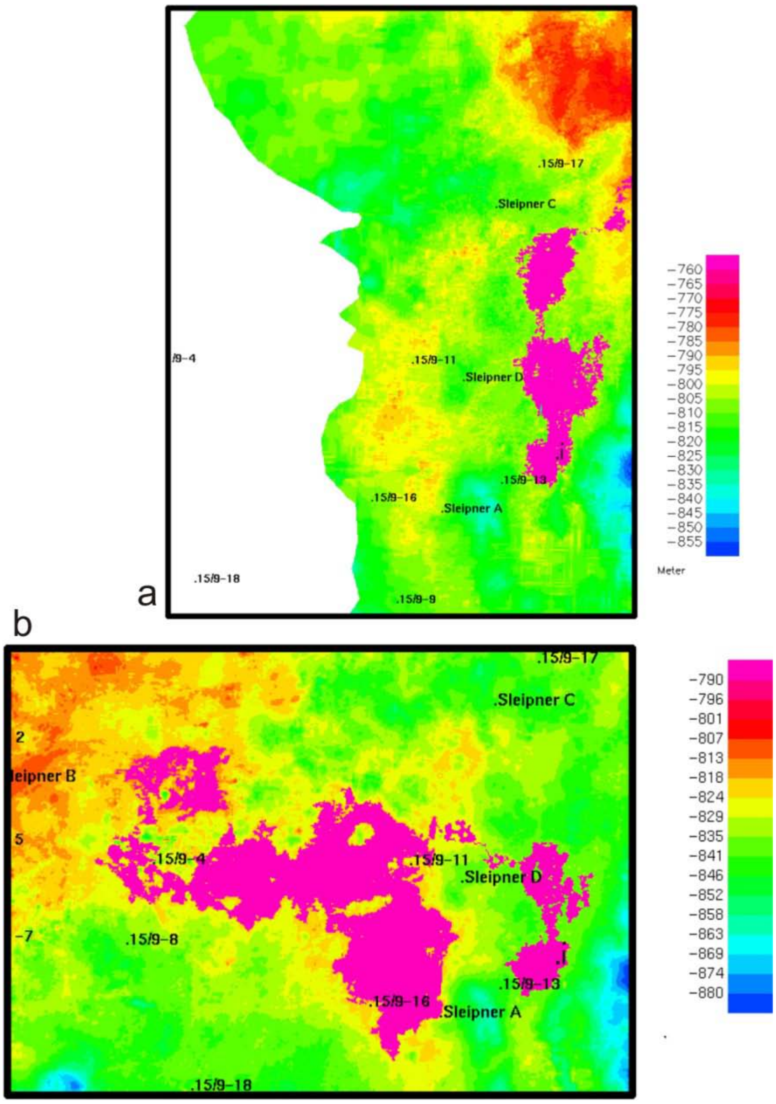

Figure 3-23: Predicted migration pathways for CO_2 migration and wellbore locations a) beneath the reservoir topseal (~5Mt in place before the CO_2 leaves the 3D area) b) ~20Mt of CO_2 in place beneath the 5-metre thick mudstone. Image from CO_2STORE, 2008.

SEMI predictions were based on the assumption that CO_2 would ultimately gather in the upper part of the reservoir via two possible scenarios: most lateral spread would occur beneath the Utsira topseal or that most spread would take place beneath the 5-metre mudstone or a combination of the two. Both scenarios suggest that the nearest well (15/9-13) to the injection point will not be impacted by CO_2, which migrates away to the north. Later in plume evolution, if substantial amounts of CO_2 accumulate beneath the 5-metre mudstone, wells to the west (15/9-11 and 15/0-16) may be impacted. If most CO_2 accumulates beneath the topseal then the CO_2 will migrate northward then eastward out of the 4D survey area.

Current time-lapse monitoring gives very precise imaging of CO_2 migration beneath both the topseal (e.g. Figure 3-11) and also beneath the 5-metre mudstone. It is clear that substantial amounts of CO_2 are accumulating at both levels. At the current time no wellbores are under threat and CO_2 is not likely to leave the 4D survey area in the near future. Continued time-lapse monitoring will be required however, coupled to updating of predictive models, and an extended baseline dataset may be required at some stage.

3.3.5.3 MIGRATION OF CO_2 OUTSIDE THE SLEIPNER LICENCE

The overall approach to monitoring possible migration of CO_2 out of the Sleipner licence is identical to that adopted for monitoring encroachment onto wellbores – predictive simulation and seismic monitoring.

The edge of the Sleipner licence is 3.3 km to the east of the injection point - nearly 2 km further east than the eastern edge of the current 4D survey area. There appears to be no near-term risk therefore of CO_2 migrating outside of the licence area.

3.3.5.4 Generic public relations issues

Because the Sleipner injection operation is offshore and closely connected with ongoing hydrocarbons production, it does not seem to have attracted much adverse public attention. It is clear however that potentially serious public relations issues can arise suddenly and unexpectedly and monitoring data can be vital for setting minds at rest.

A good example of this was a recent article published in the magazine New Scientist, which suggested that CO_2 injection at Sleipner had triggered a Magnitude 4 earthquake in 2008. The article further suggested that if the earthquake had been much larger there would have been a risk of tsunami. The source for this rumour appears to have been a consultant based in California.

Microseismic monitoring is not carried out Sleipner for a number of reasons, both practical and scientific. There is no suitable monitoring well (to be effective microseismic monitoring really needs to be deployed downhole), the predicted injection-induced pressure increase is far below the level likely to induce geomechanical effects and in situ stresses are similarly low, rendering the site seismically stable. In order to refute the New Scientist article objectively therefore, it was necessary to utilise an external monitoring dataset; namely the ongoing BGS records of world earthquakes (Brian Baptie personal communication). Recorded seismicity data in recent decades for the central and northern North Sea show that the vicinity of Sleipner is seismically rather inactive compared to areas to the west and north (Figure 3-24). More specifically, the period prior to injection (2006) was rather more seismically active than the period afterwards, a consequence of natural variation. Since the year 2000, there have been no earthquakes of >ML3.0 within fifty kilometres of Sleipner (Figure 3-24). These datasets were presented to New Scientist which has since issued a full retraction.

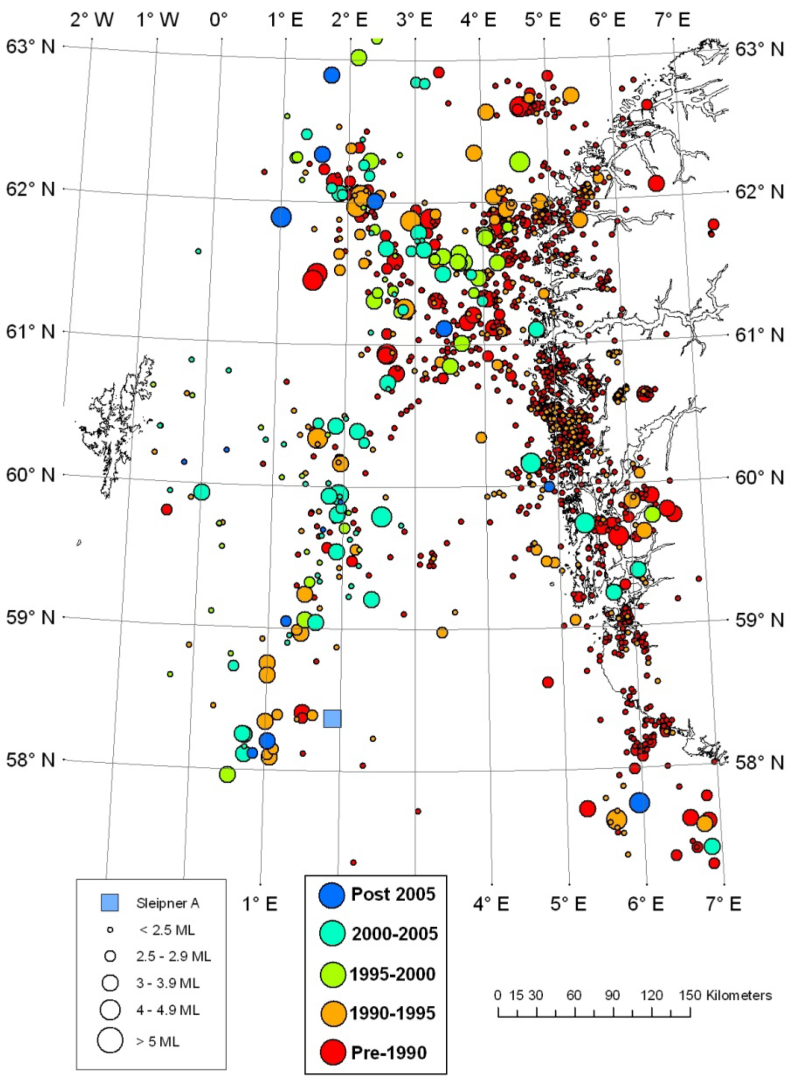

Figure 3-24: Observed seismicity in the central and northern North Sea (Source British Geological Survey).

A key public acceptance issue is leakage integrity. At Sleipner the most effective tool for this, certainly to provide early warning is the surface seismic. However it is likely that, for public acceptance purposes, easily understood tools which provide more familiar information, such as seabed imaging or seabottom videos may well be more valuable.

More generally, an important public acceptance requirement of monitoring is that it can provide convincing evidence that the operator understands how his site is behaving and that predictions of future site behaviour will be robust. At Sleipner the current uncertainty on how the CO_2 is passing through the thin intra-reservoir mudstones is not thought to be relevant in terms of overall storage site performance, but it nevertheless can be seized on by interested parties as demonstrating a level of uncertainty. Thus, media articles by Greenpeace have focussed on this issue to suggest that the storage operation is not well understood and therefore is potentially unsafe. The logical extrapolation by Greenpeace is unreasonable, but it is difficult to counter this type of argument without setting out the full technical case in considerable detail.

To demonstrate a firm understanding of reservoir processes, invasive monitoring, such as would be provided by monitoring wells, is invaluable. A hypothetical well based monitoring programme was designed for Sleipner as part of the SACS project (Carlsen et al., 2001), but has not been implemented. A number of observation well configurations were suggested including into the CO_2 plume and into the adjacent and overlying aquifers (Figure 3-25). It was suggested that resistivity (to monitor saturation), gamma, pressure and temperature and possibly sonic logs and multicomponent seismic would form the main monitoring tools.

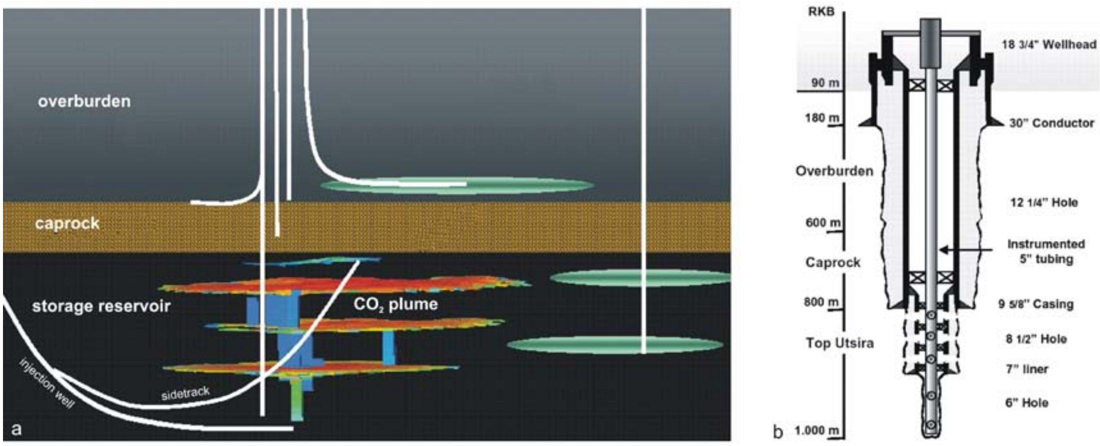

Figure 3-25: Hypothetical proposal for well-based monitoring at Sleipner. Courtesy of SACS project

3.3.6 Overall efficacy of the techniques at Sleipner

3.3.6.1 Seismic

The time-lapse 3D surface seismic methodology has proved to be highly effective at Sleipner. Surface seismic is in any case the most powerful general-purpose subsurface imaging technology currently available, but it is particularly suitable for a case like Sleipner given the shallowness of the Utsira reservoir which, with a top around 800m, is in fact close to the minimum limit for dense-phase storage of CO_2. Shallow reservoirs are generically conducive to high quality seismic imaging for two main reasons. Firstly, thinner overburdens cause relatively little signal attenuation and dispersion. Secondly shallow reservoirs tend to be relatively unconsolidated with high porosity, and a relatively weak rock framework. Replacing pore-water by CO_2 has a relatively large effect in terms of seismic response, giving large changes in reflectivity and velocity pushdown. Also the Utsira reservoir is thick, and the plume is quite tall (around 200 m) which also maximises all of the key seismic quantification attributes (notably total reflectivity and velocity pushdown).

The hi-resolution 2D survey was also notably successful, although the technique is clearly close to its operational limit at Sleipner – the upper part of the plume was very clearly imaged but signal penetration was visibly failing in the deeper parts. This is quite significant from the cost angle, because high resolution 'site-survey' acquisition is much less expensive than conventional 2D acquisition. In terms of quantitative repeatability, one of the high resolution lines was shot twice for the purpose of testing this, but analysis has not been carried out so far.

In general, deeper, thinner and more consolidated reservoirs will have markedly poorer seismic responses for a given amount of injected CO_2. McKenna et al. (2003) give a detailed assessment of the rock physics of various reservoirs over a range of depths and show that seismic response decreases steadily with depth of burial. At the time of writing, time-lapse 2D and 3D datasets have recently been acquired at the Snøhvit storage site. It will be interesting to compare the different seismic responses obtained in the very different conditions at Snøhvit and at Sleipner.

3.3.6.2 Gravity

As with seismic, the shallowness of the Utsira reservoir is an important positive factor in terms of gravimetric monitoring; the strength of the gravity response varying as the inverse square of the depth of the gravity source. In addition, the highest amplitude gravity signal for a given mass deficit is obtained when the mass deficit is concentrated at a point source. Clearly this is not physically realistic, but the properties of the Utsira reservoir act in this direction - the high porosity means that the CO_2 plume occupies a relatively small volumetric envelope and the high reservoir thickness means that the CO_2 plume is relatively thick, giving a larger peak gravity signal than the same amount of CO_2 spread more widely through a thin reservoir. Nevertheless, the gravimetry at Sleipner is still quite marginal, with time-lapse gravity changes close to the detectability limit for the method. Overall, time-lapse gravimetry at Sleipner would have been more effective if a true baseline survey (i.e. pre-injection) had been acquired. Data analysis would also be more effective without the need to take into account the strong time-lapse signature of the deeper producing gas field.

As discussed above, published studies on Sleipner gravimetry have concentrated on density determination, and assume that all of the known injected CO_2 is present as a free phase, with none in solution. This is a significant assumption, because when CO_2 dissolves in the reservoir water it loses much of its gravimetric signature. Given that reservoir temperatures are now seemingly well-constrained (see above), with a likely CO_2 density of around 700 kgm^{-3}, it may be that modelling could be usefully directed at estimating the amount of CO_2 dissolved which is a significant uncertainty in predictive flow simulations.

The changing seabed at Sleipner, due to bottom currents is having a significant effect on the elevations of the permanent concrete benchmarks deployed for the gravity readings. This ultimately limits the repeatability and the measurement sensitivity.

3.3.6.3 Seabottom EM

In principle, the Sleipner plume should be ideally suited to imaging by electrical methods, due to its shallowness, lateral extent and significant thickness. However, acquisition conditions are not ideal due to the shallow water depths (typically around 80 m). In shallow water it is possible for the EM signal to follow a propagation path from the transmitter upwards through the water column to the surface, horizontally through the air (which has a very high resistivity), and back down through the water column to a seafloor receiver. This airwave component can mask the received signal from the subsurface.

3.3.6.4 Seabed imaging

The relatively shallow water depths enables high resolution acoustic images to be obtained, with a resolution of 1 metre or thereabouts. This should enable detection of new morphological features arising from CO_2 leakage at the seabed. A drawback at Sleipner is the changing seabed conditions caused by erosion and deposition of sediment by bottom currents. This may significantly limit the time-lapse capability of the method.

3.3.7 Monitoring programme in context of latest regulatory requirements

3.3.7.1 EU Storage Directive / OSPAR

Although the Sleipner storage project predates, and therefore does not fall within, the recently developed framework of European CCS regulation, it is instructive to assess to what extent the current monitoring programme would address these regulatory requirements.

Monitoring requirements of the European Directive and OSPAR are framed around enabling the operator to understand and to demonstrate understanding of current site processes, to predict future site behaviour and to identify any leakage. Further requirements of the monitoring include early identification of deviations from predicted site behaviour, provision of information needed to carry out remediative actions and the ability to progressively reduce uncertainty. In other words monitoring should effectively underpin the Framework for Risk Assessment and Management (FRAM).

The current monitoring plan at Sleipner largely meets these objectives. In terms of understanding current site processes overall plume development has some uncertainties, notably transport of CO_2 through the thin intra-reservoir mudstones, but in general terms the physics seems to be satisfactorily understood. Migration of the topmost CO_2 layers is crucial to predicting plume development in the medium term, in particular lateral migration of the plume in the upper reservoir. Chadwick & Noy (in press) have shown that mismatches between observed and simulated behaviour are most likely down to small uncertainties in the geological model rather than to misunderstanding of the controlling processes. In terms of leakage, as discussed above, the monitoring systems have limited detection capability, but taken together the monitoring observations and the site characterization data show no indication of any leakage.

Perhaps the most uncertain elements of the current regulations are the arrangements for site closure i.e. transfer of liability from the operator to the State.

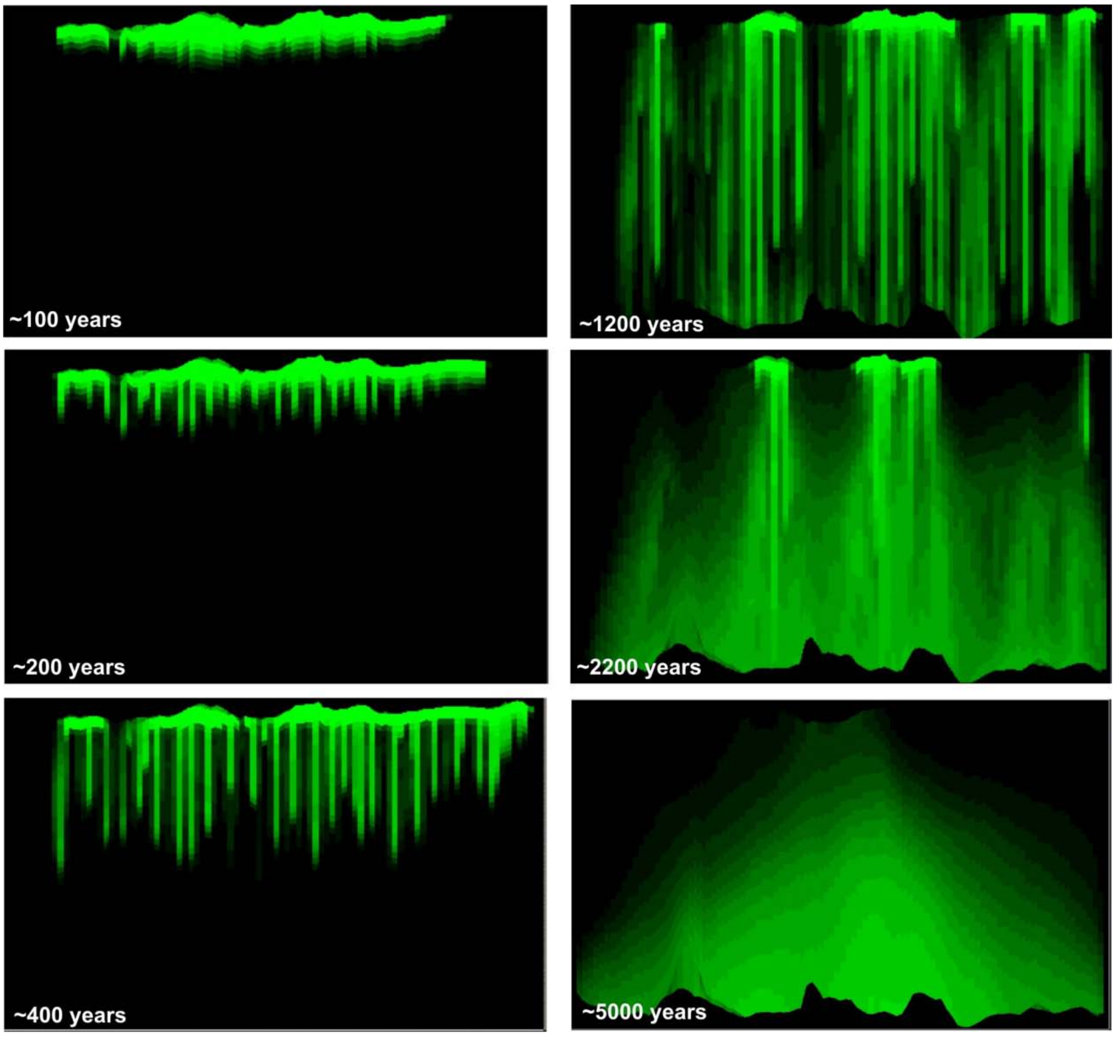

Figure 3-26: Long-term predictive model of the fate of the CO_2 plume at Sleipner showing progressive gravitational stabilization of the plume. Free CO_2 trapped at the reservoir top (~100 years) progressively dissolves and as CO_2 in solution sinks towards the base of the reservoir. After about 5000 years all free CO_2 has dissolved [corrected from CO_2STORE, 2008].

The overall philosophy of the EU Directive is enshrined in the three minimum geological criteria for transfer of liability:

- Observed behaviour of the injected CO_2 is conformable with the modelled behaviour.
- No detectable leakage.

- Site is evolving towards a situation of long-term stability.

The first two bullets have been covered above. The requirement concerning demonstration of long-term stabilization is more challenging and depends almost exclusively on long-term predictive simulation of site behaviour. Post-injection monitoring will of course be a requirement and this can help to establish the path to long-term stabilization, but the ability of short-term monitoring to convincingly support such long-term forecasts will always be limited.

For Sleipner the key stabilization process is dissolution of free CO_2 into the reservoir pore-waters (Figure 3-26). Perhaps the main weakness of the current non-invasive monitoring system (see below) is its inability to detect or calibrate this process, as dissolved CO_2 is invisible on seismic.

3.3.7.2 EMISSIONS ACCOUNTING (E.G. ETS)

The current monitoring system at Sleipner is not directed towards the requirements of emissions accounting which require some form of quantitative assessment of site leakage. In fact, even if Sleipner were operating under the European CCS regulations, there would not currently be a requirement for emission accounting as there is no evidence that the site might be leaking.

3.3.8 Remarks on additional monitoring options

Perhaps the key additional monitoring component which would significantly reduce many aspects of current uncertainty would be a monitoring well. In principle, a well through the plume could dramatically reduce quantitative uncertainty by providing a detailed vertical profile of CO_2 saturations in the plume. Sampling, possibly with core, might also cast light on flow mechanisms through the intra-reservoir mudstones. A major disadvantage of drilling such a well however would be the risk to containment integrity by puncturing the caprock (the current injection well is horizontally emplaced, beneath the CO_2 plume, so does not comprise a containment risk. Another issue is that the full efficacy of a monitoring well cannot now be realised, since downhole baseline (pre-injection) measurements are no longer possible.

More pragmatically, if technically feasible, it may be possible after injection has ceased to provide instrumentation in the injection well for post-injection monitoring. One key monitoring tool might be downhole fluid geochemistry. This would provide some constraints on the amount and/or rate of dissolution from the plume – a key long-term stabilization parameter.

3.4 MILLER

Confidential information on the proposed monitoring plan for Miller was provided by BP to assist the project team with understanding requirements for MMV for such a site. Details of the Miller plan are not therefore included in this report, although some of the learnings from Miller are reflected in the generic plans presented in Chapter 8.

3.5 K12-B

3.5.1 Background to the K12-B storage operation

Two CO_2 injection field tests have been carried out in the nearly depleted K12-B gas field, located in the Dutch sector of the Southern North Sea, some 150 km northwest of Amsterdam (Figure 3-27). K12-B was the first CO_2 injection site in the Netherlands. The first test (from May 2004 to January 2005) consisted of CO_2 injection through a single well (K12-B8) in a depleted reservoir compartment to test the injectivity. The second test (started in February 2005 and still ongoing) comprises injection in a nearly depleted reservoir compartment comprising two gas production wells (K12-B1 & K12-B5) and one CO_2 injection well (K12-B6). For both test phases about 30,000 Nm^3 CO_2 per day is re-injected into the field, corresponding to about 20 ktonnes per year.

Since the start of the CO_2 injection in 2004 an extensive monitoring program has been executed. This section provides an overview of these monitoring activities and their results.

The K12-B gas field has been producing natural gas from 1987 onwards and is currently operated by GDF Suez E&P Nederland B.V. The K12-B structure was proved in 1982 by the K12-6 exploration well. The natural gas contains 13% CO_2 which is removed from the gas stream at the production platform.. The reservoir lies at a depth of approximately 3800 meters below sea level, and the temperature of the reservoir is about 128 ºC. To date, the K12 B field has produced more than 12 billion cubic meters (BCM) of gas, about 90% of the initial gas in place (IGIP). The initial reservoir pressure of 400 bar has dropped to approximately 40 bar.

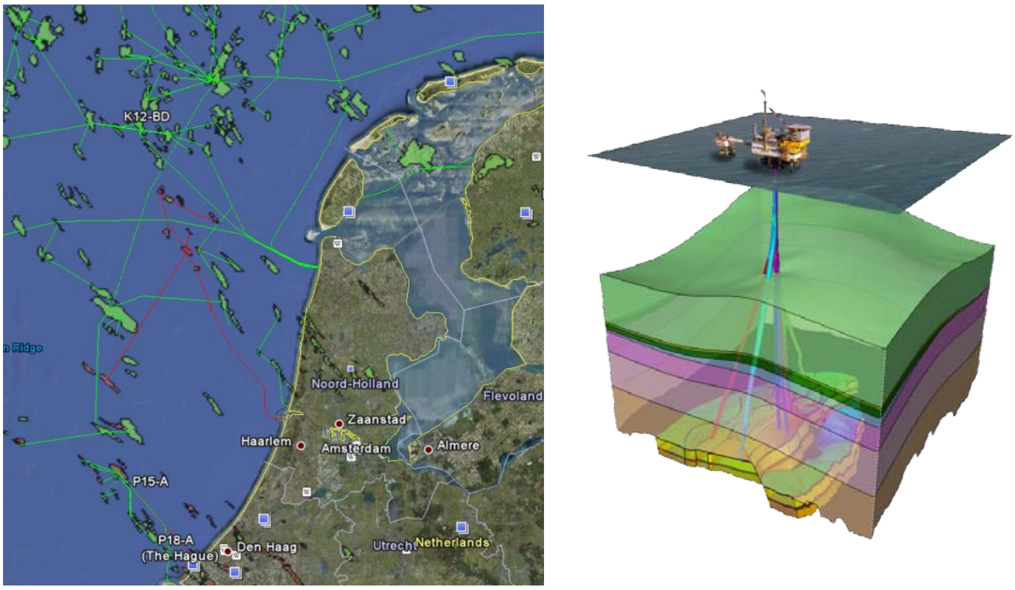

Figure 3-27: Location and 3D impression of the K12-B gas field and the overburden (right: improved after Geel et al., 2005).

3.5.2 Geological Setting

3.5.2.1 INTRODUCTION

K12-B is typical of Dutch gas fields. The reservoir consists of Rotliegend sands of the Slochteren Formation (Van Adrichem Boogaert and Kouwe, 1993, 1994a; Wong et al., 2007) and the seal is made up by thick layers of rock salt from the Zechstein Supergroup (Figure 3-28). At the K12-B location, the Slochteren Formation consists of 2 Members: the Upper Slochteren Member and the Lower Slochteren Member. At K12-B the production of natural gas solely takes place from the Upper Slochteren Member although several wells have been drilled as deep as the Carboniferous.

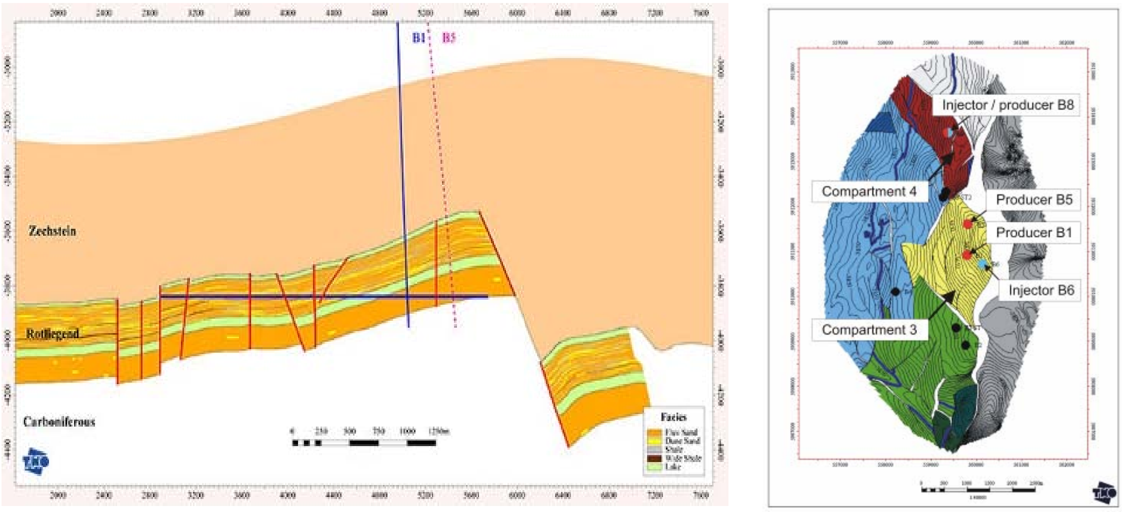

Figure 3-28: East - West profile through the K12-B field. The blue line indicates the gas – water contact and an overview of the compartments and relevant wells of the K12-B field (left: courtesy TNO - Geel et al., 2005, right: courtesy TNO - Vandeweijer et al., 2009).

The Zechstein Supergroup forms the seal, which consists of several hundred meters of halite and other evaporites with possibly some minor intercalations of carbonates and claystones. These deposits are regarded as the best possible seal for any kind of reservoir.

3.5.2.2 SEDIMENTARY FACIES

Geological studies (Hagoort & Associates, 1989; Geel et al., 2005) indicate that the reservoir is highly heterogeneous, as a result of sedimentary, diagenetic, and tectonic processes. Sedimentary heterogeneities include a complex interfingering of high-permeability (300-500 mD) aeolian facies, low permeable fluvial facies (5-30 mD), and several mud-flat facies that act as vertical flow barriers. It is most likely that the several meters thick aeolian sands, which form about 11% of the gross rock volume, will act as conduits for the CO_2. The lateral extent of individual aeolian units is estimated to be no more than a few hundred metres. Shales comprise 16% of the volume and fall into two categories. A minority have a field-wide extent, while most of the shales cannot be correlated between more than two wells, corresponding to a lateral extent of a few hundred meters.

3.5.2.3 DIAGENESIS

Reservoir diagenesis is considered to be the main controlling factor for fluid flow. Its influence is demonstrated in two different ways:

1. A number of diagenetic processes resulted in the formation of authigenic illite, kaolinite, and carbonate cements, which in places effectively block vertical flow through the reservoir. These diagenetic zones seem to be confined to the shales.
2. Permeability and porosity are much lower in the water-bearing zone below the gas column which can be attributed to the presence of diagenetic cement.

3.5.2.4 Faulting

The K12-B field consists of a number of tilted fault blocks which are not or only slightly in pressure communication. All the faults are normal faults with moderate throws (10-100 meters), apart from the main boundary fault which has a throw of 500-900 meters. Most fault zones are completely cemented, as testified by one well that penetrates a fault, and by the hydrostatic pressures encountered in undrained fault compartments. None of the faults extend to the top of the overlying salt seal; the ductile nature of the salt prevents fault propagation within the Zechstein Group.

3.5.2.5 Geocellular model

A 3D geocellular model was derived from the seismic interpretation of the Top Rotliegend and information on well tops from the eight K12-B wells. Well logs for porosity, permeability, and original water saturation were used to populate the geocellular models. 3D reservoir properties were generated to represent the heterogeneities discussed above. In order to retain the heterogeneity, a finely layered model was built with a vertical resolution of 1-2 meters. The 3D geocellular model served as a basis for fluid flow simulations, both for gas production and CO_2 injection.

3.5.2.6 Overburden properties

The top seal Zechstein Group sequence thickens towards the north as a result of structural deformation. One of the objectives of the seal characterization was to distinguish and map the different salt minerals. There are no Zechstein Group cores of the in this area nor any age data. Therefore correlation was purely based on log response. Evaporite lithology was estimated from the gamma-ray and sonic logs to enhance the visual correlation. Based on those two logs, the following lithologies and minerals could be identified with reasonable confidence: shale, halite, dolomite, anhydrite, polyhalite, carnallite, and bischoffite.

The correlation of lithologies within the Zechstein Group could only be made on a simplified scale due to the moderate structural deformation of the salts. Seismic cross-sections demonstrate possible detailed correlation for the lower part and upper part of the Zechstein Group only. This observation is confirmed by the well logs, where the thick halite layer in the middle part of the Zechstein Group could not be subdivided. Therefore the Zechstein Group was divided into three units: Lower, Middle, and Upper. The Lower Unit is dominated by a basal calcareous sequence. The upper part of this sequence is formed by a thick layer of nearly pure rock salt. This halite layer thickens from 75 meters in the south-western part of the field to more than 450 meters in the northeast. The top of the Lower Unit can be recognized by a sharp transition to a unit with alternating clays, halite and carnallite. This Middle Unit contains carnallite and polyhalite layers having a maximum thickness of 10 meters. Bischoffite is present in thin layers (up to 2 meters thick). The top of the Middle Unit is marked by a pronounced anhydrite layer. The Upper Unit is dominated by rock salt. Carnallite layers occur in the upper part of the unit while in the southern part of the area clay layers are abundant in the lower part.

3.5.3 Risk profile

The K12-B field is a currently producing gas field where the salt seal has trapped the natural gas, with its 13% CO_2 content, for millions of years. Moreover, the current quantities of injected CO_2 are relatively small. Performance assessment has demonstrated that, should migration of CO_2 to shallower strata or even to the surface occur, the most likely migration pathways are along the wellbores penetrating the reservoir. Therefore monitoring of the K12-B CO_2 injection is mainly focussed on the integrity of the wells.

A second goal for the monitoring activities is to gain a better understanding of the behaviour and migration of the CO_2 in the reservoir. Since K12-B is still producing natural gas, while CO_2 injection takes place, this is closely linked with the enhanced gas recovery (EGR) potential of the CO_2 injection. Maintaining pressure in the reservoir through CO_2 injection and sweeping natural gas in the process can increase production and extend the lifetime of the field before watering out. However, early CO_2 breakthrough would lead to uneconomical production. Therefore, the flow and mixing of methane and CO_2 in the reservoir need to be well understood.

In summary the main monitoring aims to be addressed are:

1. Well integrity;
2. Tracking CO_2 migration and gas mixing in the reservoir.

3.5.4 Monitoring Programme at K12-B

Due to different monitoring goals the individual monitoring methods can be divided into two categories. Firstly, methods focussed on well integrity and secondly, methods focussed on the migration of CO_2 in the reservoir. The second goal is linked strongly to the integration of the measurements into reservoir models.

K12-B provides an important example of well integrity monitoring for offshore CO_2 storage. Due to the acidic nature of CO_2 in water, and the uncertainties about the actual down-hole conditions, establishing and monitoring any change in the integrity of the injection well is of great importance. This is done by closely monitoring the integrity of the well and its tubing and by establishing the conditions (pressure and temperature) in the wellbore over its full length.

The monitoring technologies deployed to meet these two principal objectives are as follows:

Well integrity:

1. Multi-finger imaging tools
2. Electromagnetic imaging tool
3. Cement bond log
4. Down hole video log
5. Pressure and temperature gradient profiling

Migration of the CO_2 in the reservoir:

1. Chemical tracers
2. Production gas analysis
3. Injection gas analysis
4. Production logging
5. Production water analysis
6. Pressure fall off measurements

3.5.5 Results of the monitoring programme, assessment of efficacy

In this section a description is given of the individual monitoring tools adopted in the K12-B field, and an assessment is made of the efficacy of the tools.

A general overview of when each tool or techniques was applied is given in Table 3-3.

Table 3-3: Overview of applied monitoring tools and techniques.

1.	Multi finger imaging tools	2005, 2006, 2007, 2009
2.	Electromagnetic imaging tool	2009
3.	Cement bond log	2007 (Failed)
4.	Down hole video log	2007
5.	Pressure and temperature gradient profiling	2004, 2005, 2007
6.	Chemical tracers	From 2005 and onwards
7.	Production gas analysis	From 2005 and onwards
8.	Injection gas analysis	2004, 2005, 2007
9.	Production logging	2005, 2007 (Failed partially)
10	Production water analyses	2005, 2007
11.	Pressure fall off measurements	2004, 2005, 2007

3.5.5.1 MULTI-FINGER IMAGING TOOLS

Since the start of the CO_2 injection in early 2005 in the multi well compartment (compartment 3), time lapse pipe integrity surveys have been performed. The goal of these surveys was to image and monitor the inner tubing of well K12-B6 during prolonged exposure to CO_2. A breach in the tubing would allow CO_2 into the annulus, where it could find its way up through the wellbore and eventually even migrate into shallower formations.

Multi-finger imaging tools, like the Kinley Caliper and the PSP (Production Services Platform) Multi-finger Imaging Tool (PMIT), provide high resolution multiple internal tubing radii measurements using mechanical callipers (Figure 3-29).

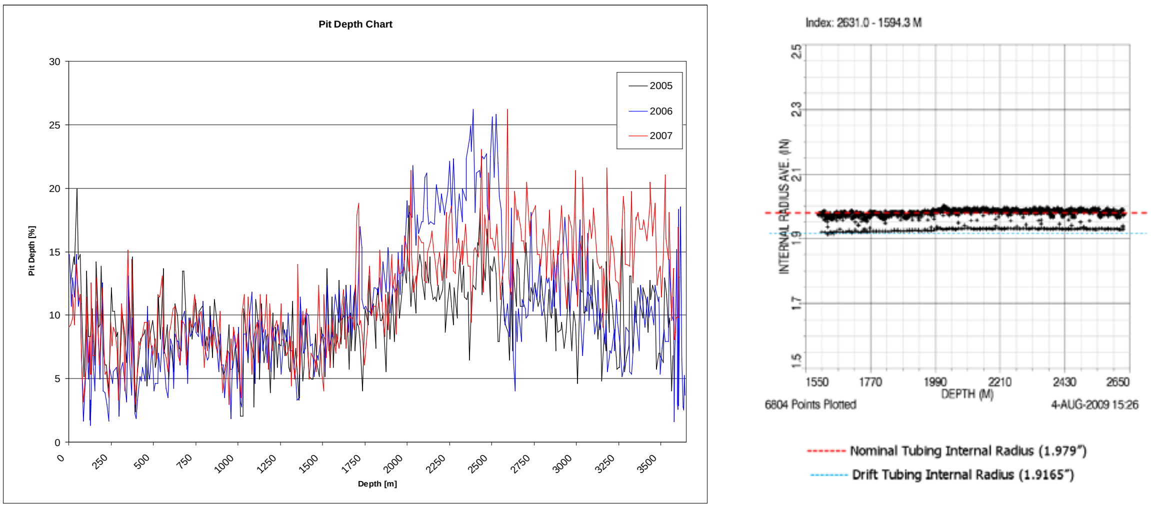

Figure 3-29: Right: PMIT measurements showing the internal radius average versus depth. Left: earlier multi finger caliper results displaying the measured pit depth versus depth (Left: improved after Vanderweijer et al., 2009, right: courtesy CO_2ReMoVe project).

Even though the injected CO_2 is known from gas compositional analyses to be very dry, and thus should not be corrosive, some serious changes were witnessed on the first time lapse run in 2006.

A further time lapse run could not directly confirm possible ongoing corrosion, hence in combination with the results from a downhole video log, an electromagnetic imaging tool was run.

3.5.5.2 ELECTROMAGNETIC IMAGING TOOL

An electromagnetic imaging tool, like the EMIT, measures and maps the inner pipe diameter and the total thickness of all concentric pipes. An EMIT was used by mid 2009 to image the pipe integrity of the K12-B6 well (Figure 3-30). The EMIT was used because of the severe scaling (mineral precipitation dating from the time the K12-B6 well was a gas producing well) hampered the interpretation of the tubing integrity based solely on the results of multi finger imaging tools. The magnetic energy used by the EMIT is insensitive to most of the common minerals precipitated in wellbores. Therefore it is well suited to image the pipe integrity through thick layers of scaling.

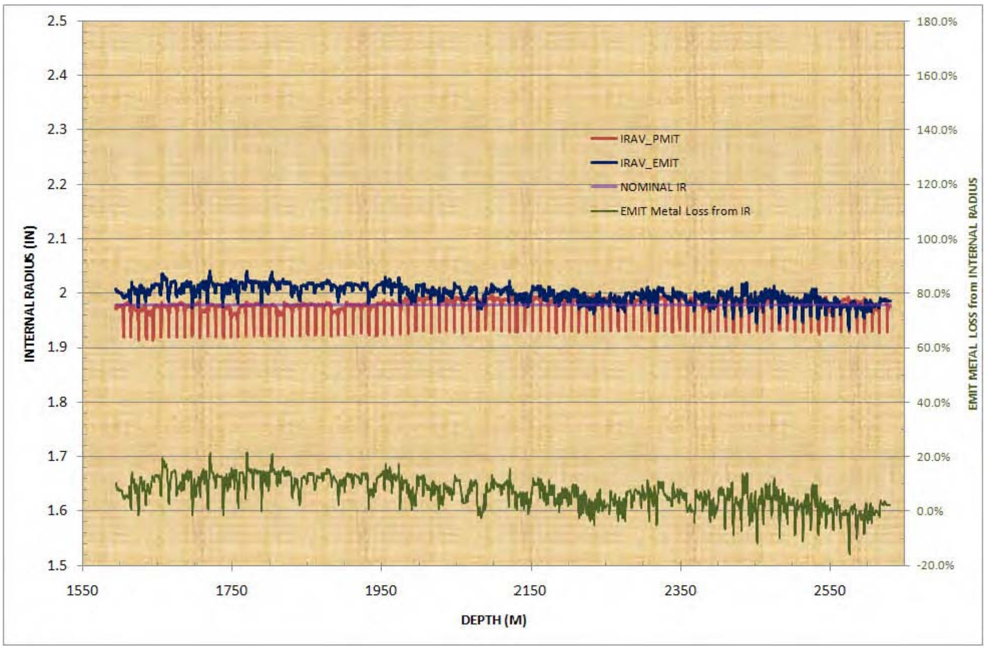

Figure 3-30: EMIT and PMIT results showing the internal radii and the metal loss deducted from the internal radius measurements of the EMIT (image courtesy CO_2ReMoVe project).

Contrary to the slightly erratic readings from the earlier multi finger imaging tools the EMIT results showed a very consistent pipe integrity over the measured interval, without any alarming values. The current plan provides for further usage of the EMIT in order to create a time-lapse series of measurements.

3.5.5.3 GAMMA RAY

Together with the EMIT and PMIT tools a gamma ray tool was lowered. This tool has produced data on the radioactive properties of material (probably scaling) present in the well bore of well K12-B6 (Figure 3-31).

These measurements, although not directly linked to well integrity, provide insight in the mineral composition of the scale and the overall state of the inner tubing.

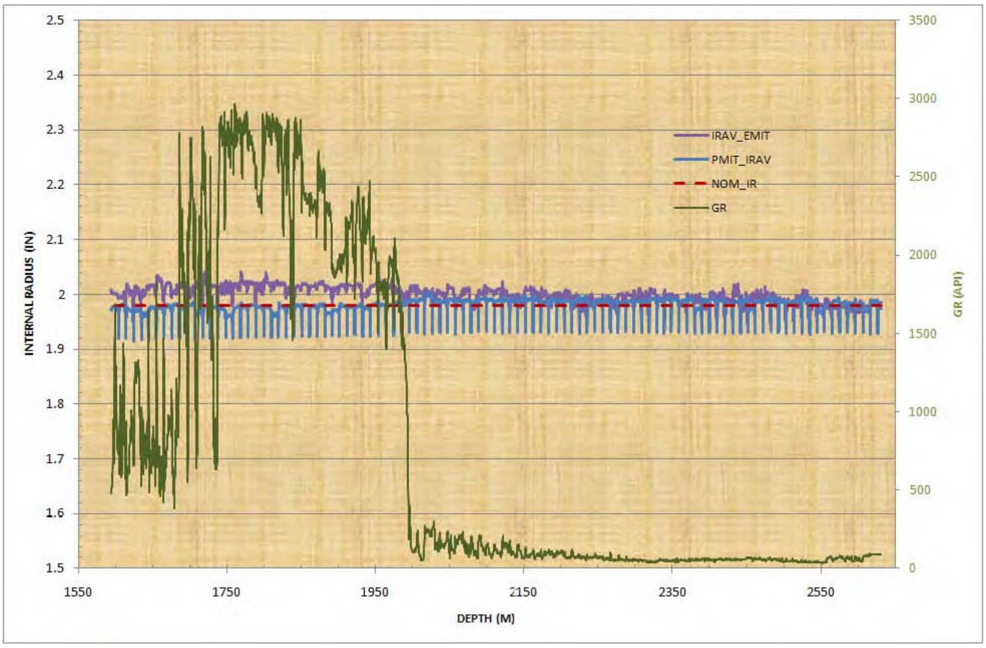

Figure 3-31: EMIT and PMIT results showing the internal radii and the results of the Gamma Ray. Note the extremely high gamma ray values between 1600 and 2000 m (image courtesy CO_2ReMoVe project)

The measurements indicate the presence of more radioactive material between 1600 and 2000m. This is much shallower than the interval where the video log observed scaling preventing certain logging activities (see next paragraph).

3.5.5.4 Cement Bond Log

Sonic bond tools or cement bond tools transmit a signal through the well to the casing and formation and then measure the magnitude and transit time of the refracted signal. The strength and transit time of the refracted signals provide information about the bond between the casing and the cement, the density of the cement, and the bond between the cement and the formation (Duguid and Tombari, 2007).

The wells at K12-B use Portland cement to bond the casing to the surrounding rock. In order to inspect the cement condition of the CO_2 injection well K12-B6, a cement bond log was planned. However, a downhole obstruction prevented the log from being completed successfully The obstruction will possibly be removed in the future enabling the execution of a successful CBL.

3.5.5.5 Downhole video log

The downhole video log (DHV log) was used to image the nature of the obstruction met by the cement bond tool. An obstruction can have several causes, e.g. a deformation of the pipe, debris or the result of accreted scale.

During the 2nd half of 2008 the DHV log imaged the obstruction which stopped the cement bond tool (and in the future other tools) being lowered down to reservoir level. The obstruction in well K12-B has been interpreted as accreted scale (Figure 3-32).

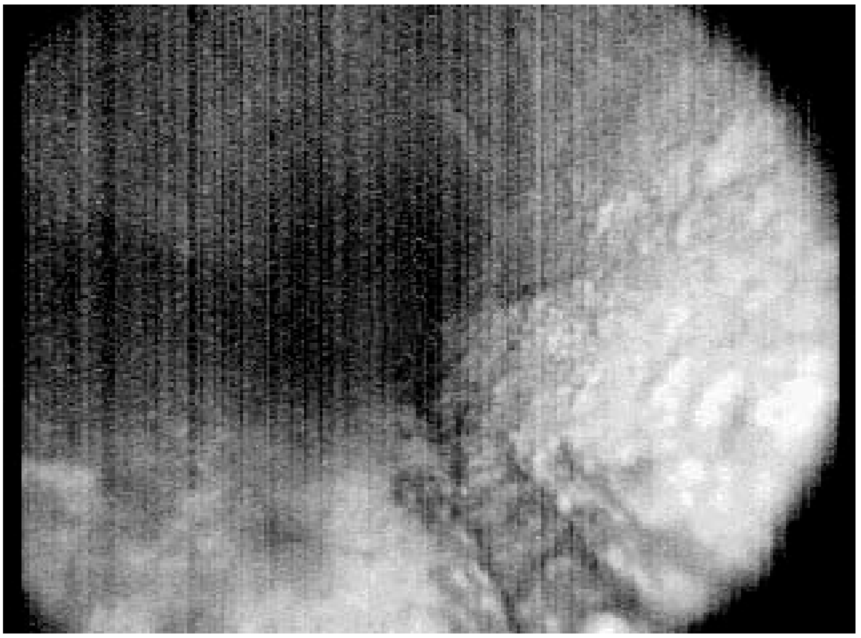

Figure 3-32: DHV image from K12-B6 at approximately 3700 m depth (AH WLM). Bright, cloudy structured scale on the liner walls is clearly visible. The straight feature in the scale is probably a drag mark of centralizer arms of logging tools (courtesy TNO/GDF Suez - Vandeweijer et al., 2008).

3.5.5.6 Pressure and temperature gradient profiling

Pressure and temperature was measured along the well with the aim of assisting in the evaluation of CO_2 phase behaviour during injection and to validate PVT tables used in reservoir modelling. Both pressure and temperature are being measured at various locations (Figure 3-33):

1. At the outlet of the compressor,
2. At the wellhead,
3. Along the well trajectory and
4. At reservoir depth.

These measurements provide a thorough insight into the phase behaviour of the CO_2 in the wellbore and in the reservoir, and markedly improve the reservoir simulation results. Furthermore these measurements give information about the gas-water contact (GWC) and aquifer drive, similarly contributing to an improved reservoir simulation model.

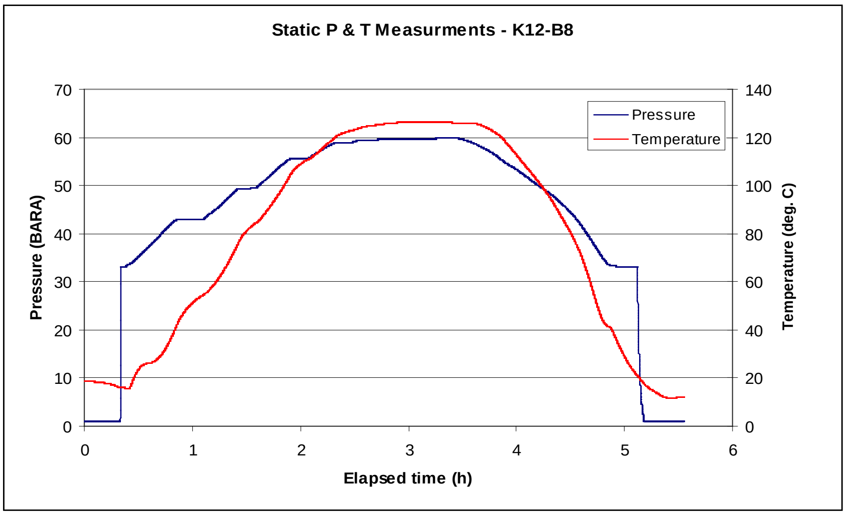

Figure 3-33: Static pressure gradient and temperature measurements of the K12-B8 well. This well was used as a CO_2 injection well during a test in 2004 (courtesy TNO/GDF Suez - Vandeweijer et al., 2008).

3.5.5.7 CHEMICAL TRACERS

Since the injected CO_2 originates from the same reservoir into which it is being re-injected, tracers added to the re-injected CO_2 stream enabled the investigation of the migration and the EGR potential of the reservoir, the partitioning behaviour of the CO_2 and CH_4 and indirectly monitoring the breakthrough of the injected CO_2.

On the 1st of March 2005, 1 kg of two chemical tracers was injected into compartment 3 via well K12-B6. The selected tracers were perfluorocarbons (Figure 3-34):

1. 1,3 Perfluorodimethylcyclo-hexane (1,3 PDMCH)
2. Perfluoromethylcyclopentane (PMCP).

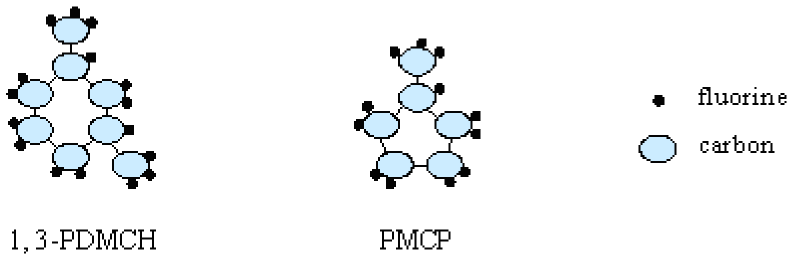

Figure 3-34: Molecular composition of the tracers injected in K12-B6 (courtesy TNO/GDF Suez - Kreft et al., 2006).

Regular sampling took place at the producers: K12-B1 and K12-B5. An objective of the tracer injection was to accurately assess the flow behaviour in the reservoir and the associated sweep efficiency of the injected CO_2. Without the tracers it would be difficult to accurately determine the flow between injector and producers.

Another objective was to establish the rate of migration of the CO_2 compared with that of the methane. These rates may differ significantly. The low injection rates of CO_2 and the corresponding slow flow of the gaseous phase can be expected to allow for some degree of interaction with the aqueous phase (connate water) within the gas cap. As the solubility of CO_2 (mass fraction $\approx$ 0.010) is much higher than the solubility of methane (mass fraction is negligible), this should lead to a stronger interaction of the CO_2 with the connate water in the reservoir, and thus additional retardation of the CO_2 with respect to the methane. Both tracers mentioned are water insoluble and thus follow more closely the behaviour of the methane. If the CO_2 retardation is significant, the tracer front should arrive before that of the injected CO_2 front.

One additional sample was taken from well K12-B3 in order to investigate the sealing capacity of the fault between compartments 3 and 3a, however results are still pending.

Tracer concentration data (Figure 3-35) of both tracers at K12-B1 and K12-B5 show tracer breakthrough after 130 (August 2005) and 463 days (June 2006), respectively. The measurements of the tracers in both producers prove that the injected particles have reached the producers.

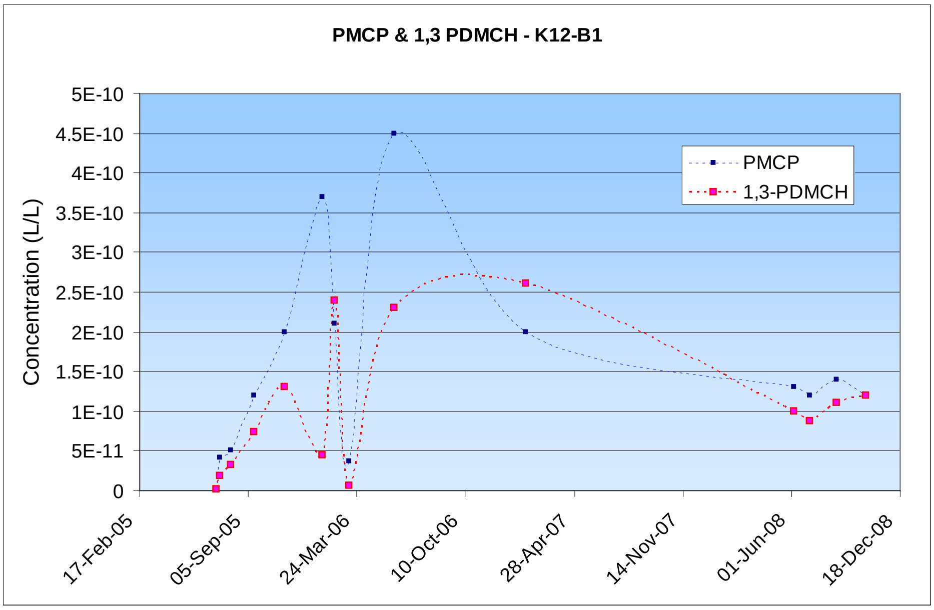

Figure 3-35: Tracer concentrations as a function of time at the B1 well (courtesy TNO/GDF Suez - Vandeweijer et al., 2008).

3.5.5.8 Production gas analysis

Samples were taken at regular intervals from the production gas stream from wells K12-B1 and -B5. The samples were tested for CO_2 concentration in accordance with ISO 6974. The results of these analyses were used to improve understanding of the reservoir dynamics and to evaluate reservoir models (Figure 3-36).

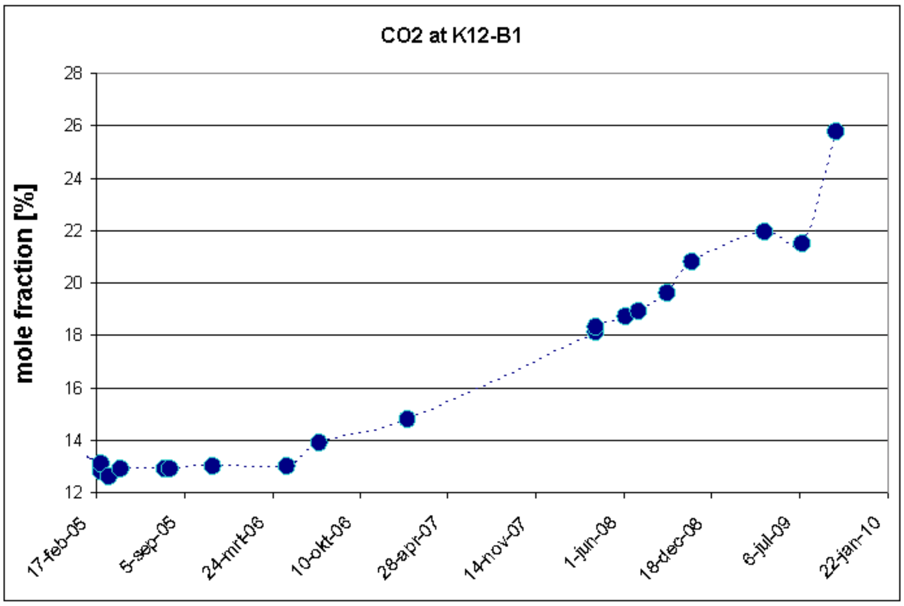

Figure 3-36: CO_2 concentration at the K12-B1 production well. Note the breakthrough mid 2006 and the rather erratic behaviour during 2009 (courtesy TNO).

3.5.5.9 Injection gas analysis

Multiple gas samples have been taken from the gas stream of the injection wells K12-B6 and K12-B8. This was done to assess the composition of the injected gas, which is of importance for the reservoir modelling and the well integrity studies. It consisted mainly of CO_2 (92%) and CH_4 (6%) and traces of some other hydrocarbons, N_2 and O_2. The samples contained little or no water vapour, which if it were present, could make the injected gas very corrosive.

3.5.5.10 Production logging

In order to analyze bottomhole flow conditions during the production of the K12-B wells, a memory production log (MPLT) survey was conducted in January 2008. This survey took place in the K12-B1 and B5 wells. Although the plan was also to log the injection wells (K12-B6 and B8) these wells were not logged due to complications. The B1 and B5 wells posed no problem.

The K12-B1 and B5 wells were produced with minimum flowing well head pressure during the MPLT production period, prior to the actual production run, for 1.0 hrs. The retrieved data again provide input for detailed reservoir studies.

3.5.5.11 Production water analysis

Production water analysis has been performed on samples taken in 2007. Prior to the CO_2 injection, several of these samples were analysed but no consistency in the data was found: the composition of the production water was found to be very variable. This is probably because slugs of water rise irregularly with the gas stream, dissolving and precipitating chemical components on their way up. More recent analysis of the production water did not lead to any new conclusions other than that sampling water at the platform does not give much information about the down-hole conditions.

3.5.5.12 Down hole P and T measurements

Since the start of CO_2 injection the bottomhole pressure in various wells has been monitored with the aid of downhole memory gauges Accurate downhole pressure and temperature data is very important because of the extreme density variations CO_2 can go through during injection. For example at the K12-B6 well the CO_2 is subcritical at the wellhead and becomes supercritical at a depth of about 2,000 meters. Once in the reservoir, due to the lower pressure, the CO_2 becomes subcritical again. These changes go hand in hand with substantial volumetric changes and are critical in order to create accurate reservoir simulations.

3.5.5.13 Pressure fall off measurements

The well bore storage, permeability and skin have been evaluated with the aid of fall off measurements. For well K12-B8 fall off measurements indicated that permeability has remained unchanged, that the skin factor has decreased and that well bore storage appears to be small.

Pressure fall off measurements have shown that CO_2 injection at K12-B does not cause problems related to changing reservoir permeability, increasing skin factors or extreme well bore storage.

3.5.5.14 Well head production and injection measurements

Basic data on the well head temperature, pressure and flow rate of the producing and injecting wells are required for any simulation. These data can be acquired easily by the operator. Sometimes, for example due to incorrect allocation schemes, inconsistencies can be created in these data. Due to the accurate reservoir models created for K12-B these inconsistencies showed up quite regularly, which complicated simulations. In the end, simulation models were used as a tool for checking the quality of the production and injection data (Figure 3-37), after which specific corrections to the data could be made. An example of this is the situation where the well head pressure is high, indicating that a well has been shut-in, although the flow rates still indicate a certain amount of flow.

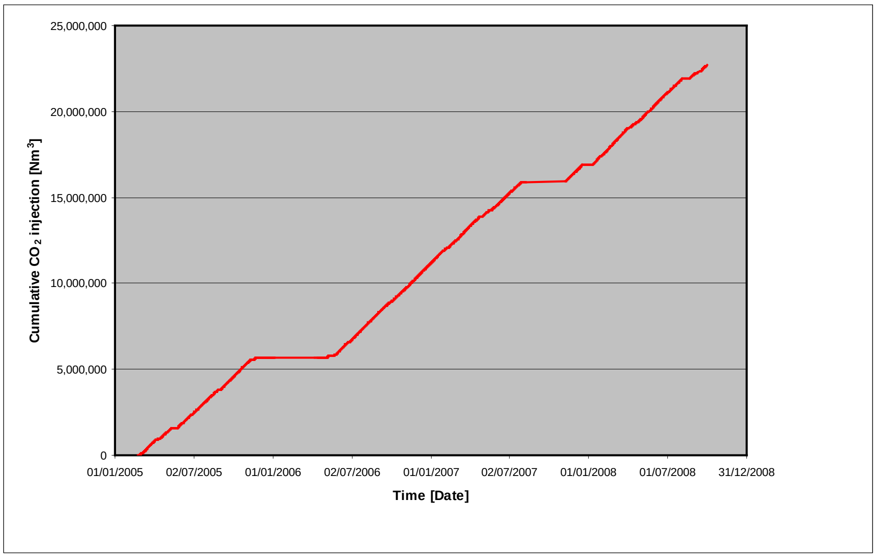

Figure 3-37: Cumulative CO_2 injection as function of time (courtesy TNO/GDF Suez - Vanderweijer et al., 2008).

3.5.6 Comparison of the monitoring programme with IEAGHG monitoring selection tool

The main discrepancy between the proposed monitoring plan described above and the outcome of using the IEA-GHG monitoring selection tool is the application of time-lapse seismic monitoring. The main goals of the time-lapse monitoring would be imaging of CO_2 migration in the reservoir and the possible migration of CO_2 to shallower strata.

At K12-B, imaging and detecting CO_2 saturation distributions from time-lapse seismic data within the gas reservoir is considered to be impossible. The difference in impedance between gas saturated and CO_2 saturated reservoir rock at such large depths is simply too small to detect.

In addition, taking into consideration the extremely good seal over the reservoir, proven by the fact that it has captured the natural gas with its high CO_2 content for millions of years, and the relatively small amounts of CO_2 injected in the reservoir, the chances of leakage through the seal are believed to be minimal.

The main risk factor considered for K12-B is leakage through the wells caused by a deterioration of the cement or steel casing. Therefore the monitoring program is largely focussed on detecting any possible deterioration in the wells. Because of the relatively small amounts of CO_2 injected the risks are considered small. However, the monitoring does give information on possible rates of deterioration. These rates are useful for upscaling the experiment for the injection of larger quantities of CO_2.

Pragmatically, 3D seismic datasets already cover the K12-B field and could be considered as reasonable pre-existing baseline datasets. In the unlikely event that migration through the overburden were detected (e.g. by pressure monitoring in the reservoir), repeat seismic datasets could be acquired in the future if deemed necessary.

Since the K12-B field has produced gas for 20 years now, a reservoir simulation model with an excellent history match was available from the start. The tracers allow an accurate assessment of the CO_2 flow behaviour in the reservoir and the associated sweep efficiency of the injected CO_2. Without the tracers it would be difficult to accurately determine the physical communication between injector and producers because the injected CO_2 originates from the reservoir gas and therefore cannot be chemically distinguished from the naturally occurring CO_2 in the reservoir.

Microseismic monitoring is not included in the current monitoring programme. In view of the relatively small amounts of CO_2 injected this seems reasonable. If the experiment were to be upscaled to larger quantities and a longer injection period the pressure increase in the reservoir might give rise to detectable events. In that case microseismic monitoring should be considered.

3.5.7 Monitoring programme in context of latest regulatory requirements

3.5.7.1 EU Storage Directive / OSPAR

Although the K12-B storage project predates and therefore does not fall within the recently developed framework of European CCS regulation, it is instructive to assess to what extent the current monitoring programme would address these regulatory requirements.

Monitoring requirements of the European Directive and OSPAR are framed around enabling the operator to understand and to demonstrate understanding of current site processes, to predict future site behaviour and to identify any leakage. Further requirements of the monitoring include early identification of deviations from predicted site behaviour, provision of information needed to carry out remediative actions and the ability to progressively reduce uncertainty. In other words monitoring should effectively underpin the Framework for Risk Assessment and Management (FRAM).

With respect to understanding current site processes and predict future site behaviour, different reservoir models have been created each with a particular focus such as CO_2 flow in the reservoir, breakthrough at the wells and chemical reactions particularly in the near wellbore area. A more detailed overview of the different models is given below. The main conclusions so far are that pressure behaviour is matching quite accurately the simulation results. For K12-B pressure monitoring in the reservoir is considered the key monitoring technology. The fact that the cap rock consists of salt, that has retained CO_2 and is the best possible seal because of its plastic behaviour, leads to the belief that migration out of the primary reservoir through the cap rock could only occur through faults (not likely) or along wells. If migration through the cap rock occurred, this would be picked up by a deviation from the expected pressure in the reservoir. For the current demonstration project with relatively small amounts of CO_2 injected, this would not be easy to detect. However, for larger injection volumes, the difference could be picked up, although a quantitative analysis has not been carried out so far.

The latest models suggest that there might be some communication between different compartments of the K12-B reservoir. With respect to tracking the plume in the reservoir this needs to be further analysed by matching the pressure observations in different compartments with the overall model of the reservoir. Migration out of the primary reservoir is not expected due to the excellent sealing properties of the cap rock..

Demonstration of the long term fate of the CO_2 is currently based on experiments on core data, on analogue reservoirs containing higher concentrations of CO_2 and on long term simulations calibrated to the short term models. The most important conclusion is that the CO_2 will remain in the reservoir. More detailed modelling of the long term fate in terms of dissolution and mineralisation are part of ongoing work. Preliminary conclusions show that these effects are minor due to the low water saturations and the low reactivity with the reservoir rock.

For site abandonment and transfer of liability the main issues foreseen are the abandonment of the wells and monitoring after injection has stopped. As for the operational period, in the post-injection phase monitoring will consist of well integrity logging and pressure monitoring as long as the wells are open.. If the quantities of injected CO_2 were to increase significantly, seismic data acquisition (2D or 3D) might be required at the end of injection to “prove” the absence of migration outside the primary reservoir and to create a baseline before the abandonment phase. However, as long as pressure monitoring does not indicate any irregularities it is unlikely that seismic data would be required.

Abandonment of the wells at K12-B could potentially be done by using the salt itself as seal (milling out the well in the cap rock section and letting the salt “flow in”). A decision on this approach, or the alternative more traditional plugging or pancake plugs, has yet to be taken. If technically feasible, pressure (and possibly pH) monitoring and sampling above the plugged section should be carried out for a few years, until the plug has demonstrated its integrity. Shallow monitoring at the well head using acoustic and in situ gas measurements or sampling techniques can then potentially be applied in the years after abandonment. Again, the latter becomes more important if the experiment was upscaled or any irregularities in pressure behaviour were observed.

In summary, considering the overall philosophy of the EU Directive enshrined in the three minimum geological criteria for transfer of liability:

- Observed behaviour of the injected CO_2 is conformable with the modelled behaviour.
- No detectable leakage.
- Site is evolving towards a situation of long-term stability.

One can say that these three conditions can be fulfilled mainly by monitoring pressure in the reservoir.

A more detailed discussion on the different flow models currently developed for K12-B follows.

3.5.7.2 3D Geochemical flow model

A 3D simulation of fluid flow and geochemical reactivity during CO_2 injection was performed in TOUGH2, a multiphase fluid and heat flow simulator developed by the Lawrence Berkeley National Laboratory. For geochemical reactivity simulations, the TOUGHREACT module was used and for simulating the dissolution and structural trapping of CO_2 injection the TOUGH2/EOS7C module was used (BRGM, 2006).

Results

The initial 13% of CO_2 in the reservoir has created a geochemical equilibrium between the CO_2 and the present mineral composition. The results of the simulations show that because of this equilibrium CO_2 injection will not have much effect on the mineralogy and porosity of the reservoir. Only minor pH variations are observed both in reservoir and cap rock (Figure 3-38). Mineral reactivity is also minor and occurs mainly at the water gas contact. Dry out is observed around the injector well inducing anhydrite precipitation in association with dissolution of some carbonates. Further results show relatively short CO_2 breakthrough times for the two producers (K12-B1 60 days and B5 one year) and a linear increase of reservoir pressure from about 47 bar to 104 bar.

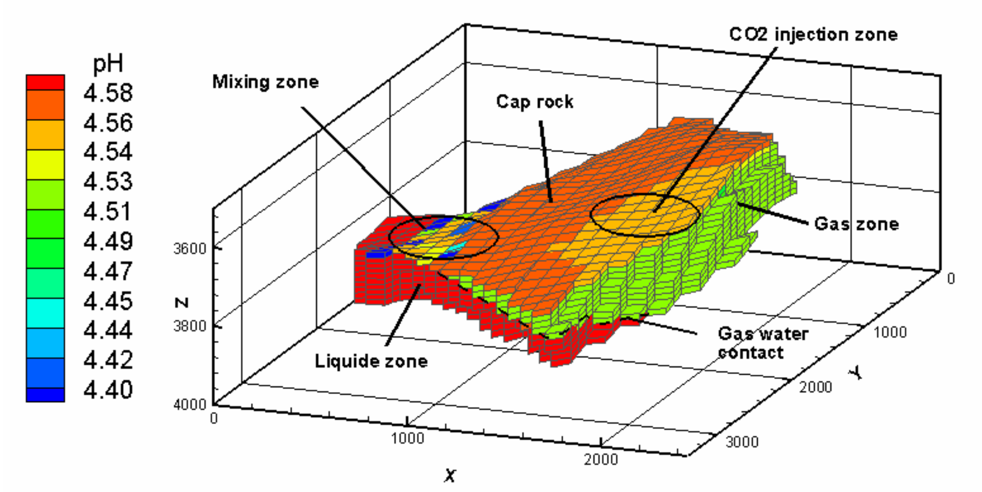

Figure 3-38: pH values at the end of the injection for the case A. Four zones are distinguished: (i) the liquid phase saturated part (below the gas water contact), (ii) the gaseous part of the field, (iii) the cap rock and (iv) a small region located at the gas water contact area in the cap rock, with average pH values of 4.58, 4.51, 4.55 and 4.0, respectively (image from Audigane et al., 2006, ©AAPG 2006. Reprinted by permission of the American Association of Petroleum Geologists whose permission is required for further use).
N.B. This diagram may be re-used by ETI in a summary report but should not otherwise be reproduced without separate permission from AAPG

3.5.7.3 SIMED II FLOW MODEL FOR COMPARTMENT 4

The Dutch ORC (Offshore Re-injection of CO_2) project comprised two injection tests at different locations in the K12-B reservoir. The first test in 2004 comprised CO_2 injection, using well K12-B8, into the depleted single-well compartment: compartment 4.

For the purpose of history matching, the apparent volume of gas-in-place was considered to be located in three sub-compartments, separated by flow barriers. Once the gas pressure difference across a flow barrier had reached a sufficient level, the gas would break through and an additional volume of gas would become connected to the production well. The barriers are thought to be either internal faults or horizontal shale layers.

Results

From the reservoir engineering work the following conclusions can be drawn with respect to analysis and verification of the observed data:

1. The permeability of the reservoir is not affected by injection of CO_2.
2. The observed CO_2 phase behaviour and reservoir response fell within the expected range.
3. Reservoir response and CO_2 phase behaviour can be predicted with the aid of existing theoretical correlations and software applications.

Later in 2008 this model was updated during a reproduction test to investigate the mixing of CO_2.

Results of this test showed that the production rate and the variation in CO_2 concentration of the produced gas, corroborates model predictions, which indicate that CO_2 plumes can persist for a long time. Although CH_4 and CO_2 are fully miscible, instant mixing does not seem to occur and gravity segregation seems an important factor when it comes to CO_2 injection (BRGM 2006).

3.5.7.4 SIMED II FLOW MODEL FOR COMPARTMENT 3

As already mentioned, the ORC project comprised two injection tests at different locations in the K12-B reservoir: The SIMED II flow model for compartment 3 initially provided evaluations related to the 2nd test of the ORC project (Kreft et al., 2006). Later this model was updated in the follow-up project (Vandeweijer et al, 2008) and under a monitoring program funded by the CO_2ReMoVe consortium. The model comprises compartment 3 including the 3 wells, K12-B1, B5 and B6 (Figure 3-39). During this test, which commenced in February 2005 and is still ongoing, the CO_2 is injected in the supercritical phase using well K12-B6.

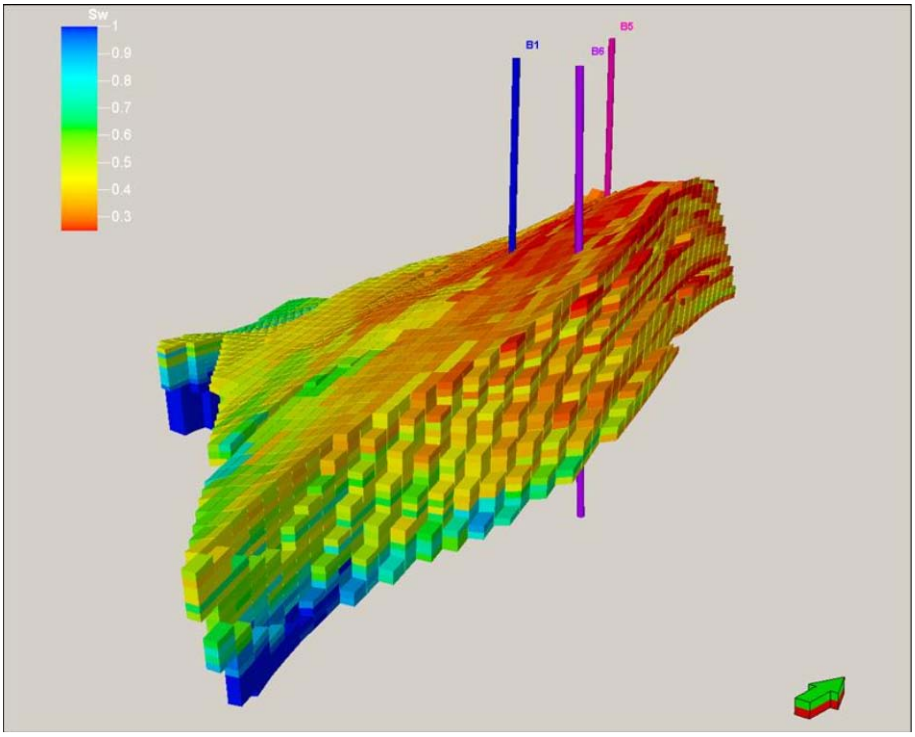

Figure 3-39: Initial water saturation of the reservoir simulation model (image taken from Van Der Meer et al., 2006, CASTOR project WP3.3.3)

The SIMED II model for compartment 3 shows an excellent pressure match for all three wells. The pressure response to rapid rate changes was closely modelled with changes in local or relative permeabilities. More local effects such as the amplitude between static and flowing bottomhole pressures were matched by changes in local permeabilities, well skin factors and water influx (thought to come from below the reservoir).

3.5.7.5 ECLIPSE FLOW MODEL FOR COMPARTMENT 3 AND 3A

For practical reasons during 2008 the need emerged for a new reservoir model. The formerly used reservoir simulation software was an in-house adapted version of SIMED II, which could not be shared. The new reservoir model had to be usable by other parties including GDF Suez, the operator of K12-B. It was decided that for further reservoir modelling work the compositional reservoir simulator ECLIPSE 300 would be used.

The new reservoir model was specifically meant to focus on some anomalies in pressure observed between the injection well K12-B6 and the producers in the same compartment (K12 B1 and B5) and the breakthrough times of the chemical tracers in the production wells. Moreover, this new reservoir model incorporates both compartment 3 and 3a (Figure 3-40). These two compartments were initially thought to be more or less separated by a low permeability zone (a fault) (Geel et al., 2005) but might be in communication with each other after all, as the pressure decrease during the years of production appears identical.

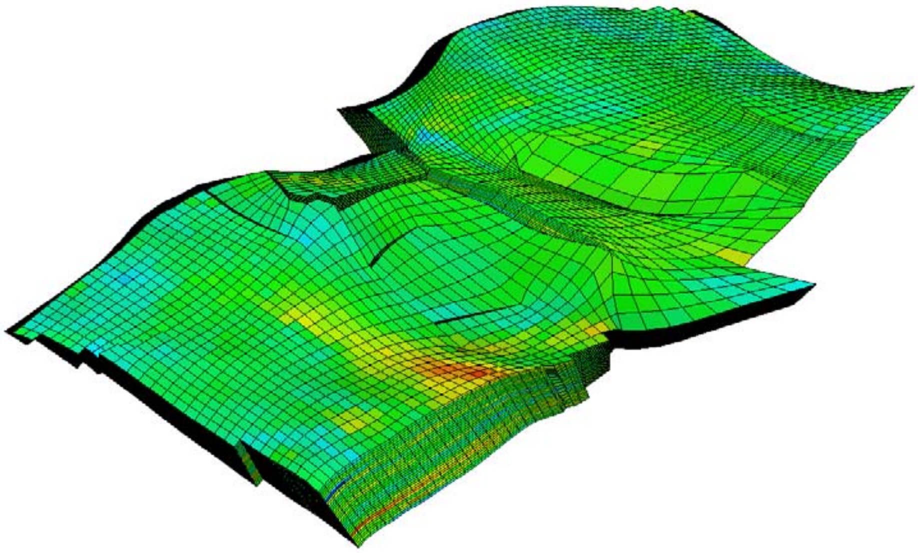

Figure 3-40: 3D reservoir model of compartment 3 and 3a (image courtesy CO2ReMoVe project).

Initial results show that the rate constrained model shows some irregularities similar to those of the SIMED II model. These irregularities consist of inaccurate breakthrough times for the CO_2 at the production wells and some mismatches with the observed downhole pressures for the injection and the production wells. Further analysis and updating is currently ongoing.

In summary, the K12-B monitoring plan is focussed on two objectives: well integrity and the potential of CO_2 injection for EGR. The proposed monitoring strategy seems adequate to fulfil both goals.

3.5.7.6 Emissions accounting (e.g. ETS)

The current monitoring system at K12-B is not directed towards the requirements of emissions accounting, which require some form of quantitative assessment of site leakage. In fact, even if K12-B were operating under the European CCS regulations, there would not currently be a requirement for emission accounting as there is no evidence that the site might be leaking.

Nevertheless, suppose that quantification of a leakage became necessary, this would essentially be carried out based on a combination of measurements and models as suggested in the NSBTF (2009) report. Primary estimates would be made by matching the pressure decrease observed in the reservoir to a quantity of escaping CO_2. This method would have a large uncertainty and is highly model based. It will be difficult to discriminate between for example mineralization and dissolution effects, water influx, etc. and migration out of the storage complex. Seismic data can be used to identify migration pathways to the seabed and/or possible capture below secondary seals. In case of observed leakage at the seabed, more detailed in situ measurements and/or sampling campaigns would be carried out to quantify the leakage.

3.5.8 Remarks on additional monitoring options

Perhaps the key additional monitoring component in terms of public confidence would be some form of seabed imaging providing an easy to understand picture of the seabed. In time-lapse mode a demonstrable lack of change is a powerful indicator of seal integrity. Any seabed changes that do occur can be targeted by in situ measurements of gas or a sampling survey to show whether or not CO_2 leakage is involved. The key area for such monitoring would be around the K12-B platform over the two compartments where CO_2 is being injected.

The structure and topography of the sea bottom could be imaged with a multibeam echo sounder and/or side-scan sonar. To obtain a detailed image of the first ten meters of the sea bottom sub-bottom profiler lines are envisaged. These would cover the depth range where core samples can be taken. Finally, high resolution seismic using a sparker or boomer would provide a detailed image of the subsurface down to about 100 metres depth. The aim of this survey would be to link shallow features such as shallow gas pockets or faults to deeper structures observed on the 3D seismic data.

3.6 P18 GAS FIELD

3.6.1 Background to the P18 (& P15) storage operation

Since 1993 high calorific gas has been produced from the P15 and P18 blocks, off the Netherlands. This is done from several platforms, among which the P18-A satellite platform, and the P15-ACD processing and accommodation structure, respectively lie 20 and 40 km NW of Rotterdam (Figure 3-41).

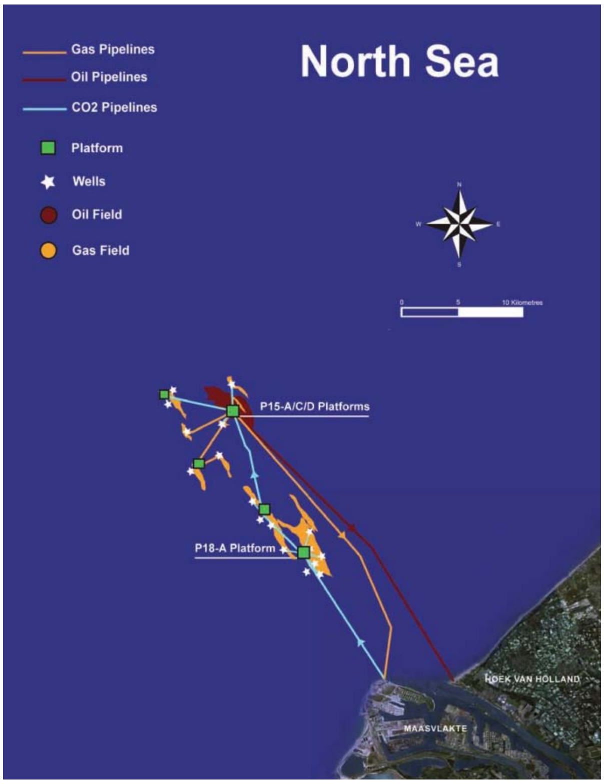

Figure 3-41: Location P15/P18 complex relative to the Dutch shore. Source: CO_2 offshore storage, deep under the Dutch North Sea, (image courtesy TAQA; TAQA, 2009)

The almost depleted gas reservoirs at P15 and P18 are considered suitable for CO_2 storage. They contained large amounts of natural gas under high pressures for millions of years. Furthermore, there is a lot of high quality geological data for these specific structures, to assist in safely storing CO_2. They are relatively close to large CO_2 emitters and are located offshore, which would likely avoid complex permitting procedures.

The CO_2 would be injected into a sandstone formation below impermeable layers of Triassic clay at over 3 km depth.

3.6.1.1 Infrastructure

The P18 installation consists of a 4 legged steel jacket (Figure 3-42). Its primary function is the production and transfer of wet gas to the P15-D processing platform some 20 km further offshore (Figure 3-43).

Figure 3-42: P18-A Satellite platform. (image courtesy TAQA; TAQA, 2009)

The P15-ACD installation comprises two 6 legged steel jackets and one 4 legged steel jacket (Figure 3-43). Their functions are:

P15- A	Well production
P15-C	Oil processing and accommodation
P15-D	Gas and condensate processing, compression and transporting to shore, metering and control

Figure 3-43: P15-ACD Processing & Accommodation Platforms. (Image courtesy TAQA; TAQA, 2009)

3.6.1.2 ROADMAP

Injection of CO_2 in the P18 and P15 fields is planned in several phases:

Phase 1 - From the P18-A platform CO_2 can be injected into several depleted gas reservoirs using multiple injection wells. The combined theoretical storage capacity accessible from this platform amounts to around 41 million tonnes of CO_2. The effective storage capacity will depend on the maximum permitted reservoir pressure.

Phase 2 - After natural gas production ceases from the P18-A platform, the existing pipeline to P15-ACD can be used to transport CO_2 to this central facility from where CO_2 can be distributed to the P15 reservoirs, providing an additional 44 million tonnes of theoretical storage capacity.

Phase 3 - When natural gas throughput ceases completely, the 26 inch pipeline can be turned to CO_2 transport duty. The P15-ACD facility could then be used for many years to boost pressure to transport CO_2 north to other depleted gas reservoirs.

This section will describe phase 1 of the CO_2 storage project.

3.6.2 Geological Setting

3.6.2.1 Structure

The reservoir structures comprise multiple compartments bounded by a system of NW-SE oriented faults forming horst and graben structures. The reservoir rocks are of Triassic age, belonging to the Bunter Sandstone ("Main Buntsandstein Subgroup", Van Adrichem Boogaert and Kouwe, 1994b; Wong et al., 2007) (Figure 3-44), and consist of sandstones intercalated with thin layers of shale. The tops of the compartments lie at depths between 3175 m and 3455 m below sea-level (Figure 3-45).

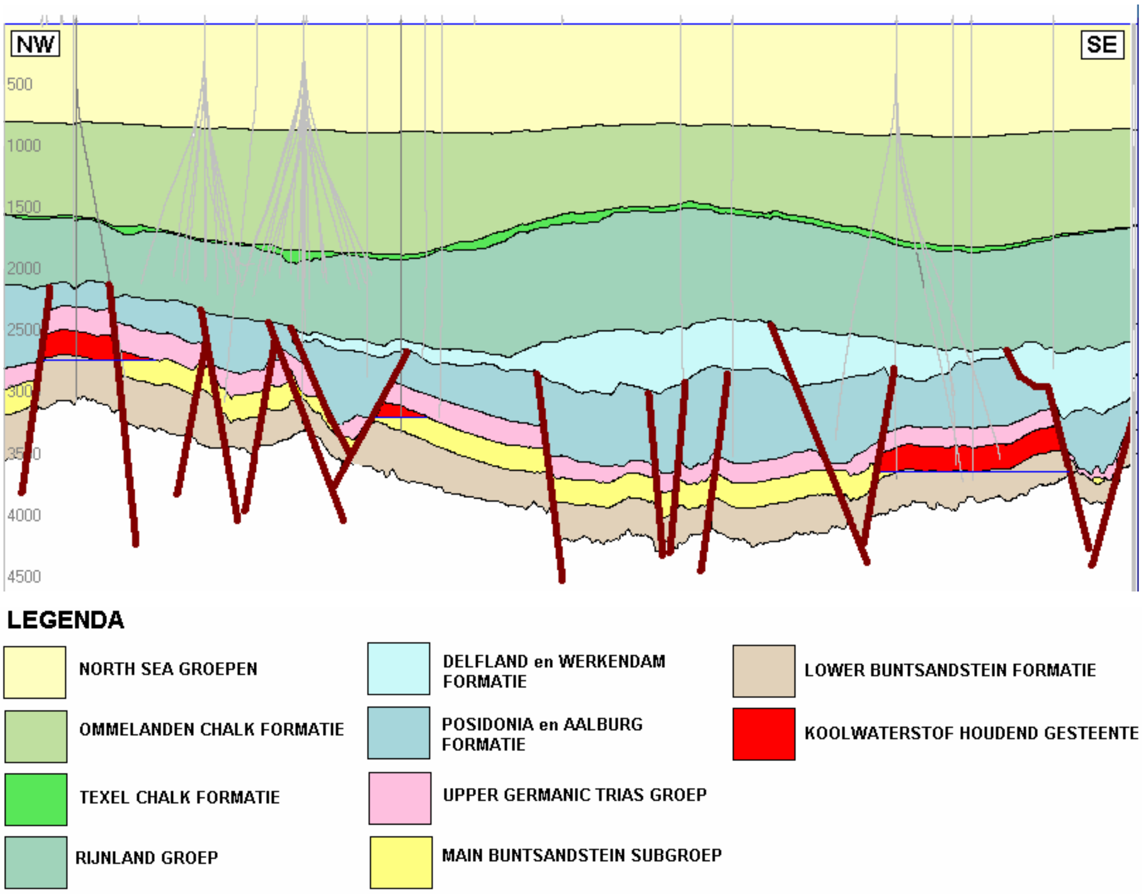

Figure 3-44: Geological cross section of the P15 field, illustrating the stratigraphy and geological setting. Source: Winningsplan P18a, P18c & P15c (courtesy TAQA)

The reservoir rocks were deposited in a typical desert environment with scarce but intense rainfall. The reservoir consists mainly of dune (aeolian) and river (fluvial) sediments. The aeolian sands have the best reservoir properties, comprising clean, well sorted sands with relatively low shale content.

The source rocks for the natural gas, present in the reservoir structures, are the coal layers from the underlying Carboniferous.

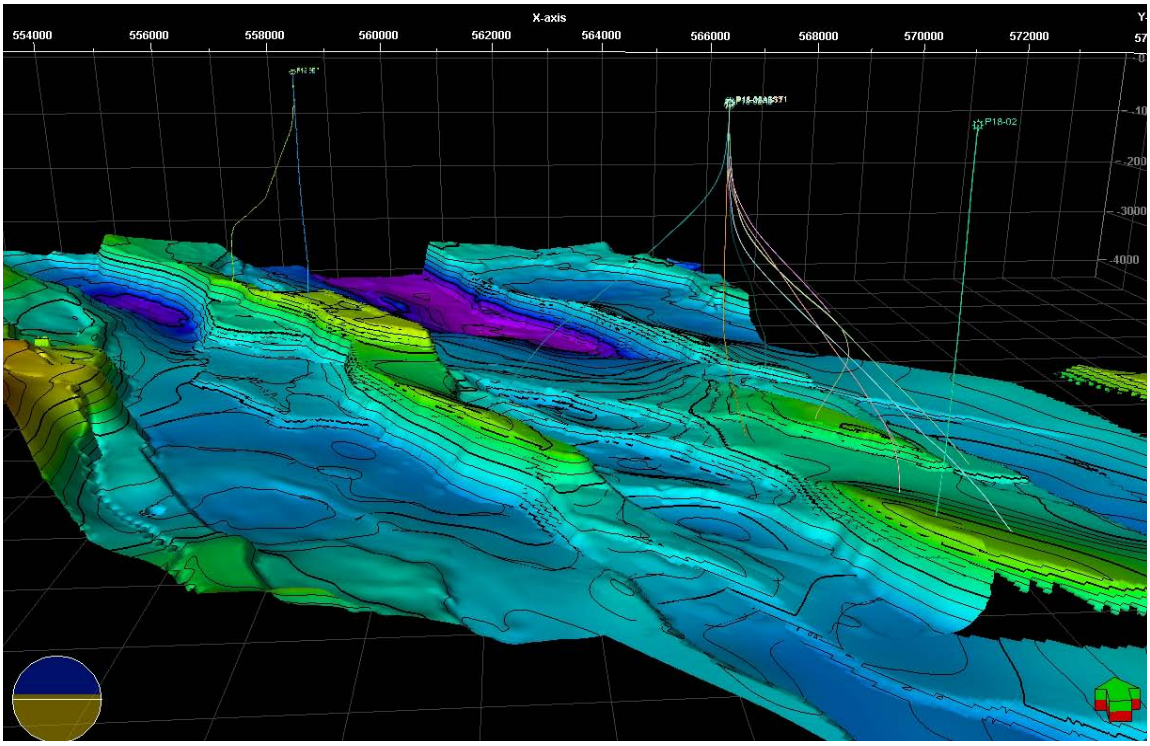

Figure 3-45: 3D view on the top Bunter from a geological model which is still under construction (image courtesy CATO2 project).

3.6.2.2 Reservoir properties

At P18 the Main Buntsandstein Subgroup consists of several units:

- The Hardegsen Fm.
- The Detfurth Fm.
- The Volpriehausen Fm.

Based on well log data the porosity in the Hardegsen Formation varies around 10-12% and in the Deturth Formation it is slightly lower at about 9-11%. Maximum porosities encountered in the clean sandy parts of both formations are around 21 %. The combined thickness of both formations is about 100 m and permeabilities range generally from 0.1 -100 mDarcy. The Volperiehausen has a much lower porosity, around 5%, and also lower permeability. The thickness of the Volperiehausen is around 100 m. Table 3-4 sums up some general data about these formations at P18. The irreducible water content is around 15 to 20 % and the abandonment pressures for the compartments are about 20 to 30 bars.

Table 3-4: General data on Main Buntsandstein Subgroup sandstones at the P18 location.

Formation	Porosity	Thickness
Hardegsen Fm.	10 % – 12 %	100 m (combined thickness)
Detfurth Fm.	9 % - 11 %	
Volpriehausen Fm.	5 %	100 m

For the different reservoir compartments (i.e. P18-2, P18-4 and P18-6) an estimate has been made, based on the gas production history, of the total storage capacity per compartment (Table 3-5).

Table 3-5: General data on the compartments at P18.

Compartment	Initial conditions		CO_2 storage capacity (Mt)	Depleted by	wells
	bar	ºC			
P18-2	355	126	32	2017	3
P18-4	340	117	8	2015	1
P18-6	364	117	1	2015	1

Much of the general information of the P18 field also applies to the P15 gas field (Table 3-6) although depletion dates were not readily available. The geological setting is the same. The platform infrastructure is more complex than that at the P18 location, which is merely a satellite platform.

Table 3-6: General data on the compartments at P15.

Compartment	Initial conditions		CO_2 storage capacity (Mt)	Depleted by	wells
	bar	ºC			
P15-9	347	117	11	?	2
P15-10	272	104	1	?	1
P15-11	283	102	16	?	2
P15-12	301	112	2	?	1
P15-13	288	107	9	?	1
P15-14	334	107	2	?	1
P15-15	318	120	1	?	1
P15-16	290	109	1	?	1

3.6.2.3 OVERBURDEN PROPERTIES

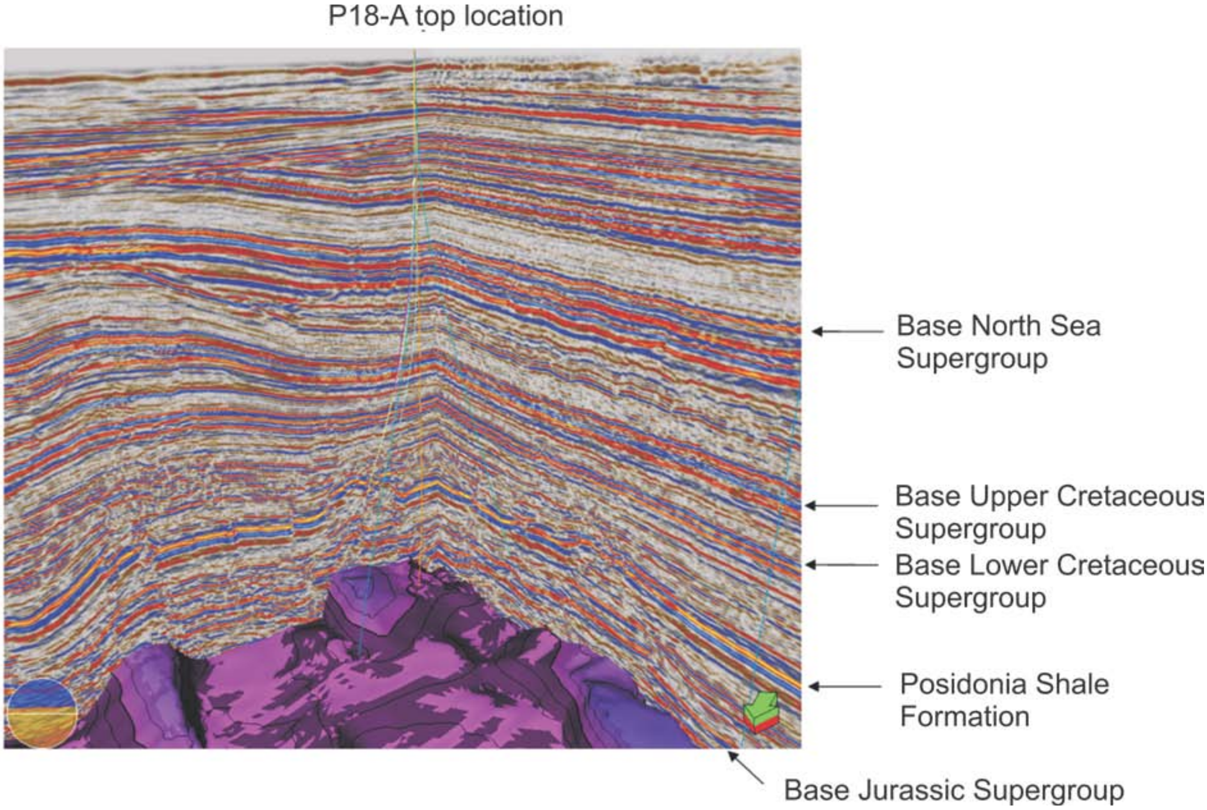

Figure 3-46: Seismic section of the overburden at P18-A. The surface represents the base of the Lower Germanic Trias Group (also base of the reservoir). Note the fractured nature of the Triassic and Jurassic sediments (up to the Posidonia Shale Formation) and the continuity of the Lower Cretaceous and younger sediments (courtesy CATO2 project)

The overburden at P18-A is formed by several geological formations. The North Sea Supergroup, of Cenozoic age, is the shallowest stratigraphical unit and comprises mostly siliciclastic sediments, from approximately seabed to 1000 m depth. It encompasses the Lower, Middle and Upper North Sea Groups, the bases of which are marked by distinct unconformities. The lower group comprises Palaeocene and Eocene strata, predominantly marine deposits, the middle group includes mainly Oligocene marine strata, and the upper group consists of the marine to continental Miocene and younger sediments. The North Sea Supergroup in the area of interest is unfaulted at seismic resolution scale. Clayey sequences are very abundant, especially in the lower parts of the North Sea Supergroup and could very well act as secondary seals. The presence of trap structures has not yet been investigated.

The North Sea Supergroup unconformably overlies the Upper Cretaceous Supergroup, which ranges from approximately 1000 m to 2400 m depth, and in this area comprises the Ommelanden Formation, the Texel Formation and the Texel Greensand Member. During the Late Cretaceous, the influx of fine-grained clastics into the marine realm (Lower Cretaceous) diminished. A fairly uniform succession of marls and limestones of the Texel and Ommelanden Formations developed. These sediments have an earthy texture and are commonly known as 'chalk'. The sealing properties of these formations are questionable although this interval is largely unfaulted.

The Lower Cretaceous Supergroup consists of the Holland Formation, the Vlieland Claystone Formation and Vlieland Sandstone Formation and ranges from approximately 2400 m to 3400 m depth. In locations close to P18-A, some of the sandstone layers present in this interval are gas bearing, demonstrating the sealing capacity of various claystone intervals in this succession.

In the area of interest the Lower Cretaceous is mainly unfaulted (on seismic resolution scale), improving the likelihood that layers in this level could indeed act as secondary seals.

At P18-A the Jurassic Supergroup consists of the Nieuwerkerk Formation, Lower Werkendam Member, Posidonia Shale Formation, Aalburg Formation and the Sleen Formation and ranges in depth from approximately 3400 m to 3900 m. The Nieuwekerk Formation predominantly comprises continental deposits, whereas the other formations consist of marine sediments mainly in the form of clays which could very well act as secondary (or even primary) seals.

The primary seal is formed by clay layers from Triassic and lower Jurassic age (the Upper Germanic Trias and Altena Group). Faults are present in this primary seal, but these do appear to be sealing and in general do not penetrate the caprock further upwards than the Posidonia Shale Formation (Figure 3-46). Reservoir closure along the bounding faults is obtained by juxtaposition of shale layers of various ages and clay smear. These bounding faults do not continue further upward into the overburden than the shales of the Altena Group. Due to the sealing nature of the bounding faults there is no water drive in the compartments.

3.6.3 Risk profile

The risks for migration out of the reservoir into the overburden or for leakage at the sea bottom are considered minimal for P18, which is a depleted gas field with no active aquifer drive. This means that the reservoir is well below hydrostatic pressure. Injection of CO_2 will be done in such a way that the average reservoir pressure remains below the initial gas pressure and below fracture pressure. This reduces considerably the risk of cap rock breaching.

The caprock has proved to be gas tight. Of course the properties of CO_2, especially in combination with connate water, are different from methane, which means that dissolution and precipitation of minerals, respectively creating or blocking migration pathways, needs to be thoroughly investigated. This is part of the characterization of the reservoir and caprock. Furthermore the possibility of fault reactivation needs attention, since the reservoir has been depressured (depleted) and CO_2 injection would involve repressuring. Again this is mostly a matter of proper characterization.

The injectivity of the reservoir is considered to be an issue. The main reservoir is heterogeneous with potentially rapid lateral facies changes typical of a fluviatile setting. This may lead to problems during injection such as local pressure build-up. This will be noticed immediately by monitoring the required injection pressure. Apart from geological heterogeneity of the reservoir, near wellbore effects such as salt precipitation or Joule Thompson effects (like freezing) of the CO_2 due to adiabatic expansion might also cause problems. Again, these effects will be immediately measured through the required injection pressure.

In terms of migration of CO_2 into the overburden the main potential pathways considered are:

- Along existing or new wellbores
- Along fault (zones)

A more detailed analysis of the state of the existing wells is still to be performed. Characterization of these wells, followed by well integrity measurements, are necessary. In the worst case this may require a work-over of one or more of the wells.

Migration along the fault zones is not considered likely, since the faults appear to be sealing and in general do not penetrate the caprock further upwards than the Posidonia Shale and Aalburg Formation (Figure 3-46).

Laterally the reservoir is constrained by a structural closure and sealing faults. Migration within the reservoir is therefore not a crucial parameter to monitor. However, it does provide input for the predictive simulation models demonstrating a proper understanding of the reservoir and associated flow processes.

3.6.4 Possible monitoring programme at P18

Since this project is still at an early stage, no monitoring plan exists yet. However, current ideas about a monitoring programme are as follows:

- Continuous pressure and temperature at the wellhead and downhole.
- Composition of the injected gas.
- Seismic monitoring to identify potential migration out of the reservoir and accumulation into shallower gas pockets.
- Repeated well integrity logging.
- Side-scan and/or multibeam survey to detect existing pockmarks at the seabottom. In case pockmarks are detected, in situ gas measurements and/or samples will be taken and analysed.
- Sniffers at the seabottom to detect potential leakages around the wellbores.
- Well tests during shut-in periods.

One or more of the existing wells will probably be converted into monitoring wells. For the monitoring wells the following are envisaged:

- Continuous pressure and temperature downhole.
- Gas sampling and analysis.
- Repeated RST logging (combined with sonic, neutron and resistivity logging).
- Repeated well integrity logging.
- Potentially microseismic monitoring to measure fault reactivation.
- Potentially tracers to detect arrival of the CO_2 front.
- Sniffers at the seabottom to detect potential leakages around the wellbores.

3.6.4.1 Results of the monitoring programme, assessment of efficacy and flexibility

Since this is only a planned project, no monitoring results have been obtained yet.

3.6.4.2 Comparison of the monitoring programme with IEA-GHG tool

Comparison of the developing monitoring programme with the more generic recommendations from the IEA-GHG Monitoring Selection Tool are instructive. Input parameters for the IEA-GHG tool were set for an offshore site with a depleted gas reservoir at a depth in the range 2500-4000 m. Duration of the project was set to 10 years with an annual injection rate of 1 million tonnes. In reality this might be higher, but this does not significantly influence the outcome of the suggested monitoring plan.

The tool has options for choosing pre-injection, injection, post-injection and post-abandonment monitoring. For simplicity, the injection phase monitoring option was taken as this in most cases will assess all of the feasible tool combinations. Plume tracking, seal integrity, migration, calibration and integrity were selected as the key monitoring objectives.

Tools were selected and ranked for both the ‘Basic’ and ‘Additional’ monitoring options.

The 'Basic' monitoring package provides a selection of 'core' tools that would be employed to adequately verify that injection and storage were behaving as expected, to identify any deviations from predicted behaviour, and to provide the basis for robust prediction of longer-term site performance. The 'Additional' monitoring package includes techniques that provide additional, possibly complementary, datasets to the basic package. These could be required in the event that observed site behaviour were to deviate from that predicted, or less radically, for supplementary monitoring aims addressing particular scientific or public confidence issues. These would typically include storage efficiency and fine-scale processes, quantification, seismicity and surface/atmospheric measurements. These techniques would normally be used in addition to those selected from the basic package. In particular site-specific circumstances, 'Additional' techniques may appropriately replace one or more of the core 'Basic' techniques.

The match between the foreseen monitoring methods and the basic monitoring program resulting from the IEA-GHG tool (presented in Table 3-7) is very high. The difference is mostly in the rating and prioritization of the different methods and in the absence of a monitoring well for the IEA-GHG tool program. Furthermore no special emphasis has been put in the IEA-GHG tool to monitor well integrity. Additional monitoring techniques suggested by the IEA-GHG tool are included in Table 3-8.

Table 3-7: Basic monitoring program resulting from the IEA-GHG monitoring tool

Tool	Rating %	Plume	Seal	Migration	Calibration	Integrity
3D surface seismic	75	2.7	2.7	4.0	2.7	3.0
Geophysical logs	50	1.0	2.0	0.0	3.0	4.0
Downhole fluid chemistry	50	0.7	1.3	3.0	2.0	3.0
Downhole pressure/temperature	50	1.0	3.0	0.0	3.0	3.0
2D surface seismic	35	1.3	1.3	2.0	1.3	1.0
Microseismic monitoring	27	1.3	1.3	0.7	0.7	1.3

Table 3-8: Additional monitoring program resulting from the IEA-GHG monitoring tool

Tool	Rating %	Plume	Seal	Migration	Calibration	Integrity
Multicomponent surface seismic	63	2.0	2.7	3.0	2.0	3.0
Tracers	45	1.0	2.0	2.0	2.0	2.0
Long-term downhole pH	35	0.7	1.3	3.0	2.0	0.0
Cross-hole seismic	30	1.3	1.3	1.0	1.3	1.0
Vertical seismic profiling (VSP)	20	0.7	0.7	1.0	0.7	1.0
Bubble stream detection	13	0.0	0.0	0.7	0.0	2.0
Cross-hole EM	11	0.3	0.3	0.7	0.3	0.7
Boomer/Sparker profiling	10	0.0	0.0	1.0	0.0	1.0
Headspace gas	10	0.0	0.0	0.7	0.0	1.3
Seabottom EM	9	0.3	0.0	1.3	0.1	0.0
Surface gravimetry	8	0.1	0.0	1.3	0.1	0.0
Permanent borehole EM	8	0.3	0.3	0.0	0.3	0.7
Seawater chemistry	7	0.0	0.0	0.7	0.0	0.7
Multibeam echo sounding	7	0.0	0.0	0.0	0.0	1.3
Sidescan sonar	7	0.0	0.0	0.0	0.0	1.3
Well gravimetry	6	0.1	0.1	0.7	0.1	0.0
High resolution acoustic imaging	5	0.0	0.0	0.0	0.0	1.0
Bubble stream chemistry	3	0.0	0.0	0.0	0.0	0.7
Cross-hole ERT	3	0.3	0.0	0.0	0.3	0.0
Tiltmeters	2	0.0	0.2	0.0	0.2	0.0
Ecosystems studies	2	0.0	0.0	0.0	0.4	0.0
Electric Spontaneous Potential	0	0.0	0.0	0.0	0.0	0.0
Fluid geochemistry	0	0.0	0.0	0.0	0.0	0.0
Surface gas flux	0	0.0	0.0	0.0	0.0	0.0
Non dispersive IR gas analysers	0	0.0	0.0	0.0	0.0	0.0

A more detailed description of these aims follows.

CO_2 Plume imaging

The key tool for plume imaging in general is 3D surface seismic. Geophysical logs, downhole fluid chemistry and downhole pressure-temperature measurements provide ancillary information. During the injection phase, microseismic monitoring may provide data on the location of the advancing CO_2 front and 2D surface seismic may be a cost-effective alternative to full 3D. Note that the seismic methods do not attain the maximum scores (4) for efficacy, this is because of the considerable depth of the P18 storage reservoir, which renders surface seismic methods less than optimally effective. Additionally, for P18 the presence of gas within the reservoir makes the feasibility of repeated seismic surveys for plume detection questionable.

Top seal integrity

The key tools for topseal integrity are downhole pressure/temperature logging and 3D surface seismic. Geophysical logs and downhole fluid chemistry are also potentially useful, particularly if top seal breakdown is close to monitoring wells. During the injection phase, microseismic monitoring could provide data on whether the topseal is being geomechanically compromised. As above, during the injection phase, 2D surface seismic may be a cost-effective alternative to full 3D, but will not provide full areal coverage of the top seal.

CO_2 migration in the overburden

The key tools for the detection and imaging of CO_2 migration in the overburden are downhole fluid chemistry and 3D surface seismic respectively. The former can detect, through pH changes, very small amounts of ingress of CO_2 into permeable formations. Surface 3D seismic can provide full coverage of the overburden volume and utilise its full imaging/resolution potential in the shallower overburden. During the injection phase, microseismic monitoring may provide data on the location of the migrating CO_2 front. As above, during the injection phase, 2D surface seismic may be a cost-effective alternative to full 3D, but will not provide full areal coverage of the overburden. Geophysical logs would not provide reliable indications of generalised CO_2 migration within the overburden except where free CO_2 accumulates in very close proximity to the wellbores.

Calibration of flow simulations

The calibration of flow simulations combines aspects of several of the above aims, effective plume imaging, accurate pressure and temperature monitoring and insights into fine-scale and geochemical processes. Likely tools are downhole pressure/temperature measurements, geophysical logs and 3D surface seismic. For P18 where seismic imaging might be difficult, downhole pressure/temperature is probably the key technology. Downhole fluid chemistry also has a role, particularly in constraining amounts of dissolution. As in a number of cases above, microseismic monitoring may be useful in the injection phase, and 2D seismic may in certain circumstances replace 3D acquisition.

Well integrity

The key tool for monitoring well integrity is clearly geophysical logging, aimed both directly at the wellbore (cement bond logging etc), but also at the surrounding formations (saturation logging). Pressure-temperature logging and downhole fluid chemistry are also potentially very useful. Non-well-based tools include 3D surface seismic for volumetric imaging of the overburden around the wellbores and multibeam echo sounding to detect surface changes around the wellbore. During the injection stage, well-based microseismic monitoring can also provide information on flow and degradation processes around the wellbores.

3.6.5 Monitoring programme in context of latest regulatory requirements

3.6.5.1 EU Storage Directive / OSPAR

Monitoring requirements of the European Directive and OSPAR are framed around enabling the operator to understand and to demonstrate understanding of current site processes, to predict future site behaviour and to identify any leakage. Further requirements of the monitoring include early identification of deviations from predicted site behaviour, provision of information needed to carry out remediative actions and the ability to progressively reduce uncertainty.

The P18 reservoir is a nearly depleted gas field with proven capability to retain natural gas over geological timescales. This makes it reasonable to assume that the reservoir is capable of retaining CO_2 as well (with the reservoir pressure remaining below the initial gas pressure). Nevertheless, an important difference with respect to a field like K12-B is the nature of the caprock, consisting of shale instead of salt. Chemical reactions induced by CO_2 contact with the shales, combined with possible geomechanical weakening, need to be characterised and evaluated thoroughly, though no major effects are expected. This would be based on core analysis and reactive transport simulations.

The main components for monitoring deviations in expected behaviour indicating potential migration out of the storage complex consist of pressure (and temperature) monitoring. After proper history matching any deviations from the expected pressure trend during and after the operational phase is a strong indicator for migration out of the storage complex. As for the K12-B reservoir, pressure monitoring has the potential to be a powerful tool at this site, since there is no strong aquifer drive masking potential deviations. A more detailed analysis of the sensitivity of pressure monitoring with respect to migration out of the storage complex needs to be carried out.

Tracking the plume in the reservoir will most likely be carried out either through monitoring well(s) or by seismic data. For the latter a sensitivity analysis needs to be undertaken. With residual gas present in the reservoir it is unlikely that a detectable signal can be picked up. Migration out of the reservoir (laterally or vertically), however, will probably be picked up by seismics. Monitoring wells will provide valuable input (samples, logs) to determine the migration pathways and the importance of the different trapping mechanisms in the reservoir.

Well integrity is considered the most important issue. Therefore a regular well monitoring programme is envisaged.

Considering the overall philosophy of the EU Directive enshrined in the three minimum geological criteria for transfer of liability:

- Observed behaviour of the injected CO_2 is conformable with the modelled behaviour.
- No detectable leakage.
- Site is evolving towards a situation of long-term stability.

One can say that the three objectives can be covered by the proposed monitoring programme. The main question will be whether characterisation of the caprock in combination with reservoir pressure monitoring provides sufficient confidence to omit seismic monitoring for detecting migration out of the storage complex. Further sensitivity analyses (ongoing work) will be needed to provide that answer. In case of doubt seismic data acquisition might very well be imposed by the regulator.

3.6.5.2 Emissions accounting (e.g. ETS)

Quantitative monitoring for ETS will only be required, if there is an indication of leakage. Currently there is no requirement for emission accounting as there is no evidence that the site will leak. However, in case irregularities are observed for example in the downhole pressure and temperature measurements, the need for additional monitoring to detect migration pathways out of the storage complex becomes stringent.

A key question for quantitative monitoring is, of course, to what extent does state-of-the-art technology allow for an accurate quantification. In that perspective the NSBTF (2009) suggests in general choosing a combination of a model-driven approach in combination with a monitoring strategy to best estimate the leakage for ETS purposes.

For P18 a sound strategy would be to detect leakage to the surface by geophysical methods like seismic data (detection of gas chimneys) or sea-bottom sonar techniques (detection of pockmarks) and then carry out in situ gas measurements and/or sample these leakage areas for direct CO_2 detection. Based on these observations an estimate can be made of leakage rates for the area. In case of wellbore leakages an additional monitoring program in and around the wells is suggested.

4 Leakage parameters, scenarios, accuracy

4.1 EXECUTIVE SUMMARY

This chapter presents modelling work examining CO_2 leakage parameters at four different theoretical North Sea sites and a review of CO_2 leakage parameters from the literature.

Modelling work undertaken by Quintessa examined CO_2 migration out of the main storage container at four theoretical sites designed to cover the range of likely storage options in the UK North Sea. These generic site types are essentially the same as those used for preparing monitoring schemes in Chapter 8, and examples of each of these types were included in the examination of actual monitoring plans in Chapter 3.These studies provided estimates of limits and ranges of parameters that could be monitored at future CO_2 storage sites, using the results from simplified systems level models. Parameters derived from modelling plausible scenarios can help to prioritise suitable monitoring tools and determine monitoring strategies. The sites were specified to represent all the major Features, Events and Processes (FEPs**),** including potential migration paths likely to be encountered.

Scenarios were investigated for each site type using Quintessa's QPAC-CO2 computer code. Important processes that can be modelled with this code include the advection of groundwater and CO_2 due to pressure and density variations, state changes caused by pressure and temperature variations, and CO_2 dissolution in groundwater. Rapid simulations at the full system scale were possible which allowed different parameter sensitivities to be explored. This type of investigation would not be possible with conventional reservoir models which take longer to run and cover a smaller area because of their finer scale. Values for formation water pH were calculated separately using the geochemical modelling code PHREEQC v 2.15 and the thermodynamic database "data0.ypf.R2". In each case, the potential leakage paths were specified to occur at the same distance from the injection well, in order to allow comparison of the results. Simulation results found that if the leakage pathway is reached by the CO_2 during injection then leakage will be more significant than if the CO_2 arrives at the pathway only after injection has ceased. The simulations were run for 500 years in order to cover any likely period for which monitoring might be required. However, while breakthrough times to the leakage pathway can be relatively short, simulations showed that peak CO_2 fluxes may not have had sufficient time to develop over the simulation run period in under-pressured or hydrostatic scenarios.

Simulation results suggest that initial reservoir pressure conditions influence where and when monitoring is appropriate. For all sites wells were the main CO_2 leakage pathway considered, although leakage through a fault or through a zone of overburden with enhanced permeability was also considered. Simulation results suggested that chemical monitoring of a typical cap rock would be unnecessary because of the small amount of CO_2 involved and the very long timescales. Leakage that occurs via a fault or through enhanced-permeability overburden was found to discharge much more significant volumes of CO_2, for the cases studied, than when it occurs via a borehole, despite the time for a borehole to respond being typically much shorter. Seawater pH changes above a leakage pathway were found to be extremely small if only CO_2-charged water discharges, but much more significant (1 pH unit or more) if free CO_2 discharges. However, these changes are very much controlled by the rate of mixing of seawater at the discharge point. The aquifer scenario simulation results suggested that if migration occurred along a wellbore, additional storage might be found in unbounded aquifers above the main storage reservoir and these aquifers would be the most appropriate monitoring target to show that the borehole was not providing a leakage pathway.

Leakage parameters assessed by the literature review included CO_2 flux, concentration, distribution and duration both from observations and simulations. Leakage parameters were calculated from a variety of methods, including direct field measurements. Scenarios were divided into the following categories; natural CO_2 releases; CO_2 injection sites; CO_2-EOR sites; experimental sites and numerical models.

Natural CO_2 releases exist mainly in volcanic or hydrothermal areas, where deep sourced CO_2 is released to the surface. This allows investigation of potential CO_2 pathways, fluxes and environmental impacts. Flux rates range typically from background values (10^{-3} tonnes/m^2/year)up to a few tonnes/m^2/year. **CO_2 injection sites** at both the pilot and commercial-scale have, in almost all cases, not detected leakage, as they were chosen carefully as secure containers (In Salah, Sleipner, Frio and Nagaoka show no leakage, a low flux rate leak was detected from West Pearl Queen). Methods including tracers and isotopic CO_2 signatures have been used to determine if any CO_2 detected originates from the stored CO_2 or comes from unrelated biogenic sources. **CO_2-EOR sites** have been operating in some cases since the 1970s and as such data on gas releases experienced at these sites can aid estimation of CO_2 leakage parameters. Expected leakage rates are very low; for example, at Weyburn, only about 0.001 % of the predicted total CO_2 stored at cessation of injection is expected to leak over 5000 years. Research at these sites indicates that old wells not designed for CO_2 contact are the most likely source of leakage. **Experimental sites** specifically designed to monitor leakage parameters from CO_2 injection into the shallow subsurface to monitor the effects and rate of leakage. Carbon dioxide release rate and location can be controlled to mimic, for example, potential diffuse leakage or sudden leakage from a point source such as a fault. These experiments also suggest that CO_2 releases become concentrated into ‘hot spots’ which incidentally may aid detection of low level releases. **Numerical models** have been developed to investigate CO_2 migration and leakage from a variety of storage scenarios and over a variety of timescales. Data from real sites are input wherever possible and output effects including subsurface CO_2 saturations and seabed pH perturbations.

4.2 INTRODUCTION

Leakage scenario modelling was performed by Quintessa to determine plausible leakage parameter variations for four scenarios selected to represent typical conditions in the southern and central North Sea. The outputs also provide insights into the likely sensitivities of these parameters to CO_2 migration at the full storage system level.

An extensive review of literature describing leakage parameters such as flux, distribution and duration was carried out by BGS. Findings give an indication of realistic detectability of CO_2 leakage and illustrate the potential magnitude of leakage which could be expected if a storage site were compromised by reference to existing experiences. These include data from natural analogue sites, experimental sites where small amounts of CO_2 is deliberately leaked to test the flux rates, monitoring methods and assess ecosystem effects, CO_2-EOR sites, CO_2 injection sites purely for CO_2 storage and numerical models.

4.3 LEAKAGE SCENARIO MODELLING

This section reports work carried out by Quintessa under sub-contract to the BGS. Outputs from scoping calculations are presented to determine measurement limits and ranges, for a selection of key parameters that might be monitored, for several plausible leakage scenarios at a range of potential offshore UK storage sites. The outputs also provide insights into the likely sensitivities of these parameters to CO_2 migration at the full storage system level.

The limits and ranges of parameters that could be monitored at an actual site will depend upon the specific characteristics of CO_2 storage there. Consequently, as no sites have yet been selected, the focus was on developing an understanding of the processes that influence relevant parameters. This information can then be used as an input to subsequent project tasks, and can aid the identification of priorities for further work.

Four generic storage sites were specified to represent the characteristics of the kinds of sites that are most likely to be used to store CO_2 in the UK's continental shelf. Scenarios for actual storage and "worst case" leakage were then specified for each generic storage site. The plausible effects of this leakage were calculated using simplified systems level models implemented in Quintessa's QPAC-CO_2 numerical modelling code. This code simulates multi-phase migration of CO_2 and water throughout the modelled domains, which are represented by simplified model grids. The pressure- and temperature- dependency of free CO_2 density and solubility are taken into account, along with the salinity of the water phase. For the reported application, the systems modelling approach implemented in QPAC-CO_2 has the major advantage compared to conventional reservoir models that simulations are relatively rapid. This is possible largely through the inherent stability of the employed numerical method, which enables relatively coarse and stylised systems model grids to be used in addition to conventional reservoir model style grids. A consequence of the rapid simulations is that couplings between many processes can be simulated at the full system scale, allowing sensitivities among different parameters to be explored while considering all the relevant features of the system. It would not be practicable to explore sensitivities in this way using slower conventional reservoir simulation models.

The systems models implemented in QPAC-CO_2 output the following key properties as functions of time:

- fluxes of free and dissolved CO_2 throughout each storage system;
- cumulative masses of free and dissolved CO_2 throughout each storage system;
- fluid pressures throughout each storage system; and
- spatial distributions of free CO_2 throughout each storage system.

Values for formation water pH were calculated separately using the geochemical modelling code PHREEQC v 2.15 and the thermodynamic database "data0.ypf.R2". The so-called "Pitzer" approach to calculating activity coefficients was used since it gives the most accurate results in the highly saline formation waters considered. These calculations took as inputs the aqueous CO_2 concentrations calculated using the QPAC-CO_2 systems level models.

Scoping calculations were also undertaken separately from the QPAC-CO_2 simulations to determine the plausible impacts on seawater pH of any leakage to the seabed.

For comparison with the results of the simulations of leakage via "worst-case" leakage pathways, scoping calculations were also carried out to determine the maximum likely rates of CO_2 seepage into a caprock immediately above a storage reservoir.

The calculations focussed on exploring the consequences of some examples of "worst case" CO_2 leakage from these different sites. The rationale was that, if variations in a parameter would not be large enough to monitor under these extreme circumstances, then developing and applying monitoring technologies for the parameter would not be a priority. The calculations were also designed to determine the importance of couplings between the main processes that influence the considered parameters. The aim was to help determine the circumstances under which it would be inappropriate to monitor a given parameter.

An expert workshop was convened to define generic storage sites and potential leakage scenarios as a basis for the study. The workshop was attended by participants from Quintessa, BGS and TNO.

Systems models were then developed to analyse these entire generic storage systems. Such systems models complement reservoir models, which represent only part of a system. By representing an entire system, it is possible to calculate the sensitivity of a parameter in one part of the system, to variations in the same parameter or a different parameter, in another part of the system. For example, a systems model representing a CO_2 storage system could be used to determine the sensitivity of groundwater pH in a shallow part of the system to the pressure at which CO_2 is injected into a deeper storage reservoir (for a given representation of the geology, including faults, cap rock etc). However, this kind of systems level treatment requires that the representation of the system should be simplified in order that calculation times are acceptably short. Simplification typically involves excluding Features, Events and Processes (FEPs) that are clearly unimportant; and / or specifying a relatively coarse discretisation of the system.

4.3.1 Scenarios

4.3.1.1 Generic site descriptions

The expert workshop reviewed information about actual and possible CO_2 storage sites within the North Sea. Based on this review, four generic sites were then defined to represent the characteristics of the different kinds of sites that are most likely to be used to store CO_2. The generic sites were specified to represent all the major kinds of FEP, including potential leakage paths, likely to be encountered in an actual offshore storage site adjacent to the UK. Thus, calculations to scope the behaviour of CO_2 in each of these four types of sites will output plausible ranges for parameters that could be monitored in the vicinity of actual storage sites, for the considered scenarios.

The participants in the workshop reviewed all the FEPs in Quintessa's widely used and freely accessible on-line CO_2 FEP database (http://www.quintessa.org/co2fepdb/ ; Savage et al., 2004; Quintessa, 2010). Those FEPs that were considered to be important in one or more of the general types of storage sites were identified. This FEP list and the treatment of the FEPs are given in Appendix 1 (Volume 2).

This approach led to the specification of four kinds of generic sites:

- Southern North Sea Type 1 Storage Sites (Figure 4-1);
- Southern North Sea Type 2 Storage Sites (Figure 4-2);
- Central and Northern North Sea Fault Block-type Storage Sites (Figure 4-3); and
- Central and Northern North Sea Aquifer-type Storage Sites (Figure 4-4).

The key distinguishing characteristics of these generic sites are:

- Storage reservoir conditions (water salinity and pressure);
- Boundary conditions;
- Caprock characteristics;
- Overburden characteristics (notably whether or not aquifers occur); and
- Geological structures.

The important aspects of the North Sea Type 1 storage site, (Figure 4-1) of which the K12-B site in the Dutch sector of the North Sea is an example, are:

- The CO_2 storage reservoir is a depleted hydrocarbon reservoir.
- Wells are the main kind of potential leakage path to be considered.
- The CO_2 storage reservoir is compartmentalized by faults and the storage capacity of any given compartment may be relatively limited.
- Initially, a CO_2 storage compartment will be underpressured, owing to previous extraction of hydrocarbons. However, the pressure will rise during injection and may

become over-pressured. After closure, the pressure in a compartment is expected to return to normal values (which may be hydrostatic or slightly overpressured).

- The salt in the caprock and in the shallower overburden will exert a pressure on well bores, leading to their eventual closure.

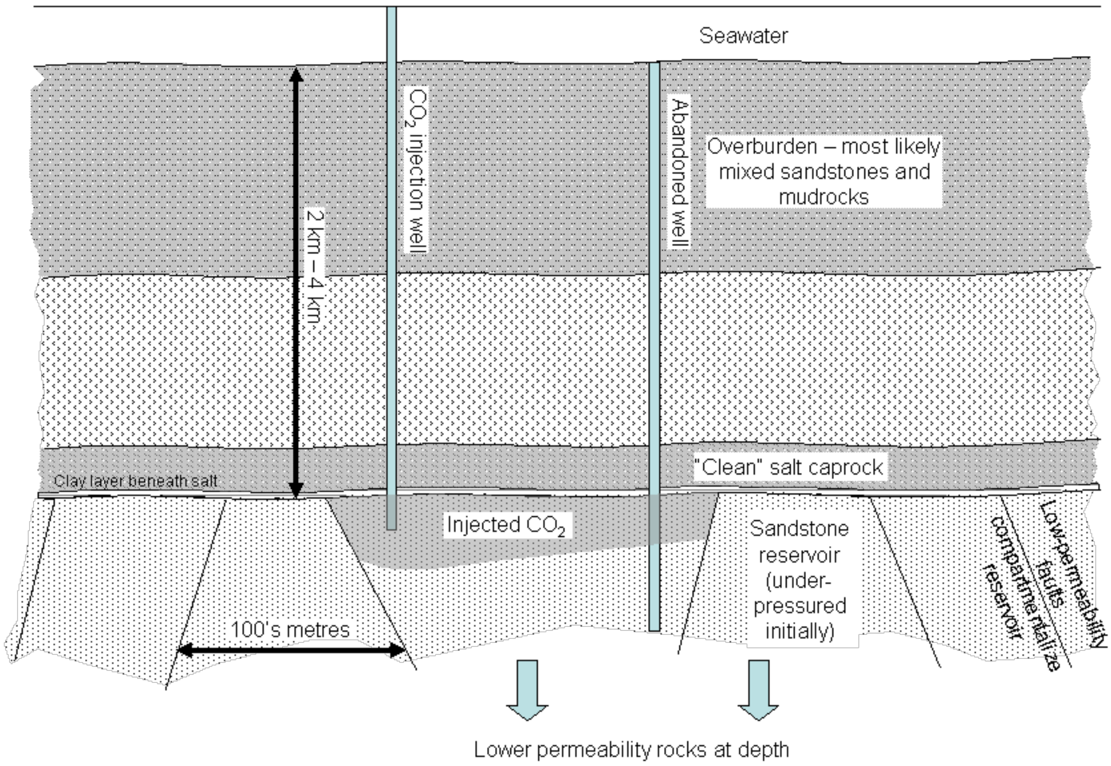

Figure 4-1: Schematic illustration of a Type 1 CO_2 storage site in the southern North Sea(which is broadly similar to the K12-B site in the Dutch sector of the North Sea).

In contrast, the North Sea Type 2 storage site (Figure 4-2) is broadly similar to the P-18 site, also in the Dutch sector of the North Sea. This kind of storage site has several important aspects.

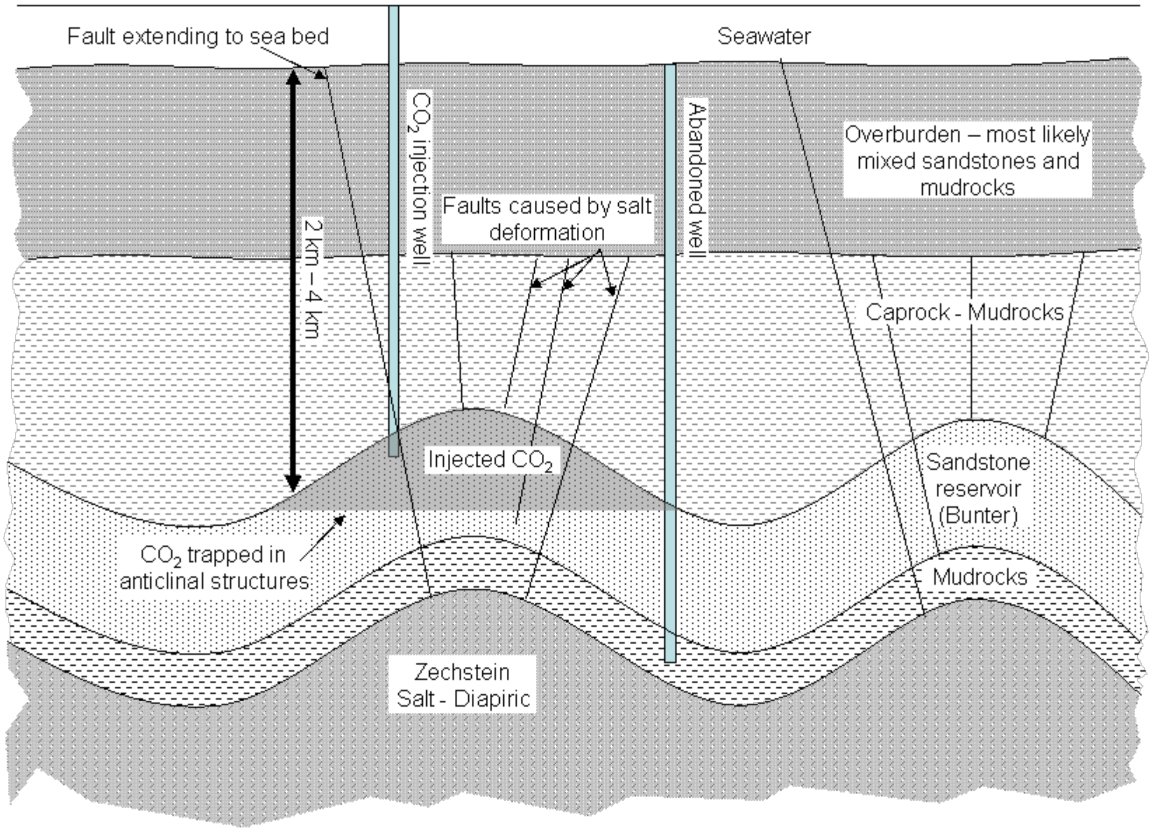

Figure 4-2: Schematic illustration of a Type 2 CO_2 storage site in the southern North Sea (which is broadly similar to the P-18 site in the Dutch sector of the North Sea).

- The CO_2 storage reservoir is a depleted hydrocarbon reservoir.
- The CO_2 trap is an anticlinal structure formed above deeper salt diapirs.
- Wells are potential leakage pathways that need to be considered.
- Faults formed in the axes of the anticlinal structures owing to tension developed during folding and may potentially act as leakage pathways.
- Some of these faults may extend as far as the seabed while others terminate at depth.
- The caprock is a mudrock-dominated sequence and, unlike in the Type 1 storage site, there is no great thickness of salt in the overburden.
- Initially the reservoir may be under-pressured owing to hydrocarbon extraction. During injection of CO_2 the pressure will rise and may become slightly over-pressured. After closure, pressures will return to normal values which may be hydrostatic.

Fault block type CO_2 storage sites in the central or northern North Sea (Figure 4-3) are broadly similar to the CO_2 site proposed by BP in the Miller Field. This kind of storage site has the following important aspects.

- The CO_2 storage reservoir is a depleted hydrocarbon reservoir.
- The reservoir rock is sandstone that is compartmentalized by faults and lies within a series of horst blocks and graben structures. There may be water drive in some compartments but not in others.
- Wells are the main kind of potential leakage path to be considered.

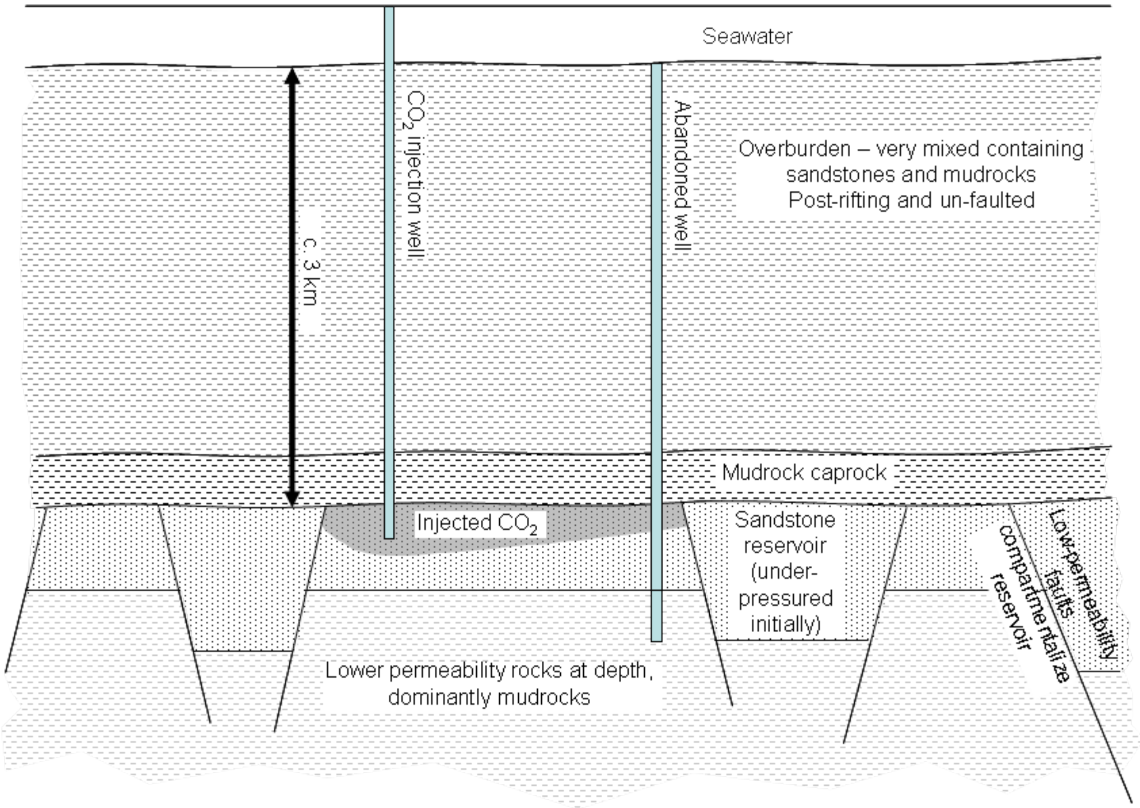

Figure 4-3: Schematic illustration of a fault block type CO_2 storage site in the central or northern North Sea (which is broadly similar to the Miller Field).

- There are no salt deposits in the over-burden, unlike at Southern North Sea Storage Site Type 1.
- Initially the reservoir may be under-pressure owing to hydrocarbon extraction. During injection of CO_2 the pressure will rise and may become slightly over-pressured. After closure, pressures will return to normal values, which may be hydrostatic.

Aquifer-type storage sites, such as those that occur in the central and northern North Sea (Figure 4-4) are broadly similar to the CO_2 storage site at Sleipner. The main features of this kind of storage site are as follows:

- The CO_2 storage reservoir is a “saline aquifer”.
- Initially, the reservoir is normally pressured, with pressures being close to hydrostatic.
- The reservoir extends laterally for a considerable distance (tens to hundreds of kilometres) and migration of the injected CO_2 plume will be effectively unconstrained laterally.

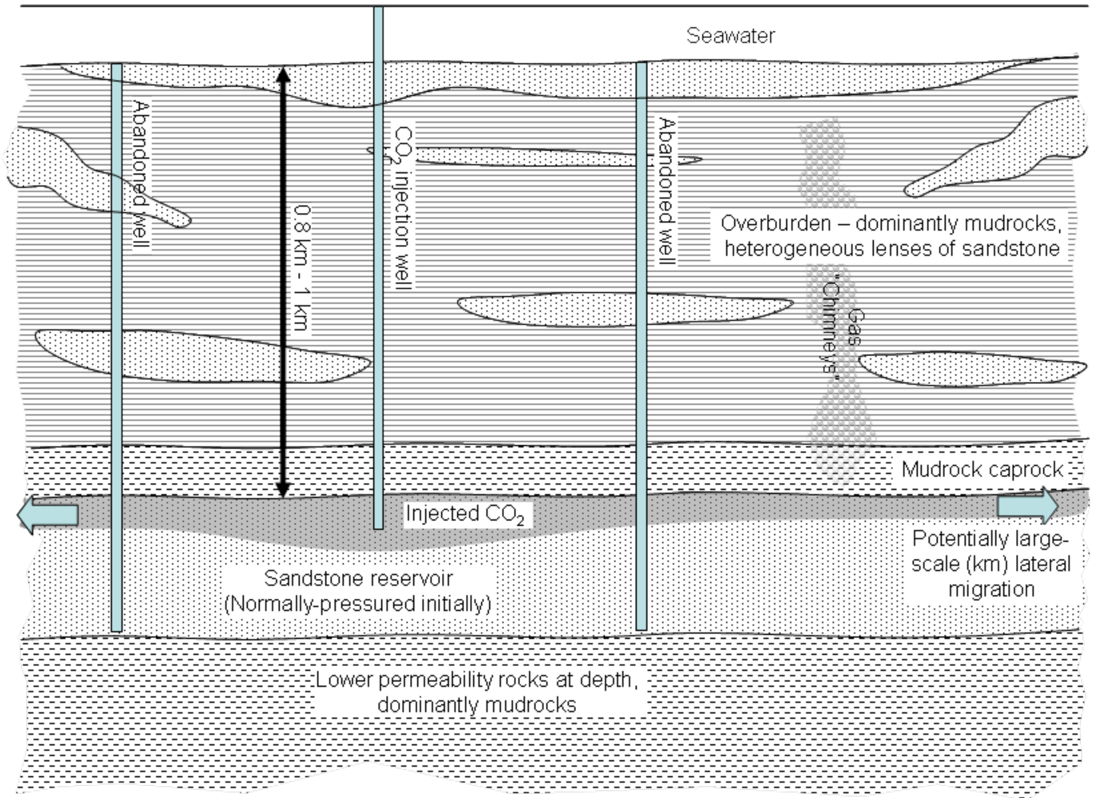

Figure 4-4: Schematic illustration of an aquifer-type CO_2 storage site in the central or northern North Sea (which is broadly similar to Sleipner).

- The relatively long distance for which the CO_2 may migrate means that it is possibly more likely than in other kinds of reservoir, that wells (including abandoned wells) will be encountered by the CO_2.
- The over-burden is very heterogeneous, containing both sandy lenses and more continuous mudrocks. If connected, it is possible that the sand lenses could represent leakage pathways.
- There may be gas chimneys in the over-burden. These chimneys are sub-vertical zones within which gas fills the pore space. These features are significant because effectively there would no capillary entry pressure that migrating CO_2 would need to exceed to enter them. Consequently, if these chimneys are sufficiently connected they may represent potential leakage pathways for CO_2 migration. There was some debate at the workshop as to whether these features are likely to be significant. It was noted that if only 2% of the porosity is filled by gas then the gas-containing structure will tend to be resolved on seismic profiles. However, if the gas content is as low as this, then such a "chimney" may not be an effective CO_2 leakage pathway. It follows that the chimneys that are seen on seismic profile may not in fact represent potential pathways for CO_2 migration. Additionally, the origin of these features is open to debate. A true gas chimney is indicative of past gas migration and represents the residual gas that was left behind when gas migrated through a rock mass. However, many of the apparent gas chimneys seen in seismic profiles may in fact indicate in-situ biogenic gas formation. Owing to the uncertainty concerning whether or not gas chimneys are likely to occur, it was agreed to undertake calculations to explore their potential significance in the event that they do occur.

4.3.1.2 LEAKAGE SCENARIOS

Having specified the different kinds of storage site, the participants in the expert workshop discussed the ways in which the important FEPs could be represented within generic scenarios. It was concluded that scoping calculations should be undertaken to explore the consequences of *hypothetical* leakage through different kinds of *hypothetical* leakage pathways. The aim was *not* to predict leakage, but rather to identify how monitoring could verify such leakage in the unlikely event that it occurs unexpectedly, and also determine how monitoring can build confidence that such leakage does not occur. To this end it was decided that the scoping calculations should investigate the following basic scenarios:

- CO_2 leakage through a well (essentially a 1D leakage path, henceforth termed the "well leakage scenario");
- CO_2 leakage through a fault (essentially a 2D leakage path, henceforth termed the "fault leakage scenario");
- CO_2 leakage through a zone of rock with enhanced permeability (essentially a 3D leakage path, representing either heterogeneously distributed interconnected permeable strata within a dominantly impermeable overburden, or a gas chimney, henceforth termed the "leaking caprock and enhanced-permeability overburden scenario");

For comparison, it was also decided to scope the small extent to which CO_2 will seep into the caprock.

It was agreed that each scenario would have the following common features:

- A reservoir;
- An impermeable caprock;
- An impermeable overburden containing a "deep aquifer" and a "shallow aquifer";
- Representation of seawater at the top boundary;
- Explicit representation of an injection well.

4.3.2 Numerical models

4.3.2.1 CODE DESCRIPTION

The scenarios described in Section 4.3.1 were investigated using Quintessa's QPAC-CO_2 computer code (Quintessa, 2008). This software consists of Quintessa's general purpose multi-physics modelling code QPAC, and a collection of modules designed to enable the behaviour of CO_2 to be simulated. The most important module simulates multi-phase flow, which enables modelling of the most important processes connected with CO_2 migration and partitioning between different phases. The code also has default parameter values for all associated physical properties, which can be over-ridden by the modeller if necessary. Important processes include the advection of groundwater and CO_2 due to pressure and density variations, state changes caused by pressure and temperature variations, and CO_2 dissolution in groundwater. In summary, the main features of the model, as implemented in QPAC-CO2 for the work reported here are:

- Multi-phase flow;
- CO_2 dissolution using the Peng-Robinson Equation of State (EOS) used for CO_2 and the Rowe-Chu equation for water pressure and density;
- Spatially variable, but temporally invariant temperature;
- The CO_2 dissolution model including both salinity control and fugacity; and

- Solution of the following eight variables per compartment per time step:
  - amount of water;
  - amount of free CO_2;
  - saturation of water;
  - saturation of free CO_2;
  - pressure of water;
  - pressure of free CO_2;
  - molar volume of free CO_2; and
  - amount of dissolved gas.

For the reported application, the systems modelling approach implemented in QPAC-CO_2 has the major advantage compared to conventional reservoir models that simulations are relatively rapid. This speed is possible largely through the inherent stability of the employed numerical method which enables relatively coarse and stylised systems model grids to be used in addition to conventional reservoir model style grids. A consequence of the rapid simulations is that couplings between many processes can be simulated at the full system scale allowing sensitivities among different parameters to be explored while considering all the relevant features of the system. It would not be practicable to explore sensitivities in this way using slower conventional reservoir simulation models.

4.3.2.2 Representations of scenarios

Using QPAC-CO2, the various scenarios described in Section 4.3.1 were represented within a single basic systems model that contains all the “scenario-defining” features (Figure 4-5). By appropriate parameterisation, these different features could be turned on and off in order to produce the different scenarios. The spatial dimensions represented by the model were chosen to allow ready scaling to other dimensions.

Within the model representation of a particular kind of site, each of the alternative potential leakage paths was specified to occur at the same distance from the injection well. This approach was taken to allow ready comparison of the results from calculations representing the different scenarios. The distance was calculated during initial test simulations to be the same as the distance travelled by the margin of the CO_2 plume during 10 years of injection.

In the scenario where CO_2 leakage can occur through a zone of rock with enhanced permeability, the simulated leakage path had anisotropic permeability, with vertical permeability and horizontal permeability being specified separately. The reservoir had a sufficiently fine spatial discretisation to allow an adequately realistic representation of the CO_2 plume’s extent.

The duration of the simulations was 500 years, which was considered sufficient to *bracket* the period for which conceivably monitoring will be undertaken. This choice of duration recognizes that the actual period for which monitoring will be carried out is presently undefined. While monitoring will not be undertaken for such a long period, plausibly it could be carried out for > 100 years.

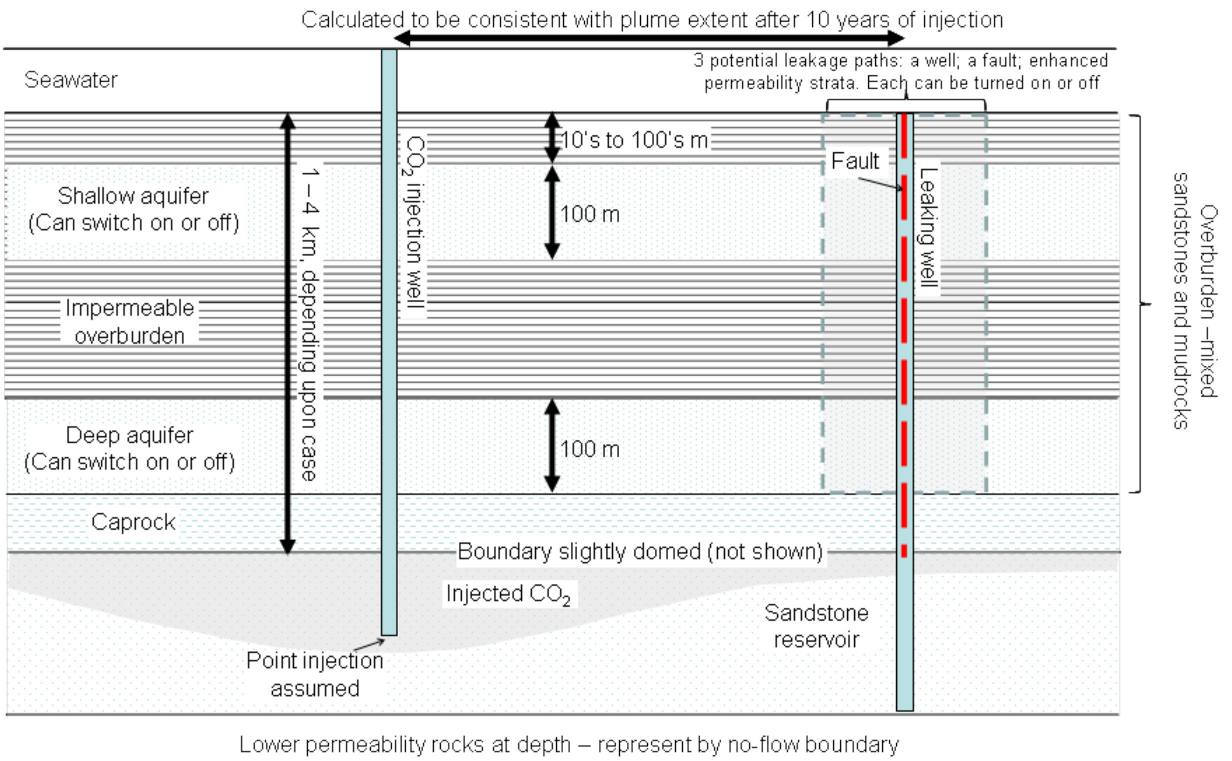

Figure 4-5: Schematic illustration of a systems model to represent the various scenarios. As implemented within QPAC-CO2, the model is three-dimensional.

4.3.2.3 Calculation of cases and parameterisation

The hypothetical extreme leakage scenarios presented in Section 4.3.1 were represented using three basic model cases:

Case 1 has a relatively deep reservoir filled initially with brine. The initial water in the reservoir, prior to CO_2 injection, is below hydrostatic pressure and the final fluid pressure in the reservoir, at the end of CO_2 injection, is hydrostatic.

Case 2 has a relatively shallow reservoir filled initially with saline water. The initial water in the reservoir, prior to CO_2 injection, is at hydrostatic pressure and the final fluid pressure in the reservoir, at the end of CO_2 injection, is slightly above hydrostatic pressure. Following the end of injection, the latter pressure decreases rapidly to hydrostatic pressure.

Case 3 has a relatively shallow reservoir filled initially with brine. The initial water in the reservoir, prior to CO_2 injection, is at hydrostatic pressure and the final fluid pressure in the reservoir, at the end of CO_2 injection, is just below (85%) of lithostatic pressure.

It should be noted that the description of Case 1 covers both the Type 1 CO_2 storage site in the southern North Sea (Figure 4-1) and the fault block type CO_2 storage site in the central or northern North Sea (Figure 4-3). These two kinds of site differ primarily in the characteristics of the overburden, there being salt in the former but not in the latter. This distinction is significant for the applicability of certain kinds of monitoring, notably by seismic methods, but is not relevant to the calculations presented here, which simulate CO_2 migration via leakage pathways.

Parameter values were supplied by BGS and TNO and are plausible values, based on published literature, for the considered generic sites. The parameter values are given in Table 4-1,

Table 4-2 and Table 4-3 corresponding to Case 1, Case 2 and Case 3 respectively.

For each of these basic modelled site types, the three alternative leakage scenarios were investigated:

- Case 1_Well, Case 2_Well and Case 3_Well investigate leakage through a well in Cases 1, 2 and 3 respectively.
- Case 1_Fault, Case 2_Fault and Case 3_Fault, investigate leakage through a fault in Cases 1, 2 and 3 respectively.
- Case 1_Cap, Case 2_Cap and Case 3_Cap investigate leakage through a leaking caprock and enhanced-permeability overburden in Cases 1, 2 and 3 respectively.

Thus, in the figures and tables below, each case is denoted by a number (1, 2 or 3) that denotes the overall site type, followed by an identifier that indicates the kind of leakage path being evaluated. Implicit in the designation of the site type are the reservoir geometry and the initial and final pressure conditions.

Table 4-1: Key Parameters for Case 1

Parameter	Media	Value	Comments
Intrinsic Permeability (mD)	Reservoir	70	Expert judgment of project team
	Well	1000	As discussed
	Fault	0.5	Notional, assuming only a small fraction of the gridded volume is 'flowing'
	Failed Cap	0.5	As above
	Deep aquifer	1000	
	Upper aquifer	3000	
Porosity (-)	Reservoir	0.15	
	Well	0.15	
	Fault	0.01	Notional, assuming only a small fraction of the gridded volume is 'flowing'
	Failed Cap	0.01	As above
	Deep aquifer	0.3	
	Upper aquifer	0.37	
Salinity (ppm)	Reservoir	250000	
	Well	35000	
	Fault	35000	
	Failed Cap	35000	
	Deep aquifer	250000	
	Upper aquifer	35000	
Top Elevation (m)	Reservoir	-3000	
	Well	-190	
	Fault	-190	
	Failed Cap	-190	
	Deep aquifer	-1000	
	Upper aquifer	-190	This is the top elevation. In the failed cap scenario there are no deep or shallow aquifers, hence the 'failed cap' media type runs from the reservoir top to the model top (-190 m). The model has -190 m of seawater above the seabed.
Key Dimensions (m) (1/4 model)	Reservoir	2500x4500x140	
	Well	0.2 (diameter)	
	Fault	2500 m x 220	Size on grid
	Failed Cap	220 x 240	Size on grid
	Deep aquifer	linear: 4000x2500x100	radial dimensions used for

Parameter	Media	Value	Comments
		radial: 4000x100	well leakage and linear for fault
	Upper aquifer	linear: 4000x2500x100 radial: 4000x100	radial dimensions used for well leakage and linear for fault

Table 4-2: Parameterisation for Case 2

Parameter	Media	Value	Comments
Intrinsic Permeability (mD)	Reservoir	1000	
	Well	1000	Expert judgment of project team
	Fault	0.5	Notional, assuming only a small fraction of the gridded volume is 'flowing'
	Failed Cap	0.5	As above
	Deep aquifer	1000	
	Upper aquifer	3000	
Porosity (-)	Reservoir	0.3	
	Well	0.15	
	Fault	0.01	Notional, assuming only a small fraction of the gridded volume is 'flowing'
	Failed Cap	0.01	As above
	Deep aquifer	0.3	
	Upper aquifer	0.37	
Salinity (ppm)	Reservoir	35000	
	Well	35000	
	Fault	35000	
	Failed Cap	35000	
	Deep aquifer	35000	
	Upper aquifer	35000	
Top Elevation (m)	Reservoir	-1800	
	Well	-190	
	Fault	-190	
	Failed Cap	-190	This is the top elevation. In the failed cap scenario there are no deep or shallow aquifers, hence the 'failed cap' media type runs from the reservoir top to the model top (-190 m). The model has -190 m of seawater above the seabed.
	Deep aquifer	-1000	
	Upper aquifer	-190	
Key Dimensions (m) (1/4 model)	Reservoir	12500x22500x140	
	Well	0.2 (diameter)	
	Fault	2500 m x 250	Size on grid
	Failed Cap	250 x 250	Size on grid
	Deep aquifer	linear: 4000x2500x100 radial: 4000x100	radial dimensions used for well leakage and linear for fault
	Upper aquifer	linear: 4000x2500x100 radial: 4000x100	radial dimensions used for well leakage and linear for fault

Table 4-3: Parameterisation for Case 3

Parameter	Media	Value	Comments
Intrinsic Permeability (mD)	Reservoir	100	This value is at the lower end of the range reported for the Utsira Sand
	Well	1000	Expert judgment of project team
	Fault	0.5	Notional, assuming only a small fraction of the gridded volume is 'flowing'
	Failed Cap	0.5	As above
	Deep aquifer	1000	
	Upper aquifer	3000	
Porosity (-)	Reservoir	0.2	
	Well	0.15	
	Fault	0.01	Notional, assuming only a small fraction of the gridded volume is 'flowing'
	Failed Cap	0.01	As above
	Deep aquifer	0.3	
	Upper aquifer	0.37	
Salinity (ppm)	Reservoir	250000	
	Well	35000	
	Fault	35000	
	Failed Cap	35000	
	Deep aquifer	250000	
	Upper aquifer	35000	
Top Elevation (m)	Reservoir	-1800	
	Well	-190	
	Fault	-190	
	Failed Cap	-190	This is the top elevation. In the failed cap scenario there are no deep or shallow aquifers, hence the 'failed cap' media type runs from the reservoir top to the model top (-190 m). The model has -190 m of seawater above the seabed.
	Deep aquifer	-1000	
	Upper aquifer	-190	
Key Dimensions (m) (1/4 model)	Reservoir	2500x5000x140	
	Well	0.2 (diameter)	
	Fault	2500 m x 250	Size on grid
	Failed Cap	250 x 250	Size on grid
	Deep aquifer	linear: 4000x2500x100 radial: 4000x100	radial dimensions used for well leakage and linear for fault
	Upper aquifer	linear: 4000x2500x100 radial: 4000x100	radial dimensions used for well leakage and linear for fault

These different model cases can be mapped to the generic sites and scenarios described in Section 4.3.1, as shown in Table 4-4

Table 4-4: Summary of initial calculation cases, showing correspondence between cases calculated with the generic systems model in Figure 4-5, and the different types of storage site.

Simulations undertaken with generic systems model illustrated in Figure 4-5				Corresponding Storage Site			
Cases				Southern North Sea Type 1 Storage Sites	Southern North Sea Type 2 Storage Sites	Central & Northern North Sea Fault Block-type Storage Sites	Central & Northern North Sea Aquifer-type Storage Sites
Case	Initial reservoir pressure	Final reservoir pressure *(Note 2)*	Injection duration				
Leaking well scenario							
1_Well	Under-pressured (*Note 1*)	Hydrostatic *(Note 1)*	50 years	Corres-pondence	Corres-pondence	Correspondence	No correspondence
2_Well	Hydrostatic	Hydrostatic+ *(Note 3)*	50 years	Weak corres-pondence	Corres-pondence	Correspondence	Correspondence
3_Well	Hydrostatic	Sub-lithostatic (*Note 4*)	50 years	Weak corres-pondence	Corres-pondence	Correspondence	Weak Correspondence
Leaking fault scenario							
1_Fault	Under-pressured (*Note 1*)	Hydrostatic *(Note 1)*	50 years	No corres-pondence	Corres-pondence	No correspondence	No correspondence
2_Fault	Hydrostatic	Hydrostatic+ *(Note 3)*	50 years	No corres-pondence	Corres-pondence	No correspondence	No correspondence
3_Fault (*Note 4*)	Hydrostatic	Sub-lithostatic (*Note 5*)	50 years	No corres-pondence	Corres-pondence	No correspondence	No correspondence
Leaking caprock and enhanced overburden permeability							
1_Cap	Under-pressured (*Note 1*)	Hydrostatic *(Note 1)*	50 years	No corres-pondence	Corres-pondence	No correspondence	No correspondence
2_Cap	Hydrostatic	Hydrostatic+ *(Note 3)*	50 years	No corres-pondence	Corres-pondence	No correspondence	Correspondence
3_Cap	Hydrostatic	Sub-lithostatic (*Note 5*)	50 years	No corres-pondence	Corres-pondence	No correspondence	Weak Correspondence

Notes:

1. The under-pressured case corresponds to a depleted hydrocarbon reservoir that has not regained equilibrium after cessation of hydrocarbon extraction. The actual pressure used in the calculations was a plausible minimum value, obtained from a review of North Sea data. Maximum permitted simulated pressure in the under-pressured case was limited to hydrostatic.
2.
3. The final pressure was determined by the nature of the boundary conditions. A hydrostatic boundary condition corresponds to cases where the reservoir is open laterally. A sub-lithostatic boundary condition corresponds to cases where the reservoir is confined laterally by low-permeability faults and / or lower permeability rock formations faulted against the reservoir.
4. The final pressure *within the modelled section of reservoir* diminishes towards a hydrostatic value. The final pressure was calculated by the model, given a fixed hydrostatic pressure at a distance far from the modelled section of reservoir.
5. Although the case does not correspond to any of the chosen sites, it was considered in the calculations as a basis for comparison with Case 3_Well and Case 3_Cap.
6. The maximum permitted simulated pressure *within the modelled section of reservoir* was a plausible maximum percentage of actual lithostatic pressure, based on a review of North Sea data.

It was sought to compare cases where leakage occurs during injection (when injection itself provides a driving force for leakage) with those after injection (when there is no driving force from injection). However, while a plausible injection period could be specified (nominally set at 50 years), the timing of post-injection leakage could not be constrained. Therefore, to bound the effects of post-injection leakage a small number of alternative cases were evaluated in which injection ceased after 10 years. By this time the CO_2 plume had migrated only as far as the leakage path.

It is apparent from Table 4-4 that Case 3_Fault does not correspond to any of the specified generic sites. This is because the only site at which over-pressuring is likely to occur do not have significant faults penetrating the caprock and overburden (Figure 4-1 and Figure 4-3).

4.3.2.4 Discretisation

Compared to reservoir simulation models that are commonly employed by the hydrocarbons industry, the systems models used in the present work had much coarser spatial discretisations. A reservoir model would typically represent a domain of similar size to the reservoirs considered here by using tens or hundreds of thousands of cells. In contrast the models described here represented entire storage systems using only around 2500 compartments. The relatively small number of compartments included in these models means that the spatial variability of parameters is represented less precisely and accurately than would be the case for a typical reservoir model. However, the relatively coarse discretisation means that compared to a reservoir model, a greater number of processes can be considered at the systems level. Therefore, the discretisation adopted for the work is more appropriate for the kinds of scoping calculations needed to meet the project's objectives.

The discretisations used for the different model cases developed in the present work are illustrated in Figure 4-6 to Figure 4-12.

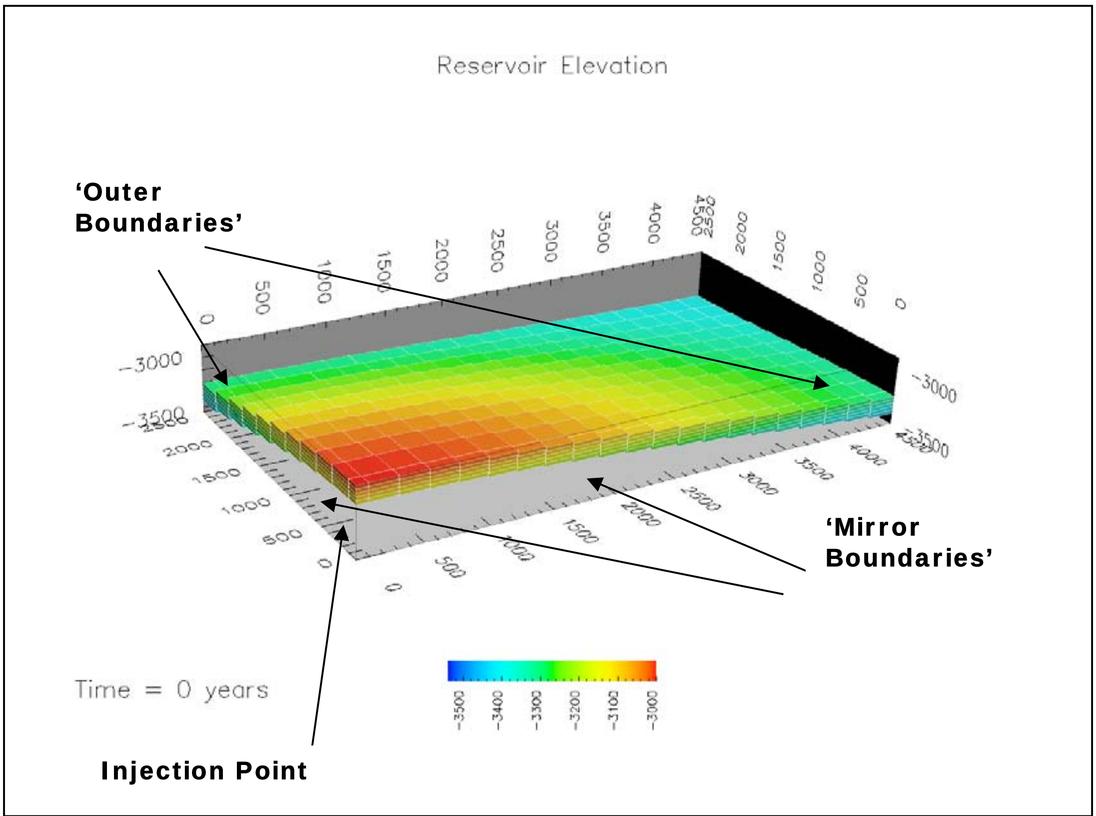

Figure 4-6: Reservoir used for the relatively deep reservoirs (Case 1). Coloured by elevation (m). Note that the model is designed to represent ¼ of a 3D anti-form with injection under the top of the dome at the base of the reservoir.

It should be noted that the leakage paths are positioned different distances away from the injection well in Case 1 (Figure 4-7, Figure 4-8 and Figure 4-9) and in Cases 2 and 3 (Figure 4-10, Figure 4-11 and Figure 4-12). The reason is that the different boundary conditions and final pressure constraints in the different cases caused varied extents of CO_2 plume migration after 10 years.

Initially, test simulations were undertaken for each reservoir type (c.f. Figure 4-7 and Figure 4-10), but no leakage path was specified. In the simulation representing Case 1, CO_2 was injected at a constant (and maximum) injection rate until the pressure at the injection point reached 95% of the hydrostatic pressure. Thereafter, the injection rate was decreased to zero when a mean reservoir pressure of 105% hydrostatic was attained. The injection rates were adjusted so that, given these pressure constraints, after 50 years the injection rate was zero. Using the adjusted injection rate, the extent of CO_2 plume migration after 10 years was established. In each subsequent simulation the centre of the considered leakage path was sited at this distance from the injection point.

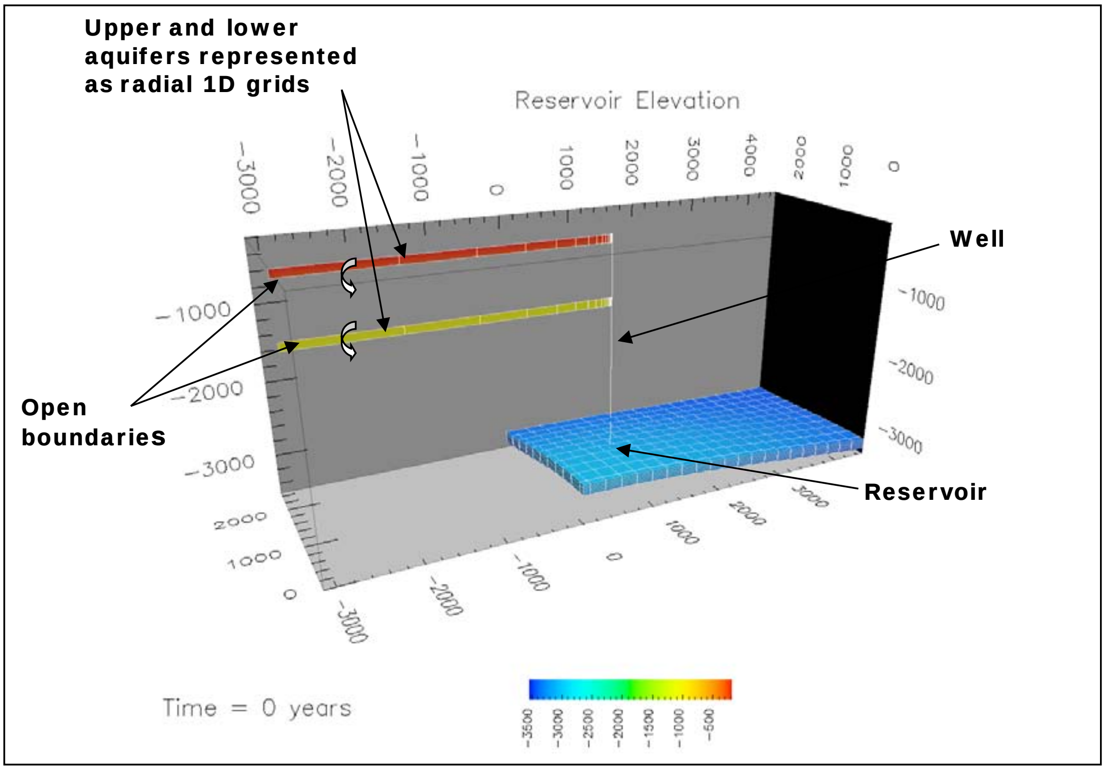

Figure 4-7: Model discretisation used for relatively deep reservoirs (Case 1_Well) – Well leakage case. Coloured by elevation (m).

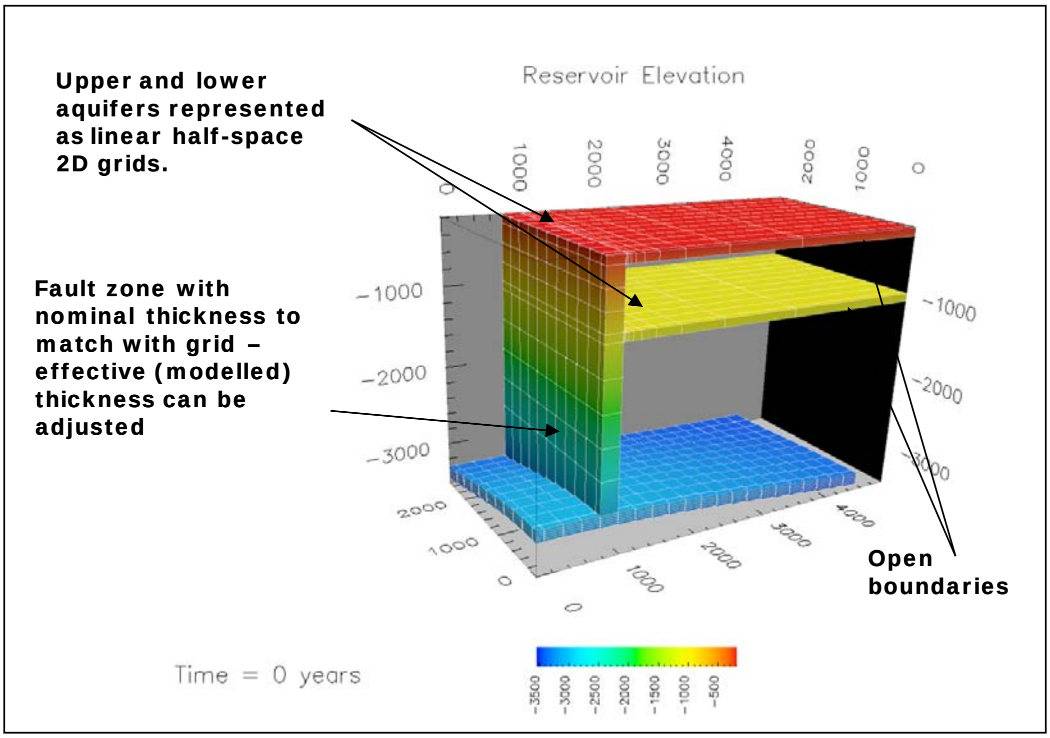

Figure 4-8: Model discretisation used for relatively deep reservoirs (Case 1_Fault) – Fault leakage case. Coloured by elevation (m).

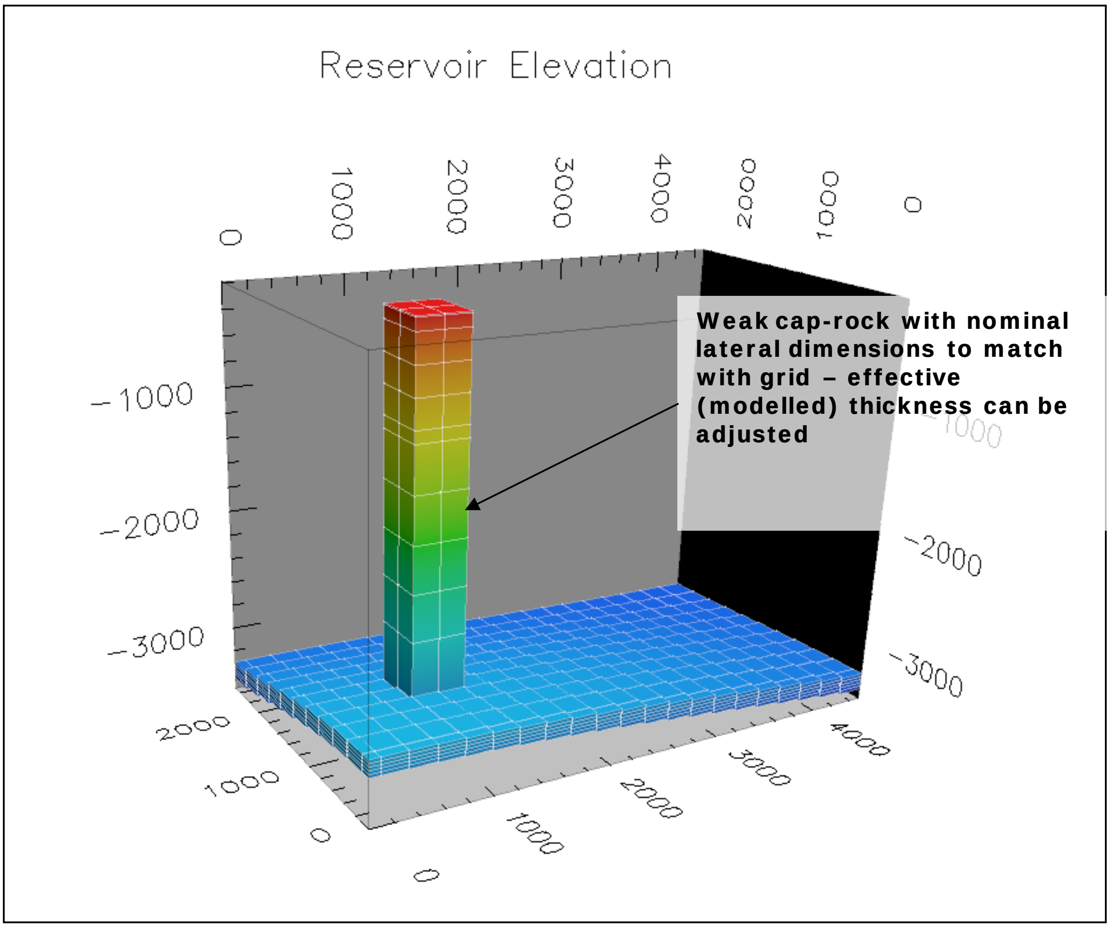

Figure 4-9: Model discretisation used for relatively deep reservoirs (Case 1_Cap) – localised Cap leakage case. Coloured by elevation (m).

Similarly, test simulations were undertaken for Case 2, again without any representation of leakage paths. The injection rate was adjusted so that it became zero after 50 years, given the constraints on pressure. As for Case 1, the leakage paths in subsequent simulations were then placed at a distance from the injection point equal to the maximum distance from this point reached by the CO_2 plume after 10 years of injection.

To facilitate comparison between modelled cases with similar overall reservoir geometry, in simulations for Case 3, the leakage paths were positioned at the same distance from the injection point as in Case 2.

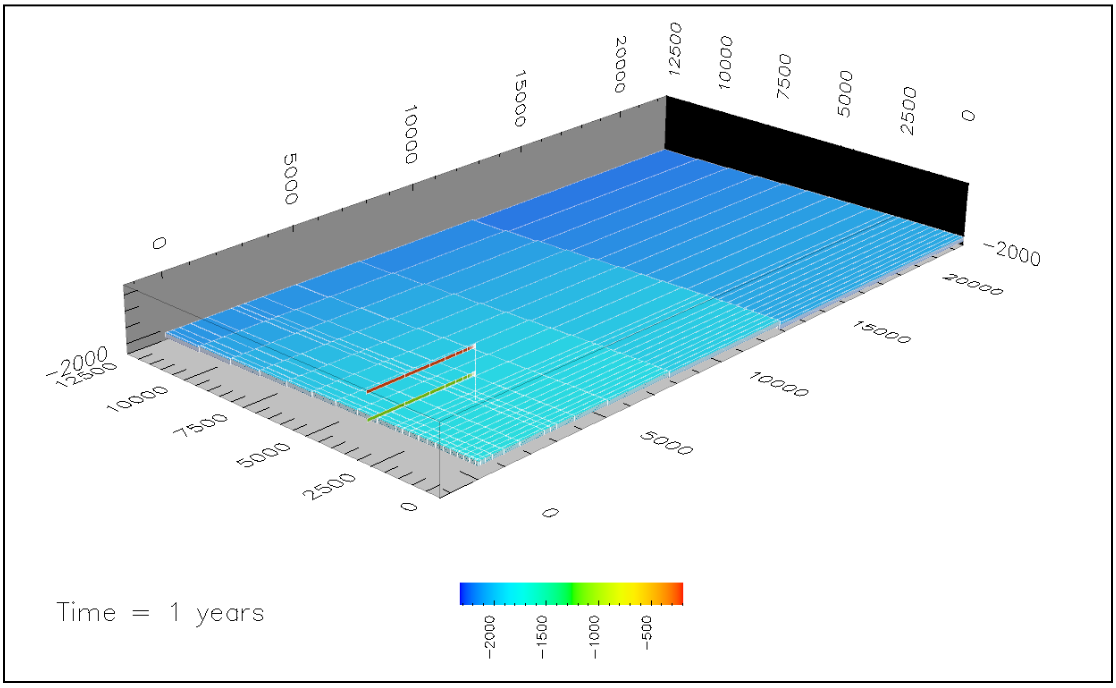

Figure 4-10: Model discretisation used for relatively shallow reservoirs (Cases 2_Well and 3_Well) – Well leakage cases. Coloured by elevation (m).

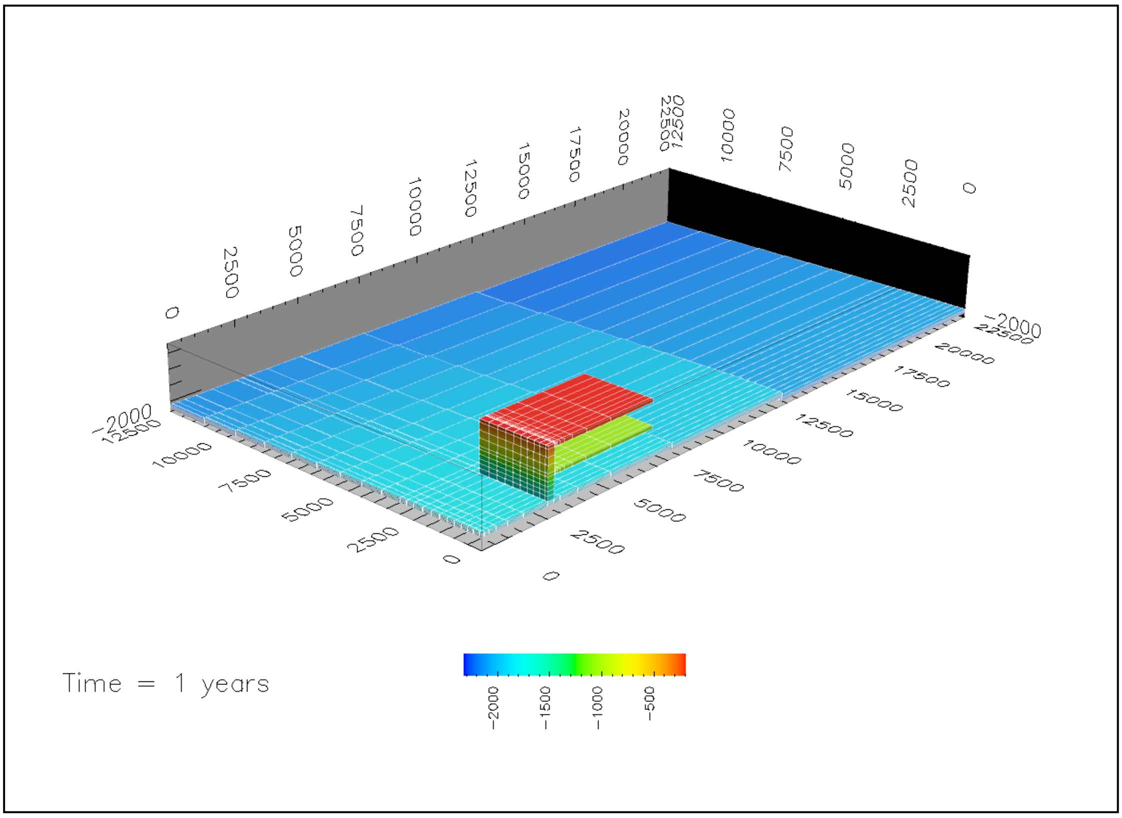

Figure 4-11: Model discretisation used for relatively shallow reservoirs (Cases 2_Fault and 3_Fault) – Fault leakage cases. Coloured by elevation (m).

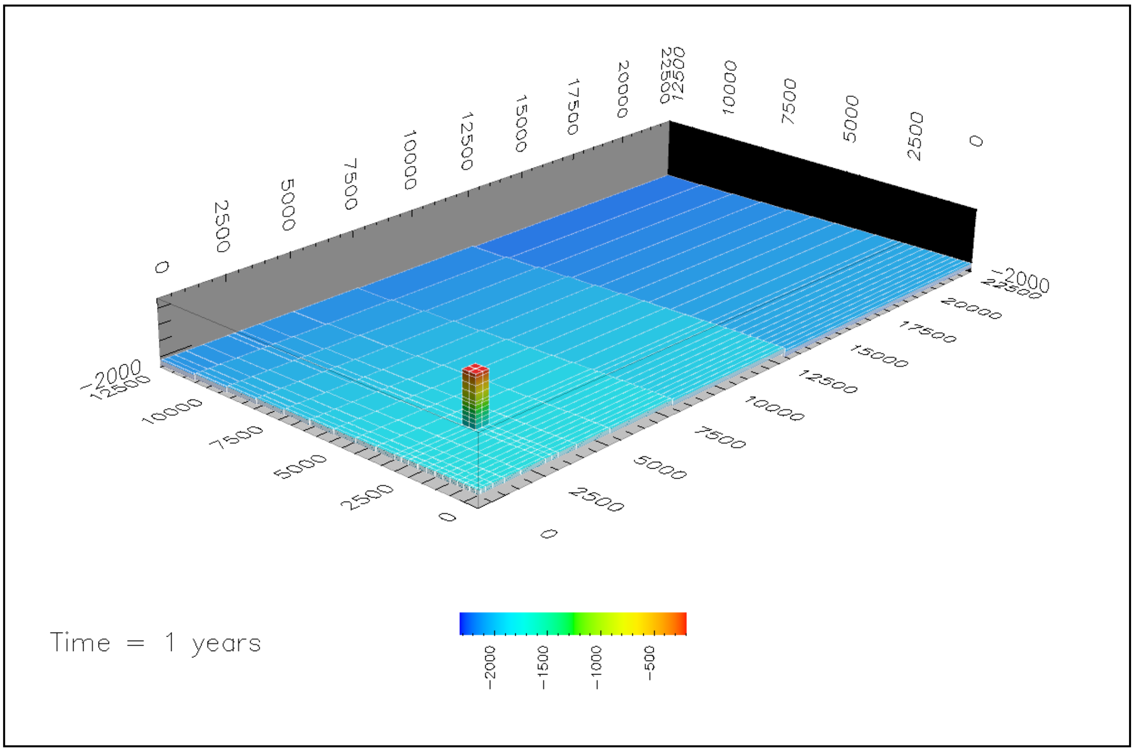

Figure 4-12: Model discretisation used for relatively shallow reservoirs (Cases 2_Cap and 3_Cap) – localised Cap leakage case. Coloured by elevation (m).

4.3.3 Leakage modelling results

4.3.3.1 INJECTION

The modelled CO_2 injection rates varied from case to case owing to:

- the differing initial and final pressure constraints and boundary conditions in the three different basic model cases and;
- the different properties of the various leakage paths.

In Case 1_Well, Case 2_Well, Case 1_Fault, Case 2_Fault, Case 1_Cap and Case 2_Cap the injection was managed through a maximum rate, which was then limited by formation pressure in the injection compartment, in a similar way to that described for the test cases in Section 4.3.2. In these cases injection ramped down from the maximum rate at 95% of hydrostatic to zero at 105% of hydrostatic.

In Case 3_Well, Case 3_Fault and Case 3_Cap, the injection was similarly managed. In this case injection ramped down from the maximum rate at 80% lithostatic, to zero at 90% lithostatic (assuming bulk density of 2500 kg m^{-3}).

In each case, differing degrees of containment gave rise to different reservoir pressures and hence slightly varying total injection volumes. This is consistent with expected real field operation.

The CO_2 injection rates and total injected masses of CO_2 in each of the modelled cases are tabulated in Table 4-5 and illustrated in Figure 4-13 to Figure 4-16.

The flux of injected CO_2 is dependent upon the pressure in the reservoir at the commencement of injection and the final pressure attained, both of which reflect in turn the boundary conditions (whether the reservoir is effectively open laterally or confined). Thus, the highest injection rates were attained in Case 2, in which injection took place in a shallow reservoir without lateral confinement (Figure 4-13 to Figure 4-16).

In Case 3, the shallow, but confined nature of the reservoir causes the pressure initially to increase following the on-set of injection. The injection rate falls accordingly. However, as the CO_2 plume increases in size, the resistance to additional injection of CO_2 decreases and the rate of injection increases once more. This increase continues until near-lithostatic pressure is attained, when the injection rate is specified to decrease.

Table 4-5: Relationship between injection rates across different cases and leakage scenarios.

Simulation Case	Peak injection rates	Time of peak injection rates	Cumulative injected mass of CO_2 at 50 y
	tonnes y^{-1}	y	tonnes
1_Well	3.75E5	35	1.63E7
2_Well	9.38E6	50	4.69E8
3_Well	4.43E6	20	2.03E8
1_Fault	3.75E5	30	1.55E7
2_Fault	9.38E6	50	4.69E8
3_Fault	4.47E6	20	2.05E8
1_Cap	3.75E5	35	1.63E7
2_Cap	9.38E6	50	4.69E8
3_Cap	4.44E6	20	2.03E8

4.3.3.2 FLUXES AND RESPONSE TIMESCALES

The time-dependent fluxes at selected locations are plotted for a sub-set of cases in Figure 4-13 and Figure 4-14.

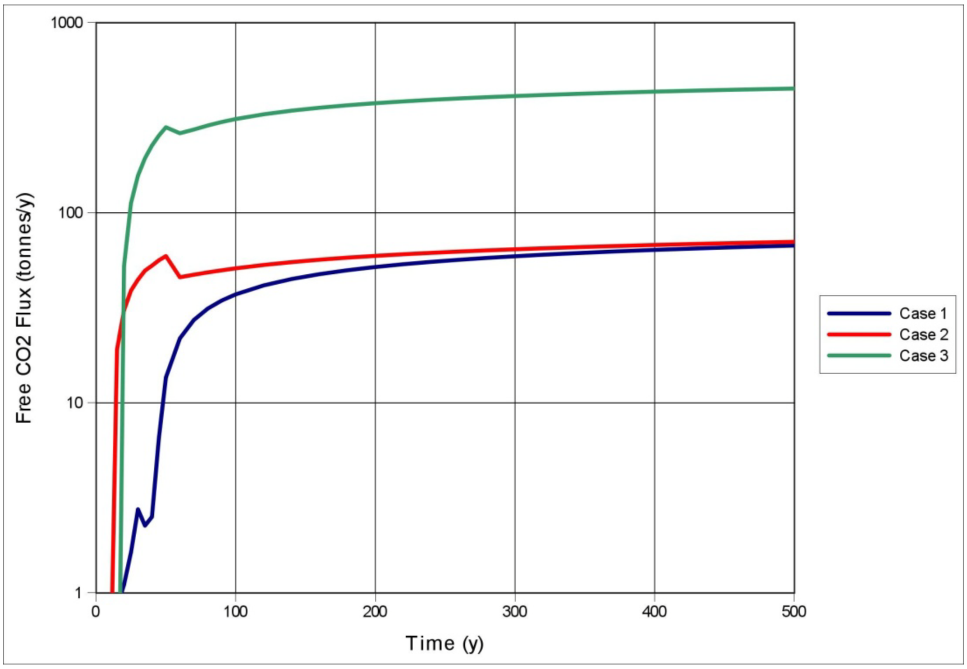

Figure 4-13: Time-dependent variant fluxes of free CO_2 (tonnes y^{-1}) at the boundary between reservoir and well leakage pathway for Case 1_Well, Case 2_Well and Case 3_Well.

The model did not consider the detailed characteristics of the well; it was simply specified that the well failure resulted in a given value of enhanced permeability. For Case 1_Well, the aquifers act as significant CO_2 sinks and effectively buffer the release to seabed. Most leaked CO_2 in the well case enters the deep aquifer and spreads throughout. At 500 years free CO_2 even leaves the outer radial boundary of the deep aquifer. Peak water concentrations are approximately 0.23 mol l^{-1} adjacent to the well. Despite a reservoir loss rate of approx 20,000 kg y^{-1}, only 3 kg y^{-1} makes it to the sea bed (8 kg y^{-1} after 500 y)

Case 2_Well, gives a generally similar response to Case 1_Well, but tends to be faster because CO_2 and water are more mobile in an unconstrained reservoir. The amount of CO_2 dissolution in Case 2_Well is also higher than in Case 1_Well because the salinity is considerably lower; the reservoir in Case 1 contains brine with Total Dissolved Solid (TDS) content = 250,000 mgl^{-1}, whereas in Case 2, the reservoir contains brine with TDS = 35,000 mgl^{-1}.

The behaviour for Case 3_Well is quite different from the other cases, principally because the CO_2 becomes over pressurised (85% of lithostatic pressure). This pressurisation radically increases the speed at which migration through the leakage pathways occurs and the leakage rates once breakthrough has been achieved.

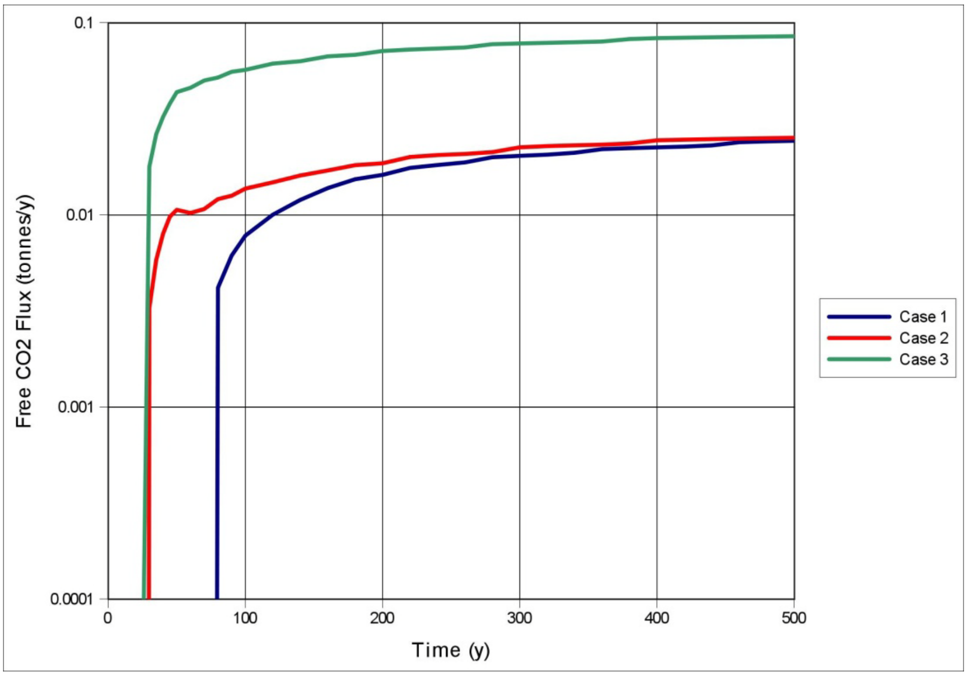

Figure 4-14: Time-dependent variant fluxes of free CO_2 (tonnes y^{-1}) at the intersection of the well leakage pathway and the sea bed for Case 1_Well, Case 2_Well and Case 3_Well.

In contrast the Case 1_Fault showed almost no interaction with the aquifers, and almost all CO_2 lost from the reservoir travels up to the seabed. The control on this is the effective area of intersection. In the fault case there is a large plan area (albeit at a low permeability) that can take buoyant CO_2, relative to the lateral intersection with the aquifer. Consequently considerable vertical migration is possible even given the highly permeable lateral route through the aquifers. Losses from the fault and cap cases are significant in terms of reservoir containment. Clearly if there was a much more permeable well or a poorer connection then the well pathway could dominate.

As for Case 1_Well, Case 2_Fault is broadly similar to Case 1_Fault, except that responses are faster in Case 2_Fault, owing to the unconfined nature of the reservoir. In contrast, Case 3_Fault once again gave considerably different results, owing to the more highly pressurised final condition.

The breakthrough times of free CO_2 and dissolved CO_2 at important locations in the generic sites are shown for all cases and scenarios in Table 4-6 and Table 4-7 respectively.

Table 4-6: Times of Free CO_2 breakthrough to important locations (y).

Case	Reservoir boundary (if open)	Reservoir to leakage pathway	Leakage pathway to lower aquifer	Leakage pathway to upper aquifer	Boundary fluxes from the lower aquifer	Boundary fluxes from the upper aquifer	Leakage pathway to sea bed
1_Well	500	9	40	60	220	-	70
2_Well	0	10	10	20	280	0	25
3_Well	500	15	15	20	60	-	25
1_Fault	500	4	100	200	50	50	200
2_Fault	0	3	120	240	0	0	260
3_Fault	500	6	25	50	360	6	50
1_Cap	500	7	-	-	-	-	90
2_Cap	0	10	-	-	-	-	280
3_Cap	500	15	-	-	-	-	60

Table 4-7: Times of Dissolved CO_2 breakthrough to important locations (y).

Case	Reservoir boundary (if open)	Reservoir to leakage pathway	Leakage pathway to lower aquifer	Leakage pathway to upper aquifer	Boundary fluxes from the lower aquifer	Boundary fluxes from the upper aquifer	Leakage pathway to sea bed
1_Well	500	0	40	50	140	50	500
2_Well	30	500	0	20	180	360	500
3_Well	500	10	2	20	500	340	500
1_Fault	500	0	60	180	500	60	180
2_Fault	30	2	2	220	0	5	220
3_Fault	500	2	3	40	180	7	45
1_Cap	500	0	-	-	-	-	90
2_Cap	30	8	-	-	-	-	240
3_Cap	500	10	-	-	-	-	25

The CO_2 plume tends to dissolve CO_2 in the water ahead of it, which in turn tends to be pushed up the leakage pathway, ahead of the rising CO_2 (especially near the CO_2 phase transition). This means dissolved CO_2 can reach the sea bed ahead of the main free CO_2 plume. It should be noted that here, breakthrough is defined as the first time where 1% of peak flux is exceeded at a given location. Because dissolved fluxes tend to peak earlier than free fluxes (once the free CO_2 pathway gets established and reaches a dynamic equilibrium, water tends not to be pushed ahead to any great degree), this definition tends to make the breakthroughs for dissolved gas earlier.

For each of these locations, given in Table 4-7, peak fluxes and times at which these peak fluxes occurred are given for free CO_2 and dissolved CO_2 in Table 4-8 and Table 4-9 respectively.

Table 4-8: Peak fluxes (tonnes y^{-1}) and times of peak fluxes (y) at important locations for Free CO_2.

Case	Reservoir boundary (if open)		Reservoir to leakage pathway		Leakage pathway to lower aquifer		Leakage pathway to upper aquifer		Boundary fluxes from the lower aquifer		Boundary fluxes from the upper aquifer		Leakage pathway to sea bed	
	Flux	Time	Flux	Time	Flux	Time	Flux	Time	Flux	Time	Flux	Time	Flux	Time
1_Well	0.0E+00	0	6.7E+01	500	6.5E+01	500	9.2E-01	500	6.5E+01	500	4.2E-27	500	2.4E-02	500
2_Well	8.4E-24	50	7.0E+01	500	6.9E+01	500	9.5E-01	500	6.9E+01	500	4.3E-27	500	2.5E-02	500
3_Well	0.0E+00	0	4.5E+02	500	4.5E+02	500	3.6E+00	500	4.5E+02	500	2.4E-26	500	8.5E-02	500
1_Fault	0.0E+00	0	5.5E+04	35	3.6E+03	240	1.9E+02	320	5.2E-26	260	3.2E-27	260	5.6E-03	500
2_Fault	8.4E-24	50	3.4E+04	5	7.8E+03	500	5.1E+02	500	1.0E-25	500	1.4E-26	420	1.2E+04	500
3_Fault	0.0E+00	0	1.8E+05	50	1.2E+05	50	3.4E+03	500	6.0E+04	500	1.0E-25	420	3.8E+04	500
1_Cap	0.0E+00	0	4.6E+04	35	-	-	-	-	-	-	-	-	5.5E+03	200
2_Cap	8.4E-24	50	7.4E+03	15	-	-	-	-	-	-	-	-	4.1E+03	500
3_Cap	0.0E+00	0	3.7E+04	50	-	-	-	-	-	-	-	-	2.6E+04	500

The maximum peak flux of CO_2 in this table is for Case 3_Fault. However, even this peak flux only implies several million tonnes are lost to the lower aquifer within the considered time frame, which itself is a much greater quantity than any CO_2 leaking from the entire system. The total injected mass of CO_2 at 50 years is given in Table 4-10. For Case 3_Fault, the total mass injected was 2.05E8 tonnes. Thus, around 3% of the injected CO_2 leaked over this timescale.

Table 4-9: Peak fluxes (tonnes y^{-1}) and times of peak fluxes (y) at important locations for Dissolved CO_2.

Case	Reservoir boundary (if open)		Reservoir to leakage pathway		Leakage pathway to lower aquifer		Leakage pathway to upper aquifer		Boundary fluxes from the lower aquifer		Boundary fluxes from the upper aquifer		Leakage pathway to sea bed	
	Flux	Time	Flux	Time	Flux	Time	Flux	Time	Flux	Time	Flux	Time	Flux	Time
1_Well	0.0E+00	0	2.4E+00	30	6.9E-01	45	1.9E-02	60	5.3E-01	220	3.6E-06	440	0.0E+00	0
2_Well	4.7E+03	500	3.4E-01	10	6.8E-02	15	6.5E-02	25	6.0E+00	280	1.6E-05	500	0.0E+00	0
3_Well	0.0E+00	0	4.8E-01	20	7.3E-01	20	1.6E-02	25	2.6E+00	60	1.3E-02	500	0.0E+00	0
1_Fault	0.0E+00	0	2.3E+03	10	1.6E+02	140	9.2E+00	300	1.4E-04	1	2.5E-04	260	2.0E+01	300
2_Fault	4.7E+03	500	9.0E+02	10	2.6E+02	120	3.1E+01	260	1.4E-03	500	1.4E-03	420	9.2E+01	260
3_Fault	0.0E+00	0	2.4E+02	6	5.4E+02	30	5.8E+01	60	1.1E+03	320	1.0E-02	420	1.6E+02	60
1_Cap	0.0E+00	0	8.5E+02	0	-	-	-	-	-	-	-	-	5.6E+01	120
2_Cap	4.7E+03	500	7.4E+02	15	-	-	-	-	-	-	-	-	2.5E+01	320
3_Cap	0.0E+00	0	1.3E+02	20	-	-	-	-	-	-	-	-	1.4E+02	70

It is stressed that tables Table 4-8 and Table 4-9 do not show the time for breakthrough, but rather the time of maximum (peak) CO_2 flux at the stated localities within the modelled time frame of 500 y. Thus, a peak flux at 500 y means that the maximum simulated flux occurred at this time. However, if the flux was still increasing at 500 years, the maximum peak flux would occur after this time. Since the models were not run to longer times, the actual time of peak flux could not be specified. Of course it would be possible to run the models to longer times. However, given the target of the investigations was to shed light on monitoring strategies that will be employed on shorter timeframes, long-term monitoring was not carried out.

Of importance for designing monitoring programmes is knowledge of the areas over which the leakage of CO_2 is likely to occur. Peak areal fluxes of free CO_2 and dissolved CO_2 are tabulated for the same locations as considered previously in Table 4-10 and Table 4-11 respectively.

Table 4-10: Peak areal fluxes (tonnes m^{-2} y^{-1}) at important locations for Free CO_2.

Case	Reservoir boundary (if open)	Reservoir to leakage pathway	Leakage pathway to lower aquifer	Leakage pathway to upper aquifer	Boundary fluxes from the lower aquifer	Boundary fluxes from the upper aquifer	Leakage pathway to sea bed
1_Well	0.0E+00	1.9E+00	5.2E-01	7.3E-03	2.6E-05	0.0E+00	1.9E-01
2_Well	0.0E+00	2.0E+00	5.5E-01	7.6E-03	2.7E-05	0.0E+00	2.0E-01
3_Well	0.0E+00	1.3E+01	3.5E+00	2.9E-02	1.8E-04	0.0E+00	6.8E-01
1_Fault	0.0E+00	1.9E-01	2.0E-02	1.2E-03	0.0E+00	0.0E+00	1.2E-02
2_Fault	0.0E+00	1.4E-01	3.1E-02	2.0E-03	0.0E+00	0.0E+00	1.9E-02
3_Fault	0.0E+00	2.9E-01	4.9E-01	1.4E-02	2.4E-01	0.0E+00	6.1E-02
1_Cap	0.0E+00	2.2E-01	-	-	-	-	2.6E-02
2_Cap	0.0E+00	2.9E-02	-	-	-	-	1.6E-02
3_Cap	0.0E+00	1.5E-01	-	-	-	-	1.0E-01

Table 4-11: Peak areal fluxes (tonnes m^{-2} y^{-1}) at important locations for Dissolved CO_2.

Case	Reservoir boundary (if open)	Reservoir to leakage pathway	Leakage pathway to lower aquifer	Leakage pathway to upper aquifer	Boundary fluxes from the lower aquifer	Boundary fluxes from the upper aquifer	Leakage pathway to sea bed
1_Well	0.0E+00	6.9E-02	5.5E-03	1.5E-04	2.1E-07	0.0E+00	0.0E+00
2_Well	8.8E-03	9.7E-03	5.4E-04	5.1E-04	2.4E-06	0.0E+00	0.0E+00
3_Well	0.0E+00	1.3E+01	3.5E+00	2.9E-02	1.8E-04	0.0E+00	6.8E-01
1_Fault	0.0E+00	4.2E-03	6.2E-04	4.6E-05	0.0E+00	0.0E+00	4.5E-05
2_Fault	8.9E-03	1.4E-03	1.0E-03	1.2E-04	0.0E+00	0.0E+00	1.5E-04
3_Fault	0.0E+00	3.9E-04	2.2E-03	2.3E-04	4.4E-03	1.2E-07	2.6E-04
1_Cap	0.0E+00	4.0E-03	-	-	-	-	2.6E-04
2_Cap	8.8E-03	3.0E-03	-	-	-	-	1.0E-04
3_Cap	0.0E+00	5.2E-04	-	-	-	-	5.7E-04

To illustrate the impact of the pressure conditions in the reservoir on the leakage fluxes, time-variant fluxes of CO_2 at the intersection between a fault leakage pathway and the seabed are given for the three basic cases in Figure 4-15. This figure shows clearly that the leakage fluxes in Case 3, which had the greatest final mean reservoir pressure at the end of CO_2 injection (85% of lithostatic in contrast to near-hydrostatic in the other cases), were much greater than for the other cases.

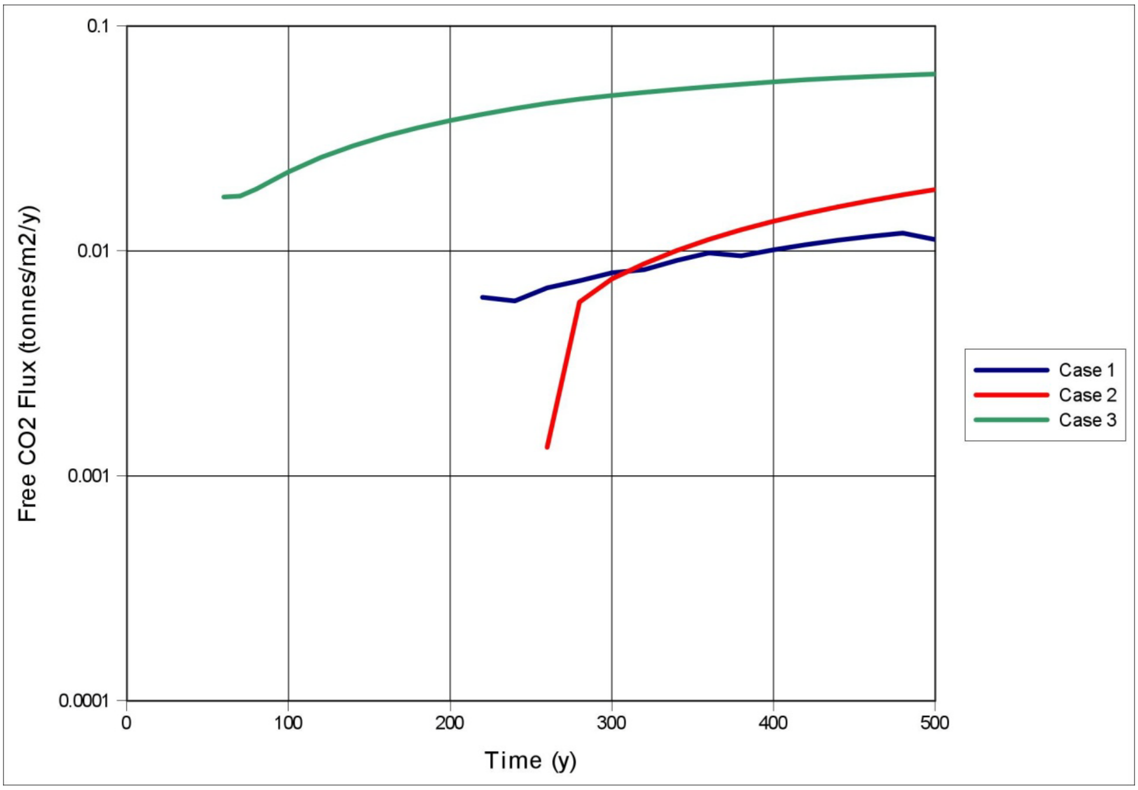

Figure 4-15: Time variant areal fluxes of free CO_2 (tonnes m^{-2} y^{-1}) at the intersection of the fault leakage pathway and the sea bed for Case 1_Fault, Case 2_Fault and Case 3_Fault

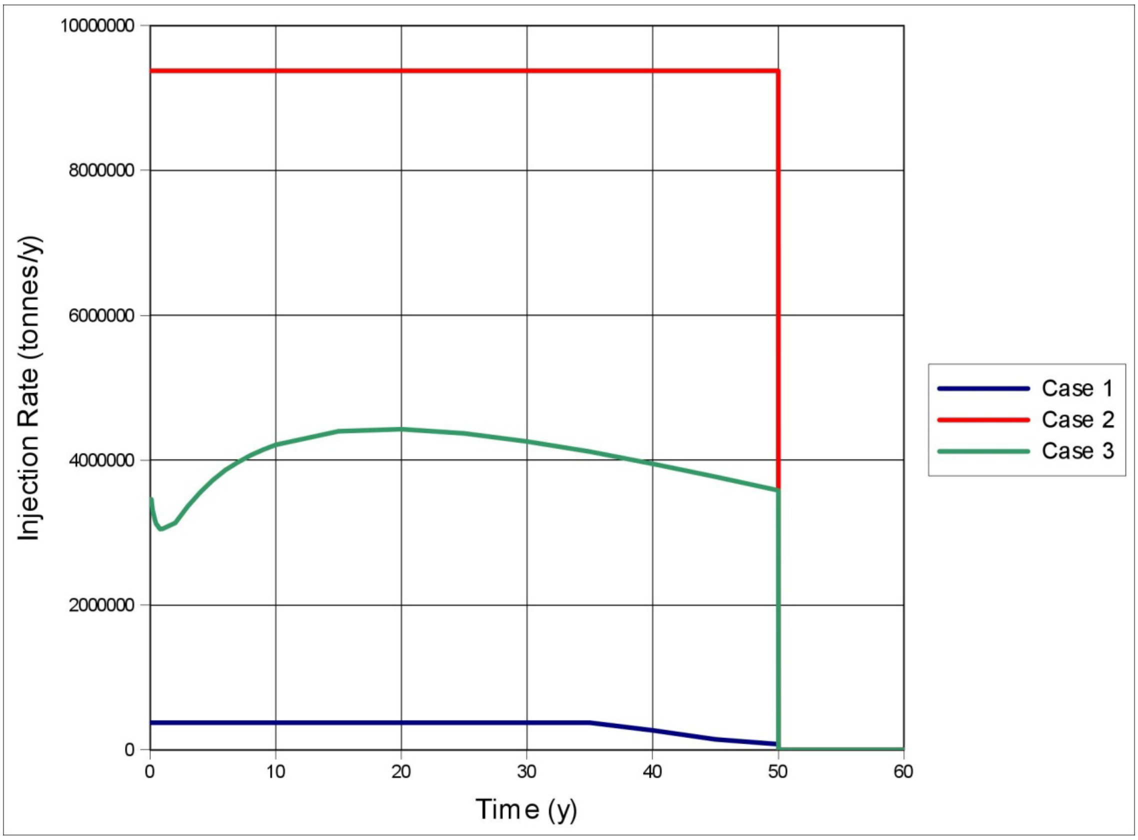

Figure 4-16: Time-variant injected flux of CO_2 at the injection point. Fluxes are shown for the fault leakage cases Case 1_Fault, Case 2_Fault and Case 3_Fault. In all cases injection rates were limited so that the maximum formation pressure was not exceeded in the injection compartment at any time during injection.

4.3.3.3 DISPOSITION OF CO_2

The final spatial distributions of CO_2 within a site are relevant to the design of monitoring programmes since they allow definition of the rock volume to be monitored. Cumulative masses of free CO_2 and dissolved CO_2 in important locations at the end of the simulation period of 500 years are tabulated for each case in Table 4-12 and Table 4-13 respectively.

Table 4-12: Cumulative mass of Free CO_2 after 500 years (tonnes) at important locations.

Case	Reservoir boundary (if open)	Reservoir to leakage pathway	Leakage pathway to lower aquifer	Leakage pathway to upper aquifer	Boundary fluxes from the lower aquifer	Boundary fluxes from the upper aquifer	Leakage pathway to sea bed
1_Well	0.0E+00	2.4E+04	2.3E+04	3.3E+02	1.6E+04	2.0E-24	7.7E+00
1_Fault	0.0E+00	5.3E+06	9.2E+05	4.3E+04	1.5E-23	6.5E-25	1.0E+06
1_Cap	0.0E+00	3.6E+06	-	-	-	-	2.0E+06
2_Well	2.3E-21	2.9E+04	2.9E+04	3.9E+02	1.4E+04	2.1E-24	9.2E+00
2_Fault	2.3E-21	6.4E+06	2.2E+06	9.1E+04	2.6E-23	1.1E-24	1.8E+06
2_Cap	2.3E-21	1.4E+06	-	-	-	-	5.9E+05
3_Well	0.0E+00	1.8E+05	1.8E+05	1.5E+03	1.7E+05	3.3E-24	3.4E+01
3_Fault	0.0E+00	6.4E+07	4.7E+07	1.2E+06	3.5E+06	1.3E-23	1.2E+07
3_Cap	0.0E+00	1.0E+07	-	-	-	-	8.6E+06

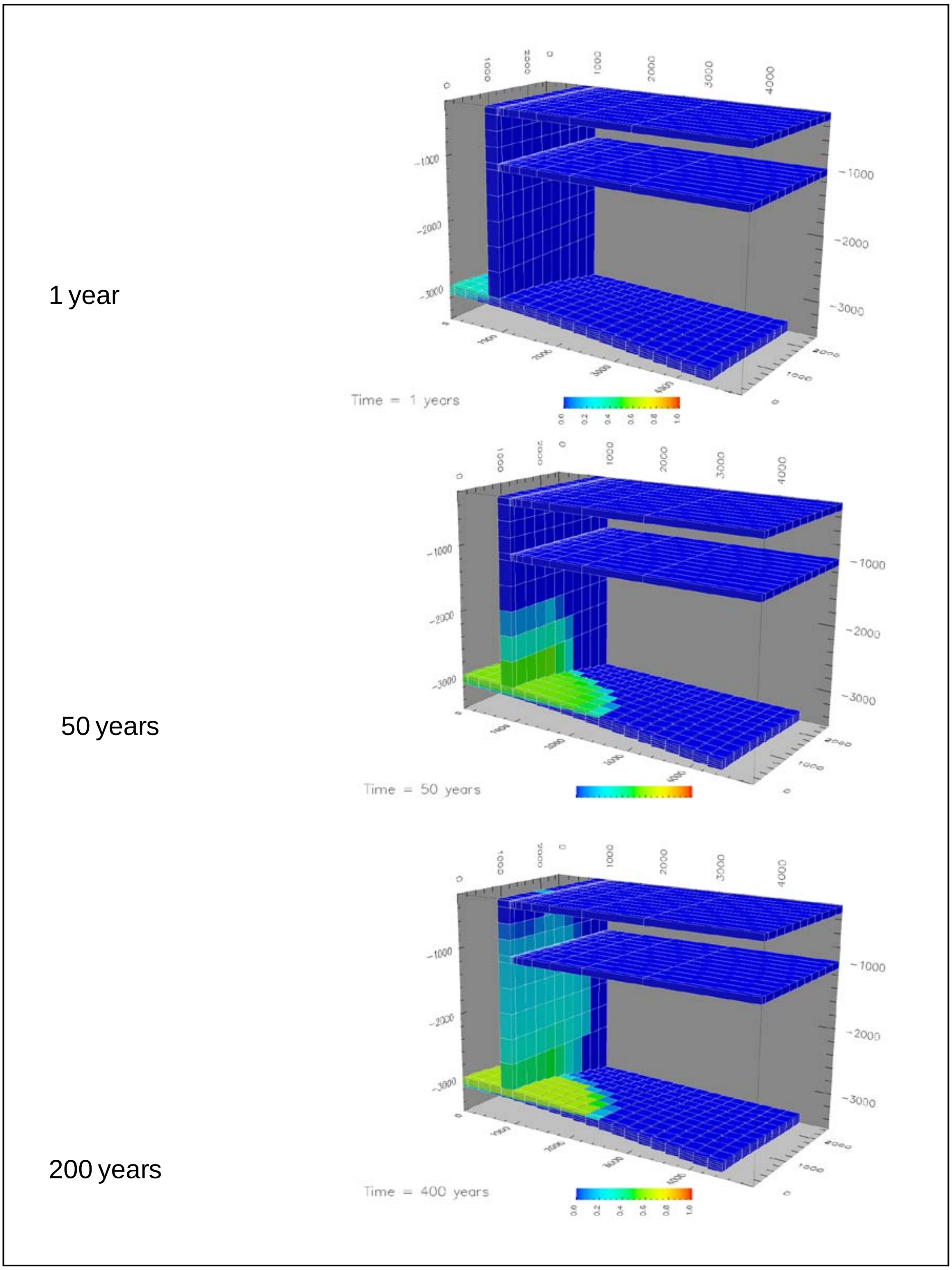

Figure 4-17: Time series of CO_2 saturation variation for the Case 1_Fault model (1, 50, and 200 years).

To illustrate how the spatial disposition of CO_2 depend upon the relative permeabilities of reservoir, leakage pathway and any aquifers in the overburden, outputs from Case 1_Fault are shown after 1, 50 and 200 years in Figure 4-17. In this case there is almost no interaction between the migrating CO_2 and the aquifers. The reason for this, as stated earlier, is the effective areas of intersection. In the fault case there is a large plan area (albeit at a low permeability) that can take buoyant CO_2, relative to the lateral intersection with the aquifer.

Table 4-13: Cumulative mass of Dissolved CO_2 after 500 years (tonnes) at important locations.

Case	Reservoir boundary (if open)	Reservoir to leakage pathway	Leakage pathway to lower aquifer	Leakage pathway to upper aquifer	Boundary fluxes from the lower aquifer	Boundary fluxes from the upper aquifer	Leakage pathway to sea bed
1_Well	0.0E+00	2.7E+02	2.8E+02	4.6E-01	2.9E+01	1.7E-04	0.0E+00
1_Fault	0.0E+00	1.1E+05	3.0E+04	1.1E+03	2.7E-04	4.4E-02	2.3E+03
1_Cap	0.0E+00	1.6E+04	-	-	-	-	4.3E+03
2_Well	1.2E+06	1.3E+00	3.8E+00	5.8E-01	2.8E+02	3.7E-04	0.0E+00
2_Fault	1.2E+06	6.6E+04	3.5E+04	1.8E+03	3.6E-01	9.3E-02	5.7E+03
3_Cap	0.0E+00	1.8E+04	-	-	-	-	8.5E+03
3_Well	0.0E+00	1.8E+02	2.9E+02	5.0E-01	3.6E+01	1.7E-01	0.0E+00
3_Fault	0.0E+00	2.4E+04	7.9E+04	4.1E+03	2.1E+05	1.3E+00	1.3E+04
2_Cap	1.2E+06	4.0E+04	-	-	-	-	2.3E+03

4.3.3.4 Dissolved gases in aquifers

Any relatively permeable horizons that might occur in the overburden above the cap rock could potentially form reservoirs for secondary CO_2 storage. Consequently, such aquifers may be targets for monitoring. However, not all aquifers will be accessible to migrating CO_2. It is therefore important that designs for monitoring programmes are founded on an understanding of the factors that influence whether CO_2 will enter these aquifers. To inform the development of this understanding, the distributions of dissolved gases in the modelled aquifers are given in Table 4-14.

Table 4-14: Characteristics of dissolved gasses in the Lower and Upper aquifers.

Case	Peak Fraction Impacted (-)		Peak Average Concentration (mol l^{-1})		Peak Maximum Saturation (-)		Peak Maximum Concentration (mol l^{-1})		Time of Peak Impact (y)	
	Lower	Upper	Lower	Upper	Lower	Upper	Lower	Upper	Lower	Upper
1_Well	1.00E+00	4.35E-01	1.80E-01	4.92E-02	1.40E-01	8.43E-02	2.72E-01	4.47E-01	200	440
2_Well	1.00E+00	4.35E-01	1.58E+00	5.76E-02	1.41E-01	8.47E-02	1.58E+00	4.47E-01	160	380
3_Well	1.00E+00	1.00E+00	1.80E-01	2.14E-01	1.94E-01	1.02E-01	2.79E-01	4.47E-01	60	400
1_Fault	6.46E-02	1.28E-02	2.48E-02	3.84E-03	1.53E-01	8.57E-02	1.82E-01	4.47E-01	500	480
2_Fault	9.77E-02	2.69E-02	1.03E-01	6.49E-03	1.64E-01	9.35E-02	1.58E+00	4.48E-01	460	500
3_Fault	1.00E+00	3.15E-01	1.81E-01	6.08E-02	3.03E-01	1.98E-01	1.82E-01	4.50E-01	260	480

The temporal variations in average dissolved CO_2 concentrations in the upper and lower aquifers for the three modelled cases where leakage occurs through a fault are illustrated in Figure 4-18. This figure shows that, as expected, the concentrations of CO_2 in the lower aquifer are higher than in the upper aquifer. The actual concentrations are quite small, but in principle would be easily detectable if samples could be obtained.

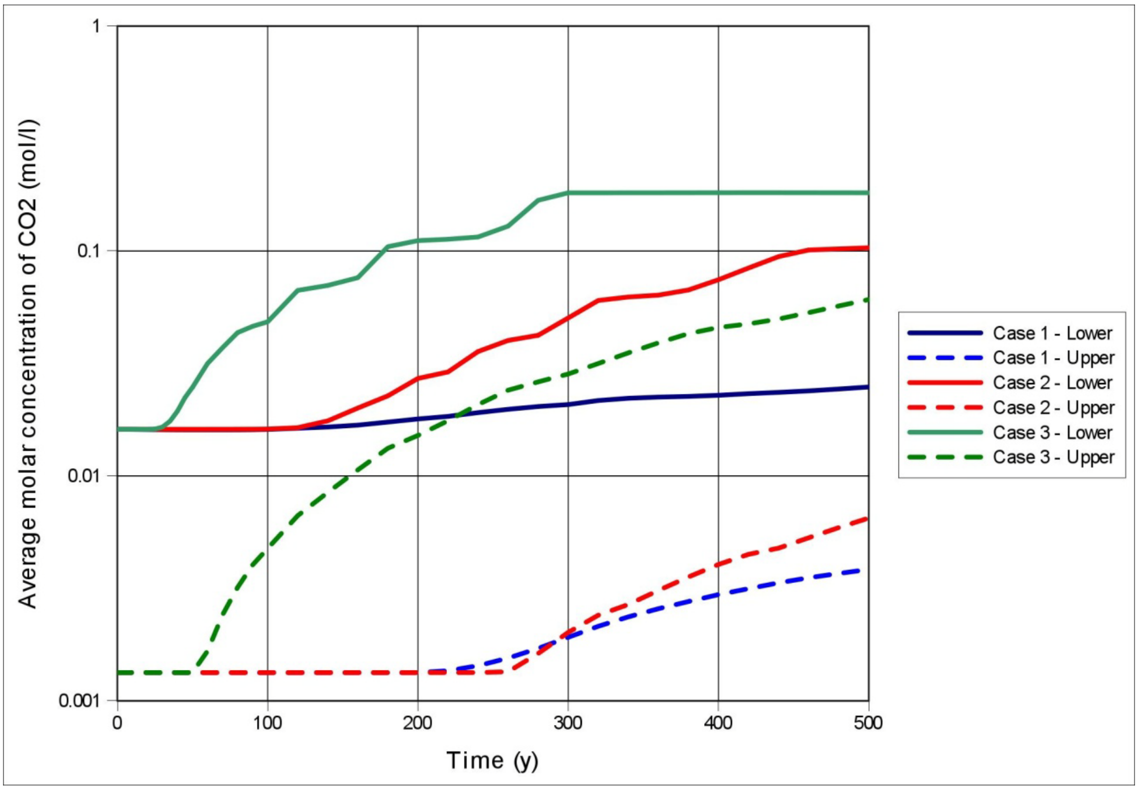

Figure 4-18: Calculated average concentrations of dissolved gas in the upper and lower aquifers as a function of time for fault leakage cases, Case 1_Fault, Case 2_Fault and Case 3_Fault.

4.3.3.5 Gas pressures

Gas pressures could be monitored to indicate whether the system is behaving as expected. Temporal variations in pressure at different locations in the leakage pathway are illustrated for the “leaking caprock and enhanced-permeability overburden scenario” in Cases 1, 2 and 3 (Case 1_Cap, Case 2_Cap and Case 3_Cap), in Figure 4-19, Figure 4-20 and Figure 4-21 respectively. Comparison between these figures shows the strong dependency of the pressure variation on the initial pressure conditions in the reservoir.

The models contained no injection well as such, but rather CO_2 was injected directly into the reservoir. Equivalent bottom hole pressures were calculated (and used to limit injection) by specifying the well geometry. The pressures are therefore cell averaged formation pressures at different radii from the injection location.

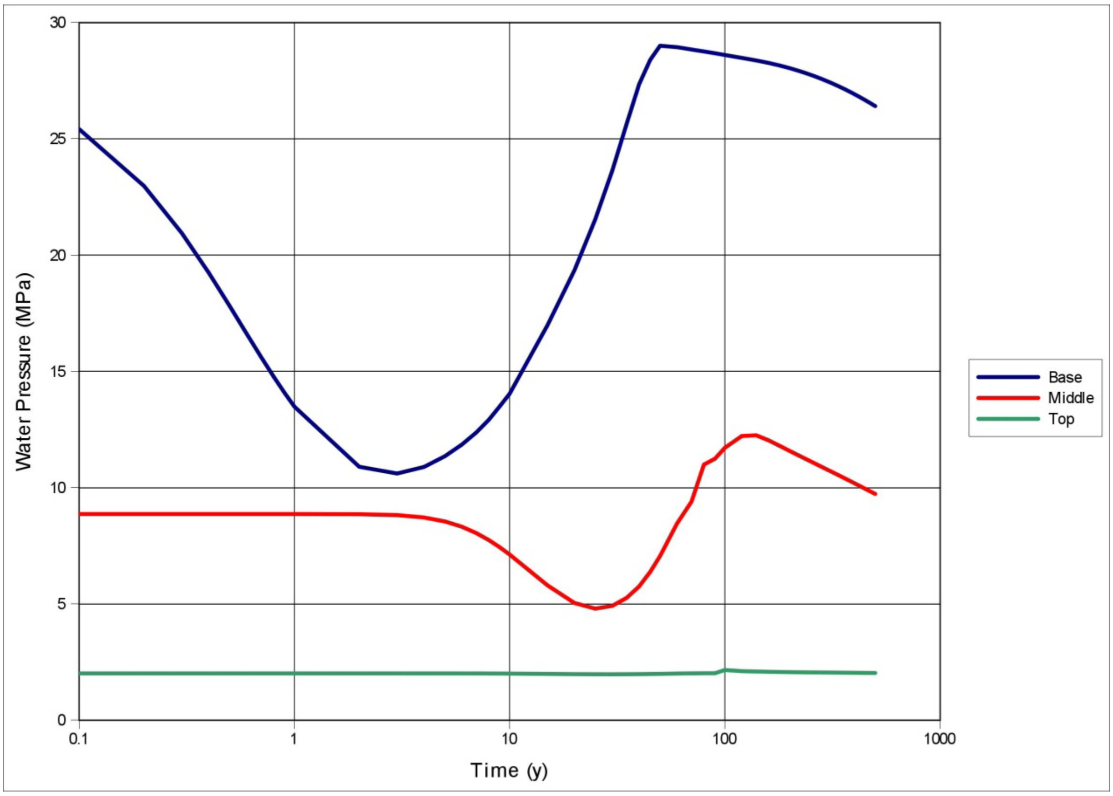

Figure 4-19: Gas pressures (MPa) in the reservoir and at the base (-3000 m), centre (-1405 m) and top (-190 m) of the leakage pathway as functions of time for Case 1_Cap.

Figure 4-19 shows the pressure response at the base of the failed cap for Case 1_Cap. The failed cap gives the greatest mean representative variation in pressure of the three leakage modes. Clearly in this case the system showed the impact of the low initial reservoir pressure (the cap zone and reservoir are not in equilibrium at t=0). Also shown are the effects of subsequent injection, and the initiation of upwards pressure-driven flow (especially between 2 and 20 years) through the leaking zone, combined with buoyancy effects, which then tend to dominate by >20 years.

In contrast, the Case 2_Cap pressure response was much smaller (Figure 4-20). In this case the system showed only minor pressure impacts as a result of the injection and subsequent gas migration and as such CO_2 migration up the pathway is largely buoyancy driven.

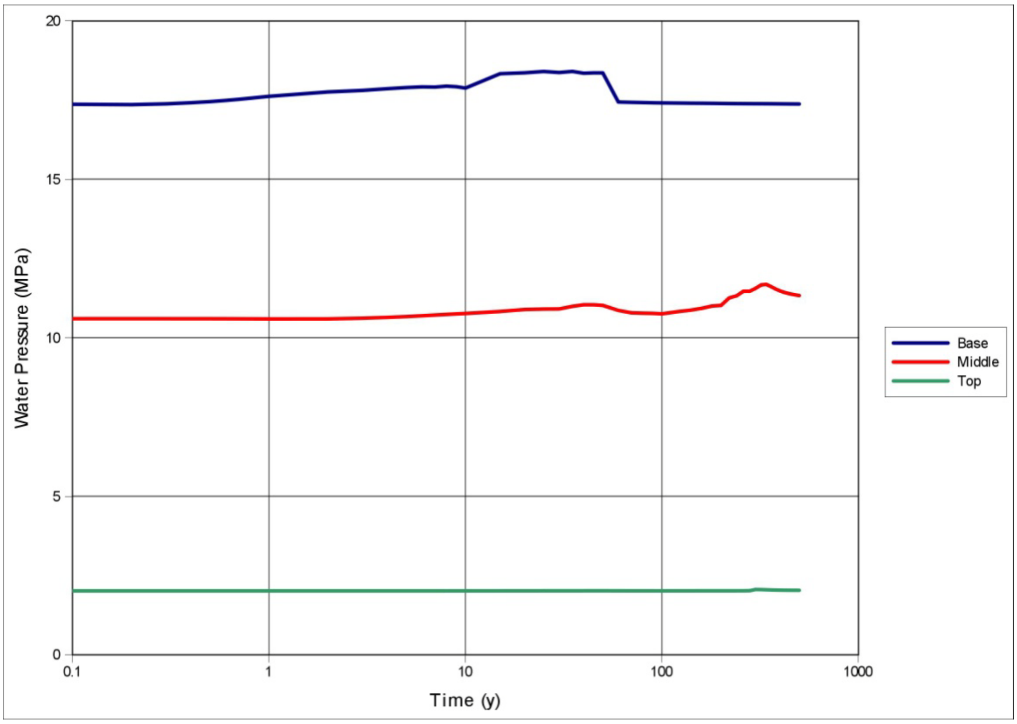

Figure 4-20: Gas pressures (MPa) in the reservoir and at the base, centre and top of the leakage pathway as functions of time for Case 2_Cap.

The Case 3_Cap pressure response was much greater than in Case 2_Cap and similar in magnitude to that shown by Case 1_Cap (Figure 4-21). Case 3_Cap showed the impact of injection, and the initiation of upwards pressure-driven flow along the leaking zone in addition to buoyancy effects. However, the temporal variations in the responses differed markedly between Case 1_Cap and Case 3_Cap. Whereas the former case showed a decrease in pressure over the first few years of injection, followed by a later increase, the latter showed a steady increase in pressure from the on-set of injection. These reflect the differing initial and final pressures.

It would also be possible to monitor pressure variations within any relatively permeable formations that occur within the overburden above the reservoir. However, in the cases considered in the present work, the most extreme calculated pressure responses in the aquifers were quite small. The most extreme variations occurred in Case 3_Fault. In this case, the final reservoir pressure at the termination of injection was relatively high, at 85% of lithostatic pressure. Consequently, there was a relatively steep pressure gradient driving CO_2 along the fault leakage pathway. Nevertheless, the pressure responses in the two aquifers were relatively small (Figure 4-22).

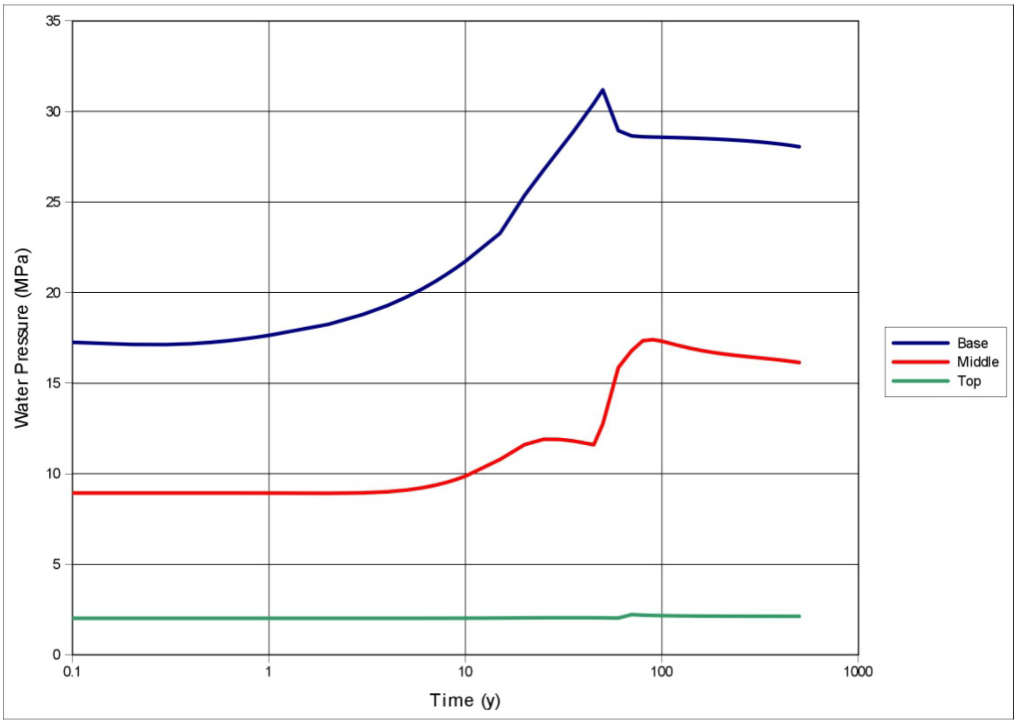

Figure 4-21: Gas pressures (MPa) in the reservoir and at the base, centre and top of the leakage pathway as functions of time for Case 3_Cap.

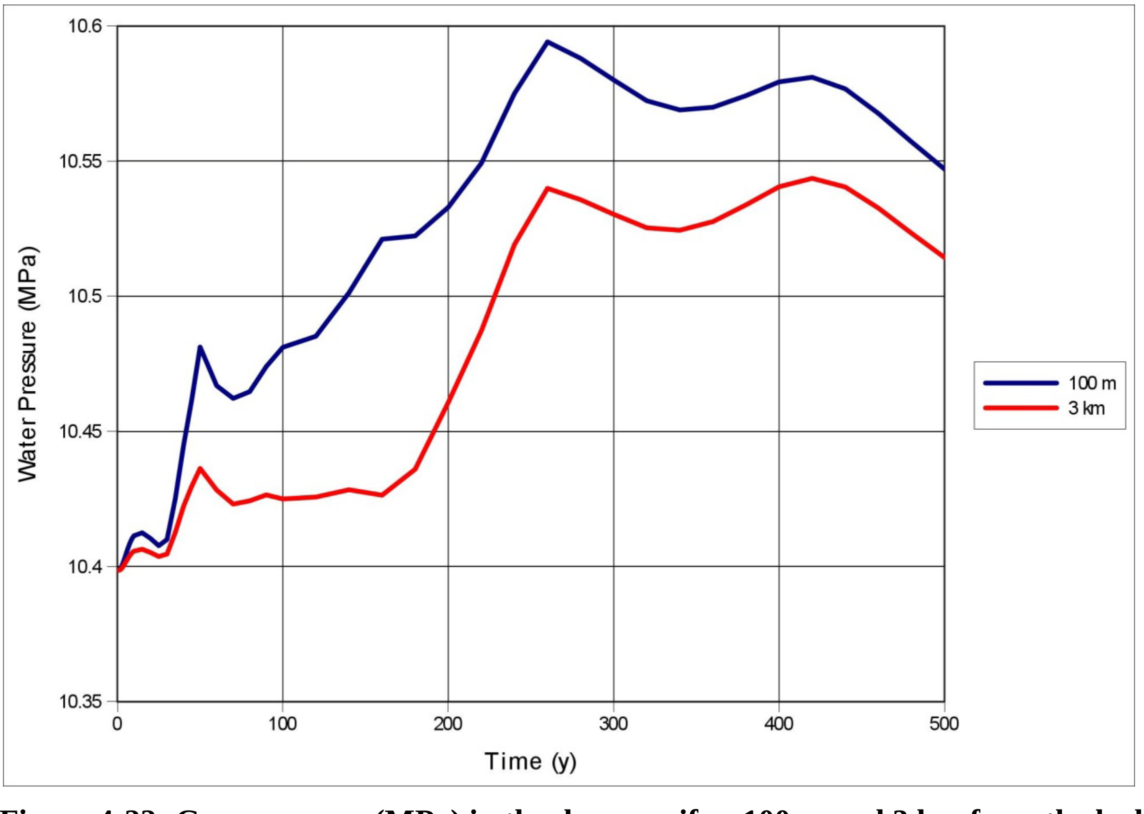

Figure 4-22: Gas pressures (MPa) in the deep aquifer, 100 m and 3 km from the leaking fault for the Case 3 fault leakage case. This case shows the most extreme (and yet relatively modest) pressure variation in the aquifers as a result of CO_2 leakage.

4.3.4 10 year injection cases

For comparison with the outputs from simulations of CO_2 injection over 50 years, cases were run for the Fault and Well leakage scenarios where CO_2 injection was halted after 10 years (the approximate time that the CO_2 plume interacts with the leakage pathway). These cases represent the consequence of leakage from the reservoir being identified at the earliest possible opportunity and injection ceasing as a consequence.

The cases are difficult to compare with the 50-year cases because the volumes and reservoir dispositions of CO_2 are so different, but the following observations can be made for the Well leakage cases:

- In all cases losses from the reservoir continued to the end of the run, albeit at significantly reduced rates.
- Peak well loss rates and cumulative losses for the closed reservoir cases (1 and 3) are reduced by 2-3 orders of magnitude, such that no leakage occurs to the seabed or the upper aquifer. Impacts to the lower aquifer extend to a maximum of 20% of the volume and then only at very low saturations.
- For the open reservoir case (Case 2) peak well loss rates and cumulative losses are only reduced by approximately a factor of two. The open boundaries of this case allow the CO_2 to spread more widely along the top of the reservoir and permit a higher net injection rate than Cases 1 and 3, hence leakage can be sustained due to the higher CO_2 saturations at the base of well.

For the fault leakage cases the behaviour is slightly more variable, but can be summarised as follows:

- Case 1: Losses from the reservoir are reduced by approximately a factor of 5 (total and maximum rate). This reduction in loss is sufficient that the gas does not break through to the sea bed or the aquifers; the inflow of water into the reservoir from the aquifers is sufficient to dissolve all leaking free CO_2. Leakage is maintained until the end of the model run.
- Case 2: The open boundaries again allow CO_2 to spread significantly right up to and beyond the leakage pathway; hence the fault is able to generate a stable leakage pathway. As such the maximum leakage rates and cumulative amounts are only reduced by approximately 2/3 versus the 50 year injection case. Leakage is maintained until the end of the model run.
- Case 3: The high pressurisation and significant size of the fault zone allows a significant CO_2 saturation pathway to be maintained between the CO_2 'bubble' and the leakage pathway. The key difference with Case 1 fault leakage is that the over-pressurisation allows pathways to the aquifers and seabed to be maintained. All peak flux rates and cumulative fluxes are reduced by a factor of approximately 5. Leakage is maintained until the end of the model run.

In all cases it appears that leakage is maintained at a significant fraction of the 50 year rates for most cases. An effective termination of leakage to aquifers and seabed only occurs in Case 1, where the inflowing water from the aquifers is sufficient to dissolve all the reduced quantity of free CO_2 leaving the reservoir. It is also clear that the disposition of CO_2 in the reservoir relative to the leakage pathway is important in the reduced injection time cases. If a CO_2 saturation link cannot be maintained between the leakage pathway and the main bubble of CO_2, then significant leakage cannot occur. In the case with open boundaries (Case 2), there is a much greater areal spread of CO_2 along the upper boundary of the reservoir, and a larger mass injected generally, enabling such a link to be maintained.

4.3.5 Offline calculations

4.3.5.1 WATER PH

The pH of the formation waters and seawater depends upon a large number of factors, many of which will be site-specific, including: the formation water chemistry; temperature; the mineralogy of the rock formation; and mixing between different waters. For these reasons, it is not possible to calculate precise values of pH for the various waters at a storage site. Therefore, this section describes calculations that are designed to scope plausible magnitudes of pH changes for the considered scenarios.

The pH of the different waters in each of these scenarios could have been calculated using the QPAC-CO_2 code. However, in order to minimise the simulation times with this code, and hence maximise the number of simulations that could be undertaken, these pH values were calculated separately. The PHREEQC 2.15 geochemical modelling code (Parkhurst and Appelo, 1999) was used for this purpose.

Geochemical calculations of this kind involve the calculation of activity coefficients for aqueous species. For relatively dilute solutions, with ionic strengths up to around 0.8 (or TDS of about 35,000 mgl^{-1}, similar to that of seawater), the so-called “ion pairing and complexing” approach is commonly used (e.g. Davies, 1962; Helgeson, 1969). However, at progressively higher salinities this approach becomes increasingly inaccurate and would give very inaccurate results for salinities of about 250,000 mgl^{-1}, the highest considered in the present work. For this reason, the PHREEQC calculations were carried out using the alternative “specific ion interaction” approach (Pitzer, 1987 and references therein), which is appropriate for very saline solutions. This approach was implemented using the thermodynamic database “data0.ypf.R2” (USDOE, 2007), which is the most complete one available for this purpose. The database was produced by Sandia National Laboratories and is freely available in a format suitable for use with the EQ3/6 geochemical modelling code (Wolery, 1992). Quintessa has re-formatted the database to allow it to be used with PHREEQC (Benbow et al., 2008).

The QPAC-CO2 output includes calculated concentrations of dissolved CO_2 at important localities within each generic storage site (Table 4-14). To calculate corresponding values for pH requires knowledge of the compositions and pH of the various natural waters prior to the introduction of CO_2. However, the compositions of formation waters in the North Sea are wide-ranging and reported compositions are often incomplete (Warren and Smalley, 1994). Therefore, for the scoping calculations reported here, theoretical formation water compositions were calculated so as to be:

- broadly similar to published compositions of similar salinity;
- internally consistent (e.g. charge-balanced); and
- consistent with likely mineral-water buffering reactions (e.g. as reported in Hutcheon et al. 1993).

The following constraints were specified:

- pH was consistent with albite / Na-beidellite buffering (following Hutcheon et al, 1993).
- Na concentrations were adjusted so that, given the other constraints, the water attained the required TDS (either 35,000 mgl^{-1} or 250,000 mgl^{-1}).
- Cl concentrations were adjusted to achieve charge balance.
- In the case of the formation waters with 35,000 mgl^{-1} TDS, Ca concentrations had the same ratio with respect to Na concentrations as reported for seawater (Na/Ca = 45.57; Summerhayes and Thorpe, 1996).

- In the case of formation waters with 250,000 mgl^{-1} TDS Ca concentrations had the same ratio with respect to Na concentrations as reported Permo-Triassic basinal brine (Na/Ca = 49.53; Bath et al., 2003).
- HCO_3 concentrations were constrained by equilibrium with calcite.
- In the case of the formation waters with 35,000 mgl^{-1} TDS, SO_4 concentrations had the same ratio with respect to Na concentrations as reported for seawater (Na/Ca = 16.61; Summerhayes and Thorpe, 1996).
- In the case of the formation waters with 250,000 mgl^{-1} TDS, SO_4 concentrations were constrained by equilibrium with anhydrite.
- Al concentrations were constrained by equilibrium with Beidellite-Na.
- Si concentrations were constrained by equilibrium with chalcedony[3].

The pH values that are produced by the dissolution of CO_2 in the formation waters are shown in Table 4-15.

Table 4-15: Calculated pH in the lower and upper aquifers corresponding to the peak average and peak maximum CO_2 concentrations in Table 4-14. The first three rows show the calculated formation water pH prior to addition of CO_2.

Case	Peak Fraction Impacted (-)		pH at Peak Average Concentration (-)		Peak Maximum Saturation (-)		pH at Peak Maximum Concentration (-)		Time of Peak Impact (y)	
	Lower	Upper	Lower	Upper	Lower	Upper	Lower	Upper	Lower	Upper
1_No CO_2	-	-	6.13	8.04	-	-	6.13	8.04	-	-
2_No CO_2	-	-	7.19	8.04	-	-	7.19	8.04	-	-
3_No CO_2	-	-	6.13	8.04	-	-	6.13	8.04	-	-
1_Well	1.00E+00	4.35E-01	3.59	4.39	1.40E-01	8.43E-02	3.42	3.59	200	440
2_Well	1.00E+00	4.35E-01	3.39	4.33	1.41E-01	8.47E-02	3.39	3.59	160	380
3_Well	1.00E+00	1.00E+00	3.59	3.83	1.94E-01	1.02E-01	3.41	3.59	60	400
1_Fault	1.00E+00	4.35E-01	4.41	5.47	1.40E-01	8.43E-02	3.58	3.59	200	440
2_Fault	9.77E-02	2.69E-02	4.41	5.24	1.64E-01	9.35E-02	3.39	3.59	460	500
3_Fault	1.00E+00	3.15E-01	3.59	4.31	3.03E-01	1.98E-01	3.58	3.58	260	480

The pH values in Table 4-15 are minimum values that would be produced by adding the specified amounts of CO_2 to the formation waters, because no mineral buffering reactions are specified. That is, once a theoretical natural water composition had been calculated as described above, no further mineral reactions were permitted during the simulated addition of CO_2. This is a limiting case; in reality it is expected that there would be some significant mineral reactions over monitoring timescales. Most likely these reactions would involve carbonate mineral phases

[3] The thermodynamic database "data0.ypf.R2" contains data for aqueous silica, but not for chalcedony, Therefore, thermodynamic data for chalcedony were taken from the thermodynamic database "llnl.dat" which is distributed with the PHREEQC package.

(most probably calcite and / or dolomite). Reactions involving silicate minerals are likely to be too slow to exert much of an effect over these relatively short time intervals.

In both the upper and lower aquifers, the leakage of CO_2 would have a marked influence of pH in all cases. It is noteworthy that the pH variation in the shallow and deep aquifers differs most in the cases 2_Well and 2_Fault. The reason is that the formation water salinity is the same in both aquifers in these cases, which means that the effect of salinity on CO_2 solubility does not compensate for the fact that less CO_2 reaches the upper aquifer. Such a compensation effect helps to explain the similar variations in pH in the shallow and deep aquifers in the other cases; in these the deep aquifer contains water with 250,000 mgl^{-1} TDS whereas the shallow aquifer has water with 35,000 mgl^{-1} TDS.

It was beyond the scope of the work reported here to develop detailed models for the pH variations in seawater that would be caused by any CO_2 discharge at the seabed, although such specialist models could be developed using QPAC-CO_2. These pH variations will depend upon several factors, but notably upon the relative rates of seawater movement and discharge of free CO_2 or CO_2-bearing water, and the consequent extent of mixing between seawater and discharging fluid. Illustrative calculations were undertaken to estimate plausible variations in pH that might arise near the seabed as a result of these processes. These calculations used the seawater composition reported by Summerhayes and Thorpe (1996).

The variations in pH that would be caused by mixing between formation water and seawater in various proportions are illustrated in Figure 4-23.

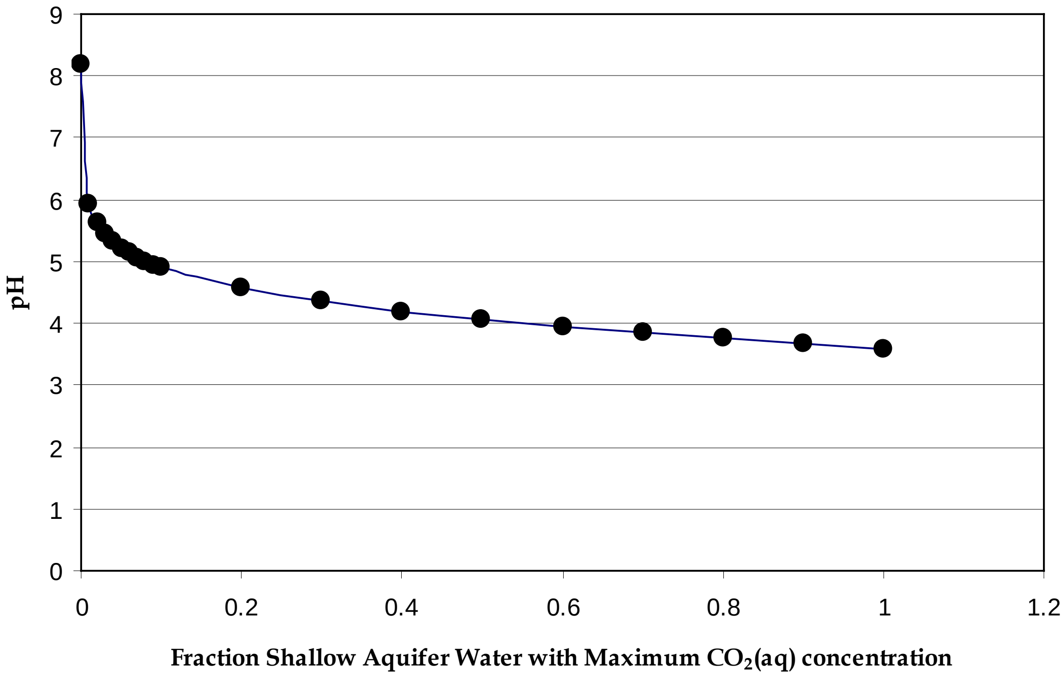

Figure 4-23: pH of different mixtures between seawater and discharged shallow aquifer water with a CO_2 concentration 0.45 mol l^{-1}, the maximum value calculated.

This figure illustrates that only small proportions of discharging water would have a significant effect on the pH of the mixture; a mixing fraction of only 0.1 would cause a decrease in pH of c. 3 units from the seawater pH of 8.2. However, the actual pH changes that occur would depend upon the rate of discharge of either free CO_2, or CO_2-bearing water, and the rate at which seawater moves across the discharge site. Calculations were therefore carried out to scope the effects of discharge from each kind of potential leakage pathway into a notional 1 m^3 volume of seawater lying immediately above the intersection of the pathway with the seabed (Figure 4-24). These calculations used the peak areal fluxes of free CO_2 and the peak areal fluxes of dissolved

CO_2, as shown in Table 4-10 and Table 4-11 respectively. For each leakage pathway and peak CO_2 flux, the pH of the seawater was calculated by specifying that the seawater overlying the discharge location was completely replaced in illustrative times of 1s, 1 minute, 1 hour and 1 day. In the cases where dissolved CO_2 discharged, the discharging water had the same composition as the shallow aquifer water used to calculate the pH variations shown in Figure 4-23. The quantity of this shallow aquifer water that would discharge in each time interval was calculated and then added to the considered volume of seawater.

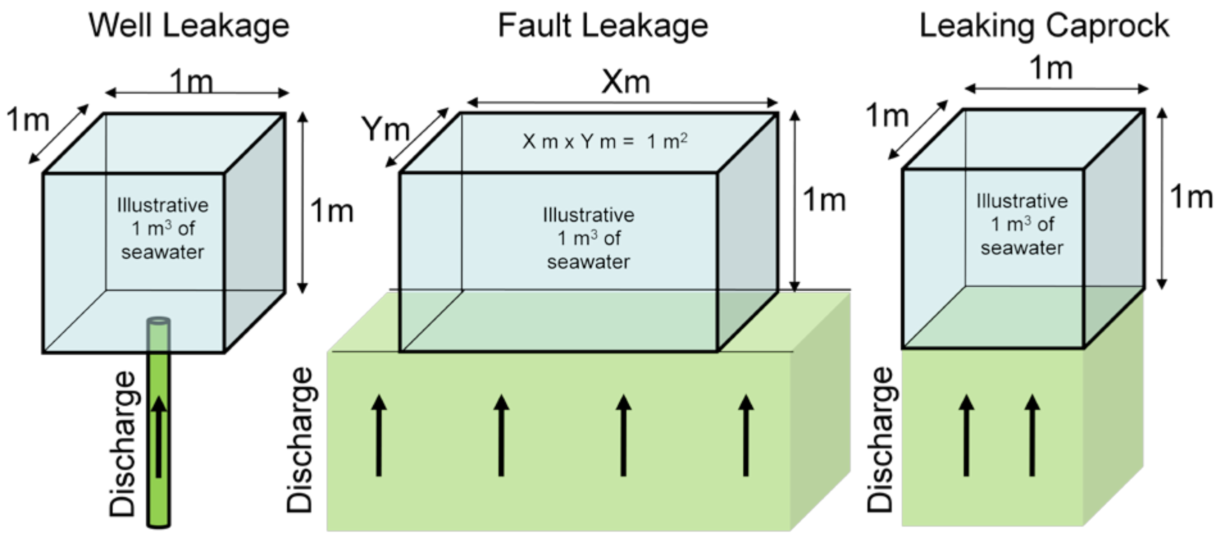

Figure 4-24: Schematic illustrations of the situations represented by the calculations to scope the effects of CO_2 discharge at the sea bed from each kind of potential leakage pathway.

The results of these illustrative calculations for the discharge of free CO_2 are shown in Table 4-16 while the results for the discharge of formation water with the peak dissolved CO_2 concentration are shown in Table 4-17.

Table 4-16: pH corresponding to the peak free CO_2 flux to the seabed in each of the calculation cases. The pH values are given for different illustrative rates of seawater displacement (1 m^3 volume of seawater is replaced in 1s, 1 min, 1 hour and 1 day).

	pH corresponding to peak free CO_2 flux				
Case	Initial	1s	1 min	1 hour	1 day
		-	-	-	-
1_Well	8.2	8.20	8.20	8.12	7.06
2_Well	8.2	7.06	7.06	7.04	6.72
3_Well	8.2	7.06	7.05	6.99	6.36
1_Fault	8.2	7.06	7.06	7.02	6.55
2_Fault	8.2	7.06	7.06	7.00	6.40
3_Fault	8.2	7.06	7.05	6.89	5.97
1_Cap	8.2	7.06	7.05	6.98	6.29
2_Cap	8.2	7.06	7.06	7.01	6.46
3_Cap	8.2	7.06	7.05	6.81	5.77

Table 4-17: pH corresponding to the peak dissolved CO_2 flux to the seabed in each of the calculation cases. The pH values are given for different illustrative rates of seawater displacement (1 m3 volume of seawater is replaced in 1s, 1 min, 1 hour and 1 day).

	pH corresponding to peak dissolved CO_2 flux				
Case	Initial	1s	1 min	1 hour	1 day
		-	-	-	-
1_Well	8.2	8.20	8.20	8.20	8.20
2_Well	8.2	8.20	8.20	8.20	8.20
3_Well	8.2	8.20	8.20	7.90	6.47
1_Fault	8.2	8.20	8.20	8.20	8.19
2_Fault	8.2	8.20	8.20	8.20	8.15
3_Fault	8.2	8.20	8.20	8.20	8.11
1_Cap	8.2	8.20	8.20	8.20	8.11
2_Cap	8.2	8.20	8.20	8.20	8.17
3_Cap	8.2	8.20	8.20	8.19	8.01

These calculations show that leakage of dissolved CO_2 will produce only a very small variation in pH near the seabed. This variation will be <1% of the seawater value when seawater turnover times are 1 day or less, except for Case 3_well when the turnover rate is 1 day. This latter case is expected to have the greatest effect on pH since it has the highest reservoir pressure driving flow (sub-lithostatic) and the smallest area of discharge.

In contrast, discharge of free CO_2 could plausibly produce a much larger effect on seawater pH than discharge of water containing dissolved CO_2. For all the times considered, in all cases except Case 1_Well, the pH variation caused by leakage would be > 1 pH unit. In Case 1_Well, such a large change would occur if the seawater was replaced in a day or greater; for shorter times of turnover, there would be an effect < 0.2 pH units. This result is to be expected, since Case 1_Well had the smallest driving force for flow, the reservoir being under-pressured initially and hydrostatically pressured at the end of injection.

4.3.5.2 Diffusion through the caprock

The likely impact of diffusion of CO_2 through the caprock in water can be bounded by some simple calculations of:

- maximum expected flux rates of dissolved CO_2 in water;
- representative timescales for "breakthrough" of dissolved CO_2 in water.

A diffusive flux can be calculated using:

$$q = \frac{\Delta c}{d}\frac{D}{\tau}\theta$$

If it is conservatively assumed that the caprock thickness (d) is 100m, its porosity (θ) is 10% and the effective tortuosity (τ) is 3, then given a maximum feasible dissolved CO_2 concentration of 2 mol l^{-1} (Δc), and a diffusivity (D) of CO_2 in water of 1.6e-9 m^2 s^{-1} the peak flux rate (q) would be 1.067E-09 mol m^{-2} s^{-1}, or 1.48E-6 tonnes m^{-2} y^{-1}. Hence over a square kilometre (for example) it would be possible to lose approximately 1.5 tonnes per year. Clearly this quantity is very small relative to the volume of CO_2 that would be stored in a typical reservoir (probably several hundred million tonnes).

The mean distance of diffusion, x, is typically described as being proportional to $\sqrt{D_{eff}t}$, where t is the time in seconds and D_{eff} is equal to $\frac{D}{\tau}$. Therefore, assuming that:

$$t = \frac{x^2}{D_{eff}}$$

using the same parameters as used for the flux calculation, the mean travel time across the cap rock is the order of 1.875E+13 s, or approximately 600,000 years.

4.3.6 Discussion of leakage modelling

The work reported here aimed to scope the likely magnitudes of CO_2 leakage in a small number of hypothetical extreme leakage scenarios for a number of different kinds of CO_2 storage sites. A related purpose was to explore the couplings between the key processes that influence such migration and hence relationships between the parameters that potentially might be monitored. The aim is that the resulting understanding of these couplings can be used to help determine the circumstances under which different kinds of monitoring strategy would be appropriate. The purpose of the work was not to produce detailed predictive numerical models, nor to explore combinations of different leakage paths that might occur at any particular site.

Commensurate with these goals of the work, the "systems modelling" approach aimed to focus only on the important effects influencing the migration of free CO_2 and CO_2-charged water. Significant non-isothermal effects are not anticipated other than very close to the injection well and it was assumed that the injection would be done in such a way as to avoid, for example, local freezing. Thus, non-isothermal effects were excluded from the model for this scoping project. Temperature effects on fluid behaviour were accounted for with an imposed temperature.

To meet the stated goals it was also important for each modelled system to be represented at a similar level of complexity throughout, focussing on key processes that affect the bulk-scale behaviour and avoiding the need for detailed site-specific information. This approach enables the results from different cases to be compared readily.

Similarly, consistent with the objectives of the work, only Darcy flows were investigated. This approach is appropriate for determining the large-scale disposition of CO_2. However, it is recognised that at an actual storage site, non-Darcy flow might be important. It would be appropriate to explore the implications of such flow processes using more detailed models, but these were outside the scope of the work.

Leakage along any kind of pathway (wells in particular) can lead to many different outcomes depending on the extent to which complexities are introduced. Additionally, leakage may occur through a combination of different pathways. For example a partially sealed well may connect the reservoir to a shallower aquifer, which in turn is connected to the surface by a relatively permeable fault pathway. However, the precise combinations of complex phenomena and leakage pathways will be site-specific and hence not amenable to generic numerical analysis. Therefore the approach taken in the overall project is to deduce the implications of this complexity for monitoring based upon both the simplified systems model calculations and a review of actual site data. That is, the scoping calculations reported here are only one part of the project.

The well was represented as a series of compartments having circular cross-sections with the diameter of a typical well. The transport properties of the compartments can be set independently of those of the surrounding rock allowing the well to have, for example, lower or higher permeability than the surrounding rock. When developing the scenarios, consideration was given to allowing the well's properties to vary over time. However, it was agreed that temporal variations in properties are likely to be small over the timescales considered and therefore the decision was taken not to include these variations in the model (though the code would allow such variations to be simulated). Different sections of the well could have been assigned different properties, allowing partial failure to be simulated. For example, the lower part of the well could be more permeable than the upper part, allowing CO_2 to rise from the reservoir to the upper aquifer through the well, whereupon CO_2 would migrate through the aquifer. However, this level of detailed analysis was not considered necessary to meet the objectives of this particular task.

The objective of including the shallow aquifer was to investigate how any non-well leakage might disperse within this formation and what the lag time might be for CO_2 to reach seawater. In the scoping calculations there was a relatively thin layer (few 100's of m) thick layer through which CO_2 transport could occur only by diffusion. The existence of this low-permeability unit enabled CO_2 to disperse laterally within the shallower aquifer; in the absence of this unit, the CO_2 would tend to rise directly to the seabed.

Simulations of differing and variable injection rates and near-wellbore pressures could potentially provide insights into far-field pressure effects which may affect leakage. However, while variable injection rates could be modelled, the injection rates were kept constant during each simulation to aid comparison between models.

The well leakage scenario considered only leakage through a different well to the injector well. It was assumed that an injector well would be drilled and sealed with high levels of quality control. Therefore, the main risk of leakage was considered to be via older abandoned wells or orphaned wells. These wells may have been sealed in the past under less well-controlled or even unknown conditions. Nevertheless, some insights can be gained by comparing the 50-year simulations with the small number of 10-year simulations. The latter demonstrate that leakage rates through a given type of pathway will be relatively low when there is no driving force for CO_2 migration from active injection. Leakage through the injection well is expected to be similar to this situation; by definition there will be no driving force for leakage from injection itself.

The models were arranged in such a way that the phase transition between supercritical CO_2 and gaseous CO_2 occurred between the upper and lower aquifers. An important finding was that this transition influences the rate at which any breakthrough to the seabed will occur. The rate of CO_2 migration through a leakage path will tend to increase when the CO_2 reaches the depth of this transition.

4.3.7 Conclusions from leakage modelling and offline calculations

The work has estimated limits and ranges of parameters that could be monitored at future CO_2 storage sites, using simplified systems level models of generic CO_2 storage areas. These generic site descriptions were specified to represent the main kinds of offshore storage systems in the UK's continental shelf that could be used. The estimated parameter values are plausible for the hypothetical "worst-case" leakage scenarios examined at each kind of site and are not predictive. Predictive models would require more detailed simulations using actual site information; the behaviour of an actual site will depend upon the specific characteristics of CO_2 storage there. Instead, parameter values calculated for the generic CO_2 storage systems can be used to deduce those circumstances in which it is unlikely to be useful to monitor a particular parameter. That is, if the parameter is unlikely to vary detectably in the "worst-case" leakage scenarios considered, then it would not give a detectable response should less extreme leakage occur. Conversely, those parameters that do vary in a way that could be detectable in these extreme circumstances would have a higher priority for monitoring. However the results presented here do not prove that the parameter would definitely vary detectably in these less extreme cases; additional modelling of these cases would be needed to shed light on this.

The work has also helped to develop an understanding of the processes that influence relevant parameters. This information can be used to help deduce likely variations of the considered parameters at actual storage sites and for scenarios different to those considered here. The understanding is also an input to subsequent project tasks, and can aid the identification of priorities for further work.

It was beyond the scope of the work reported here to evaluate the overall significance of the results for monitoring strategies. However, the following observations are made:

- Initial reservoir pressure conditions influence:
  - where monitoring is appropriate; and
  - when monitoring is appropriate.
- In cases where the reservoir is initially under-pressured, monitoring of pressure variations in the reservoir prior to CO_2 injection could potentially indicate the existence of any potential leakage paths that occur.
- Intermediate unbounded aquifers, in the overburden between the CO_2 storage reservoir and the seabed are more likely to provide additional accessible storage capacity where leakage occurs via a well than when leakage occurs via a fault or overburden of enhanced permeability. Therefore, it would be more appropriate to monitor such aquifers in order to demonstrate that a well is not leaking than to demonstrate that any fault leakage paths or enhanced permeability overburden leakage paths do not occur.
- While breakthrough times to the leakage pathway can be relatively short, breakthroughs to the seabed and aquifers can be significantly longer than the injection duration, in under-pressured or hydrostatic cases often being tens or hundreds of years after injection has finished. It is also the case that for many of the simulations (running out to 450 years after the cessation of injection), the peak fluxes to the seabed and/or the aquifers have not had sufficient time to develop.
- Volumes of CO_2 that are discharged to the seabed are much more likely to be significant compared to the total stored volumes of CO_2 when leakage occurs via a fault or enhanced-permeability overburden than when leakage occurs via a borehole. However, the time for a borehole to respond to leakage (i.e. create a pathway for significant gas migration) is typically much shorter.
- pH changes seawater above a leakage pathway will be extremely small if only CO_2-charged water discharges, but much more significant (1 pH unit or more) if free CO_2 discharges.
- Transport of CO_2 through a typical caprock by diffusion will be extremely slow and negligible. A loss of caprock integrity would need to occur in order to achieve significant leakage. Monitoring of chemical changes in the caprock is unnecessary.
- The location of any potential pathways relative to the margin of the injected CO_2 plume at the termination of injection is a control on leakage rates. If the pathway is reached by the CO_2 while injection is still on-going, then leakage will be more significant than if the CO_2 arrives at the pathway only after injection has ceased.
- If a CO_2-saturated link cannot be maintained between a discrete leakage pathway and the main bubble of CO_2, then significant leakage cannot occur.

4.4 LITERATURE REVIEW

This section summarises the currently available information on leakage parameters (flux, concentration, distribution, duration, etc) from observations and simulations.

Approximately 125 scientific papers were reviewed and divided into the following categories:

- Natural CO_2 releases (Table 4-18)
- CO_2 injection sites (Table 4-19)
- CO_2-EOR sites (Table 4-20)
- Experimental sites (Table 4-21)
- Numerical models (Table 4-22)

A representative selection of the results is displayed in Table 4-18 to Table 4-22. A full tabulation is available as an Excel spreadsheet. CO_2 fluxes have been calculated from a variety of methods, including direct field measurements using accumulation chambers equipped with infrared gas analysers, laboratory gas chromatography (GC-MS) or computed from SO_2 flux data using CO_2/S ratios. A similar range of techniques has been used to measure concentrations of CO_2.

Authors present data in a wide range of units, e.g. moles, grams, kilograms, tonnes, with or without defining area, and with different units of time (days, years etc). Alternatively, results may be expressed as the total amount of leakage or as a percentage of the total of injected CO_2. These values have, as far as possible, been standardised in tonnes, square metres and years, with the data also being given in the original units. The following conversion factors were used:

1 tonne CO_2 = 556.2m^3 (at 25°C, 1 atm)

1 mole CO_2 = 44g

1000 litres CO_2 = 1 m^3

4.4.1.1 NATURAL CO_2 RELEASE

Deep sourced CO_2 is naturally emitted at the surface, mainly from volcanic (e.g. Figure 4-25) or hydrothermal areas, or where a natural CO_2 reservoir has a conduit to surface (e.g. Crystal Geyser, Utah, where the present conduit is an old oil exploration well). These locations provide study sites to investigate potential CO_2 pathways, fluxes and environmental impacts, which can provide insights into what might happen in the unlikely event of CO_2 leakage from a storage complex. However, a limitation is that actual storage projects would not be sited in such geologically unsuitable areas. Also, in many of these cases, CO_2 has been emitted for long time periods and equilibrium conditions might have been reached that may not reflect processes and effects at the onset of leakage. Notwithstanding these provisos, natural leakage can provide useful insights into patterns and rates of surface leakage.

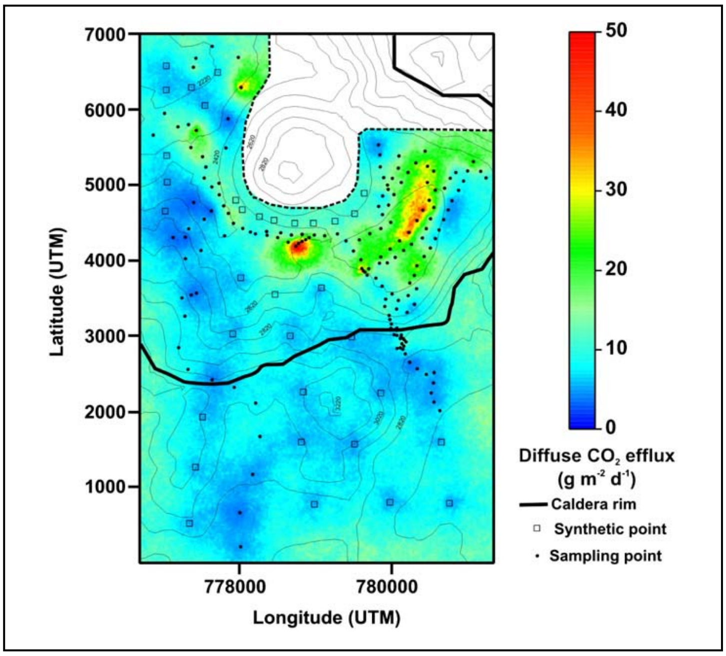

Figure 4-25: Spatial distribution of the diffuse CO_2 flux around the Pululahua volcano, Ecuador, from the average of 100 Gaussian simulations (from Padrón et al, 2008, image reproduced with permission of Elsevier)

Variations in deep CO_2 flux from natural analogues were previously thought to be solely due to changes in volcanic activity (e.g. Giammanco et al, 1998). However, more recent studies suggest that they can also be strongly influenced by changes in meteorological conditions (e.g. in the Azores, Viveiros et al, 2008) and/or changes in the shallow hydrologic system (e.g. in Long Valley Caldera, California, Bergfeld et al, 2006). At Mammoth Mountain, California, deep CO_2 flux has actually been relatively constant since 1997, after being initiated by earthquakes associated with shallow magma intrusion in 1990 (Rogie et al, 2001). These studies show that emission rates measured depend very much on environmental conditions leading up to and during data collection. Note that CO_2 emitted from deep sources (e.g. magmatic degassing or decomposition of limestones) can be distinguished from biogenic sources of CO_2 using isotope analysis (Chiodini et al, 2008). In this example soil gas CO_2 from a hydrothermal source had a mean $\delta^{13}C$ of -2.3 ‰ whereas that from a biogenic source had a mean of -19.4 ‰. However, it may not always be possible to use isotopes to identify injected CO_2 as some sources (e.g. from fossil fuels such as coal) may have signatures that overlap with biogenic CO_2. At Weyburn the C isotopic signature of the injected CO_2, after mixing with gas in the reservoir, would be very difficult to separate from that of biogenic CO_2. Emission distribution is controlled by many factors including permeability, the fracture network, hydrogeology, soil properties and the mode of degassing.

Concentrations of CO_2 in soil gas from volcanic or hydrothermal areas range from background values (generally low percentage levels) up to 100%. Other gases may accompany the CO_2, such as radon (Rn) and hydrogen sulphide (H_2S). Flux rates typically range from a few g/m^2/day ($\leq$ 0.001 t/m^2/year) to a few kg/m^2/day ($\geq$ 1 t/m^2/year). Studies at such sites indicate that areas of CO_2 escape can range from small gas vent features a few metres or tens of metres across to larger areas of more diffuse outgassing with dimensions of hundreds of metres (e.g. Annunziatellis et al, 2008; Jones et al, 2009). The latter cases present a much greater challenge in detecting and quantifying the leakage, as they potentially overlap the range of natural background biogenic flux, that can exceed 10^{-4} t/m^2/year, although values are typically an order of magnitude lower in late autumn or winter (Jones et al, 2006), making those the best times of year for onshore measurements

Total fluxes for all volcanic areas when aggregated can reach 600 million tonnes/year (Mörner and Etiope, 2002), whilst world mid-ocean ridge emissions are estimated at 0.5-2x10^{12}

moles/year, (22-88 million tonnes/year) (Resing et al, 2004).. For comparison, an offshore vent off Ischia Island, Italy emits an estimated 1.4 x 10^6 litres/day (Hall-Spencer et al, 2008), equivalent to 22,000 tonnes/year over an area of 3,000 m^2 i.e. an average flux rate of 7.3 $t/m^2/year$. A second vent emits at half the rate over an area of 2,000 m^2 i.e. an average flux rate of 5.5 $t/m^2/year$

4.4.1.2 CO_2 INJECTION SITES

CO_2 is being injected into a range of underground storage sites at a number of locations, both as pilot tests and commercial projects. These sites are designed and chosen to avoid leakage occurring and long term behaviour of the CO_2 has been modelled. To date, monitoring programmes in place have not detected leakage at the majority of these sites in these relatively early stages. For example no leakage has been detected at Frio or Nagaoka (Michael et al, 2010), In Salah or Sleipner (Hermanrud et al, 2009). An exception is at West Pearl Queen, New Mexico where a potential leak of 0.0085% per year of the injected CO_2 (total 2090t) was detected using perfluorocarbon tracers around the injection well (Figure 4-26; Wells et al, 2007). This extended up to 300 m from the well. An investigation into the suitability of Teapot Dome hydrocarbon field in Wyoming as a potential CO_2 storage site, detected small quantities of CO_2 seeping to the surface (max flux 733 $mg/m^2/day$, equivalent to $0.27t/m^2/year$). These were interpreted to be the result of microbial oxidation of methane as the CO_2 was isotopically enriched and gave ^{14}C dates close to 38,000 years within 5 m of the surface (Klusman, 2006) suggesting that low levels of hydrocarbon escape from the reservoir may be taking place.

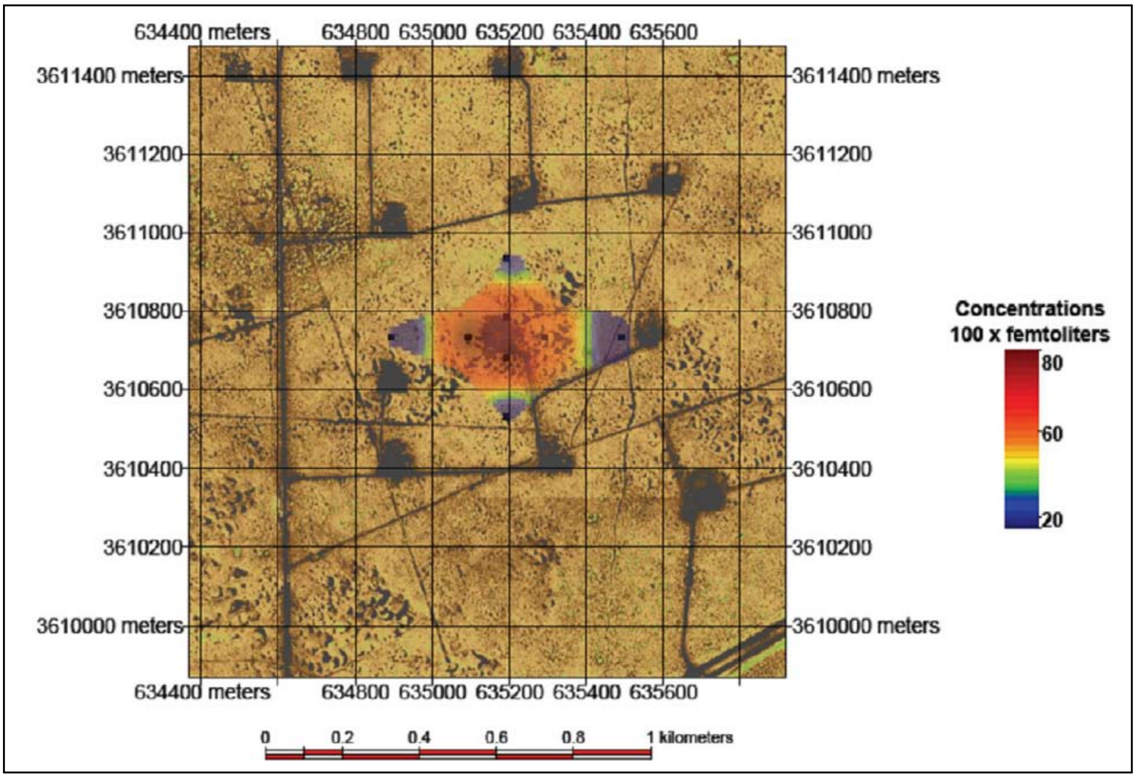

Figure 4-26: Spatial distribution of average tracer concentration observed at the West Pearl Queen CO2 injection site, New Mexico. (The dark-coloured features are roads and well pads) (from Wells et al., 2007, image reproduced with permission of Elsevier).

4.4.1.3 CO_2-EOR SITES

CO_2 has been injected for Enhanced Oil Recovery (EOR) since the 1970s. During this process some CO_2 also gets stored underground. Many of these CO_2-EOR sites now have monitoring programmes to assess migration and check for any leakage. In general these have detected no leakage, e.g. Weyburn-Midale (Jones et al, 2006; White and Johnson, 2009) and Pembina Cardium (Shevalier et al, 2009). At Rangeley, where CO_2 has been injected since 1986, initial estimates of leakage of 3800t/yr (Klusman, 2003a) were revised to <170 t/yr after computations indicated that much of the CO_2 detected was due to the microbial oxidation of methane, rather than leakage of injected CO_2 (Klusman, 2003b) and it is possible that in fact no deep origin CO_2 is escaping at all. Flux rates at Rangeley are very low (0.2-3.8 g/m^2/day mean winter-summer values, equivalent to 7 x 10^{-5} and 1.4 x 10^{-3} t/m^2/year) and the microseepage was inferred from detailed sampling and isotopic analysis to depths of up to 10 m. There was no discernible difference in flux rates at the site compared with a control area. It is highly unlikely that an operator would be required to carry out such detailed investigations for an offshore storage site and therefore microseepage on this scale (with uncertainty as to whether it is occurring or not) would probably go undetected offshore.

As part of the risk assessments for these EOR-CO_2 storage sites, simulations have been carried out to estimate possible leakage over longer timescales. For example at Weyburn a mean leakage rate of $4x10^{-4}$kg/day ($1.46x10^{-4}$ t/year) from several hundred abandoned wells over 5000 years was predicted (Zhou et al, 2005, quoted in Stenhouse et al, 2009) i.e. only about 0.001 % of the total CO_2 proposed to be stored.

Available data on leakage incidents from EOR and natural gas sites can be used as an aid to estimating risk of leakage from CO_2 sequestration sites, (Duncan et al, 2009) although the blowouts described are related to CO_2 extraction for production rather than injection of the gas into new wells for storage. Most incidents of accidental leakage from underground CO_2 were due to wellhead component failure rather than leakage through wellbore walls or through the rocks themselves. A study by Bachu and Watson (2009) into wellbore failures of Canadian EOR and acid gas injection wells indicated that wells built specifically for CO_2 injection had significantly fewer failures than those drilled for other purposes that were subsequently converted into CO_2 injection wells. Well failure is monitored by regulation and can be detected and repaired (Bachu and Watson, 2009). In terms of well bore integrity, investigations at an EOR well in Texas that has been exposed to CO_2 for 35 years found that the wellbore system continued to act as a barrier to significant CO_2 flow (Carey et al, 2007), despite minor carbonation of well cement along the lowermost parts of the steel casing-cement and cement-rock interfaces. The cement in the well was standard Portland cement, not a specific formulation designed to withstand contact with CO_2 At a CO_2 production well, with Portland cement/fly ash cement plugs, where CO_2 had been produced for 21 years, the well still showed good integrity (Crow et al, 2010).

4.4.1.4 EXPERIMENTAL SITES

Experiments have been set up to deliberately inject CO_2 into the shallow subsurface in order to monitor leakage fluxes and to study ecosystem impacts, because there is limited data on leakage from real CO_2 storage sites. For example the ZERT (Zero Emission Research and Technology Centre) site in Montana and the ASGARD (Artificial Soil Gassing and Response Detection) site in the UK. Further sites are proposed for new projects, such as the CO_2 field lab project in Norway (led by Sintef), which plans to use an onshore coastal site, and under the RISCS (Research into Impacts and Safety in CO_2 Storage) project (led by BGS) where both onshore and offshore experiments are planned.

The ZERT site is set up with a 98m cased horizontal well about 2m deep which has 70m of slotted casing to allow CO_2 to exit from 6 zones. There is also a 3.2m deep vertical well on the site. CO_2 was injected into the horizontal well at rates appropriate to examining potential diffuse leakage and sudden leakage from a point source such as a fault. This included a 0.1 tonne/day release (equivalent to 36.5 t/year) over 10 days and a 0.3 tonne/day release (equivalent to 110 t/year) over 7 days. During the 0.1 tonne/day release, CO_2 was detected 2.5m from the injection site after 1 day using stable isotope analysis of gas collected from accumulation chambers. After 8 days of injection, the amount detected at the surface using accumulation chambers (Figure

4-27) was very similar to that which had been injected. (Spangler et al, 2009). Maximum fluxes detected were 1600g/m^2/day (0.58t/m^2/year) for the lower injection rate and ~6000g/m^2/day (2.2t/m^2/year) for the higher injection rate. These values were an order of magnitude greater than background for the lower injection rate with measurements around the maxima showing a gradation down to background levels. These experiments also suggest that CO_2 releases become concentrated into 'hot spots' which incidentally may aid detection of low level releases (Strazisar et al, 2009) if those hot spots can be identified.

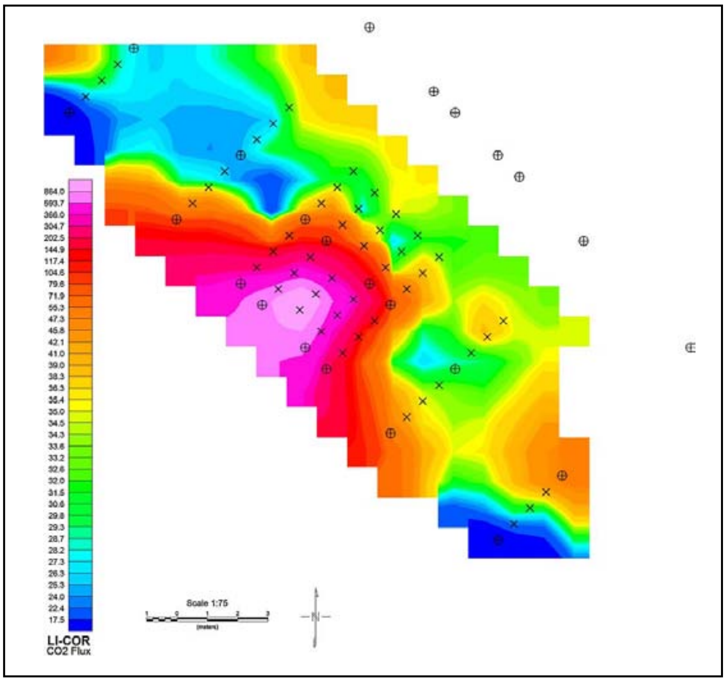

Figure 4-27: Map of CO_2 soil–gas fluxes taken over the part of the ZERT experimental CO_2 injection test site in Montana. (Strazisar et al, 2009, image reproduced with permission of Elsevier).

At the ASGARD site, CO_2 can be introduced by diffuse injection from pipes at a depth of 0.6m into up to 30 x 6.25m^2 plots. In one experiment CO_2 was injected at a rate of 3 litre/minute (2.8t/yr) for 19 weeks. Leakage rates measured were approximately one third of the injection rate at 1.02 litres/minute (0.96t/year) because a significant portion of the CO_2 migrated laterally outside of the plot boundaries (West et al, 2009). Flux rates for a later experiment with a flow rate of 1 litre/minute (0.9 t/yr) ranged from background values of around 20 g/m^2/day (7.3 x 10^{-3} t/m^2/yr) to 2000 g/m^2/day (0.73 t/m^2/yr).

The measured fluxes and observations from these experimental controlled release sites add to our understanding of and ability to detect potential leakage from underground CO_2 storage.

4.4.1.5 Numerical models

Numerical models of various kinds have been developed to model CO_2 migration and leakage from storage sites. Models fall broadly into two categories: those that simulate the fate of CO_2 migrating from a reservoir at depth and those that simulate CO_2 leaking from the surface ('emissions'). There is limited data on leakage from real CO_2 storage sites due to the careful site selection and the limited time since storage has been initiated. However, where possible, leakage fluxes and scenario parameters have been based on the small amount of published data. For example, Blackford et al (2008) modelled 3 different leakage scenarios, as follows:

- Long term diffuse seepage (e.g. through a permeable formation) using the Rangely CO_2-EOR initial estimated surface flux rate of 3800t/yr.
- Long term leaks (e.g. well head failure) equivalent to 5 and 50 times the Sleipner injection input rate released over 1 year.
- Short term leak (e.g. pipeline fracture) equivalent to 5 and 50 times the typical pipeline capacity over 1 day.

Specific scenarios have also been modelled, e.g. leakage up a fault (Chang et al, 2009), leakage through wellbore failure (Figure 4-28; Pawar et al, 2009), leakage through permeable pathways in the caprock (Grimstad et al, 2009), the mobilisation of metals from groundwater as a result of CO_2 leakage (Zheng et al, 2009) and the dispersion of leaking CO_2 in the atmosphere (Chow et al, 2009). Results of release fluxes (emission rates), durations and distributions vary widely according to input parameters.

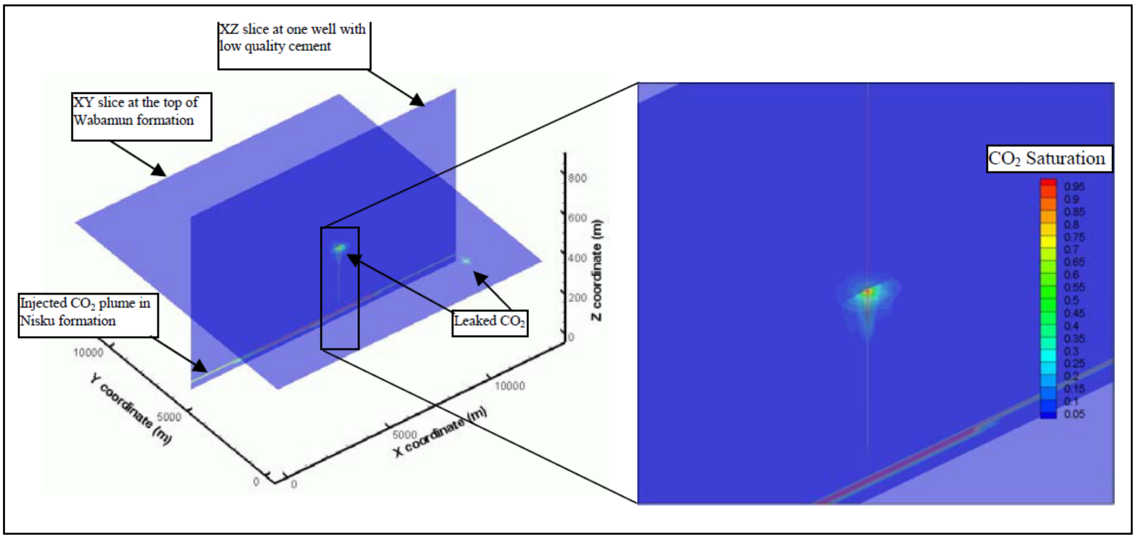

Figure 4-28: Cross-sectional views showing the CO_2 plume from two leaking wells after 100 years of injection using data from an abandoned well leaking natural gas in Alberta, Canada (from Pawar et al, 2009, image reproduced with permission of Elsevier).

The models which investigate the fate of CO_2 emissions from the surface include those by Blackford et al (2008) and Kano et al. (2010). They describe the effects of the investigated fluxes from the sea bed in terms of pH perturbations and CO_2 concentration levels respectively. Effects range from those indistinguishable from background, for the 'reasonable case scenario' leaks to those for the 'extreme worst case scenarios' which created up to -1 pH unit perturbations persisting for up to 20 days (Blackford et al, 2008) and concentrations greater than 1000ppm (Kano et al., 2010). The models simulating CO_2 release from the reservoir at depth include those investigated by Pawar et al. (2009) and Chang et al (2009). Pawar et al.'s model investigating possible movement up abandoned wellbores found that the CO_2 migration occurred up the wells which had unknown (assumed high permeability) cement quality, depending on their proximity to the injection point. In one example, up to 0.25% of the total injected CO_2 migrated into the overlying aquifer where it extended about 400m from the well (Figure 4-28). Chang et al (2009) investigated migration up a fault with varying permeability and number and position of lateral leakoff pathways. For a scenario with 2 lateral leakoff pathways, only 15% of the CO_2 reached the top of the fault, equating to a flux of 0.07kg/m^2/s (2200t/m^2/yr). This model showed that larger scale migration from the reservoir did not necessarily create a larger surface emission, depending strongly on the attenuation of the leak by fault permeability and lateral migration pathways.

The current models described here highlight potential leakage pathways and possible emission fluxes should CO_2 storage sites leak. These models and simulations are an important part of the risk assessment process to assess the fate of injected CO_2. The parameter inputs and models themselves will be refined as more data is collected as CO_2 storage site development progresses.

Table 4-18: Selected natural CO_2 release

Natural analogue	CO_2 source	CO_2 flux rate (g/m^2/day)	Flux rate equivalent in t/m^2/yr	Study area	CO_2 flux distribution	CO_2 concentration	Measurement tool	Reference
Furnas and Fogo volcanoes, Sao Miguel Island, Azores	Diffuse volcanic	Mean: 8-600 (range: 0-4605.4)	0.0029-0.22 (mean) (range: 0-1.7)	4 automatic stations	Diffuse volcanic emissions near fumarole fields	Up to 96.6% in soil. Up to 22.8% in dwelling	Accumulation chamber; infrared CO_2 detector at 4 automatic stations	Viveiros et al, 2008
Laacher See caldera, Germany	Degassing from magma chamber in East Eiffel volcanic field	Close to vent centres: 500-1200	0.18 - 0.44	~100000 m^2	2 conspicuous gas vents, some areas of diffuse flux	Close to vent centres: ~ 100%	Open path laser system (quad bike-mounted); portable pumped infrared analyser; accumulation chamber with infrared CO_2 analyser	Jones et al, 2009
		Diffuse flux: 23-54	0.0084-0.020			Diffuse flux: 9.1%		
		Background: ~<30	0.011			Background: ~4%		
Latera caldera, Italy	Mainly metamorphic alteration of limestone at depth related to magma intrusion	Horizontal profile (site 5) mean: 131.1 (range: 3.25-3569.73)	0.048 (mean) (range: 0.0012-1.3)	550m horizontal profile on caldera plain (AC: 202 samples)	4 vents (location controlled by permeable pathways within faults)	17.8% mean (range 0.42-85.92%)	Open path laser system; eddy covariance; soil gas (60-80 cm depth); accumulation chamber and infrared CO_2 detector	Annunziatellis et al, 2008
		Background: <22	<0.0080			Background: <2.5%		
Horseshoe lake, Mammoth Mountain, California, USA	Diffuse volcanic	Mean: 1346 (range: 218-3500)	0.49 (mean) (range: 0.080-1.3)	~120000 m^2: 1 EC station; 170 AC samples, (27m spacing)	Diffuse from tree-kill area	Not available	Eddy covariance station; accumulation chamber with flux meter	Lewicki et al, 2008
Ukinrek Maars, Alaska, USA	Diffuse magmatic degassing (related to Ukinrek Maars basalt)	4 plant-kill zone mean flux: 689-1190 (estimated total 21-44t/day)	0.25-0.43	~31,000-50,000m^2. (131 randomly chosen sites)	Diffuse emissions, 4 zones of plant-kill	Spring gas bubbles: 97.6% Soil gas 91.5%	Accumulation chambers with infrared gas sensor; soil gas (70cm depth); water and gas samples from springs	Evans et al, 2009
Pululahua caldera, Ecuador	Diffuse volcanic	Diffuse mean peak flux: 84.3 (range: non detectable to 141.7) Total CO2 emission: 270t/day, or 9.8t/km^2/day	0.031 (mean) (range: non-detectable - 0.052)	172 samples over 27.6km^2 (100m spacing)	SW-NW trend along east of inner caldera indicates structural control	Not available	Soil gas accumulation chambers with portable non dispersive infrared CO_2 analyser (NDIR) and portable flux meter.	Padrón et al, 2008
		Background: 8.4 (accounts for >90% of diffuse emission)	0.0031					

Table 4-19: selected CO_2 injection sites

CO_2 injection site	Amount injected	CO_2 Leakage rate and distribution	Flux rate equivalent in $t/m^2/yr$	Study area	Time since injection	Measurement tool	Reference
Sleipner, North Sea	>10Mt	None detected to date	0	1 injection well	13 years	4D seismic and gravity	Hermanrud et al, 2009
In Salah, Algeria	>3Mt	None detected to date	0	3 injection wells, shallow microseismic monitoring test wells	5 years	Various geomechanical and geophysical techniques	Rutqvist et al, In press
Nagaoka, Japan	10 400t	None detected to date	0	3 observation wells	6 years	P-wave velocities and geophysical logs	Sato et al, 2009; Xue et al, 2009
Ketzin, Germany	20kt of 60kt	None detected to date	0	1 injection, 2 observation wells (50-100m apart)	1 year	Various geochemical and geophysical techniques	Schilling et al, 2009; Giese et al, 2009
Frio Brine, Texas, USA	1600t	None detected to date	0	1 observation well + injection well, 4 shallow monitoring groundwater wells. 100 geochemical samples	5 years	Various geophysical & geochemical techniques	Muller et al, 2007; Kharaka et al, 2009
		0 leakage predicted. CO_2 migrated > 300m within target reservoir. 0–5% of CO_2 free and mobile gas (far from reaching the top of the formation).	0	~2.7km^2	10 years	TOUGH2 simulator, history matched to observations	Ghomian et al, 2008
West Pearl Queen pilot CO_2 storage site, New Mexico, USA	2090t	~ 0.0085% of the total CO_2 injected leaks per year. (i.e. 0.17765t/yr) Directional to 300m and diffusive to 100m from the injection well. Lineaments in caliche coincide roughly with NW and SW leakage trends. (none detected from other nearby wells)	Not available	Sampling in 6 concentric circles to 600m diameter around injection well	7 years	3 perfluorocarbon tracers in soil gas and atmosphere	Wells et al, 2007
Teapot Dome, Wyoming, USA	>2.6Mt	Max flux detected: 733mg/m^2/day (92.8% derived from methanotrophic oxidation of microseeping hydrocarbons (the remainder is derived from oxidation of organic matter))	0.27	3 anomalous 10m boreholes	3 years	Various geophysical & remote sensing baseline surveys, soil gas and reservoir simulations etc.	Friedmann and Stamp, 2006; Klusman, 2006
		Background: 227.1mg/m^2/day (dominated by biological sources)	0.083	40 surface samples across 40.5km^2, 5 x 10m boreholes. (>2200 wells exist, 1200 may be accessed).			

Table 4-20: Selected CO_2-EOR sites

CO_2 EOR site	CO_2 leakage rate	CO_2 leakage rate in t/yr	Study area	Time since injection (years)	CO_2 concentration	Measurement tool	Reference
Pembina Cardium, Canada	None detected to date (3 of 169 wells identified as high risk for potential leakage)	No surface monitoring	2 injection wells, 6 producing wells, 2 deep monitoring well, shallow groundwater monitoring wells	6	N/A	Geochemical and geophysical monitoring programme	Shevalier et al, 2009
Weyburn, Canada	None detected to date		~15km², 50-60 wells	9	N/A	Geochemical and geophysical monitoring programme	White and Johnson, 2009
Weyburn, Canada	Zero by natural pathways, Mean: $4x10^{-4}$kg/day from several 100 abandoned wells (95% of simulations yielded <$1.6x10^{-3}$ kg/day). <0.001% cumulative of CO_2 in place by end of EOR.	$1.46x10^{-4}$ (per well)	Several hundred wells	5000	N/A	Numerical model simulation	Zhou et al, 2005 quoted In Stenhouse et al, 2009
Weyburn, Canada	Zero by natural pathways, estimated 6 t/yr from abandoned wells.	6	~1000 wells	5000	N/A	Estimation from simulation	Chalaturnyk et al, 2004 quoted in Holloway, 2007.
Rangeley, Colorado, USA	<3800 t/yr (10.4 t/day) subsequently revised to <170 t/yr, which may all be due to methanotrophic oxidation.	0, 170, 3800	78km²	17	N/A		Klusman 2003a;c
West Texas EOR well, USA	Evidence for CO_2 migration adjacent to the caprock (carbonated Portland cement). However, the wellbore system continued to provide an effective barrier to significant fluid flow after 30 years of CO2 exposure.	Not available	Core sample of casing, cement and caprock	35	N/A	Core sample analysis and numerical simulations using FLOTRAN	Carey et al, 2007
Various EOR, USA, Canada	Range: ~ <1MMcf-10MMcf/day (7 short-lived accidental releases from wellhead). Max: 40MMcf of CO_2 (~10MMcf /day over 4 days)	50-500 (max: 2000)	1 well	Not available	4750ppm 60m from release, dissipated within 30 mins)	Company engineers' estimates	Duncan et al, 2009

Table 4-21: Selected experimental controlled CO_2 release sites

Experimental site	Injection rate	CO_2 flux rate	Flux rate equivalent in $t/m^2/yr$	Distribution	Study area	Time since CO_2 release	CO_2 concentration	Measurement tool	Reference
ZERT (Zero Emission Research and Technology Centre), Montana, USA	10 days at 0.1 t/day (Release 1) and for 7 days at 0.3 t/day (Release 2) through horizontal pipe	Close to injection rate after 8 days of injection. (using accumulation chamber methods). Release1 max soil flux: ~1600 $g/m^2/day$; Release 2 max soil flux: ~6000 $g/m^2/day$.	0.58 (release 1 max); 2.2 (release 2 max)	6 elevated flux hot spots along well path. Lateral spread ~<5m. Detected 2.5 m away after 1 day in accumulation chambers and 7m after 10 days in plants (using stable isotopes)	~0.12 km^2. 98 meter long horizontal well at ~2m depth; 3.2m vertical well. 5 pairs of shallow water monitoring wells	Detection after 1-10days	Soil gas background: 4000 ppm; routinely 30,000ppm during 0.3t/day release	Near surface detection techniques including: accumulation chamber, eddy covariance, soil gas, perfluorocarbon tracer, stable isotopes etc	Spangler et al, 2009; Lewicki et al, 2009;
	10 days at 800ml/min (~0.76t/yr) through vertical well	723ml/min (~0.68t/yr) (Detected flux rate within 10% of injected rate). Max flux ~3000g/m2/day	1.1 (max)	Return to background within 5m from injection. (detected up to 3.5m away using chambers, 5m using tracers)		5 tracer surveys, after 1, 2, 3, 4 & 7 days	62vol% at 1m above injection point; 14.7%vol% at 1m depth, 1m to SE of injection	Tracers, soil gas, accumulation chambers, 2D resistivity profiles	Strazisar et al, 2009
ASGARD (Artificial Soil Gassing and Response Detection), UK	3 l/min ~ 2.8 tonnes/yr over 19 weeks	Flux including background CO_2 was 1.02 l/min (~0.96t/yr), approx 1/3 of injection rate (some injected CO_2 migrated out of plot boundary).	~0.15	Roughly circular concentration profile. Some injected CO2 migrated out of plot boundary	6.25m^2 x 30 plots. Diffuse injection at 0.6m depth	19 weeks	Roughly circular concentration profile. Higher concentrations to W and S at 70cm depth. Max: 87% at 65-70cm depth	Accumulation chambers, soil gas, botanical and microbial surveys	West et al, 2009
Kit Fox field experiments, Nevada, USA	CO_2 emitted at surface for 2-5 min periods ("continuous plume") or for 20-25 sec periods (transient "puffs")	Concentration measured. Compared to atmospheric dispersion models.	Not available	Short term variation in wind speed caused CO_2 concentration peaks up to 100,000ppm.	Emission from 2.25m^2. Flat billboard obstacles simulate 1/10 scale industrial site. Monitors downwind concentric arcs at 25, 50, 100 and 225 m from source	~10 mins	Variations up to 30,000 ppm in 1 second	84 CO_2 concentration monitors, 5 Meteorological towers (wind speed and direction each second). Atmospheric dispersion models: Fluidyn-PANACHE and ALOHA	Mazzoldi et al, 2008

Table 4-22: Selected numerical models

CO_2 numerical model	Scenario	Leakage from reservoir	Leakage from surface	Leakage rate equivalent in t/m²/yr	Study area	Time since release	Concentration / results	Modelling package	Reference
Offshore Japan leakage scenarios	Leakage into the ocean from a fault	N/A	Extreme case: 94,600 t/yr (large fault connected to reservoir) i.e. $4x10^{-5}$ kg/m²/s	1.26	Fault 25m wide, 3km long within 4 x 2 x 0.188 km 3D model	10 days	<300ppm floating near fault; >1000 ppm momentarily at fault surface fault	MEC ocean model (includes topography, tides & current simulations) incorporating 2 -phase flow	Kano et al, 2010
			Reasonable case: 3,800 t/yr (seepage of Rangeley EOR site) i.e. $1.61x10^{-6}$ kg/m²/s	0.051		10 days	Within range of background fluctuation		
North Sea leakage scenarios	Leakage into the ocean from various scenarios	N/A	Long term diffuse seepage ((e.g. through permeable formation) equivalent to $3.02x10^3$t/yr (representing Rangeley data) and $3.02x10^5$ t/yr) i.e. 3.85 and $3.85X10^2$mmol/m2/day	$6.2x10^{-5}$ and $6.2x10^{-3}$	49km², 2 sites (one, 138m deep, stratified in summer; two, 28.5m deep, well mixed)	4 years	Max pH reduction of 0.12: significantly less than natural variability	POLCOMS-ESREM-HALTAFALL marine systems model	Blackford et al, 2008
			Long term leak (e.g. well casing failure) 5.43 $x10^6$t over 1 year (5 and 50 times Sleipner input rate) i.e. $6.93x10^3$ and $6.93x10^4$ mmol/m2/day	0.11 and 1.1		1 year	-0.5 to-1.0 pH units disturbances, creates a plume of acidified water. Small regions persist ~ 1 week		
			Short term leak (e.g. pipeline fracture) $1.49x10^4$t and $1.49X10^5$t over 1 day (5 and 50 times typical pipeline capacity) i.e. $6.93x10^3$ mmol/m2/day	0.11		1 day	-0.1 to -0.2 pH units tailing off after 3-9days; >-0.5 pH units, disturbances persist up to 10 and 20 days after larger leak		
Simplified model of CO2 leak up a fault	Leakage up a conductive vertical fault	0.26 kg CO2/m2/s	15% (0.07kg/m2/s) reaches the top of the fault.	2200	1000m long vertical fault abutting 500m thick storage reservoir. (2 lateral leakage pathways)	Not available	Attenuation is proportional to the ratio of fault permeability to leakoff coefficient. Deeper leakage pathways attenuate leakage much more than shallower ones.	Quasi-1D model for migration of buoyant fluid. Commercial simulator for 2D verification	Chang et al, 2009
Near Morrinville, Alberta, Canada	Leakage through cased well with bad cement	Injection rate 1 Mt/yr for 100 years.	Total leak into aquifer (not to surface) through all wells max 0.25% of injected CO_2 (i.e.~0.25Mt cumulative)	~2500	13 km x 13 km, 23 wells	100 years	Natural gas leak at surface used for modelling parameters	FEHM (non-isothermal, multi-phase simulator)	Pawar et al, 2009

5 Monitoring Requirements

5.1 EXECUTIVE SUMMARY

This chapter evaluates the findings of earlier chapters and the review of existing techniques (Chapter 10, Volume 2). Monitoring and measurement technologies and techniques are assessed in order to identify gaps where those available do not adequately meet UK offshore regulatory requirements. This indicates where improvements are required and where development effort needs to be focussed.

Regulatory requirements for storage site monitoring are based on three mandatory high-level requirements (to demonstrate understanding of storage site performance via matched predictive modelling and monitoring; to demonstrate zero leakage, or if leakage does occur, to measure it for possible accounting; and to calibrate and support models of long-term site performance and stabilisation), with a desirable additional public-acceptance criterion of demonstrating attainment of strategic emissions reduction targets. Within this framework operators are relatively free to design monitoring regimes around appropriate technologies on a site-specific basis.

In this context the ten monitoring objectives used in the web-based IEA GHG CO_2 Storage Monitoring Tool and applicable for UK offshore storage are outlined. The monitoring and measurements necessary to meet these objectives and comply with regulatory requirements are reviewed. There is discussion on the concept of ‘acceptable leakage’ and its projected effects on overall emissions targets – especially with respect to timescales, which may be of the order of hundreds of years and thus have significant implications for monitoring regimes.

Measurement capabilities are described for the key monitoring technologies likely to be deployed in the UK offshore. We consider what each tool can be used to measure, its sensitivity and accuracy and its spatial, volumetric and temporal coverage. These criteria are then evaluated in terms of their effectiveness in developing a monitoring strategy, where different technologies are deployed together, and where their results are interpreted jointly. This serves to highlight where technologies and methodologies are adequate and where developments are needed; for the latter, pointers are given to the improvements which need to be made. A sensitive and accurate tool may fail to detect leakage because its area of coverage is small, but when combined with a method with good spatial coverage (but lower sensitivity) leaks may be both detected and quantified.

It is concluded that technologies and methodologies developed in the hydrocarbons industry, for monitoring oil and gas reservoirs, are generally mature and adequate for monitoring CO_2 storage reservoirs to comply with requirements. There are, however, some specific areas requiring development and further testing for CO_2 storage is needed. In contrast, much technology designed specifically for detecting and quantifying CO_2 leakage is not yet mature and will require significant development.

5.2 INTRODUCTION

The objective of this chapter is to synthesise the findings of earlier chapters, and the review of techniques in Chapter 10 (Volume 2), in order to assess the measurement requirements for UK offshore MMV and to outline the efficacy of existing measurement technologies. By examining the capabilities of existing tools, used individually or in combination, key technological and methodological gaps will be identified. These will be assessed further in subsequent chapters of the report.

The regulatory requirements for monitoring at CO_2 storage sites define high-level objectives (Chapter 2). A judgement can be made about more specific requirements, and how those might be met, when large-scale storage takes place in future.

MMV schemes proposed or deployed at actual North Sea sites have been considered in Chapter 3.

Chapter 4 presents some possible leakage situations, with insights into how much might be leaking (based on generic assumptions) or emitted and the nature of the leakage. This information helps to define the type of monitoring that might be required to detect and measure it. In practice, any measurements are likely to be used to constrain predictive modelling and the outcomes of the initial simulations would be used to help define monitoring strategies.

Existing monitoring tools have been outlined in Volume 2 (Chapter 10).

The purpose of this chapter is to identify where existing MMV technologies are likely to fall short of what is needed to satisfy the requirements for demonstrating storage performance and detecting and quantifying leakage. This will lead to a definition of the extent to which improvement is needed in both qualitative and quantitative terms and will help to focus investigation of technological developments in the following chapters of the report.

The focus is on monitoring tools considered to be most appropriate for UK offshore storage. The resolution, accuracy and detection limits of these tools are discussed and their applicability for different types of monitoring considered. We also make initial suggestions on how the tools may be used together in an overall monitoring strategy (this is considered in more detail in Chapter 8). Shortcomings in available techniques are highlighted as they help to define areas that might require future research and development and this is developed further in Chapters 6 and 7.

With some specific exceptions (discussed in later chapters) techniques focussed on deep monitoring, based on decades of continuing development in the oil and gas industry, are considered relatively mature and adequate to meet requirements. While leakage is not expected at any storage site that has been suitably characterised and designed, regulations place greater emphasis on monitoring leakage and its impact. Our review to date indicates technologies for assessing and quantifying leakage require greater development and as such form the focus here.

5.3 MEASUREMENT REQUIREMENTS

Regulatory needs for storage site monitoring can be distilled into four high-level requirements:

1. To demonstrate robust understanding of storage site performance via matched predictive modelling and monitoring.
2. To demonstrate zero leakage, or if leakage does occur, to measure it for possible accounting as part of the ETS.
3. To calibrate and support models of long-term site performance and stabilisation.
4. To satisfy strategic emissions reduction objectives.

The first three requirements are mandatory. The final requirement is not mandatory but is nevertheless important, particularly for early storage projects, as the ability to demonstrate storage efficacy in terms of emissions mitigation is important for public acceptance of CCS.

5.3.1 Generic monitoring aims

To satisfy these high-level requirements, a number of generic monitoring objectives can be identified. The IEAGHG Monitoring Selection webtool identifies ten such objectives (http://www.co2captureandstorage.info/co2monitoringtool/). The objectives outlined below are extracted from the webtool, and adapted to the particular circumstances of UK offshore storage.

Plume imaging: The ability to explicitly image the plume of free CO_2 in the subsurface is a first-order determinant of storage performance and is likely to be a pre-requisite for many, though not all, storage situations. In the early stages of CO_2 injection, plume imaging is likely to involve tracking/mapping free CO_2 in the primary storage reservoir using time-lapse seismic surveying. In the longer term, plume imaging could involve tracking CO_2 migration into strata adjacent to the storage reservoir, such as the overburden, and might trigger other monitoring.

Topseal Integrity: Close monitoring of the reservoir topseal for evidence of failure or leakage will be important during the injection stage of a project. During this period, and for some time afterwards, reservoir pressures are likely to be significantly elevated immediately beneath the caprock. A maximum permissible (threshold) pressure is likely to have been determined during site characterisation, prior to injection. Evidence of reduced seal integrity or failure could be obtained from a number of monitoring techniques including direct detection or imaging of free CO_2, pressure changes in the reservoir or overburden, induced microseismicity or changes in aquifer chemistry. Monitoring in the overburden is likely to be required if CO_2 has migrated from the storage reservoir. The principal techniques deployed for monitoring plume migration in the reservoir (e.g. 3-D seismic) would be equally suitable for monitoring migration in the overburden.

Quantification: It is a regulatory requirement that the mass of CO_2 injected for storage is measured at the wellhead via some form of flow meter, although this is not a monitoring consideration for this study. Independent confirmation of the injected mass in the subsurface is not a regulatory requirement, not least because this would be technically very challenging and in many cases impossible at present. Nevertheless, in some circumstances it may be desirable to obtain quantitative information about aspects of the CO_2 plume in order to demonstrate understanding of flow processes in the reservoir, for example saturation, extent of dissolution, and residual trapping. These can to some extent be inferred from 3-D seismic data, but further development using other monitoring techniques is needed.

In the event that leakage to the atmosphere or seawater column has been positively identified, quantification of the mass of these emissions will be required to account for site emissions in the ETS and for the UK emissions inventory.

Storage efficiency and fine-scale processes: Long-term storage security and capacity is influenced by a number of factors that include plume migration, CO_2 dissolution in reservoir pore waters, structural and stratigraphical trapping and residual gas trapping in pore spaces. These processes are often influenced by fine-scale variations in reservoir geometry, lithology, pore architecture, permeability and pore water chemistry. In addition, key reservoir monitoring parameters such as seismic velocity are influenced by fine-scale processes such as fluid mixing scales. Specialised monitoring tools can be targeted on particular parts of the storage reservoir to help gain insights into these processes.

Calibration of predictive models: Predicting how the CO_2 will be stored over the long-term requires the integration of many geological processes in a predictive model. Such models require detailed site-specific geological knowledge of the reservoir, caprock and overburden. For a given formation the following parameters may need to be included: horizontal and vertical permeability, porosity, thickness, lateral extent, structure, fractures and faults, formation water chemistry, lithology, geomechanical properties, in situ stresses, pressure and temperature. By acquiring monitoring data on key processes and their interactions during and after injection, outputs from the predictive models can tested and calibrated, enabling the models to be suitably modified. This will decrease uncertainty in long term model predictions.

Near surface migration (<25m depth) and leakage to the water column: detection and measurement: As well as defining ultimate storage performance, leakage to surface could have safety and environmental impacts. Monitoring technologies to detect and/or measure surface leakage may well be routinely deployed prior to injection as part of the site baseline characterisation process. Repeat monitoring is likely to be required to establish natural cycles in background variations, such as diurnal and seasonal variations in biogenic CO_2, so that any future leaks can be identified and separated from background variations.

Seismicity and earth movements: In some cases CO_2 injection can lead to increased (micro) seismic activity and, in some circumstances, to detectable ground movements. For UK offshore storage the latter is not likely to be a significant problem, although it could help to define the position of the CO_2 plume. In depleted hydrocarbon fields reservoir damage through depletion and subsequent CO_2 injection may also need to be evaluated, particularly where fault reactivation is considered to pose a potential risk.

Well integrity: The ability of wells to retain CO_2 during the injection, post-injection and post-closure phases, is an important consideration in many storage situations. Geomechanical, and in the longer term geochemical, processes have been postulated to degrade well integrity. The UK offshore area is likely to contain significant numbers of wells of varying ages and styles of completion and abandonment. While new completion materials, such as CO_2-resistant cements, will greatly enhance the stability of new wells, older wells may need initial appraisal, and possible workover prior to injection and monitoring during injection and post-injection phases.

5.3.2 Monitoring to meet regulatory requirements

With the exception of a specific requirement to measure reservoir pressure and temperature (in order to determine CO_2 phase behaviour and state), the EC Storage Directive does not prescribe specific measurement techniques that should be deployed in CO_2 storage projects (Chapter 2).

However the four high-level monitoring requirements outlined have implicit measurement requirements which are discussed in the following:

5.3.2.1 MEASUREMENT REQUIREMENTS TO DEMONSTRATE UNDERSTANDING OF STORAGE SITE PERFORMANCE

This requirement is essentially addressed by deep-focussed monitoring systems aimed at testing and calibrating predictive performance models. Systems may incorporate tools as follows:

- Technologies to detect the presence, location and migration paths of CO_2 in the subsurface
- Technologies to provide information about pressure-volume behaviour and the areal/vertical distribution of the CO_2 plume to test and refine numerical 3-D reservoir simulations. Tools should provide a wide areal spread in order to capture information on any previously undetected potential migration pathways across the extent of the complete storage complex.

As illustrated by the examples in Volume 2 (Chapter 10), measurement requirements and methodologies for deep-focussed monitoring are highly site-specific. In general terms a UK offshore operator must consider what techniques are needed to monitor plume migration in 4D; the impact of injection on subsurface pressures, the possible displacement of fluids (e.g. saline water) that could have impacts beyond the storage reservoir (e.g. on neighbouring resources or storage sites) and the presence (or anticipated presence) of migration pathways that could affect adjacent areas or ultimately leak to the seabed, including the potential impacts of any leak on ‘legitimate users of the sea’. In the offshore such users could include: fishermen, maintenance personnel for offshore structures and the crew and passengers of ships.

Quantitative acceptance criteria for the verification of storage site performance have not yet been defined, but will likely be highly site-specific. It is anticipated that detailed agreements on measurement requirements for performance verification will form part of the storage licence. In general it is likely that large-scale factors such as the number and spacing of monitoring wells or the spatial extent and repeat frequency of time-lapse seismic will be more important than the exact measurement capability of an individual monitoring tool.

In general, the key deep-focussed monitoring technologies are relatively mature. Current measurement capabilities of some deep-focussed tools are outlined below. It is clear that continued deployment and testing in storage situations will lead to evolutionary improvements.

5.3.2.2 MEASUREMENT REQUIREMENTS FOR THE DETECTION AND QUANTIFICATION OF LEAKAGE

Under the EU Storage Directive operators will be required in the first instance to demonstrate that no leakage is occurring. If at some point the monitoring indicates that this is not the case, the operator will then have to measure the leakage in order to establish his position with respect to ETS credits.

The question arises therefore as to the definition of 'zero leakage'. Clearly no monitoring system is sufficiently sensitive to guarantee zero leakage by itself. Other criteria, such as conformance with the predictive models and known sealing performance of the overburden, need to be included in the equation. Because the regulations require that monitoring systems will be capable of detecting '*any* release of CO_2 from the storage complex' (EC Directive 2009/31/EC, Article3, para. 5), a tension might therefore arise between operators and regulators over the sensitivity and costs of the proposed monitoring technologies to be deployed. Operators may wish to underplay the sensitivity of monitoring to avoid either overly burdensome and therefore costly monitoring or the costs of remediating very small leaks.

The required sensitivity of leakage monitoring under the Storage Directive is therefore not defined. One possible approach may be for regulators to define an overarching performance requirement for initial leakage monitoring (see 5.2.2.4 below).

In the event that any likelihood of leakage is indicated by deep-focussed monitoring, or leakage is explicitly identified through shallow or surface monitoring, then the operator is required by draft amendments to the ETS Directive to monitor the leakage until no more leakage is detected. The operator will then be required to do one or more of the following:

- Accept that CO_2 will be emitted to the seawater and pay the equivalent value in lost emissions credits under the ETS. This will require installation of a robust leakage measurement system.
- Undertake some form of mitigation and/or remediation, and then carry out one or more of the following:
    - Monitor the success of the mitigation
    - Revise storage capacities,
    - Alter injection strategies
    - Stop injection and apply for site closure (only possible when no liabilities for the leak remain)
    -

In order to decide which options are most appropriate, the operator will require some key information concerning the leak, requiring a range of monitoring techniques:

- Where is the leak?
- Whose CO_2 is it (where multiple stores are in the vicinity)?
- What is the scale
    - how much CO_2?
    - how long has it leaked / will it leak?
    - What is the areal extent?
- What are the potential impacts?
    - environmental
    - financial

Once this information is available, operators will be able to decide, based on a techno-economical evaluation and through dialogue with the regulators, the most appropriate course of action. The financial, legal and reputational impacts on a project of a significant leak, i.e. one that requires intervention and remediation, could be very high.

5.3.2.3 Measurement requirements to calibrate and support models of long-term site performance and stabilisation

Operators will need to demonstrate appropriate understanding of site performance throughout the injection and post-injection periods. Following site closure, in order for operators to transfer liability for the site back to the competent authority, they will need to demonstrate that site performance is such that it will contain CO_2 permanently, in accordance with the agreed Framework for Risk Assessment and Management. A key element of this will be the need to demonstrate a validated understanding of long-term trapping mechanisms leading to a stabilised containment. The principal medium to long-term stabilisation processes that can be addressed by monitoring are likely to be pressure decline and CO_2 dissolution into the formation water, with the subsequent potential for mineral trapping through geochemical reactions also being addressed as a secondary priority (since such reactions are typically very slow and occur on geological timescales). Pressure decrease can clearly be confirmed by downhole monitoring for as long as the wells remain open. Validation of rates of dissolution and further mineral trapping is more challenging, and should be provided from a range of activities:

- Laboratory experiments to help constrain likely geochemical reactions and dissolution rates.
- Reservoir simulations, including coupled flow and geochemical reactions, to predict longer-term reservoir behaviour particularly dissolution.
- Direct monitoring of reservoir processes such as rates of CO_2 dissolution to confirm the long-term predictive models are reasonable.

A key measurement parameter to establish rates of CO_2 dissolution would be pH. Though downhole sampling is being trialled in small-scale pilot projects (see Section 5.1.1) and at Weyburn, a current technological gap is the capability to continuously monitor in situ pH in boreholes accurately. Key challenges are reliable and stable pH sensors and accurate and stable calibration.

One constraint on the use of downhole monitoring data, as discussed in Section 5.1.2, is that such data are essentially 1-D, and whilst they can indicate the local proportion of CO_2 in solution, they cannot measure the total amount of CO_2 dissolved. This reservoir-scale parameter is dependent on the amount of contact between CO_2 and formation water which itself is dependent on saturation, permeability, reservoir heterogeneity and injection strategies. However, combination with plume imaging and other data could allow estimates to be calculated

To verify long-term future site containment requires validated reservoir simulations. This validation includes matching data acquired during operational and post-injection phases to simulated reservoir behaviour. This behaviour can be measured in a range of ways which could include: plume imaging (seismic), tracers, pressure, CO_2 solution amounts and rates, and temperatures. It is likely that the geological model will be refined based on this data to more closely match predicted behaviour with the measurements.

5.3.3 Monitoring requirements to satisfy strategic emissions reduction objectives

As discussed above, the mandatory measurement requirements aim to establish understanding of current storage site performance, to establish leakage amounts if present and to assist in the prediction of future performance with the ultimate aim of enabling transfer of liability.

Demonstrating site performance in terms of emissions mitigation is not mandatory, but may nevertheless be considered desirable. Indeed the possibility of setting generic site performance thresholds has been an issue of much debate in regulatory circles though we believe it is widely accepted that this is not practicable. However, in order to evaluate monitoring capabilities we require a form of threshold to be defined against which we can assess techniques.

A logical measure of satisfactory containment performance in terms of emissions mitigation could be to estimate how well a nominal storage site should perform in order to fulfil its basic emissions reduction function. Lindeberg (2003) showed how different storage retention times were related to future stabilised atmospheric concentrations – sites retaining CO_2 for several thousand years (or longer) can be considered as providing effective mitigation. In a simpler treatment, Hepple & Benson (2003) have calculated global site leakage rates consistent with a range of atmospheric stabilisation targets (at CO_2 concentrations of 350, 450, 550, 650 and 750 ppm). By assuming that the rate of leakage is proportional to the amount of CO_2 stored at any given time, acceptable annual site leakage rates can be calculated. Although simplistic, this approach forms a credible basis for a preliminary treatment of the problem. Thus, according to Hepple & Benson, stabilization at any atmospheric CO_2 level less than 550 ppm would require average annual leakage rates to be less than 0.01% for all IPCC emission scenarios, this figure is similar to the effective annual leakage allowable under Lindeberg's model.

The question arises therefore as to what measurement requirements would be needed to ensure that emissions from a given storage site are below the required emissions threshold. Estimates of flux rates to the seabed from the leakage scenarios developed in Chapter 4 can be used to investigate this.

Calculations based on different leakage scenarios indicate that a range of flux rates could be expected, dependent on the assumptions made in each scenario (Table 4-8 and Table 4-9). In all cases peak flux rates are not reached until after injection has finished, but as a means of illustration we could consider a scenario whereby subsurface monitoring has detected a migration event at depth which was predicted to result in leakage to the seabed surface at some point in the future. The estimated fluxes can be considered as predictions of the amounts of CO_2 expected to be released. The peak annual flux can then be compared, as a percentage, to the total amount of CO_2 injected in each scenario (Table 5-1).

Case	Cumulative injected mass of CO_2 at 50 y	Leakage pathway to sea bed, peak flux	Free CO_2 at seabed as a percentage of total CO_2 injected.
	tonnes	Tonnes per year	%
1_Well	1.63E+07	2.40E-02	1.47E-07
2_Well	4.69E+08	2.50E-02	5.33E-09
3_Well	2.03E+08	8.50E-02	4.19E-08
1_Fault	1.55E+07	5.60E-03	3.61E-08
2_Fault	4.69E+08	1.20E+04	2.56E-03
3_Fault	2.05E+08	3.80E+04	1.85E-02
1_Cap	1.63E+07	5.50E+03	3.37E-02
2_Cap	4.69E+08	4.10E+03	8.74E-04
3_Cap	2.03E+08	2.60E+04	1.28E-02

Table 5-1: The percentage of calculated free CO_2 for a range of leakage scenarios (see Chapter 4 for details)

This comparison indicates that none of the leaking well scenarios would lead to the 0.01% performance standard being exceeded. Leakage via a fault in Case 3 (shallow saline aquifer) exceeds the performance standard, though it should be remembered that this case is not considered representative of most North Sea storage sites, where faults do not penetrate from the reservoir to the seabed. Two of the failed caprock leakage scenarios, Case 1 (deep underpressured reservoir) and Case 3 (shallow saline aquifer), result in leakage rates that exceed the performance standard. In these conceptual examples, the proportion of CO_2 leaking annually is estimated to be 0.034% for Case 1 and 0.013% for Case 3. Therefore in these cases the operator could decide appropriate increased monitoring and mitigation actions to prevent this leak. These additional actions would be balanced against the value of CO_2 at the time which would need to be surrendered if no action were taken and leakage was allowed to take place.

For the purpose of this simple illustration, we have ignored the fact that the predicted peak flux rates for free CO_2 only occur after several hundred years and average fluxes over the long-term are significantly lower than the peak values. In practice however, these would be important factors to consider. Predictions of leakage after hundreds of years raise questions about the duration of monitoring necessary and whether sites would be licensed that needed monitoring over such long implied timescales. The regulator would have to make a judgement in such cases that also took the likelihood of leakage into account.

If we assume that the annual leakage rate for a hypothetical site does match the performance criterion of 0.01% annual leakage, and taking a storage case of 10 Mt per year for 50 years, it is possible to calculate the amounts leaked (Table 5-2).

end of year	cumulative amount injected (kt)	cumulative leakage (kt)	cumulative amount stored (kt)
10	100000	50	99950
20	200000	200	199800
30	300000	450	299550
40	400000	800	399200
50	500000	1250	498750
75	500000	2500	497500

Table 5-2: Hypothetical masses of CO_2 stored and leaked assuming a 10 Mt per year injection rate and an annual leakage rate of ~0.01%.

With large-scale storage such as this it is clear that even though the annual leakage rate is low, absolute leakage amounts are quite high. After 10 years, such a site would have leaked around 50kt of CO_2. This increases to 1250 kt after 50 years (end of injection). Post-injection, assuming that the site continues to leak at 0.01% per year, the measurement requirement is even less stringent at 2500 kt. Such amounts of CO_2 should be readily detectable using current monitoring technologies (see below).

5.4 TOOL MEASUREMENT CAPABILITIES

Before discussing the monitoring systems necessary to meet the measurement requirements for storage sites it is helpful to assess the current measurement capabilities of some key monitoring tools. These are summarised in Appendix 3 and Appendix 4 (Volume 2) and then discussed in the following text, which focuses on those deemed to be most relevant to offshore UK monitoring.

5.4.1 Deep-focussed tools

A number of surface-deployed, deep-focussed methods can provide either full spatial sampling or integrative coverage of the storage complex.

5.4.1.1 3D SURFACE SEISMIC

3D surface seismic is probably the tool of choice for subsurface detection and measurement. Its key strength is the fact that it provides a combination of quite high sensitivity with continuous and uniform coverage of the subsurface, such that its sensitivity approximates its measurement capability.

Detection of CO_2 in the overburden, as 'bright spots', can potentially be used to estimate migration fluxes. Bright-spots on time-lapse data can arise directly from the reflectivity of a CO_2 accumulation, or as a consequence of velocity pushdown produced by the CO_2 accumulation. To be detectable the CO_2 accumulation must have lateral and vertical dimensions sufficient to produce a discernible seismic response. A study by Myer et al. (2002) based on theoretical resolution considerations, has suggested that CO_2 accumulations as small as 10000 to 20000 tonnes should be detectable under favourable conditions.

Results from the Sleipner time-lapse surveys (Chapter 3) indicate that these figures may be somewhat conservative. Repeatability noise (which depends on the accuracy with which successive surveys can be matched), rather than resolution, may be the key parameter controlling detection thresholds.

The capability of the 3D surface seismic data at Sleipner to detect the migration of small quantities of CO_2 can be illustrated by examining the topmost part of the 1999 plume, which is marked by two small CO_2 accumulations trapped directly beneath the caprock (Figure 3-14). From the reflection amplitudes the net volumes of the two accumulations can be estimated at 9000 and 11500 m^3 respectively. Other seismic features on the time-slice can be attributed to repeatability noise, arising from minor mismatches of the 1999 and 1994 (baseline) surveys. For a patch of CO_2 to be identified on the data it should be possible to discriminate unequivocally between it and the largest noise peaks, so it is clear that the level of repeatability noise plays a key role in determining the detectability threshold. Preliminary analysis suggests that accumulations larger than about 4000 m^3 should exceed the threshold. At high saturations, this would correspond to about 2800 tonnes of CO_2 at the top of the reservoir where CO_2 has a density of about 700 kg m^{-3}, but less than 600 tonnes at 500 m depth, where the density is considerably lower. The detectable mass would be even lower for CO_2 at lower saturations.

The actual detection capability may, however, depend on the nature of the migrating CO_2 stream. Small thick accumulations in porous strata would tend to be readily detectable, whereas distributed leakage through low permeability rocks may be difficult to detect explicitly with conventional seismic techniques, although velocity pushdown generated by such an accumulation should be visible on time-lapse differenced data. Similarly, leakage along a fault within low permeability rocks may be difficult to detect

5.4.1.2 CROSS-HOLE SEISMIC

Also known as cross-well profiling this technique is a potentially useful adjunct to surface seismic where appropriate wells are available. At least two relatively closely-spaced wells are required, straddling a part of the reservoir where CO_2 is present, injected CO_2 being detected by changes in seismic velocity in or around the reservoir.

A cross-hole seismic study at Nagaoka, Japan was based on three wells all within 120 m of the injection point and provided a 160 m long profile through the reservoir at the injection point. Comparison of the baseline survey and the repeat after the initial phase of injection clearly revealed a zone of reduced velocity due to the injection of 3200 t of CO_2 (the actual amount of CO_2 contributing to the detectable change on the cross-section between the wells would of course have been considerably less than this).

Similar results were obtained in a study at the Frio project in Texas, where the injection of 1600 t CO_2 was detected between repeat cross-hole surveys. In this case, the post-injection velocity anomaly was imaged sufficiently well to indicate the lie of the CO_2 plume with respect to the geological structure and so obtain valuable direct comparison with the reservoir injection simulation (Chapter 10).

Cross-hole seismic has a potentially higher resolution than surface seismic because it uses higher frequency sources and because source to receiver distances are shorter giving less signal attenuation. Its main purpose in monitoring large-scale storage may be to provide fine-scale detail on CO_2 distributions within the reservoir to support and calibrate predictive flow simulations. There is also the possibility of using it to detect quite small amounts of leakage into the overburden above a CO_2 store, particularly around wellbores. This method could therefore have a role in the long-term monitoring of CO_2 storage sites after completion of injection.

The key limitations on the use of cross-hole seismic are availability of suitable wells, the limited areal coverage and cost. For this method to provide effective results it is essential that wells are selected such that 2D profiles between them intersect the storage reservoir. The wells also need to be closely spaced, of the order 50 to 2000 m apart. This may present problems in fields with a low density of accessible wells, such as some in the North Sea.

Seismic sources and receivers need to be installed in the wells on a long-term basis for time-lapse surveys, where good repeatability is obtained because of the well-constrained positioning possible in boreholes. Well seismic technology is developing rapidly with new down-hole source and receiver equipment becoming available. Down-hole sources typically use pulse (e.g. sparker, airgun) or vibrator (e.g. rotary vibrator, piezoelectric) technologies packaged into sondes. Source equipment is not usually deployed in injection wells and tends to require more maintenance than receivers. Receiver strings now utilise miniature geophones or fibre optic sensors, which allow more receivers to be used, providing higher resolution at relatively lower cost. Such receivers may be installed in the casing annulus of an injection well, so one well fulfils both injection and monitoring purposes; however injection usually needs to be suspended during seismic acquisition.

Although installation and maintenance are high-cost, surveys can be conducted at low-cost using automated, unmanned techniques with results transmitted for processing and analysis at remote locations.

5.4.1.3 Vertical seismic profiling (VSP)

The oil and gas industry makes extensive use of VSP for reservoir production monitoring and it is expected to prove equally useful in CO_2 storage site monitoring. This technique employs surface seismic sources with down-hole receivers to image subsurface reflectors and velocity structure around a well. It was developed from earlier, simpler 'check shot' well seismic methods which provided velocity and time calibration data for interpretation of conventional seismic surveys. There are similarities with both surface and cross-hole seismic methods and, likewise, changes in a reservoir are detected by comparing results from successive surveys.

The main controlling factor on subsurface coverage is the design of the surface source array. A basic survey uses a seismic source at (zero-offset VSP) or close to (offset VSP) the well and provides quite a narrow zone of coverage. A walkaway VSP employs a source moving away from the well along a radial line to produce a 2D profile, typically of length 100—2000 m. Several profiles radiating in different directions can be combined to create pseudo-3D coverage around the well. Full 3D VSP coverage can be provided by either moving the source over a grid centred on the well, or by overlapping VSPs at adjacent wells. A typical 3D VSP grid would cover an area of 5 x 5 km.

VSP provides high-resolution coverage around a wellbore, with excellent velocity control because survey geometry is well-constrained. Multi-component receivers can be used to detect anisotropic effects in the reservoir and overburden. These characteristics suggest that small quantities CO_2 of should be detectable and that this method has potential as a leakage detection technique. This was confirmed by comparison of experimental VSP surveys before and after injection of 1600 t of CO_2 at the Frio site in Texas, which produced good imaging of the CO_2 plume located at 1500 m depth. The results obtained suggest that the method would be able to detect smaller quantities than this and that seismic ray path modelling should be able to delimit reliably the extent of a CO_2 plume.

The VSP method has fewer operational limitations and lower costs than cross-hole seismics. Only one well is required, which may also be an injection well. Single-well operation with older VSP equipment would require regular lengthy suspensions of injection for deployment of a receiver string in the well and acquisition of data. Seismic 'acquisition while producing' receivers are available for oil and gas wells, but current versions may not be suitable for use in CO_2 injection wells due to the corrosive effects of CO_2. However the miniature geophone and fibre optic sensors now becoming available could be permanently installed in the casing annulus of an injection well permitting single-well operation with minimal interruption to injection – ideal for time-lapse surveys. Surface seismic sources are also generally cheaper to deploy than down-hole sources. Where multiple wells are available a more detailed picture of the reservoir can be obtained, especially if it is possible to acquire overlapping VSP coverage.

A novel application of VSP is for ultra-high resolution travel-time (HRTT) measurement. In this configuration high frequency receivers are placed in the wellbore beneath the CO_2 plume. Changes in travel-time and attenuation from a high frequency seismic source above the plume can be used for direct quantification and mapping plume extents. With potential resolution of fractions of a millisecond this is a high precision tool, capable of detecting CO_2 layers less than 1 m thick. However, to our knowledge HRTT has not yet been successfully deployed in CO_2 storage. Depending on logistics the method is potentially very suitable for deployment in deviated injection wells where the wellbore lies beneath the buoyant CO_2 plume (such as at Sleipner).

5.4.1.4 Well seismic: integrative considerations

Once installed permanent well-based seismic receiver equipment can be used for VSP, cross-hole and passive microseismic monitoring applications. This offers a significant cost benefit when two or more methods are employed.

There are also some cross-over technologies in use. By conducting a VSP with receivers in a sub-horizontal well and a source towed along the well's surface track, it is possible to process the results using cross-hole tomographic techniques and so obtain a velocity tomogram of the vertical section.

Cross-hole source and receiver equipment may be used in the same well to produce a 'single-well profile', which is like a vertical version of a conventional 2D seismic profile. These have applications in imaging steeply dipping structures adjacent to reservoirs such as the flanks of salt bodies.

Finally, down-hole receiver arrays can be used in conjunction with conventional seismic surveys. For example if a conventional 3D seismic survey centred on the platform is being acquired then receiver strings in the wells can be used to record VSP data at the same time, providing a significant cost benefit.

5.4.1.5 SURFACE GRAVIMETRY

Gravimetry is a volumetric 'integrator' so does not suffer from sampling problems as such. Compared to seismic however its resolution and intrinsic detection capability are very poor.
The viability of monitoring injected CO_2 with repeated gravity measurements is strongly dependent on CO_2 density and subsurface distribution. In general terms the size of the gravity change gives information on subsurface volumes and densities, while the spatial variation in gravity gives information on lateral CO_2 distribution. The weakest aspect of the gravity data is in resolving absolute depth information on the CO_2 accumulation.

Although of much lower spatial resolution than the seismic methods, gravimetry offers some important complementary adjuncts to time-lapse seismic monitoring. Firstly, it can provide independent verification of the change in subsurface mass which may enable estimates to be made of the amount of CO_2 going into solution, an important element in long-term performance prediction (dissolved CO_2 is effectively invisible on seismic data). Secondly, deployed periodically, gravimetry could be used as an 'early warning system' to detect the accumulation of migrating CO_2 in shallow overburden traps where it is likely to be in the low density gaseous phase with a correspondingly strong gravity signature.

The detection limits of gravimetry are highly site specific: low CO_2 density and a spatially confined CO_2 bubble will give the largest gravity change for a given mass, shallow depths and high temperatures favouring lower densities. Recent work at Sleipner (Volume 2 Chapter 10) suggests that measurement accuracy for repeat surveys offshore may be as low as 3 to 5 μGal. At these repeatability levels, under favourable conditions, accumulations of CO_2 in the gaseous state of less than 1 Mt may be detectable at depths around 500 m (Figure 5-1). Such a figure seems quite large, but in the context of a possible future large-scale storage site, would be less than 1% of the total amount stored, but this is greater than a 0.01% performance standard. For general measurements within a reasonably shallow storage reservoir, injected CO_2 masses of more than about 2 Mt would be expected to produce a detectable response.

5.4.1.6 DOWNHOLE PRESSURE AND TEMPERATURE

Monitoring the pressure and temperature regime in a reservoir is of fundamental importance in reservoir engineering, to determine the mechanical integrity of the reservoir and the physical properties of the fluids it contains. Therefore technologies to measure these parameters have been well-developed for the oil and gas industry, are widely available and low-cost. The same instrumentation should be usable at CO_2 storage sites and has been demonstrated by some of the experimental studies.

Sensors are installed at well bottom, well head and various levels in between. This allows monitoring to detect changes not only in the reservoir but in the caprock, overlying strata and in the wellbore itself – where a sudden pressure drop might indicate loss of integrity in the casing or cement bond. However pressure changes need careful interpretation based on the speed with which they occur, where in the well they occur, the pressure history of the well and correlation with observations from other monitoring methods. For example, a pressure drop might be due to the opening of a migration pathway within the reservoir or to the dilation of a fracture into the seal.

Results from the Frio project in Texas established that pressure and temperature monitoring was critical to interpreting and understanding the CO_2 phases in the injection plume. Pressure monitoring at the Nagaoka site in Japan ran continuously from pre-injection through to post-injection, and results showed a good correlation with injection rates and that reservoir pressures did not reach or exceed the predicted reservoir fracture pressure.

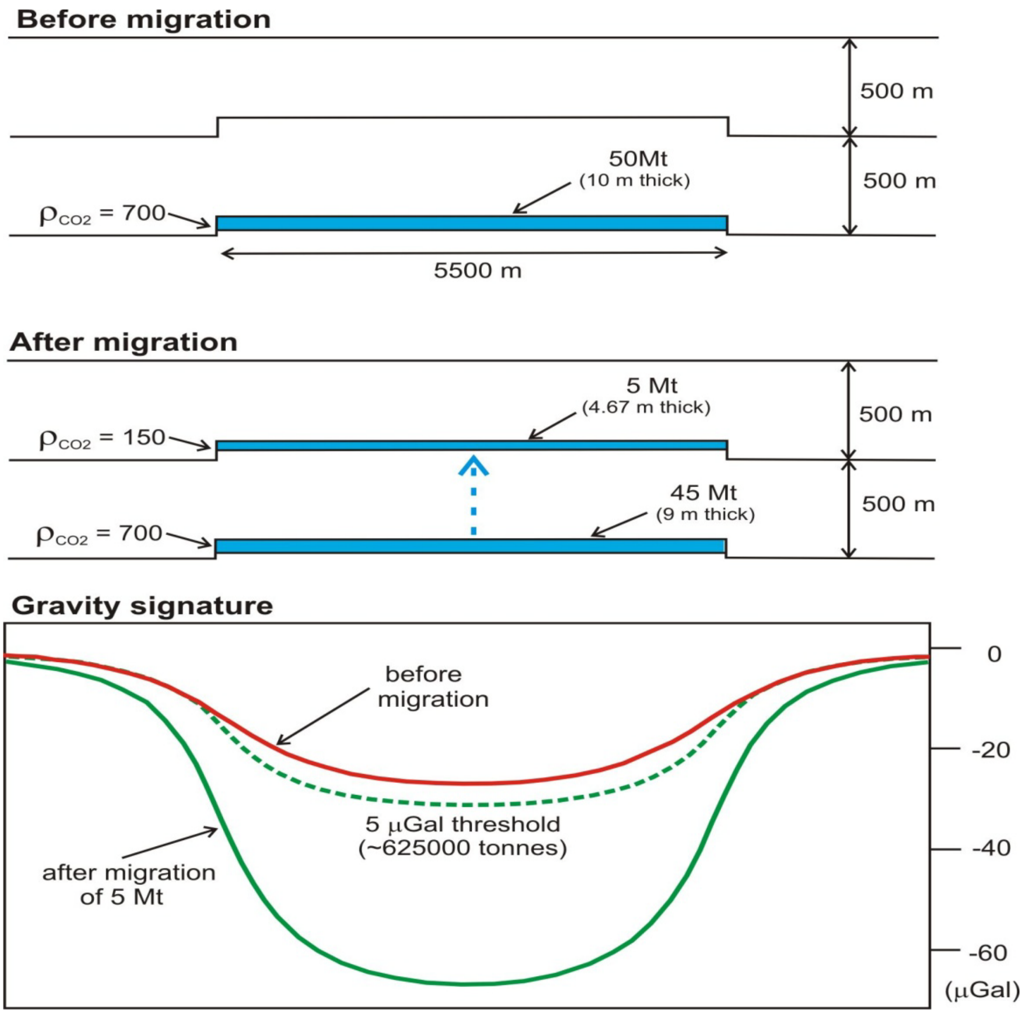

Figure 5-1 Gravity models to illustrate changes in gravimetric signature caused by migration of 5 Mt of CO_2 from the primary storage reservoir to shallower depth. Note 625000 tonnes of CO_2 migrating would produce a change of 5 μGals (image courtesy British Geological Survey).

In addition to monitoring for non-conformances, pressure is a key tool for validating and calibrating predictive models, as typified by the pressure monitoring at K12-B (Chapter 3). It is clear that the current sensitivity / accuracy of downhole pressure tools are more than sufficient to establish whether a predictive model is working or not. The main issue here is what degree of mismatch between a model prediction and a monitoring measurement is allowable before the model is declared invalid.

Downhole pressure monitoring essentially integrates the pressure response from a large volume of reservoir, albeit with limited directional information. Pressure measurement can also be made continuously and are likely to be a key aspect of routine reservoir monitoring in injection wells. They are also likely to be made in monitoring wells either located within the reservoir (at some point along the flow path from the injection well) and/or in overlying aquifers to monitor for possible CO_2 leakage. The sensitivity of pressure monitoring to detect such leakage will depend on the mass of CO_2 that leaks and the resultant change in pressure. This will require site-specific calculations to establish the likely sensitivity requirements. An example of downhole pressure monitoring sensitivity is Schlumberger's Unigauge Tool, for which they quote a pressure resolution of 0.07-1.03 kPa and accuracy of ±17-69 kPa. Such sensitivities should be adequate for monitoring requirements.

Continuous temperature profiling outside and inside the wellbore is being trialled at Ketzin (Chapter 10, Volume 2). Results so far are very good and have enabled very detailed monitoring of the physical state of CO_2 within the wellbore. Temperature is also very sensitive to fluid flow and changes can be diagnostic of CO_2 migration around the wellbore.

5.4.1.7 Other downhole measurements

Analysis of reservoir formation waters has been demonstrated in two small-scale pilot projects at Frio (in Texas) and Otway (in SE Australia) and extensively at Weyburn. Preservation of samples at *in situ* pressures is important as depressurisation results in CO_2 outgassing which will affect the sample chemistry. The U-tube sampler allows the collection of suitably preserved samples and also real-time analysis (Freifeld et al., 2005, 2006). The sampler was further developed and implemented in the Otway Basin Pilot Project, where modifications enabled tracers to be injected alongside the CO_2 stream (Stalker et al, 2008). At Otway, three samplers were placed within a single borehole to enable samples of either gas or formation water to be taken at different target depths. These sampling devices allow detailed geochemical and flow measurements to be undertaken directly in the reservoir (or indeed in overlying aquifers if this was deemed necessary). These tools have been developed and tested at very small scale pilot sites and have been deployed in only a single well drilled specifically for the purpose. They have been used to test a range of tracers and to monitor geochemical interactions at specific depths in a reservoir. Analysis of formation waters may also provide useful information on rates of CO_2 dissolution and subsequent fluid-rock interactions which may provide data on long-term trapping mechanisms and help to establish assurance of long-term containment. The use of tracers and of direct formation water sampling in wells on the expected plume migration path could also provide direct evidence of CO_2 movement through a reservoir.

Both deployments of the U-tube sampling tool were undertaken at onshore pilot-scale research projects. Further development of these types of sampling systems would be needed for routine deployment in more remote offshore environments. Key areas for development might be ensuring robustness and reliability for continuous operation in remote platforms and also automatic operation for normally unmanned platforms.

Borehole mounted equipment can sample only a very limited rock volume immediately around the wellbore (or between wellbores, in the case of crosshole deployments though these are typically limited to imaging along 2D sections between boreholes). The location of the wells and also of the monitoring equipment, including fluid samplers, within the wells, requires very careful consideration to ensure they are located appropriately. In addition, the sampling frequency is also an important consideration, requiring close co-ordination with predictive modelling to optimise information retrieval (e.g. detection of the migrating plume front). Nevertheless there is considerable potential for developing cheaper, automated monitoring systems that allow direct monitoring of reservoir processes such as geochemical interactions.

A major limitation of downhole monitoring systems is the availability (number, location and spatial coverage) of the potential monitoring wells. For depleted hydrocarbon fields, existing wells would have been for exploration or production and would not be optimally located for monitoring plume movement or formation water sampling. In addition, the number of wells will naturally have been kept to a minimum during hydrocarbon production. As production declines and wells water out, they are either shut-in or more completely abandoned, further reducing their subsequent availability for monitoring (and injection) purposes. These constraints make the use of downhole monitoring (with the exception of pressure and other simple technologies) a challenge and an operator and regulator will have to weigh the benefits of such monitoring against the costs of new dedicated monitoring wells.

The integrity of existing wells is also an important consideration as old wells could provide potential pathways for CO_2 migration. Downhole tools exist for monitoring well integrity (Chapter 10, Volume 2) and there has been some application of these with respect to CO_2 projects. However, more testing is needed for CCS and, in particular thresholds for detection of migration in wells need to be better established (see Chapter 6).

Inaccessible abandoned wells may exist offshore and, by definition, would not be amenable to monitoring with downhole methods. Non-invasive techniques, such as seismic methods, would have to be used to monitor around the wellbore or surface monitoring (e.g. bubble detection, seabed imaging or continuous measurement of gas or pH) deployed around the wellhead. This is discussed in more detail in subsequent chapters.

5.4.2 Shallow-focussed tools

The primary requirement of shallow monitoring is the detection of CO_2 emissions from the seabed or providing assurance that no emissions have occurred. An important requirement is the acquisition of baseline data against which to assess subsequent changes. The various methods available for near surface monitoring can provide 2-D or 3-D coverage or point information. They give data at a particular moment in time. Repeat surveys may indicate time-lapse changes, whilst continuous monitoring methods can be used at particular locations. The latter are important as they may detect transient leakage changes that could be missed by discrete time-lapse surveys.

5.4.2.1 SEABED IMAGING

As described in Volume 2 (Chapter 10), there are a variety of techniques for imaging the seabed, which might detect changes in seabed properties caused by CO_2 escape. Shallow seismic techniques, such as boomer, sparker or pinger, can detect surface features (e.g. pockmarks) along 2-D lines and may identify subsurface zones with gas that cause acoustic blanking. However, this effect can be caused by gas concentrations as low as 2% (Section 10.1.9) and currently these indirect methods cannot identify what gas is causing the effect.

The most promising methods for seabed imaging in relation to likely UK CO_2 storage are multibeam echo sounding and sidescan sonar (Sections 10.1.13 and 10.1.14). These are high resolution methods capable of detecting small features (< 1m). In addition to mapping seabed topographic features the intensity of backscattered sound gives information on the nature of the sea floor and could pick up changes due to CO_2 escape. More significantly, these methods have been able to detect gas bubbles in the water column, although at the present time, refinements to identify the gas present in the bubbles have yet to be developed. Fish-finding echo sounders can also be used to detect bubbles (Section 10.1.15) and some models allow mapping of data. However, multibeam and sidescan methods are better suited to systematic coverage of large areas.

A limitation on the detection of gas emissions through seabed features is that not all gas escapes are associated with changes in sea floor morphology. In some instances gentle seeps could form without accompanying pockmarks or other features. Factors such as flux rate, pathways and sediment type are all important here, with pockmarks being more commonly developed in muddy sediments than in sands. Pockmarks are widespread naturally-occurring seabed features, formed by escaping methane or water and therefore the formation of new pockmarks by themselves may not be indicative of CO_2 leakage.

Bubble detection by sonar is probably a more reliable means of identifying gas leakage but, at least at present, follow-up *in situ* sampling and analysis is required to identify the gas. In the future it may be possible to use the acoustic properties or behaviour of the bubbles (given that CO_2 is more soluble than methane) to make an assessment of the type of gas. Detection limits for bubble density have yet to be established and there are very few case studies in the use of the technique for CO_2, although a simple fish finder was successfully used to detect CO_2 bubbles in the Laacher See in southern Germany. Most case studies relate to releases of methane or water.

5.4.2.2 Measurement of gas and other parameters

Whilst sonar techniques have great potential for rapidly surveying large areas in search of gas emissions other techniques are needed to determine whether CO_2 is escaping or measure other parameters that may be associated with CO_2 release.

Gas concentrations can be measured as free gas or dissolved in seawater. Free gas analysis requires the collection of samples by in situ instruments, ship-deployed samplers or those operated from ROVs or by divers. Dissolved gas can also be measured by *in situ* monitoring stations, from stationary survey vessels and from underway vessels. Direct sample collection allows for subsequent shipboard or onshore laboratory determinations with very low detection limits (parts per million levels). Instruments placed on the sea floor, in the water column or on a buoy are generally less sensitive, but still capable of measuring fractions of 1% of CO_2. Flux rates can be measured by collection of gas through upturned funnels or through gas analysis and flow rate determinations.

Other parameters, which may be related to CO_2 emission, can be measured using commercially available devices. For example CTDs (Conductivity-Temperature-Depth measuring probes), usually operated to make vertical profiles of water properties, are used routinely to determine conductivity, temperature, pressure and pH (amongst others properties). Such techniques could be adapted for underway operation and direct detection of CO_2 could be added to them.

Biomarkers are another possible way of monitoring CO_2 release through its effect on the ecosystem. This could involve macrobiological or microbiological responses or even effects at a molecular level in key organisms. These studies are, however, in their infancy, with only a few studies having been carried out to date (Section 10.6.1). These do appear to indicate ecosystem responses to escaping CO_2 and suggest there to be potential in such methods. Further investigations are planned under new projects such as the EC FP7 project RISCS (started January 2010) and n projects that have -yet to start such as ECO2 (in negotiation with the EC).

5.5 MONITORING STRATEGY AND TOOL INTEGRATION

5.5.1 Tool capability

There are two key components to measurement capability: instrumental sensitivity and accuracy, and sampling efficiency (spatial or volumetric coverage, and temporal coverage). How these two components combine determines the overall measurement capability of the tool.

A monitoring tool (such as a surface deployed gas flux meter) may have a very high sensitivity but may only be able to sample at individual point locations (Figure 5-2).

If the tool is co-incident with the leak, then a very small leak could be detected and perhaps measured. A more likely scenario is that the leak may be partially or wholly displaced from the sensors, meaning that leakages may be inaccurately measured or missed altogether.

The key to improving measurement capability may be to design integrated monitoring systems which combine tools with complementary sensitivity and sampling characteristics.

5.5.2 Monitoring strategy

The literature review of observed or predicted CO_2 releases and the results of the modelling carried out in Chapter 4 provide some useful information in relation to detection capability. They give some insights into the nature of possible emissions in terms of areal extent, the amount of gas released and flux rates.

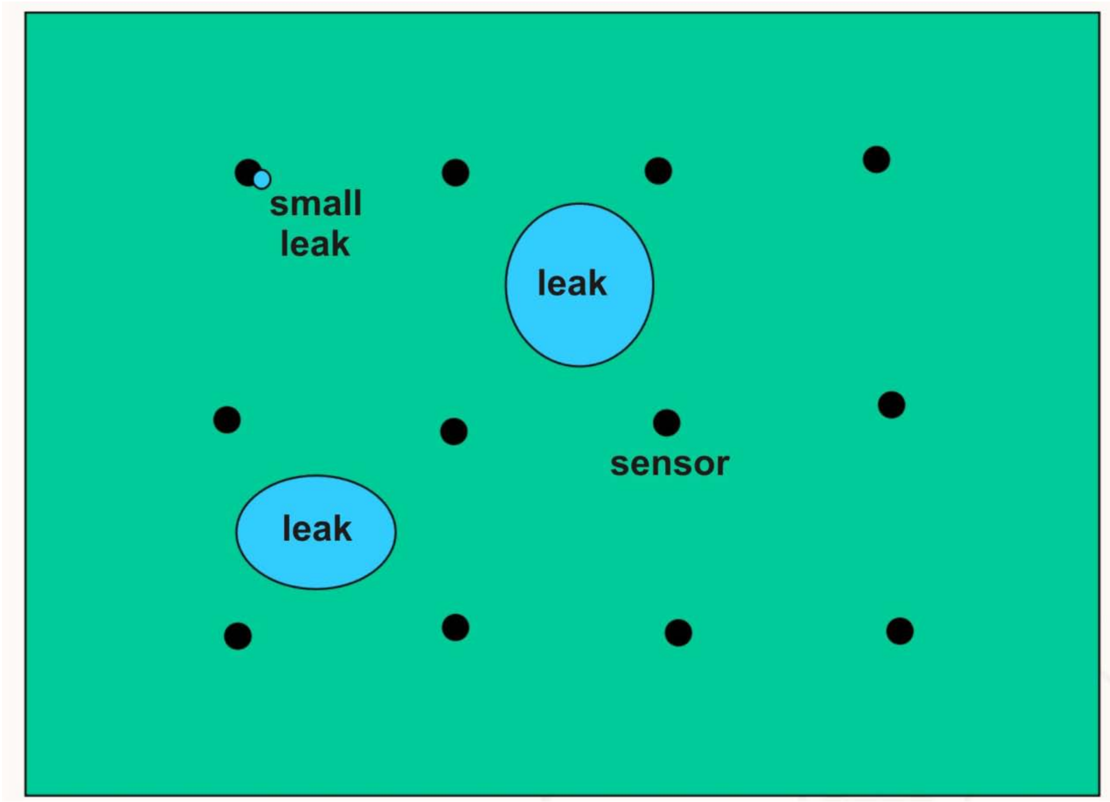

Figure 5-2 Schematic view of a leakage monitoring system deploying a grid of point sensors. Very small leakages can be detected, but only if they are co-incident with the sensor. Conversely, larger leakages may be missed (image courtesy British Geological Survey).

Observations from naturally-occurring leakage sites show that in general the localities of active CO_2 venting are small in relation to the total area over which CO_2 emissions are being produced, coming from only a few percent of the total area. Thus monitoring techniques need to be designed to detect small features (10 m or less across) and, given the scale necessary for commercial CO_2 storage, to be able to provide coverage over large areas (hundreds of square kilometres). Subsequent measurements of the emitted gas would likely be confined to relatively small areas requiring detailed study. This means that, provided a gas vent is spotted, detection of even low levels of release should be possible.

Leakage rates and distribution are governed by geological conditions. They may be initiated by events such as seismic activity and are then controlled by factors such as permeability, fracture patterns, lithology and hydrogeology. Rates therefore vary with time and monitoring needs to be designed to take that into account, for example by using continuous measurements to assess variability.

Flux rates from natural and experimental CO_2 emissions have mostly been measured onshore. They range from rates in excess of 1 t CO_2 m^2 yr^{-1} at actively venting sites to background values three orders of magnitude smaller. Areas of diffuse leakage can occur and these are far more difficult to identify (at least onshore) as they overlap with background values. Large ranges of flux values have also been derived from modelling of leakage (both from other studies and in this project; Chapter 4) depending on the specific scenario and the input parameters.

From the scenarios modelled in Chapter 4 a number of observations can be drawn which are pertinent to monitoring. Initial pressure conditions in the reservoir are likely to have a bearing on monitoring strategy. Reservoirs which are under-pressured initially are the least likely to leak significant amounts of CO_2 via any pathway until pressures build up towards hydrostatic. Nevertheless, pressure changes in shallow, overlying aquifers do suggest that monitoring of pressure in these zones would be an appropriate monitoring technique. The generic flow simulations (Chapter 4) indicate pressure increases of around 30 KPa up to 3 km from a hypothetical leaking fault, and more for a leaking well. This would be readily detectable with current downhole pressure measurement tools, which are capable of detecting pressure changes far smaller than this. An important issue is the fact the modelled scenarios indicated a wide range of breakthrough times for free and dissolved CO_2 at different locations. In some cases this did not occur for hundreds of years, which would almost certainly fall outside the time envelope being considered for monitoring under developing regulations (Chapter 2).

Detection of seabed leakage of CO_2 is likely to require a combination of methods. 3-D surveillance techniques, such as multibeam echo sounding, are necessary to ensure rapid coverage of large areas. They may need to be repeated at regular intervals, depending on the licence conditions and certainly should be deployed if deeper-focussed methods suggest that leakage may be occurring. Ship-borne measurement of CO_2, pH and related parameters, near to the seabed, can only provide 2-D coverage. However, they could detect gas escape under circumstances where there is no discernible effect on seabed topography and where bubble streams are of too low a density to be picked up by sonar techniques. Point measurements of CO_2 and other parameters are needed to establish that the gas emissions are indeed CO_2. More detailed follow-up analysis may then be necessary to confirm that the CO_2 has come from the storage site. This could entail the use of isotopes or tracers. Continuous monitoring at key sites (e.g. wells, faults and environmentally sensitive areas) would help to ensure that transient emissions are not missed – flux rates can vary over time, with discrete pulses of gas being possible.

5.5.3 Quantification

In the event of leakage, robust, defensible quantification of CO_2 leaks will be required to satisfy the ETS requirements. This will require techniques to be used in combination as outlined above. Accurate measurements of gas concentrations and flow rates would have to be made at leakage localities. Some continuous sets of measurements would be needed to assess temporal variations. These sets of measurements would then have to be integrated with the areal monitoring surveys to produce an estimate of the total CO_2 emitted. Specific attention would have to be paid to determination of errors, which is likely to be quite challenging but essential for the calculation of carbon allowances to be surrendered.

5.5.4 Deep-focussed monitoring

Deep-focussed monitoring technologies do not measure surface leakage explicitly, so cannot provide a direct indication of site emissions performance. However the ability to reliably detect small fluxes of CO_2 migrating out of the primary storage reservoir can place a useful upper bound on any consequent surface leakage, and, perhaps more importantly, can provide powerful insights into current and future containment processes.

Adopting this approach, Chadwick et al. (2009) were able to show that the absence of detectable migration out of the storage reservoir at Sleipner at the time of the 2002 time-lapse seismic survey was consistent with a ‘leakage’ rate of less than 0.02 % per annum. The continued absence of detectable migration out of the storage reservoir (as evidenced by the most recent 2008 survey) enables leakage rates to be constrained at even lower levels. Clearly, the longer that migration out of the reservoir remains undetectable, the tighter the rates can be constrained. This approach however does not take into account the possibility that several undetected smaller amounts of CO_2 may be migrating from more than one point in the reservoir. On the plus side detection of migration from the primary reservoir is an inherently conservative performance measure, as this will generally significantly exceed any subsequent leakage, due to other trapping processes such as dissolution that operate on CO_2 as it migrates through the overburden towards the surface.

5.6 DISCUSSION

Observation of natural and experimental emissions of CO_2 and modelling of credible scenarios for leakage suggest a wide range of possible CO_2 concentrations and flux rates. For a given amount of CO_2 leakage or emission it is very hard to arrive at definitive figures for the flux rates that will result at the sea floor or the CO_2 concentrations in the seawater. It is possible to envisage a wide range of values depending on the particular circumstances. This is borne out by the modelling described in Chapter 4 where the amounts of CO_2 emitted were either negligible (< 100 kg y^{-1} for the well and one of the fault cases) or ran to thousands or tens of thousands of tonnes per year. Observation from natural leakage sites suggests there is a tendency for CO_2 to vent at specific locations over rather small areas (typically 1-100 m across for any given individual vent). The CO_2 concentrations and fluxes at such sites are generally well above background and can be measured readily by existing instruments. Detection capabilities of individual tools are summarised in Appendix 4 (Volume 2).

Prior to reaching the seabed, it has been shown that the migration of relatively small amounts of CO_2 can be tracked in the subsurface using 3-D seismic, ranging from a few thousand tonnes at a shallow storage reservoir (although more than this in deeper reservoirs) to hundreds of tonnes at 500 m depth, although detection may be more difficult along faults or distributed through low permeability rocks and is likely to vary from site to site. However, there is a strong likelihood that, using seismic and other deeply-focussed methods, it will be possible to detect the movement of CO_2 in the subsurface and get early warning of leakage to shallow levels enabling shallow-focussed monitoring to be targeted.

Deep focussed tools, such as seismic, are well established technologies with a proven track record in CO_2 storage. Most invasive tools (downhole techniques) are also mature and generally fit for purpose. However, more testing is required with CO_2 and there are some specific areas with potential for development. These are examined in Chapters 6 and 7. Inaccessible abandoned wells present a monitoring challenge, which is discussed further in subsequent chapters.

Section B

Monitoring Gaps and Developments

6 Developing Technologies

6.1 EXECUTIVE SUMMARY

This chapter is a counterpart to Chapter 5 in that it presents gaps in monitoring technologies as identified by service companies, R&D teams and those involved in CCS projects, and indicates how such organisations see developments addressing these gaps.

Some sixty organisations were approached for their views. Most CO_2 monitoring is carried out using existing tried-and-tested oil and gas field monitoring technologies, but there are some methods or adaptations specific to CO_2 monitoring either available or in development.

Joint interpretation methods represent a gap, which is also a major focus of the oil and gas industry for its reservoir monitoring, modelling and simulation programmes.

The lack of a strategy for dealing with abandoned wells was identified as an important gap. It was felt that technologies existed to address the monitoring issues, but there were significant risks in deployment (e.g. damage to a well completion during installation subsequently forming a CO_2 migration pathway).

The gaps identified from discussions with third parties were then compared with, and cross-referenced to, the gaps identified previously in Chapter 5. A full catalogue of gaps is presented in Appendix 5 (Volume 2) under six themes: monitoring strategy; monitoring large areas with non-invasive techniques; monitoring in and around wells; ETS or shallow monitoring; monitoring injection at the well head; environmental impact assessment. Within each theme the gaps have been prioritised according their importance for production-scale use of CCS.

This analysis allowed collation of an inventory of novel technologies. For each, we present a summary of the developments identified followed by more detailed descriptions. These are grouped according to the basis of the technology and the drivers for development. Descriptions are cross-referenced to relevant material elsewhere in this report, mainly in Chapter 10. The methods and developments included in the inventory can be summarised as:

Seismic methods: there is potential for permanent installations for example using Ocean Bottom Cables (OBCs) and scope for multi-component data. Improvements are also foreseen in: hardware (wireless, improved sensitivity, MEMS, optical sensors, continuous recording, improved sources); processing (improved imaging, joint inversion); interpretation (data assimilation, visualisation). Inversion of pressure and saturation are envisaged from AVO or multi-component data. Improvements are also occurring in the resolution of sub-bottom profiling.

High-resolution sea bottom imaging and bubble detection: forward-looking sonar instruments, can survey over 100 m ahead of the survey ship, and downward looking systems (e.g. sidescan sonar and multibeam echo sounding) can map seabed features with increasing resolution and detect bubbles. However, most experience is with methane or water and not with CO_2. Development is needed to establish detection limits for bubble streams, whether bubble composition can be determined and development of permanent detectors for critical locations (e.g. near old wellbores).

Geophysical logs: this is a mature technology, but more experience with CO_2 is needed. New concepts for well integrity logs include electro-chemical techniques. Integrity logs need more testing to establish threshold values for detectable leakage in wellbores. Custom completions for monitoring at different levels, such as the Westbay System, need further evaluation.

Downhole P/T: distributed temperature sensors seem to be a mature technology.

Chemical methods: developments are needed for downhole fluid chemistry and for new sampling devices. Permanent downhole pH sensors are not yet available. Improved sampling devices and CO_2 detectors are under development. Microbial monitoring and developments in biogeochemical methods are also occurring.

EM or resistivity based methods: testing joint inversion with seismics for CO_2.

Gravimetry: developments in gravity gradiometry have not been considered for CO_2. Borehole applications have not yet been explored sufficiently.

Other techniques: ecosystem impacts are being examined in new European and UK projects, including the use of a benthic chamber, and some microbiological developments have been made by Statoil. No real development in tiltmeters is foreseen. New tracers are being tested. Drill cores which maintain the pressure of seabed samples could potentially be used to sample shallow (up to 500 m below seabed) sediments for CO_2. The sound of CO_2 bubbles in the water could also be detected at short range (up to 15 m) from a fixed monitoring position or a ROV, using directional microphones. Noise logging in boreholes is experimental for CO_2. Fixed underwater cameras may have the potential to detect bubbles.

Each novel technology identified in the inventory has been assessed in terms of its maturity, limitations and the improvements foreseen from current developments. Many developments are incremental and the main need is for more testing with CO_2. Shallow-focussed monitoring is, in general, in need of more developmental effort than deep-focussed techniques.

6.2 INTRODUCTION

In Chapter 5 a gap analysis was carried out based on examples of monitoring found in the literature and our knowledge of specific projects. This Chapter describes essentially a bottom-up approach, where third parties have been contacted to give their opinion on current gaps in monitoring technology and their view on developments to bridge those gaps. A full list of parties approached, consisting of research groups, service companies and project leaders of ongoing R&D / demonstration projects, is provided.

A compilation of all the gaps identified both in Chapter 5 and this Chapter is provided, subdivided into different categories. The main conclusions from Chapter 5 with respect to gaps in monitoring technologies were that deep monitoring methods can be considered relatively mature, and adequate to meet requirements with incremental developments, but that technologies for assessing and quantifying leakage require greater development and have not been addressed sufficiently to date.

This analysis was generally supported by the approached parties. Additionally, gaps were identified related to defining optimum monitoring strategies, the lifetime of permanent (downhole) sensors and the unexploited potential of integrating various monitoring methods. The latter is described in Chapter 7.

Finally a full overview of developments of different techniques is provided including an assessment of the maturity, detection improvements and limitations.

6.3 INVENTORY OF NOVEL TECHNOLOGIES: DISCUSSIONS WITH THIRD PARTIES

In order to draw up an inventory of new developments in monitoring technologies a number of research groups, service companies and integrated projects have been approached. A full list is provided in Table 6-1. Discussions about new technology developments and identified gaps in monitoring have been held with all these parties, using a prepared questionnaire as guidance (Appendix 2, Volume 2). The next sections will provide a more detailed description of the gap analysis and of novel technologies.

Table 6-1: Different groups approached for the novel technology inventory

Organisation	Contact person	Field of expertise and related projects or site(s)
Aanderaa Data Instruments AS	Trond Gulbrandsoy	sea water monitoring stations
AML Oceanographic	Tom Dakin	manufacture oceanographic instruments
Applied Acoustics	Adam Darling	Boomer/sparker manufacturer
Applied Signal Technology Inc		
Atlas Elektronik UK Ltd, Atlas Hydrographic	Daniel Rosenboom	multibeam echo sounder and sub-bottom profiler
Biosonics	Eric Munday	sonar equipment and software
Blueview	Jason Seawall	Multibeam echo sounder - 'acoustic movie'
BP	Walter Crow	Lead well integrity expert in the Carbon Capture Project (CCP), field of expertise well integrity.
Canadian Geological Survey	Don White	Leading geophysicist in the Weyburn project, also involved in other Canadian pilots.
Chesapeake Technology Inc		Software processing for viewing sonar data
C-MAX Ltd		Standard sonar equipment
CO2GEONET: NIVA	Dominique Durand / Andrew Sweetman	Field of expertise in marine biology, member of CO2GEONET.
CO2GEONET: OGS, URS, BGR	Dino Viezzoli, Salvatore Lombardi, Franz May	Group of marine biologists member of CO2GEONET involved in studies in the Gulf of Trieste, Panarea, and in the EU CO2ReMoVe project
CodaOctopus	Blair Cunningham, Rolf Kahrs Hansen	Echoscope
CONTROS Systems and Solution GmbH	Stefan Kramer	HydroC CO2 sensor
Edgetech	Nick Lawrence	Manufacturer of sonar and sub bottom profiling equipment
EIVA	Niels Jorgen Vase	Naviscan
Foundation Sensor Universe	Eugene de Geus / Henk Koops	Field of expertise mostly in hardware development for sensors, coordinators of a network of >80 sensor vendors in the Netherlands
FUGRO	Brian Mackenzie	Sediment corer
Gardline Marine Sciences	Paul Scibilia	Major survey company
Idronaut	Fabio Confaloneiri	deep water, continuous sea water monitoring equipment
Imagenex	Helmut Lanziner	Sector scanner/forward looking sonar
IMARES	Chris Karman	Field of expertise in marine biology

Organisation	Contact person	Field of expertise and related projects or site(s)
Innomar technologie Gmbh	Jens Lowag	Parametric sub-bottom profiler SES2000
ION	Wouter Kool	Field of expertise seismic monitoring, business developer for ION.
Instrument Concepts	Mark Wood	Mono-directional/directional underwater microphones
IVS 3D	Moe Doucet	Software for processing sonar and multibeam data
Kemijoki Aquatic technology Oy		Aquatic sonar
Knudsen Engineering Ltd	Judith Knudsen	Hydrographic equipment and echo sounders used for sub bottom profiling
Kongsberg Maritime Ltd		TOPAS PS18 parametric sub-bottom profiler, EM 3002 multibeam echo sounder, TOPAS profile
L-3 communications ELAC Nautik Gmbh		Sidescan sonar ELAC 2900 and SUGAR, KLEIN 5000 multibeam sidescan sonar and KLEIN 3000 digital sidescan sonar
Marine Electronics Ltd		Standard multibeam echo sounder
National Oceanographic Centre Southampton		Field of expertise in marine biology
Norbit	Trond Danielsen	Manufacturer of sonar equipment
Nordic Sonar		high resolution (20mm) forward looking sonar equipment
OceanLab	David Sproule	benthic assessments
Oktopus GmbH		Gravity and sediment corers
Optimare	Theo Hengstermann	CO_2 sensor and fibre optic probe
OPTEC		SHOALS 3000 (Airborne LIDAR bathymetry)
PanGeo Subsea Inc		
Plymouth Marine Lab	Steve Widdecombe	Field of expertise in marine biology
Pro-Oceanus systems	Norma Yong	CO2-pro
Questor	Chris Elliot	
R2 Sonic LLC	Cris Sabo	SONIC 2024 Multibeam echo sounder
RESON	Alan Kenny	SeaBat Sonar 7125, 7128, multibeam SeaBat 7107
Rovtech Systems Ltd	Howard Smith	Manufacturer of underwater cameras, lights and pan/tilt units
S.E.A	Ben Hinett	Very wide swath (200m), high resolution (1cm) sonar and multibeam sea floor imagery

Organisation	Contact person	Field of expertise and related projects or site(s)
Seamap UK Limited & SEISMIC ASIA PACIFIC PTY. LTD	Chris Toner	Manufacturer/provider of equipment e.g. sidescan sonars, multibeam echo sounders, hydrophones, etc
Seatechrim		glass sensors for chemical/radioactive pollutant
Sercel	Laurent Guenneugues	
SLB Carbon Services	Laurent Jammes, Matteo Loizzo Tony Booer	Main field of expertise in well integrity, involved in numerous CO2 projects worldwide.
Sonardyne Ltd	David Brown	long life sub sea sensor data loggers
Sonavision Ltd	Nick Peters	real time seabed discrimination device
Sound Metrics Corp		high resolution, high frame rate imaging sonars and software
Statoil	Hans-Kristian Kotlar	Microbial monitoring
TNO / TUD	Rob Arts	Coordinator of the storage and monitoring part of the Dutch CATO-2 national program.
Tritech	Maurice Fraser	Eclipse multibeam imaging sonar
University of Groningen (RUG)	Harro Meijer	Main field of expertise in atmospheric monitoring, involved in the Dutch CATO-2 national program.
Valeport		Woods hole group
Weatherford	Peter Elkington / Jos Jonkers	Field of expertise in well monitoring, involved in projects at Weyburn, Canadian pilots + MMV work at Lacq (F), GFZ (D) , Vattenfall (Dk) and JAPEX (J)

In general, the discussions with the different contacts led to the conclusion that, for the deep geophysical monitoring technologies, no major breakthroughs are expected from current developments (e.g. personal communication Don White). The main emphasis is more on applying oil- and gas technology to CO_2 storage projects for demonstration purposes. After the initial 4D seismic successes at Sleipner and Weyburn, the focus has shifted towards EM or electrical resistivity based technologies. Added value is particularly sought by combining different methods and applying joint inversions such as CSEM-seismic inversion or gravity-seismic inversion.

In the CCP-2 project feasibility studies have been carried out both for EM and for gravity responses (Kieke et al., 2009). Recent results at Ketzin from ERT measurements are promising and during the last CO2SINK monitoring workshop (24-25 February 2010) the need for a joint inversion of the seismic-ERT data was expressed and is now planned.

For well integrity a number of technologies have been tested recently in wells as reported in Chapter 3 and Chapter 10. From the CCP2 project the main conclusion was that current technology provides sufficient resolution to detect significant leakage (personal communication Walter Crow). This was corroborated by the views of Schlumberger Carbon Services (personal communication Laurent Jammes and Matteo Loizzo). The heart of the question however is to determine just how small a leakage rate needs to be measured. McKinley (1994) used several types of logging. In general, the oxygen activation (specific to water channelling) measured migration to as low as 2 gallons/minute (approximately 10 litres/minute). There seems to be sufficient capability in the tools on the market today to satisfy the need to detect very low rates of leakage, but this capability requires setting up the well completion in a way that enables the technology to be used. A very simple adjustment to packer depth in the completion would be to have it positioned at a point above the bottom of the caprock to facilitate log measurements through one string of casing. In general, there is a need to determine the threshold of detection to use in this case.

CCP3 plans to include a test for the determination of the threshold for migration along the cement barrier to determine the lowest detection limit for existing technologies. The program has not been developed as yet, but could include acoustic logs for cement quality (indirect measurements) as well as radioactive tracer, noise and temperature logs (some of which could be considered direct measurements).

Both Schlumberger Carbon Services and the CCP2 project identified the lack of a clear strategy for monitoring abandoned wells as a serious gap, to which no clear solution has been identified. Of course a work-over of the well, using for example pancake plugs, is a solution to minimize the risk for migration along abandoned wells. Currently research is ongoing on the quality of abandoned wells. In all cases the decision on re-completion of the well should be based on a thorough risk analysis. Input for the risk assessment consists of the history of the well as laid down in well reports and experiences from wells around the world.

Monitoring of inaccessible abandoned wells is currently limited to geophysical methods (essentially seismics) to look at spreading of CO_2 around the borehole in permeable layers and to surface (sea bottom) monitoring including bubble detection, in situ gas measurement and sampling. Little experience has yet been gained with these methodologies offshore.

Instrumentation of abandoned wells that are still accessible is considered as a risk in itself. In one of the regional partnership programs in the US, the Westbay System, compliant with EPA standards, has been used at the aquifer levels. The completion is may, however, be a weak point.

For shallow techniques more developments directly applicable to CO_2 storage are taking place.

6.4 COMPILATION OF GAPS

This section provides an overview of gaps that have been identified by the parties contacted (Table 6-1) or identified from our existing knowledge or in the literature. This section gives an overview of all the gaps, including those mentioned by, or arising from discussions with, the third parties without prior knowledge of the gaps identified in this project that were outlined in Chapter 5. This allows a cross check with the gaps identified earlier.

Appendix 5 (Volume 2) gives a complete overview of the gaps identified in this project. These gaps have been categorised according to the following themes:

1. Monitoring strategy:

   This concerns especially the strategy for detecting potential leakage and of not using all available data to its maximum value because of poor integration between different methods. Developments in this field are particularly discussed in Chapter 7.

2. Monitoring large areas with non-invasive techniques

   Though most of the non-invasive geophysical monitoring techniques seem quite mature, there are certain aspects of their use to solve particular problems posed by CO_2 storage, such as detecting pressure build-up over large areas, brine displacement and improved understanding of the reservoir processes to calibrate flow models, which are not yet fully developed. Current developments are described in this chapter, mostly focussed on improving resolution of the various methods, for example by using permanent sensor networks, whilst Chapter 7 deals with combining different methods.

3. Monitoring in and around wells

   The main gaps concerning monitoring in and around wells are focussed on assuring well integrity, the development of robust permanent downhole sensor systems with an extended lifetime (in particular the development of downhole pH sensors and of downhole sampling systems) and finally in getting more control on threshold values for leakage detection. Developments both in hardware and in testing are described in this chapter. The necessity of combining well integrity measurements is described in Chapter 7.

4. ETS or shallow monitoring

   The detection and quantification of leakage is considered a very immature area. A large part of this chapter describes the developments in shallow acoustic methods (improved resolution, speed of acquisition, quantitative data interpretation, fixed monitoring stations). In Chapter 7 examples of strategies for detecting methane seepages in the North Sea are provided, that could be applied to CO_2 storage as well. Furthermore, little is known about natural background CO_2 fluxes at the seabed.

5. Monitoring injection at the well head

   Measuring the exact quantities of injected CO_2 at the wellhead is not trivial if there are impurities present. Flow meters currently depend heavily on thermodynamic models. The only real developments here seem to be to improve thermodynamic models.

6. Environmental impact assessment

   The impact of CO_2 leakage at the sea bottom is not sufficiently known. Experiments making use of in-situ measurements using a benthic chamber lander are described in this chapter. New research projects are addressing this issue.

The individual gaps, as described in Appendix 5 (Volume 2), within each of these categories have been qualified as high (red), medium (orange) and low (green) priority based on the discussions and on the need to have these gaps bridged in order to roll-out CCS on a large scale. A condensed overview on the key future developments, on the status and on the relevance for the different types of storage reservoirs as identified for the North Sea is given in the table.

Besides the gaps identified, some major trends came out of the discussions. These can be summarised as:

1. Most technology developments are incremental, few completely new technologies are being developed
2. Most new developments occur in shallow monitoring
3. Current well integrity monitoring capabilities seem adequate in operating wells
4. Integration of methods is happening more and more
5. More demonstration projects are needed to test methodologies
6. The link between modelling and monitoring is crucial

The following section gives an overview of individual technological developments, whilst the added value of integrating different techniques is described in Chapter 7.

6.5 INVENTORY OF NOVEL TECHNOLOGIES: DESCRIPTION OF THE TOOLS AND CURRENT APPLICATIONS

This section provides a more detailed description of novel technologies. The main developments have been categorized in line with the scheme used in Chapter 10 (Volume 2). For each of the following subsections the corresponding section in Chapter 10 is indicated in brackets. Each subsection starts with a short summary of the main developments identified, followed by a more detailed description.

6.5.1 (10.3.1-10.3.7) Seismic methods (mainly hydrocarbon industry driven):

In summary the following developments have been identified:

- Potential for permanent installations using OBC, scope for multi-component data
- Improvements in hardware (wireless, improved sensitivity, MEMS, optical sensors, continuous recording, improved sources)
- Improvements in processing (improved imaging, joint inversion)
- Improvements in interpretation (data assimilation, visualisation)
- Inversion of pressure and saturation from AVO or multi-component data
- Improvements in resolution of sub-bottom profiling

6.5.1.1 OBC AND SEABED RECORDING

No major innovations seem currently ongoing with respect to seismic methods other than improvements of existing technologies coming from oil- and gas exploration and production. The main driver for these technologies still seems to be the oil and gas industry. Interesting applications, applied for oil and gas, but not yet for CO_2 storage, consist of the deployment of permanent Ocean Bottom Cables (OBC) on the sea bed. BP currently has commercial life of field seismic systems up and running, located at Valhall (Norway) and Clair (UK) along with Azeri-Chirag (Azerbaijan) which is a partially permanent operation. At the Vallhall Oilfield (Barkved, 2004; Barkved and Kristiansen, 2005) both production and ground movement (subsidence in this case) have been measured successfully from repeated active seismic surveys.

In principle the permanent installation of the OBCs allows more flexible acquisition over time only requiring deployment of a seismic source. In the case of Vallhall, where BP has deployed seabed recording equipment developed by OYO Geospace since 2003, it allows more frequent time lapse seismic data acquisition (twice a year) at reasonable costs (i.e. ship time for a seismic source). The buried cable array on the seabed includes a combination of geophone and hydrophone receivers to capture seismic data on each occasion that a vessel ‘shoots’ over the reservoir. The reason for burying the system is that it gives a superior signal compared with untrenched deployment and to avoid damage due to fishing activities (Smit et al., 2006). The system relies on electronics to relay the data to the offshore installation to which the network of cables is hooked up. In the case of CO_2 monitoring the advantage would be (besides the option of more frequent acquisition) the option for long term monitoring again at reasonable costs. Improved repeatability due to the permanent receivers leads to a higher resolution of the time lapse signal allowing smaller time shifts and amplitude variations induced by the CO_2 to be picked up. The improved repeatability opens the possibility of acquiring sparse 4D seismic data by deploying fewer receivers (Smit et al., 2006). The higher repeatability makes up for the loss of coverage (fold).

The use of OBCs furthermore allows the direct recording of multi-component data instead of converted waves using more conventional streamer data. The additional acquisition of shear waves provides potential for measuring anisotropy in the overburden related to (induced) fracturing, for improved interpretation of stress effects in and above the reservoir and for improved characterization of pressure and saturation effects in the reservoir. The latter is particularly of interest for CO_2 storage to identify pressure effects far away from the injection and monitoring wells and to identify the “affected space” (i.e. storage complex) in the subsurface. The methodology to discriminate between pressure and saturation from time-lapse seismic data does exist, though it still has quite a lot of uncertainty. In the Weyburn project this type of inversion is envisaged for application to CO_2 storage (Ma and Morozov, 2010). Several oil- and gas applications have been reported in the literature, as at the Gulfaks field (Landro, 2001).

In November 2009 the Norwegian OCTIO Group based in Bergen launched the latest permanent reservoir monitoring system, for life of field seismic, as part of its growing activity. This system is built around ION’s VectorSeis Ocean which uses an advanced digital MEMS (Micro Electro Mechanical System) sensor system. MEMS are based on accelerometers, but with a feedback loop to cancel mass displacement in the sensor itself. This allows for acquisition of broadband signals (Mougenot, 2004). A power supply is required for the operation of this system.

Fibre optic solution proponents – CGGVeritas (Optowave), Petroleum GeoServices (Optoseis) and Stingray (Fosar) - argue that the subsea components of their systems are completely passive in that they have no electronic components and therefore no power is required. They say this should provide a longevity and reliability advantage over traditional electrical systems since the in-sea sensor equipment is not prone to electrical noise, leakage or short-circuit. It is also said that the low power loss and large bandwidth of optical fibres enables high data transmission rates over long lead-in cables and allows the transmission of huge amounts of information over long distances. This becomes significant when a field is operated from subsea installations with the platform several kilometres from the producing wells.

Currently it is difficult to predict whether companies like OCTIO and OYO Geospace, which have developed conventional multi-component ocean bed cable designs will be overtaken by the fibre optic providers, or whether there will be a place for both solutions.

On land permanent seismic receivers are now combined with permanent active sources (Meunier et al., 2001). No developments have been encountered in this direction for offshore applications.

For downhole applications fibre optic geophones are available (e.g. Weatherford). In principle these sensors are less sensitive to harsh environments and potentially have a longer lifetime. These geophones could be permanently installed in the casing annulus of an injection well permitting single-well operation with minimal interruption to injection – ideal for time-lapse surveys. However, little experience has been gained so far using these sensors, and certainly not to test the life time.

A novel application of Vertical Seismic Profiling is for ultra-high resolution travel-time (HRTT) measurement. In this configuration high frequency receivers are placed in the wellbore beneath the CO_2 plume. Changes in travel-time and attenuation from a high frequency seismic source above the plume can be used for direct quantification and mapping plume extents. With potential resolution of fractions of a millisecond this is a high precision tool, capable of detecting CO_2 layers less than 1 m thick. However, to our knowledge HRTT has not yet been successfully deployed in CO_2 storage. Depending on logistics the method is potentially very suitable for deployment in deviated injection wells where the wellbore lies beneath the buoyant CO_2 plume (such as at Sleipner).

6.5.1.2 Shallow seismic monitoring

With respect to shallow monitoring, small improvements in resolution and survey speed of shallow sub-bottom profiling have been made. Sonars with dual frequency use the different behaviour of the sound pulses of the water column to give an image of the seabed to a resolution of a few centimetres. For example, the Innomar Technologie Gmbh parametric sub-bottom profiler, SES2000, has a stated resolution of 5cm and sediment penetration depth of up to 40 m. The instrument has a narrow beam of 1.8 º. Accuracy of this system is given as 0.02 m plus 0.02% water depth at 100 kHz and 0.04 m plus 0.02% water depth at 10 kHz. This can be used in water of up to depths of 400 m and can do up to 30 pings per second, improving survey speed. The Kongsberg Maritime Ltd, TOPAS PS18, parametric sub-bottom profiler has a similar resolution and a higher ping rate of 40 Hz and surveys with this equipment could proceed at about 14 knots in calm clear water and water depths of 20 to over 1,000 m. For deeper sediment penetration (up to 150 m), resolution was reduced to about 0.3 m) for the PS18. The Atlas Hydrographic, ATLAS P70 Parasound, sonar has a resolution of up to 0.06 m and can penetrate up to 200 m into the seabed sediments in water depths of up to 11,000 m. Swath width is 4.5º by 5º. It uses dual frequencies (18 kHz and a higher frequency of 18.5 – 21 kHz). Set up costs for the Atlas Parasound P70 were stated as around 1.5 million Euros. Sonavision have a real time sea floor characterisation device that could be used for time lapse monitoring of the sea bed above a CO_2 storage site. Currently it has been used to monitor for changes in sediment caps on toxic waste and other environmental surveys.

6.5.1.3 Acoustic coring

The technology of 3-D seismics can be adapted for the shallow section by recording at high resolution and frequency. This has been used to look at gas accumulations and transport pathways close to seabed offshore Norway (Andreassen et al., 2007; Hustoft et al., 2007) and on the Nile Delta (Sharp and Samuel, 2004). This typically involves using sampling rates of 1ms or finer.

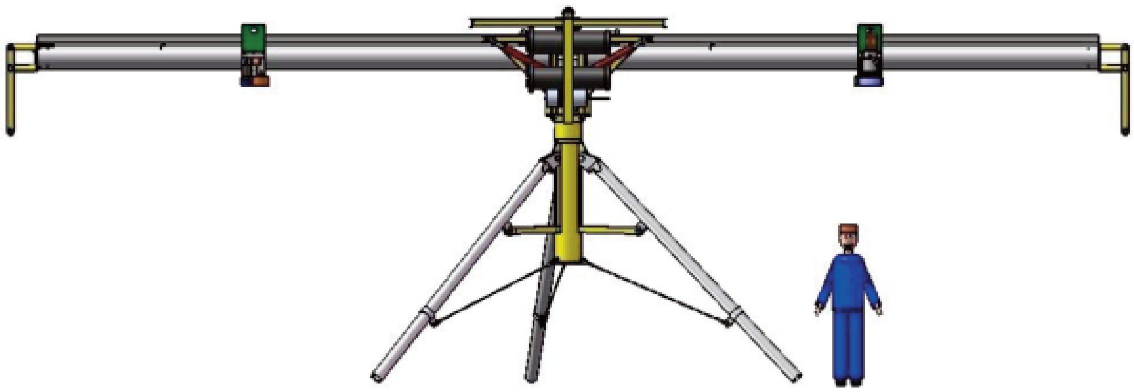

Figure 6-1: Acoustic corer (image courtesy Henrik Lundorf Nielsen, PanGeo Subsea Inc)

A novel system of 3D seismic to allow even higher detail is acoustic coring (developed by PanGeo Subsea Inc) , whereby instead of using a towed array, a scanning system on a seafloor mounted tripod is used. Acoustic coring produces a 3D image up to 14m diameter to a depth of 30 to 80m depending on soil complexity. Its resolution is approximately 0.1m at seafloor reducing to 0.5m at 20m depth in typical soil conditions. The system has been used to detect boulders and has been proposed for shallow gas detection. Its application could be to trace the pathway to the seabed for a known seepage location (Figure 6-1, Figure 6-2) although the spatial coverage is somewhat limited.

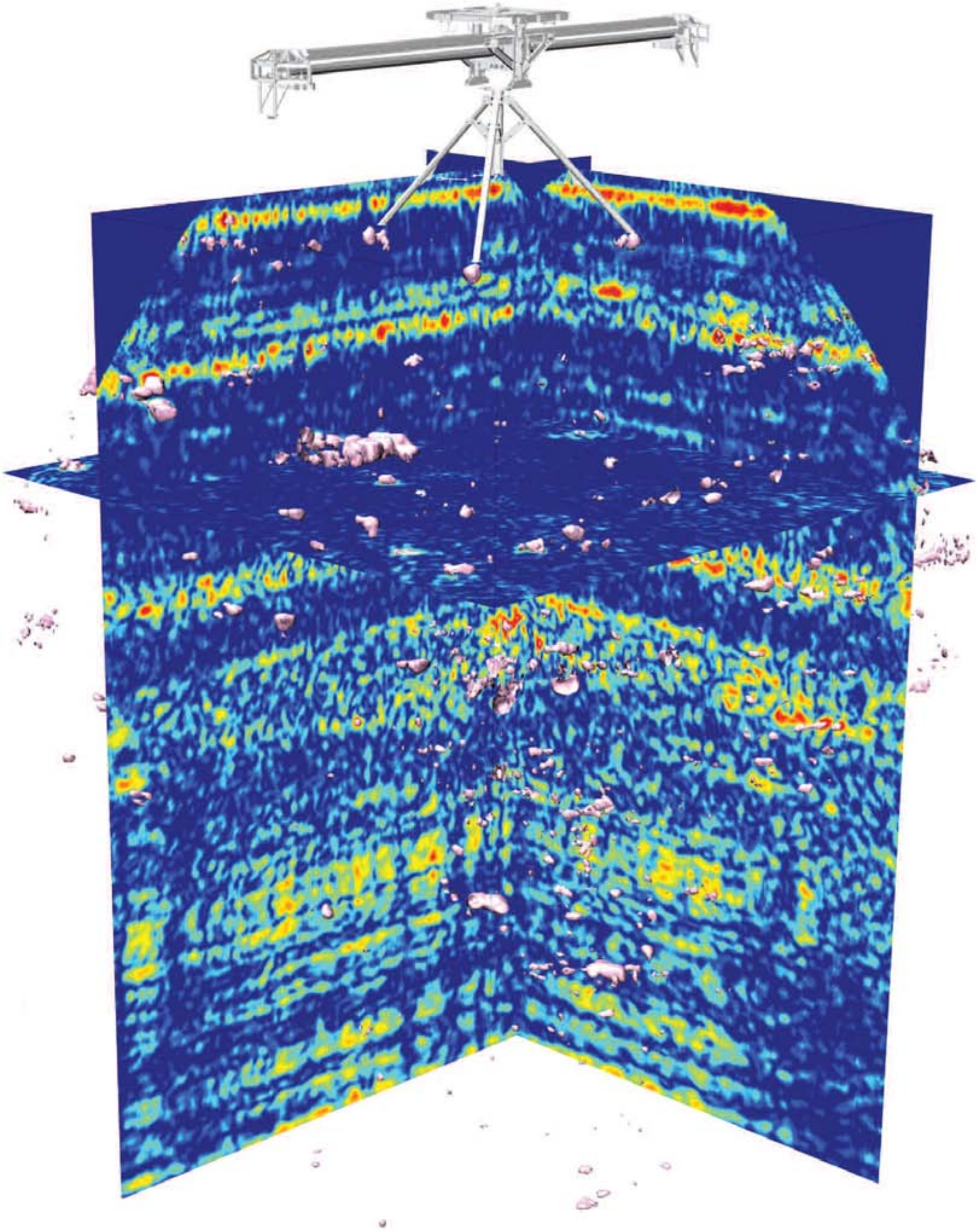

Figure 6-2: 3D volume generated by Acoustic Scanner (image courtesy Henrik Lundorf Nielsen, PanGeo Subsea Inc)

6.5.1.4 PRESSURE SAMPLING

Pressure sampling provides a means of recovering sediment cores held at in-situ pressure. This aims to avoid sediment disturbance caused by gas in sediment as cores are brought to the surface. This is particularly important when gas is held within hydrates and large volume changes occur when it sublimates. In recent years EU funded projects HYACE and HYACINTH have led to the development and deployment of two systems to fit within shallow drillings systems, the Fugro pressure corer (FPC) and the HYACE rotary corer (HRC). These were developed to support studies of methane hydrates. The FPC uses a hammer driven by mud circulation to drive a sampler into the sediment and seal it. The HRC uses a mud motor to drive a cutting shoe into lithified sediments. Both systems have been used in programmes in the Gulf of Mexico (Chevron-DOE JIP programme), offshore Cascadia (IODP Leg 204), Bay of Bengal (Indian hydrates study) etc. The former has been used more frequently. The latter has been modified into the Fugro Rotary Pressure Corer (FRPC). The systems are designed to hold the cores under pressure within an autoclave before transfer to a logging system including, magnetic, gamma, resistivity, X-ray (Schultheiss et al., 2006). The recovered cores have been logged to show the location of the hydrates within the core and how it changes as the cores are depressurized. This has generally shown that methane is located in distinct layers or along fractures within the cores rather than disseminated throughout. This could also be expected for CO_2 within sediments.

These technologies could be used to measure the amount and location of CO_2 gas within the shallow sediment sequence (approx less than 500m sub-seabed depth). This might be monitored as a possible precursor to leakage or as a means of identifying that gas in the sediments was not related to CO_2 leakage.

6.5.2 (10.3.8, 10.3.13 – 10.3.15) High-resolution sea bottom imaging and bubble detection

In summary the following developments have been identified:

- Surveys searching for bubbles in the water column, there are various forward-looking sonar instruments, which could survey over 100 m ahead of the survey ship, and downward looking systems with differing capabilities.
- Bubble stream detection: development of permanent detector for critical locations (e.g. near old wellbores)

6.5.2.1 High resolution seabed imaging

High resolution seabed imaging can image centimetre-scale features on the seabed in ideal conditions. There have been some small improvements in the resolution and survey speed for sidescan sonar instruments. For example, the RESON SeaBat sonar 7125 operates at dual frequencies (200/400 kHz) to give a bathymetry resolution of 0.006 m (water depth up to 500 m on towfish or 6000 m on a ROV). The S.E.A. SWATHplus sonar can survey a wide swath at high resolution (0.01 m) with a range of up to 200 m from a ROV or AUV, recommended track width for surveys is 150 m. Swath coverage is 15 – 20 times water depth monitored from 50 m above the seabed. The swath width is up to 50º. The SWATHplus sonar is depth rated to 1000 m though instruments designed for deeper water are available. There is also an interferometric SWATHplus sonar which has a swath width of 15 to 20 times water depth when ship mounted and used in water depths of less than 15 m. The Applied Signal Technology Inc. PROSAS Surveyor PS60 sonar for deep water can cover 3 km^2/hour with a resolution of 0.03 m, it uses synthetic aperture sonar to fill in the gap observed directly underneath the instrument reducing the need for overlap of survey lines and has a swath width of up to 500 m. It can be deployed in water depths of up to 6000 m from a ROV. The Applied Signal Technology Inc FrontRunner Nadir Gap Filler Sonar is a recently developed tool.

Multibeam echo sounders can also be used to image the seabed at centimetre-scale resolution, for example the R2 Sonic LLC SONIC 2024 multibeam echo sounder uses 256 beams (0.5 to 1º wide) in a swath up to 160º wide, showing seabed features and bathymetry with resolution of a few centimetres. The Atlas Hydrographic Inc Hydrosweep DS is a high resolution echo sounder for use in deep water (up to 11 km) to collect bathymetric (resolution up to 0.061 m), as well as backscatter and sidescan data with track coverage of 5.5 times water depth (up to maximum absolute coverage of 30 km) using frequencies of 14 – 16 kHz. The repeatability of sonars and multibeam echo sounders to detect changes in the seabed is highly dependent on accuracy of positioning.

6.5.2.2 Bubble detection

Gas bubbles in the water column are good reflectors of high-frequency signals. The development of forward-looking sonars allows monitoring of the water column, which could potentially be used to locate bubbles if there is a sufficient quantity present. Some sonars have been tested with methane bubbles, particularly for detection of leakage from pipelines, but testing with CO_2 would be required. Many of the forward looking sonars have been developed for object avoidance and so often have a narrow swath of a few degrees. The Reson SeaBat 7128 is an exception having a 128 degree wide swath using 256 beams. It operates at a single frequency of either 200 or 400 kHz (with a range of 200 m and 500 m from the instrument respectively). It is depth rated up to 6000 m. The Imagenex sector scanner operates with a 20 – 60º wide swath with a vertical range of 20 º at frequencies of 120 - 1000 kHz, with a penetration depth of 300 – 10 m respectively from the instrument.

Multibeam echo sounders can also be used to image the water column, however, this generates huge quantities of data for onboard storage and processing. Multibeam echo-sounders typically survey a 50 - 120º swath. Detailed multibeam echo-sounder surveys are also possible, for example, the CodaOctopus echo sounder and the Sound Metrics Corp Didson can image fish swimming and bubbles in a radius of a few tens of metres. The CodaOctopus echo sounder has over 16000 beams which can image at a resolution of 0.03 m and a range of 50 – 60 m. The image can be updated up to 12 times per second allowing a ‘sound movie’. This echo sounder has also been used to estimate the volume of a methane plume based on the energy in the water obtained from the intensity of the return signal. However, the mathematical models are designed to estimate volume from observation of the start of the methane plume and so establishing the volume of an established leak would be more difficult. The Sound Metrics Corporation Didson300 records high resolution sonar at 20 frames per second which can be ROV/AUV mounted. It has a range of 35 m and can be used in water depths of up to 300 m. Sound Metric has also developed an ‘acoustic video camera’ ArisSentinel3000 which produces near video quality, 30 frames/second sonar that has been used in the hydrocarbon industry for detecting leaks of oil, gas and hot water from pipelines in water depths of up to 300 m.

There have been some other interesting software developments, for example Tritech have tested software algorithms which can recognize bubbles rising vertically as different from fish swimming horizontally on methane plumes. This could potentially be employed at a fixed monitoring station. IVS 3D demonstrated examples of processing sonar and multibeam data including showing methane plumes and creating an isosurface showing the energy levels in the water (Figure 6-3).

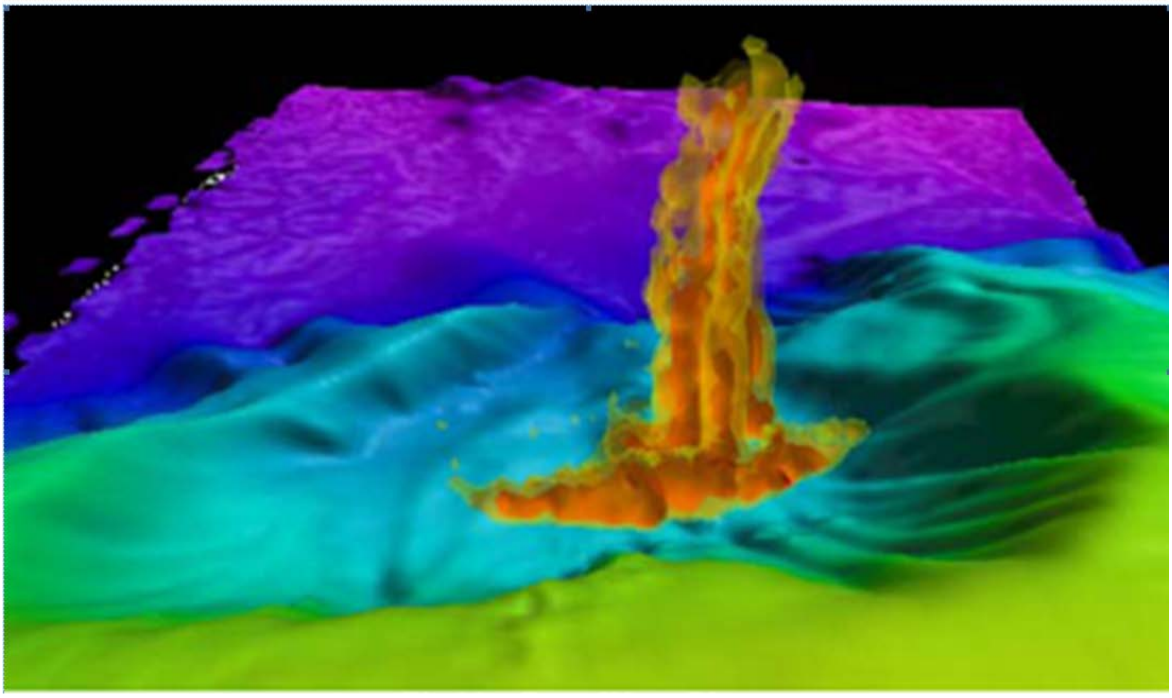

Figure 6-3: Deep water plume (height about 200 m) showing energy levels in the water (image courtesy M. Doucet, IVS 3D Inc.)

6.5.3 (10.4.1, 10.4.5) Geophysical logs

In summary the following conclusions have been reached:

- Mature technology: more experience with CO_2 is needed
- New concepts for well integrity logs: electro-chemical techniques
- Integrity logs (EMIT, PMIT, CBL, USIT, IS): need more testing to establish threshold values
- Custom completions for monitoring at different levels, such as the Westbay System, need further evaluation

Within the Dutch CATO2 program at TNO Industry & Technology there is a focus on CO_2 interaction with cement and steel.(Loizzo et al., 2009). Two important issues are the overall corrosive action of the CO_2, and the so-called pitting corrosion which attacks the steel intensely on a local scale.

A number of electrochemical techniques have been identified in the past and have been scrutinized in the laboratory under high-pressure CO_2 conditions for their effectiveness in pinpointing the amount and type of corrosion. From these laboratory experiments, Electrochemical Impedance Spectroscopy (EIS) and Linear Polarization Resistance (LPR) seemed most promising for further scrutiny in downhole conditions. In addition the LPR results can be used to calculate the corrosion rate. On account of these results, specifications for downhole application are to be drawn up by TNO in collaboration with Schlumberger. This research is only at a conceptual stage.

The Westbay System from Schlumberger Water Services (SWS) has been in use for groundwater quality monitoring for over 25 years and is accepted as providing auditable quality-assurance for compliance with regulatory regimes. Custom casing is installed in observation boreholes, in which packers are used to divide the well bore into separate monitoring zones; each zone being effectively isolated from those above and below to prevent cross-contamination. Measurements, such as hydraulic conductivity and fluid pressure can then be made in each zone, with sampling probes used to obtain fluid samples at formation pressure. This system has a good track-record in detecting contamination of aquifers by pollutants leaching from landfill and mine waste sites, and has been deployed to monitor radioactive waste repositories. SWS have supported its trial use in connection with the Ohio River CO_2 Storage Project. Although some results suggesting its effectiveness have been reported at an SWS-sponsored Westbay user group meeting there does not seem to be any publication in the peer-reviewed literature. A limitation of the system as it stands is that the maximum depth for installation is about 1200 metres. The system does not appear to have been trialled offshore. However, its track-record indicates that it is worthy of further evaluation for monitoring shallow aquifers above a CO_2 store. Testing would be needed at deeper levels, and at an offshore site, to confirm the effectiveness of the custom casing completion in a CO_2 store.

6.5.4 (10.4.2-10.4.3) Downhole P/T

In summary the following conclusions were reached:

- Distributed Temperature Sensors seem to be a mature technology

Both downhole pressure and temperature tools are considered mature technology and currently available on the market. The main identified gap for permanent downhole pressure and temperature sensors seems to be the lifetime of the sensors, currently estimated at 10 years. No real developments have been identified.

6.5.5 (10.6) Chemical methods

In summary the following developments have been identified:

- Downhole fluid chemistry: development of new sampling devices
- Permanent downhole pH: sensor not readily available
- Sampling downhole and at/near the sea bottom: improved sampling devices under development
- CO_2-detectors: some detectors have been or are under development
- Microbial monitoring: developments in biogeochemical methods

6.5.5.1 DOWNHOLE CO_2 DETECTION

Optimare have developed a fibre optic chemical sensor (FOCS) for CO_2 detection at CO_2 storage sites. An experimental version of this has been successfully tested at the Ketzin pilot site in Germany which consists of a downhole probe on 800m of fibre optical cables with an uphole detection system. Optimare are further developing this equipment to enable CO_2 detection downhole to avoid problems arising from using the very long fibre optic cables.

In the system used at Ketzin, CO_2 enters the downhole probe via a CO_2 permeable membrane and induces a pH change in a pH-sensitive chromophore polymer layer. The pH changes, induced downhole inside the probe, are detected at surface via the fibre optical cable using a Laser-Induced Fluorescence (LIF) spectrometer with an Intensified Charge Couple Device (ICCD) detector. Measurement frequency is limited to a few minutes by the time required for the gas exchange between the gas volume in the probe and the downhole environment. The sensor can detect CO_2 partial pressures up to 10 bar (the lower limit has not yet been well characterised but is on the scale of a few mbars in air). Optimare are developing an ‘integrated sensor’ consisting of two LEDs as light sources and photodiodes as detectors to allow detection downhole. This has been successfully tested in the laboratory, however the communication system required from the downhole sensor to the surface has yet to be developed (Rainer Schultze, Optimare, pers. comm.).

A gas membrane sensor (GMS), developed at the Helmholtz Centre, Potsdam (Zimmer et al, 2008), was also used at Ketzin in the two 800 m monitoring wells (at 50 and 100m from the injector well). This allowed detection of gases including Hydrogen, helium, methane, nitrogen oxygen, argon, carbon dioxide and krypton using a downhole probe and uphole detector with a capillary tube between them. The probe contains a phase separating silicone membrane, permeable for gases. Gas samples are pushed to the surface up the capillary tubes using pressurised argon gas, where they are analysed in real-time with a portable mass spectrometer. This method detected CO_2 breakthrough and the krypton tracer gas in the closest monitoring well, after 531 tonnes of CO_2 had been injected. Increasing reservoir concentrations of helium, hydrogen, methane and nitrogen were also identified (Giese et al., 2009). Schlumberger Carbon Services is working on a downhole fluid analyser to obtain improved downhole fluid measurements of:

- pH
- Amount of dissolved CO_2.

No further details were provided, development is estimated at 5-10 years.

6.5.5.2 Underwater CO_2 detection

There are a few research instruments capable of measuring CO_2 concentrations and fluxes in sea water However, development is ongoing, for example within CO_2GeoNet where the Sapienza University of Rome (SUR), the Italian National Institute of Oceanography and Experimental Geophysics (OGS) and the German Geological Survey (BGR) are all involved. Some commercial developments are also under way as outlined below.

New instruments for measuring the partial pressure of CO_2 in water have been developed by CONTROS, the HydroC-CO_2 is laboratory-calibrated and samples take less than one minute (this can be decreased by pumping water onto the membrane but that increases power use). The CO_2 is separated out from the water by a membrane, and as there is no water inside the instrument, this eliminates humidity effects and reduces maintenance. The CO_2 is detected using an infra-red detector with an optical filter which uses the characteristic frequency of CO_2 to create a small potential difference which is either recorded in an internal datalogger or transmitted via cable to the surface. The partial pressure of CO_2 can be converted to ppm, the HydroC-CO_2 has a range of 300 – 1,000 pm and an accuracy of 10 ppm. The instrument is depth rated to 6,000 m and 40 - 50 were deployed in the North Sea in 2009. There is also a hull-mounted version operated by SubSeaTech, which is essentially the same tool, but adapted to cope with being occasionally out of the water as the boat moves through the waves.

The Pro-Oceanus Systems CO_2-pro instrument samples CO_2 partial pressure, using a sodium hydroxide solvent to absorb the CO_2. It can detect 0 – 600 ppm, though it can be calibrated for higher ratios (thousands of ppm). The CO_2-pro takes about 15 minutes to equilibrate to establish a baseline, then the sampler can be moved to another location. The CO_2-pro can also be left at a permanent monitoring station and will remain calibrated for up to year (and possibly longer though this has not yet been tested).

Aanderaa Data Instruments manufacture anchored sea water monitoring tools, for example temperature, pH and oxygen. They are developing/ a CO_2 sensor, primarily for use in fish farming. The data can be collected and stored at the seabed and transmitted when triggered by a signal sent from a ship. The CO_2 sensor is autonomous and provides calibrated data in the range 500 – 50,000 ppm. The CO_2 sensor requires 15 mW for one minute of sampling and can sample at intervals from 2 seconds to 4 hours. It utilises a foil which fluoresces in response to the change in pH, by measuring lifetime of this fluorescence and temperature, the partial pressure of CO_2 is determined. It is planned that the CO_2 sensor will withstand water depths of up to 6,000 m. The CO_2-sensor is still undergoing field testing and performance evaluation. Current tools can potentially be deployed for long periods without maintenance, for example, their oxygen sensor has been deployed maintenance-free on the seabed for up to 4.5 years.

CTD monitors

Idronaut produces deep water CTD and pH sensors (down to 7,000 m), with an accuracy of 0.007 mS/cm and resolution of 0.001 mS/cm for conductivity and accuracy of 0.01 pH and resolution 0.001 pH. However, currently they have no direct CO_2 sensor

Mass spectrometer

SRI International and the University of South Florida (http://www.sri.com/esd/marine-tech/chemsensors/in-situ-spectro.html) are involved in the development and operation of underwater mass spectrometers. These are able to make in situ quantitative measurements of volatile organic compounds (VOCs) and dissolved gas concentrations, including CO_2. Detection limits for VOCs are typically less than 5 ppb and approximately 10 ppm for CO_2. Developments are underway which expect to enhance this to around 1ppm. Currently this technology has been tested to 2000 m and a system deployable at 4000m, and possibly greater depths, is being designed, involving improvement of the pressure housing and sampling pump. They have been deployed on ROVs and vertical profiling winches for sea bed surveys and sea water profiles. Long term deployments for up to two weeks are also possible and, in principle, they could be deployed for longer, although design enhancement may be necessary to overcome biofouling and maintaining calibration. The equipment comprises a linear quadrupole mass spectrometer with a polydimethylsiloxane (PDMS) membrane inlet system. Initially developed, in part, for locating hydrocarbon seeps, this equipment could also be used for detecting CO_2 leakage from the seabed. (Timothy Short, SRI International, pers. comm.).

Fast sensors

OGS see sensor accuracy in the dissolved phase as an important area requiring development. Also they regard the development of fast-response pH, pCO_2, and DIC sensors, which could be mounted on a wide range of platforms, as very important for an accurate quantification of CO_2 leakage in the marine environment. Coupling of fast response sensors with instruments able to evaluate fluid dynamics at the micro-structural level, as is already done at the land-atmosphere interface using eddy covariance systems, would also be a major advance. In the near future OGS hope to purchase an eddy covariance system for measuring vertical flux of oxygen in seawater and so gain experience that could be applied to CO_2flux measurement once fast response sensors are available. The oxygen system would be tested on the MAMBO buoy in the Gulf of Trieste. Development of eddy covariance methods for oxygen flux offshore has been undertaken at the Max Planck Institute and Geomar in Germany (e.g. Berg et al, 2007, 2009). Flux measurements also formed part of the suite of measurements that has been made to date using the MAMBO buoy, and BGR have developed similar inverted funnel methods to measure flux elsewhere, although, in general there has been little experience of measuring CO_2 fluxes offshore.

Development of fast-response sensors forms part of the EC proposal ECO2. Development of mature technologies for measuring droplets and bubbles are also part of this proposal, which is currently in contract negotiation with the EC. The commercial development of fast sensors is probably still several years away.

Natural baselines

A major gap in current knowledge is that of background levels of CO_2 offshore and of flux rates from the seabed into seawater. There are very few measurements in the literature except in areas with abnormal emissions, for example seafloor volcanoes or hydrothermal systems. OGS and SUR have proposed determining an annual seawater baseline for a site in the Adriatic Sea above a CCS candidate site. This would be based on laboratory analysis of samples from a dense grid

(OGS+SUR), deployment of novel sensors (SUR) and automated measurements using commercial (slow) sensors (ADCP, conductivity, temperature pH and pCO_2) at two locations. The project could get the go ahead in 2010.

SUR continues to develop low cost offshore monitoring stations involving multiple sensors to cover an area. So far the power and data transmission is provided by a cable link to the shore or via a buoy. Further development of data transmission from the sensor to the sea surface is required.

6.5.6 (10.7) EM or resistivity based methods

In summary the following developments have been identified:

- Testing for CO_2 joint inversion with seismics

A more detailed description is provided in Chapter 7 on the potential for joint interpretation/inversion combined with seismic data. These methods are now being used in current demonstration projects like Sleipner (CSEM), Ketzin (ERT) and other sites such as Frio. Most of the development is in the interpretation of the data in terms of CO_2 saturation. Applications include both measurements from the surface, crosswell measurements and combinations of both.

6.5.7 (10.8) Gravimetry

In summary the following developments have been identified:

- Developments in gravity gradiometry: not considered yet for CO_2
- Borehole application: have not yet been explored sufficiently

The only real field test so far for CO_2 storage applying (micro) gravity from the surface (i.e. sea bottom) as a monitoring tool has been at Sleipner, as reported in Volume 2 and Chapter 3.

Borehole gravimetry could potentially detect CO_2 away from the borehole. . A baseline borehole gravimetry survey has been acquired at the Cranfield SECARB Regional Partnership site by BP in September 2009 from two wells separated by 100ft (approx 30m). A repeat survey is planned for the third quarter of 2010 after approx 750,000 tonnes of CO_2 are injected into two intervals. It will be evaluated and reported as part of CCP activities and through the regional partnership.

Concerning borehole tools four main commercial players have been identified:

1. Micro-g Lacoste (http://www.microglacoste.com/bhg.htm)

   This appears to be the only system that has been deployed in oil fields so far; field-reported repeatability of the tool is about 5-7 microGal; The tool is quite large in diameter (4.12” or almost 10.5 cm) which limits its application '

2. Scintrex;

   Scintrex cooperate closely with Micro-g. Their tool is new (based on a quartz spring as in their CG-5, state of the art relative gravimeter). The new sonde is very small in diameter (about 5cm) which is a significant improvement compared with the conventional borehole gravimeter. It can operate in deviated wells up to 60 degrees. The instrument prototype has been tested and the summary of its features/results is presented in Seigel et al, (2009). The instrument is designed for mining applications. Research is planned to increase the operable instrument temperature to 140 ºC.

3. Gravitec

   http://www.gravitec.co.nz/gravity_gradiometer.html

   http://www.gravitec.co.nz/publications.html

Gravitec developed a new concept based on the use of ribbon strings to measure gravity gradients. The tool prototype is being tested and some improvements are still needed since it does not meet the target repeatability (it achieves about 50 Eotvos the target is close to 1-2)

4. Lockheed Martin

   Lockheed Martin propose an absolute gravity tool based on the free fall principle (similar to the FG5 surface gravimeter of Scintrex. It is still under development. During discussions last year no prototype was yet ready, just separate parts tested The objectives/features are very ambitious: about 2.5 cm diameter, about 1-2 microGal sensitivity/precision and high temperature operable. First well tests are envisaged in 2010.

BP, in collaboration with Cambridge University nanotechnology unit, has started a three year nanoscale gravity sensor MEMS development through a grant from the UK technology strategy board. The sensor design has been established and the outcome will be a testable sensor and downhole pilot test.

Similarly, at the Twente University in the Netherlands research is being done on the development of a MEMS (Micro Electro Mechanical System) gradiometer but this is still at the concept stage.

6.5.8 (10.9) Other techniques

In summary the following developments have been identified:

- Ecosystem studies: Benthic chamber in development
- Biological Monitoring: ecosystem impacts are being examined in new European and UK projects and some microbiological developments made by Statoil
- Tiltmeters: No real development foreseen
- Tracers: New tracers are being tested
- Drill cores which maintain the pressure of the samples could potentially be used to sample shallow (up to 500 m below seabed) sediments for CO_2, for example, the corer developed by Fugro.
- The sound of CO_2 bubbles in the water could also be detected at short range (up to 15 m) from a fixed monitoring position or a ROV, using directional microphones (developed by Instrument Concepts)
- Noise logging (e.g. by WellTec)
- Fixed underwater cameras to detect bubbles

6.5.8.1 CO_2GEONET BENTHIC LANDER AND OCEANLAB LANDER

For ecosystem studies, of importance for Environmental Impact Assessments, a benthic chamber lander is under development within CO_2GeoNet. Autonomous benthic landers (typically made of stainless steel) provide a powerful platform for carrying out short- to long-term in situ benthic studies and when used in-conjunction with benthic chambers, can be used to simultaneously sample and experimentally manipulate large volumes of sediment (up to 10,000cm^3) and quantify a variety of biological properties and functions over time-scales of days to weeks, such as biodiversity, nutrient fluxes, biogeochemical cycling by microbes, meio- and macrofauna, bioturbation and biological respiration without significantly disturbing the sediment fabric or introducing significant experimental artefacts. Furthermore, when operational, they are less demanding on ship-time (and thus on money) than conventional techniques, because when the lander has been deployed, the ship is free to undertake other operations until it is time for the lander to be recovered (Tengberg et al., 1995).

Figure 6-4: Photo of a Benthic Chamber Lander (image reproduced with permission of IFM-GEOMAR, ifm-geomar.de 2010).

The CO_2GeoNet benthic chamber lander is a fully autonomous system capable of carrying out in situ experiments at depths of up to 6,000m. The system operates by first sinking autonomously to the seafloor. Here, onboard computers drive 2 benthic chambers (400cm^2) into the sediment, in which a number of experiments are carried out (e.g. benthic respiration, nutrient cycling, and anthropogenic impacts at the seafloor). At the end of the experiments (typically 36-48hrs later, depending on sediment respiration), the chambers are shut with seafloor sediments enclosed (for later analysis), extracted from the sediment via powerful drive motors, and the system is retrieved.

At present the CO_2GeoNet system includes:

1) a lander frame
2) 21 buoys
3) 2 benthic chambers
4) 2 oxygen optodes
5) 2 acoustic releases with communications unit

The system is being configured for experiments and additional funding is currently being sought to buy an additional chamber (cost. approx 40,000Euro).

Further developments for which funding is being sought include the following:

- A titanium benthic lander frame for long-term (months) studies, and a benthic lander TV launcher module for targeted, soft lander deployments so that specific ecological niches can be studied.

- A unique oxygen regulation (gas exchange) system for basic and applied long-term studies on benthic ecosystems (e.g. the long-term effects of CO_2 leakage on benthic ecosystem functioning).
- A unique CO_2 sub-sediment injection system capable of facilitating realistic studies on the effects of CO_2 leakage on the benthic environment and benthic boundary layer immediately above the sediment-water interface.

The system will be ready to carry out the first experiments within the EU CCS project 'RISCS' towards the end of 2010, after which it will be available for a variety of different uses (see Table 6-2).

Table 6-2: Some examples of the types of research that the CO2 GeoNet lander will be capable of undertaking, highlighting the flexible nature of the infrastructure.

Types of use	Description of use
CCS research	Baseline/monitoring surveys, identification of bio-indicators of CO_2 leakage.
Ocean acidification research	The lander can be used to study the effects of acidified sea/pore water on calcification rates, benthic processes.
Aquaculture research	The benthic chambers can be used to study the effects of organic matter loading on seafloor habitats. Isotopically labelled fish farm food can be added inside the chambers (via chamber particle injectors) to trace how carbon and nitrogen from fish farm waste is transported through the benthic food-web.
Oil and Gas Industry	Entire infrastructure can be used to assess the impacts of drill cuttings/ oil pollution on the seafloor around platforms
Geotechnical research	The lander frame can be used as a platform for ocean bottom seismometer studies/ earthquake research etc.

Oceanlab at the University of Aberdeen have been undertaking research using autonomous lander monitoring stations at the sea floor with acoustic links to surface, they have a case study offshore Angola which has been monitoring for two years. The lander station is rated to 12 km water depth and can carry other instrumentation including bioluminescence cameras and methane sensors. It is mainly used for benthic sweep and bioturbation to quantify activity of benthic turnover which could potentially be useful for ecosystem impact surveys if combined with CO_2 sensors.

6.5.8.2 Biological monitoring and DNA

In the future it is possible that DNA sequencing techniques may develop to recognize the presence of CO_2 favourable organisms. Recently DNA studies have found DNA sequences common to methane seepage sites which can be used to assess the methanogenic capacity of sediment at a site.
Statoil has a patented technology in the use of DNA characterization for detection of microorganisms associated with oil. This method will be tested on Krechba samples to check the ability to discriminate between areas with CO_2 / CH_4 micro-seepage and areas without.

In recent years Statoil have characterized microbial communities in several hot oil reservoirs throughout the world through the Statoil Biotech program. Microbial societies in a variety of other hydrocarbon environments, like terrestrial mud volcanoes and oil seeps, as well as seabed hydrocarbon seeps, have also been examined. Based on these findings they have built up a 16S rRNA gene library which can be used for a) comparison of microbial communities in oil reservoirs, b) elucidation of microbial processes associated with natural oil environments, c) developing methods for gene-based oil exploration, etc. Further development and testing would be required to extend this approach for the detection of CO_2 migration or leakage.

The method could potentially be used on samples obtained from boreholes at depth, or in the shallow subsurface or on the seabed. However, it is unlikely to be able to discriminate between CO_2 from different sources and its viability would need to established against more direct measurement of CO_2.It could have promise as a mean of detecting micro-seepage at rates that are below the detection limits of direct in situ measurements.

At Ketzin, DNA & RNA finger printing was used to identify microbe types and FISH (Fluorescence in situ hybridisation) to quantify microbes using fluorescence (Morozova et al., in press). There were some issues with injectivity due to microbial activity after drilling mud containing cellulose was shut in the wellbore for a while.

6.5.8.3 General comments on biological monitoring

Biological monitoring occurs at many levels from identifying species communities to health of organisms. The former involves assessing both abundance and diversity and how that might change from a baseline. However the natural variation may be quite large and need to be considered in designing both baseline and monitoring surveys.

In the event of seepage it can be expected that microfaunal communities will respond more quickly than macrofaunal ones and these could be initially detected by non-biological surveys. For example bacterial mats could develop which would be detected by acoustic methods.

Whilst a CO_2 gas seepage could be recognised first from biological data, for example by detecting changes in the behaviour of benthic fauna, it is more likely that biological studies will monitor the impact of a seepage site or event and provide information on recovery following any mitigation efforts. The range of changes that could be detected (abundance, diversity, physiology) should allow the impacts of seepage to be quantified.

Biological techniques are expensive in time with results usually available some time after data acquisition.

6.5.8.4 Directional microphones and noise logs

Instrument Concepts has developed a microphone and directional microphone for listening for bubbles in the water column. These instruments need to be deployed from a buoy or other static installation (ships are too noisy). The directional microphone can also be deployed from a ROV as it can isolate the engine noise. Range of detection is 3 Hz – 1600 Hz in water depths of up to 3,500 m. Deep water bubbles tend to be higher frequency than shallow water bubbles. Range of detection is only about 15 m, so this technique would most likely be useful for fixed monitoring stations located near identified risks. The directional microphone is still quite experimental but has been quality assessed by a third party and tested on methane leaks from pipelines.

The noise log or survey, also sometimes called the sound survey (Sonan Log, Borehole Audio Tracer Survey (BATS), AcoustiSonde Log, and others) is essentially a very sensitive detector of the sound produced by fluid flow. The sounds of moving fluids or the hiss of escaping gas are caused by disturbances in a liquid / gas interface or by turbulence in the fluid stream. . In a wellbore environment, the noise log is very effective for gas detection as it flows up through liquid, but it is also effective for the detection of various kinds of gas, water, or oil single phase flow, including channelling behind pipe (assuming there is adequate turbulence in any given situation to produce enough noise). The noise tool itself is nothing more than a microphone (hydrophone), and associated amplification / line driving circuitry, in a pressure housing constructed to withstand downhole conditions. Surface equipment again amplifies the signal, and further processes it. There are two types of noise surveys, the stationary survey with measurements made at various stations downhole, and the much less common continuous survey, usually focusing on higher audio frequencies, and used for gas entry and leak detection in casing. Measurements of sound within the audible range of frequencies (20-20,000 Hz) are usually most indicative of turbulent flow behind pipe. Stationary measurements are made in the more common noise logging methodology because tool and cable noise from scraping against the casing wall would otherwise dominate the record. In shallow wells, even machinery noise at surface can be a problem. At each depth stop, at least four noise frequency readings are taken. Usually a coarse grid of station spacing of 50 or 100 feet (15-30 m) is used to locate high noise areas, then much closer spacing can be employed for detailed investigation, finally down to every two or three feet (60-90 cm). In the US EPA underground injection control (UIC) program the noise log is authorized as a mechanical integrity test (MIT) for the demonstration of external integrity of injection wells. The Norwegian company WellTec has developed high quality noise logging tools (personal communication Matteo Loizzo).

6.5.8.5 Underwater cameras

Rovtech Systems Ltd have underwater cameras which could potentially be used to look for CO_2 bubbles. However, they indicated they did not expect visibility to be more than a few metres in the North Sea so it is likely this technology could only be applied in conjunction with other monitoring technologies if a leak were detected as part of another survey. The cameras can pan about 350 ° and tilt and can be mounted on fixed points or ROVs.

6.5.8.6 Ion-selective sensors

Seatechrim develops chalconide ion-selective glass sensors which detect chemical/radioactive pollutants. They could potentially be mounted on a buoy in regions of high risk. If sufficient quantities of pollutant are detected, the device is triggered to transmit data from the surface via satellite. It is depth rated to 300 m.

6.6 INVENTORY OF NOVEL TECHNOLOGIES: ASSESSMENT OF DEVELOPMENTS

In this section the novel technologies identified in the previous section are assessed against the criteria of maturity, detection improvements and limitations (Table 6-3). The same format is used as in Appendix 3 (Volume 2).

Table 6-3: Assessment of the novel technologies

Parameter/ technique	Overview	Maturity	Detection improvements	Limitations
Permanent Ocean Bottom Cables	3D seismic acquisition using permanent OBC cables as receivers.	An established but specialised technique in other fields, the use of which for CO2 has yet to be fully demonstrated.	Superior to conventional 3D seismics due to higher repeatability and multi-component acquisition, however due to permanent installation only sparse acquisition geometry	Dissolved CO_2 is essentially invisible on seismic. High capital costs to install, lower operational costs for acquisition (allowing for more frequent acquisition)
Shallow acoustic techniques	Imaging of the sea bottom and of the shallow sediments below the sea bottom.	An established but specialised technique in other fields, the use of which for CO_2 is as yet unproven	Improvements in resolution, penetration depth and speed of survey compared to conventional techniques	Time-lapse changes may be a result of processes other than leakage. Requires additional sampling to verify.

Parameter/ technique	Overview	Maturity	Detection improvements	Limitations
Fibre optic downhole probe for CO_2 detection		The tool is under development, initial tests take place at Ketzin		
Downhole in-situ Hydroc-CO_2 detector	Membrane separator of water and CO_2 coupled to an infrared analyser. Data is stored or transmitted to the surface via a cable	The tool has been deployed in the North Sea in 2009.		
Sea-bottom Pro-Oceanus CO_2 detector	Solvent to separate the CO_2	Longer term deployment has not been tested yet.	Sampling mode (every 15 minutes) or permanent mode (calibrated up to a year)	
Downhole fluid analyser SLB	A tool to measure long term pH downhole, currently no stable tools are on the market	Expected development time of the tool is 5-10 years.	Improved pH estimation and improved quantification of CO_2 in the presence of water.	No details were provided for confidentiality reasons
DNA characterization for detection of microorganisms	The method could potentially be used on samples obtained from boreholes at depth, or in the shallow subsurface or on the seabed	Application to CO_2 is in the first testing phase.	Potentially detect micro-seepage at rates that are below the detection limits of direct in situ measurements	Unlikely to be able to discriminate between CO_2 from different sources, viability needs calibration to more direct measurement of CO_2
Borehole gravity tools	Detection of fluid fronts away from the borehole	First application to CO_2 storage is ongoing	Sensitive to density differences	Method is sensitive to non-repeatability such as tool location, difficult to achieve proper repeatability in time-lapse mode
Benthic chamber lander	Short- to long-term in situ benthic studies, quantify biological properties such as biodiversity, nutrient fluxes, biogeochemical cycling by microbes, meio- and macrofauna, bioturbation and biological respiration	First experiments in North Sea expected end of 2010	Especially suitable for EIA studies	
Directional microphone	Deployed for listening for bubbles in the water column	Experimental but quality assessed by a third party and tested on methane leaks from pipelines	Suitable for identified risk areas	Limited detection range (15 m), deployment from a buoy
Noise logging	Detection of sounds of moving fluids or the hiss of	No application yet to CO_2 storage	Additional tool for well integrity measurements	Detection limits still uncertain

Parameter/ technique	Overview	Maturity	Detection improvements	Limitations
	escaping gas			
Camera for bubble detection	Visual detection of bubble streams	No application yet to CO_2 storage	Suitable for identified risk areas	Limited view in the North sea

It is apparent that most of the developments listed are incremental or simply need testing at CO_2 storage sites. Most of the deep-focussed geophysical tools are well developed after decades of experience and investment in the oil- and gas industry. However, specific needs for CO_2 storage seem to be the characterisation of long-term processes in the storage complex and of more particular issues like brine displacement. In that perspective developments of permanently installed sensor networks and gaining experience with resistivity based methods is clearly a gap and a trend induced by CCS. The lifetime of sensors (particularly in the acid environment created by CO_2 dissolution in water) becomes more and more of an issue and developments in hardware are currently being addressed for example through the use of optical sensors (i.e. fibre optics).

For shallow methods developments are completely different. There is a clear need for early warning systems in case CO_2 migrates upward out of the storage complex or even leaks at the seabed. The first challenge is to detect such migration pathways, the second is to detect and quantify any associated leakages. Both aspects will be discussed further in Chapter 7, which discusses the importance of combining different monitoring methods in a clear strategy. Purely from a technological point of view, developments can be observed focussing on improving resolution and speed of acquisition for shallow acoustic methods and development of related inversion algorithms to determine amounts of CO_2 leaking at the seabed. Furthermore developments of permanent bubble detectors could be continuous monitoring of high-risk areas (or at least areas with a higher uncertainty) such as inaccessible abandoned wells.

A third category of monitoring developments is in well-based technologies. These can be split into techniques to monitor the subsurface, including sampling and logging methods, and to those to monitor the integrity of the wellbore. A good example of a clear gap in the first category, where technology is now being developed, is stable downhole pH sensors. For the second group technology seems adequate, though little experience has been gained yet and developments are still ongoing to improve the methods. Especially in the latter group again combining different tools clearly improves the interpretation of potential upward migration of CO_2, since most methods are indirect.

Geophysical techniques, like offset-VSP and crosswell seismic, with the possibility of imaging in the reservoir with higher resolution than surface seismics, have clearly been identified as suitable methods to increase our understanding of processes in the reservoir. Similar trends can be observed as for the surface seismics, meaning more experience is needed with case studies and the benefit of using permanent systems. The latter could also be combined with passive seismic monitoring.

The next chapter provides more insight into the potential added value, or even necessity, of combining different monitoring technologies.

7 Integration potential

7.1 EXECUTIVE SUMMARY

This Chapter describes the potential for integrating two or more monitoring technologies. Here we consider the integration potential from two aspects: the potential for joint interpretation of the outputs from a range of technologies, and/or the joint acquisition of monitoring data via simultaneous deployment, for example in a borehole or on a ship. The benefits of integrating monitoring technologies include: optimising detection and quantification of CO_2 migration and leakage, reducing deployment costs and improving understanding of reservoir processes such as dissolution. Typical monitoring techniques suitable for joint interpretation are injection well and monitoring well data and geophysical measurements such as seismic (including vertical seismic profiling - VSP), microseismic, gravity and controlled source electromagnetic (CSEM). Joint interpretation leads to a better constrained model of the reservoir. Improved reservoir characterisation over time will reduce uncertainties in the future behaviour of CO_2 in the reservoir. Combinations of methods covering wide areas for detection, with local methods for quantification can be used to detect and characterise migration or leakage.

Selection of tools to be integrated will be based on providing complementary monitoring capabilities which improve detection and measurement both spatially and temporally. For example, geophysical methods providing detection of migration and leakage over large areas may be integrated with more direct measurement techniques deployed in wells or at the seabed which are more spatially constrained but provide higher measurement frequency and/or resolution. Further integration could include more detailed analysis to quantify rates of movement (especially flux to seabed if leakage is occurring), composition and source of CO_2. One example described in this chapter is the integration of multibeam echo sounder imaging to detect a potential leakage feature on the seabed combined with subsequent analysis of headspace gas taken from sediment cores to confirm the composition of the gas (in this case naturally-occurring methane). Similar integrated approaches with 2D seismic have been successfully used to explore for shallow gas fields in the Southern North Sea. Joint interpretation of a range of shallow geophysical technologies showed their potential to monitor shallow CO_2 movement onshore whilst individual techniques were not able to provide a definitive interpretation in isolation.

Joint interpretation of seismic and gravity data has been demonstrated at Sleipner. The combined use of gravity with seismics, as partially tested at Sleipner, could, in specific circumstances, reduce the cost of monitoring where borehole-gravity measurements could be used in conjunction with pressure-test data and/or surface seismic data to enable a statistical interpolation of predicted changes in the saturation of CO_2 at a lower cost than simply using 4D seismic. Specific examples of joint acquisition are provided to illustrate the benefits for integration. Permanent well and seabed geophone installation has high installation costs but provide significant benefits in terms of continuous passive microseismic monitoring and for regular or periodic active seismic surveys. Similarly, down-hole receivers can be integrated with conventional 2D/3D surface seismics to significantly reduce costs. Downhole permanent sensors can now include geophones, temperature and pressure sensors, with noise sensors becoming available to provide more continuous real-time monitoring of events. Assessing well integrity requires the joint deployment of a number of technologies, such as multifinger callipers and electromagnetic tools, to confirm that results from individual technologies are indicative of material degradation.

7.2 INTRODUCTION

As outlined in Chapter 6 added value is obtained by combining different monitoring technologies, both for improved reservoir characterisation and for better detection of migration and leakage. The expected benefits can be divided into the following objectives:

1. Use various monitoring methods to develop an optimal strategy to detect and quantify CO_2 migration out of the storage complex and possibly leakage to the sea bottom.
2. Combine different monitoring technologies at the acquisition stage to make it more cost-effective and to obtain correlated data.
3. Use complementary measurements to increase understanding of reservoir behaviour by joint interpretation. This may lead to a better understanding of processes like dissolution and mineralisation.
4. Use joint inversion of various monitoring measurements to assess CO_2 spreading in the reservoir for improved quantification including uncertainties in time. A better understanding of the different models, honouring **all** monitoring data will lead to more constrained predictions of future plume development and CO_2 behaviour.
5. Use combinations of monitoring tools to ensure well integrity. Currently combinations of logging tools are used to identify corrosion effects or fluid migration along interfaces between steel-cement and cement-rock through both joint interpretation and joint inversion. (Described in more detail in Chapter 10.)

The first objective is focussed on the combination of methods covering large areas (mostly geophysical methods) combined with more direct local measurements or sampling. The latter can be taken from wells or from the near-surface (i.e. sea bottom). Examples of tests and of developments are provided in Section 7.3. Proposed strategies generally use complementary measurements in terms of spatial and/or temporal resolution.

The second objective, discussed in Section 7.4, is less technology driven, but assesses whether smart combinations in acquisition can be applied for various monitoring methods.

The third and fourth objectives are more focussed on an improved understanding of the processes. The complementarity of the proposed methods is sought in the various parameters that the methods are sensitive to and is less related to scale. A description with examples is provided in Section 7.5.

The fifth objective is related to combining monitoring methods (mostly well logging tools) to ensure well integrity. A large number of tools are available, which are able to pick up irregularities that might result from vertical CO_2 migration along a wellbore (i.e. along the near-wellbore area). The majority of these methods only provide circumstantial evidence. A combination of methods is expected to be better for determining whether or not irregularities can really be ascribed to undesired migration. The description is part of Section 7.5.5 and 7.5.6.

7.3 MONITORING STRATEGY TO DETECT AND QUANTIFY LEAKAGE

7.3.1 Monitoring strategy for leakage detection and quantification

As outlined in Section 5.5, improved measurement capability requires integrated monitoring systems which combine tools with complementary sensitivity and sampling characteristics.

Monitoring techniques need to be able to detect small leakage features (10 m or less across) and provide coverage over large areas (hundreds of square kilometres). However, subsequent detailed measurements of the leak are likely to be confined to relatively small areas.

Rates of leakage may vary with time and monitoring plans need to take that into account, for example by using continuous measurements to assess variability.

Indications from the literature and modelling (Chapter 4) suggest a wide range of possible flux rates. Background natural seabed concentrations and fluxes of CO_2 are poorly constrained outside of volcanic areas. They would need to be established by baseline measurements.

Modelling described in Chapter 4 indicated a wide range of breakthrough times for free and dissolved CO_2 at different locations. In some cases this did not occur for hundreds of years, which would almost certainly fall outside the time envelope being considered for monitoring under developing regulations.

Detection of seabed leakage of CO_2 is likely to require a combination of methods. 3-D surveillance techniques, such as multibeam echo sounding, are needed for rapid coverage of large areas. Their deployment could be triggered by indications of possible leakage from deeper-focussed methods. Ship-borne measurement of CO_2, pH and related parameters, near to the seabed, can only provide 2-D coverage. However, it could detect more diffuse leakage, which had little effect on seabed topography and where bubble streams were of too low a density to be picked up by sonar techniques. Point measurements of CO_2 and other parameters are needed to establish the characteristics of the gas emissions. More detailed follow-up analysis, using isotopes or tracers, may be necessary to confirm that the gas has come from the storage site. Continuous monitoring at key sites (e.g. wells, faults and environmentally sensitive areas) would help to ensure that transient emissions are not missed.

7.3.2 Example of a combined strategy using seismics, sea bed imaging and headspace gas sampling

Gas accumulated in or moving through the shallow subsurface can be detected by using geophysical monitoring techniques (Schroot et al., 2004). In seismic and acoustic datasets the presence of gas may result in a variety of different expressions. Although the chemical composition of natural gas (mainly consisting of CH_4) differs from CO_2 the physical behaviour is similar. The interpretation of such expressions, or geophysical anomalies, as features related to gas can be confirmed by the examination of geochemical anomalies.

In the Dutch sector of the southern North Sea a variety of seismic and acoustic anomalies assumed to be related to the occurrence of shallow gas were observed. Some of these features were selected for a marine sampling campaign in the summer of 2002.

A good example of a seafloor pockmark was found in Netherlands licence block A11 (Schroot et al., 2004) with a multibeam echo sounder image of the seafloor which clearly indicates the crater-like depression (Figure 10-49). Maximum depth of the crater is about 2 m. Six shallow sediment cores were collected in 2002 (core lengths are up to 3.4 m). The methane concentrations measured in the headspace (interstitial) gas of the sediment samples were plotted. The highest CH_4 concentration (122.6 ppm) is found in the core from the centre of the feature. This value is significantly higher than background values. It is remarkable that the location of the anomaly almost coincides with the presence of a smaller, so-called unit pockmark. Unit pockmarks are features of a few metres in diameter, occurring within the larger depression, probably representing the most recent sites of venting. At distances of only some tens of metres away from such anomalies concentrations can already drop to background values.

In the northernmost part of the Dutch sector of the Southern North Sea a number of shallow Pliocene-Pleistocene gas fields were discovered in the 1980s by drilling clear bright spots (seismic anomalies). The gas field in licence blocks B10 & B13 is one example. The field is obviously leaking hydrocarbons (almost purely methane) into the shallow subsurface and into the water column. This can be observed on high frequency acoustic profiles such as the XStar profiles acquired by TNO in 2002 (Figure 10-25). Gas plumes are visible in the water column. Methane concentrations as high as 10,395 ppm were found close to one of the gas vents and confirm the acoustic anomalies. The fact that close to the strongest acoustic anomaly the methane concentrations drop to 39 ppm indicates that the lateral variation in concentrations and fluxes is high.

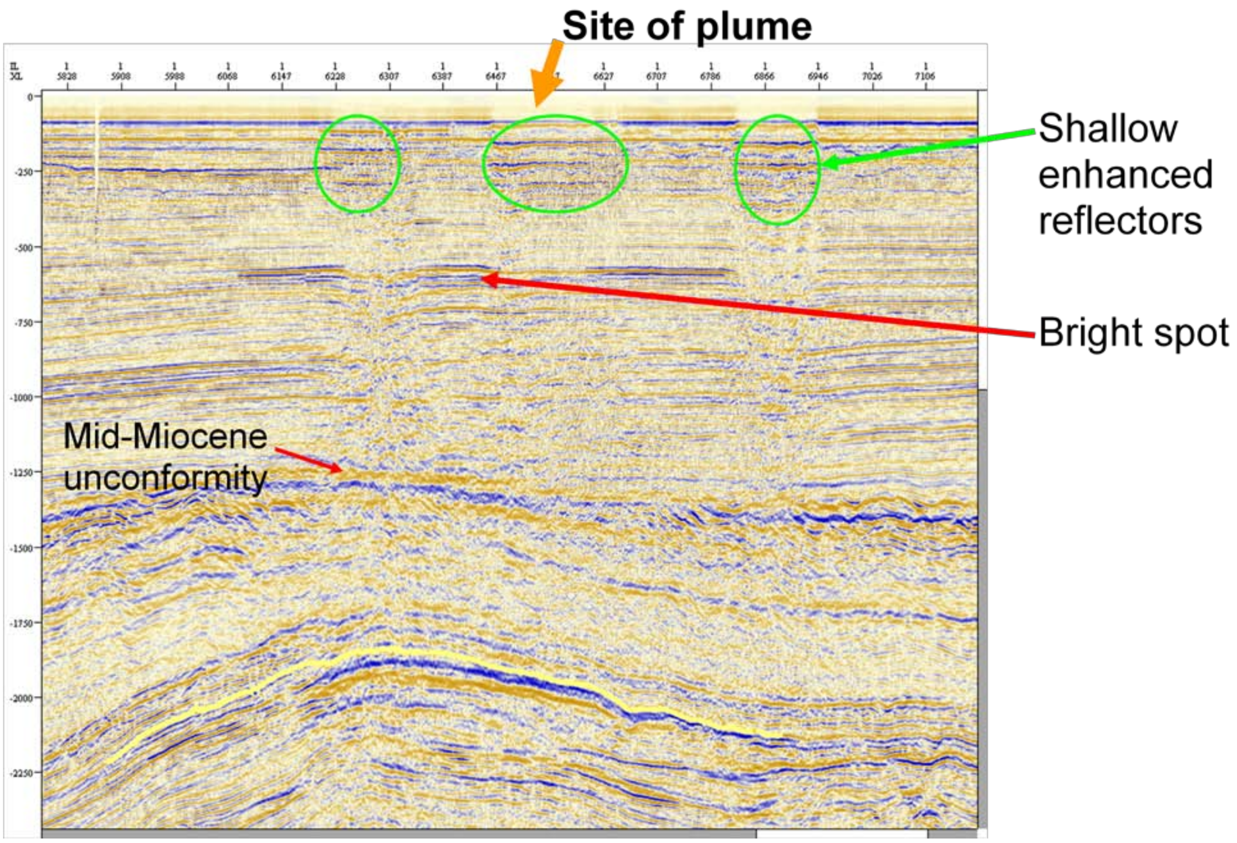

Figure 7-1 About 13 km long portion of 2D seismic profile SNST87-03 from 1987 showing the bright spot corresponding to the gas reservoir and patches of enhanced reflectors in the shallowest sediments visible, indicating gas saturation (courtesy TNO).

A standard 2D seismic profile (from 1987) running across the field (Figure 7-1) shows the leaking gas reservoir as a bright spot and also shows enhanced reflectors in the shallowest sediments over the field. The gas saturation here is not laterally continuous, with the central patch of shallow enhanced reflectors coinciding with the location of the strongest plume.

In the Netherlands licence block F3, gas accumulations at Pliocene-Pleistocene levels can also be observed as bright spots. As in B13, the gas sands of block F3 are leaking. But this time the expression on 3D seismic data is that of a gas chimney. The chimney is immediately adjacent to a fault, which may have provided a migration pathway for the gas. Methane concentrations in the sediment samples were only slightly elevated. At various levels where the faults intersect high porosity layers gas is (perhaps temporarily) trapped as small gas pockets, visible on the seismic data as small bright spots. Yet another bright spot in the area can be observed which is not associated with any expressions of leakage.

As illustrated in these examples, migration of gas to the near-surface environment can have different expressions on seismic and acoustic data, depending on both local circumstances and types of surveys and data. Migration and leakage can be detected or monitored using the appropriate techniques. It is always advisable to verify the geophysical interpretations through geochemical monitoring. Preferential migration and leakage through faults and fractures is found to be a widespread mechanism.

7.3.3 Monitoring of CO_2 migration out of the storage complex using combined methods

The added value of joint interpretation of various types of data to detect migration of CO_2 out of the reservoir has been demonstrated at the natural analogue site at Latera as part of the European

CO_2GEONET project (Arts et al., 2008). The study area is located in the west-central part of the Italian peninsula, about 100 km north of Rome within the now extinct Latera caldera.

Figure 7-2 shows a 3D model with the results of various shallow monitoring techniques applied.

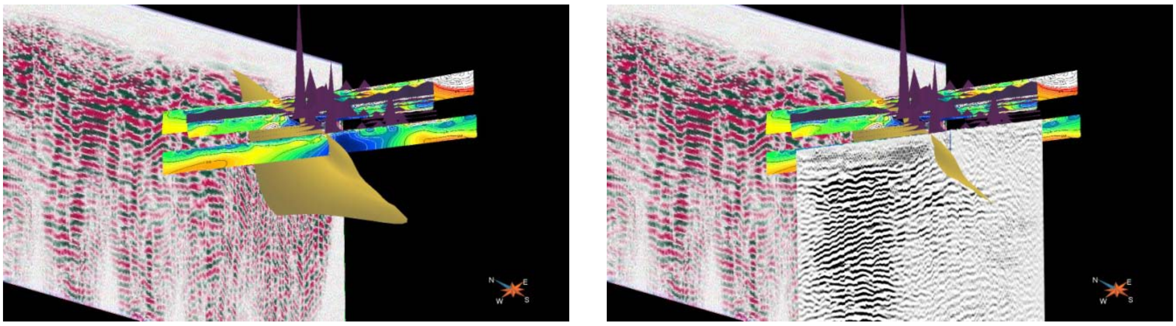

Figure 7-2 Snapshots of the 3D integrated data model, including three GE profiles showing the low resistivity anomaly coinciding with the main gas vent, gas fluxes coinciding with the low resistivity area and seismic lines showing a clear change in character at the northern boundary of the GE anomaly. The SP measurements ("filled" central line) and the magnetic measurements (solid central line) show the same delineation as observed on the seismic, EM and flux data. (adapted from Arts et al., 2008a reproduced with permission of Elsevier)

Despite the fact that the area is heavily affected by both regional faults and local collapse structures, deep drilling has shown that some CO_2 remains trapped in areas where the overlying flysch sequence is still intact. CO_2 is being continuously produced; however, a portion of it migrates along the numerous faults and is released to the atmosphere from gas vents. The occurrence of these gas-transmitting faults represents an excellent natural test site to study the application of various geophysical tools to better understand CO_2 leakage and migration.

A small study area of approximately 500 x 200 metres in the centre of the caldera clearly shows a change in vegetation at locations where CO_2 (and limited H_2S) reaches the surface. Small bubbles can even be observed along part of a narrow creek within the survey grid. Different geophysical monitoring techniques were deployed at this site: 2D reflection seismics (testing MiniGun, PWD and MiniVib sources), 2D refraction seismics, multi-channel analysis of surface wave (MASW), ground penetrating radar (GPR), microgravity, magnetometer, self-potential (SP), 2D and 3D geo-electrical and electro-magnetic (EM31 and EM34) measurements. Furthermore, CO_2 flux measurements were performed on a dense grid over the study area, and a limited number of soil gas samples collected along two profiles, to "ground-truth" the geophysical results.

Though this case study is onshore in a volcanic area, and very different from offshore UK circumstances, it is considered useful to demonstrate the added value of combined interpretation of monitoring data. The most striking result of this study has been that no single method was able to clearly identify the mechanism leading to the migration of the CO_2 to the surface. Joint interpretation of the different types of data has constrained the interpretation considerably and clearly leads to the conclusion of open fault related fluid migration.

7.4 JOINT ACQUISITION OF MONITORING DATA

There is scope for joint data acquisition using different monitoring methods. This may be by sharing facilities or equipment to reduce costs, for instance a ship deployed for a seismic survey might simultaneously gather sonar data. Or two or more methods may be used in conjunction to provide correlated data, for example permanent well pressure sensors and geophones might record a sudden fracture by a pressure drop and a microseismic event. Oil and gas industry requirements are the driver for this, but the techniques are equally applicable to CO_2 storage.

7.4.1 Combined seismic methods

Permanent well-based and seabed seismic receiver equipment (known as 'Life of Field Seismic', LoFS) may be used for continuous passive microseismic monitoring and for regular or periodic active seismic surveys. (These methods are described in detail in Chapter 10.) LoFS systems have high installation costs but offer significant economic benefits when two or more seismic methods are employed and when used for long-term data gathering. These systems also offer opportunities for acquisition during conventional towed-streamer seismic surveys, e.g. for acquiring wide-azimuth data. (BP, 2005) On-going development of acquisition and processing technologies means that LoFS systems installed now are likely to still be in use when now novel techniques reach the production stage.

Down-hole receiver arrays, whether permanent or temporary, can be used in conjunction with conventional seismic surveys. When a conventional surface 2D/3D seismic survey centred on the platform is being acquired then receiver strings in the wells can be used to record 3D or walkaway VSP data from the surface survey shooting pattern, providing a significant cost benefit (see also Blackburn et al., 2007).

Multiple or simultaneous acquisition may employ seismic sources and receivers, tuned to provide different signal characteristics, or separate seismic and acoustic methods. The key requirements are that the various systems do not interfere with each other in operation, and that it is possible to discriminate between them in signal processing. Modern marine seismic vessels are equipped to manage multiple streamers and towed sources (e.g. WesternGeco's DISCover system using six shallow and two deep streamers); and source and receiver equipment for some acoustic methods can be hull-mounted so it is physically separated from towed equipment. Signal processing can discriminate between sources as long as their signatures have distinct characteristics, in terms of frequency content and pulse shape.

The dominant driver in development of joint seismic acquisition is the oil industry and its requirements to contain exploration and production costs by maximising the data gathering potential of expensive resources (survey ships). However, benefits have been recognised in the data obtained, for example a sea-bed receiver array originally deployed for 4D reservoir monitoring being used to record wide offset data from an adjacent conventional survey.

7.4.2 Combined well methods

Multiple geophysical well logging tools are conventionally run at the same time in a tool string. There are limitations on the types of technologies combined to prevent interference ; for example, a tool string would not contain both a tool with a radioactive source and one that monitored natural radioactivity. Other limitations relate to the mechanics of the tool string – where it would become too long or too heavy to manage – and the capacity of the electrical and data connection up the cable to the surface. These issues are being addressed by miniaturisation, with new slimline and compact logging tools becoming available; and by new data capture technologies, such as data storage, built-in memory and fibre-optic data cabling, where the wireline simply becomes a means of providing power.

Permanent well instrumentation is increasingly being developed to provide different types of sensors at multiple levels in monitoring wells. Geophones and pressure and temperature sensors have been widely developed for this role, with noise sensors becoming available. Used together they permit continuous, real-time correlation of events in the well, which may allow the significance of such events to be either discounted or identified as requiring further investigation.

7.4.3 Other combined methods

Geophysical surveys using different methods can, in principle, be acquired at the same time as long as they do not have operational incompatibilities and do not generate signals that interfere with each other.

Marine gravity and magnetic acquisition is now routinely carried out during marine seismic surveys because operational difficulties have been overcome by a combination of instrument design and data processing techniques. Gravity observations are affected by the motion of the vessel and by the seismic source pulse; however the latest marine gravimeters dynamically compensate for the ship's motion and rapid sampling, together with timing and signal information from the seismic equipment, can be used to compensate for seismic effects. A marine magnetometer is normally towed away from magnetic interference from the ship, which can present operational problems with streamers and towed seismic sources. But with modern seismic vessels equipped to manage multiple streamers and sources, it is no longer a significant problem to add a magnetometer and keep it sufficiently offset from the other towed equipment to either foul it or be affected by local induced magnetic fields[4].

There is currently significant interest in the oil industry in electromagnetic methods, especially in shallow marine settings. Several marine seismic companies (e.g. WesternGeco, Petroleum Geo-Services) have either run demonstrations[5] or begun offering services[6]. Although a marine EM source can be towed by a seismic vessel, with the sensor and recording equipment installed aboard, none of the contractors mention joint EM and seismic acquisition. It is not clear if this is because the equipment and operational procedures are not yet sufficiently developed, or because there is some fundamental interference problem, perhaps induction between a towed EM source and towed seismic equipment. This might be a future development opportunity.

7.5 JOINT INTERPRETATION OF MONITORING DATA

The most obvious example currently available of joint interpretation of monitoring data is Sleipner, where both time-lapse seismic data and gravity data provide complementary information on the spreading of the CO_2 plume. Whilst seismic data is essentially sensitive to the compressibility of the CO_2, the gravity data can be related directly to the density contrast induced by the CO_2 replacing the formation water. A more thorough description has been provided already in Chapter 4.

Similarly at Sleipner the added value of using Controlled Source Electromagnetics (CSEM) data in combination with seismic data is being investigated. With the CSEM data particularly sensitive to the resistivity this can potentially resolve low concentrations of CO_2 better than seismic measurements, which are much less sensitive to small CO_2 concentration differences.

Both examples represent a joint interpretation of the data, i.e. both datasets are more or less treated separately and the results are used in a common framework. A joint inversion may lead to even better results. This implies that the parameters like CO_2 concentration and temperature can be inverted simultaneously (i.e. through a single combined objective function) leading to a better constrained problem. For the examples mentioned above work is in progress in, for example, the European CO_2ReMoVe project.

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[4] For example, see: Fugro's web site, http://www.fugro-gravmag.com/service/marine.php; Getech's web site, http://www.getech.com/services/marine-gravity-magentic-data.htm.

[5] See: PGS's proof of concept at http://image.exct.net/lib/fefe1272736704/d/1/PGS_EOI_Email.pdf?et_cid=38052890&et_rid=385756653&linkid=Read+more+about+this+Joint+Industry+Project.

[6] See: e.g. WesternGeco's Controlled Source Electromagnetics (CSEM) and Marine Magnetotellurics (MMT) services, at http://www.westerngeco.com/services/electromagnetics.aspx.

Another example of joint interpretation is the combination of seismic and micro-seismic data. The localisation of microseismic events requires a good velocity model of the subsurface. This can be obtained with seismic data. Microseismics have been investigated at Weyburn and their use is envisaged at In Salah.

7.5.1 Seismic and Insar measurements

An approach taken at Krechba has been the integration of the current 3D seismic dataset with time lapse satellite images, injection history, wellhead sampling (pressures and fluid samples) and tracers (Raikes et al., 2008). This has allowed the Krechba project team to understand the possible subsurface movement of CO_2 better in the absence of repeat seismic surveys.

Available information from cores, FMI and seismic data indicates the injection reservoir and the immediate overburden section are fractured, with the predominant fracture orientation being NW-SE. Recent tracer, wellhead and satellite image data strongly support this conclusion.

Integration of the 3D seismic cubes with the satellite image data has revealed trends and insights into the structures at Krechba which probably control the movement of CO_2 in the subsurface. It is believed that deep seated (below reservoir) faults may control the Krechba structure at the Carboniferous injection level, resulting in fracture swarms running NW-SE along the east (and possible the west) flanks of the field.

An inversion scheme to constrain the flow simulations by using the Insar data is proposed by Vasco et al. (2008). In principle the scheme is suitable for combining various types of data.

7.5.2 Joint EM-seismic interpretation

To improve the interpretation of controlled-source electromagnetic (CSEM) data it is desirable to include information from seismic data in a joint interpretation. The higher resolution of the seismic image makes it possible to accurately determine the depth of resistivity contrasts detected by the CSEM data (e.g. Hansen and Mittet, 2009). The simplest way of incorporating seismic data in a CSEM inversion is to divide the resistivity model into large volumes of homogeneous resistivity where the shapes of the volumes are obtained from the seismic horizons.

To interpret collected CSEM data sets, many numerical modelling algorithms have been developed. The electromagnetic (EM) method obviously has some drawbacks. First, the resolution of EM is much lower than that of seismic. Second, EM data inversion has ambiguities in distinguishing hydrocarbon-bearing from CO_2-bearing layers because of the lack of any significant contrast in resistivity.

Because seismic and EM methods have their advantages and disadvantages, integrating these two different types of data can potentially improve the reliability of reservoir evaluation. According to Hu et al. (2009) the study of integrating electromagnetic and seismic data for geophysical exploration can be classified into two categories. The first category is based on the link between conductivity and seismic velocity through the petrophysical relationship, e.g. fluid saturation, porosity (Hoversten et al., 2006). Unfortunately, these petrophysical relationships are not simple and may not be accurate or unique. The second category utilizes the structural similarity between the conductivity and seismic velocity profiles of the targeted regions (Gallardo and Meju, 2003; Meju et al., 2003; Gallardo and Meju, 2004).

Nine years on from the first proof of concept survey it is instructive to reflect on the reasons for the slow adoption of CSEM methods, as was done by MacGregor and Cooper (2010; Figure 7-3) who envisaged a number of possible causes. For a new technology to be adopted, the value of the information it can supply must be clearly demonstrated to a wary client base, and to be useful it must be presented in a way that can be incorporated easily into existing workflows. This requires the sharing of expertise across the industry to increase the knowledge and understanding of CSEM methods among the geophysical profession at large. It is particularly important that the applicability of the method, and the uncertainties in the resulting interpretations, be clearly communicated and understood. The lack of published case studies also hinders the widespread adoption of the technology: companies considering applying CSEM methods in their acreage have little material to refer to. In addition, whereas there has been widespread investment in acquisition technology, there has been less investment in interpretation methods. There are few commercial interpretation platforms available to companies wishing to use CSEM methods, making use and understanding of the results even harder.

	CSEM interpretation risk	Seismic availability	Well availability
Frontier Exploration	High	Sparse 2D	None
Exploration	Model dependant	2D perhaps 3D	None or limited
Appraisal	Low	3D	Several
Monitoring	Low	3D/4D	Many

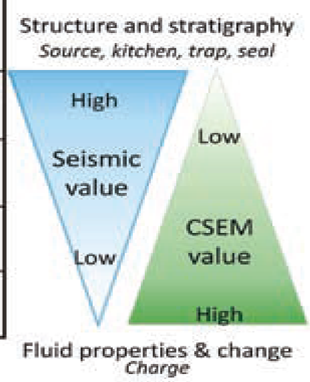

Figure 7-3 Schematic diagram illustrating the applicability of CSEM and seismic methods across the oil field life cycle (image taken from MacGregor and Cooper (2010), reproduced with permission of the European Association of Geoscientists & Engineers)

7.5.3 Joint gravity-seismic

The best example of joint use of gravity and seismic data for CO_2 storage is at Sleipner (overview in Arts et al., 2008 and latest results in Alnes et al., 2008). For Sleipner the geometry of the CO_2 plume interpreted from the time-lapse seismic data has been used as input for the inversion of the gravity data, or more precisely as a constraint on the estimation of the density of the CO_2 in the reservoir. The best-fit average density of CO_2 is 760 kg m^{-3}. Estimates of the reservoir temperature combined with the equation of state for CO_2 indicate an upper bound on CO_2 density of 770 kg m^{-3}. The gravity data suggest a lower bound of 640 kg m^{-3} at 95% confidence.

Gasperikova and Hoversten (2008) presented a modelling study to explore the feasibility of using gravity data further. They present three scenarios, for which gravity inversions illustrate that the general position of density changes caused by CO_2 can be recovered but not the absolute value of the change. Analysis of the spatial resolution and detectability limits shows that gravity measurements could, under certain circumstances, be used as a lower-cost alternative to seismic measurements. However, a priori knowledge, in most cases derived from seismic data (such as geometry) would be required. The authors suggest that borehole-gravity measurements should be used in conjunction with pressure-test data and/or surface seismic data to provide a basis for statistical interpolation of predicted changes in the saturation of CO_2. This may provide a low-cost way of monitoring changes within the reservoir, with only the initial 3D seismic survey being relatively expensive.

7.5.4 New developments in joint inversion of monitoring data

New developments currently ongoing in the oil and gas industry, but essentially coming from oceanography and meteorology, make use of combinations of different types of data such as production data and geophysical data. Increasingly, automated history matching techniques like the Ensemble Kalman Filter (Evensen, 2003, 2007) are used, which update reservoir properties based on such combined data. Skjervheim et al. (2005, 2006), Skjervheim and Rudd (2006) and Trani et al. (2009) assimilated, for example, production and inverted seismic data on a synthetic reservoir showing a good estimation of reservoir porosity and permeability and an improved history match of production data, particularly when using seismic data. The advantage of the method is that it is sequential, taking into account data of different types as it becomes available. The same techniques could be applied for CO_2 storage as well.

The EnKF requires an ensemble of models, which should reflect the geological knowledge and its uncertainty. Different types of information are used for generating the ensembles, for example 3D seismic, well log information and conceptual geological information. Updating is carried out by forward simulation of the ensemble of realisations and then constraining and updating the members of the ensemble using incoming monitoring data. These methods are often part of concepts referred to as intelligent fields, e-fields or smart fields, where the idea is to instrument fields with all types of sensors and get updates of the reservoir state automatically, such that production can be optimised. The benefit of applying this methodology for CO_2 storage still needs to be demonstrated, and research is planned, or example, in the Dutch CATO-2 programme. The expected benefits are an improved history match of the model to the data and, through the stochastic nature of the approach, more insight into the uncertainties of the forecast future behaviour of the reservoir.

7.5.5 Well log data

Logging results can detect initial CO_2 breakthrough and, under favourable circumstances, may even provide information on CO_2 saturations. The effect of CO_2 replacing formation water can be observed through increased resistivity, CO_2 being less conductive than saline formation water. CO_2 infiltration leads to a decreased hydrogen content, consequently resulting in a reduced neutron porosity measurement. A strong effect can be expected for sonic logging, as only small amounts of CO_2 cause an increased sonic signal as a result of a significant decrease in compressional wave velocity. Finally, time lapse pulsed neutron measurements (e.g. reservoir saturation tool; RST) are effective for monitoring CO_2 migration, as a result of the large contrast between saline formation water and CO_2 (Freifeld et al., 2009). These effects will be reduced as CO_2 dissolves in the formation water. CO_2 saturations can be calculated using Gassmann's equation and the corrected neutron porosity (see Xue et al., 2006). Advanced logging tools, such as the distributed thermal perturbation sensor (DTPS), providing high resolution data on formation thermal conductivity, also act as a proxy to estimate CO_2 saturations. An increase of CO_2 saturation will lead to a reduction in bulk thermal conductivity (Freifeld et al., 2009). Applying a combination of techniques will increase the reliability of a well log interpretation.

7.5.6 Example for of well integrity from K12-B - EMIT/PMIT acquisition

The Platform Multifinger Imaging Tool (PMIT) is a multifinger calliper tool which provides high resolution internal tubing radii measurements using mechanical callipers. The Electro Magnetic Imager Tool (EMIT) uses electromagnetic technology to measure and map the inner pipe diameter and the total thickness of all concentric pipes.

At well K12-B severe scaling interfered with the multifinger calliper measurements affecting its ability to determine tubing integrity. Results from time-lapse multifinger calliper show inconsistent results in relation to a process like corrosion inside the tubing (see Figure 7-4)

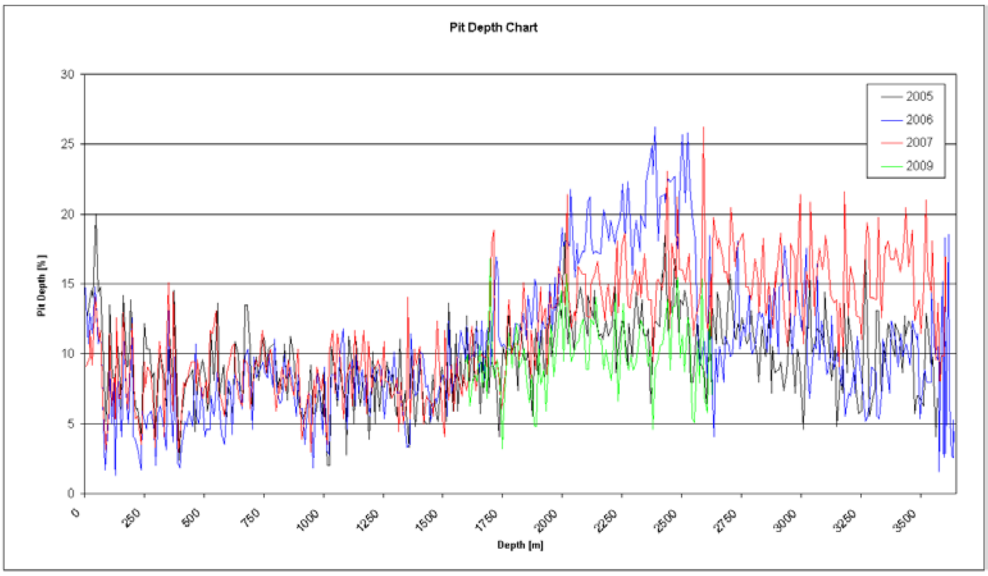

Figure 7-4 Time-lapse results of multifinger calliper surveys showing the maximum pit depth measured by one of the mechanical callipers (courtesy TNO).

The electromagnetic tool measurements, multifinger calliper measurements and measurements from a simultaneously run gamma-ray (2009 survey), enabled a comprehensive interpretation of the data. It was deduced that multiple types of scale were present inside the tubing, but that the integrity of the well was not at risk. Further preliminary interpretations indicate that the electromagnetic tool shows a slight increase of the internal radius where the multifinger calliper tool shows a slight decrease (Figure 7-5). This phenomenon coincides with a severe drop in natural gamma-ray response and is under further investigation.

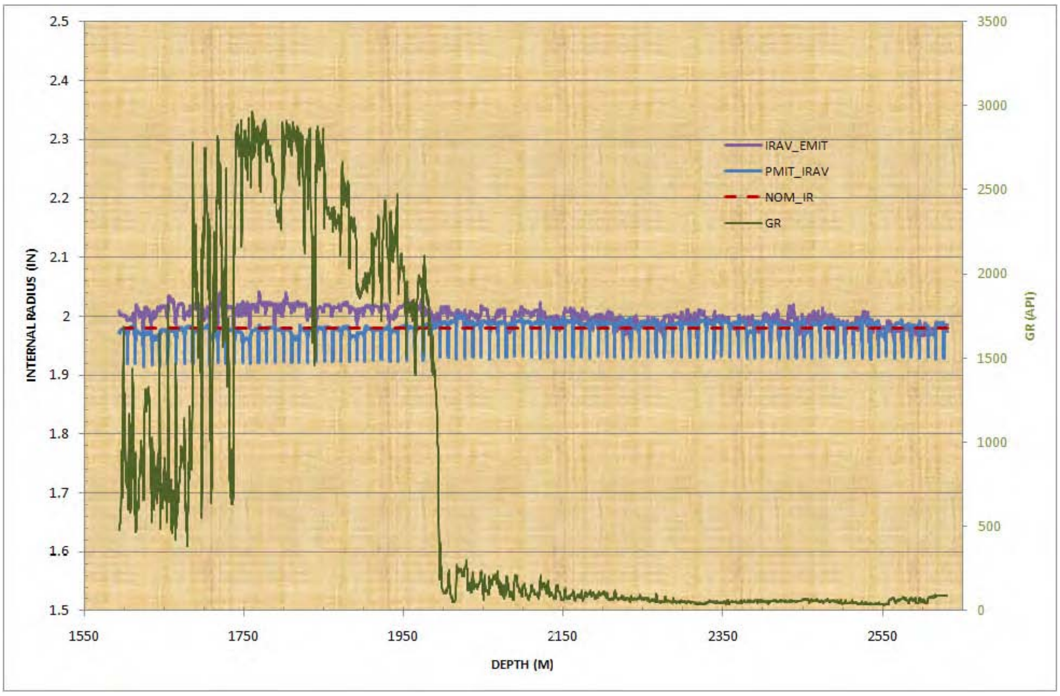

Figure 7-5 EMIT and PMIT results showing the internal radii with gamma-ray. (image courtesy CO2ReMoVe project)

Further development and testing of combined interpretation using different tools for well integrity is ongoing, for example at Schlumberger.

7.6 DISCUSSION

The added value of combining methods can be summarised as:

- Joint interpretation of various monitoring techniques leads to a better constrained model of the reservoir. Current experiences such as at Sleipner are based on using one method (generally seismics) to estimate the spreading of CO_2 in the reservoir, and a second method in a model-based approach to determine, for example, the concentration of CO_2 within the plume (resistivity based methods) or the pressure-temperature conditions (gravity). Typical monitoring techniques suitable for joint interpretation are seismic methods (including VSP), microseismic methods, gravity data and CSEM data.
- Improved characterisation of the reservoir states in time, leads to an improved history match and hence to better predictions of reservoir behaviour. Note that the latter conclusion is often made, but is far from obvious. It is more correct to say that taking into account the uncertainties in the history match leads to an improved estimate of the uncertainties of the future behaviour of CO_2 in the reservoir. Typical combinations of monitoring data to be used for CO_2 storage in UK offshore environments are injection well data (injection rates, pressure and temperature), monitoring well data (fluid sampling, tracer detection and well log data) and geophysical measurements (seismics, VSP, gravity and CSEM).
- Combinations of methods covering wide areas (less suitable for quantification) combined with local methods (more focussed on quantification) can be used for the shallow subsurface as part of a strategy to detect and characterise migration or leakage. Typical combinations of monitoring data are, therefore, wide-area acoustic techniques and seismic data combined with more local measurement or sampling techniques.

Chapter 8 describes in more detail the proposed strategies for the types of likely reservoirs identified for the UK offshore sector.

Section C

Recommendations for UK-relevant development

8 Monitoring methodology for offshore UK sites

8.1 EXECUTIVE SUMMARY

Monitoring plans for UK offshore storage sites are a regulatory requirement. They will need to demonstrate appropriate site performance, to monitor and evaluate deviations from expected performance and to measure CO_2 emissions should leakage occur. Here we consider monitoring methodologies for four generic storage site types, which cover the likely range of storage scenarios in the North Sea. They comprise: depleted gas fields beneath the Zechstein Salt in the southern North Sea; saline aquifers and depleted gas fields above the Zechstein Salt in the southern North Sea; depleted hydrocarbon fields in the central and northern North Sea and saline aquifers in the central and northern North Sea. The generic monitoring methodology comprises two distinct elements: a core monitoring programme designed to meet the regulatory requirements of a conforming site (i.e. one that behaves as expected during its lifetime) and an additional monitoring programme designed to address the requirements of a storage site that does not perform as expected. The core monitoring programme will be defined as part of the storage licence. It is aimed at performance verification, the monitoring and management of any site-specific containment risks identified in the Framework for Risk Assessment and Management (FRAM) and the detection and evaluation of performance irregularities including early warning of potential leakage. The additional monitoring programme is contingent upon the development of a significant performance irregularity. It comprises a portfolio of targeted monitoring tools held in reserve to evaluate and manage the range of possible irregularities and meet the needs of any associated remediation. The additional monitoring programme includes any requirement for emissions measurement under the ETS.

Specific methodologies for the core monitoring programme depend on storage site type. Depleted hydrocarbon fields are assumed to have secure geological seals, so monitoring emphasis is on possible migration and leakage along wellbores. Saline aquifers have geological seals whose properties are less well understood and there will be a greater emphasis on non-invasive monitoring tools providing wide spatial coverage. For all site types, the priority is to deploy pre-emptive deep-focussed monitoring systems targeted on the primary storage reservoir and its immediate surroundings, with the aim of identifying irregularities as soon as possible, and before they become too serious to be remediable. Shallow-focussed systems, deployed at the seabed or in the seawater column, aim to provide additional assurance that leakage is not occurring. Fit-for-purpose baseline data is essential, and for shallow-focussed systems must be sufficiently robust to allow quantitative measurement of emissions should the need arise.

Key technologies for deep-focussed monitoring include downhole pressure and temperature (P,T) measurement on the injection well and 3D (in some cases 2D) surface seismic. If suitable wellbore infrastructure is available, remote (from the injection wells) P, T monitoring, saturation logging and downhole fluid sampling may be appropriate. With the exception of CO_2 saturation logging (which has, however, seen some application for CCS) these are generally mature technologies with ongoing improvements driven by the oil industry. Key technologies for shallow-focussed monitoring include multibeam echo sounding, sidescan sonar, bubble stream detection and seabed measurements and/or sampling. These technologies are less mature than the deep focussed tools particularly in terms of accepted practice for effective deployment.

Methodologies for the additional monitoring programme depend very specifically on the nature of the irregularity, and thus may evolve with time. They may require further deployment of tools already used in the core programme or the use of specific new tools such as seawater chemistry or crosshole seismic. Such tools may however be relatively developmentally immature, have unproven longer-term reliability or have stringent wellbore infrastructure requirements. For emissions quantification the ability to integrate spatially extensive information from non-invasive surveys (e.g. sonar imaging) with local detailed sample measurements will be required.

The risk assessment undertaken for a CCS project will need to cover the most likely risks and define additional monitoring to address those risks.

8.2 INTRODUCTION

This chapter provides an overview of the likely elements of monitoring systems for offshore storage projects in the UK North Sea. It does not set out to be prescriptive nor should it be considered as providing recommendations for any particular site,., Its purpose is to illustrate the types of monitoring strategies that might be suitable for a range of likely storage sites in the UK offshore sector, which in turn will help to identify priorities for future development in Chapter 8.

The high-level regulatory requirements (Chapter 2) and the more detailed assessment of monitoring objectives (Chapter 5) can be addressed by an integrated monitoring scheme with two basic components: a core monitoring programme and a contingent additional monitoring programme.

The core monitoring programme is designed to meet the regulatory requirements of a conforming site (i.e. one that behaves as expected during its lifetime). It is aimed at performance verification, the monitoring and management of any site-specific containment risks identified in the Framework for Risk Assessment and Management (FRAM) and the detection of performance irregularities including early warning of potential leakage.

The additional monitoring programme is designed to address the requirements of a storage site that does not perform as expected. It comprises a portfolio of targeted monitoring tools held in reserve to meet the possible range of significant irregularities and the needs of any associated remediation. The additional monitoring programme includes any requirement for emissions measurement under the ETS.

A simple flowchart has been developed to explain the methodology (Figure 8-1).

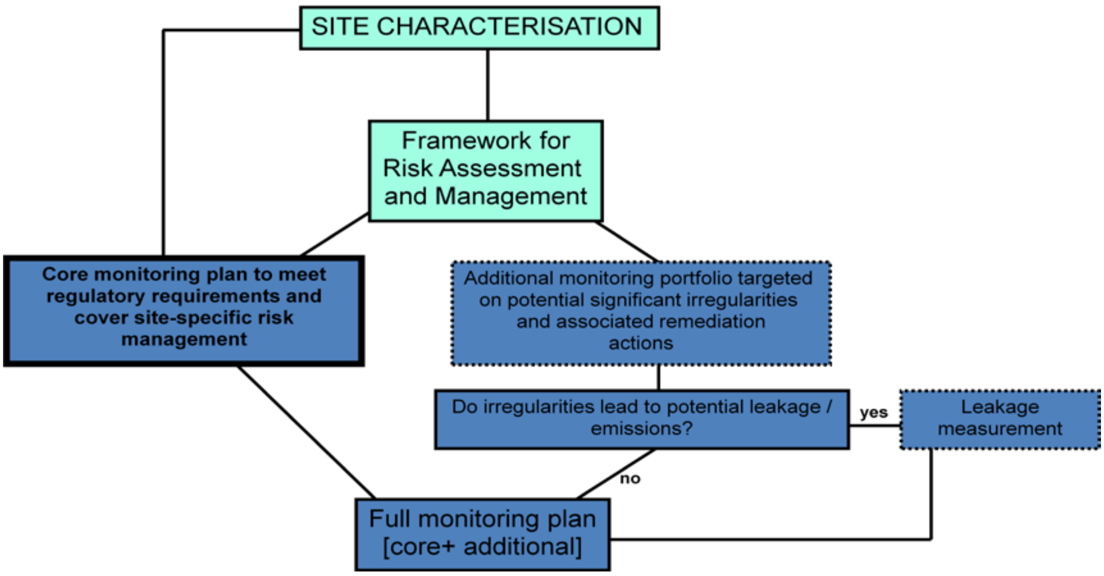

Figure 8-1 Flowchart showing the proposed methodology for monitoring plan development

8.2.1 The Core Monitoring Plan

The core monitoring programme must be capable of providing the information necessary to demonstrate satisfactory site performance and also to demonstrate that the operator has sufficient understanding of current site processes to make reliable predictions of future performance. Four principal monitoring objectives can be distilled from Chapter 2 and are summarised below.

- Comparison of actual site behaviour with modelled behaviour (model verification) and calibration of predictive modelling.
- Demonstration of no detectable leakage.
- Effective monitoring of identified containment risks.
- Indication of significant performance irregularities, in particular those that may lead to a risk of leakage or a risk to the environment or human health.

8.2.2 Additional Monitoring Programme

The additional monitoring programme becomes applicable when the storage site ceases to behave as predicted and an irregularity becomes sufficiently significant to require additional monitoring actions. The thresholds or events which determine significant irregularity will have been defined in the monitoring plan. It should provide the information necessary to track and characterise the irregularity, to re-design or re-calibrate predictive models and to decide on any necessary remediation. In the event that the irregularity leads to, or is likely to lead to, leakage, the additional monitoring programme must provide the capability of measuring this leakage as required by the ETS. These objectives are summarised below:

- Provision of additional data to re-design or re-calibrate predictive models.
- Provision of information for remediation actions and to assess their efficacy.
- Measurement of leakage for emissions quantification.

8.2.3 Infrastructure and timing

Key factors to be taken into account when designing a monitoring programme are the availability of site infrastructure, which will determine the type of monitoring tools that can be deployed, and the changing monitoring requirements during the project lifetime.

8.2.3.1 Site infrastructure

Site infrastructure relates to the number and distribution of wellbores, either active or abandoned, within the storage complex. Wellbores that are accessible and used for monitoring purposes are hereafter referred to as surveillance wells. They provide cost-effective opportunities for the deployment of invasive monitoring tools, but also are potentially detrimental in providing possible migration and leakage pathways. It is therefore useful to discriminate between monitoring technologies which are invasive or non-invasive with respect to the storage complex (Chapter 10, Volume 2).

<u>Invasive monitoring tools</u> are deployed via wellbores. They offer a wide range of monitoring options with high resolution and detection capability. However, with the exception of downhole pressure measurement, and cross-hole methods, coverage is limited to the vicinity of the wellbore.

<u>Non-invasive monitoring tools</u> are generally remotely positioned with respect to the storage reservoir. They do not require wellbore infrastructure and, although limited in terms of absolute resolution and detection capability, they do have the ability to provide broad spatial coverage of the storage system.

A key issue, particularly with respect to invasive monitoring, is reliability. Experience from current sites suggests that monitoring tools deployed downhole can have limited reliability. There are two main reasons for this: physical damage to the tools as they are deployed into the wellbore and longer-term degradation of the tools as they sit in the hostile downhole environment (high temperature and pressure and low pH). Reliability can seriously affect the efficacy of a monitoring programme and should be taken into account in its design.

8.2.3.2 Project Stages

For the purposes of setting a monitoring programme, an injection project can be split into four stages:

- Pre-injection (monitoring baselines)
- Injection (main operational monitoring)
- Post-injection (monitoring leading to transfer of responsibility)
- Post-transfer (monitoring after transfer of responsibility)

How the main monitoring objectives relate to these four stages is summarised in Figure 8-2 and discussed in more detail in the site-specific sections below.

	pre-injection	injection	post-injection	post-transfer
Core Monitoring Programme				
Model verification and calibration	1	2	2	0
Leakage detection	1	2	2	0
Monitoring containment risks	1	2	2	0
Performance irregularities	1	2	2	0
Additional Monitoring Programme				
Re-calibrate models	0	3	3	0
Remediative actions	0	3	3	0
Leakage measurement (ETS)	1	3	3	3
0 = no monitoring				
1 = acquire baselines				
2 = active time-lapse monitoring				
3 = contigency monitoring				

Figure 8-2: The main monitoring objectives related to the four project phases

For offshore sites the requirements for post transfer monitoring are likely to be minimal, with the exception of any requirement for leakage quantification that might be carried over from the pre-transfer stage. Whether transfer could occur if any leakage were demonstrably still occurring is uncertain. Post transfer monitoring is not considered further in this chapter.

8.2.4 Baseline surveys

Before turning to site specifics, some general points about baseline monitoring are worth making.

A fit-for-purpose baseline dataset has to provide sufficient and suitable pre-injection information to enable injection-related changes to be adequately identified and characterised. Storage-related effects will need to be larger than, or in some way different to, natural variations in order to be detected readily.

Some surveys measure a parameter which may change naturally on the timescale of an injection project. A good example of this would be seabed imaging where shifting seabed sediments or natural gas fluxes might produce significant natural changes over time. A sufficient number of repeat baseline surveys should be acquired to characterise these changes and enable them to be reliably distinguished from storage related effects. Natural concentrations of CO_2 in seawater and fluxes from the seabed are poorly known. They would need to be established (including their variability) to account for any subsequent leakage.

The aim of seabed imaging in the North Sea is to identify change, whether in seabed morphology or the acoustic response of the sediment. In parts of the North Sea (e.g. off East Anglia) the seafloor is covered by migrating bedforms. In the most dynamic areas sandbanks can move tens of metres per year. This also occurs in the northern North Sea where strong currents are present, such as around the Pentland Firth and off Rattray Head. In shallow water (<30 m depth) storms can induce sudden changes in seabed morphology. However in water depths greater than 100 m there is generally little evidence of bedform migration. In general terms, therefore, the seabed in the central and northern North Sea may be somewhat more stable than farther south and the necessity for seabed imaging would therefore be reduced. The added value of sea bed imaging should be assessed for each site as for all other monitoring methods. Natural variations in sea bed morphology can be estimated either from (multiple) seabed imaging datasets or from sediment transport models. An advantage of seabed imaging is that a wide area can be covered at a relatively low cost.

The area of coverage (surface and subsurface) of initial baseline monitoring need not encompass the entire long-term predicted extent of the plume footprint. It would be perfectly reasonable to acquire sufficient data to cover early plume development and then extend the baseline monitoring coverage progressively as the plume develops.

Whether legacy datasets (pre-existing data acquired for other purposes such as hydrocarbon exploration and production) can reasonably be used for baseline purposes is an area of current debate. Legacy datasets have been successfully used at Sleipner, for example. On the other hand it is very unlikely that the legacy data were acquired with the same target objectives as the monitoring surveys, and so they are unlikely to be optimally tuned. Careful analysis is required to judge whether existing datasets will make suitable baseline surveys for a particular site. Key criteria include the age and purpose of the legacy dataset, the objectives of the monitoring survey and the geological characteristics of the site.

In addition to the monitoring requirement described here, baseline information on the seabed environment and ecosystems will also be required to inform the environmental impact assessment (EIA). These are not considered further here.

8.2.5 The generic sites

Four UK offshore storage types have been defined that typify the broad characteristics of the main storage options in the UK North Sea. They are essentially generic versions of the four real sites described in Chapter 3 and comprise two from the southern North Sea and two from the central / northern North Sea (Table 8-1).

Table 8-1 Summary descriptions of four generic types of storage site that cover the potential CO_2 storage sites in the UK North Sea.

Type	Typical locations	Descriptions
Type 1	Southern North Sea (Figure 8-3)	Depleted gas fields, underpressured at the start of storage, in compartmentalised reservoirs, bounded by low-permeability faults with generally little aquifer recharge. Zechstein salt forms a high-quality low-permeability seal. The overburden above the salt comprises dominant mudstone (proven seal for natural gas) with Bunter sandstone and Chalk.
Type 2	Southern North Sea (Figure 8-4)	Depleted gas fields, underpressured at the start of storage, and aquifers of Bunter sandstone at 2-4 km depth in anticlinal structures above Zechstein salt. Caprocks are proven seals for natural gas. Although faulted, fault zone permeabilities are variable. Larger faults may extend to seabed.

Type 3	Central and Northern North Sea (Figure 8-5)	Depleted hydrocarbon fields at depths of around 3km, bounded by variable-permeability faults with aquifer recharge in some fields. Seals are mudstone caprocks proven to retain natural gas. The overburden is generally unfaulted, comprising sequence of sandstones and mudstones.
Type 4	Central and Northern North Sea (Figure 8-6)	Laterally extensive sandstone aquifers between 0.8 and 2km depth, sealed by mudstones (proven to retain CO_2 at Sleipner). The largely unfaulted overburden is dominated by mudstones with sandstone lenses and may contain “gas chimneys”.

8.3 MONITORING METHODOLOGY FOR A TYPE 1 SITE

8.3.1 Site scenario

The Type 1 site comprises depleted gas fields, strongly underpressured at the start of injection, in compartmentalised reservoirs, bounded by low-permeability faults with generally little aquifer recharge. Zechstein salt forms a high-quality low-permeability seal. The overburden above the salt is dominantly mudstone (proven seal for natural gas) plus Bunter sandstone and Chalk. Seismic imaging of the reservoir is difficult due to the acoustically opaque salt topseal, so reservoir monitoring depends on invasive technologies deployed in surveillance wells. The number of surveillance wells used will depend on the site-specific requirements taking into account the potential for cost-effective utilisation of existing wellbores. Monitoring for CO_2 migration out of the reservoir is focussed exclusively on the wellbores.

The current storage site at K12-B corresponds broadly to a Type 1 site, albeit with much smaller amounts of injected CO_2. In terms of the simulations in Chapter 4, Type 1 sites correspond generally to the modelled Case 1 (underpressured), with reservoir pressure histories mostly below hydrostatic.

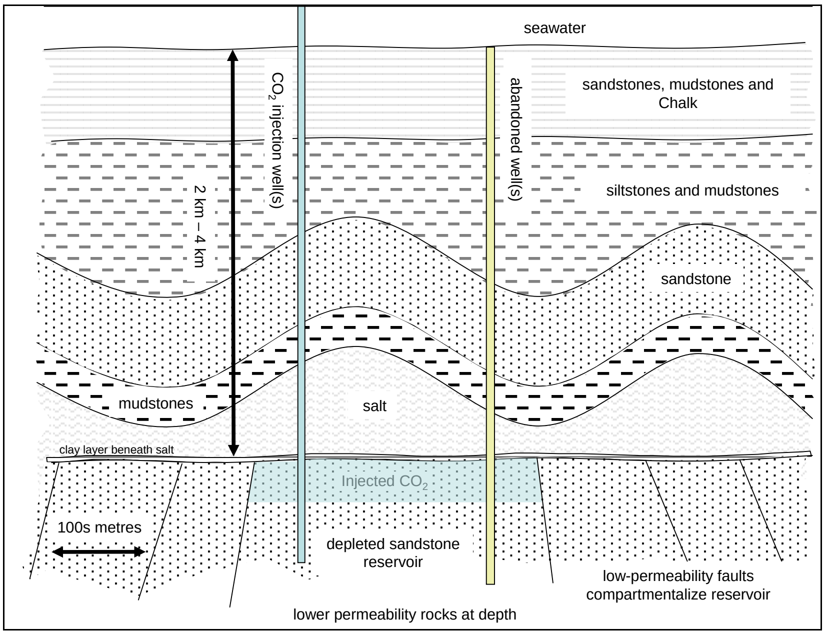

Figure 8-3: Type 1 storage site: depleted gas field, beneath the Zechstein salt, southern North Sea

8.3.2 Core monitoring

Type 1 sites tend to have limited spatial spread of the CO_2 plume, due to their laterally sealing fault boundaries and are also not very suitable for non-invasive imaging of the plume in the reservoir due to the presence of the thick salt topseal. Because of this, and the likely presence of significant wellbore infrastructure, invasive monitoring methods will play a significant role.

8.3.2.1 Pre-injection (baseline) monitoring

Tool deployment for baseline monitoring is driven by the needs of the injection-phase monitoring system which are described in the next section so will not be discussed in detail here. A fit-for-purpose baseline dataset has to provide sufficient and suitable pre-injection information to enable injection-related changes to be adequately identified and characterised.

Potentially useful baseline tools are listed below:

- Baseline monitoring in any surveillance wells
- 2D surface seismic focussed on the wellbores (with the additional aim of identifying any pre-injection migration of natural gas around the wellbore)
- Seabed imaging (e.g. multibeam echo sounding and sidescan sonar)
- Bubble stream detection, measurement and mapping

One baseline survey that may not be deployed during the injection phase is 3D surface seismic.

3D seismic: The received wisdom is that surface seismic methods are not suitable for monitoring Type 1 storage sites due to the thick salt topseal which acts as an acoustic barrier. Whilst it is true that the topseal does render imaging of the plume within the reservoir very difficult, the overburden is unaffected, so 3D seismic does have a potential role to play in detecting out-of-reservoir migration. Because of the secure salt topseal, migration through the geological seals is considered very unlikely, however, so a dedicated 3D baseline survey may not be required. Legacy data are commonplace in the southern North Sea (c.f. the K12-B and P18 fields described in Chapter 3) and a suitable dataset could be used for baseline purposes to supplement the 2D seismic surveys.

8.3.2.2 Injection stage monitoring

In terms of the core monitoring programme, activities will be most intense during the injection stage. The four principal core monitoring objectives (see 8.2.1) are all applicable.

<u>*Comparison of actual site behaviour with modelled behaviour (model verification) and calibration of predictive modelling.*</u>

For Type 1 sites the main performance indicators in comparing actual site behaviour with modelled behaviour are reservoir pressure and plume migration.

Downhole pressure and temperature: Downhole P and T measurement deployed on the injection wells is an important tool for testing and calibrating predictive flow simulations, both from the point of view of pressure evolution and also from constraining CO_2 fluid properties. Additional P, T monitoring on other surveillance wells is also likely to be deployed to test reservoir connectivity and the nature of the reservoir boundaries.

Downhole saturation logging: The reservoir saturation tool (RST) can provide high resolution information on fluid distributions, providing fine-scale information on plume structure. It would be deployed on surveillance wells, or possibly on an injection well during workover.

Downhole fluid sampling: Geochemical monitoring may well be deployed in surveillance wells across the reservoir to establish plume breakthrough (a key determinant of migration velocity and reservoir permeability) either by direct detection of CO_2 or via the deployment of tracers. Temporal accuracy of these methods depends on the repeat frequency of the surveys. Novel continuous monitoring methods such as the U-tube or continuous pH measurement would be very suitable for accurate timing of plume breakthrough, but are not proven in a commercial setting, especially in the offshore environment.

<u>*Demonstration of no detectable leakage.*</u>

Demonstration of no detectable leakage in Type 1 sites depends on combining an observed absence of time-lapse changes in the overburden or at the seabed with a robust site characterisation that demonstrates seal integrity. It is accepted that the thick salt topseal forms a secure and proven hydrocarbon seal, so leakage risks are assumed to be restricted to the wellbores. Leakage monitoring, focussed on the wellbores should be deployed for assurance, even though the flow simulations (see below) suggest that any leakage would be small to non-existent.

Downhole pressure: Pressure monitoring, in or above the reservoir, is a potentially powerful means of detecting fluid migration from the storage reservoir. An abrupt fall in reservoir pressure could signify leakage around a wellbore. Pressure monitoring above the topseal in surveillance wells would also be useful for detecting fluid flow out of the reservoir.

Seabed imaging: Seabed surveys are inexpensive and can be integrated with conventional or high resolution seismic surveys. Careful assessment will be required to distinguish significant time-lapse changes from naturally-occurring effects. Surveys would be focussed on the seabed footprints of the wellbores (including any deviation in the wellbore trajectories and sidetracks) but include a wider area to allow for lateral migration from the wells.

Bubble-stream detection: Additional leakage assurance could be provided by bubble-stream detection surveys. These could be acquired periodically over the wellbore footprints to ensure no significant changes are occurring (changes in bubble stream density in a pre-existing stream, or development of a new stream). For cost-effective data acquisition bubble-stream detection and seabed imaging can be acquired together and also integrated with surface seismic acquisition.

<u>*Effective monitoring of identified containment risks.*</u>

Migration along wellbores

The salt topseal is a secure and proven hydrocarbon seal in Type 1 storage sites, so specific containment risks are restricted to the wellbores, a number of which are likely to be impacted. Typical well densities for southern North Sea gas fields are around one well per two square kilometres, some wellbores comprising a number of sidetrack wells branching off the main production string. In fact the flow modelling in Chapter 4 suggests that wellbore leakage (Case 1_well) is likely to be very small in the injection phase due to the depleted reservoir pressures. For example, during the injection period, modelled flow rates impacting on the wellbore in the reservoir are less than 10 tonnes per year (Figure 4-13) and modelled flow rates at the seabed are zero (Figure 4-14). The figures do of course depend on the assumed flow parameters of the wellbores. These are quite conservative for migration outside of the casing, but migration inside an unobstructed wellbore, although considered unlikely, would lead to greater amounts of leakage.

Because of the low predicted flow rates, wellbore monitoring to detect CO_2 migration out of the reservoir is unlikely to involve deployment of expensive and possibly unreliable downhole tools, at least as part of the core monitoring programme. Ideally some form of cheap and robust passive downhole system might be deployed (see below), but currently suitable technologies are not available. Instead, seabed surveys (see above) would be deployed for assurance and possibly also 2D seismic.

2D seismic: Relatively inexpensive 2D seismic surveys would provide the main basis for establishing whether there is evidence of migration up the outside of the wellbore and laterally into the overburden. These would be deployed in star-configuration over the wellbores.

Seabed Imaging and Bubble Detection. These could be integrated with 2D seismic in a cost-effective manner by combining the techniques on the survey vessel.

Wellbore monitoring. An effective methodology for leakage assurance in accessible wellbores might comprise a long-term passive pH measurement system for migration inside of the wellbore; outside of the wellbore, long-term detection of CO_2 migration is very challenging. Currently technologies for robust long-term measurements are not available.

Migration pathways in the overburden

For Type 1 sites migration through the geological seals is considered extremely unlikely. Any migration in the overburden would be via the wellbores and monitoring requirements would be covered by the above.

Lateral migration into neighbouring assets

If the reservoir boundaries are impermeable then migration into neighbouring fields should not be a problem. Downhole pressure monitoring on the injection wells might be sufficient to demonstrate boundary integrity. If surveillance wells are utilised then pressure mapping from all wells could give indications of unplanned migration.

Induced geomechanical effects

Type 1 sites with their very low initial pressures and ductile, self-annealing topseal are not considered to be geomechanically vulnerable.

<u>Indication of significant performance irregularities that may lead to a risk of leakage or a risk to the environment or human health.</u>

Irregularities may be identified in the course of monitoring for any of the objectives above. If these are deemed to be significant, particularly with the potential to lead to leakage, then additional monitoring will be required (see section 8.3.3). Perhaps the most significant monitoring action in this category would arise if changes in seabed or bubble-streams were detected. Measurements of the gas would then be required to establish the cause of the observed changes and whether or not it constituted a significant irregularity.

Seabed gas measurements: In situ measurements would be made using existing or developed sensors or samples of headspace gas and seawater would be collected and analysed by standard laboratory procedures to verify whether or not the gas is CO_2. If it is CO_2 then isotopic or tracer analysis would be carried out to test whether or not it could have come from the storage site. If this proves to be the case then the additional monitoring programme would be triggered.

8.3.2.3 POST-INJECTION MONITORING

Post-injection, the core monitoring programme has similar aims to the injection-phase monitoring. The emphasis is still on model verification and demonstrating lack of leakage, and any significant irregularities would still trigger the additional monitoring programme. An important new requirement is to demonstrate robust longer-term prediction capability, in particular to show that the site is evolving towards long-term stability.

In general terms, preference will likely move further towards non-invasive monitoring systems, as the site operator seeks to complete and abandon their injection and any surveillance wellbores.

<u>Comparison of actual site behaviour with modelled behaviour (model verification)</u>

Monitoring requirements are similar to those of the injection phase. The frequency of time-lapse repeats is determined by the requirements of demonstrating site stabilization (see below).

<u>Demonstration of no detectable leakage</u>

Monitoring requirements are similar to those of the injection phase. For the leaking well scenario, flow modelling (Chapter 4) indicates that flow rates at the reservoir / wellbore interface and at the seabed are maintained at similar levels to the latter part of the injection phase i.e. very small.

<u>*Site stabilisation*</u>

There are two main site stabilization processes at Type 1 sites as predicted by the models: pressure decline and geochemical stabilization.

Pressure decline

Type 1 sites will typically have closed reservoir boundaries, so pressure decline will be slow.

Geochemical stabilization

Geochemical processes are much slower than the physical processes governing migration of the free CO_2 plume and demonstrating the extent to which they are occurring is challenging. Because of the intrinsic security of a Type 1 site (thick salt topseal and likely lack of overpressure) the requirement to demonstrate the onset of dissolution will probably not be as strong as with a Type 2 or Type 4 site.

Downhole Fluid sampling: Downhole fluid sampling (e.g. for HCO_3^-) and pH measurement could be continued to establish the degree of ongoing dissolution if required.

8.3.3 Additional Monitoring Methodology

Unlike the core monitoring programme, which is driven by high-level regulatory requirements, the additional monitoring programme is highly site-specific and driven by the demands of a particular performance irregularity. In this section we discuss some monitoring strategies that would be useful in the context of the sort of irregularity that might be encountered at a Type 1 site.

Additional monitoring would be triggered by a performance irregularity significant enough to require additional information to secure and maintain site performance. It should provide the data necessary to track and characterise the irregularity and to design suitable remediative actions. In the event that the irregularity leads to or is likely to lead to leakage, the additional monitoring programme must provide the facility to measure this leakage as required by the ETS. The events or thresholds which define a significant irregularity will be included in the monitoring plan.

Three principal objectives for additional monitoring have been defined (see Section 8.2.2).

8.3.3.1 PROVISION OF ADDITIONAL DATA TO RE-DESIGN OR RE-CALIBRATE PREDICTIVE MODELS.

For Type 1 sites, significant irregularities in predictive modelling are most likely to comprise unexpected pressure changes and discrepancies in plume spreading. Options for additional monitoring include additional (more frequent) and focussed deployment of technologies already utilised as part of the core monitoring programme or deployment of new, specialised monitoring tools, described below. Deployment of downhole tools may be practicable in pre-existing well stock, but a specifically positioned new surveillance well is likely to be more effective. A new well would of course also be used to gain additional geological information to improve the reservoir characterisation.

<u>*Unexpected pressure changes*</u>

Unexpected pressure increase suggests problems with permeability connectivity in the reservoir. For scenarios where pressure is only recorded in the injection wells it may be necessary to obtain additional pressure measurements from elsewhere in the reservoir, perhaps allied to specific flow tests (water injection or production with pressure history measurements), to establish regional hydraulic connectivity.

Unexpected pressure decrease may be an indicator of significant migration of CO_2 from the primary storage reservoir and would trigger additional monitoring focussed on establishing the cause of the pressure decrease and the design of suitable remediation (see below).

Discrepancies in plume spreading

Significant discrepancies in predicted and observed plume spreading within the reservoir, as indicated by well breakthrough times, are likely to be due to imperfect understanding of reservoir internal structure and of the fine-scale flow processes and detailed saturation distributions in the constituent layers of the plume. Key determinants of plume spreading behaviour are the thickness and geometry of the spreading CO_2 layers and fluid saturations within them.

Downhole tools: A number of downhole techniques can be used to obtain more detailed information on the internal structure of the plume, particularly CO_2 layer thicknesses and saturations. Highest resolution is obtained from geophysical logging tools such as the RST, which is particularly effective when combined with fluid sampling. Crosshole seismic can give 2D spatial imaging of plume layers in the vicinity of the wellbore, and combined with the RST can give indications of fluid saturations in 2D. However there are technical issues regarding its implementation, reliability and infrastructure requirements (Chapter 10, Volume 2) . Borehole microgravimetry may also be useful in assessing CO_2 layer thicknesses. Vertical seismic profiling (VSP) methods, as with surface seismic, are likely to be of limited efficacy beneath the thick salt topseal.

8.3.3.2 PROVISION OF INFORMATION FOR REMEDIATION ACTIONS.

Monitoring focussed on remediation actions would be a response to irregularities which point to possible migration of CO_2 out of the reservoir, either up a wellbore or laterally into a neighbouring asset. Monitoring is also required to establish the efficacy of the remedial actions.

The former would most likely be identified by significant pressure loss. Depending on the amount of monitoring already deployed, the vulnerable wellbore might be readily identifiable. Vulnerable, accessible wellbores should be tested immediately. Standard well integrity testing might include technologies to assess the current condition of the wellbore, such as cement bond logs, multifinger callipers and visual inspections for corrosion and scaling. Additional monitoring for evidence of fluid changes around the outside of the wellbore would be useful, with saturation (RST) and temperature logging established techniques.

Inaccessible wellbores are more problematical and non-invasive methods would have to be deployed. 2D surface seismic could be deployed in star configuration centred on the wellbores, to establish if significant fluxes are present outside the wellbores.

The possibility of (more rapid) migration inside the wellbore would be covered by detailed shallow-focussed monitoring: seabed imaging and bubble-stream detection in the first instance, followed by measurement of CO_2 concentrations and fluxes, such as by semi-permanent seabed monitoring systems around the wellhead. If the above methods do not establish the location of the irregularity, then a repeat 3D surface seismic may have to be acquired to accurately locate any time-lapse changes in the overburden.

Once the location, nature and severity of the irregularity are established, then a suitable remediation plan would be developed.

Unwanted lateral migration of the plume will be a difficult issue to address. It may be that monitoring in a neighbouring asset will be required, for example using downhole techniques.

8.3.3.3 MEASUREMENT OF LEAKAGE FOR EMISSIONS QUANTIFICATION (UNDER THE ETS).

For Type 1 sites by far the most likely leakage scenario is via migration along or into a wellbore. Fault and caprock leakage scenarios are not considered here. Scoping simulations (Chapter 4.3, Case 1_Well) indicate that significant well leakage might occur at relevant timescales. The simulations have further established the broad scale of leakage, including possible breakthrough times, albeit with poorly-constrained flow parameters.

Well leakage

For the well leakage case, leakage of free CO_2 to the seabed was estimated to take 70 years from initial migration and for dissolved CO_2 breakthrough was estimated to take 500 years. Peak flow of free CO_2 to the seabed was estimated to be 0.024 t/yr at 500 years (end of simulation), with peak areal fluxes estimated to be 0.19 t/m^2/yr, giving a footprint for the escaping CO_2 of only 0.126 m^2. No flux of dissolved CO_2 to the seabed was predicted. Estimated changes in seawater pH were calculated for a range of seawater displacement rates at peak free CO_2 flux rates. These indicated that pH may decrease by up to 1.14 pH units. This is readily detectable, but only occurred for a rate of seawater displacement where 1 m^3 takes a day to be displaced. Higher water displacement rates produce much lower pH changes which would not be detectable (e.g. 1 m^3 per hour gives a change of less than 0.1 pH units). No change in pH due to dissolved CO_2 is predicted. The ability to detect and measure such low rates of CO_2 emission would, therefore, very much depend on the actual areal footprint of the leak and the rate of seawater mixing.

Evidence from other studies suggests that emission points from wells are likely to be confined spatially to a few square metres of the seabed. However, CO_2 may migrate laterally along permeable strata away from the well bore before reaching the seabed and hence could reach the seabed some distance from the well. Tracking of this movement at depth is needed to determine the correct area to look for and measure fluxes. An appropriate technology for this is high-resolution 2D seismic profiles arranged in a star pattern centred on the wellhead.

For well leakage, the key measured parameter is the flow of free CO_2 to the seawater column. Measurement of free CO_2 flow could be by flux meter or by measuring bubbles using sonar, microphone or video techniques, but further development and testing of these technologies are required. The sensors must be placed as close to the emission point as possible to ensure all bubbles are measured and the proportion of CO_2 dissolving into seawater prior to measurement is minimised. Bubble densities determined by remote methods such as multibeam/sonar offer the potential to measure CO_2 fluxes over larger areas. However further development is required to demonstrate the quantification capabilities of these non-invasive technologies.

In situ measurements of gas composition would be made using existing or developing techniques and/or samples of headspace gas and seawater. These would be collected and analysed to establish the gas composition including the proportions of any other components such as methane and H_2S, hydrocarbons and any added components such as tracers, as well as the proportion dissolved in the seawater. Temporal variations in the flow rates would also need to be established requiring repeat measurements at an initial interval of days to weeks. Where variations are not detected on this timescale, intervals between measurements may increase to up to every six months. The frequency of repeat measurements will depend on the temporal variability, with greater variations requiring increased frequency of measurement. Technologies for continuous emission detection and measurement, such as inverted funnel accumulation chambers, are currently being developed in the CO_2ReMoVe project and could be deployed at a leakage site. Inspection by ROV or diver further allows a visual check on flux variations.

To satisfy the ETS an inventory of the total amount of CO_2 emitted from the storage site must be made on an annual basis. This will based on the fluxes measured and area over which the CO_2 is being emitted. Measurement would continue until monitoring indicates that remediation has been successful.

8.4 MONITORING METHODOLOGY FOR A TYPE 2 SITE

8.4.1 Site scenario

The Type 2 site comprises depleted gas fields and saline aquifers of Bunter sandstone at 2-4 km depth in anticlinal structures above Zechstein salt. Caprocks are proven seals for natural gas, but faults do occur locally and in places may extend to the seabed (Figure 8-4). In the depleted gas fields reservoir pressures may remain below hydrostatic throughout the injection phase. In the aquifer sites pressures will rise above hydrostatic and care must be taken to monitor any vulnerable faults. Because of the higher pressures, wellbores will comprise a key containment risk, more so than for Type 1 sites. In terms of the simulations in Chapter 4, Type 2 sites span all of the modelled cases (1, 2 and 3) with potential pressure histories ranging from under-pressured to sub-lithostatic.

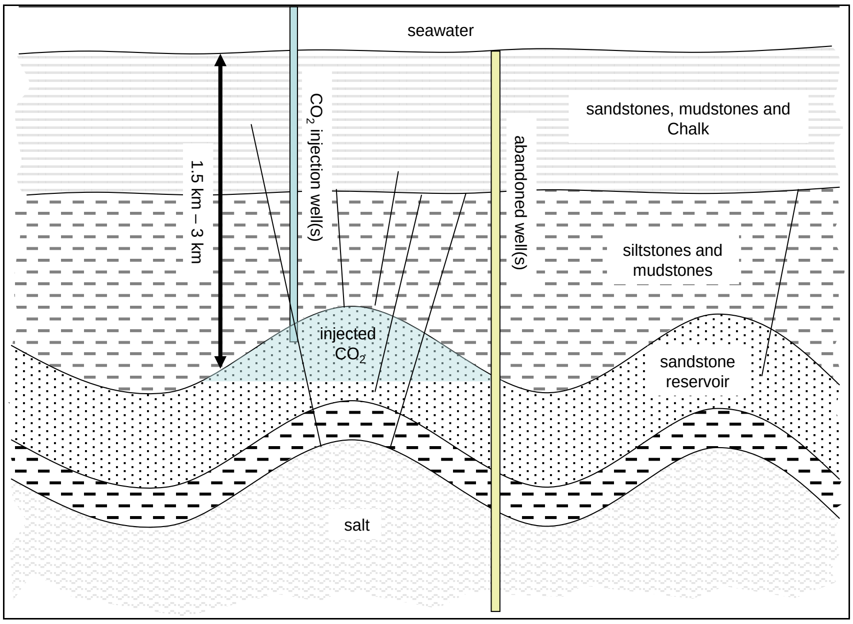

Figure 8-4: Type 2 storage site: depleted gas field / saline aquifer above the Zechstein salt, southern North Sea

8.4.2 Core monitoring

Within the core monitoring programme, monitoring objectives will evolve during the four stages of the project lifetime. Type 2 sites will generally have structural closure (Figure 8-4), so plume migration in the reservoir should be spatially limited and relatively predictable. Monitoring systems will therefore have to cover smaller areas than, for example, Type 4 sites.

8.4.2.1 PRE-INJECTION (BASELINE) MONITORING

Tool deployment for baseline monitoring is driven by the needs of the injection-phase monitoring system which are described in the next section so will not be discussed in detail here. Suffice to say that a fit-for-purpose baseline dataset has to provide sufficient and suitable pre-injection information to enable injection-related changes to be adequately identified and characterised.

Potentially suitable baseline tools are listed below (brackets signify possible cost-effective alternative):

- 3D seismic

- (2D seismic)
- Seabed imaging by multibeam echo sounding and/or sidescan sonar
- Bubble stream detection, measurement and mapping
- Baseline monitoring in any surveillance wells

8.4.2.2 INJECTION STAGE MONITORING

In terms of the core monitoring programme, activities will be most intense during the injection stage. The four principal core monitoring objectives (see Section 8.2.1) are all applicable.

Comparison of actual site behaviour with modelled behaviour (model verification) and calibration of predictive modelling.

For Type 2 sites the main performance indicator in comparing actual site behaviour with modelled behaviour is plume migration, sweep or storage efficiency (whether or not the plume spreads uniformly through the reservoir pore-space or preferentially utilises high permeability pathways, by-passing the pore-space), closely followed by reservoir pressure.

3D and 2D time-lapse seismic: Type 2 reservoirs cover a range of depths but in general are likely to be suitable for time-lapse monitoring with surface seismic methods, a proven and mature technology.

The key non-invasive technology for plume-tracking is 3D time-lapse seismic which provides spatially continuous and uniform subsurface coverage with high resolution. Required resolution capabilities for a particular storage site will depend on the type of uncertainties inherent in the predictive flow modelling.

The repeat time-lapse interval for 3D seismic depends on the predicted plume geometry and the nature of modelling uncertainties, but is likely to be in the range of 2-3 years initially, increasing to ~ 5 years as the project proceeds.

In most Type 2 sites, stratal dips are significant, and the dominant migration direction should be reasonably well constrained, so it is likely to be cost-effective to deploy 2D surveys periodically rather than full 3D seismic.

Downhole pressure and temperature: Downhole P and T deployed in the injection wells is an important tool for testing and calibrating predictive flow simulations. Pressure measurements in other surveillance wells would also be desirable to help confirm reservoir flow properties and to constrain the wider reservoir pressure increase.

Other invasive surveys: The deployment of other well-based tools in Type 2 sites, possibly in remotely situated surveillance wellbores would likely depend on the availability and distribution of pre-existing well infrastructure. If a suitable wellbore were available in an appropriate location then saturation logging (RST) and possibly geochemical monitoring would provide useful local detail for model verification.

Demonstration of no detectable leakage.

Demonstration of no detectable leakage depends on demonstrating an absence of time-lapse changes in the overburden or at the seabed, combined with a robust site characterisation. In Type 2 sites which are saline aquifers, the topseal is not a proven hydrocarbon seal, so possible heterogeneities in the overburden must be monitored.

3D time-lapse seismic: This is the only proven and mature tool that provides continuous volumetric coverage of the overburden with high resolution. It should be deployed periodically to demonstrate that time-lapse changes in the overburden are not developing. It may not be necessary to acquire 3D seismic over the full baseline area at every repeat, but rather to focus on identified potential migration pathways such as faults that have been identified on the 3D baseline. Full volumetric coverage of the overburden must be obtained periodically however, by ensuring that the cumulative spatial coverage of successive repeat surveys achieves this.

Seabed imaging: Seabed surveys are inexpensive and can be integrated with conventional or high resolution seismic surveys. Careful assessment will be required to distinguish significant time-lapse changes from naturally-occurring effects.

Bubble-stream detection: Additional assurance for zero leakage could be provided by bubble-stream detection surveys. These could be acquired periodically to ensure no significant changes are occurring (changes of bubble stream density in a pre-existing stream, or development of a new stream). For cost-effective data acquisition bubble-stream detection and seabed imaging can be acquired together and also integrated with surface seismic acquisition.

Downhole pressure and temperature: Downhole pressure measurement in the reservoir and also in the overburden, particularly if deployed in the injection well, can help to monitor whether CO_2 is migrating out of the reservoir.

The non-invasive and downhole monitoring systems deployed in combination should be sufficient to demonstrate no leakage. In common with all monitoring tools, these systems have finite detection capability (e.g. a few thousand tonnes or less for 3D seismic), but, in combination with a secure topseal and overburden characterisation, 'no detectable leakage' should amount to a robust statement regarding site performance. In demonstrating leakage performance, due account must also be taken of specific containment risks (see below).

Effective monitoring of identified containment risks.

For Type 2 storage sites the main containments risks are migration along wellbores, and migration through geological flaws in the topseal and overburden. Induced geomechanical effects may also be significant where faulted caprocks are coincident with areas where predicted pressure increase is significant. In general terms, monitoring of containment risks would form a subset of the more general strategy for monitoring to prove no detectable leakage (see above).

Wellbores

The condition of wellbores will have been assessed during site characterisation but some well integrity risks may remain. The main difference compared to Type 1 sites is the fact that plume migration can be predicted and imaged, so the necessity of monitoring these wells will depend on the likelihood and timing of the CO_2 plume impacting on any given wellbore. This will have been assessed as part of the FRAM and different wellbores will be prioritised for monitoring. For wellbores that are expected to be impacted by the plume, core monitoring will likely be non-invasive (unless downhole monitoring systems are already deployed for other purposes) and probably integrated within similar surveys deployed for leakage detection (see above).

Modelling in Chapter 4 addresses the case of wellbore leakage for a Type 2 site. The assumed leaky wellbore flow permeabilities (1000 mD) are fairly arbitrary based on a judgement of likely values for migration outside of the casing, but nevertheless the modelling does provide some useful illustrative figures. It suggests that where reservoir pressures remain below hydrostatic, wellbore leakage will be very small (cf. Type 1 sites). For reservoir pressures significantly above hydrostatic (Case 3_well) it may be that CO_2 could reach overburden formations very soon (< 1 to 5 years) after CO_2 arrives at the wellbore in the reservoir. Modelled flow rates impacting the reservoir / wellbore interface place a useful upper limit on possible CO_2 transport into any overburden formation, and range from around 50 to 400 tonnes per year. This suggests that several thousand tonnes of CO_2 could be available for accumulation within overburden formations during the injection phase. The modelling also suggests that CO_2 could reach the seabed within 10 years of arriving at the reservoir / wellbore interface. Modelled flow rates at the seabed are very low (<0.1 tonnes per year), but if wellbore permeability were higher (for example if migration were to occur inside a largely unobstructed wellbore), then seabed flow rate could be similar to that at the reservoir / wellbore interface.

Monitoring for wellbore migration must therefore cover the range of eventualities.

3D and 2D seismic: The 3D time-lapse surveys would provide the main basis for establishing whether there is evidence of migration up the outside of the wellbore and laterally into the overburden. Depending on the perceived vulnerability of the wellbores, additional high-resolution 2D surveys, possibly in star-configuration over the wellbores, could be deployed.

Seabed imaging and bubble stream detection: Repeat surveys should be acquired over the seabed footprints of the wellbores (including any deviation in the wellbore trajectories and sidetracks), particularly to identify migration inside the wellbore.

Migration pathways in the overburden

Generic candidate features for possible overburden migration would be faults, gas chimneys or stratigraphical features such as connected sand bodies.

Modelling in Chapter 4 addresses the scenarios for fault leakage in a Type 2 site. Fault flow permeabilities represent hypothetical worst-case scenarios, but nevertheless the modelling does provide some useful illustrative figures. The potential for migration out of the reservoir is greater for the modelled leaky fault than for the modelled leaky well (due to the much greater lateral extent of the former), but there is considerable sensitivity to the reservoir pressure conditions. Thus for the underpressured case (Case 1_fault), flow rates into the overburden increase to 55 ktonnes per year mid-way through the injection phase, giving the potential for readily detectable accumulations. On the other hand only trace amounts of CO_2 reach the seabed, even centuries after injection (Table 4-8). For higher reservoir pressures (Case 3_fault) much larger amounts of CO_2 are available for accumulation in the overburden and significant amounts of CO_2 may reach the seabed on extended timescales (Table 4-8). In absolute terms the figures are relatively meaningless as they assume that the faults are permeable to seabed and assigned flow properties are arbitrary, but they do show the much greater potential for migration out of overpressured reservoirs compared with underpressured ones.

3D and 2D seismic: The 3D time-lapse surveys would provide the main basis for establishing whether there is evidence of migration up faults and laterally into the overburden. Cost-effective monitoring by 2D seismic deployed over vulnerable faults could also be deployed, with the proviso that full volumetric coverage would not be obtained.

Seabed imaging and bubble stream detection: Repeat surveys should be acquired over the seabed footprints of the plume and any identified features in the overburden which may signify possible migration pathways. These can be integrated with the surface seismic surveys.

Lateral migration into neighbouring assets

The key issue here is to track lateral spread of the CO_2 plume, and 3D seismic provides the most accurate means of doing this (tracers may also be useful to establish the source of CO_2 in areas of multiple stores). For Type 2 sites, generally utilising well-defined structural closures, unexpected lateral migration would be less likely to occur than with other site types.

Induced geomechanical effects

Detailed site characterisation will establish *in situ* stresses, the degree of structural compartmentalisation and reservoir dimensions. In Type 2 sites it is likely that these parameters will be such that monitoring for geomechanical effects in the core monitoring programme will be adequately covered by downhole pressure and temperature measurements in the injection wells (where pressure change will be highest) and in any available surveillance wells.

<u>*Indication of significant performance irregularities that may lead to a risk of leakage or a risk to the environment or human health*</u>

Irregularities may be identified in the course of monitoring for any of the objectives above. If these are deemed to be significant, particularly with the potential to lead to leakage, then additional monitoring will be required (see Section 8.4.3). Perhaps the most significant monitoring action in this category would arise if changes in seabed or bubble-streams were detected. Measurements of the gas would then be required to establish the cause of the observed changes and whether or not it constituted a significant irregularity.

Seabed gas measurements: In situ measurements would be made using existing or developed sensors and/or samples of headspace gas and seawater would be collected and analysed by standard laboratory procedures to verify whether or not the gas is CO_2. If it is CO_2 then isotopic or tracer analysis would be carried out to test whether or not it could have come from the storage site. If this proves to be the case then the additional monitoring programme would be triggered.

8.4.2.3 POST-INJECTION MONITORING

The post-injection core monitoring programme has similar aims to the injection-phase monitoring. The emphasis is still on model verification and demonstrating lack of leakage, and any significant irregularities would still trigger the additional monitoring programme. A new requirement is to demonstrate robust longer-term prediction - in particular that the site is evolving towards long-term stability.

In general terms, preference will move further towards non-invasive monitoring systems, as the site operator seeks to complete and abandon their injection and any surveillance wellbores.

Comparison of actual site behaviour with modelled behaviour (model verification)

Monitoring requirements are similar to those of the injection phase. The frequency of time-lapse repeat is determined by the requirements of demonstrating site stabilization (see below).

Demonstration of no detectable leakage

Monitoring requirements are similar to those of the injection phase. For the leaking well scenario, flow modelling (Chapter 4) indicates that flow rates at the reservoir / wellbore interface and at the seabed are maintained at similar levels to the latter part of the injection phase. For leaking faults flow rates in the post injection phase may well exceed those of the injection phase.

Site stabilisation

There are three main site stabilization processes at Type 2 sites: pressure decline, spatial stabilization of the free CO_2 plume and geochemical stabilization.

Pressure decline

Type 2 sites will typically have large reservoir volumes but with a variable degree of hydraulic compartmentalisation. Post-injection pressure decline in the reservoir should therefore be significant and readily characterised within a few years by measurements in the injection and any other surveillance wells.

Spatial stabilization

Establishing the final location and disposition of the free CO_2 plume is a critical first step towards demonstrating long-term stabilization, because it determines the extent to which the plume may impact on new containment risks in the future. For Type 2 sites utilising a structural closure, and where no significant irregularities have arisen in the injection phase, this assessment should be reasonably straightforward. A single post-injection 3D seismic survey may suffice.

Geochemical stabilization

Geochemical processes are much slower than the physical processes governing migration of the free CO_2 plume and demonstrating that they are occurring is challenging. In a Type 2 storage site, dissolution / convection is an important medium to long-term stabilization process, acting on timescales ranging from decadal to millennial. Long-term flow simulations illustrate how dissolution /and convection should lead to stabilization, but some form of verification is likely to be required.

Geochemical monitoring is the key to establishing the onset of dissolution / convection. Downhole fluid sampling (e.g. for HCO_3^-) and pH measurement may or may not have been carried out in the injection phase depending on the availability of surveillance wells. If it had, then the presence of dissolved CO_2 would likely have been demonstrated. But simple dissolution is not the key parameter. It is more important to establish the onset of convection, which is the means by which new formation water can contact the plume and enable dissolution to continue in the longer-term. The best option is to deploy fluid sampling down dip of the plume (down the direction of inclination of the strata), where, if convection has begun, CO_2-saturated water sinking from the plume will be present. This would require a monitoring well, but a horizontal injection well could serve the purpose as it would lie beneath at least part of the plume and could therefore be expected to intersect any significant downward migration of CO_2-saturated brine.

Other specialised technologies may be of utility in demonstrating dissolution/convection when deployed beneath the plume, such as ultra-high resolution travel-time monitoring and borehole microgravimetry. Careful assessment of parameter variation and the measurement limitations of the tools would be required prior to deployment.

[N.B. Time-lapse resistivity logging at Nagaoka in Japan has been used as evidence of the onset of dissolution / convection. This is exceptionally useful for demonstrating the generic process. However formation water in Type 2 North Sea storage sites will be too saline for resistivity logging to be effective.]

8.4.3 Additional Monitoring Methodology

Unlike the core monitoring programme which is driven by high-level regulatory requirements, the additional monitoring programme is highly site-specific and driven by the demands of a particular performance irregularity. In this section therefore we discuss some monitoring strategies that would be useful in the context of the sort of irregularity that might be encountered at a Type 2 site.

Additional monitoring would be triggered by a performance irregularity that becomes significant enough to require additional information to secure and maintain site performance. It should provide the data necessary to track and characterise the irregularity and to design suitable remediation. In the event that the irregularity leads to or is likely to lead to leakage, the additional monitoring programme must provide the capability of measuring this leakage as required by the ETS.

Three principal additional monitoring objectives have been defined (see Section 8.2.2.

8.4.3.1 PROVISION OF ADDITIONAL DATA TO RE-DESIGN OR RE-CALIBRATE PREDICTIVE MODELS.

For Type 2 sites significant irregularities in predictive modelling are most likely to comprise either major discrepancies in the extent and direction of plume spread or unexpected pressure changes. Options for additional monitoring include additional and focussed deployment of technologies already utilised as part of the core monitoring programme or deployment of specialised monitoring tools. Deployment of downhole tools may be practicable in pre-existing well stock, but a specifically positioned new surveillance well is likely to be more effective. A new well would of course also be used to gain additional geological information to improve the reservoir characterisation.

<u>*Unexpected pressure changes*</u>

Unexpected pressure increase is evidence of problems with permeability connectivity in the reservoir. For scenarios where pressure is only recorded in the injection wells it may be necessary to obtain additional pressure measurements from elsewhere in the reservoir, allied to flow testing, to establish regional hydraulic connectivity.

Passive seismics: In Type 2 sites excessive pressure rise may lead to critical stressing of faults in the reservoir and overburden, leading to geomechanical instability. One way to monitor this is to deploy a passive seismic (microseismic) monitoring system which would give warning of seismic stress release around the reservoir. Because the long-term reliability of the technique is uncertain it would probably not be deployed as part of the core monitoring programme but rather as a contingency measure should a clear irregularity arise.

Unexpected pressure decrease may be an indicator of significant migration of CO_2 from the primary storage reservoir and would trigger additional monitoring focussed on establishing the cause of the pressure decrease and the design of suitable remediation (see below).

Discrepancies in plume spreading

Significant discrepancies in predicted and observed plume spreading within the reservoir are likely to be mostly due to imperfect understanding of reservoir internal structure and of the fine-scale flow processes and detailed saturation distributions in the constituent layers of the plume (sweep efficiency). Poorly-constrained top reservoir topography may also lead to significant discrepancies in plume behaviour. Unexpected migration of CO_2 into the overburden would trigger immediate additional monitoring.

3D and 2D time-lapse seismic: Additional repeat surface seismic focussed on the irregularities will help to gain improved understanding of migration pathways in the reservoir and more closely monitor the rate of the advancing CO_2 front to constrain reservoir flow parameters.

Downhole tools: A number of downhole tools can be used to obtain more detailed information on the internal structure of the plume, particularly CO_2 layer thicknesses and saturations. Highest resolution is obtained from geophysical logging tools such as the RST (Reservoir Saturation Tool), which is particularly effective when combined with fluid sampling. Borehole seismic methods such as 3D VSP (Vertical Seismic Profiling) can give higher resolution imaging of plume layers in the vicinity of the wellbore, a possible indicator of reservoir permeability structure. A variant on VSP, ultra-high resolution travel-time measurement, uses specialised downhole receivers deployed beneath the plume and is potentially a very powerful tool for constraining layer thickness. Borehole microgravimetry may also be useful in this respect.

8.4.3.2 PROVISION OF INFORMATION FOR REMEDIATION ACTIONS.

Monitoring focussed on remediation actions would be a response to irregularities which point to possible migration of CO_2 out of the reservoir that could lead to future leakage. Evidence of this would be, as discussed above, imaged migration of CO_2 into the overburden, excessive pressure increase or unexpected pressure loss in the reservoir. Monitoring is also required to establish the efficacy of the remedial actions.

The most likely cause of significant pressure loss would be migration along a either a wellbore or a fault. Vulnerable, accessible wellbores should be tested. Standard well integrity testing might include technologies to assess the current condition of the wellbore, such as cement bond logs, multifinger calipers and visual inspections for corrosion and scaling. Additional monitoring for evidence of fluid changes around the outside of the wellbore would be useful. Saturation logging and temperature logging would be most useful in this respect. Inaccessible wellbores are more problematical and non-invasive methods would have to be deployed. 2D surface seismic could be deployed in star configuration centred on the wellbores, to establish if significant fluxes are present outside the wellbores. The possibility of (more rapid) migration inside the wellbore would be covered by detailed monitoring: seabed imaging and bubble-stream detection in the first instance. Possible deployment of semi-permanent seabed monitoring systems around the well head should also be considered.

To test for migration along a fault, 2D surface seismic could be deployed transecting the more vulnerable fault systems.

If the above spatially-focussed methods do not establish the location of the irregularity, then additional 3D surface seismic may have to be acquired to accurately locate any time-lapse changes in the overburden.

Once the location, nature and severity of the irregularity are established, then a remediation plan would be developed.

8.4.3.3 Measurement of leakage for emissions quantification (under the ETS).

For Type 2 sites leakage scenarios of relevance are via a leaky wellbore, or via flaws in the caprock, particularly via a fault. Scoping calculations (Chapter 4) indicate that, due to the significant reservoir overpressures, all three leakage scenarios could lead to CO_2 emissions in quantities and at timescales within the monitoring period for storage sites. Results of the scoping calculations for specific scenarios relevant to Type 2 sites are summarised below and the components of a monitoring plan necessary to quantify the resultant emissions are listed.

Well leakage

For the well leakage case, leakage of free CO_2 to the seabed was estimated to take between 25 and 70 years and for dissolved CO_2 breakthrough was estimated to be 500 years. The earliest breakthrough was modelled in the 1_Well case. The peak flow rate of free CO_2 to the seabed was estimated to be between 0.025 and 0.085 t/yr at 500 years (end of simulation), with peak areal fluxes estimated to be between 0.19 and 0.68 t/m^2/yr, with highest fluxes in the 3_Well case. Estimated changes in pH for 1m^3 of seawater for a range of seawater displacement rates at peak free CO_2 flux rates, indicated pH decreased by between 1.14 and 1.84 pH units for free CO_2, which should be readily detectable. A change in pH due to dissolved CO_2 of 1.73 pH units is predicted.

Evidence from other studies (Chapter 4) suggests that emission points from wells are likely to be confined spatially to a few square metres of the seabed. However, CO_2 may migrate laterally along permeable strata away from the well bore before reaching the seabed. Tracking of this movement at depth is needed to determine the correct area to look for and measure fluxes. An appropriate technology for this is high-resolution 2D seismic profiles arranged in a star pattern centred on the wellhead.

For well leakage, the key measured parameter is the flow of free CO_2 to the seawater. Measurement of free CO_2 flow would be by flux meter or by measuring bubbles using sonar, microphone or video techniques. Further development and testing of these technologies are required. The detection limits needed to measure the types of flow rate estimated above are unclear and instrumental robustness (especially if permanently deployed) is unproven. The sensors must be placed as close to the emission point as possible to ensure all bubbles are measured and the proportion of CO_2 dissolving into seawater prior to measurement is minimised. Bubble densities determined by remote methods such as multibeam/sonar offer the potential to measure CO_2 fluxes over larger areas. However further development is required to demonstrate the quantification capabilities of these non-invasive technologies.

In situ measurement of gas composition would be made using existing or developing techniques and/or samples of headspace gas and seawater would be collected and analysed to establish the gas composition including the proportions of any other components such as methane and H_2S, hydrocarbons and any added components such as tracers, as well as the proportion dissolved in the seawater. Temporal variations in the flow rates would also need to be established requiring repeat measurements at an initial interval of days to weeks. Where variations are not detected on this timescale, intervals between measurements may increase to up to every six months. The frequency of repeat measurements will depend on the temporal variability, with greater variations requiring increased frequency of measurement. Technologies for continuous emission detection and measurement are currently being developed and could be deployed at a leakage site.

Wells considered to have a higher risk of leakage may also have permanent monitoring stations deployed above them to detect and measure any leak. Inspection by ROV or diver further allows a visual check on flux variations. Evidence from other studies suggests that emission points from wells are likely to be confined spatially to a less than a few tens of m^2 of the seabed. However, CO_2 may migrate laterally along permeable strata away from the well bore before reaching the seabed.

Fault leakage

For the fault leakage case, breakthrough of free CO_2 to the seabed was estimated to between 50 and 260 years and for dissolved CO_2 breakthrough was estimated to be 45 to 220 years. Peak flow rate of free CO_2 to the seabed was estimated to be 5,600 to 38,000 t/yr at 500 years (end of simulation), with peak areal fluxes estimated to be between 0.012 to 0.061 t/m^2/yr. Peak flux of dissolved CO_2 to the seabed was estimated to vary from 20 t/yr at 300 years for the 1_Fault case to 160 t/yr at 60 years for the 3_Fault case. Peak areal fluxes of dissolved CO_2 are very small (less than 0.0003 t/m^2/yr) which are likely to be below detection thresholds. Estimated changes in pH for a range of free CO_2 flow rates, indicated pH decreased by between 1.14 and 2.23 pH units, which is easily detectable. A small change of up to 0.09 pH in seawater due to dissolved CO_2 is produced, which may be close to detection thresholds for current instruments

Caprock leakage

For the caprock leakage case, breakthrough of free CO_2 to the seabed was estimated to be between 60 and 280 years and for dissolved CO_2 between 25 and 240 years. Peak flow rate of free CO_2 to the seabed was estimated to be between 4,100 and 26,000 t/yr at 500 years (end of simulation). Peak flow of dissolved CO_2 was calculated to be between 56 t/yr at 120 years (for 1_Cap) and140 t/yr after 320 years (for 3_Cap). Peak areal fluxes were estimated to be 0.016 and 0.1 t/m^2/yr. Estimated changes in pH for a range of free CO_2 flux rates, indicated pH decreased by between 1.14 and 2.43 pH units, which is easily detectable. A small change of 0.19 pH in seawater due to dissolved CO_2 is produced, which is detectable by current technologies.

For both caprock and fault leakage, the seabed breakthrough of either free or dissolved CO_2 may occur on timescales relevant to the monitoring period. For these scenarios the area over which leakage is occurring must also be determined, for example by sidescan sonar, multibeam echo sounding or bubble-stream detection. Detection thresholds for these techniques have yet to be determined however.

Point flow measurements would then be deployed as described above.

In addition to the free CO_2 measurements described above, the scoping simulations indicate that significant amounts of dissolved CO_2 might also be present in the seawater column. For the ETS the monitoring plan should also be able to account for any dissolved component of leaked CO_2. This would require the use of sensors either to measure dissolved CO_2 directly or to measure pH. These technologies require further development. Seawater samples would be required to validate direct *in situ* measurements. These would need to be collected and preserved at in situ pressures and temperatures to ensure sample degassing did not affect the validity of the analysis. Where leakage is restricted to discrete bubble streams, each individual stream would need to be measured separately. Evidence from analogue studies (Chapter 4) indicates that this is more likely than larger more diffuse areal releases. Where only dissolved CO_2 is being emitted, towed pH and dissolved CO_2 sensors, for example mounted on a Conductivity-Temperature-Depth probe (CTD) deployed in the water column close to the seabed could be used to determine the footprint of leakage. However, such sensors will be limited by their detection capabilities and the scoping calculations described above indicate that expected pH changes may well be below current detection limits when considering leakage via a fault. Further development of techniques to measure dissolved CO_2 fluxes to the seabed are needed. The depth of the CTD deployment will reflect the degree of mixing between waters containing dissolved CO_2.

To satisfy the ETS an inventory of the total amount of CO_2 emitted from the storage site must be made on an annual basis. This will based on the fluxes measured and area over which the CO_2 is being emitted. Measurement would continue until monitoring indicates that remediation has been successful.

8.5 MONITORING METHODOLOGY FOR A TYPE 3 SITE

8.5.1 Site scenario

The Type 3 site comprises depleted hydrocarbon fields at depths of around 3km, bounded by variable-permeability faults with aquifer recharge in some fields. Top seals are mudstone caprocks proven to retain oil and natural gas. The overburden is generally unfaulted, comprising a thick sequence of sandstones and mudstones. Overall, the monitoring approach is similar to that of Type 1 sites, based around the assumption of secure geological seals and no significant faulting. In terms of the simulations in Chapter 4, the range of Type 3 sites spans all of the modelled Cases 1, 2 and 3, with pressures varying from under-pressured to sub lithostatic. The proposed storage at Miller in the central North Sea (Section 3.4) would fall into the Type 3 category.

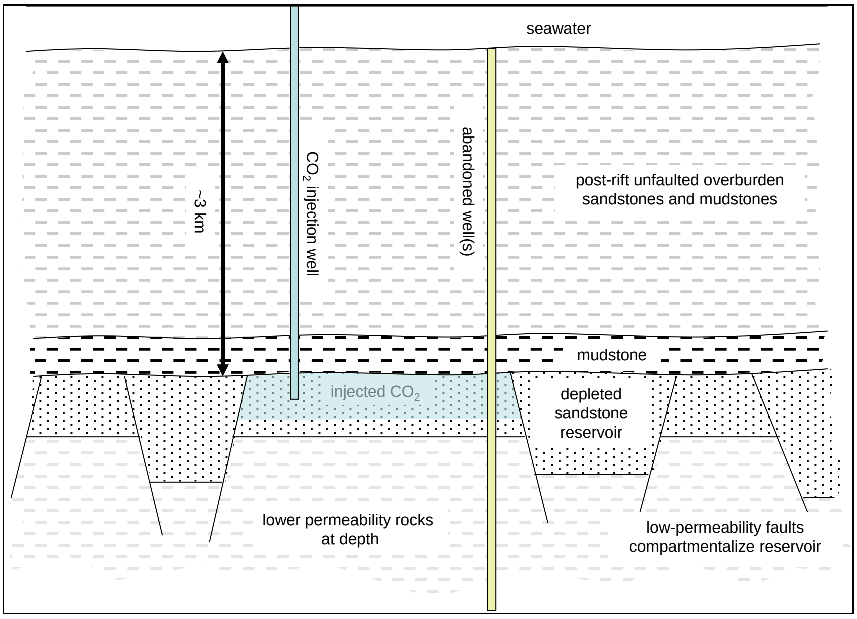

Figure 8-5 Type 3 storage site: depleted hydrocarbon (mostly oil) field Central / Northern North Sea

8.5.2 Core monitoring

Although perhaps not as secure as the salt top seals of Type 1 sites, the presence of thick proven seals in the central and northern North Sea reduces the need for plume imaging and monitoring of topseal integrity. Leakage via faults is considered a much lower risk than in Type 2 sites, but may still require some evaluation. The likely availability of wellbore infrastructure means that surveillance wells could play an important part in the monitoring strategy.

8.5.2.1 Pre-injection (baseline) monitoring

Tool deployment for baseline monitoring is driven by the needs of the injection-phase monitoring system which are described in the next section so will not be discussed in detail here. A fit-for-purpose baseline dataset has to provide sufficient and suitable pre-injection information to enable injection-related changes to be adequately identified and characterised.

Potentially useful baseline tools are listed below:

- Baseline monitoring in any surveillance wells (including Vertical Seismic Profiling, VSP)
- 2D seismic
- Seabed imaging (e.g. multibeam echo sounding and sidescan sonar)
- Bubble stream detection, measurement and mapping

The considerable depth, varied fluid content and varied pressures in Type 3 reservoirs are likely to render imaging of the plume within the reservoir with seismic quite challenging. Imaging of the shallower overburden is unaffected however. Because Type 3 sites are proven hydrocarbon traps, migration through the geological seals is considered to be very unlikely, so a dedicated 3D baseline survey may not be required. Legacy data are commonplace in the central and northern North Sea and a suitable dataset could be used for cost-effective baseline purposes to supplement the 2D seismic time-lapse surveys.

8.5.2.2 Injection stage monitoring

In terms of the core monitoring programme, activities will be most intense during the injection stage. The four principal core monitoring objectives (see Section 8.2.1) are all applicable.

<u>*Comparison of actual site behaviour with modelled behaviour (model verification) and calibration of predictive modelling*</u>

For Type 3 sites the main performance indicators in comparing actual site behaviour with modelled behaviour are reservoir pressure and plume migration.

VSP: Likely deployed in 3D mode with offset sources, VSP can offer improved seismic resolution compared to surface seismic methods. This is particularly useful in the deep reservoirs characteristic of Type 3 sites. 3D-VSP can provide spatial imaging of the plume in the vicinity of the wellbores, providing information on plume geometry and spreading rate. Time-lapse VSP demands good repeatability which requires permanently-placed downhole receivers.

Downhole pressure and temperature: Downhole P and T deployed in the injection wells is an important tool for testing and calibrating predictive flow simulations, both from the point of view of pressure evolution and also from constraining CO_2 fluid properties. Additional P, T monitoring on other surveillance wells is also likely to be deployed to test reservoir permeability and connectivity and the nature of the reservoir boundaries.

Downhole saturation logging: The reservoir saturation tool (RST) can provide high resolution information on fluid distributions, providing fine-scale information on plume structure. It should be deployed as required in the surveillance wells.

Downhole fluid sampling: Geochemical monitoring may well be deployed in surveillance wells across the reservoir to establish plume breakthrough (a key determinant of migration velocity and reservoir permeability) either by direct detection of CO_2 or via the deployment of tracers. The temporal accuracy of these methods depends on the repeat frequency of the surveys. Novel continuous monitoring methods such as the U-tube or continuous pH measurement would be very suitable for accurate timing of plume breakthrough.

Demonstration of no detected leakage

Leakage assurance in Type 3 sites depends on an absence of observed time-lapse changes in the overburden or at the seabed, combined with a robust site characterisation. In particular, the topseal is a proven hydrocarbon seal, so leakage risks are assumed to be restricted to the wellbores.

Downhole pressure: Pressure monitoring, in or above the reservoir, is a potentially powerful means of detecting fluid migration from the storage reservoir. An abrupt fall in reservoir pressure could signify leakage around a wellbore. Pressure monitoring above the topseal in surveillance wells would also be indicative of fluid flow.

Seabed imaging: Seabed surveys are inexpensive and can be integrated with conventional or high resolution seismic surveys. Careful assessment will be required to distinguish significant time-lapse changes from naturally-occurring effects. Surveys would be focussed on the seabed footprints of the wellbores (including any deviation in the wellbore trajectories and sidetracks).

Bubble-stream detection: Additional assurance for zero leakage could be provided by bubble-stream detection surveys. These could be acquired periodically to ensure no significant changes are occurring (changes in bubble stream density in a pre-existing stream, or development of a new stream). For cost-effective data acquisition bubble-stream detection and seabed imaging can be acquired together and also integrated with surface seismic acquisition.

In common with all monitoring tools, the systems have finite detection capability, but in combination with a secure topseal and overburden characterisation, ‘no detectable leakage’ should amount to a robust statement regarding site performance. In demonstrating leakage performance, due account must also be taken of specific containment risks (see below).

Effective monitoring of identified containment risks

Migration along wellbores

Type 3 storage sites have a proven hydrocarbon seal, so specific containment risks are restricted to the wellbores and, to a much lesser extent faults. The condition of wellbores will have been assessed during the site characterisation but some well integrity risks may remain. The necessity of monitoring these wells will depend on the likelihood and timing of the CO_2 plume impacting on any given wellbore. This will have been assessed as part of the FRAM and different wellbores will be prioritised for monitoring. For wellbores that are expected to be impacted by the plume, core monitoring will likely be non-invasive (unless downhole monitoring systems are already deployed for other purposes) and probably integrated within similar surveys deployed for leakage detection (see above).

The flow modelling in Chapter 4 suggests that applicable wellbore leakage scenarios (Case 2_well and Case 3_well) can provide some useful conceptual figures. If reservoir pressures do rise significantly above hydrostatic (Case 3 models) the modelling suggests that CO_2 will reach overburden formations very soon (< 1 to 5 years) after CO_2 arrives at the wellbore in the reservoir. Modelled flows impacting the reservoir / wellbore interface place a useful upper limit on possible CO_2 transport into any overburden formation (Figure 4-13). They range from an initial 50 tonnes per year to around 400 tonnes per year after a decade or so. This suggests that several thousand tonnes of CO_2 could be available for accumulation within overburden formations during the injection phase. The modelling also suggests that CO_2 will reach the seabed within 10 years of arriving at the reservoir/wellbore interface. Modelled flow rates at the seabed are very low (<0.1 tonnes per year), but if wellbore permeability were higher (for example if migration were to occur inside a largely unobstructed wellbore), then seabed flow rate could be similar to that at the reservoir / wellbore interface; around 400 tonnes per year after a decade or so. If reservoir pressures do not rise significantly above hydrostatic however (Case 2 models), flow rates and amounts of CO_2 will be much lower.

The figures do of course depend on the assumed flow parameters which are not well constrained. They are quite conservative for migration outside of the casing, but migration inside an unobstructed wellbore would lead to greater amounts of leakage.

Monitoring in surveillance wells as part of the core monitoring programme may involve deployment of downhole tools. Low cost permanent sensors such as pH measurement would be favoured.

2D seismic: 2D seismic surveys would provide the main basis for establishing whether there is evidence of migration up the outside of the wellbore and laterally into the overburden. These would be deployed in star-configuration over the wellbores and also across any faults considered to be at risk. The 2D surveys could be integrated in a cost-effective manner with seabed imaging and bubble-detection.

Seabed imaging and bubble stream detection: Repeat surveys should be acquired over the seabed footprints of the wellbores (including any deviation in the wellbore trajectories and sidetracks), particularly to identify migration inside the wellbore.

Seabed surveys (imaging and bubble detection) would be deployed for assurance.

Migration pathways in the overburden

For Type 3 sites migration through the geological seals is considered unlikely. Faults provide much the likeliest potential pathway, and any movement of CO_2 into faults should be covered by 2D seismic as deployed above.

Lateral migration into neighbouring assets

Lateral migration of CO_2 in and around the storage reservoir would be covered by the downhole monitoring and the 2D seismic.

Induced geomechanical effects

Type 3 sites with their low initial pressures and considerable reservoir depth are not considered to be particularly vulnerable to geomechanical effects. Downhole pressure monitoring on the injection wells and a number of surveillance wells should be sufficient to control pressure evolution in the reservoir.

<u>Indication of significant performance irregularities that may lead to a risk of leakage or a risk to the environment or human health.</u>

Irregularities may be identified in the course of monitoring for any of the objectives above. If these are deemed to be significant, particularly with regard to potential leakage, or migration into neighbouring assets, then additional monitoring will be required (see Section 8.5.3). Perhaps the most significant monitoring action in this category would arise if changes in seabed or bubble-streams were detected. Measurements of the gas would then be required to establish the cause of the observed changes and whether or not it constituted a significant irregularity.

Seabed gas measurements: In situ measurements would be made using existing or developed sensors and/or samples of headspace gas and seawater would be collected and analysed by standard laboratory procedures to verify whether or not the gas is CO_2. If it is CO_2 then isotopic or tracer analysis would be carried out to test whether or not it could have come from the storage site. If this proves to be the case then the additional monitoring programme would be triggered.

8.5.2.3 POST-INJECTION MONITORING

The post-injection core monitoring programme has similar aims to the injection-phase monitoring. The emphasis is still on model verification and demonstrating lack of leakage, and any significant irregularities would still trigger the additional monitoring programme. A new requirement is to demonstrate robust longer-term prediction - in particular that the site is evolving towards long-term stability.

In general terms, preference will move further towards non-invasive monitoring systems, as the site operator seeks to complete and abandon their injection and any surveillance wellbores.

Comparison of actual behaviour with modelled behaviour (model verification)

Monitoring requirements are similar to those of the injection phase. The frequency of time-lapse repeat is determined by the requirements to demonstrate site stabilization (see below).

Demonstration of no detectable leakage

Monitoring requirements are similar to those of the injection phase. For the leaking well scenario, flow modelling (Chapter 4) indicates that flow rates at the reservoir / wellbore interface and at the seabed are maintained at similar levels to the latter part of the injection phase, with a nominal 500 tonnes per year impacting on the wellbores in the reservoir (Figure 4-13). This leads to the possibility of significant accumulation in suitable overburden formations. Modelled flow rates at the seabed are still very small. It may be that a first repeat 3D seismic survey at this stage would provide assurance that no significant amounts of CO_2 have migrated anywhere in the overburden, to support the case for transfer of responsibility.

Site stabilisation

There are two main site stabilization processes at Type 3 sites: pressure decline, spatial stabilization of the CO_2 plume and geochemical stabilization.

Pressure decline

Type 3 sites will typically have intra reservoir flow boundaries, so pressure decline may be slow. It may be possible to distinguish pressure decline due to the onset of dissolution from pressure decline due to unwanted migration into neighbouring assets by geochemical monitoring (see below).

Spatial stabilization

Establishing the final location and disposition of the free CO_2 plume is important for Type 3 sites because it determines the extent to which the plume may impact on new containment risks in the future, particularly neighbouring assets. Cost-effective monitoring need not cover the whole plume, but rather that part of the leading migrating edge which is generating the uncertainty. Depending on details of the particular storage site, post-injection 2D seismic surveys will likely be required.

Geochemical stabilization

Geochemical processes are much slower than the physical processes governing migration of the free CO_2 plume and demonstrating that they are occurring is much more challenging. In a Type 3 storage site the onset of dissolution / convection may be detectable by downhole fluid sampling, including pH measurement.

8.5.3 Additional Monitoring Methodology

Unlike the core monitoring programme which is driven by high-level regulatory requirements, the additional monitoring programme is highly site-specific and driven by the demands of a particular performance irregularity. In this section therefore we discuss some monitoring strategies that would be useful in the context of the sort of irregularity that might be encountered at a Type 3 site.

Additional monitoring would be triggered by a performance irregularity that becomes significant enough to require additional information to secure and maintain site performance. It should provide the data necessary to track and characterise the irregularity and to design suitable remediation. In the event that the irregularity leads to or is likely to lead to leakage, the additional monitoring programme must provide the capability of measuring this leakage as required by the ETS.

Three principal objectives for additional monitoring have been defined (see Section 8.2.2).

8.5.3.1 PROVISION OF ADDITIONAL DATA TO RE-DESIGN OR RE-CALIBRATE PREDICTIVE MODELS.

For Type 3 sites significant irregularities in predictive modelling are most likely to comprise unexpected pressure changes and discrepancies in plume spreading. Options for additional monitoring include additional and focussed deployment of technologies already utilised as part of the core monitoring programme or deployment of new, specialised monitoring tools.

Unexpected pressure changes

Unexpected pressure increase suggests problems with permeability connectivity in the reservoir. For scenarios where pressure is only recorded in the injection wells it may be necessary to obtain additional pressure measurements from elsewhere in the reservoir, allied to flow testing, to establish regional hydraulic connectivity.

Unexpected pressure decrease may be an indicator of significant migration of CO_2 from the primary storage reservoir and would trigger additional monitoring focussed on establishing the cause of the pressure decrease and the design of suitable remediation (see below).

Discrepancies in plume spreading

Significant discrepancies in predicted and observed plume spreading within the reservoir, as indicated by well breakthrough times, are likely to be due to imperfect understanding of reservoir internal structure and of the fine-scale flow processes and detailed saturation distributions in the constituent layers of the plume.

Downhole tools: A number of downhole tools can be used to obtain more detailed information on the internal structure of the plume, particularly CO_2 layer thicknesses and saturations. Highest resolution is obtained from geophysical logging tools such as the RST (Reservoir Saturation Tool), which is particularly effective when combined with fluid sampling. Borehole seismic methods such as 3D VSP (Vertical Seismic Profiling) can give higher resolution imaging of plume layers in the vicinity of the wellbore, a possible determinant of reservoir permeability structure. A variant on VSP, ultra-high resolution travel-time measurement, uses specialised downhole receivers deployed beneath the plume and is potentially a very powerful tool for constraining layer thickness. Borehole microgravimetry may also be useful in this respect.

Crosshole seismic can give 2D spatial imaging of plume layers in the vicinity of the wellbore, and combined with the RST can give indications of fluid saturations in 2D. However there are technical issues regarding its implementation, reliability and infrastructure requirements (Chapter 10, Volume 2). Borehole microgravimetry may also be useful in assessing CO_2 layer thicknesses.

8.5.3.2 PROVISION OF INFORMATION FOR REMEDIATION ACTIONS.

Monitoring focussed on remediation actions would be a response to irregularities which point to possible migration of CO_2 out of the reservoir, either up a wellbore or laterally into a neighbouring asset. Monitoring is also required to establish the efficacy of the remedial actions.

The former would most likely be identified by significant pressure loss. Depending on the amount of risk-focussed monitoring, the vulnerable wellbore might be readily identifiable. Otherwise a repeat 3D survey, integrated with seabed imaging and bubble detection may be the most effective option. Once the location, nature and severity of the irregularity are established, then a suitable remediation plan would be developed.

Unwanted lateral migration of the plume is a difficult issue to address. It may be that monitoring in a neighbouring asset may be required.

8.5.3.3 MEASUREMENT OF LEAKAGE FOR EMISSIONS QUANTIFICATION (UNDER THE ETS).

Type 3 sites are similar to Type 1 sites in that by far the most likely leakage scenario is via migration along a wellbore. Fault and caprock leakage scenarios are not considered. Due to the higher reservoir pressures, and non-salt topseal, potential leakage rates are higher than for Type 1 sites. Scoping simulations (Chapter 4.3, Case 1_Well) indicate that significant well leakage might occur at relevant timescales. The simulations have further established the broad scale of leakage, including possible breakthrough times, albeit with poorly-constrained flow parameters.

Well leakage

For the well leakage case, breakthrough of free CO_2 at the seabed was estimated to be between 25 and 70 years and for dissolved CO_2 around 500 years. Earliest breakthrough is modelled in the 1_Well case. Peak flux of free CO_2 to the seabed was estimated to be between 0.025 and 0.085 t/yr at 500 years (end of simulation), with peak areal fluxes estimated to be between 0.19 and 0.68 t/m^2/yr, with highest fluxes in the 3_Well case. Modelling indicates no dissolved CO_2 is expected to reach the seabed. Estimated changes in pH for 1m^3 of seawater for a range of seawater displacement rates at peak free CO_2 flux rates, indicated pH decreased by between 1.14 and 1.84 pH units for free CO_2, which is easily detectable. A change in pH due to dissolved CO_2 of 1.73 pH units is predicted.

Evidence from other studies (Chapter 4) suggests that emission points from wells are likely to be confined spatially to a few square metres of the seabed. However, CO_2 may migrate laterally along permeable strata away from the well bore before reaching the seabed. Tracking of this movement at depth is needed to determine the correct area to measure fluxes. An appropriate technology for this is high-resolution 2D seismic profiles arranged in a star pattern centred on the wellhead.

For well leakage, the key measured parameter is the flow of free CO_2 to the seawater. Measurement of free CO_2 flow would be by flux meter or by measuring bubbles using sonar, microphone or video techniques. Further development and testing of these technologies is required. The detection limits needed to measure the types of flow rate estimated above are unclear and instrumental robustness (especially if permanently deployed) is unproven. The sensors must be placed as close to the emission point as possible to ensure all bubbles are measured and the proportion of CO_2 dissolving into seawater prior to measurement is minimised. Bubble densities determined by remote methods such as multibeam/sonar offer the potential to measure CO_2 fluxes over larger areas. However further development is required to demonstrate the quantification capabilities of these non-invasive technologies.

In situ measurements of gas composition would be made using existing or developed techniques and/or samples of headspace gas and seawater would be collected and analysed to establish the gas composition including the proportions of any other components such as methane and H_2S, hydrocarbons and any added components such as tracers, as well as the proportion dissolved in the seawater. Temporal variations in the flow rates would also need to be established requiring repeat measurements at an initial interval of days to weeks. Where variations are not detected on this timescale, intervals between measurements may increase to up to every six months. The frequency of repeat measurements will depend on the temporal variability, with greater variations requiring increased frequency of measurement. Technologies for continuous emission detection and measurement are currently being developed and could be deployed at a leakage site. Inspection by ROV or diver further allows a visual check on flux variations.

Wells considered to have a higher risk of leakage may also have permanent monitoring stations deployed above them to detect and measure any leak

To satisfy the ETS an inventory of the total amount of CO_2 emitted from the storage site must be made on an annual basis. This will based on the fluxes measured and area over which the CO_2 is being emitted. Measurement would continue until monitoring indicates that remediation has been successful.

8.6 MONITORING METHODOLOGY FOR A TYPE 4 SITE

8.6.1 Site scenario

The Type 4 site comprises a laterally extensive sandstone aquifer between 0.8 and about 2 km depth, with a mudstone topseal. The largely unfaulted overburden is dominated by mudstones with sandstone lenses and may contain topseal flaws such as connected sand bodies or chimneys of residual gas (Figure 8-6). Because these sites do not have a proven geological seal and some Type 4 sites are flat-lying, monitoring must be laterally extensive to provide full spatial coverage of the overburden. Other Type 4 reservoirs were deposited on basin margins and their relatively large lateral extent increases the potential for migration up dip (i.e. up the inclined rock strata). In terms of the simulations in Chapter 4, Type 4 sites correspond to the modelled Case 2 with pressures somewhat above hydrostatic. The current storage site at Sleipner (Section 3.3) corresponds broadly to a Type 4 site.

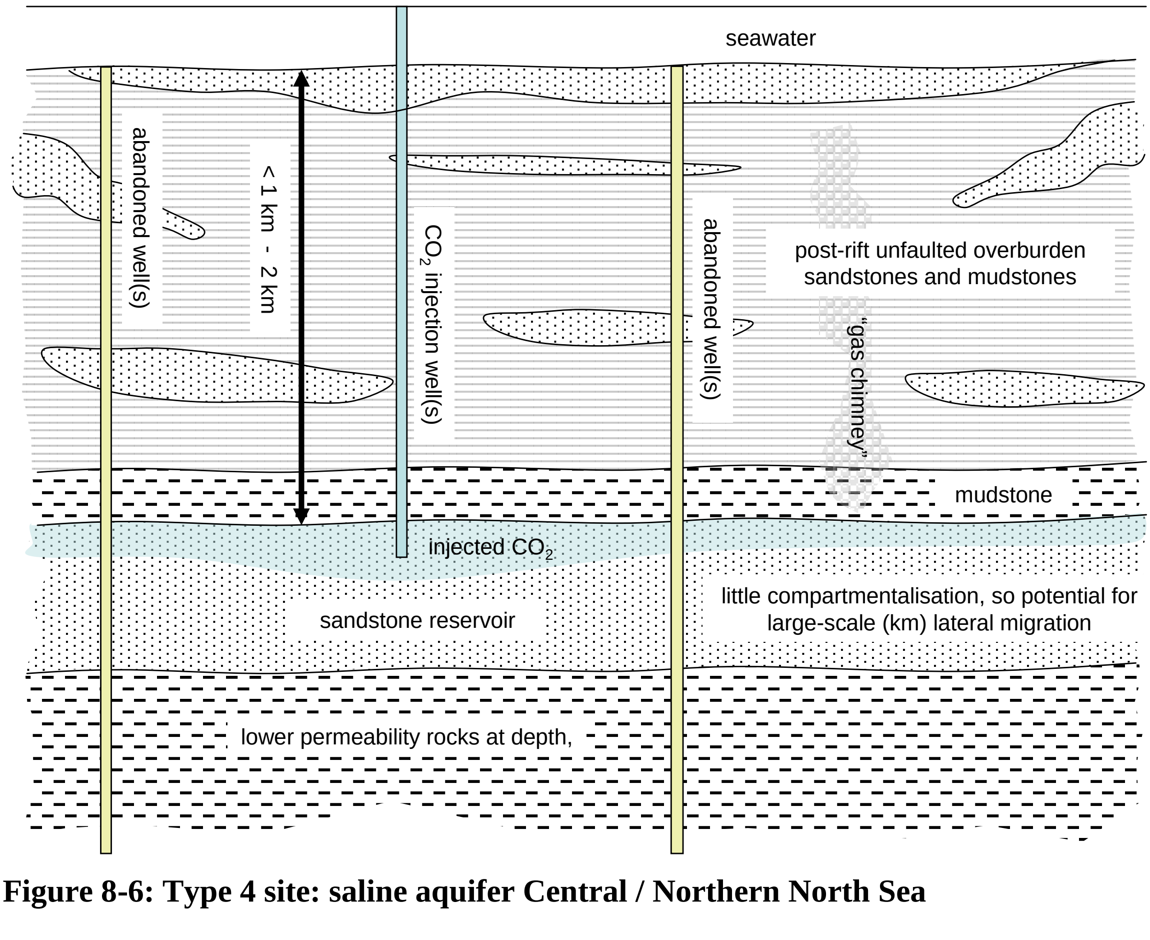

Figure 8-6: Type 4 site: saline aquifer Central / Northern North Sea

8.6.2 Core monitoring

Within the core monitoring programme, objectives will evolve during the four stages of the project lifetime (Figure 8-2). Type 4 sites tend to have quite flat-lying reservoir tops, so plume migration can be considerable, perhaps tens of square kilometres. Monitoring systems will therefore have to cover wide areas and non-invasive tools will form the principal component of the monitoring strategy.

8.6.2.1 Pre-injection (baseline) monitoring

Tool deployment for baseline monitoring is driven by the needs of the injection-phase monitoring system which are described in the next section so will not be discussed in detail here. Suffice to say that a fit-for-purpose baseline dataset has to provide sufficient and suitable pre-injection information to enable injection-related changes to be adequately identified and characterised.

Potentially suitable baseline tools are listed below:

- 3D seismic
- (2D seismic)
- Seabed imaging (multibeam echo sounding)
- Bubblestream detection, measurement and mapping
- Baseline monitoring in any surveillance wells

8.6.2.2 Injection stage monitoring

In terms of the core monitoring programme, activities will be most intense during the injection stage.

The four principal core monitoring objectives (see Section 8.2.1), are all applicable during this stage.

Comparison of actual site behaviour with modelled behaviour (model verification) and calibration of predictive modelling.

For Type 4 sites the main performance indicator in comparing actual site behaviour with modelled behaviour is plume migration including sweep or storage efficiency (whether or not the plume spreads uniformly through the reservoir pore-space or preferentially utilises high permeability pathways, by-passing the pore-space), and reservoir pressure.

3D and 2D time-lapse seismic: Type 4 reservoirs are relatively shallow with high porosity and high mechanical compliance. This renders them particularly suitable for time-lapse monitoring with surface seismic methods, a proven and mature technology.

The key non-invasive technology for plume-tracking is 3D time-lapse seismic which provides spatially continuous and uniform subsurface coverage with high resolution. History-matching at Sleipner has shown that to image the broad aspects of plume spreading and migration beneath the topseal requires the detection of CO_2 layers of the order of 5 m thick or less. More subtle aspects of CO_2 migration, particularly rapidly migrating thin streamers, which determine sweep efficiency, require a detection capability in the order of 2 m or less. Whether these stringent resolution capabilities will actually be required for a particular storage site will depend on the type of uncertainties in the predictive flow modelling utilised in the FRAM.

The repeat time-lapse interval for 3D seismic depends on predicted plume geometry and the nature of modelling uncertainties, but is likely to be in the range 2-3 years initially, increasing to ~ 5 years as the project proceeds.

It may well be cost-effective to deploy 2D surveys periodically rather than full 3D seismic.

Downhole pressure and temperature: Downhole P and T deployed on the injection wells is an important tool for testing and calibrating predictive flow simulations, both from the point of view of pressure evolution and also from constraining CO_2 fluid properties.

The deployment of other well-based tools in Type 4 sites, possibly in remotely situated surveillance wellbores would likely depend on the availability and distribution of pre-existing well infrastructure. If a suitable wellbore were available in an appropriate location, as determined by predictive reservoir simulation, then pressure, saturation logging and possibly geochemical monitoring would provide useful local detail for model verification. However in general terms, given the likely wide plume spread, invasive monitoring would not necessarily be cost-effective as a significant number of wells might be required.

Demonstration of no detectable leakage.

Demonstration of zero leakage depends on demonstrating an absence of time-lapse changes in the overburden or at the seabed, combined with a robust site characterisation. In Type 4 sites the topseal is not a proven hydrocarbon seal, so possible heterogeneities in the overburden must be monitored.

3D time-lapse seismic: This is the only proven tool that provides continuous high resolution volumetric coverage of the overburden. It should be deployed periodically to demonstrate that time-lapse changes in the overburden are not occurring. It may not be necessary to acquire 3D seismic over the full baseline area at every repeat, but rather to focus on potential migration pathways such as gas chimneys that have been identified on the 3D baseline. Full volumetric coverage of the overburden must be obtained periodically however, by ensuring the cumulative spatial coverage of successive repeat surveys achieves this.

Seabed imaging: Seabed surveys are inexpensive and can be integrated with conventional or high resolution seismic surveys. Careful assessment will be required to distinguish significant time-lapse changes from naturally-occurring effects.

Bubble-stream detection: Additional assurance for zero leakage could be provided by bubble-stream detection surveys. These could be acquired periodically to ensure no significant changes are occurring (changes in bubble stream density in a pre-existing stream, or development of a new stream). For cost-effective data acquisition bubble-stream detection and seabed imaging can be acquired together and also integrated with surface seismic acquisition.

Downhole pressure and temperature: In the large permeable aquifers characteristic of Type 4 storage, downhole reservoir pressure and temperature measurements deployed in the injection well are unlikely to provide particularly sensitive indications of migration into the overburden.

The three non-invasive time-lapse monitoring systems deployed in combination should be sufficient to demonstrate no leakage. In common with all monitoring tools, the systems have finite detection capability (e.g. a few thousand tonnes or less for 3D seismic), but, in combination with a credible topseal and overburden characterisation, 'no detectable leakage' should amount to a robust statement regarding site performance. In demonstrating leakage performance, due account must also be taken of specific containment risks (see below).

Effective monitoring of identified containment risks.

For Type 4 storage the main containments risks are migration along wellbores, migration through geological flaws in the topseal and overburden, and lateral migration into neighbouring commercial assets. Induced geomechanical effects are also discussed. In general terms, monitoring of containment risks would form a subset of the more general strategy for monitoring to prove zero leakage (see above).

Migration along wellbores

Well integrity risks are likely to be present in Type 4 storage sites and the condition of wellbores will have been assessed during the site characterisation.

The necessity of monitoring these wells will depend on the likelihood and timing of the CO_2 plume impacting on any given wellbore. This will have been assessed as part of the FRAM. For wellbores that are expected to be impacted by the plume, core monitoring will likely be non-invasive and probably integrated within similar surveys deployed for leakage detection (see above).

Modelling in Chapter 4 addresses the case of wellbore leakage for a Type 4 site (Case 2_well). The leaky wellbore flow permeabilities are poorly-constrained, tending towards worst-case scenarios, but nevertheless the modelling does provide some useful conceptual figures. It suggests that CO_2 flow rates could reach overburden formations very soon (< 1 to 5 years) after CO_2 arrives at the wellbore in the reservoir. Modelled flow rates impacting the reservoir / wellbore interface place a useful upper limit on possible CO_2 transport into any overburden formation. They range from around 20 to 50 tonnes per year. This suggests that a few thousand tonnes of CO_2 could be available for accumulation within overburden formations during the injection phase. The modelling also suggests that CO_2 could reach the seabed within 15 years of arriving at the reservoir / wellbore interface. Modelled flow rates at the seabed are very low (<0.1 tonnes per year), but if leaky wellbore permeabilities were higher (for example if migration were to occur inside a largely unobstructed wellbore), then seabed flow rate could be similar to that at the reservoir / wellbore interface.

These figures indicate that CO_2 migration along (outside) a leaky wellbore could be potentially detectable by surface seismic methods during the injection phase, via migration into overburden formations. It may also be detectable by bubble-stream methods at the seabed. If flow at the aquifer/wellbore interface can be efficiently transmitted to the seabed (for example via migration inside an unobstructed wellbore) then this should give rise to effects also detectable on seabed imaging surveys. Conversely, this latter scenario may preclude significant lateral migration into the overburden, rendering it seismically undetectable.

Monitoring for along wellbore migration must therefore cover a range of eventualities.

3D and 2D seismic: The 3D time-lapse surveys would provide the main basis for establishing whether there is evidence of migration ups the outside of the wellbore and laterally into the overburden. Depending on the perceived vulnerability of the wellbores, additional high-resolution 2D surveys, possibly deployed in star-configuration over the wellbores could be deployed.

Seabed imaging: Repeat surveys should be acquired over the location of wellbores threatened by the CO_2 plume.

Bubble-stream detection: Repeat surveys should be acquired over the location of wellbores threatened by the CO_2 plume.

Migration pathways in the overburden

Generic candidate features for possible overburden migration would be gas chimneys, stratigraphical features such as connected sand bodies and connected fault systems.

3D seismic: The 3D seismic surveys would provide spatially continuous monitoring for time-lapse changes in the overburden. The flow simulations (Chapter 4) indicate that CO_2 migrating up a feature such as a pre-existing vertical gas chimney may well remain within the chimney confines and not migrate laterally into overburden. Time-lapse changes will therefore be restricted to the chimney and the seabed above. Due to the post-rift nature of the overburden succession at Type 4 sites, faults with the necessary lateral extent and connectivity to form viable pathways are unlikely to be present.

Lateral migration into neighbouring assets

The key issue here is to track lateral spread of the CO_2 plume and 3D seismic provides the most accurate means of doing this in Type 4 sites.

Induced geomechanical effects

Detailed site characterisation will establish *in situ* stresses, the degree of structural compartmentalisation and reservoir dimensions. In Type 4 sites it is likely that these parameters will be such that monitoring for geomechanical effects in the core monitoring programme will be adequately covered by downhole pressure and temperature measurements on the injection wells.

Indication of significant performance irregularities that may lead to a risk of leakage or a risk to the environment or human health

Irregularities may be identified in the course of monitoring for any of the objectives above. If these are deemed to be significant, particularly with the potential to lead to leakage, then additional monitoring will be required (see Section 8.6.3). Perhaps the most significant monitoring action in this category would arise if changes in seabed or bubble-streams were detected. Measurements of the gas would then be required to establish the cause of the observed changes and whether or not it constituted a significant irregularity.

Seabed gas measurements: In situ measurements would be made using existing or developed sensors and/or samples of headspace gas and seawater would be collected and analysed by standard laboratory procedures to verify whether or not the gas is CO_2. If it is CO_2 then isotopic or tracer analysis would be carried out to test whether or not it could have come from the storage site. If this proves to be the case then the additional monitoring programme would be triggered.

8.6.2.3 POST INJECTION MONITORING

The post-injection core monitoring programme has similar aims to the injection-phase monitoring. The emphasis is still on model verification and demonstrating lack of leakage, and any significant irregularities would still trigger the additional monitoring programme. A new requirement is to demonstrate robust longer-term prediction - in particular that the site is evolving towards long-term stability.

In general terms, preference will move further towards non-invasive monitoring systems, as the site operator seeks to complete and abandon their injection and any surveillance wellbores.

Comparison of actual behaviour with modelled behaviour (model verification)

Monitoring requirements are similar to those of the injection phase. The frequency of time-lapse repeat is determined by the site stabilization criterion (see below).

Demonstration of no detectable leakage

Monitoring requirements are similar to those of the injection phase. For the leaking well scenario, flow modelling (Chapter 4) indicates that fluxes at the reservoir / wellbore interface and at the seabed are maintained at similar levels to the latter part of the injection phase.

Site stabilisation

There are three main site stabilization processes at Type 4 sites: pressure decline, spatial stabilization of the free CO_2 plume and geochemical stabilization.

Pressure decline

Type 4 sites will typically have large reservoir volumes, high permeability and a low degree of hydraulic compartmentalisation. Post-injection pressure decline in the reservoir should therefore be quite rapid, and readily characterised within a few years by measurements in the injection wells.

Spatial stabilization

Establishing the final location and disposition of the free CO_2 plume is a critical first step towards demonstrating long-term stabilization, because it determines the extent to which the plume may impact on new containment risks in the future. For Type 4 sites this assessment can be challenging if the top surface of the reservoir is more-or-less flat lying. Small uncertainties in the depth of a gently undulating reservoir topseal can significantly affect the reliability of predictive migration modelling. Multiple modelling realisations are likely to be required, verified by 3D time-lapse seismic - the ability to image the plume spread accurately with high resolution is crucial. Cost-effective monitoring need not cover the whole plume, but rather that part of the leading migrating edge which is generating the uncertainty. Depending on details of the particular storage site, one or more post-injection 3D surveys will likely be required.

Geochemical stabilization

Geochemical processes are much slower than the physical processes governing migration of the free CO_2 plume and demonstrating that they are occurring is much more challenging. In a Type 4 storage site, dissolution / convection is the key medium to long-term stabilization process, acting on timescales ranging from decadal to millennial. Long-term flow simulations illustrate how dissolution / convection should lead to stabilization, but some form of verification is likely to be required.

CO_2 in solution becomes seismically 'invisible' so, in theory, very accurate quantitative monitoring from 3D seismic could show the amount of dissolved CO_2. In practice however because dissolution is a slow process, the uncertainty in seismic quantification of free CO_2 (in many cases >50%) is much larger than the amounts of dissolved CO_2 during the first decades after abandonment (typically <10%).

Geochemical monitoring is the key to establishing the onset of dissolution / convection. Downhole fluid sampling and pH measurement may or may not have been carried out in the injection phase depending on the availability of surveillance wells. If it had, then the presence of dissolved CO_2 would likely have been demonstrated. But simple dissolution is not the key parameter. It is more important to establish the onset of convection, which is the means by which new formation water can contact the plume and enable dissolution to continue in the longer-term. The best option is to deploy fluid sampling underneath the plume, where, if convection has begun, CO_2-saturated water sinking from the plume will be present. If horizontal injection wells are used, these would be available for sub-plume monitoring.

Other specialised technologies, which may be of utility in demonstrating dissolution / convection when deployed sub-plume, include ultra-high resolution travel-time monitoring and borehole microgravimetry. Careful assessment of parameter variation and the measurement limitations of the tools would be required prior to deployment.

It is possible that this monitoring procedure may only have to be convincingly demonstrated once or twice at Type 4 sites. Subsequent storage sites may be able to use the results from the preceding sites as generic analogues to demonstrate the case.

8.6.3 Additional Monitoring Methodology

Unlike the core monitoring programme which is driven by high-level regulatory requirements, the additional monitoring programme is highly site-specific and driven by the demands of a particular performance irregularity. In this section therefore we discuss some monitoring strategies that would be useful in the context of the sort of irregularity that night be encountered at a Type 4 site.

Additional monitoring would be triggered by a performance irregularity significant enough to require additional information to secure and maintain site performance. It should provide the data necessary to track and characterise the irregularity and to design suitable remediative actions. In the event that the irregularity leads to or is likely to lead to leakage, the additional monitoring programme must provide the capability of measuring this leakage as required by the ETS.

Three principal additional monitoring objectives have been defined (see Section 8.2.2).

8.6.3.1 Provision of additional data to re-design or re-calibrate predictive models.

For Type 4 sites significant irregularities in predictive modelling are most likely to comprise either major discrepancies in the extent and direction of plume spread or unexpected pressure changes. Options for additional monitoring include additional and focussed deployment of technologies already utilised as part of the core monitoring programme or deployment of specialised monitoring tools. Deployment of downhole tools may be practicable in pre-existing well stock, but in a Type 4 site where plume spread can be extensive, a specifically positioned new surveillance well is likely to be more effective. A new well would of course also be used to gain additional geological information to improve the reservoir characterisation.

Unexpected pressure changes

Unexpected pressure increase suggests problems with permeability connectivity in the reservoir. For scenarios where pressure is only recorded in the injection wells it may be necessary to obtain additional pressure measurements from elsewhere in the reservoir, allied to flow testing, to establish regional hydraulic connectivity. This would require additional monitoring wells.

Unexpected pressure decrease may be an indicator of significant migration of CO_2 from the primary storage reservoir and would trigger additional monitoring focussed on establishing the cause of the pressure decrease and the design of suitable remediation (see below).

Discrepancies in plume spreading

Significant discrepancies in predicted and observed plume spreading within the reservoir are likely to be due to imperfect understanding of top reservoir topography, reservoir internal structure and of the fine-scale flow processes and detailed saturation distributions in the constituent layers of the plume (sweep efficiency). Unexpected migration of CO_2 into the overburden would trigger immediate additional monitoring.

3D and 2D time-lapse seismic: Additional repeat surface seismic focussed on the irregularities will help to gain improved understanding of migration pathways in the reservoir and keep closer tabs on the rate of the advancing CO_2 front to constrain reservoir topography and flow properties.

Downhole tools: A number of downhole tools can be used to obtain more detailed information on the internal structure of the plume, particularly CO_2 layer thicknesses and saturations. Highest resolution is obtained from geophysical logging tools such as the RST, particularly effective when combined with fluid sampling. Borehole seismic methods such as 3D VSP can give higher resolution imaging of plume layers in the vicinity of the wellbore, a possible determinant of reservoir permeability structure. A variant on VSP, ultra-high resolution travel-time measurement, uses specialised downhole receivers deployed beneath the plume and is potentially a very powerful tool for constraining layer thickness. Borehole microgravimetry may also be useful in this respect.

8.6.3.2 Provision of information for remediation actions.

Monitoring focussed on remediation actions would be a response to irregularities which point to possible migration of CO_2 out of the reservoir that could lead to future leakage. Evidence of this would be, as discussed above, imaged migration of CO_2 into the overburden or unexpected pressure loss in the reservoir.

In the latter case, the first task would be to establish the location of the irregularity.

In a Type 4 site the most likely cause of significant pressure loss would be migration along a wellbore.

Accessible wellbores should be tested. Standard well integrity testing might include technologies to assess the current condition of the wellbore, such as cement bond logs, multifinger callipers and visual inspections for corrosion and scaling. Additional monitoring for the presence of fluid changes around the outside of the wellbore would be essential. Saturation logging and temperature logging would be most useful in this respect. Inaccessible wellbores are more problematical and non-invasive methods would have to be deployed. 2D high resolution surface seismic could be deployed in star configuration centred on the wellbores, to establish if significant fluxes are present outside the wellbores. The possibility of (more rapid) migration inside the wellbore would be covered by detailed monitoring: seabed imaging and bubble-stream detection in the first instance. Possible deployment of semi-permanent seabed monitoring system around the well head should also be considered.

If the above spatially-focussed methods do not establish the location of the irregularity, then additional 3D surface seismic may have to be acquired to accurately locate any time-lapse changes in the overburden.

Once the location, nature and severity of the irregularity are established, then a suitable remediation plan would be developed.

8.6.3.3 Measurement of leakage for emissions quantification (under the ETS).

Risks of leakage for Type 4 sites are considered to be predominantly via leaky wellbores and to a lesser extent via leaky caprocks. Scoping calculations (see Chapter 4) have further established the broad scale of leakage, including possible breakthrough times, albeit with poorly-constrained flow parameters. Results of the scoping simulations for specific scenarios relevant to Type 4 sites are summarised below.

Well leakage

For the leaking well case, migration of free CO_2 to the seabed was estimated to be 25 years and for dissolved CO_2 breakthrough was estimated to be 500 years. Peak flux of free CO_2 to the seabed was estimated to be 0.025 t/yr at 500 years (end of simulation), with peak areal fluxes estimated to be 0.2 t/m^2/yr. Estimated changes in pH for 1m^3 of seawater for a range of seawater displacement rates at peak free and dissolved CO_2 flux rates, indicated pH decreased by between 1.14 and 1.48 pH units for free CO_2, which is easily detectable. No change in pH due to dissolved CO_2 is produced.

Well leakage could therefore occur in quantities and at timescale relevant to the monitoring period for storage sites.

Evidence from other studies (Chapter 4) suggests that emission points from wells are likely to be confined spatially to a few square metres of the seabed. However, CO_2 may migrate laterally along permeable strata away from the well bore before reaching the seabed. Tracking of this movement at depth is needed to determine the correct area to measure fluxes. An appropriate technology for this is high-resolution 2D seismic profiles arranged in a star pattern centred on the wellhead.

For well leakage, the key measured parameter is the flow of free CO_2 to the seawater. Measurement of free CO_2 flow could be by flux meter or by measuring bubbles using sonar, microphone or video techniques. Further development and testing of these technologies is required. The detection limits needed to measure the types of flow rate estimated above are unclear and instrumental robustness (especially if permanently deployed) is unproven. The sensors must be placed as close to the emission point as possible to ensure all bubbles are measured and the proportion of CO_2 dissolving into seawater prior to measurement is minimised. Bubble densities determined by remote methods such as multibeam/sonar offer the potential to measure CO_2 fluxes over larger areas. However further development is required to demonstrate the quantification capabilities of these non-invasive technologies.

In situ measurements of gas composition would be made using existing or developed techniques and/or samples of headspace gas and seawater would be collected and analysed to establish the gas composition including the proportions of any other components such as methane and H_2S, hydrocarbons and any added components such as tracers, as well as the proportion dissolved in the seawater. Temporal variations in the flow rates would also need to be established requiring repeat measurements at an initial interval of days to weeks. Where variations are not detected on this timescale, intervals between measurements may increase to up to every six months. The frequency of repeat measurements will depend on the temporal variability, with greater variations requiring increased frequency of measurement. Technologies for continuous emission detection and measurement are currently being developed and could be deployed at a leakage site. Inspection by ROV or diver further allows a visual check on flux variations.

Wells considered to have a higher risk of leakage may also have permanent monitoring stations deployed above them to detect and measure any leak

<u>*Caprock leakage*</u>

For the caprock leakage case, breakthrough of free CO_2 to the seabed was estimated to be 280 years and for dissolved CO_2 breakthrough was estimated to be 240 years. Peak flux of free CO_2 to the seabed was estimated to be 4,100 t/yr at 500 years (end of simulation), with peak areal fluxes estimated to be 0.016 $t/m^2/yr$. Peak flux of dissolved CO_2 to the seabed was estimated to be 25 t/yr at 320 years, with peak areal fluxes estimated to be 1.0×10^{-4} $t/m^2/yr$. Estimated changes in pH for $1m^3$ of seawater for a range of seawater displacement rates at peak free and dissolved CO_2 flux rates, indicated pH decreased by between 1.14 and 1.8 pH units for free CO_2, which is easily detectable. A small change of 0.05 pH in seawater due to dissolved CO_2 is produced, which is likely to be undetectable.

Although the simulations suggest that leakage via the caprock would not breakthrough at seabed in the time span of site monitoring operations, these are not well constrained. Should leakage occur earlier, the affected area must be determined, for example by sidescan sonar, multibeam echo sounding or bubble-stream detection.

Point flow measurements would then be deployed as described above.

In addition to the free CO_2 measurements described above, the scoping simulations indicate that significant amounts of dissolved CO_2 might also be present in the seawater column. For the ETS the monitoring plan should also be able to account for any dissolved component. This would require the use of sensors either to measure dissolved CO_2 directly or to measure pH.

These technologies require further development (Chapter 6). Seawater samples would be required to validate direct *in situ* measurements. These would need to be collected and preserved at *in situ* pressures and temperatures to ensure sample degassing did not affect the validity of the analysis. Where leakage is restricted to discrete bubble streams, each individual stream will be measured separately. Evidence from analogue studies (Chapter 4) indicates that this is more likely than larger more diffuse areal releases. Where only dissolved CO_2 is being emitted, towed pH and dissolved CO_2 sensors, mounted on a CTD deployed in the water column close to the seabed will be used to determine the footprint of leakage. However, such sensors will be limited by their detection capabilities and the scoping calculations described above indicate that expected pH changes may well be below detection when considering leakage via a fault. Further development of techniques to measure dissolved CO_2 fluxes to the seabed are needed. The depth of the CTD deployment will reflect the degree of mixing between waters containing dissolved CO_2.

To satisfy the ETS an inventory of the total amount of CO_2 emitted from the storage site must be made on an annual basis. This will based on the fluxes measured and area over which the CO_2 is being emitted. Measurement would continue until monitoring indicates that remediation has been successful.

8.7 SUMMARY

The key monitoring tools likely to be suitable for the four generic North Sea storage site types are summarised in Table 8-2.

The scoping calculations (Chapter 4) indicate that an unremediated leak could continue for periods greater than the lifetime of a project, with an ongoing ETS measurement requirement. This implies that operators will have to remediate any leak, or significant irregularity that may lead to a leak, to avoid the burden of 'interminable' monitoring. Furthermore, it is also clear that in some leakage scenarios CO_2 would not actually leak (i.e. be emitted into the sea) until decades or centuries after initiation of the irregularity. In such cases early detection of unexpected plume migration will form a key component of monitoring plans. The emphasis must therefore be on pre-emptive deep-focussed monitoring and the early identification of irregularities before they become too serious to be remediable.

In a fully developed CO_2 storage area with multiple sources of CO_2, operators would wish to establish if any leaked CO_2 is from their reservoir. The co-injection of isotopically labelled CO_2 or other tracers has been proposed to help fingerprint CO_2 sources. For example tracers injected with the CO_2 at In Salah were used to confirm that gas breaking through into a monitoring well had come from the nearest injection well.

The robust quantification of CO_2 emissions for emissions trading clearly requires further development which is discussed more fully in Chapter 9.

Table 8-2: Summary of tools suitable for monitoring North Sea storage sites

		Type 1 site	Type 2 site	Type 3 site	Type 4 site
Site-specific issues		very secure seal (salt)	partly unproven seal	secure seal	unproven seal
		numerous wellbores	faults	numerous wellbores	extensive plume migration
			well defined closures		near flat-lying
		reservoir difficult to image			
			sweep efficiency uncertain		sweep efficiency uncertain
		generally underpressured	may be strongly overpressured	underpressured to overpressured	weakly overpressured
Core Monitoring Programme		Downhole P and T on injection well	Downhole P and T on injection well	Downhole P and T on injection well	Downhole P and T on injection well
		2D seismic	3D seismic	2D seismic	3D seismic
		[3D seismic]	[2D seismic]	[3D seismic]	[2D seismic]
		Downhole P and T		Downhole P and T	
		Downhole fluid sampling		Downhole fluid sampling	
		RST logging		RST logging	
				3D-VSP	
			[[Downhole pressure]]		[[Downhole pressure]]
			[[Downhole fluid sampling]]		[[Downhole fluid sampling]]
			[[RST logging]]		[[RST logging]]
		Multibeam echosounding	Multibeam echosounding	Multibeam echosounding	Multibeam echosounding
		Sidescan sonar	Sidescan sonar	Sidescan sonar	Sidescan sonar
		Bubblestream detection	Bubblestream detection	Bubblestream detection	Bubblestream detection
		Seabed sampling	Seabed sampling	Seabed sampling	Seabed sampling
Additional Monitoring Programme (additional tools only)		[[(Crosshole seismic)]]	(Passive seismic)	[[(Crosshole seismic)]]	(Multibeam echosounding)
		[[(Borehole gravity)]]		[[(Borehole gravity)]]	(Sidescan sonar)
			(Multibeam echosounding)		(CO_2 flux)
			(Sidescan sonar)		Seawater chemistry
	ETS measurement	(Multibeam echosounding)	(CO_2 flux)	(Multibeam echosounding)	Gas analysis
		(Sidescan sonar)	Seawater chemistry	(Sidescan sonar)	High resolution 2D seismic
		(CO_2 flux)	Gas analysis	(CO_2 flux)	
		Seawater chemistry	High resolution 2D seismic	Seawater chemistry	
		Gas analysis		Gas analysis	
		High resolution 2D seismic		High resolution 2D seismic	

(….) technology of unproven efficacy in site specific context
[….] if cost-effective (e.g. by use of legacy data)
[[….]] if suitable surveillance wells available

9 Recommendations for UK-relevant development

9.1 EXECUTIVE SUMMARY

This chapter identifies where gaps exist in current monitoring technologies that should be addressed to meet the anticipated monitoring requirements for UK offshore storage. It builds on the findings and conclusions of previous chapters: summarising the regulatory requirements for monitoring, defining the likely monitoring needs for four generic offshore storage types and reviewing existing monitoring technologies and future developments including a review of new technologies that might offer increased or improved monitoring capabilities We conclude that current technologies are likely to meet most expected monitoring requirements, especially in the areas of deep-focussed monitoring since this will largely utilise mature technologies widely developed and tested in the hydrocarbon industry. No significant gaps have been identified that require the development of completely new technologies. Further, no completely new technologies are expected to be developed in the near future that will either supersede any current technologies or address the gaps identified. It is expected that incremental advances in current technologies, driven largely by market demands in the hydrocarbon and marine surveying industries, will provide beneficial improvements in monitoring capabilities for CO_2 storage.

Nevertheless, some monitoring requirements have been identified for which current technologies have yet to be demonstrated as providing full detection and measurement capabilities. These requirements are in the following areas:

1. Leakage detection and measurement (emissions quantification) technologies including both survey and continuous data collection. This may be achieved through finding and measuring bubbles acoustically and by measurement of gas concentration and flux. Testing of the latter could provide much needed natural background values for offshore environments
2. Continuous monitoring technologies, primarily monitoring geochemical processes, in boreholes.
3. High resolution time-lapse monitoring for detailed assessment of plume migration via borehole instrumentation
4. Well integrity monitoring using noise logs and establishing detection thresholds for well bore leakage using existing or refined techniques

A range of needs has therefore been identified to address these requirements, which mainly involve development and testing of existing technologies to establish their efficacy.

We recommend that consideration be given to developing UK test facilities for permanent and continuous borehole monitoring and for developing and testing CO_2 geological emission detection and measurement technologies. Alternative approaches would be to establish partnerships with existing international facilities and to work in collaboration with European and UK projects.

We also recommend dialogue with service companies and projects to help foster development in assessing well integrity, especially in plugged and abandoned wells.

Further assessment is suggested of the potential for integrated permanent monitoring technologies for specific UK offshore requirements.

Consideration should also be given to joint development with planned UK CCS demonstration projects, though discussion with DECC and project participants.

9.2 INTRODUCTION

To identify gaps in current monitoring technologies for UK offshore geological storage sites, this study has undertaken a number of activities:

1. Review of monitoring requirements defined by relevant regulations (Chapter 2).

   Three regulatory frameworks are most relevant for monitoring geological storage sites: The Oslo-Paris Convention – most often simply referred to as OSPAR; The EC Directive on Geological Storage, which is currently being implemented in the UK, and the Monitoring and Reporting Guidelines for the European Emissions Trading Scheme (ETS). These regulations identify the following monitoring objectives:

   (i) Deep focussed monitoring objectives: Migration in the reservoir and in the overburden, performance testing and calibration of predictive models of site behaviour, identification of significant irregularities, containment integrity, assessing effectiveness of remedial actions, calibration of long-term predictions.

   (ii) Shallow-focussed monitoring objectives: verification of the absence of leakage, leakage detection, assessment of environmental impacts arising from CO_2 leaks and emissions quantification.

   Note that emissions quantification is the only monitoring objective that is contingent on a leak being detected – all others are specifically required.

2. Definition of four generic storage types that represent the range of storage options available in the North Sea (Chapter 3):

   Type 1: Depleted subsalt gas fields in the southern North Sea,

   Type 2: Aquifers and depleted fields above the Zechstein Salt in the southern North Sea,

   Type 3: Depleted hydrocarbon fields in the central and northern North Sea and

   Type 4: Saline aquifers of the central and northern North Sea.

3. To constrain the potential leakage rates and timing of such leaks to more realistic boundaries, a review has been undertaken of currently available information on leakage parameters (flux, concentration, distribution, duration) from observations and simulations, combined with preliminary and generic scoping calculations (Chapter 4). These calculations have helped to identify the potential for significant irregularities related to key elements of each of the storage types and which, in extreme cases, may lead ultimately to leakage. Key findings are:

   CO_2 fluxes to atmosphere from volcanic systems can range between four orders of magnitude from 0.003 to 1.7 t/m^2/yr over areas of up to 120,000 m^2. Whilst such values are indicative of migration along faults or fractures, there are significant differences to leakage from CO_2 storage, for example: the lack of a caprock, presence of open fractures and the long term exposure of the system to fluid escape. Industrial-scale CCS projects have demonstrated that CO_2 can be injected at more than 1 Mt per year for up to 10 years without leakage – though these are either CO_2-enhanced oil recovery projects or gas clean-up projects, rather than CO_2 capture from power plants. Monitoring of the research-scale pilot test at West Pearl Queen indicated that ~ 0.0085% of the total CO_2 injected leaks per year. (i.e. 0.17765t/yr). Reviews of enhanced oil recovery projects using CO_2 indicate that leakage via natural pathways is not detected. Some leakage via well infrastructure has been experienced and at Weyburn, some simulations indicate up to 6 t/yr may leak cumulatively via abandoned wells. However it should be emphasised this is based on simulations, which make a number of assumptions, and are not based on empirical monitoring data.

   The scoping calculations evaluated three leakage scenarios at the four storage site types described above using appropriate injection rates and estimates of permeabilities of key components. The leakage scenarios considered were: through a well, via a fault and through a leaking caprock and enhanced permeability overburden. For the assumptions made, the following conclusions can be drawn (refer to Chapter 4 for more detail):

- Intermediate aquifers in the overburden are likely to offer more significant secondary storage potential where leakage occurs via a well than if it occurs via a fracture or via enhanced permeability paths through the overburden.
- CO_2 can reach potential leakage pathways relatively quickly but breakthrough to overlying aquifers or the seabed may be much slower, occurring tens to hundreds of years after the end of injection.
- Leakage via faults or through enhanced permeability in the overburden is more likely to lead to larger volumes of CO_2 being emitted than leakage via wells. However the leakage through a borehole tends to occur sooner than that through a fault or enhanced permeability zone.
- The proximity of the leakage pathway to the injection point will influence leakage rates. If a leakage pathway is encountered by the migrating CO_2 plume during injection, then leakage will be more significant than if the pathway is encountered after injection has ceased.

It should be borne in mind that the simulations only provide a range of indicative examples and other scenarios and input conditions could give different outcomes.

4. Summary of current monitoring technologies, illustrated by four case studies (Chapters 3 and 10).

   Monitoring tools can be categorised as deep-focussed, for reservoir measurements and tracking CO_2 in the subsurface, and shallow-focussed for detection and measurement of CO_2 migration in the shallow subsurface and leakage. The deep-focussed tools most likely to be needed in CO_2 storage projects are predominantly mature, being developed in the oil industry. Some of these are relatively untested for CO_2 monitoring. In contrast the shallow monitoring methodologies are typically more novel and may require further development and testing for CO_2 monitoring offshore. Technologies can also be categorised as invasive (i.e. requiring borehole deployment) and non-invasive. Relevant techniques are:

   - Seismic and acoustic techniques: very mature technologies considered to form a fundamental component of most core monitoring portfolios. Their application has been successfully demonstrated at the Sleipner CO_2 storage demonstration project over ten years and more than 10 Mt CO_2 injected, as well as at a number of other injection projects.
   - Downhole monitoring comprises invasive technologies that enable very detailed, very high resolution measurements to be made on a wide range of downhole characteristics. Properties which can be measured include formation resistivity, neutron porosity, density, gamma-ray, self potential (naturally occurring electrical potential), temperature, pressure, cement integrity, other more specialist tools include various fracture identification and imaging tools and nuclear magnetic resonance (NMR) tools. Although a mature range of technologies in the hydrocarbon exploration and production industries, many of these techniques require further development and testing to be adapted for use in monitoring and measuring injected CO_2. Some technologies have been deployed successfully at small-scale research pilot CO_2 injection tests. The measurements mostly give information only in the vicinity of the borehole, which can limit their usefulness in a wider spatial context.
   - Chemical methods are being developed that directly measure dissolved and free CO_2 in the subsurface sediments and in the water column. Establishment of baseline conditions is a prerequisite. Concentrations of CO_2 near the seabed and fluxes across

the sediment-water interface are very poorly documented except in volcanic areas. Sampling and measurement of chemical parameters such as CO_2 concentration, pH and fluid chemistry can be undertaken both in boreholes and at the seabed. Sampling in deeper formations requires specialist equipment, such as U-tubes, which are being developed but have so far only been tested onshore. Current areas of development also include continuous seabed gas measurements.

- Electromagnetic methods detect the conductive and magnetic properties of the subsurface. Free CO_2 has a high resistivity so it should be detectable through observable changes in the EM properties of the subsurface. Conversely, dissolved CO_2 has a lower resistivity than low salinity water so again may be detectable. EM tools can be deployed on the seabed surface and in boreholes. A few examples exist of their use in CCS projects and a fuller evaluation of the deployment at Sleipner is awaited.

- Microgravimetry involves repeated high precision gravity measurements on the seabed to detect changes in density in the subsurface. The size of the gravity anomaly is mainly determined by the subsurface volume/density, and the spatial variation in gravity by the lateral distribution of density. The main limitation of this technique is the lack of resolution in terms of the depth of the anomaly. Although of much lower resolution than surface seismic, the two methods can be complementary; gravity methods can provide independent verification of changes in the sub-surface mass.

- Other techniques that may be relevant to CO_2 storage monitoring include:
  - ecosystem surveys – some analogous and research studies have been undertaken to date and a ecosystem surveys form part of Environmental Impact Assessments for offshore oil and gas developments;
  - tiltmeters have been used in other marine applications and may provide information on the geomechanical integrity of the storage site; and
  - tracers that could be used to monitor the migration of CO_2, fingerprint the injected CO_2 stream and identify leakages. These have been used at a number of small-scale pilot test injections with some success.

Table 9-1 provides a summary of the monitoring technologies that have been applied at Sleipner and K12-B and have been planned for Miller and P18.

5. The measurement requirements for offshore storage sites and the efficacy of current monitoring tools have been considered (Chapter 5).

   In order to meet the high-level regulatory requirements, we have identified a number of specific monitoring objectives: plume imaging, topseal integrity, quantification, storage efficiency, calibration of predictive models, near-surface migration and leakage, seismicity and earth movements and well integrity. One further objective could be added to this list: that of demonstrating the storage site is satisfying emissions reductions objectives, i.e. that the proportion of CO_2 that could leak will not contribute to future atmospheric emissions above a certain threshold. In chapter 5, a guide of 0.01% of the total mass of CO_2 was discussed. The scoping calculation undertaken in Chapter 4 suggested that the expected amounts of CO_2 emitted from offshore storage sites would in most cases be significantly below this performance standard, for the range of leakage scenarios considered and assumptions made. Two exceptions were the failed caprock leakage scenarios for a deep underpressured reservoir and for a shallow saline aquifer. For typical injection volumes and an annual leakage rate of 0.01%, the mass of CO_2 emitted would be easily detected using currently-available technologies.

   Generally, deep-focussed tools are more mature, fully developed and tested for CO_2 storage. We conclude that the techniques currently available are likely to offer sufficient monitoring capabilities to be able to meet the objectives listed above – essentially detecting and tracking CO_2 in the deep subsurface.

While leakage is not expected at any storage site that has been suitably characterised and designed, regulations place greater emphasis on monitoring leakage and its impact. Our review indicates technologies for assessing and quantifying leakage require greater development than those used for monitoring the subsurface.

Table 9-1: Summary of monitoring technologies employed at the three of the reviewed case studies (see Chapter 3).

	Case study	Sleipner	K12-B	P18
	Storage type	Type 4	Type 1	Type 2
	Status	Ongoing, >1 Mt per year since 2006.	Ongoing small-scale injection	Planned
Seismic & acoustic	3D surface seismic	✓		
	2D surface seismic	✓		
	Shallow, high resolution seismic			✓
	Microseismic			✓
	Sonar, multibeam seabed imaging	✓		✓
EM	Controlled-source EM	✓		
Gravity	Seabottom gravity	✓		
Downhole	Pressure - Wellhead	✓		✓
	Pressure - Reservoir		✓	✓
	Tracers		✓	✓
	Downhole logging			✓
	Observation wells			✓
Geochemistry	Bubble streams as appropriate		✓	✓
	Production gas		✓	
	Injected gas	✓?	✓	✓
Well integrity	well annuli pressure			
	Pressure and temperature gradient profiling			
	Multi-finger imaging tools			
	Electromagnetic imaging tool			
	Cement bond log			
	Down hole video log			
	Gas chemistry in well annuli			

6. Appraisal of novel technologies currently in development, including information supplied by companies and research organisations undertaking CO_2 storage projects (Chapter 6).

In general, the findings supported earlier conclusions that for deep-focussed monitoring techniques, especially geophysical techniques deployed extensively in oil and gas exploration and production, no major technology breakthroughs were expected or in fact needed. Following the successful demonstration of 4D seismic at Sleipner and Weyburn, the current focus has moved to gaining greater added value by combining different methods and undertaking joint inversions such as Controlled Source ElectroMagnetic-seismic or gravity-seismic.

A recent development in seismic technology that would be of great relevance to CO_2 storage monitoring is the use of ocean bottom cables (OBC) to permanently install arrays of geophones. The advantages of OBCs are more flexible acquisition, requiring only a ship-based seismic source, increasing the number of possible surveys, reduced deployment costs (although initial installation costs may be significant) and improved resolution of the time-lapse signal. The use of OBCs also allows direct recording of multi-component data. This may allow monitoring of (induced) fracturing, for improved interpretation of stress effects in and above the reservoir, and better characterization of pressure and saturation effects in the reservoir. Both electrical and optical systems are available, with optical systems having the advantages of low power requirements, large bandwith and reduced data loss over longer distances.

Generally, current technologies for assessing well integrity are considered sufficiently developed for CO_2 storage projects. There remains an unresolved question regarding the size of leak that could occur in a failed well and if this could be detected. Research and test activities are planned to address this. Preliminary scoping calculations undertaken for this study indicate that steady state fluxes of less than 0.1 tonnes per year might be anticipated (Chapter 4). A key gap however is the ability to monitor abandoned wells, with current onshore experience limited to indirect geophysical methods such as seismics and offshore methods relying on seabottom monitoring, such as bubble detection and sampling. Inaccessible abandoned wells also present a monitoring challenge that will rely on similar techniques.

Seabed monitoring techniques such as sonar and multibeam have seen increases in resolution that currently permit very detailed spatial mapping of the seabed and up to 400 m into the seabed sediments. Forward-looking sonar technologies are now available that can readily detect bubble streams in the water column – currently these are used to look for methane leaks from gas pipelines. Further testing with CO_2 is required.

Downhole geophysical logging is a mature technology area though we conclude that more experience with CO_2 injection wells is needed. In particular, well integrity logs need more testing to establish threshold values. Some electrochemical logging techniques to monitor CO_2-induced corrosion of borehole completion materials are being developed. Initial testing of borehole gravimetry has been undertaken for CO_2 storage, and more is planned that may lead to CO_2 detection capabilities away from the borehole for integration with other techniques.

Recently downhole fluid sampling systems have been developed to allow samples at in situ conditions to be brought to the surface for offline chemical analysis (.e.g. CO_2 concentrations, tracer analyses, chemical analyses to monitor CO_2-reservoir interactions). These require further development for the offshore environment. Technologies for undertaking downhole in situ chemical analyses are being developed and require further testing.

Developments in technologies suitable for near-surface leakage detection include mass spectrometers for bubble gas chemistry and permanently installed systems for monitoring pH, temperature, O_2 and CO_2. There are a few commercial and research instruments capable of measuring CO_2 concentrations and fluxes in sea water, which are currently being developed by research organisations. Key areas of development are: fast-response pH, pCO_2, and DIC sensors, which could be mounted on a wide range of platforms, to allow underway measurements. Also the coupling of fast response sensors with instruments able to evaluate fluid dynamics at the micro-structural level to calculate flux rates, as is already done at the land-atmosphere interface using eddy covariance systems, would also be a major advance. Natural background values for near-bottom CO_2 concentrations and fluxes are almost unknown, except in volcanic areas, and building a database of such observations would give an improved understanding of baseline conditions and their variability.

Biological monitoring has potential for development as a leakage indicator, based on the effects of CO_2 on macro- or microfauna or at a molecular level, but may not be able to provide an immediate indication of leakage.

7. Assessment of the potential to combine tools to form integrated monitoring platforms.

The following benefits for combining different monitoring technologies were identified in Chapter 7:

- Use complementary measurements to increase understanding of the reservoir behaviour by joint interpretation. Joint interpretation may lead to a better understanding of processes like dissolution and mineralisation.
- Use various monitoring methods to develop an optimal strategy to both detect and quantify CO_2 migration out of the storage complex and any leakage to the sea bed.
- Use various monitoring measurements to jointly invert for CO_2 migration in the reservoir for an improved quantification including uncertainties in time. A better handle on the different models honouring *all* monitoring data will lead to a more constrained prediction of future plume development and CO_2 behaviour.
- Use combinations of monitoring tools to ensure well integrity.

8. Proposals for generic monitoring plans relevant to each storage type.

   By considering the regulatory requirements, monitoring objectives and potential risks associated with the four generic storage types, a portfolio of technologies that are likely to form the core monitoring plan can be defined. This core monitoring portfolio comprises: pressure, temperature, CO_2 plume breakthrough monitoring, seismic and well integrity monitoring. In addition, surface leakage detection will require the use of the some or all of the following techniques: seismic, sidescan sonar, multibeam (shallow seismic), bubble detection, CTDs (conductivity, temperature, depth sensors), and in situ gas measurements or sampling. Baseline surveys involving these techniques might only be repeated if any leakages were observed or suspected. However, more frequent or near-continuous measurements could be made at vulnerable points such as wellheads.

9.3 SUMMARY OF IDENTIFIED GAPS

The review of existing technologies that have been demonstrated to effectively monitor various aspects of CO_2 storage sites indicates that the major objectives of UK offshore monitoring plans are likely to be met. No new breakthrough technological advances are needed or expected in the next few years. Rather, our assessment of novel technologies suggests that development is driven as much by demand and market opportunities in other offshore industries (marine surveying for renewable energy installations, fishing, and hydrocarbon exploration, production and transport) as by the nascent CO_2 storage industry. The following general conclusions can be inferred from these reviews:

- Existing deep-focussed technologies for monitoring plume migration in the reservoir and storage complex are capable of meeting the monitoring requirements identified and are relatively mature and proven for deployment in CO_2 storage sites.
- Technologies for monitoring and detecting leaks in the shallow subsurface and for detecting and quantifying CO_2 emissions to seawater exist, having largely been developed for other industries or are in the early development stages for CO_2-specific applications. However their applicability for CO_2 storage sites has not been fully demonstrated and evaluated.
- Similarly, technologies for monitoring the well itself, or for monitoring the reservoir from a borehole, are either mature and proven within the hydrocarbon industry, or the focus of current development. Some technologies are being adapted for CO_2 storage and some new technologies for assessing well integrity are being developed.
- No new breakthrough technologies are expected in the near future, nor indeed are needed, for CO_2 storage – most technology development will be incremental and only partially driven by the CO_2 storage industry (which is very minor currently).

- Nevertheless, gaps in current technologies have been identified. These mainly relate to testing and demonstrating the capabilities of existing or new technologies in the new application of CO_2 storage monitoring. In particular these relate to shallow surface monitoring technologies and to some downhole monitoring technologies.

In the following sections these gaps are described but not prioritised. Section 9.4 provides some recommendations as to the priority areas for development.

9.3.1 Shallow Methods

Shallow focussed technologies are well developed for onshore use, but more experience and development is needed offshore. Studies of pockmarks and related features have shown that these can be imaged by a variety of sonar/seismic methods. Bubble-streams can also be seen with these techniques. Ship-based sonar can currently be used to detect bubble streams and shoals of fish (from their air-filled swim bladders). Sonar techniques could potentially be used for imaging streams of CO_2 bubbles escaping from the seabed. Bubble stream detection could be part of a robust shallow monitoring package, when used in conjunction with seabed imaging (e.g. multibeam echo sounding). However, this technique has yet to be tested in a CO_2 storage application. A limitation of the technique with respect to CO_2 monitoring is that CO_2 bubbles are more soluble than methane and so would be expected to dissolve in relatively shallow water columns. Recent modelling work by Kano et al., (2010) implied that any CO_2 leakage would be expected to dissolve within 100 m of the seabed. The vast majority of studies of fluid escape offshore have involved methane or water, so direct experience with these methods specifically on leaking CO_2 is lacking. Detection limits for bubbles, in terms of size, density and the type of gas present, have yet to be established. It is critical for CO_2 storage to establish these parameters for CO_2 release from the seabed before it can be said that techniques such as multibeam are proven for the detection of CO_2 emissions.

In addition to detection, the ability to characterise and to quantify the bubble-streams is paramount. The possibility of using the acoustic properties of the bubbles or their behaviour to discriminate, for example, between methane and CO_2 needs to be investigated. Direct remote quantification of bubble-streams, even in relative terms, is much more challenging.

3-D imaging techniques like multibeam echo sounding have much greater promise for detecting CO_2 emissions over large areas than 2-D methods, such as ship-borne CO_2 or pH measurement. However, the latter could be valuable as an alternative way of detecting CO_2, particularly if detection limits for bubble-streams proved to be too high.

Quantification of the resolution of boomer surface seismic for CO_2 bright spots in the subsurface is another identified gap that, if addressed, may lead to improved measurement of CO_2 migration and leakage.

Biomarkers are another possible way of monitoring CO_2 release through its effect on the ecosystem. This could involve macrobiological or microbiological responses or even effects at a molecular level in key organisms. These studies are, however, in their infancy, with only a few having been carried out to date (Section 10.6.1). These do appear to indicate ecosystem responses to escaping CO_2 and suggest there to be potential in such methods. Further investigations are planned under new projects such as the EC FP7 projects RISCS (started January 2010) and ECO2 (in negotiation with the EC) and the NERC-funded QICS project.

Once bubbles are detected, the gas can be measured in situ or sampled for analysis on board ship or in an onshore laboratory. Detection limits and measurement accuracy for existing laboratory equipment and available sensors are sufficiently low to meet any likely requirement to measure emissions from CO_2 storage. In situ measurement of CO_2 is possible with existing equipment, but specific offshore instruments are at an early stage of development by commercial companies or research groups, which have developed prototype monitoring stations. So far these have been linked to onshore data transmission systems or those on buoys in sheltered waters. Further development and testing for the harsher environment of the North Sea is required. Integration of laboratory measurements with direct quantification data from remote monitoring would provide the most robust form of quantification, but the latter element is not yet demonstrated. Headspace gas measurements have been undertaken at natural methane seeps in the North Sea. They have not been applied at an offshore CO_2 storage site.

Measurement of CO_2 flux offshore, as opposed to CO_2 concentration, is also not a routine method although researchers have devised prototype technologies, mostly linked to buoys (e.g. Viezzoli et al, 2008; Washburn et al, 2001). There would be much greater capability to measure fluxes if new fast response CO_2 sensors are developed, which can be coupled with fluid dynamics using eddy covariance techniques already well developed onshore and demonstrated for oxygen fluxes offshore.

9.3.2 Downhole Monitoring

Much of the preceding discussion concentrates necessarily on detecting and measuring the free CO_2 phase during injection to demonstrate various aspects of current site performance. It is also important to consider how we may use monitoring data to support the case for transfer of liability. In particular how data may be used to demonstrate that site stability will increase with time. The two key stabilization processes for the site will be pressure decrease (leading to geomechanical stabilisation of the storage complex) and dissolution (leading to gravitational stabilization of the plume). Pressure monitoring is quite well established, but the latter requires geochemical sampling of the reservoir at specific target locations. In addition, the geochemical measurements could ideally be evaluated in terms of dissolution rates, the quantity of CO_2 in solution etc. We believe these aspects to be very challenging and they may well require new integrated sampling technologies.

Long-term downhole pH can play an important role in site monitoring as it can indicate the proportion of CO_2 dissolving into the formation water or CO_2 migration or leakage. Though downhole sampling is being trialled in small-scale pilot projects (see Section 10.1.1) and at Weyburn, a current technological gap is the capability to continuously monitor in situ pH in boreholes accurately. As a large number of geochemical processes can influence pH, other tools are required for accurate geochemical monitoring. Although pH sensors for use in boreholes are commercially available, they tend to be expensive and only employed on a short-term basis. Key challenges are reliable and stable pH sensors and accurate and stable calibration. Tool development, including improvement of the length of time that sensors retain their calibration, would be required for long-term use. Laboratory-based testing of sensors under simulated reservoir conditions is required with the aim of developing a reliable downhole tool.

Downhole fluid samplers have been developed and successfully tested at small-scale research-focussed onshore storage pilot injection tests. However, they have not been tested for use offshore or in larger-scale injection systems. Their potential for providing information on rates of CO_2 dissolution in formation waters, interactions with reservoir formations and for monitoring CO_2 breakthrough and detecting tracers in observation wells (either in the reservoir or above in secondary storage aquifers) is considerable.

Technologies for deep-focussed monitoring, of which seismic techniques are probably the most useful, are generally mature. They have already demonstrated their capability for CO_2 storage. There remains, however, some scope for development of down-hole techniques, particularly with regard to continuous monitoring to detect breakthrough of CO_2 in a monitoring well.

The potential for downhole electromagnetic techniques to monitor changes in CO_2 saturation has been provisionally demonstrated (see Chapter 10, Volume 2). Current limitations are the lack of permanent borehole EM equipment and expected current lifetimes of around 5 years. In addition, it cannot be deployed in wells with steel casings so is not likely to be deployed in the North Sea. However, cross-hole electromagnetic logging, requiring two monitoring wells located close to the CO_2 plume, may be capable of detecting the plume, especially in saline aquifers.

Similarly, cross-hole electrical resistance tomography is a currently developing technique that may offer detection capabilities in saline aquifers (its non-discriminatory nature means CO_2 can not be differentiated from methane in hydrocarbon fields). It has been successfully demonstrated at Ketzin. A limitation of this technique is that it requires two monitoring wells located close to the injection site and is largely restricted to detection of lateral changes in conductivity, not changes with depth. However, the equipment is relatively easy to deploy and operate and may have a better sensitivity at high gas saturation (>20%) compared to seismic methods, although the results are lower resolution.

A novel application of Vertical Seismic Profiling is ultra-high resolution travel-time (HRTT) measurement. In this configuration receivers are placed in the wellbore beneath the CO_2 plume. Changes in travel-time and attenuation from a high frequency seismic source above the plume can be used for direct quantification and mapping plume extents. With potential resolution of fractions of a millisecond this is a high precision tool, capable of detecting CO_2 layers less than 1 m thick. However, to our knowledge HRTT has not yet been successfully deployed in CO_2 storage. Depending on logistics the method is potentially very suitable for deployment in deviated injection wells where the wellbore lies beneath the buoyant CO_2 plume (such as at Sleipner).

Borehole gravimetry is under development and the potential of existing and sensors for CCS needs appraisal.

In conclusion, monitoring tools are available or under development that cover most, if not all, of the requirements for monitoring. Nevertheless, key gaps remain:

- Reliable downhole sensors for continuous measurement of dynamic processes
  - experience so far suggests downhole deployments (especially outside casing) are very vulnerable to damage or degradation
- Remote (3D) characterisation of CO_2 bubble-streams
- Remote volumetric / quantitative measurement of CO_2 bubble streams
  - significant progress is required here
- In situ (seabed) measurement of CO_2 concentration
  - instrumentation under development but not tested in North Sea environments
  - data storage and transmission issues
- In situ (seabed) measurement of CO_2 flux
  - needs further development. Fast sensors would allow eddy covariance type methods to be used
- Effective downhole systems for measuring post-injection stabilization processes
  - long-term downhole pH sensors not proven
  - innovative downhole geochemical sampling systems not yet tested for routine deployment at industrial sites offshore
  - integrated geochemical sampling systems capable of collecting required diagnostic datasets.
- Lack of integration of different methods (joint interpretation, joint inversion): need for model based inversion
- Monitoring pressure (far) away from the injection and monitoring wells
- Well integrity
  - monitoring of well integrity of inaccessible abandoned wells
  - detection thresholds for well integrity of operating/accessible wells

9.4 RECOMMENDATIONS FOR PRIORITY DEVELOPMENT

9.4.1 Evaluating new technologies

Throughout this study, technologies have been identified that offer potential benefits for monitoring CO_2 storage sites, and these are summarised in Section 9.3. In order to identify those technologies that may be considered higher priority or meriting earlier development a number of criteria can be applied to each technology or gap (Appendix 6, Volume 2).

- The value or impact that a novel technology could make to CO_2 storage monitoring is a fundamental consideration. Here this benefit is categorised as
  - major value/impact: development, testing and/or successful deployment of this novel technology will enable an important gap in current monitoring capabilities to be overcome.
  - significant value/impact: development, testing and/or successful deployment of this novel technology will enable technologies that are already developed and applied to be used in CO_2 storage monitoring, thereby increasing the monitoring capabilities of the portfolio of techniques available.
  - minor value/impact: development, testing and/or successful deployment of this novel technology will provide incremental but nevertheless important improvements in currently available monitoring technologies.
- Timeframes for development and testing have been estimated. In many cases the development times for existing technologies , which only require testing in a CO_2 storage project, are very short They are categorised as:
  - short (1-2 years)
  - intermediate (3-5 years)
  - long (5-10 years);
- Costs for development are difficult to estimate due to a number of factors including reluctance on the part of suppliers to provide commercially sensitive information. In many cases the development costs are not high (especially for techniques already developed for other applications) but significant costs will be incurred in providing a suitable test environment. Very approximate relative estimates of development costs are categorised as follows:
  - low
  - medium
  - high
- Costs for deployment are also difficult to estimate. They are generally very sensitive to market conditions with factors such as the price of oil and gas, and the demand for offshore renewables construction (wind turbines) driving the demand and cost of ships and barges for drilling, accessing wells or conducting surveys. In the future, as CCS develops, it is possible that the cost of electricity, and the value of CO_2 within the ETS, may also begin to influence deployment costs. Maintenance costs for as yet untested technologies are also difficult to estimate. Cost reductions may be achieved by exploiting opportunities to combine technologies on single platforms or acquire several datasets during single surveys. Some technologies may be deployed in injection boreholes whereas others either require injection to be stopped (e.g. VSP) and/or for the sensors to be placed in dedicated observation wells. These variables make estimating deployment costs of, as yet unproven, technologies challenging and therefore these costs are categorised simply using a relative scale as follows:

- o low
- o medium
- o high

A primary conclusion of this study is that, in general, many techniques are already developed in other industries, notably the oil industry but also in marine surveying, that offer the potential of providing useful monitoring capabilities in CO_2 storage projects. Further, that current development is incremental and significant new technology development is neither expected nor required. These conclusions imply that in general development costs will be relatively low and will in many cases occur naturally through market demand in other industries. However, significant costs may be incurred in adapting, testing and validating these techniques for use in CO_2 storage projects. Specific areas for development are given below. Appendix 6 (Volume 2) provides a summary of the value/impact, estimated time and costs for development, estimated time for testing and estimated cost of deployment for each of the novel technologies identified above.

9.4.1.1 Downhole monitoring technologies

Development and testing of downhole geochemical tools, such as new pH sensors, improved fluid sampling devices and continuous CO_2 and tracer monitoring equipment, require access to a borehole in which CO_2 is either being injected or which is being exposed to a CO_2 plume. Costs of installing this equipment offshore may be significant, since installation will include the costs of providing a crew and appropriate ship or other access to install the equipment. Furthermore, locations of existing boreholes may not be suitable and new purpose-drilled observation wells may be required. Calibration costs are likely to be relatively small since this will be achieved in a laboratory that is capable of simulating relevant reservoir temperatures, pressures, flow conditions and chemical conditions. Although ideally this development and testing should be as realistic as possible, and therefore include offshore deployment, undertaking testing onshore would significantly reduce costs. This would imply that an onshore UK borehole facility for testing downhole monitoring technologies for CO_2 storage would provide a good first step and significant advantages for the UK specifically, both in terms of supporting UK industry development and in supporting the development of relevant monitoring technologies for offshore storage. We recommend that the feasibility of such a facility should be investigated by the ETI. The feasibility study should include consideration of objectives, scope, appropriate location (geologically relevant), infrastructure needs, capital and operational costs, funding opportunities, the permitting requirements and other options. Experience in other countries such as at the Otway Basin Pilot Project in Australia, Frio injection site in Texas and the Norwegian CO_2fieldlab, indicates that the permitting process can take 2-3 years. Another option would be working in partnership with some of the pilot injection facilities already established worldwide such as at Otway, Frio and Nagaoka.

Several downhole geophysical monitoring techniques have been identified as addressing a gap in current monitoring capabilities by offering the potential to provide detailed information on CO_2 plume migration. These techniques are ultra-high resolution travel time vertical seismic profiling (HRTT-VSP), cross-hole electromagnetic (x-hole EM) and cross-hole electrical resistivity tomography (x-hole ERT). HRTT-VSP, particularly when deployed in strongly deviated wells may provide detailed mapping of the plume at increased resolution compared with conventional 3D seismic. Similarly x-hole EM and ERT techniques provide potential for detailed plume imaging and may have particular application where conventional 3D seismic may not be so easily applied – Type 1 storage sites, below the Zechstein Salt in the southern North Sea being prime examples. Nevertheless these techniques require deployment in boreholes and will, by definition provide limited spatial coverage, in one plane. The EM and ERT methods also require two boreholes in close proximity, which must be located to enable the plane between them to intersect the migrating CO_2 plume. While this is more easily achieved on land, where access is significantly easier and borehole density is greater, offshore it is likely that to reduce capital costs, operators will wish to utilise the existing wells for storage, by converting hydrocarbon production wells to CO_2 injection wells. The locations and orientations of these wells will have been carefully optimised to maximise the efficiency of hydrocarbon production (typically being located at the top of a reservoir or structure to reduce their watering out and maximise production). Consequently, the number and locations of wells may not be ideally suited for the deployment of cross-hole monitoring technologies. It is not clear if operators will be willing to consider drilling new dedicated observation wells as the costs are high. Clearly this will only be undertaken in circumstances where the costs will lead to significantly reduced uncertainties in site performance. This presents significantly greater challenges of deployment. These factors therefore indicate that such techniques are less likely to be favourable, primary choices in monitoring technology portfolios and as such may be considered lower priorities for development and testing.

9.4.1.2 Shallow monitoring technologies

Development and testing of shallow and seabed monitoring technologies need to focus on a number of key areas (Appendix 6, Volume 2), which require integration and testing of a number of existing technologies such as sonar and multibeam echo sounding with a CO_2 bubble stream. The integration of a number of technologies into one survey will significantly reduce ship-time costs and improve monitoring capabilities since complementary datasets are acquired simultaneously. The need to test such shallow detection equipment and the need to develop, test and validate bubble stream measurement equipment would suggest that an offshore test facility is required; providing controlled and carefully constrained CO_2 streams, which can be used to evaluate these novel technologies in an experimental programme. However, although very desirable, it is likely to be very challenging to develop such facilities and test these techniques in the North Sea. Previous experiences with ocean storage research (CO_2 injection into the water column) suggests that getting permission for releasing CO_2 into the marine environment is likely to be extremely challenging and also likely to raise significant opposition from environmental groups. An alternative approach would be to utilise natural marine CO_2 seeps (such as occur off Germany and at Panarea in the Mediterranean - see Chapter 4) as natural testing grounds. Weaknesses of this approach are the variable and unconstrained nature of the seeps, the less geological and environmental relevance that volcanic systems have to the North Sea and their location at some distance from UK storage sites.

9.4.1.3 Well integrity

The assessment of leakage scenarios undertaken in Chapter 4 and our consideration of key generic risks for each of the four generic storage types present in the North Sea in Chapter 8, have identified that leakage via poorly completed or abandoned wells remains one of the key residual risks for all storage types. Establishing and monitoring the integrity of wells is therefore likely to be a major focus of monitoring in offshore storage sites. This is especially the case for older depleted hydrocarbon fields such as those of the southern and central North Sea, where the number, exact locations and condition of older, previously abandoned wells may be difficult to ascertain from desk-based reviews of drilling, workover and abandonment records. Sidetracked wells, with the potential for up to four separately commissioned and abandoned sidetracks may be particularly challenging. There are several technologies that are well-proven in the hydrocarbon industry for assessing the integrity of open, accessible wells and these have been reviewed in Chapter 10 (Volume 2), and their planned use in storage sites such as K12-B and P18 is described in Chapter 3. However, it is much more difficult to assess the integrity of previously abandoned wells to which access is no longer possible. One novel technology, albeit still requiring access to the plugged well, is a noise log that listens for the sound of gas escapes within the borehole. This and any other technologies that improve the capability to assess the integrity of plugged and abandoned wells, and detect poor or deteriorating integrity of abandoned wells should be a high priority for future development. We recommend that the ETI considers how best to encourage further developments in this area, including the developments likely to be made by service companies independently.

9.4.1.4 Permanent instrumentation

One trend in future monitoring technology development recognised in this study was the increased benefits of permanent instrumentation. Examples include:

- The use of arrays of geophones, permanently installed in ocean-bottom cables (OBC) that allow both improved resolution and accuracy when using conventional ship-based seismic sources and reduced acquisition costs which allow more frequent repeat surveys.
- The need for continuous monitoring for CO_2 emissions to the seawater column (so-called 'sniffer' technologies), particularly in locations of high risk such as around wellheads.
- Downhole permanent installations allowing either repeat surveys or continuous monitoring. Examples include: passive seismic, tiltmeters, VSP, other geophysical techniques such as EM or ERT, and permanent downhole sensors for pH, CO_2 and tracers. These may be deployed either in injection wells or dedicated observation wells.

We recommend that the ETI considers further assessment of the potential for integrated permanent monitoring technologies for the UK offshore environment, taking into account the benefits, challenges (installation, remote operation, maintenance, data retrieval, lifetimes and durability), and optimal configurations for the generic storage types.

9.4.2 Key areas for monitoring technology development and testing

All of the techniques identified above will offer some increased monitoring capability if developed and tested for CO_2 storage. By prioritising technologies it should be emphasised that those technologies that are ranked as lower priority should not be considered as not requiring further development. We only consider those technologies to have lower priority because they are being developed for other purposes, notably the hydrocarbon and marine surveying industries. They will still need testing and evaluating for use in CO_2 storage applications. The technologies that have been selected here are those that offer the greatest potential to bridge the identified gaps and meet the monitoring requirements identified in this study i.e. the potential for the identified technology to address a gap and the relative importance of that gap in terms of its significance in providing improved monitoring capability at a CO_2 storage site.

For each technology, the relative cost of deployment can also be considered. A simple bubble diagram (Figure 9-1) allows the relative merits of each technique to be compared and those potentially providing the largest value or impact for the least cost of deployment and shortest development time to be identified. Technologies that plot in the lower left quadrant are those that have high potential for addressing a significant gap in current monitoring capabilities and are relatively low cost to deploy. They might be considered to have the highest priority for development and testing. Those technologies that plot in the upper left hand quadrant have a high potential benefit to CO_2 storage monitoring capabilities, addressing key monitoring requirements, but are estimated to have higher deployment costs. These technologies merit further development as they provide particular monitoring capabilities for specific requirements. Technologies that plot in the lower right hand quadrant are those with relatively low benefit, but with lower deployment costs and as such merit further consideration but with lower priority because of the limited benefit. Those in the upper right hand quadrant are those technologies with lower relative potential benefit and higher deployment costs. These technologies would only be worth further development for specific applications, for example where existing technologies are less effective.

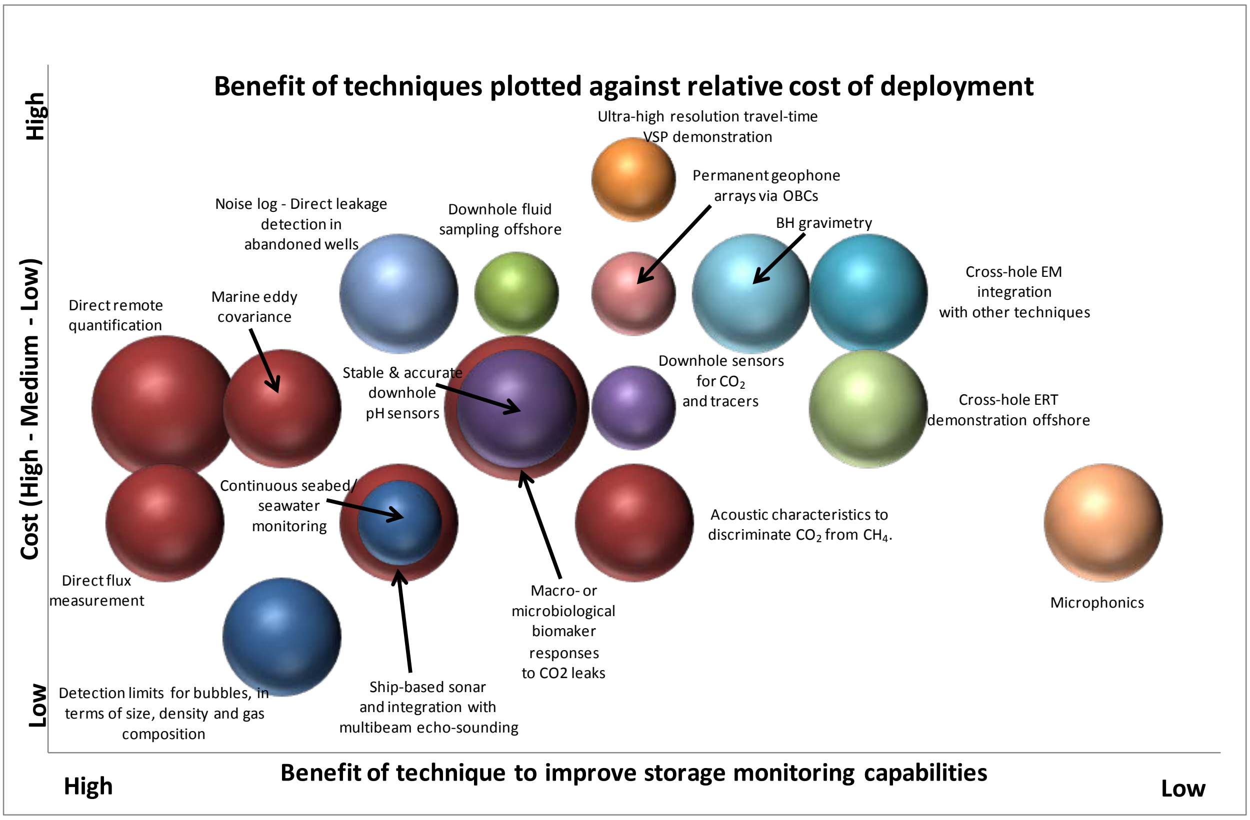

Figure 9-1: Benefits of novel techniques identified as requiring further development, testing and demonstration for monitoring CO_2 storage plotted against the estimated relative cost of deployment (high, medium or low). The size of each sphere represents the estimated time for development (large = 5-10years development, medium = 3-5 years development and small = 1-2 years development.) Note: Red spheres are CO_2 bubble stream quantification technologies; blue spheres are bubble stream detection technologies and purple spheres are downhole geochemical technologies.

The technologies identified as offering the greatest potential impact for the lowest estimated deployment costs are related to emissions detection (red spheres on Figure 9-1) and emissions quantification (purple spheres on Figure 9-1). The exception to this is microphonics, considered to have relatively smaller benefit than the other leak detection technologies included here. These technologies are further described in Chapters 6 and 10, and are summarised in Appendix 6 (Volume 2). The time needed to adapt, test and validate these technologies has been estimated as short to intermediate (i.e. up to 5 years), with the exception of direct remote quantification (such as via sonar or multibeam techniques) which has yet to be developed in any industry and will require significant fundamental research and development. These technologies are:

- CO_2 bubble stream detection
  - the use of ship-based multibeam echo sounding or other sonar techniques to detect bubble streams.,
  - evaluation of the detection limits for bubbles, in terms of size, density and gas composition
  - the potential for microphonic technologies to detect gas bubbles from infrastructure.
- CO_2 emissions quantification
  - utilising the acoustic characteristics of gases to discriminate CO_2 from CH_4.
  - direct remote quantification via acoustic methods
  - continuous seabed/seawater monitoring

- marine eddy covariance technology which requires the development of CO_2 sensors with fast response times
- direct seabed flux measurement
- development of stable, robust, cheap and accurate pH sensors for continuous seawater pH monitoring

It was concluded in our assessment of the possible timing and magnitude of CO_2 emissions that might be expected for a range of potential leakage scenarios that leaks were unlikely to lead to CO_2 being emitted at the seabed for decades to centuries after injection ceased (Chapter 4). This raises the question as to whether the emission detection and measurement technologies, identified here, need to be prioritised for development. It is likely that the early demonstration projects, which are anticipated to start injecting within the next 5-10 years will wish to gain credits for reducing emissions within the EU ETS. It is a requirement of the ETS that if any leakage occurs then it must be detected and quantified so that the equivalent credits can be accounted for. It is not clear, however, if this means that appropriate monitoring technology must be in place before injection starts. If this is the case, then development of these technologies will be a priority since the first full-scale CCS demonstration is expected to begin injecting by 2015. However, if development of these technologies can continue after injection has started, then the need to have them developed within the next 5 years is reduced. Nevertheless, it is likely both regulators and operators, including those responsible for the emissions (i.e. the power generators) will need assurance of the capability to detect and quantitatively measure emissions to appropriate detection limits. Furthermore, it is a requirement that, in order to be able to ‘delicense’ a site and hand liability back to the Competent Authority, operators must demonstrate no leakage is taking place. In addition, if a leak were to occur the operator must be able to monitor the efficacy of any remediation undertaken and this will include the need to detect and measured CO_2 emissions to the water column. These factors suggest that such technologies are very likely to be needed at the beginning of CO_2 injection projects, including the first demonstration projects, and are probably likely to be a required component of the monitoring plan, submitted as part of the storage licence application, and as such should be a high priority for ETI support. We recommend that the ETI investigates the feasibility of supporting development and testing of emissions detection and measurement technologies for offshore storage sites. Also that consideration is given to using the technology to gather data on natural background CO_2 concentrations and fluxes over a range of offshore UK environments.

The downhole continuous geochemical monitoring technologies, for monitoring CO_2, pH or tracers will provide direct empirical data on plume migration and long-term trapping mechanisms (specifically CO_2 solution and residual trapping). These technologies will be particularly relevant to Type 1 storage sites where 3D seismic imaging of the plume is not applicable. Their shorter development times (Figure 9-1) reflect the fact that both downhole geochemical and geophysical technologies have been developed for the hydrocarbon industry but require further testing in CO_2 storage situations. In addition, downhole fluid samplers such as those developed at Frio and at Otway could be further developed for remote, offshore operation. Their higher deployment costs (Figure 9-1) reflect the requirement for possible drilling of specific observation wells with associated ship, equipment and labour costs and/or access to injection wells and potential increased maintenance costs for instrumentation deployed in an offshore well. Developing long term sensors of necessity requires lengthy periods to demonstrate they will survive – at least extrapolating from several years of deployment without degradation.

The potential benefits of an onshore test facility for developing and testing downhole monitoring technologies have already been discussed. However, the first demonstration projects also provide further opportunities for technology development. It is recognised that the primary aim of these demonstrations is to show the feasibility of a range of full-chain CCS projects at full-scale in a commercially realistic manner – they are not primarily research programmes.

Nevertheless we strongly recommend that the ETI engage with both DECC and project proponents to explore the potential for undertaking research, development and technology demonstration projects in support of these larger industrial CCS demonstration projects. While the costs of providing test facilities for offshore research will be significant, they will be less than having a dedicated standalone offshore facility. Joint development with industrial demonstration and those pilot or research projects of most direct relevance (such as those in the Netherlands) will ensure technology development is relevant and meets the specific monitoring requirements of the developers.

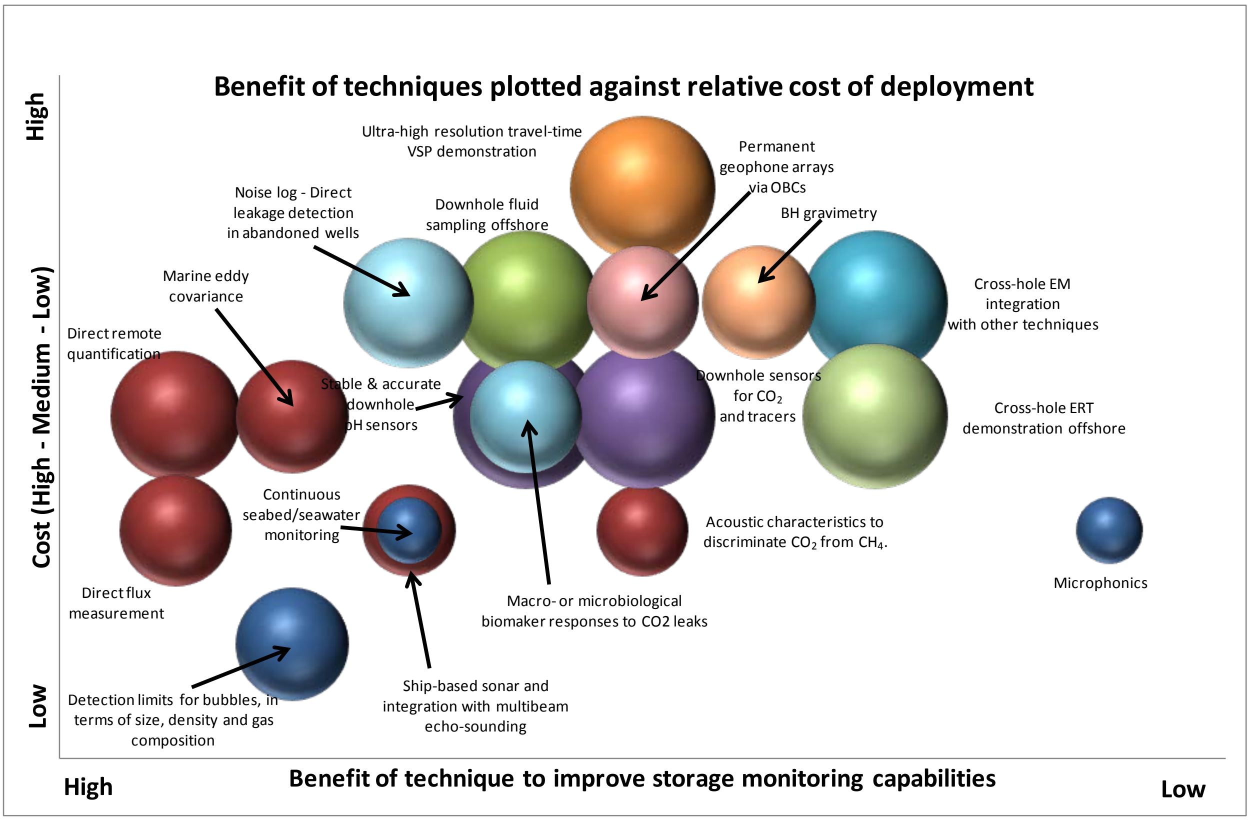

Figure 9-2: Benefits of novel techniques identified as requiring further development, testing and demonstration for monitoring CO_2 storage plotted against the estimated relative cost of deployment (high, medium or low). The size of each sphere represents the estimated cost of development on a scale of 1 to 5, with 5 being highest relative cost and 1 being lowest relative. Note: Red spheres are CO_2 bubble stream quantification technologies; blue spheres are bubble stream detection technologies and purple spheres are downhole geochemical technologies.

As has been noted above, costs of development are very difficult to estimate and here we provide only relative costs (as indicated by the diameter of the spheres in Figure 9-2). Generally the novel downhole monitoring technologies have higher development costs than the emissions detection and measurement technologies. Their higher development costs reflect the need to test in a wellbore which is exposed to a CO_2 plume. The potential benefits of developing onshore test facilities and to collaborate with early demonstration projects have been discussed above. The ship-based technologies have lower development costs since the technologies are already mature and continuing to develop for the marine surveying industries. Nevertheless the testing of these technologies with a controlled CO_2 bubble stream, as discussed above, will require development programmes to overcome significant permitting barriers and also involve significant costs for developing the test facility. However if such a facility were developed, then it could be used to test and develop a range of these ship- and seabed monitoring technologies.

We are aware of some EC FP7 projects (such as ECO2) that may provide the first steps in developing these facilities and, we recommend the ETI consider the benefits of supporting such programmes. Consideration could also be given to developing an onshore facility for initial testing.

9.5 CONCLUSIONS

A range of monitoring technologies have been identified as requiring further development and testing in CO_2 storage applications and these can be summarised as:

1. Leakage detection and measurement (emissions quantification) technologies including both survey, point and continuous data collection
    a. Bubble detection and measurement using acoustic methods
    b. Measurement of gas concentrations and fluxes and their use to gather background data for different environments
2. Continuous monitoring technologies, primarily monitoring geochemical processes, in boreholes.
3. High resolution time-lapse monitoring for detailed assessment of plume migration via borehole instrumentation
    a. VSP
    b. Permanent geophone arrays deployed in ocean bottom cables (OBCs)
    c. Cross-hole ERT
    d. Cross-hole EM
4. Well integrity monitoring using noise logs and establishing detection thresholds for wellbore leakage using existing, or refined techniques

Through a consideration of the regulatory requirements and the types of storage sites, including the potential high-level risks associated with each, the monitoring needs for UK offshore storage sites have been defined. A review of current technologies indicates that the expected monitoring requirements are, in general, likely to be met by existing available technologies, including likely future improvements in these technologies that are being driven by other offshore industries. No major gaps have been identified that require the development of completely new technologies. Rather, a number of incremental improvements and especially the testing of currently available technologies in specific CO_2 storage projects are required.

Recommendations are:

- Some downhole monitoring technologies require further development and testing in CO_2 storage projects. Research and development offshore is likely to be very expensive. Consideration should therefore be made to assess the feasibility for creating an onshore borehole technology test facility for CO_2 storage monitoring. The feasibility study should include consideration of objectives, scope, appropriate location (geologically relevant), infrastructure needs, capital and operational costs, funding opportunities, the permitting requirements and other options (such as partnering with existing facilities internationally).
- We recommend the ETI consider the benefits of supporting development programmes to develop marine CO_2 emission measurement technologies capable of quantifying the amount of CO_2 that might leak from a storage site, either directly through in situ measurement or by more advanced remote measurement (requiring significantly more fundamental research and development). We are aware of proposals from European research consortia that, if successful, may merit further ETI support and extension. The development of offshore test facilities, while undoubtedly providing very important, much

needed and unique opportunities to evaluate shallow and seabed monitoring technologies, would require significant costs and is likely to face permitting challenges. Other options that should be further explored include setting up an onshore facility for initial testing and the use of natural CO_2 systems, , particular where emissions occur in the German sector of the North Sea, or in volcanic areas, that can be used to develop and test equipment.

- We recommend that the ETI considers how best to encourage further developments in assessing well integrity, especially in plugged and abandoned wells (including wells containing one or more sidetracks) and in detecting deterioration in well integrity with time. This should take into account the independent developments likely to be made by service companies and other projects, such as CCP3, and will require dialogue with them..
- We recommend that the ETI considers further assessment of the potential for integrated permanent monitoring technologies for the UK offshore environment, taking into account the benefits, challenges (installation, remote operation, maintenance, data retrieval, lifetimes and durability), and optimal configurations for the generic storage types.

We strongly recommend that the ETI engage with both DECC and project proponents to explore the potential for undertaking research, development and technology demonstration projects in support of the planned UK CCS industrial demonstration projects. While the costs of providing test facilities for offshore research will be significant, they will be less than having a dedicated standalone offshore facility. Joint development with industrial demonstration projects will ensure technology development is relevant and meets the specific monitoring requirements of the developers.

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British Geological Survey holds most of the references listed below, and copies may be obtained via the library service subject to copyright legislation (contact libuser@bgs.ac.uk for details). The library catalogue is available at: http://geolib.bgs.ac.uk.

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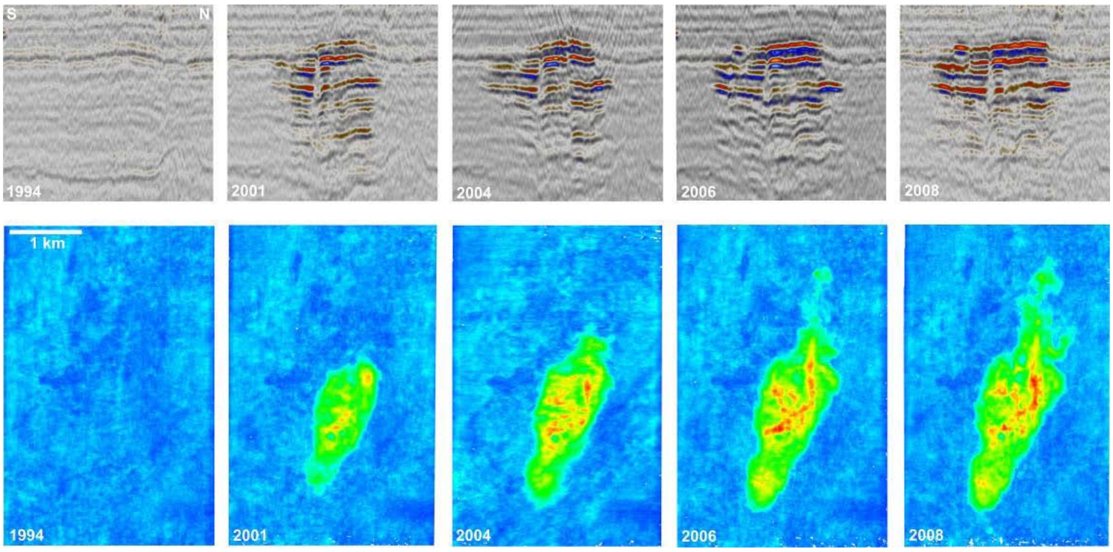
Measurement, Monitoring & Verification of CO_2 Storage: UK Requirements - Final Report: Volume 2

Energy Programme

Commercial Report CR/10/030



BRITISH GEOLOGICAL SURVEY

ENERGY PROGRAMME

COMMERCIAL REPORT CR/10/030

Measurement, Monitoring & Verification of CO_2 Storage: UK Requirements - Final Report: Volume 2

British Geological Survey: D.G. Jones, R.A. Chadwick, J.M. Pearce, C.J. Vincent, S. Hannis, D. Long, W.J. Rowley, S. Holloway, M.S. Bentham, A Kingdon.

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Repeated 3D seismic surveys across the CO_2 plume in the Utsira Formation, Sleipner. Courtesy BGS.

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Detailed technique descriptions

10 Review of measurement, monitoring and verification technologies

10.1 EXECUTIVE SUMMARY

This chapter reviews the various measurement, monitoring and verification (MMV) technologies currently available or known to be in development. Many of these technologies are well known and widely used in the hydrocarbons industry, where they have applications in reservoir monitoring and subsea site investigations. Their suitability for similar uses in CO_2 storage is discussed. The methods are classified according to their depth of focus, whether or not they are invasive, the type of property they measure and the maturity of their technologies.

Deep focussed methods are used for monitoring the reservoir, cap rock and immediate overburden. Based on reliable technologies used in the hydrocarbon industry for monitoring oil and gas reservoirs, they are used to assess the location, size and movement of the injected CO_2 plume, the effectiveness of the injection operation and any incipient failure in the integrity of the reservoir itself. **Shallow focussed** methods are based on widely used technologies for offshore site investigations. They are used for direct detection of gas migration into shallow sub–seabed sediments, leakage from the seabed or the presence of gas in the water column.

Invasive technologies provide direct measurements of physical or chemical properties within the reservoir, cap rock and overlying strata, usually by deployment of sensors in injection or observation boreholes. They provide high–value information for managing the reservoir and possible immediate detection of seal failure, but carry a higher risk of triggering a leakage from the borehole. **Non–invasive technologies** provide indirect evidence of conditions in the reservoir and associated rock volume through external measurements of physical properties. They also provide high–value information for reservoir management, with little risk of affecting reservoir integrity; however results require more interpretation and they generally do not provide immediate indications of critical situations.

Most of the technologies measure **physical properties**. This may be done directly, for example using a pressure sensor in a borehole; or indirectly, for instance as the result of analysing data from a seismic survey to determine acoustic velocity. The other methods measure **chemical properties**, to provide vital information on CO_2 concentrations in groundwater and the seawater column, other gases with the CO_2 and their likely source; that is if they match the gases injected into the reservoir, and pH. Physical and chemical properties need to be used together, for example sidescan sonar surveys may indicate a gas release pock mark on the seabed, but chemical sampling is needed to determine the source and composition of the released gas.

Many of the deep focussed techniques have been successfully tested with CO_2 at various test storage sites. These include 2D and 3D seismic evaluated at Sleipner (North Sea), multi–component seismic and microseismicity tried at Weyburn (Canada), cross–well seismic at Nagaoka (Japan) and vertical seismic profiling at Frio (USA). Other deep focussed techniques have been tested but are less well established; including electromagnetic logs tested at Lost Hills Oilfield (USA), conductivity logging at Frio, electrical resistivity tomography tried at the Vacuum Oilfield (USA) and gravimetry at Sleipner.

The majority of the shallow techniques have not been tested for monitoring CO_2 migration or leakage, so techniques which have successfully imaged seabed features, including pockmarks created by the escape of methane gas, have been considered. These include multibeam echo sounder and sidescan sonar images of the seabed and shallow sub–surface techniques (generally from the top few metres down to one kilometre) including boomer, pinger and chirp surveys. Detection of bubbles in the water column has also been considered using acoustic methods. New tools are under development, for example, one based on equipment used for locating shoals of fish.

Downhole well logging tools have also been reviewed, including standard geophysical logs such as pressure and temperature, tested at Pembina (USA), and resistivity as tried at Nagaoka. Some tools under development or where further development is needed were also identified. For example, tools designed to withstand harsh downhole conditions for long periods are not yet available to monitor long–term downhole pH. Monitoring techniques which could be used in conjunction with other surveys such as tiltmeters, tracers (tested at Frio) and ecosystem effects were also considered.

10.2 INTRODUCTION

A comprehensive portfolio of tools is available for CO_2 storage site monitoring and a number of publications have drawn up lists of monitoring tools and made suggestions for possible monitoring systems. This report draws on and updates information from a number of published sources, notably the IEAGHG Monitoring Tool:
http://www.co2captureandstorage.info/co2monitoringtool/

This is supplemented by other studies (e.g. Chadwick et al., 2009a, Pearce et al., 2005, Benson et al. 2004, Arts and Winthaegen 2005 and Winthaegen et al., 2005).

Broadly speaking, tools can be categorised as deep–focussed, for reservoir measurements and tracking of CO_2 in the subsurface, or shallow–focussed for detection and measurement of CO_2 migration or leakage, at or close to the surface (Figure 10–1). The deep–focussed tools mainly correspond to mature oil industry technologies, but are relatively untested for CO_2 monitoring, whereas the shallow monitoring methodologies are commonly novel and / or under development. Tool types can also be categorised as invasive (i.e. requiring borehole deployment) and non–invasive, which can be quite important in terms of cost and the possibility of compromising storage site integrity.

Monitoring tools have been deployed at a number of CO_2 injection projects around the world in various combinations, including offshore sites at Sleipner and Snøhvit (offshore Norway) and K12–B (Netherlands), and several industrial and pilot–scale onshore sites, for example: Weyburn (Canada), In Salah (Algeria), Cranfield (US), Nagaoka (Japan), Frio (US), Ketzin (Germany) and the Otway Basin (Australia).

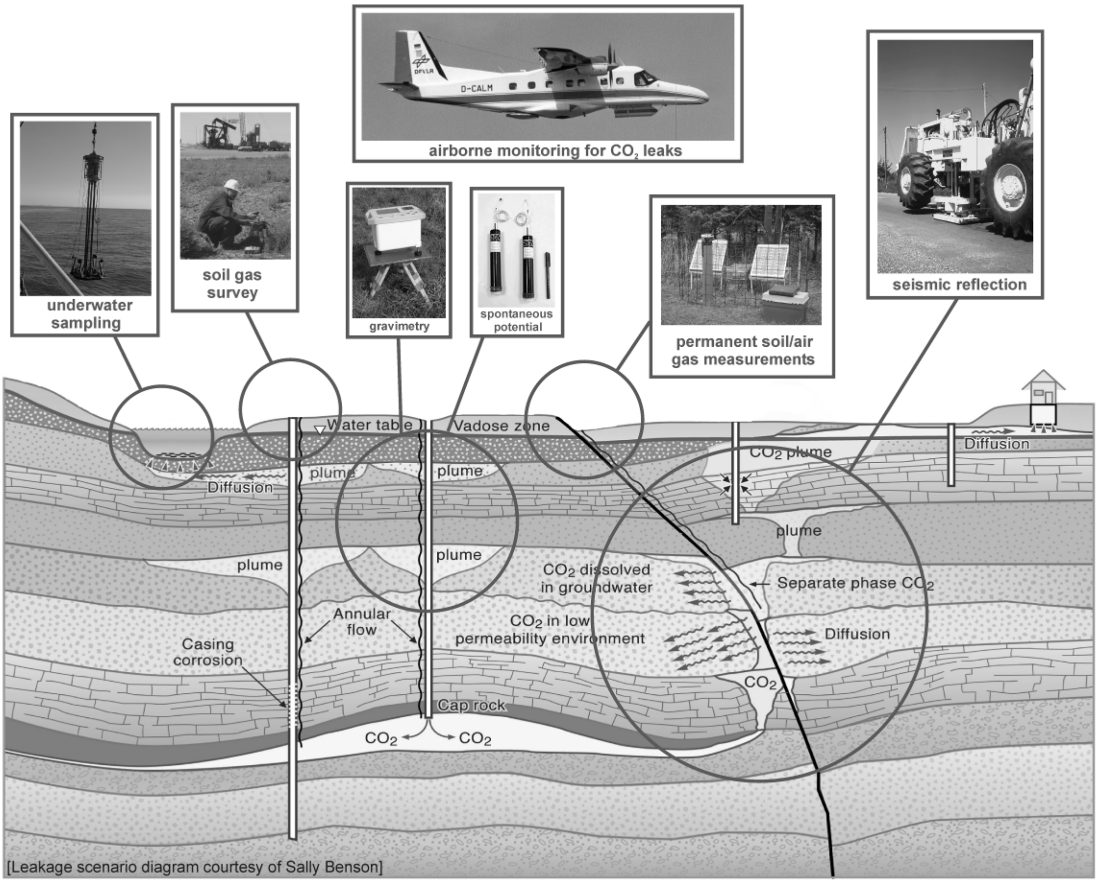

Figure 10-1: Cartoon of storage site migration and leakage scenarios with typical monitoring technologies (from Chadwick et al., 2009a).

10.3 SEISMIC AND ACOUSTIC TECHNIQUES

Seismic reflection surveys detect differences in acoustic impedance of the rock layers (ability of the rock to propagate sound waves). Because of its high compressibility, free CO_2, even in the dense phase, which dominates at likely storage depths, tends to be highly reflective in a range of geological situations; rocks saturated with CO_2 generally have significantly lower acoustic impedance than rocks filled with water. On the other hand if depleted hydrocarbon fields are used for storage, changes in acoustic impedance are not so marked and can be more difficult to predict. A limitation of seismic techniques is that dissolved CO_2 cannot be imaged directly on seismic data; so over long periods of time, the injected CO_2 will become more difficult to monitor with seismic tools. Additionally, McKenna et al. (2003) observed that the performance of seismic methods for monitoring CO_2 depends strongly on the reservoir properties and geological setting. Compacted, low porosity, low permeability (deep) reservoirs are generally less suitable for time–lapse monitoring than unlithified porous (shallow) formations.

There is some concern that low frequency sound can be harmful to marine life such as whales and dolphins, although the main concerns are linked to more powerful military applications. There are recommended procedures such as slow or soft start–ups and only during hours of daylight, as well as employing cetacean monitors (or Marine Mammal Observers (MMO). Regulations such as IACS E10 limit vibration, electromagnetic field strength and other parameters.

10.3.1 Offshore 3D/4D surface seismic reflection survey

Offshore 3D seismic data is acquired via ship–based marine survey. An acoustic source (commonly comprising an array of multiple airguns or water guns) produces a high pressure bubble that creates a propagating pressure wave. After being reflected from subsurface features the acoustic pressure wave is recorded by a complex streamer with many receivers (hydrophones) that is towed behind the ship.

A regular grid of seismic profiles is acquired using multiple sources and receivers (can be up to several thousand receivers) to produce a continuous 3D volumetric image of the sub–surface (Figure 10–2**.**).

3D seismic is the tool of choice of the hydrocarbon industry for exploration and monitoring during production of oil and gas resources. Offshore 3D seismic has also been used at Sleipner to image the injected CO_2 (see case study below). Raw data requires considerable processing on specialist software before it can be used to interpret the rock layers and CO_2 plume. The technique is generally used for interpretation of relatively deep (hundreds to a few thousands of metres below seabed) reservoirs.

A key application of 3D seismic for CO_2 monitoring is in time–lapse mode, when repeated surveys (time–lapse 3D or 4D), are used to monitor the distribution of the plume though time. Also, because the 3D seismic images the overburden as well as the storage reservoir (Figure 10–2**.**), it offers the key ability to detect and track any migration of CO_2 out of the reservoir and into the overburden. However, for migration out of the reservoir to be detected, suitable and sufficient accumulations of CO_2 should be produced.

The cost of a single small offshore 3D survey in the North Sea was estimated at 1.75 million GBP (2008). The estimated costs for 10 repeat surveys every 5 years, in the North Sea are around 33 million GBP (IEAGHG 2010).

10.3.1.1 Case study (CO_2): Sleipner project

Repeated 3D surveys have been acquired over the Sleipner site (1994, 1999, 2001, 2002, 2004, 2006, 2008), before and during injection. Key aims of the seismic monitoring are to track plume migration, demonstrate containment within the storage reservoir and provide quantitative information as a means to better understand detailed flow processes controlling development of the plume in the reservoir.

The CO_2 plume is imaged as a number of bright sub–horizontal reflections within the reservoir, growing with time (Figure 10–3**.**). The reflections mostly comprise tuned wavelets arising from thin (mostly < 8 m thick) layers of CO_2 trapped beneath very thin intra–reservoir mudstones and the reservoir caprock. The plume is roughly 200 m high and elliptical in plan, with a major axis increasing to over 3000 m by 2008.

As well as its prominent reflectivity, the plume also produces a large velocity pushdown caused by the seismic waves travelling more slowly through CO_2–saturated rock than through the virgin aquifer (Figure 10–4**.**). Pushdown is a key quantitative parameter. Analysis of reflectivity and velocity pushdown by Chadwick et al. (2005) was able to account for around 85% of the known injected amount of CO_2. Bearing in mind intrinsic uncertainties, particularly regarding CO_2 saturations, and a likely few percent of dissolved CO_2, this model is considered to be a satisfactory quantitative match and a fair representation of the sub–surface distribution.

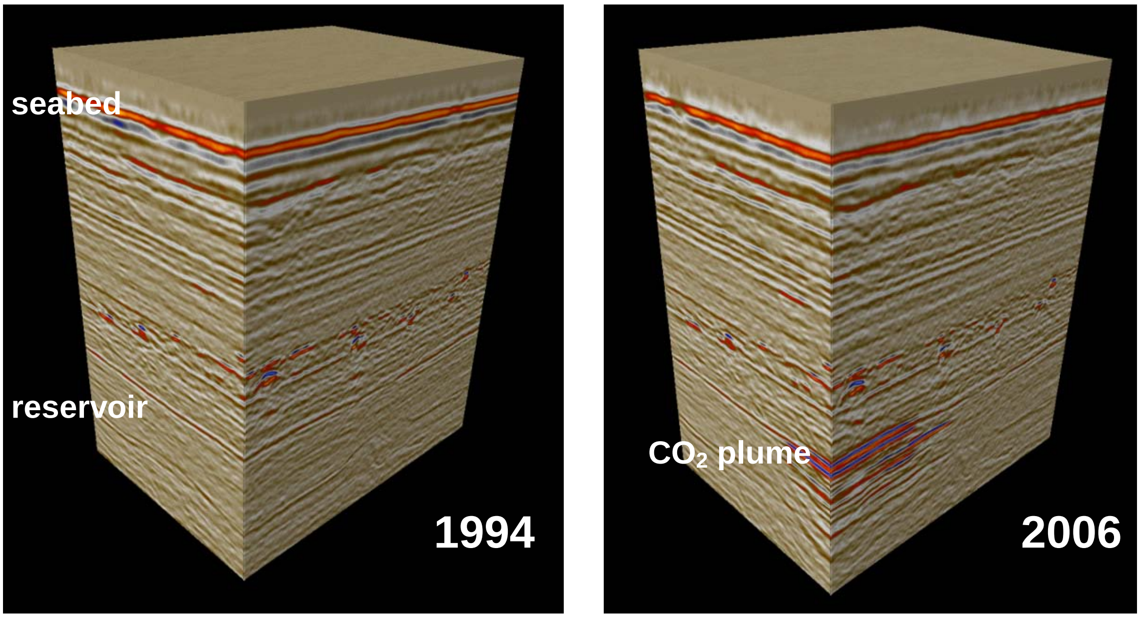

Figure 10-2: 3D seismic cubes from Sleipner. Note the data forms a continuous 3D image of the subsurface (image courtesy British Geological Survey)

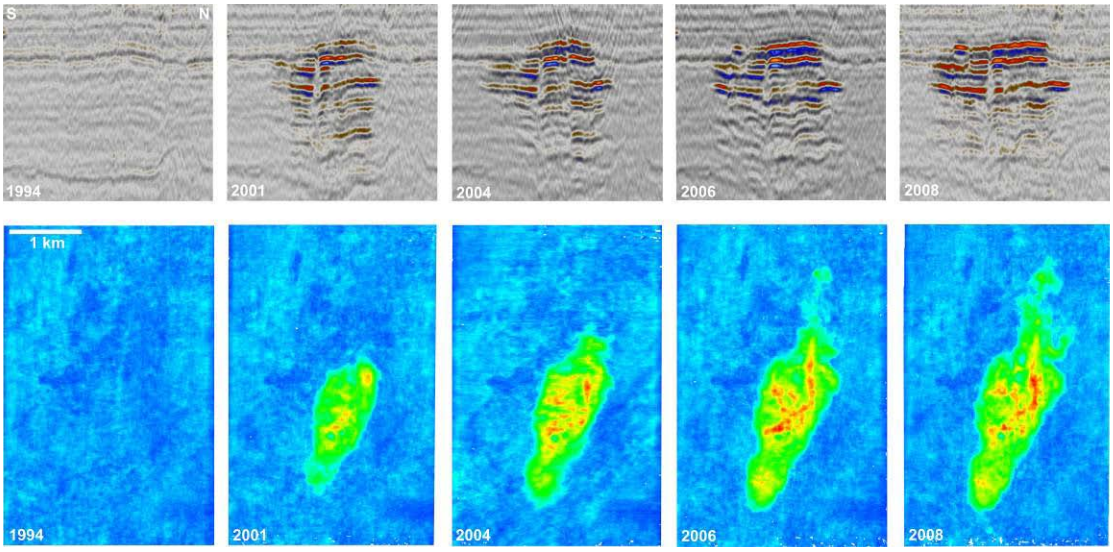

Figure 10-3: Repeated 3D seismic surveys of the Sleipner plume. Top panels show 2D cross–sections through the CO_2 plume. Bottom panels show plan view of the growing CO_2 plume (image courtesy British Geological Survey)

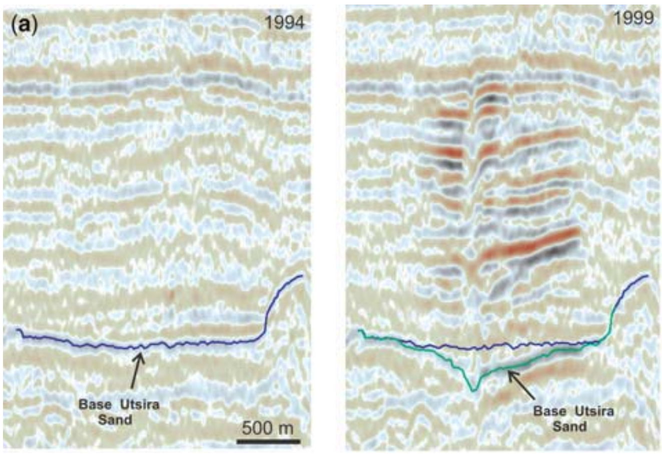

Figure 10-4: Velocity push–down observed under the CO_2 plume at Sleipner, the dark blue line shows the base of the Utsira sand as observed in 1994, the panel on the right shows the reflection from the base Utsira sand arriving later in 1999 after injection of CO_2. Note the vertical scale is two–way travel time, not depth (Chadwick et al., 2009a).

10.3.2 Offshore 2D seismic reflection survey

A 2D seismic survey at sea usually comprises a series of straight–line profiles acquired in a similar, though less complicated manner, to 3D seismic. 2D seismic is an established technique in the hydrocarbon industry, where it has been used to explore for resources and with repeated surveys to monitor fluid changes in reservoirs through time. The raw data requires considerable processing using specialist software before it can be used to interpret the rock layers and presence of CO_2. This technique is generally used for imaging of deep (hundreds to thousands of metres) subsurface rocks.

2D seismic is cheaper to acquire than a 3D seismic survey, so may be used for initial reconnaissance of a region.

A limitation of the technique is that due to the non–continuous surface coverage, 2D seismic cannot be used to verify the mass of CO_2 underground. However, repeated time–lapse seismic can be used to monitor migration of the CO_2 plume.

10.3.2.1 CASE STUDY (CO_2): SLEIPNER PROJECT

High resolution 2D seismic was deployed at Sleipner in 2006 to improve understanding of finer scale plume structure. A more–or–less star–shaped pattern of lines was acquired, centred on the plume (Figure 10–5).

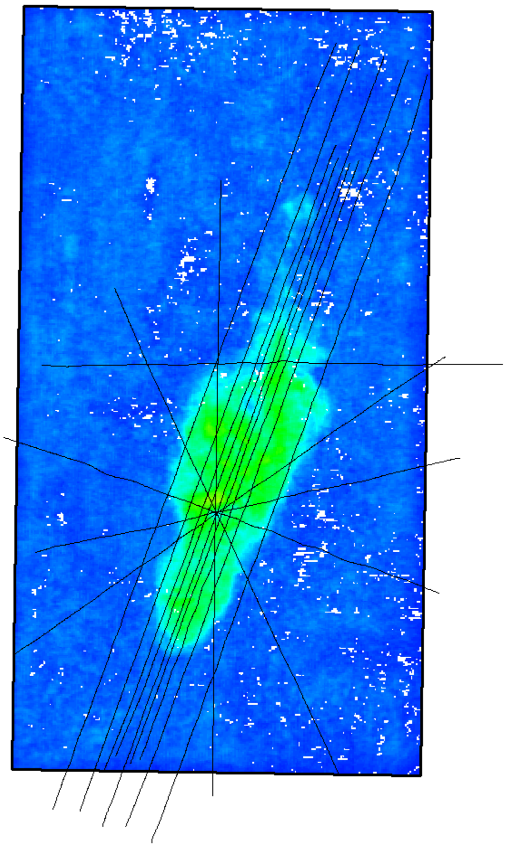

Figure 10-5: Map of 2D high resolution seismic line locations at Sleipner, superimposed on the rectangular area of the 3D seismic surveys. The backcloth shows integrated reflectivity in the Utsira Sand, the plume footprint showing as higher values (in green) (image courtesy British Geological Survey).

An example of the data is shown below (Figure 10–6). The plume is imaged clearly on the 2D data with finely–detailed resolution of the upper CO_2 layers. The deeper plume is less satisfactorily imaged however, because of signal attenuation and problems with multiples due to the relatively restricted range of source–receiver offsets available from this type of survey

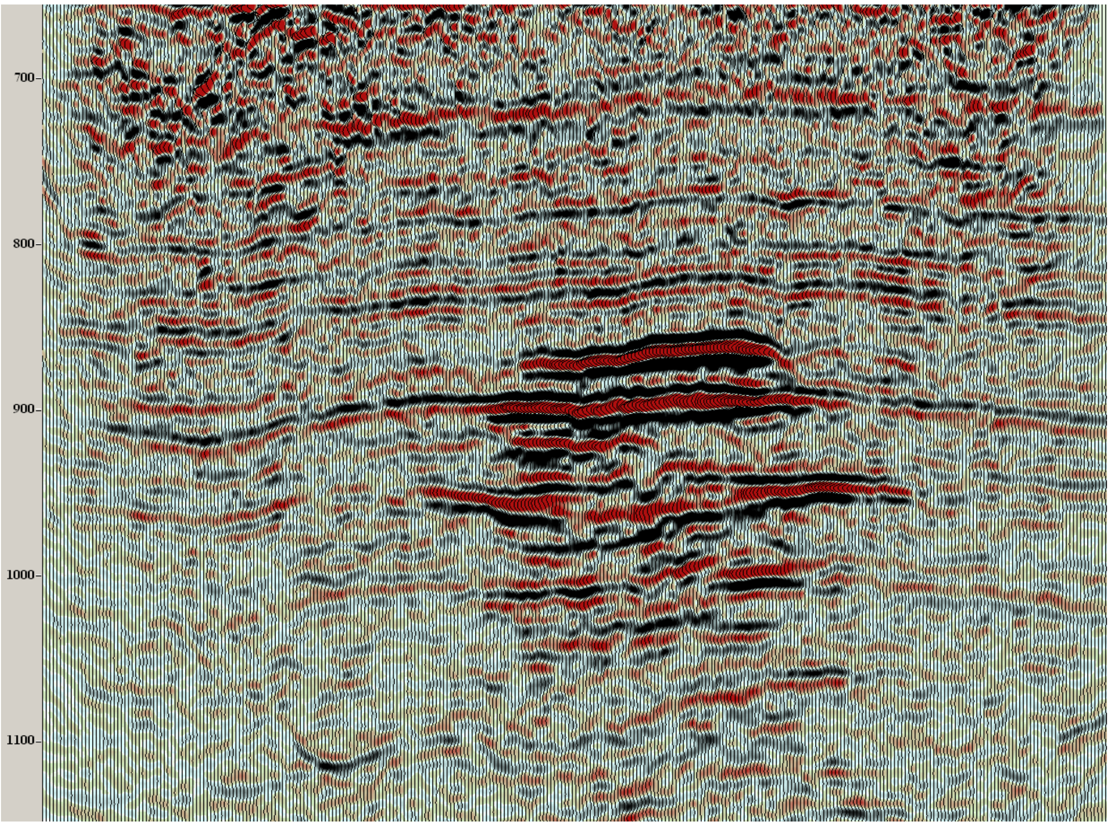

Figure 10-6: 2D high resolution seismic line through the Sleipner CO_2 plume in 2006 (image courtesy British Geological Survey).

10.3.3 Multicomponent surface seismic

Multicomponent seismic records both pressure (P) and shear (S) waves produced from the seismic source. Marine multicomponent seismic uses converted shear wave energy and requires receiver deployment on the seabed (shear waves cannot travel through water). Usually two ships are employed, one as a source vessel and the other to deploy the receiver ocean bottom cable (OBC) or receiver packages on the seabed.

The technique can be used to obtain a more complete characterisation of the subsurface, being more sensitive to fluid pressure and saturation changes than single component seismic. Shear waves are more sensitive than P waves to fractures and less sensitive to fluid content. It can be used to infer location and density of fractures and microfractures, and may potentially indicate areas where increased pore fluid pressure, resulting from injection of CO_2, has opened fractures. Shear wave anisotropy is when the S wave splits in structurally anisotropic material, into 'fast' and 'slow' orthogonal waves which arrive at different times at the receiver. The time difference and polarity of the split S waves can be used to infer fracture density, dilation, intensity and orientation.

Multicomponent techniques are more expensive than single component seismic as the receivers are more expensive and the cost is increased offshore as sea bottom deployment is required. It is an established technique for the hydrocarbon industry where it has been used to study fluid flow during primary, secondary and tertiary oil recovery. Multicomponent data requires very complex processing and analysis to make the most of its inherent capability.

10.3.3.1 Onshore case study (CO_2): Vacuum project

A pilot CO_2–EOR (CO_2–enhanced oil recovery) was undertaken in the Vacuum field, New Mexico in 1995. Two multicomponent seismic surveys were acquired eight weeks apart. Carbon dioxide was injected into fractured dolomite of the San Andres Formation, which lies at a depth of around 1310 m, through a single well shown as a yellow square in Figure 10–7 (Angerer et al., 2002; Talley et al., 1998).

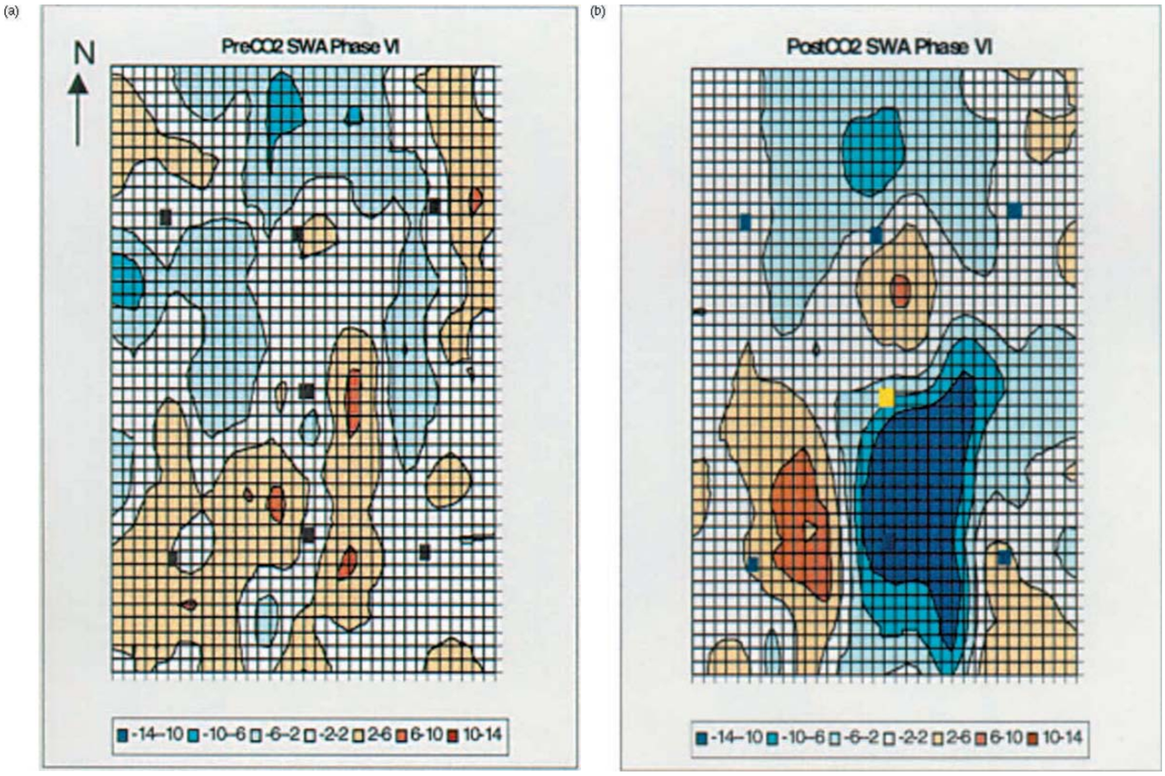

Figure 10-7: Shear wave anisotropy of the San Andres Formation, Vacuum field; pre and post CO_2 injection (%) (Angerer et al., 2002, reproduced with permission of Wiley–Blackwell.)

A baseline survey was shot before injection which showed generally negative anisotropy values (the S wave component parallel to the maximum horizontal stress is slower than the S wave component parallel to the minimum horizontal stress). Comparing the baseline survey with the results of the post injection survey showed an average 10% increase in relative anisotropy. The P wave velocities show a decrease of on average 2%. Overall, the P and S wave velocities decreased, it was concluded this was a result of CO_2 injection saturating pore space with low velocity fluid and pore fluid pressure increases widening fractures.

10.3.3.2 Onshore case study (CO_2): Weyburn, Canada

The Weyburn storage project is based around CO_2–EOR in a carbonate reservoir. The reservoir lies at depths of about 1450 m and is divided into an upper marly lower permeability (10 mD) unit and a lower vuggy higher permeability unit (15 mD). CO_2–EOR operations began in October 2000, CO_2 being injected as a miscible flood (pressure and temperature are such that CO_2 can dissolve into the oil) at a rate of 5000 tCO_2/day (Davis et al., 2003; Preston et al., 2005). It is anticipated that this project will eventually recover an additional 15 % of the original oil in place (OOIP). As part of the monitoring programme, the Weyburn Project acquired time–lapse, multicomponent (9 component) seismic surveys in 2000 (before injection), October 2001 and October 2002. The baseline survey indicated the presence of east–trending fracture zones in the reservoir.

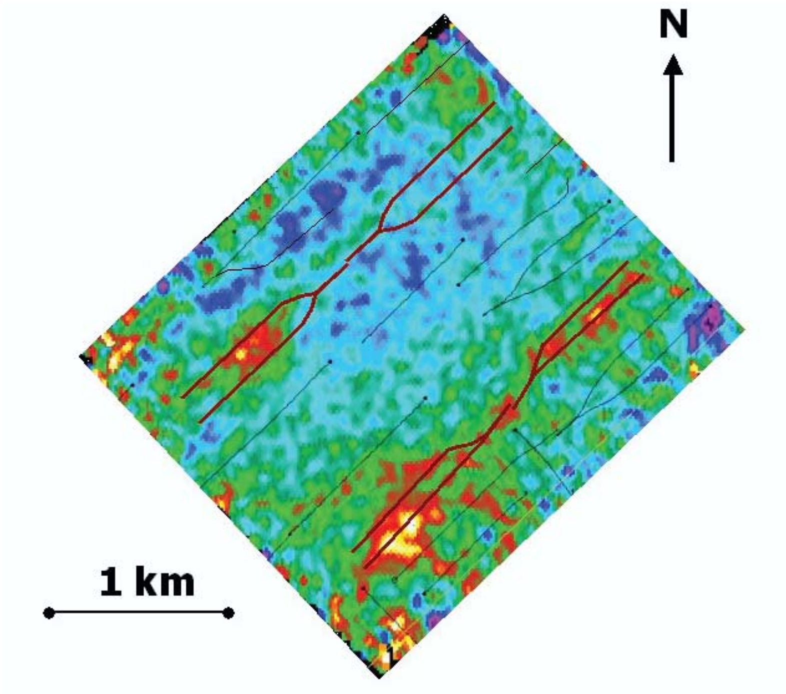

Figure 10-8: Difference in P–wave RMS amplitude between the 2001 and 2000 surveys, the red forked lines show the CO_2 injectors. Regions where amplitude has increased (warm colours) show where acoustic impedance has decreased. This map was interpreted to show that CO_2 moved preferentially along the fracture network (Davis et al., 2003) (reproduced with permission of the Society of Exploration Geophysicists).

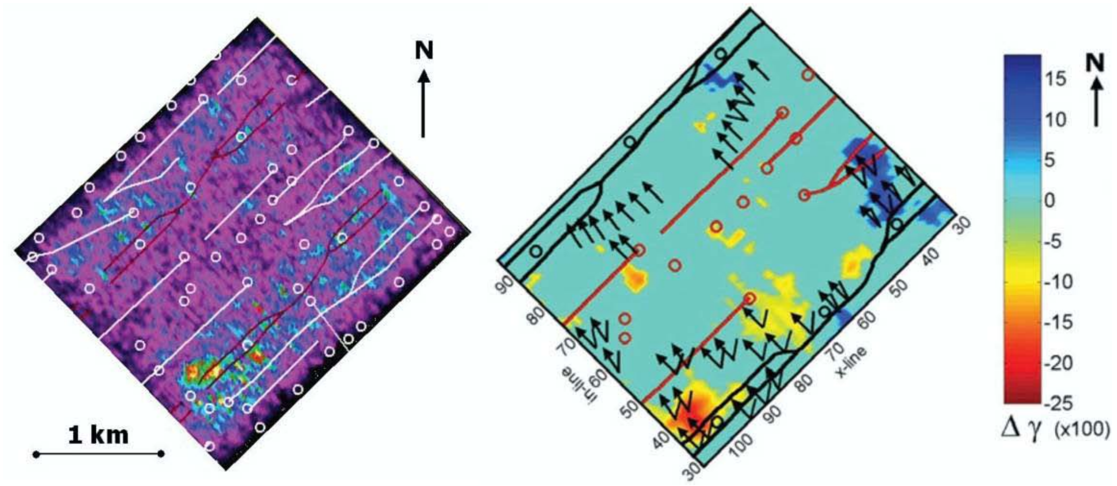

Figure 10-9: Difference between the S–wave RMS amplitudes for the 2001 and 2000 surveys showing an anomaly in the south of the reservoir (left panel) and difference in the amplitude–derived shear wave splitting data where arrows indicate the fast S–wave polarisation direction with anomalies in the south and east (right panel) (Davis et al., 2003) reproduced with permission of the Society of Exploration Geophysicists).

The P– and S–wave data were interpreted to show that CO_2 is moving preferentially along the west–west fracture network in the south of the reservoir (Figure 10–8). The shear wave splitting data (Figure 10–9) indicated that a fracture trend could be opening up in the region of the eastern injector where salt dissolution is changing from east–west trending to north–south trending (Davis et al., 2003).

10.3.4 Vertical seismic profiling (VSP)

In vertical seismic profiling (VSP) a seismic source is located at a wellhead with multiple receivers deployed down the wellbore. In more generalised forms known as walkaway or 3D VSP, multiple seismic sources are deployed around the wellhead, giving 2D or 3D subsurface imaging around the wellbore. Compared to surface seismic, it can produce improved resolution around the well, and offers the opportunity to monitor for leakage through or around the wellbore. Repeat surveys with sources progressively further from the well and multiple profiles can be used for 3D imaging and characterisation of the subsurface.

This is an established technique in the oil industry and has been tested with CO_2 storage where a small quantity of CO_2 (1600 tonnes) produced a detectable response.

A limitation of the VSP technique is that it only provides data over a limited area around the wellbore, so without a dense population of wells around the plume volumetric imaging of the plume and overburden is not possible. Also, unlike surface seismic, VSP data does not provide uniform coverage in terms of source receiver configuration (azimuths /offsets) so does not image the subsurface in a laterally consistent way.

10.3.4.1 Onshore case study (CO_2): Frio, Texas

For the Frio brine aquifer pilot study (Hovorka and Knox 2002), around 1600 tonnes of CO_2 were injected at a depth of approximately 1500 m (Figure 10–10). The Oligocene Frio Formation reservoir mainly comprises fluvial sandstones with localised shales/mudstones (Daley et al., 2006, Daley et al., 2008). This case study shows vertical seismic profiling can have high sensitivity to CO_2.

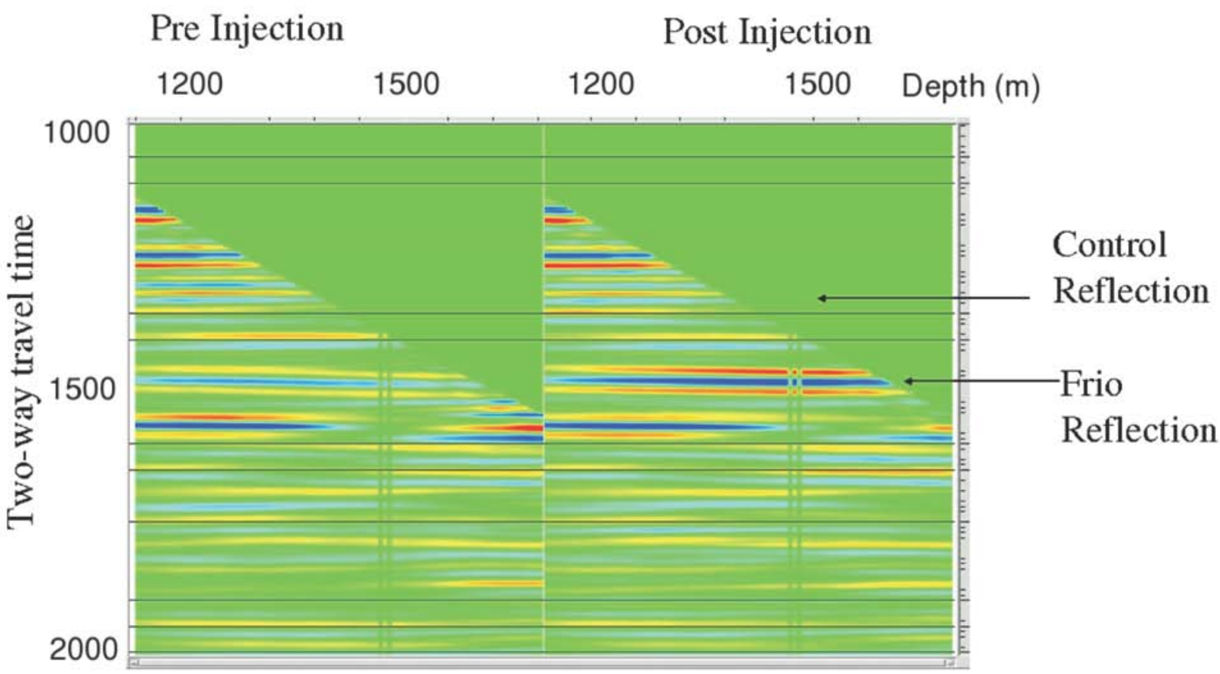

Figure 10-10: VSP reflection section at Frio showing increased amplitude at the reservoir level after CO_2 injection (image courtesy Tom Daley (LBL)).

10.3.5 Microseismic monitoring

In microseismic, or passive seismic, monitoring, low–level seismic events are recorded using surface or downhole receivers. The events are measured and triangulated, the main objective being to assess the geomechanical stability of the storage site and, in extreme cases, any induced seismic hazard due to injection. The error of locating the events increases with increasing distance from the monitoring borehole and is affected by the stratigraphy and its ability to conduct sound (ESG, 2009). The type of movement along the fracture which resulted in the microseismic event is also inferred from the geophone response to assess if the microseismic event is associated with CO_2 injection or other sources (e.g. oilfield operations). The technique can also be used to map the velocity structure of the subsurface using velocity tomography. By monitoring over time, this method could theoretically be used to map migration of the plume through induced fracturing or fracture reactivation.

A limitation of the technique is that it is a ‘passive’ seismic tool relying on natural or induced events, and so many storage sites will not be suitable.

The technique is proven for the oil and gas industry where it is used to monitor hydraulic fracturing and structural imaging in mountainous regions. Most microseismic events in oilfields are of the magnitude –1 to –3 on the Richter scale with slip vectors of a few microns (le Floch et al., 2008). Recent research by Schlumberger includes permanent real–time microseismic monitoring mounted inside the well casing (engineerlive.com 2009). Microseismicity has also been used for monitoring CO_2 injection during EOR.

10.3.5.1 ONSHORE CASE STUDY (CO_2): WEYBURN, CANADA

Cenovus Energy (previously EnCana and PanCanadian) are injecting CO_2 into the Weyburn Oilfield, at a rate of around 10 kt/day. To monitor seismic events during injection, eight tri–axial geophones were cemented in a well within 50 m of a vertical injection well. Background seismicity was recorded from August 2003 until January 2004, prior to the start of injection in the nearby well. Approximately 100 locatable microseismic events were recorded (with maximum range 500 m from the monitoring well). The majority of events were low frequency, however, high frequency events were located close to the injection and observation wells due to rock dispersion effects (adsorption of energy by the rock and pore fluids). Microseismicity was recorded from December 2003 until December 2004, injection began in January 2004. The microseismic events were concentrated between the injector and the closest active production well during the last stage of water injection and during the changeover to CO_2 injection. There were relatively few microseismic events until 18 – 19 March 2004, when 15 events were detected near a shut down production well. Increased microseismicity was also recorded in July–August 2004 at the end of a period of increased CO_2 injection rate. Figure 10–11 shows the microseismic events detected from April to November 2004 overlain on the 2002 – 2004 time–lapse seismic amplitude difference. A total of 52 kt of CO_2 had been injected in the nearby injection well. As the microseismic events show reasonable correlation with the negative amplitude difference anomaly, White (2009) interpreted these results as showing the microseismicity tracking the CO_2 distribution.

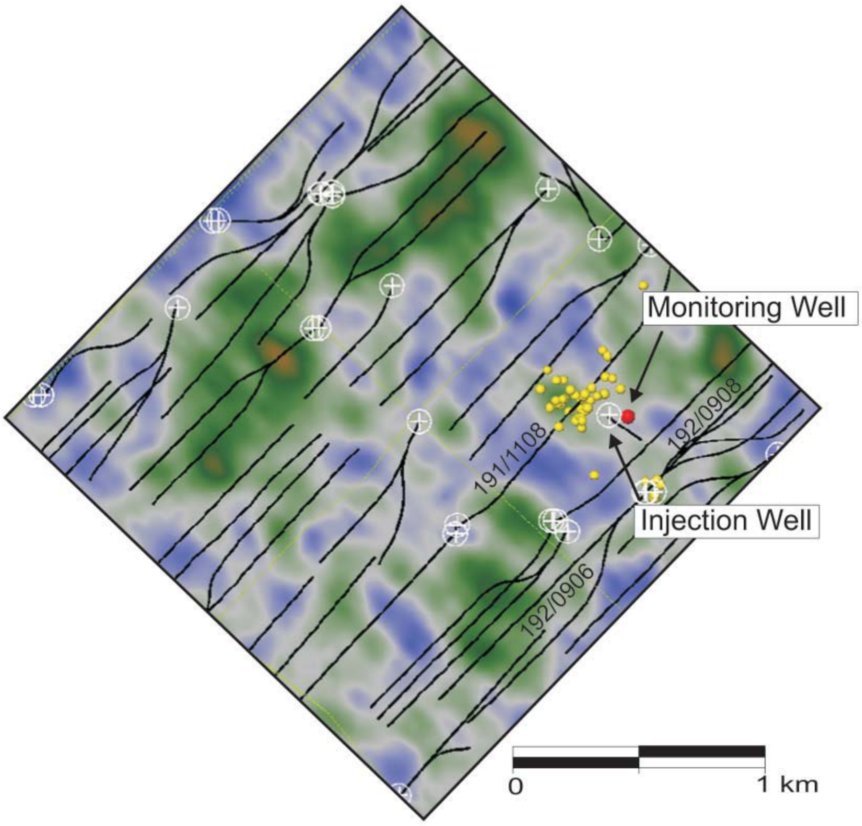

Figure 10-11: Microseismic activity (yellow dots) recorded during CO_2 injection April – November 2004 (White, 2009). By the end of this period, 51 ktCO_2 had been injected (Image reproduced with permission of the Society of Exploration Geophysicists).

10.3.6 Cross–hole seismic

Cross–hole seismic measures changes in velocity and attenuation characteristics between wells during CO_2 injection. Sources are mounted in one well and receivers in the other. These data can be used to infer CO_2 saturation and pressure. Repeated surveys can be used to monitor CO_2 movement. As cross–hole seismic uses a high frequency source (up to 1000 Hz or greater), this higher resolution data can be used to help calibrate surface–acquired seismic. Processing of the data requires specialist software.

Multi–component cross–well seismic can also be acquired using multi–component geophones, to give more detail about fluid pressure and saturation and to infer fracture density, dilation, intensity and orientation from anisotropy of shear waves.

This technique has the potential to detect small amounts of CO_2 in the subsurface which offers a potential early warning of migration into the overburden from wells.

This technique is established for the hydrocarbon industry and has been proven in the field to respond to the presence of CO_2. Pilot test suggest that quantities of CO_2 of the scale of a 1.6 – 3.2 ktCO_2 are detectable. A limitation of this method is that it requires at least two boreholes that pass close to the storage reservoir.

Costs are moderate, with a large proportion of the costs due to processing requirements. They would be high if new wells needed to be drilled.

10.3.6.1 ONSHORE CASE STUDY (CO_2): NAGAOKA, JAPAN

At Nagaoka in western Japan, approximately 10 kt CO_2 were injected into a 12 m thick sandstone reservoir at a depth of about 1000 m. Three observation wells are situated within 120 m of the injection well. Cross–hole seismic data were recorded along a 160 m long section between two of the monitoring wells, comprising a baseline survey and repeat surveys. A tomographic image from the first repeat survey (after injection of 3200 t CO_2) showed a region of reduced velocity near the injection well, interpreted as the CO_2 plume (Figure 10–12) (Sato et al., 2009).

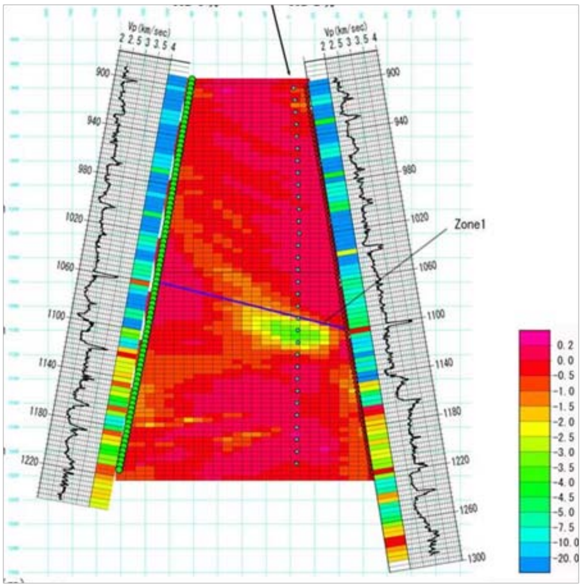

Figure 10-12: Cross–well seismic profile showing the injected 3200 t CO_2 (image courtesy of Kozo Sato, University of Tokyo, Sato et al., 2009, reproduced with permission of Elsevier)

10.3.6.2 ONSHORE CASE STUDY; FRIO, TEXAS

Approximately 1600 t CO_2 was injected into a saline sandstone formation at a depth of 1500 m below the surface over a period of 10 days. The target sandstone was the Oligocene age Frio Formation on the Gulf coast of Texas. This region had already been well characterised through oil and gas exploration and this formation has been used for fluid disposal elsewhere. The sandstone has a significant dip (16°), high porosity (up to 35%) and high permeability (2.5 D), with multiple shale seals.

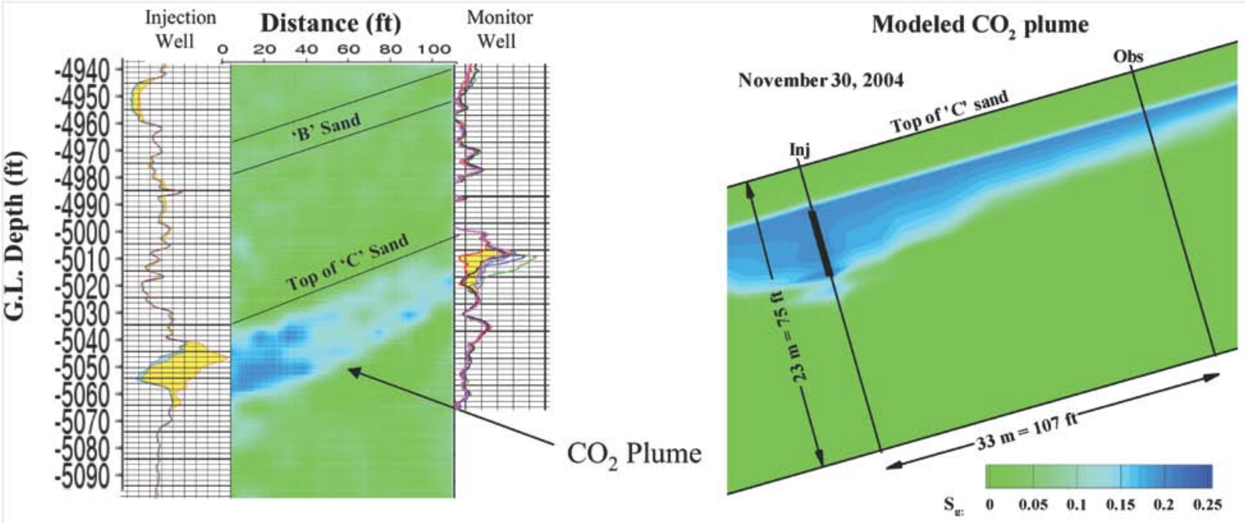

Figure 10-13: Cross–hole seismic at Frio Velocity tomography (left) compared with reservoir flow simulation (right) (Left hand image courtesy of Tom Daley (LBL), right hand image courtesy Christine Doughty (LBL)).

10.3.6.3 CROSS–HOLE SEISMIC CASE STUDY (CO_2): CALIFORNIA

A series of time–lapse seismic cross–well surveys were conducted in the Chevron–operated Lost Hills oilfield in California. In the 1970s hydrofracturing was used to improve recovery, in the 1990s water flooding was applied and in 2000 the field was selected for a CO_2–EOR pilot study. The diatomite reservoir porosity is 45 – 70%, pore size is less than 5 µm and permeability is less than 1mD. CO_2 injection began in August 2000 at a rate of 3.5 million m^3/day and was gradually increased to 12.0 million m^3/day per injection well (Gritto et al, 2003). However, these quoted figures seem very high, with Benson and Meyer (2002) quoting an injection rate of 175,000 cf/day (i.e. about 6,000 m3/day). The injection pressure was held at 5.5. – 6.2 MPa and reservoir temperature was about 41°C (Gritto et al, 2003).

The first pre–CO_2 injection surveys conducted in 2000 used a high frequency seismic P–wave source (800 – 3500 Hz) and hydrophone receivers. The second survey used an intermediate S–wave source (70 – 350 Hz) and three–component geophones. The post–CO_2 injection surveys were conducted in May 2001. These used the same sources as the pre–CO_2 injection surveys, but hydrophones were used as the receivers due to technological improvements. Inversion and processing of the data showed that the P–wave velocities dropped slightly throughout the reservoir, but with no clear localised velocity change to indicate the presence of CO_2. The largest drop in velocity (~5%) was observed above the fault, which may indicate CO_2 has migrated here (Figure 10–14). The S–wave results also show a small decrease in velocity, and the difference in the pre–and post–CO_2 injection surveys is small; the main decrease in velocity (~9%) is observed within the reservoir (Figure 10–15**.**). It was interpreted that these results showed that CO_2 had dissolved into the liquid phase in the reservoir rock and increased the pore pressure in several reservoir compartments.

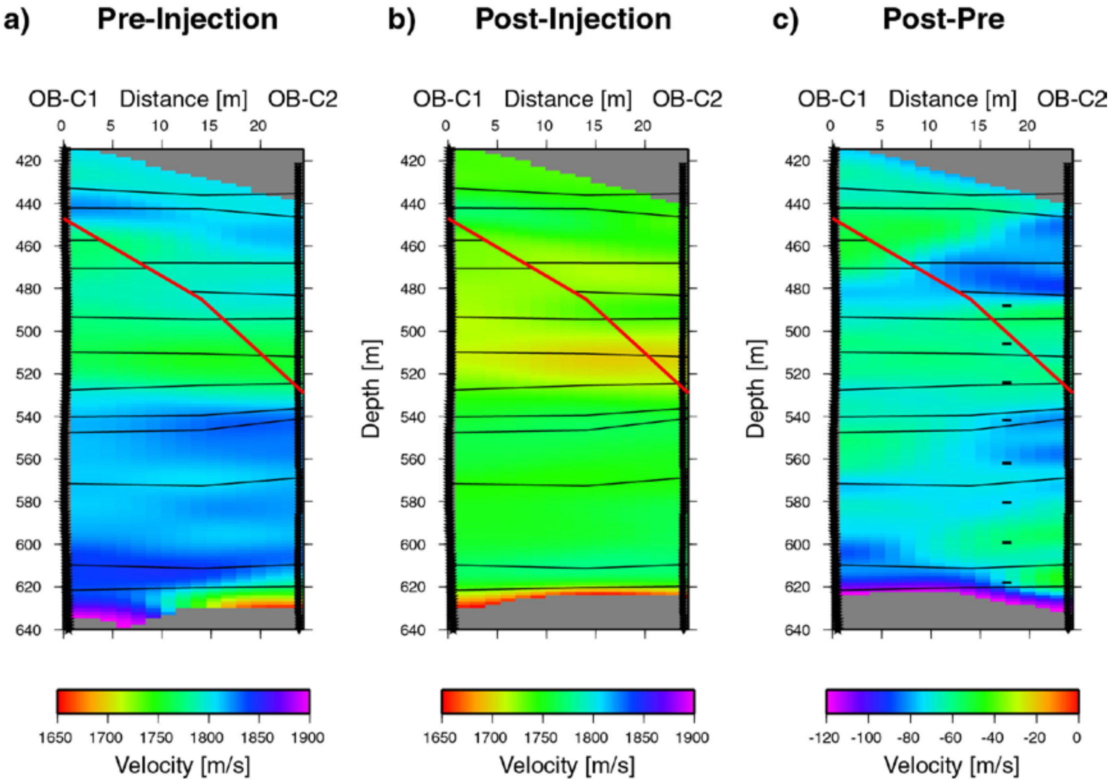

Figure 10-14: P–wave cross–hole seismic survey between observation wells (OBC1 and OBC2), (a) pre–injection of CO_2, (b) post injection of CO_2, (c) difference section (post injection minus pre–CO_2 injection values). Black dashes indicate the CO_2 injection points projected onto the imaging plane between the boreholes (Gritto et al., 2004, reproduced with permission of Wiley–Blackwell).

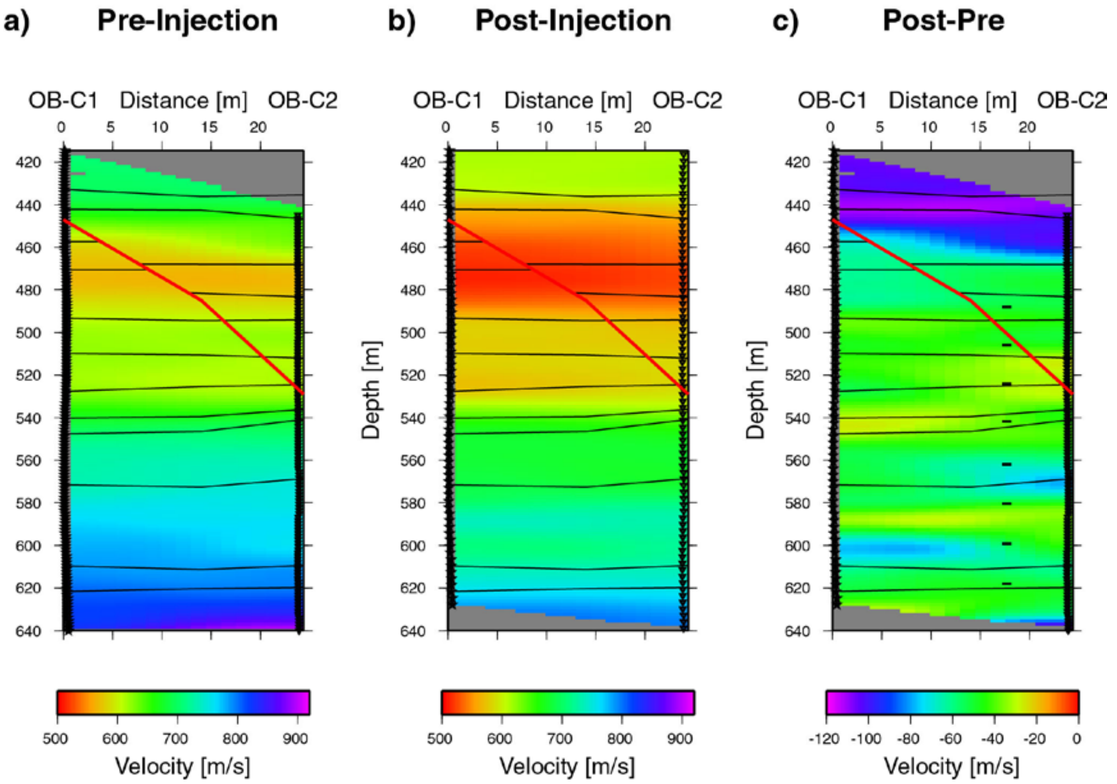

Figure 10-15: S–wave cross–hole seismic surveys, (a) pre–CO_2 injection, (b) post–CO_2 injection, (c) difference section (post–CO_2 injection minus pre–CO_2 injection values . Note the large decrease at the top of the reservoir is believed to be an artefact caused by limited ray path coverage at the top of the reservoir (Gritto et al., 2004, reproduced with permission of Wiley–Blackwell).

10.3.7 Shallow seismic profiling

A range of surface seismic techniques are available to resolve the shallow (up to about 300 m depth) sub–seabed layers. These techniques are generally 2D and utilise acoustic sources of different power and frequency range that can maximise penetration or resolution depending on the sediment properties and the technical objective. Shallow seismic profiling is potentially useful for imaging CO_2 migration and accumulation in the shallow overburden.

10.3.8 3D seismic seabed imaging

3D seismic can be utilised for monitoring the shallow subsurface and seabed, particularly in deeper water. To maximise the resolution a higher frequency source is often required than for deeper seismic reflection surveys, however by carefully designing the survey specification, the single 3D survey should allow interpretation of the seabed as well as the deeper structure.

This technique can be used to observe topographic features on the seabed, including pockmarks interpreted as gas escape structures (Figure 10–16). Within the shallow section repeated surveys could be used to identify new pockmarks (potentially indicating leakage to the seabed) or changes in reflectivity on or beneath the sea floor.

A limitation of this technique is that the appearance of pockmarks does not necessarily indicate a leak from the stored CO_2 and further investigation would be required to confirm the composition of the seeping fluid. In water depths less than about 500 m much more accurate images of the sea floor can be obtained by using higher frequency sources such as those used for multibeam echo sounding (see below) or, in deeper water, when multibeam is collected from an AUV platform.

A further limitation is identifying the source of the CO_2; this could be achieved using tracers (see section 10.9.3).

10.3.8.1 Case study (non–CO_2): Imaging the Nigerian continental slope

Repeated 3D/4D seismic surveys can be used to detect topographic changes at the seafloor. This could be used to detect gas escape features such as pockmarks. Figure 10–16 shows an azimuth map of the Nigerian continental slope showing pockmarks, mud volcanoes and fault lines. Water depth varies from about 300 m in the north–east to 800 m in the south–west. The pockmarks are aligned along fault lines, which suggests that the faults here act as fluid pathways to the surface. The high gas content in the sediments is believed to have generated the mud volcanoes. Samples taken around these features contained hydrocarbons, whereas those taken in undisturbed areas did not.

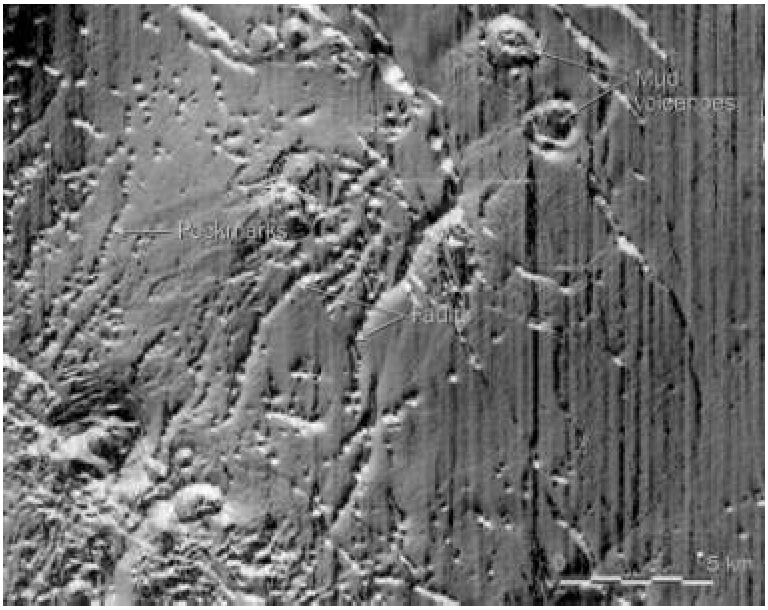

Figure 10-16: Seabed image showing various seabed features including pockmarks possibly caused by gas escape (Heggland 2003, ©AAPG 2003, reprinted by permission of the American Association of Petroleum Geologists whose permission is required for further use). The pockmarks line up along lineaments which are located above deeper seated faults. ***N.B. This diagram may be re-used by ETI in a summary report but should not otherwise be reproduced without separate permission from AAPG***

10.3.9 Boomer

Boomer is a surface seismic technique conducted offshore to image shallow (up to about 300 m) sub–seabed layers. The acoustic source contains metal plates in which electric currents are induced from charge stored in capacitors, causing the plates to rapidly separate, displacing water and creating a high frequency acoustic disturbance as the process is repeated. Boomer source frequencies typically range from 200 – 3000 Hz. Hydrophones receive the signal which is then collated and processed to produce a travel–time image similar to conventional seismic.

Resolution is generally high and, in ideal conditions, beds less than a metre thick can be resolved. This can be used to image changes in gas saturation in the shallow sediments, the sea bed morphology or bubble streams in the water. Regions of high gas saturation are shown as bright spots or blanks on the section. Analysis of reflectors can also detect small faults that may provide preferential leakage pathways for gas seepage. As with most geophysical techniques, there is a trade–off between resolution and depth of penetration; lower frequency sources have greater depth penetration but poorer resolution.

Boomer systems can be towed close to the seabed to improve resolution and decrease wave noise but this requires additional positioning systems. Increasingly ROV (remotely operated underwater vehicle) and AUV (autonomous underwater vehicle) deployed boomer systems are used in hydrocarbon site investigations. These allow high resolution in deep water. These expensive systems are usually only used in continental slope settings below 200 m water depth.

Resolution of this technique for CO_2 detection is not quantified at present. Acoustic blanking on subsurface records can be caused by small amounts of gas (< 2% by volume, Wilkens and Richardson, 1998; Judd and Hovland, 2007) and no way has yet been developed to distinguish CO_2 from other gases such as methane using this type of method. In terms of bubble detection above the seabed, escaping streams of bubbles may be intermittent and so could be missed by surveys. Another limitation of using this technique for CO_2 detection is that CO_2 is more soluble than methane and so may dissolve in relatively shallow water columns (approximately 50 m).

This technique is routinely employed in the hydrocarbon industry amongst others, but is not yet proven for use to monitor CO_2 leakage. Costs are moderate (typically upper tens of thousands of pounds for a survey, but these can be reduced if other methods are also being deployed on the same survey vessel.

10.3.9.1 CASE STUDY: LONG ISLAND, USA

During 1996, profiles were acquired near shore by the U. S. Geological Survey (USGS), in cooperation with the U.S. Army Corps of Engineers (USACE). The aim of these surveys was to map potential sand resources for beach regeneration and to map sediment movement in the southern Long Island nearshore region. The Boomer had a frequency of 300–3000 Hz (Figure 10–17).

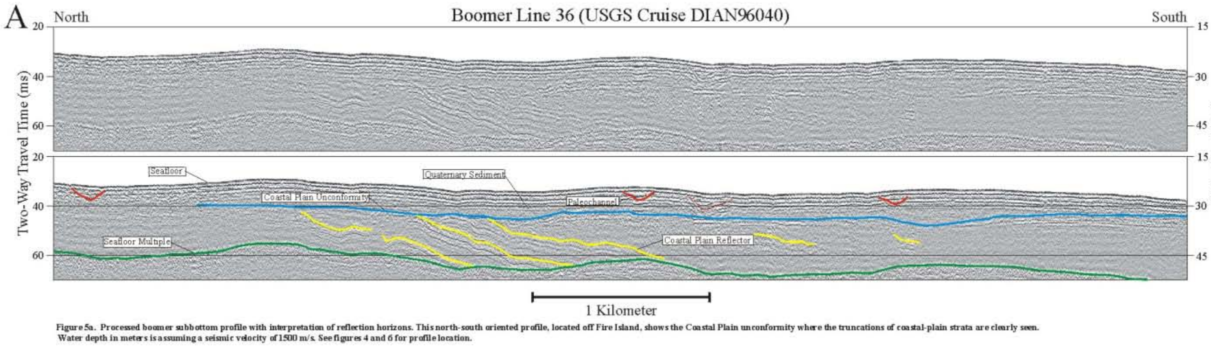

Figure 10-17: Boomer profile showing resolution of fine sedimentary layers (Foster et al., 1999). Note that two–way travel time has been converted to approximate water depth using a sound velocity of 1500 ms^{-1} for water and 1630 ms^{-1} for sediment (image courtesy United States Geological Survey).

10.3.9.2 CASE STUDY (NON–CO_2): SCOTIA POCKMARK, UK NORTH SEA

Boomer profiles over the Scotia pockmark were interpreted to show that the feature was formed prior to deposition of the most recent sediments, most likely due to violent gas escape. Natural gas is still seeping from the pockmark. The pockmark is over 450 m across and 18 m deep. The boomer data were acquired during 1990 and 1991 using a Huntec deep towed boomer operating a depth of 90 m, about 60 m above the seabed (Figure 10–18).

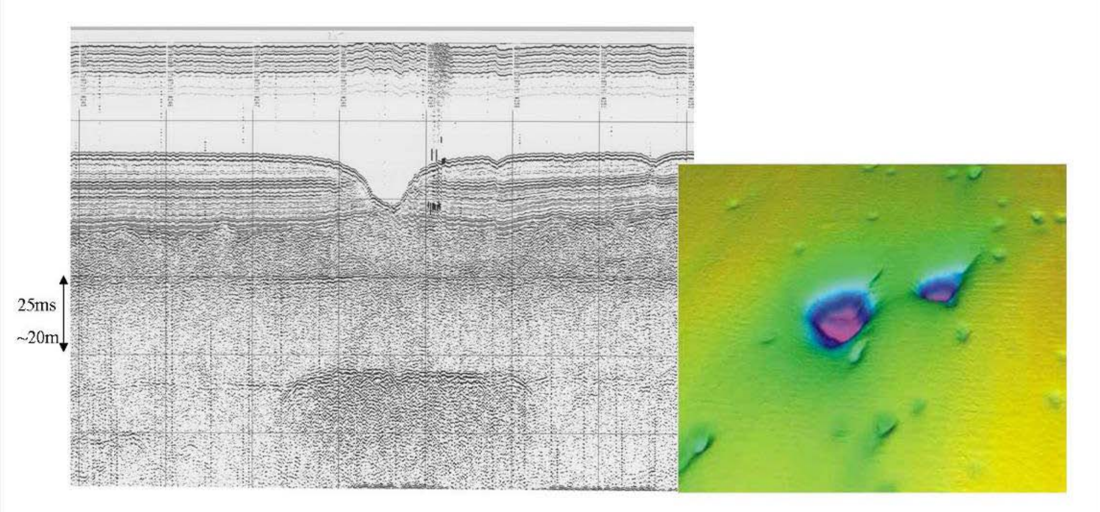

Figure 10-18: BGS Boomer profile over the Scotia Pockmark in UK block 15/25 showing shallow gas as an acoustic turbid zone beneath the pockmark and bubble plume in the water column (Judd et al., 1994). Multibeam echo sounder image of pockmark on right (Judd, 2001) reproduced with permission of the Department of Energy and Climate Change.

10.3.10 Sparker

Sparker sources use the discharge of a large capacitor to create a spark between two electrodes in the water, vaporising the water. The source is towed behind a boat, near the water surface, and the reflected sound waves created by the collapse of the bubble of vaporised water are received by a small number of hydrophones (Figure 10–19). Frequency of the source is 50 – 4000 Hz (WHSC, 2009). Depth of penetration is generally several hundred metres and can be as much as 1000 m (Sheriff and Geldart, 1995) for high energy sources (200 kJ). This technique only works in salt water as fresh water has insufficient conductivity. The data is usually filtered to a bandwidth of 800 and 2000 Hz and can give millisecond resolution (~1 m).

Sparker is routinely employed in the site survey industry (hydrocarbon exploration and renewables infrastructures), but is not yet proven for monitoring CO_2 leakage. Sparker surveys can detect seabed features on the scale of about 1 m height.

A limitation of this technique is that it is high maintenance and the boat is required to carry a high voltage power supply (3–4 kV). The sparker source, moreover, commonly does not produce a clean, repeatable signal, and has a higher dependence on good weather than other systems.

Figure 10-19: BGS tow fish (orange cable) hydrophones on reel (image courtesy British Geological Survey.

10.3.10.1 CASE STUDY (NON–CO_2): LONG ISLAND, N. Y.

In 1996, the U. S. Geological Survey (USGS), in cooperation with the U.S. Army Corps of Engineers (USACE), began surveying the southern Long Island nearshore area to map sediment movement and potential sand resources for beach regeneration. This included surveys acquired using a 100–3000 Hz single–electrode sparker source (Figure 10–20).

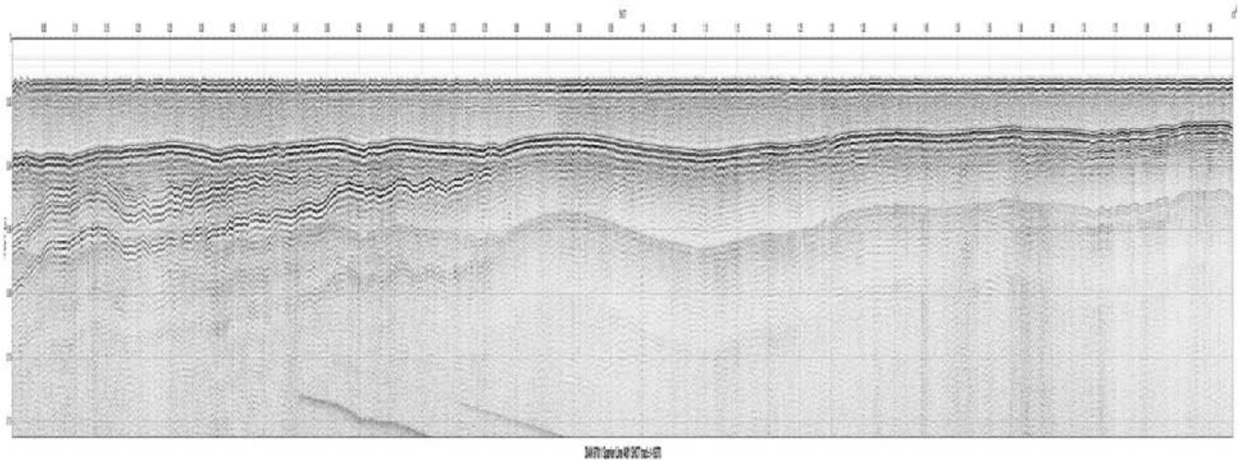

Figure 10-20: Part of a sparker survey, offshore southern Long Island, N.Y. (Foster et. al., 1999). Note that two–way travel time has been converted to approximate water depth using a sound velocity of 1500 ms^{-1} for water and 1630 ms^{-1} for sediment (Foster et al., 1999), image courtesy United States Geological Survey.

10.3.10.2 CASE STUDY (NON–CO_2): UK NORTHERN NORTH SEA

A sparker survey was acquired over the shallow Quaternary sediments in the Moray Firth area (Andrews et al., 1990). It showed good resolution of the seabed morphology and the shallow sedimentary section resolving a shallow gas pocket, a gas chimney and also a gas escape structure (pockmark) (Figure 10–21). Compare with Figure 10–18that shows a similar sequence nearby resolved by boomer.

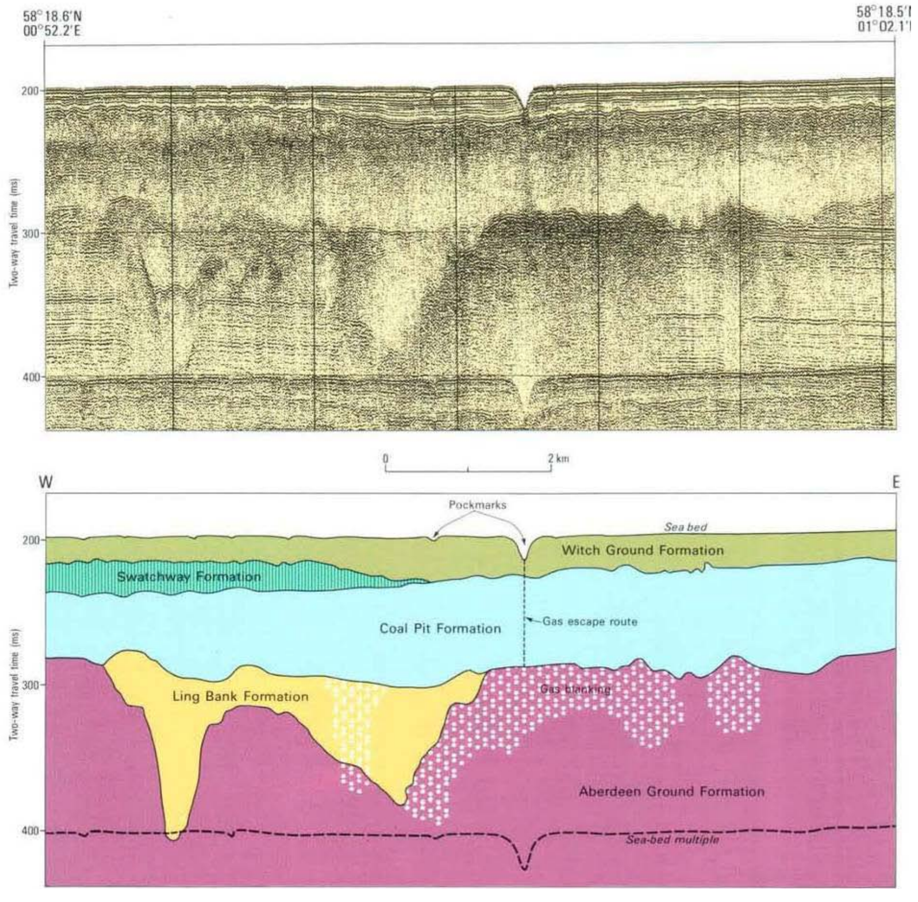

Figure 10-21: Sparker profile collected by BGS from UK block 15/25 (northern North Sea) showing gas escaping from a horizon within the Quaternary to a large pockmark on the seafloor (Andrews et al., 1990), image courtesy British Geological Survey.

10.3.11High Resolution profilers/pingers

High frequency sources such as 3.5 kHz known as pingers are often used in soft sediments. Although their penetration is restricted to at most 50 ms their resolution is high (less than 0.5 m, egssurvey.com 2009). Their signal can be obscured by the presence of shallow gas (Figure 10–22, Figure 10–23).

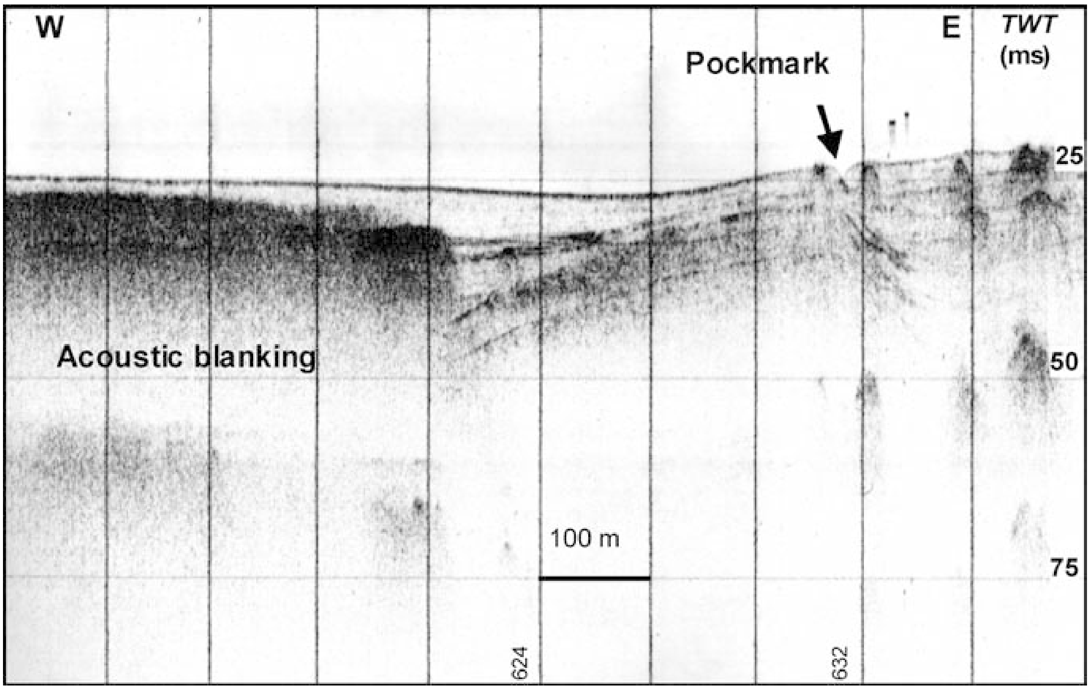

Figure 10-22: 3.5kHz profiler from the Rio de Vigo, NW Spain (Garcia–Gil, 2003). Image reproduced with permission of Springer-Verlag

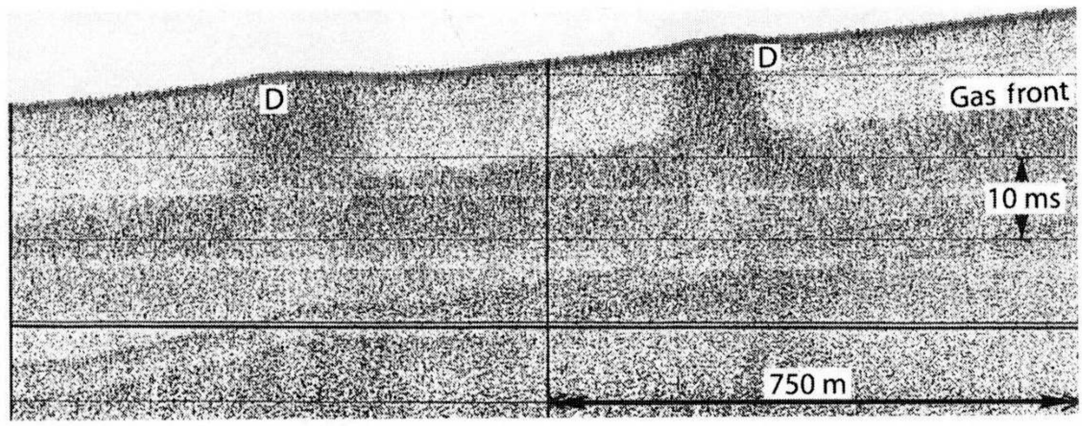

Figure 10-23: Pinger record showing seabed domes (D) associated with gas rising up from a shallow gas front, west coast of Scotland collected by R. Whittington UCW (taken from Hovland and Judd, 1988). Image reproduced with permission of Springer-Verlag

10.3.12 High resolution acoustic imaging

A high frequency source comprising directional piezoelectric sources in the frequency range 2 – 15 kHz is used to produce a high resolution image of the sea bottom and shallow marine sediments (depth penetration generally less than 100 m). Transducers such as a chirp sonar or Atlas Parasound system are hull–mounted or towed behind the boat, in a tow fish. The tow fish may be towed at the sea surface or a few metres above the sea bed, The receivers and source are usually located in the same tow fish.

Monitoring for CO_2 migration or leakage would require repeated surveys to look for changes in gas saturation or sea floor morphology. Regions on the section which are blank (Figure 10–24) or show acoustic turbidity (areas of 'noise' or unclear reflection) are interpreted to be zones of gas saturation. High resolution imaging may also show gas bubble plumes in the seawater (Figure 10–25). Natural gas chimneys or pockmarks may show potential migration routes for CO_2.

This technique is well established for use in the offshore site investigation industries principally where the seepage is methane, but has not yet been tested for monitoring CO_2. A limitation of this technique is that it will only detect gas (CO_2) that has reached the surface or very near to the surface and will not give early warning of leakage. Another limitation is that the presence of new pockmarks does not necessarily indicate CO_2 emission and further investigation to determine the cause of the seabed features would be required to confirm that the emissions are of CO_2 rather than methane or water, the main causes of pockmarks. Systems are capable of resolving seabed features down to about 1 m, but limits for bubble detection have not been established. Costs are moderate (typically upper tens of thousands of pounds for a survey, but these can be reduced if other methods are also being deployed on the same survey vessel.

High resolution seismic profiling systems such as chirp and also sidescan sonar are now installed within AUVs creating a stable platform for surveys. Chirp profiles can resolve faults in soft sediments with decimetre displacements that might provide conduits for gas seepage (Figure 10–24).

10.3.12.1 CASE STUDY (NON–CO_2): NETHERLANDS NORTH SEA

In the Netherlands offshore area, high frequency acoustic profiles were used as part of a suite of surveys to study surface and shallow sub–surface expressions of gas, including surface pockmarks and sub–surface gas accumulations.

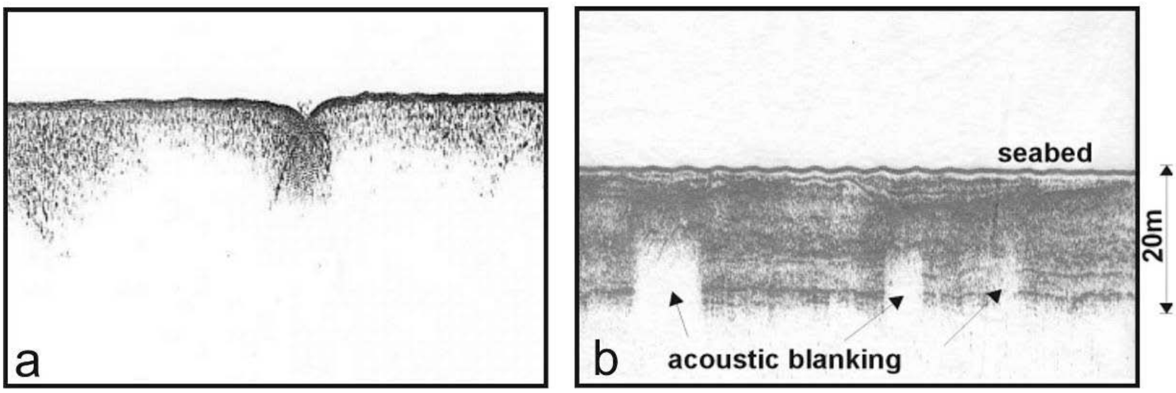

Figure 10-24: High resolution (3.5 kHz) acoustic profiles showing (a) Pockmark 40 m in diameter, 2m deep (b) acoustic blanking interpreted as gas in shallow sediments (Schroot and Schüttenhelm, 2003, image courtesy B. Schroot, TNO).

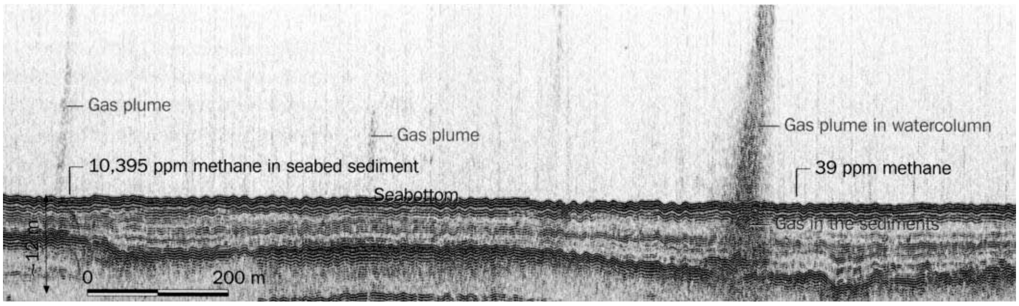

Figure 10-25: High resolution Xstar profile showing (methane) gas plumes in the water column reproduced with permission of Oil and Gas Science and Technology–Revue de L'IFP (Winthaegen et al., 2005) (image courtesy B. Schroot, TNO).

10.3.12.2 CASE STUDY (NON–CO_2): GULF OF MEXICO

A high resolution acoustic image of the seafloor was acquired in the Gulf of Mexico, in water depths around 1300 – 2200 m. This topography here is generally a result of salt movement and sediment slumping. The tow–cable lengths which would have been required for this region were such that an AUV mounted system was chosen instead. The data were collected in a 200 m wide swath and processed using 3 m wide 'bins' (Figure 10–26).

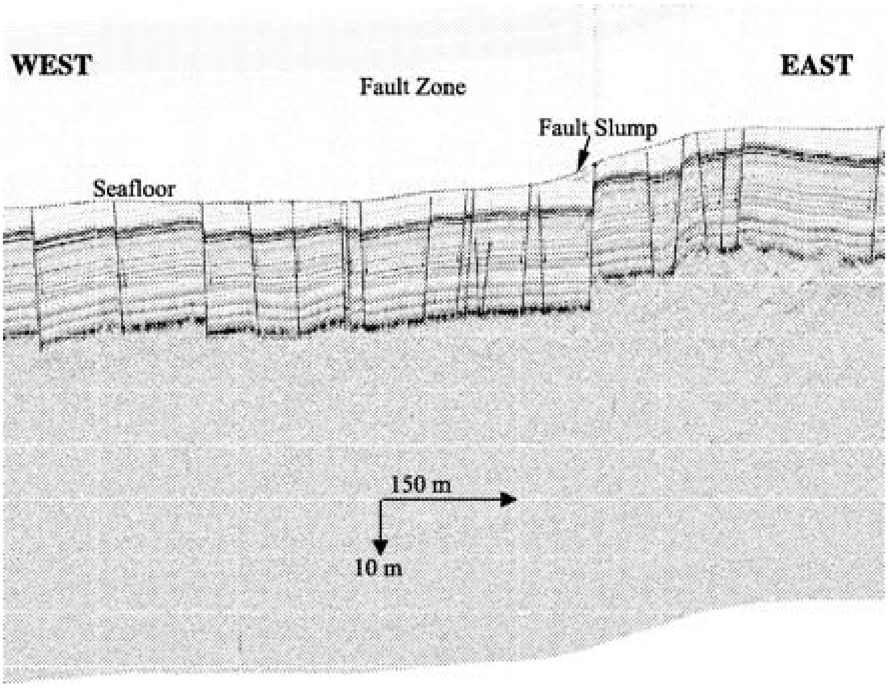

Figure 10-26: Example from the Gulf of Mexico of AUV mounted Chirp profile showing high resolution in the shallow section From Lee and George (2004) (©AAPG 2004. reprinted with permission of the American Association of Petroleum Geologists whose permission is required for further use)
N.B. This diagram may be re-used by ETI in a summary report but should not otherwise be reproduced without separate permission from AAPG.

10.3.13 Sidescan sonar

Sidescan sonar comprises an echo sounding system used to produce an image of the seabed; protruding features generally show as light areas, with an acoustic 'shadow' where the sound beam is blocked by the object and does not reach the seabed. The source and receiver are usually located in 'tow fish' pulled behind the boat or mounted into the hull. The sonar source transmits an acoustic beam perpendicular to the direction of travel of the ship and receives reflected acoustic waves from the seabed and other objects beneath the ship. An electrical impulse is used to vibrate a diaphragm in the water and the returning sound wave is detected by a hydrophone which converts the sound into an electrical impulse for digital recording. The received data are processed to produce a model of the seabed based on strength of received signal/backscatter. Generally, coarser sediments tend to reflect sound better, showing as lighter patches on the sidescan sonar image (Figure 10–27). To improve resolution, the tow fish may be towed close to the seafloor thereby requiring additional positioning information. Increasingly sidescan sonars are being placed in AUVs to eliminate the motion of the surface vessel. The shape of the beam is critical to the formation of the image, typically a side–scan acoustic beam is very narrow in the horizontal dimension (~0.1 °) and much broader in the vertical dimension (40 – 60 °) (Pearce et al., 2005).

This is an established technique, used for detecting and identifying objects on the sea floor. However, depth data are not usually provided by side–scan sonar. This method is not yet proven for monitoring CO_2.

In ideal conditions, objects less than a centimetre in size can be detected. Repeat surveys could potentially detect changes in the seabed morphology such as new pockmarks resulting from gas escape and possibly gas bubbles in the water column.

Methane seepage is often associated with the formation of cemented seafloors which is detectable on side scan sonar as areas of high acoustic returns (Figure 10–25). This may not occur with CO_2 leakage. However, biota responses to seepage may change the physical characteristics of the surficial sediments and this might be detected by side scan sonar.

A limitation of this device is that changes in seabed morphology are not necessarily a result of CO_2 leakage and would need further testing probably by ground truthing with video and sampling.

The greater part of the costs is associated with equipment setup.

10.3.13.1 CASE STUDY (NON–CO_2): RHODE ISLAND

The U.S. Geological Survey (USGS) and National Oceanic and Atmospheric Administration (NOAA) surveyed the Rhode Island Sound, about 8km south of Sakonnet Point, to interpret the superficial geology. Sidescan sonar and bathymetric data were collected over two days during March and April 2004. A Klein 5500 tow fish transmitting at 455–kHz and Triton–Elics ISIS software were used to acquire sidescan–sonar data. These data were then processed to produce a map of the seabed (Figure 10–27) with resolution of 1m per pixel.

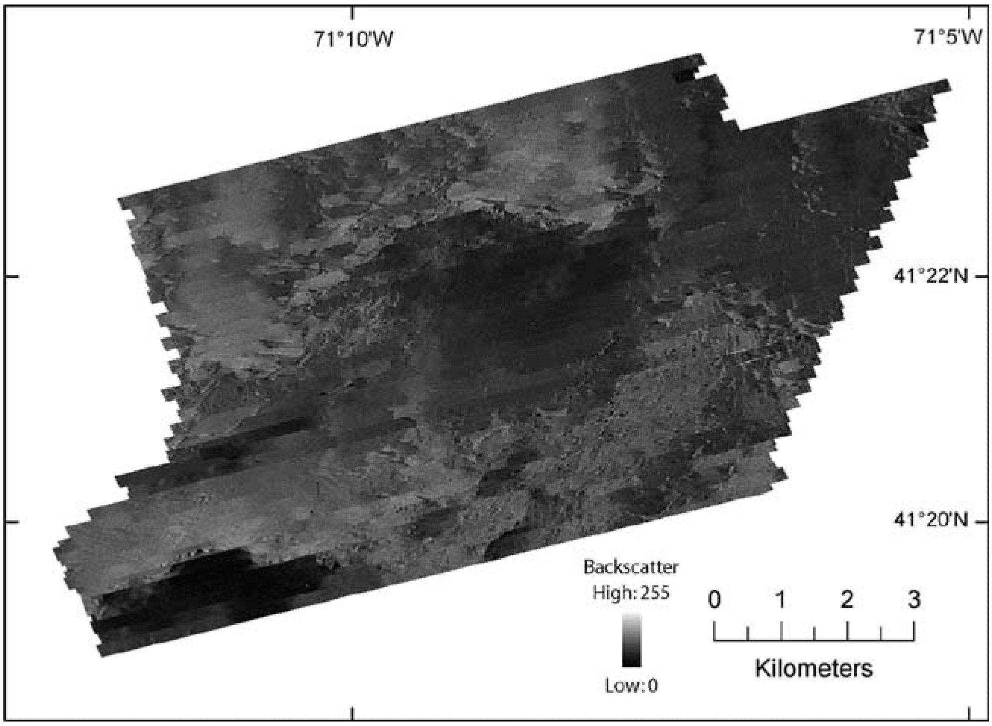

Figure 10-27: Sidescan sonar image, NOAA survey H11320. Dark regions with low backscatter are interpreted as regions of fine sediment. These images were interpreted in conjunction with bathymetric data, seismic data and sediment collection (McMullen et al., 2007, image courtesy United States Geological Survey).

Small features on the sea bed were interpreted using the sidescan sonar data (in conjunction with bathymetric data), including sand waves and marks from trawler fishing (Figure 10–28).

The sidescan sonar data were used to interpret type of sediment and sea floor morphology. This could be used to show disturbance of the sediment or new seabed features due to CO_2 leakage, however, these features could also be caused by other events and so further testing would be needed to confirm the cause.

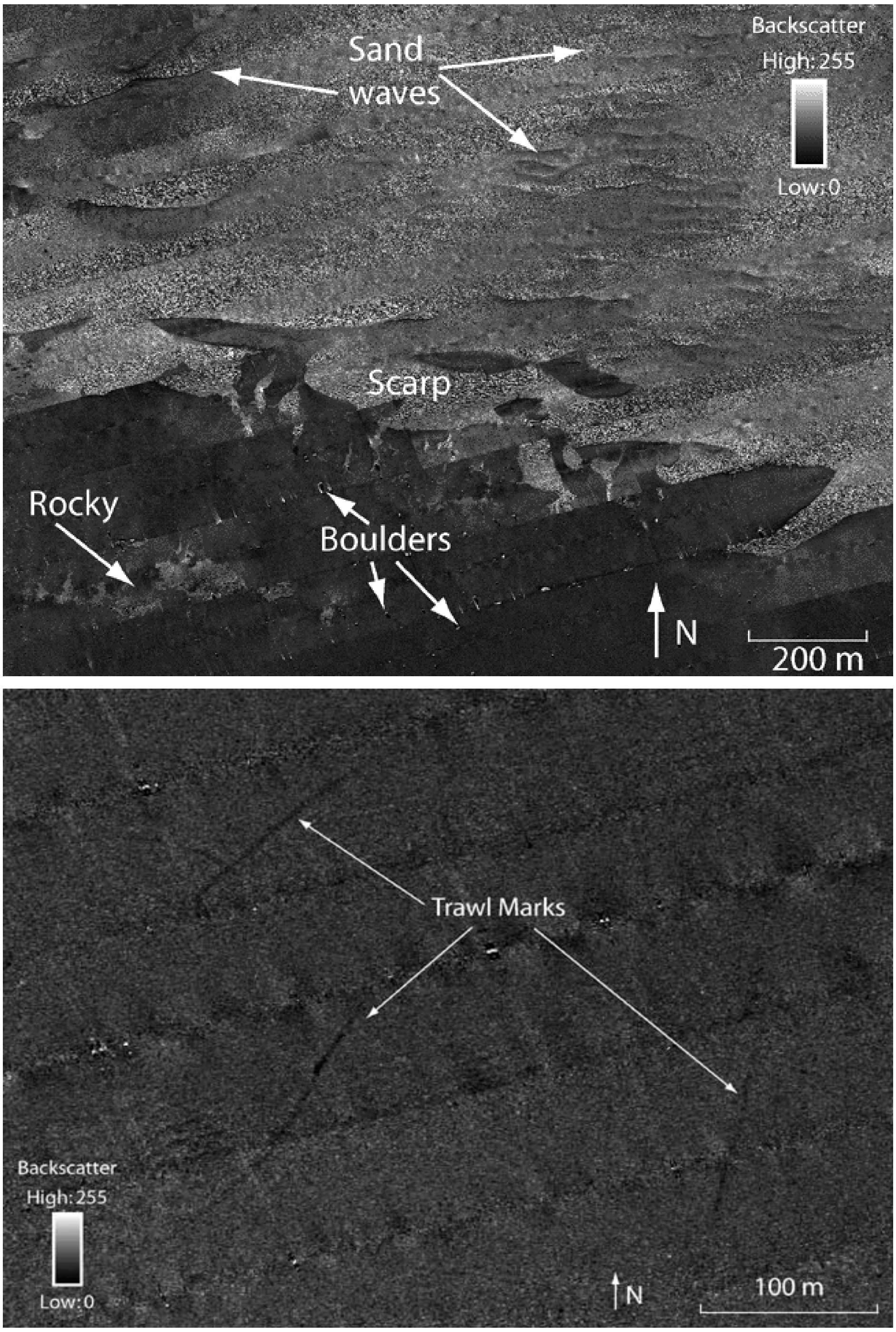

Figure 10-28: detailed sidescan sonar image, interpreted in conjunction with bathymetric data. Sand waves have curved crests oriented east–west and wavelengths of 40 to over 100 m in the west and about 50 m in the east. Trawl marks from fishing are also visible (McMullen et al., 2007, images courtesy United States Geological Survey).

10.3.13.2 CASE STUDY (CO_2): SLEIPNER

Sidescan sonar images of the Sleipner site were acquired in June 2006, in conjunction with the high resolution 2D seismic lines (see above). The sidescan sonar was able to detect the benchmarks emplaced for the gravimetry survey (about 1.5 m in diameter), showing higher resolution than the multibeam echo sounding (Figure 10–29). This image was interpreted to show no signs of CO_2 leakage.

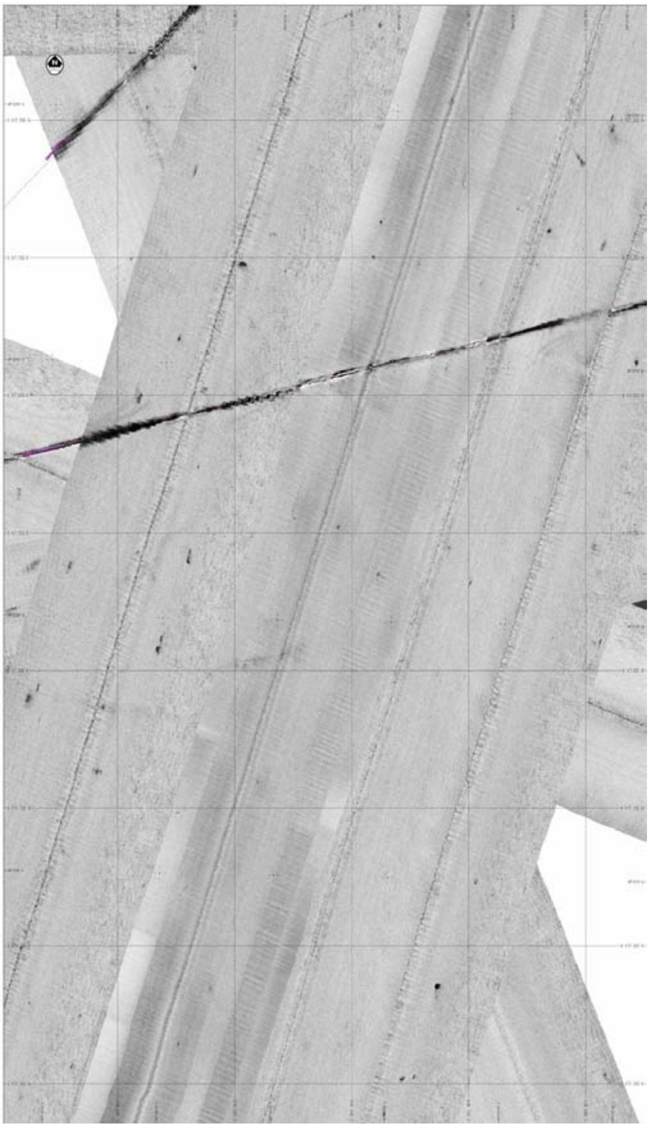

Figure 10-29: Side–scan sonar image over the Sleipner site, the two dark diagonal lines near the top of the image are pipelines (image courtesy Ola Eiken, Statoil).

10.3.13.3 CASE STUDY (NON–CO_2): SCOTIA POCKMARK

A sidescan sonar profile was acquired over the Scotia Pockmark by BGS (Figure 10–30) showing changes in the seabed and also evidence of bubbles in the water column. This pockmark is believed to be a result of rapid gas escape in the past. Gas is currently escaping in multiple streams. A survey described by Clayton and Dando (1996) states that individual bubble streams produced between 0.14 and 0.6 litres of gas per hour (approximately 5.74 litres per hour at surface temperature and pressure).

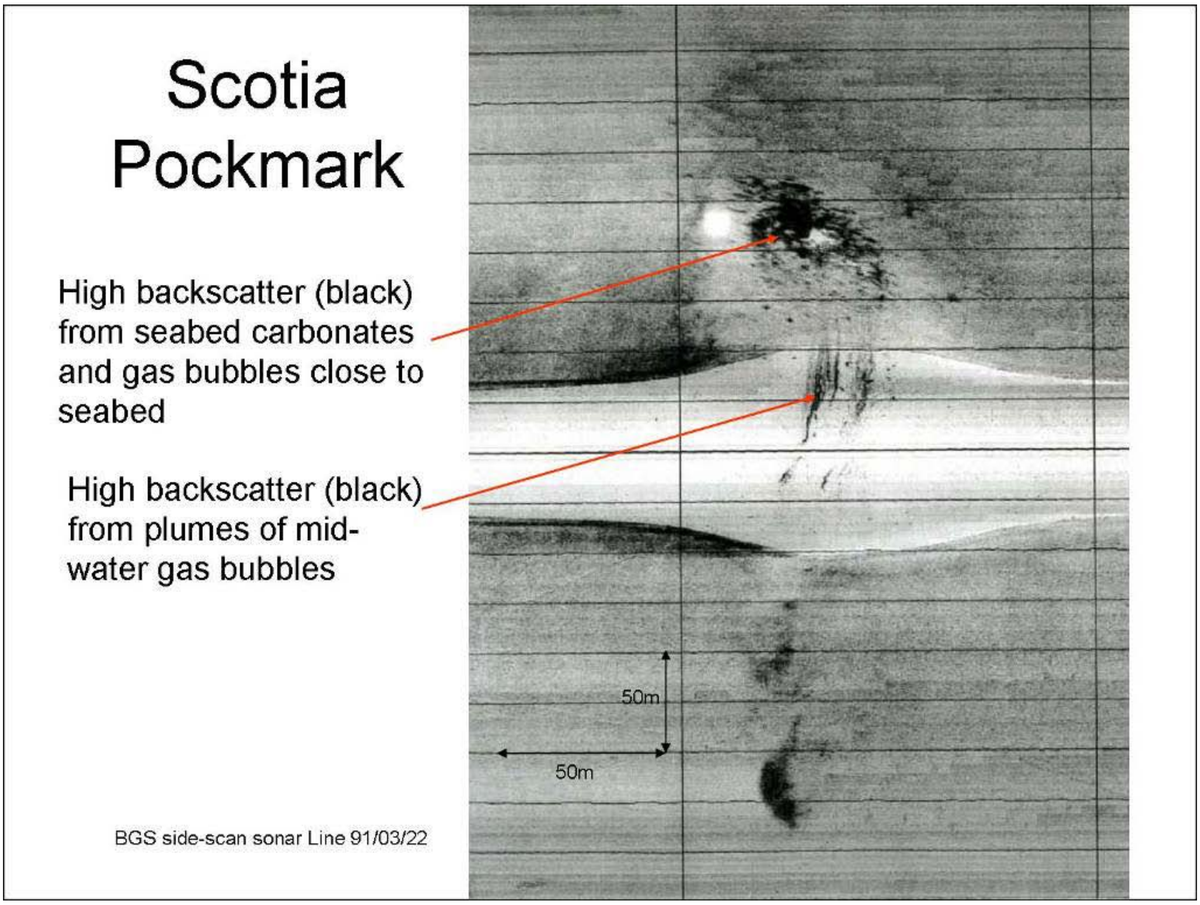

Figure 10-30: Side scan sonar image of the Scotia Pockmark in UK block 15/25 showing high backscatter from bubbles in the water and carbonate cemented seabed sediments (image courtesy British Geological Survey).

The Scotia Pockmark is one of three active pockmarks in close proximity in UK licence block 15/25. They are fed by biogenic methane from within the thick Quaternary sequence below (Figure 10–18; Judd et al., 1994). Some of the methane is oxidised as it reaches close to the seabed producing an authigenic carbonate cement that provides a strong acoustic reflector in contrast with the surrounding very soft muds. This produces a distinct feature on sidescan sonar records. Methane that fails to be oxidised in the sediments enters the water column as bubbles, providing another distinctive feature on sidescan sonar records.

10.3.13.4 CASE STUDY (NON–CO_2): OFFSHORE TAIWAN

A sidescan sonar and sub–bottom profiler survey was undertaken over pockmarks offshore SW Taiwan at a water depth of about 450 m. The sidescan image was collected with an Edgetech system using a frequency of 120 kHz and the sub–bottom profiler at 1 – 6 kHz. Blanking of the sub–bottom profiler is observed in Figure 10–31 and bright spots are seen on the sidescan image; these may be authigenic carbonates formed as a result of reaction with leaking methane gas (Shu–Kun Hsu, Taiwan University, pers. comm.).

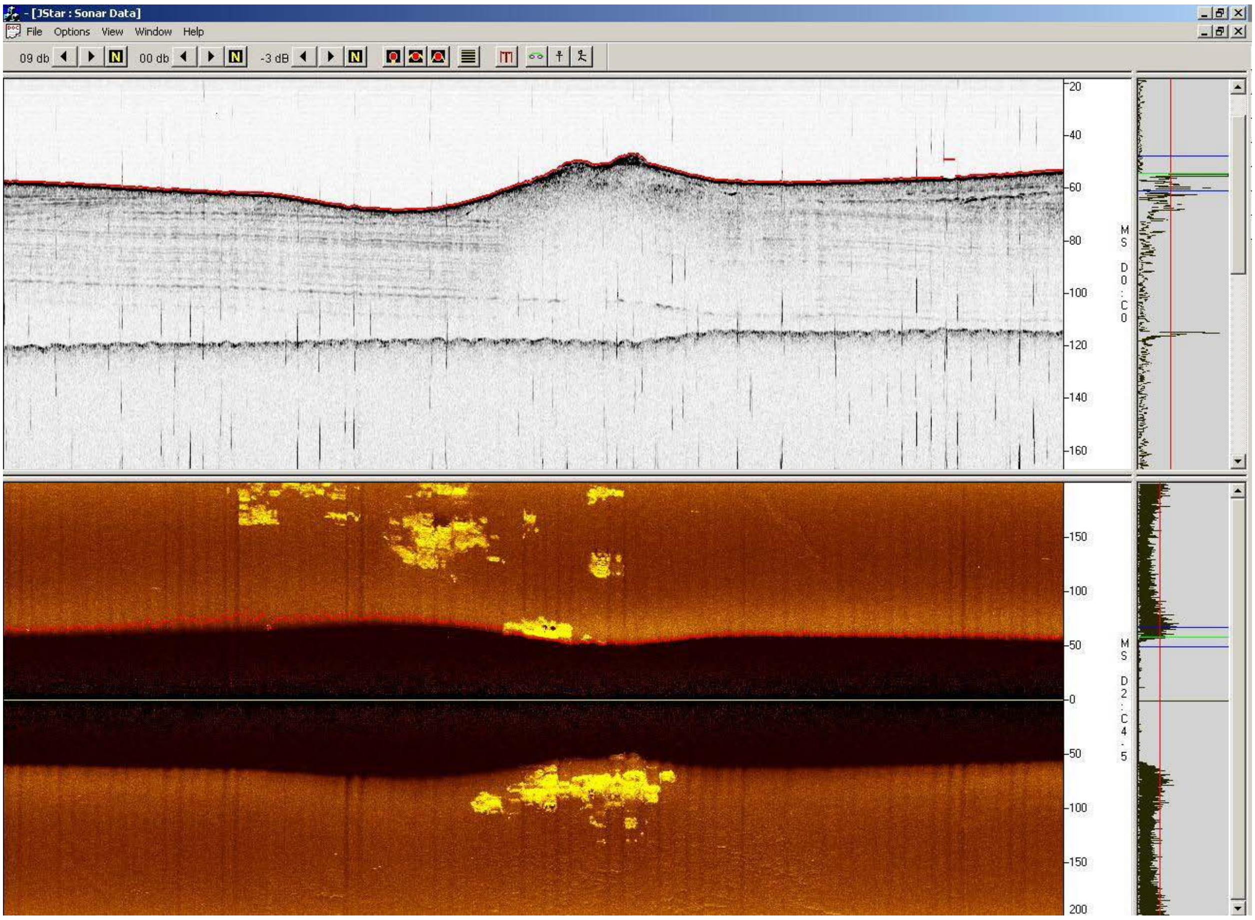

Figure 10-31: Sub–bottom profiler (top) and sidescan sonar (bottom) image over pockmarks offshore SW Taiwan. (Image reproduced courtesy of Shu-Kun, National Central University, Taiwan)

10.3.14Multibeam echo sounding

In multibeam echo sounding acoustic bathymetry and backscatter data are integrated to produce a detailed 3D model of the seabed morphology. A multibeam echo sounder may consist of an array of around a hundred single–beam echo sounders, mounted in a fan shaped array under the survey vessel. The fan has a small spread in the direction of travel, perhaps 1.5°, and a broad spread perpendicular to the direction of travel, of about 120°. The system records the time and strength of the returned signal (backscatter) which are interpreted to map water depth and the nature of the seawater/seafloor interface. The number of beams, frequency and power vary between systems depending on the water depths to be surveyed.

The pixel area increases with increasing water depth thereby meaning that image resolution decreases correspondingly, so systems are designed for particular depth with changes to beam angle and frequency.

Conducting such surveys from AUVs or ROVs, rather than using surface vessels, reduces wave and weather movements, and enables much greater resolution to be obtained, with pixels at 0.1 m or finer and vertical discrimination of a few centimetres. Unlike deep towed devices, AUVs maintain a constant speed along a predetermined track (~ 4 knots) using inertia navigation resulting in an even data density. Deep–towed tow fish are subject to increases and decreases in speed whenever cable is spooled in or out, which results in varying data densities, changes in the depth of the towed unit and increases in navigational uncertainties.

Not only does the data provide high resolution images of the seabed morphology, examination of the strength of the returning signal allows interpretation of the physical characteristics of the surface sediments. Careful analysis of the data can also detect gas bubbles in the water column (Schneider von Diemling et al., 2007).

Repeated surveys could show changes in the seabed morphology or hardness, potentially attributable to CO_2 leakage. However, some form of sampling would be required to show whether new 'pockmarks' and other features were actually resulting from CO_2 leakage, rather than natural processes. A limitation of the method is that the intensity of the returned signal can be affected by the presence of seabottom flora, which could vary over time, though this only applies where the seabed is within the photic zone.

The technique is well developed for other industries, and has high resolution, for example, the Kongsberg multibeam echo sounder has resolution of around 0.1 m (Kongsberg.com 2009)

10.3.14.1 CASE STUDY (NON–CO_2): RECHERCHE ARCHIPELAGO, AUSTRALIA

An Edgetech 272T side–scan sonar and a Reson SeaBat 8125 multibeam echo sounder were used to survey the bathymetry and conduct habitat analysis for the region west of Lion Island in about 20 m water depth. The multibeam echo sounder operated at 455 kHz and had 240 sources, each emitting a beam about 0.5° wide. The multibeam system provides bathymetric and coincident backscatter data (Figure 10–32). The backscatter intensity was also shown to be affected by the presence of seabed flora.

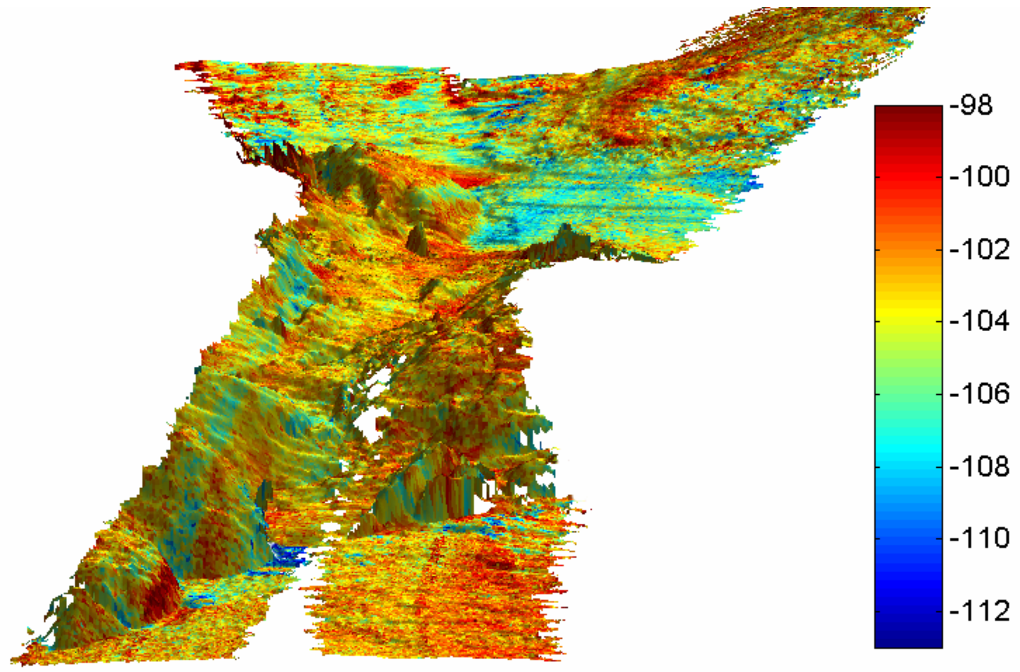

Figure 10-32: Average backscatter intensity draped over 3D bathymetry from the multibeam echo system (image reproduced courtesy of A. Gavrilov, Centre for Marine Science & Technology, Curtin University of Technology from Gavrilov et al., 2005).

10.3.14.2 CASE STUDY (NON–CO_2): WESTERN USA

An AUV for high resolution seafloor mapping was deployed over Axial Volcano, along the Juan de Fuca Ridge. The deep towed sonar was a Reson 7125, operating at 200 kHz (Figure 10–33B).

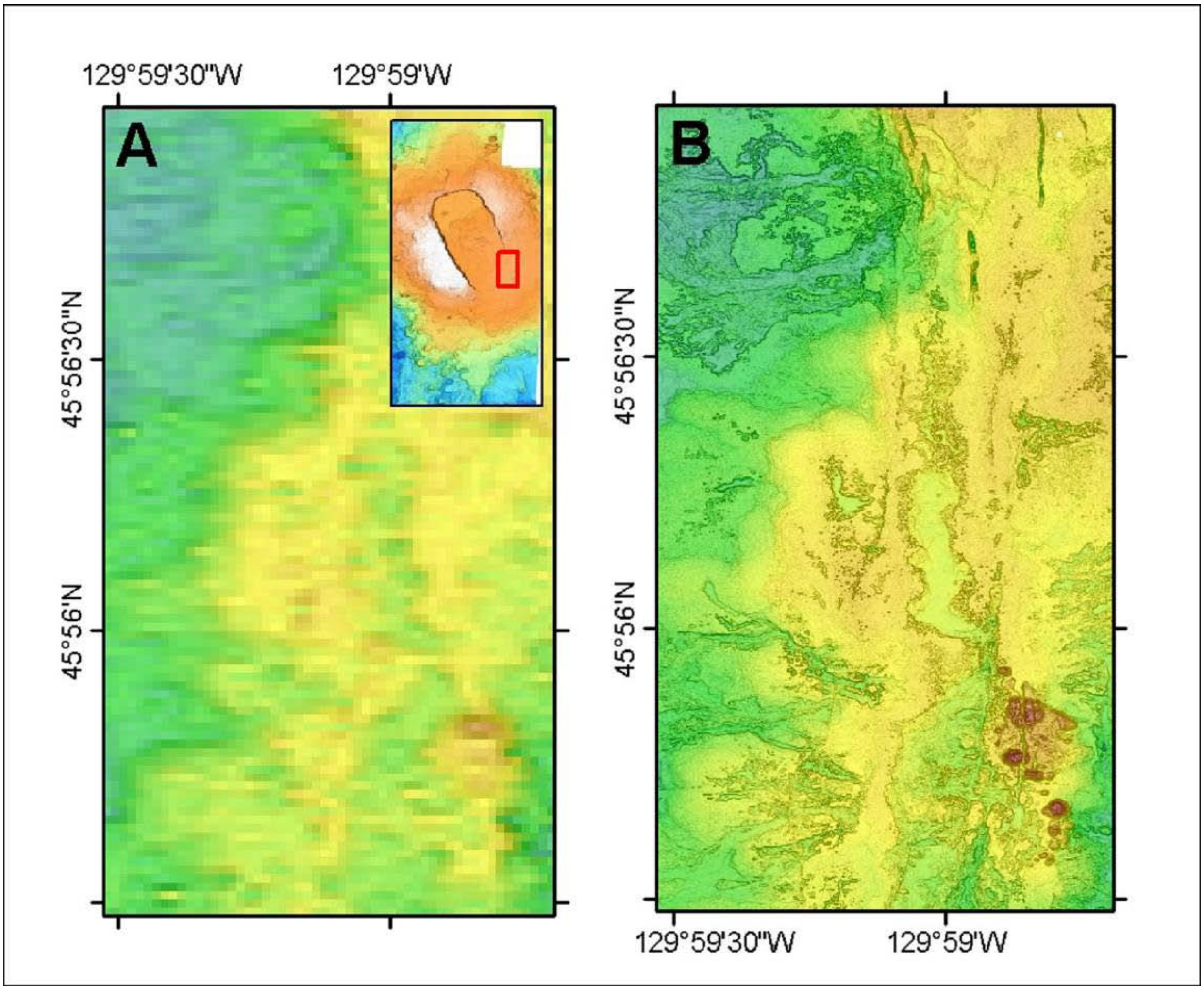

Figure 10-33: Comparison of surface (A) and (B) AUV sonar multibeam survey over an area offshore western US where water depth ranges from 1503 to 1543 m. From Paduan et al (2009), reproduced with permission of Rendiconti Online Società Geologica Italiana.

10.3.14.3 CASE STUDY (CO_2): SLEIPNER

Multibeam echo sounding was acquired over the Sleipner site (Figure 10–34). Only a single survey has been acquired so no information on possible time–lapse changes is available. Based on the single survey no unusual features were noted and it was concluded the there was no evidence of leakage.

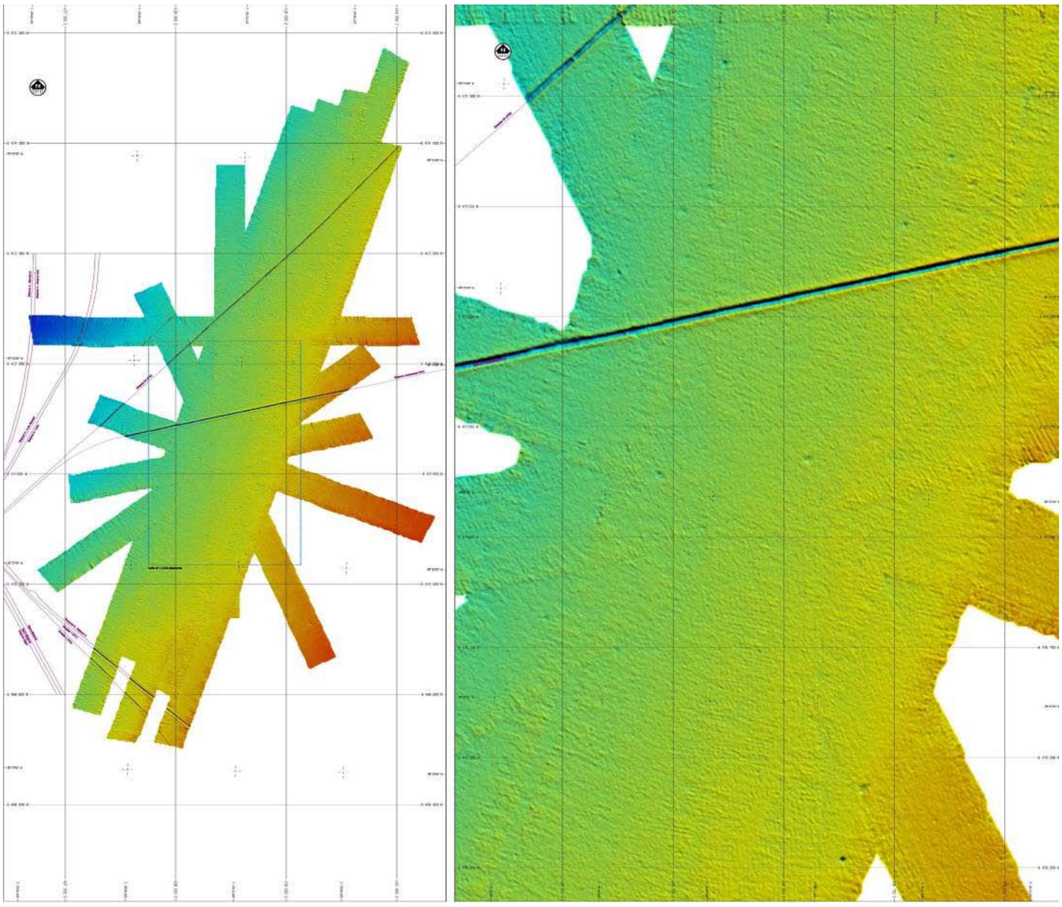

Figure 10-34: Multibeam echo sounding survey over the Sleipner site. The dark diagonal lines near the top of the image are pipelines (image courtesy Ola Eiken, Statoil).

10.3.14.4 CASE STUDY (NON–CO_2): ST. GEORGES BAY, NEWFOUNDLAND, CANADA

Multibeam bathymetric data and backscatter data were collected using a SIMRAD EM–1000 swath bathymetric system owned by the Canadian Hydrographic Service and operated by the Bedford Institute of Oceanography, Dartmouth, Nova Scotia. The survey was collected using 60 beams arrayed over a 150º wide swath in water depths of 40 – 100 m, with coverage of four to five times water depth for each beam. Survey line spacing was typically 100 m. Navigation was by GPS (global positioning system) with real–time corrections relayed from a shore station or Coast Guard beacon, providing an accuracy of ±2 m. Figure 10–35 shows a 3D view of a depression and a vertical structure tentatively interpreted as a plume of gas bubbles. The origin of this gas is not known. This survey area is underlain by Carboniferous rocks which are expected to contain hydrocarbons.

Examination of the strength of the returning signal provides information on the physical characteristics of the reflecting seabed. These usually are relative values within a single survey but when draped over the seabed terrain can aid geological interpretation.

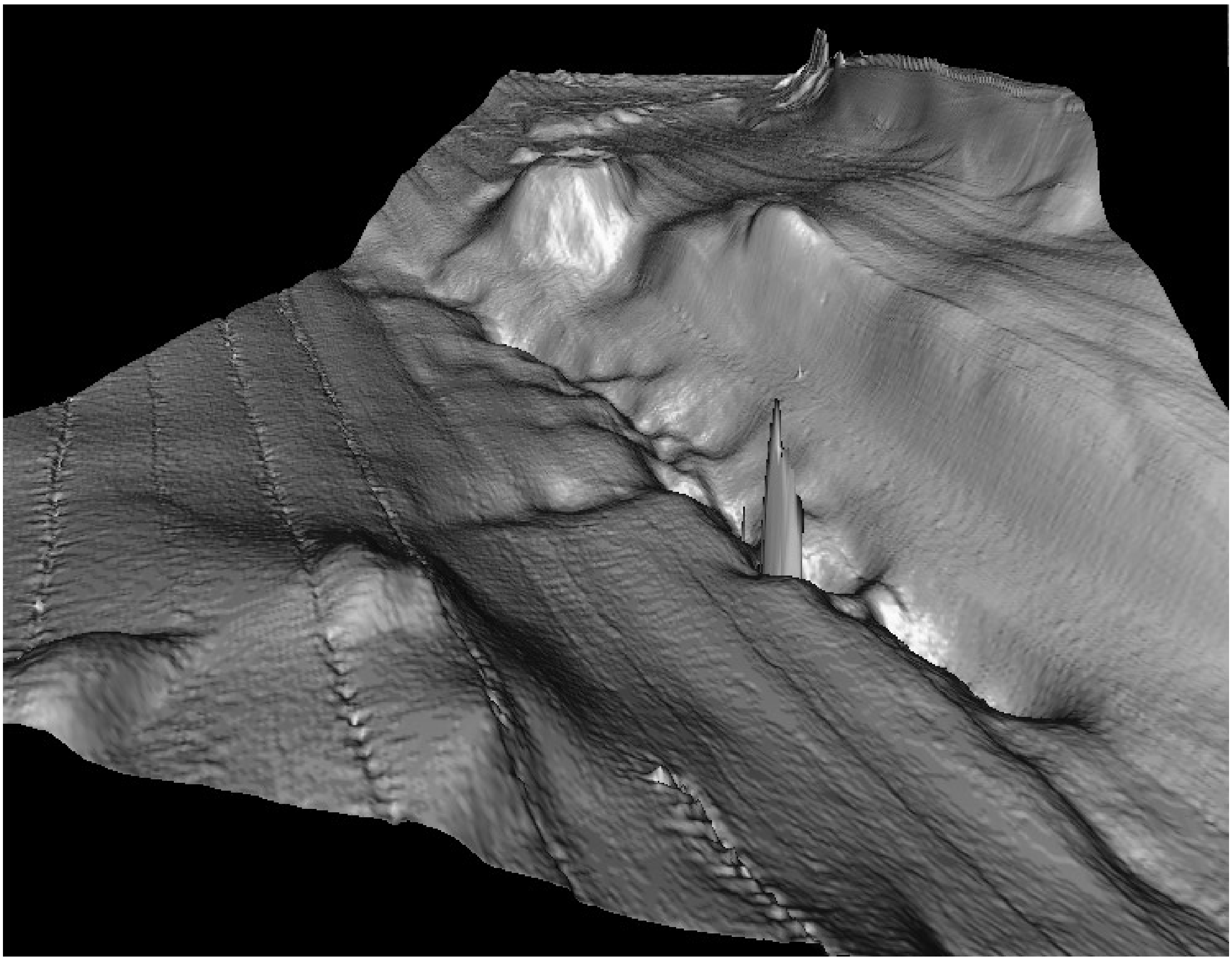

Figure 10-35: Multibeam and backscatter image of a gas plume (from Shaw et al., 1997, reproduced with permission of Springer-Verlag).

10.3.15Bubble stream detection

Ship–based sonar may be able to provide 3D data on the location of bubble streams in the water column. Currently such sonar systems are used to detect shoals of fish (by detecting their air–filled swim bladders). Sonar images are taken periodically as the ship travels. The frequency of these sources is usually 50 kHz for wide angle images in deep water and 200 kHz for higher resolution, narrow beam images.

A much lower frequency sonar system Long Range Ocean Acoustic Waveguide Remote Sensing (OAWRS) could potentially be used for a first–pass survey at lower resolution (coverage can be as much as thousands of square kilometres).

Sonar techniques could potentially be used for imaging streams of CO_2 bubbles escaping from the seabed. Bubble stream detection could be part of a robust shallow monitoring package, when used in conjunction with seabed imaging (e.g. multibeam echo sounding). However, this technique has not yet been tested with CO_2.

A limitation of the technique with respect to CO_2 monitoring is that CO_2 bubbles are more soluble than methane and so would be expected to dissolve in relatively shallow water columns. Recent modelling work by Kano et al., (2009) implied that any CO_2 leakage would be expected to dissolve within 100 m of the seabed.

Another drawback is the timing and resolution of the surveys: unless there is a continuous stream of bubbles, or bubbles are present at the time of the survey, of sufficient size to be detectable, leaks will not be identifiable.

A key aspect of CO_2 storage monitoring may be to quantify the flow rate of gas seepage. This may entail collecting the gas over predetermined periods of time. Studies of a seepage site in the Gulf of Mexico, which had shown changes in character between surveys a year apart, (MacDonald et al., 1994) included placing a bubblometer for a 44 day period which showed that the release of gas was spasmodic. The environmental data collected during the bubblometer deployment suggested that temperature was the primary controlling factor in the release of gas. This reflected the gas origin, being methane derived from hydrate accumulations outcropping at the seabed.

Costs for current sonar systems are fairly low. However, development costs would be expected for adaption of this technique for CO_2 monitoring.

10.3.15.1 CASE STUDY (NON–CO_2): GULF OF MEXICO

Natural gas seeps were imaged using a Simrad EQ50 echo sounder (frequency 38/50 kHz), Datasonics Chirp II acoustic profiler (2 to 7 kHz) and high frequency sidescan sonar EdgeTech DF–1000 over the vents (frequency 100 – 384 kHz) (De Beukelaer et al., 2003). Data were collected in 2001 and again in 2002. Bubble streams were identified using the acoustic data, however, not all the bubble streams detected by the acoustic profilers were imaged with the side–scan sonar. This was attributed to the fact that some bubbles were 'oily' having passed through oil accumulations, which affected their acoustic properties and made them difficult to distinguish from other acoustic 'shadows'. Additionally, sloping terrain made it difficult to identify bubbles with the sidescan sonar at one of the sites, as the two sides of the survey beam tended to intersect the seabed at very different angles. Some bubble streams were imaged as having wide bases and narrower tops which was thought to be an artefact of the beam angle of the acoustic instruments casting a longer acoustic 'shadow' at greater depth Figure 10–36).

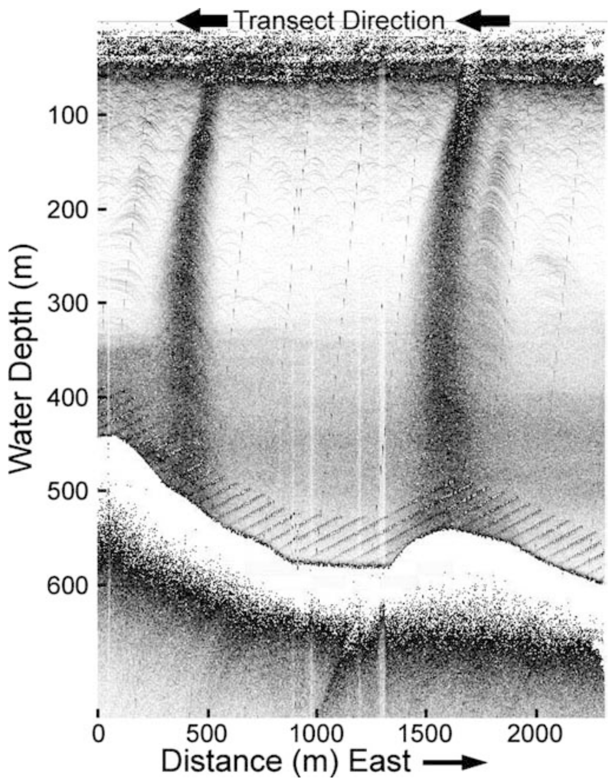

Figure 10-36: Chirp II acoustic profile showing bubble streams rising from the seabed (de Beukelaer et al., 2003, reproduced with permission of Springer-Verlag).

10.3.15.2 CASE STUDY: CENTRAL NORTH SEA (UK BLOCK 21/4)

As gas bubbles rise in the water column they normally shrink due to dissolution and most do not reach the surface (McGinnis et al., 2006). There is therefore a point where the bubble will have the critical diameter for resonance with the frequency used in the seismic system. In most multibeam surveys bubbles appear as spikes in the data and are filtered out at a very early stage in data processing, often in real time as the data is recorded.

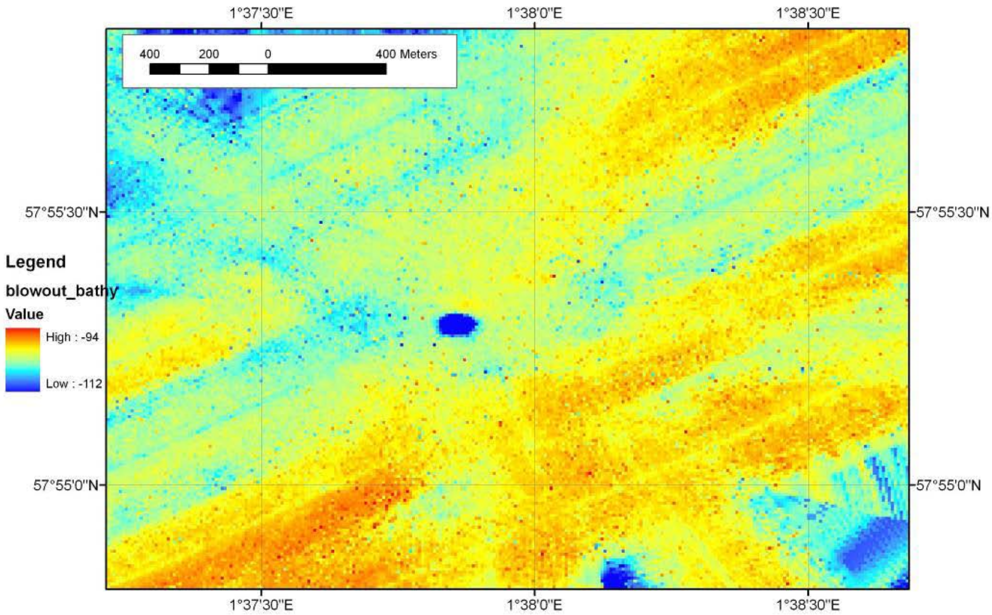

Figure 10-37: Multibeam traverses over blow–out site in UK block 21/4 Image produced by BGS from multibeam data supplied by GEOMAR showing near circular hole in seafloor. For detailed report on survey and interpretation see Schneider von Deimling et al (2007). Image courtesy British Geological Survey

There is an active gas seepage site in UK block 21/4 which resulted from a blow–out in 1990. It is a major emitter of methane from the UKCS to the atmosphere (Rehder et al., 1998). Located in about 95 m water depth, a 20 m deep, 50 m wide depression (Figure 10–37) emits gas. A series of multibeam traverses by GEOMAR showed evidence of bubbles within the water column (Figure 10–38**.**). These data points were of low quality and normally would be removed in data processing to image the seabed. However by combing the data from several traverses across the leakage site, acoustic ‘hits’ within the water column can be resolved into a column of bubbles (Figure 10–39) extending to within 7m of the sea surface (Schneider von Deimling et al., 2007). The dimensions of the imaged plume match the 30m wide bubble patch reported on the sea surface.

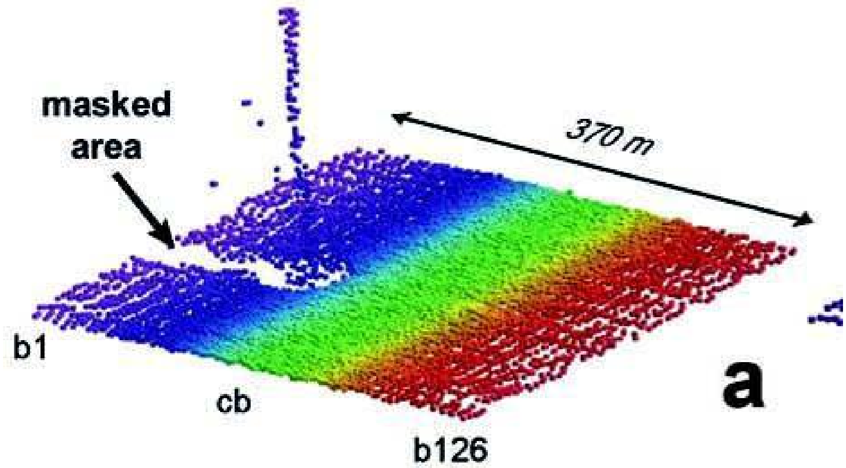

Figure 10-38: Single MBES traverse showing data points from seabed and gas bubbles in the water column (From Schneider von Deimling et al., 2007, copyright 2007 American Geophysical Union. Reproduced by permission of the American Geophysical Union)

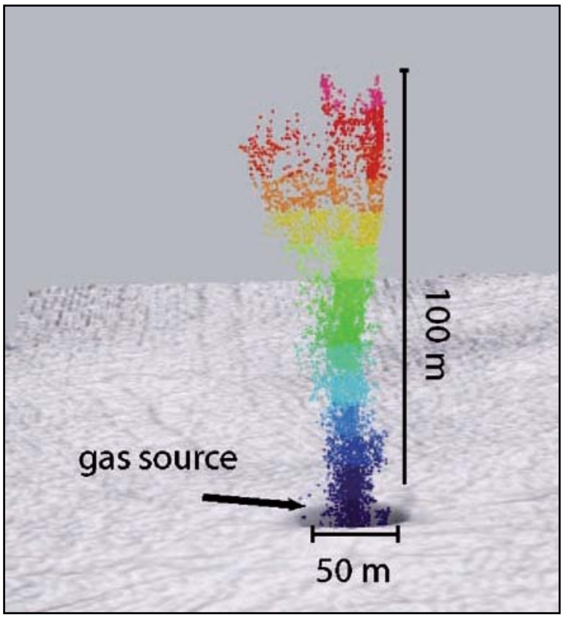

Figure 10-39: Bubble column imaged by combining data from several multibeam survey lines over blow–out in UK block 21/4. Colours indicate water depth of mid–water hits. Seabed shown in grey. (From Schneider von Deimling et al., 2007 copyright 2007 American Geophysical Union. Reproduced by permission of the American Geophysical Union)

10.4 DOWNHOLE WELL LOGGING

Downhole monitoring comprises a range of invasive technologies that enable very detailed, very high resolution measurements to be made on a wide range of downhole characteristics. Properties which can be measured include formation resistivity, neutron porosity (fast neutrons emitted by the instrument are slowed by interaction with hydrogen in the porosity to a level where they can be counted by the detector), sonic (uses an acoustic source), density, gamma–ray (natural emissions), self potential (naturally occurring electrical potential), temperature, pressure, cement integrity, other more specialist tools include various fracture identification and imaging tools and nuclear magnetic resonance (NMR) tools. These logs are obtained by lowering instruments down the borehole on a cable known as a ‘wireline’.

Many of these techniques require further development and testing to be adapted for use in monitoring and measuring injected CO_2.

A drawback to using invasive techniques is that the wellbore itself offers a potential CO_2 migration and leakage pathway. The borehole needs to properly capped and monitored to avoid leakage and suitable cement needs to be used to slow corrosion due to contact with CO_2.

10.4.1 Geophysical logs

Geophysical logs are one of the most common methods of evaluating downhole properties. The standard suite of 'open hole' logs generally includes resistivity, neutron, sonic, density, gamma ray, self–potential, temperature and cement integrity logs. Many boreholes have a steel lining or casing, and not all tools are suitable for use in such wells. Some instruments can be used with additional processing and some specialist tools have been developed for use in cased wells. Cased hole–specific tools include through–casing resistivity and pulsed neutron tools. Interpretation of borehole logs in combination provides a good assessment of the downhole characteristics.

A number of logging tools are potentially suitable for monitoring CO_2 including sonic, neutron, density, resistivity, nuclear magnetic resonance, and pulsed neutron logging tools. These logs could provide information on CO_2 migrating into the wellbore and changes in the properties of the subsurface relating to leakage.

Repeatability and accuracy of the tools vary. Schlumberger gives the accuracy of their neutron porosity log to be ± 1 to 6 % porosity depending on the formation, vertical resolution to be about 30 cm and depth of investigation (into the rocks around the wellbore) around 23 cm (Schlumberger 2009a).

The Schlumberger reservoir saturation tool (RST) records carbon, oxygen and thermal decay time measurements to determine formation oil saturation and to quantify injected water where it has different saturation to the connate water. This tool has a depth of investigation of about 20 cm and a vertical resolution of about 38 cm (Schlumberger 2009b). The tool also measures sigma' (Σ), the 'thermal neutron capture cross section' of the formation which can give CO_2 saturation where there is a Σ contrast between the CO_2 and the formation (Muller, 2007).

10.4.1.1 Case study: Nagaoka, Japan

At Nagaoka, 10400 t CO_2 was injected into a saline sandstone formation over a period of 18 months. Repeated wireline logs measuring resistivity, neutron porosity and sonic velocity were run in three observation wells though a fibre–glass casing. Baseline logs were acquired before CO_2 injection and 23 repeat surveys were carried out (Xue et al., 2006). No evidence of leakage was detected.

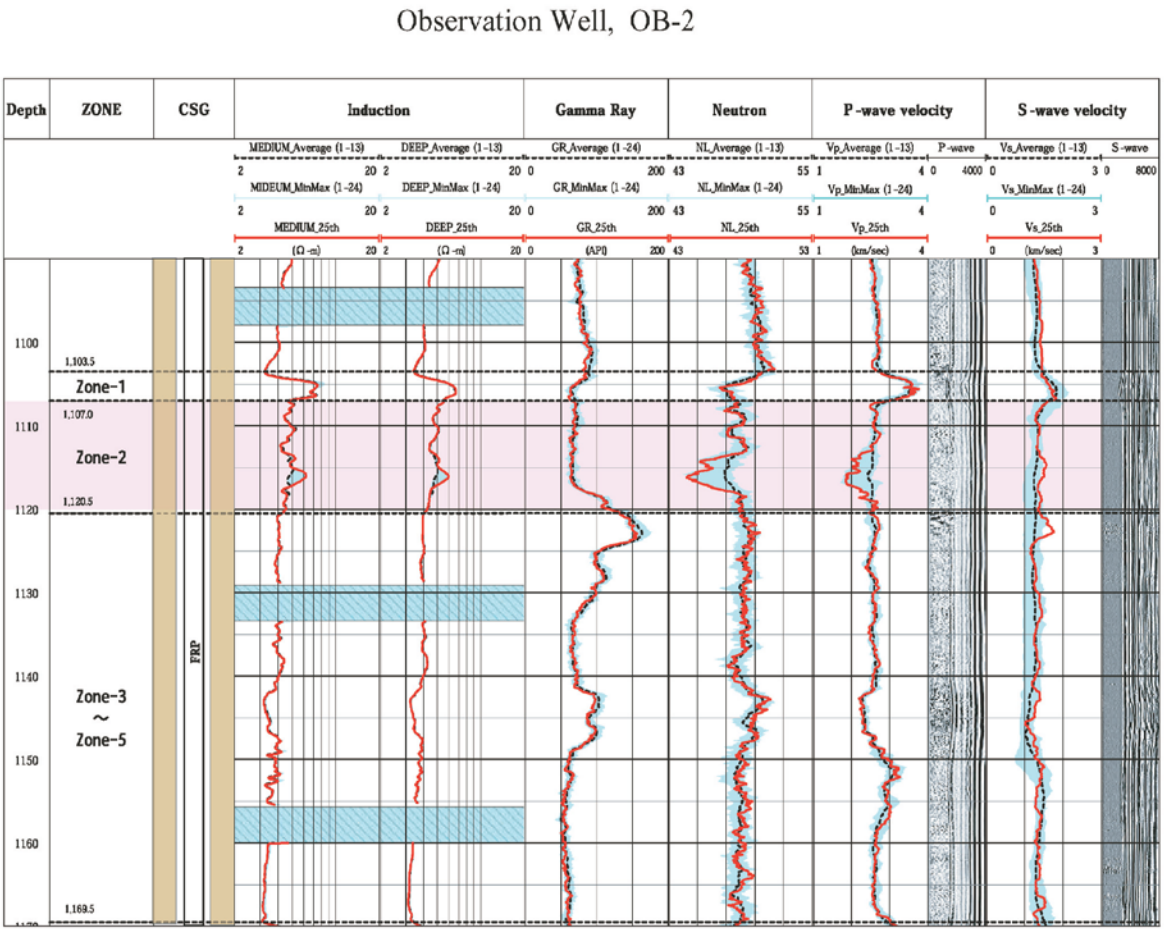

Figure 10-40: Logs for dual induction, gamma ray, neutron, sonic at an observation well. The blue areas marked on the induction log show where data could not be recorded because of steel bridges between fibreglass casings (Xue et al., 2006), image Copyright © 2006 ASEG/SEGJ/KSEG reproduced with permission of CSIRO Publishing.

The reservoir porosity was evaluated using the open–hole and cased–hole neutron porosity logs and sonic logs, these porosities were then used in the calculation of CO_2 saturation, based on the Gassmann equation for the behaviour of fluids in partially saturated rocks, using the sonic logs. P wave velocity reduction decreased significantly when CO_2 saturation was up to 20%. Above 20% saturation it was less sensitive. However the induction logs showed the resistivity continuing to increase at higher saturations, although they only implied a CO_2 saturated zone of half the width shown by the sonic and neutron logs, because the partially saturated reservoir created only very small changes in resistivity and therefore only a small response was observed on the induction log (**Figure 10–40**). In the 13 post injection surveys, the resistivity surveys showed a drop in resistivity above and below the CO2 bearing zone. This was interpreted to be the CO_2 dissolving in the formation water (and consequently increasing storage site safety) and the migration of the CO_2 plume updip (**Figure 10–41**.).

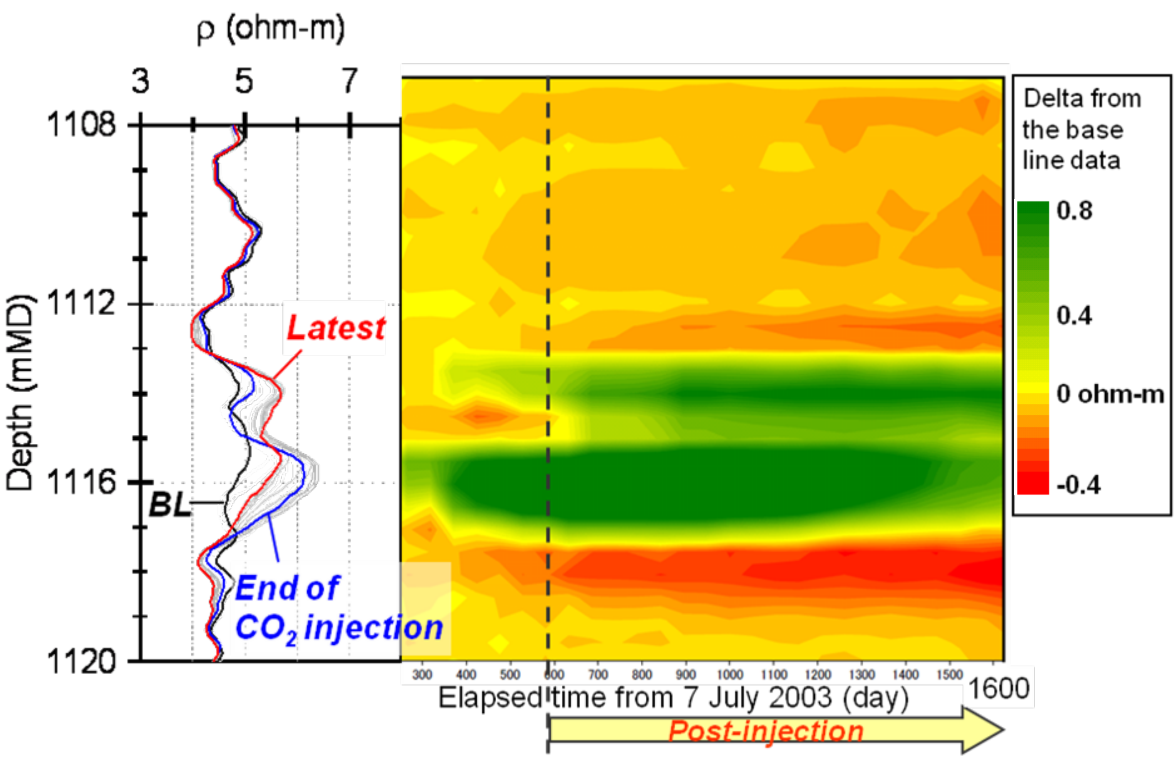

Figure 10-41: Resistivity changes obtained from time–lapse induction logging at the Nagaoka pilot CO_2 injection site (Xue et al, 2009a, Copyright (2009) Society of Petroleum Engineers. Reproduced with permission of the copyright owner. Further reproduction prohibited without permission).

10.4.1.2 CASE STUDY: FRIO, TEXAS, USA

At the Frio Brine Pilot CO_2 injection site, 1600 tonnes of CO_2 were injected into a dipping sandstone saline aquifer over a period of 11 days. Schlumberger's Reservoir Saturation Tool (RST) was used to conduct time lapse pulsed neutron logs to monitor the movement and saturation of the injected CO_2. The CO_2 saturation could be measured with high sensitivity because of the large sigma contrast between the saline formation waters (high Σ) and CO_2 (low Σ) (Müller et al, 2007).

The logs (Figure 10–42.) showed CO_2 saturations increasing up to a maximum of 65% in the injected formation and subsequently decreasing post injection, as expected. No leaks were detected from the injected formation.

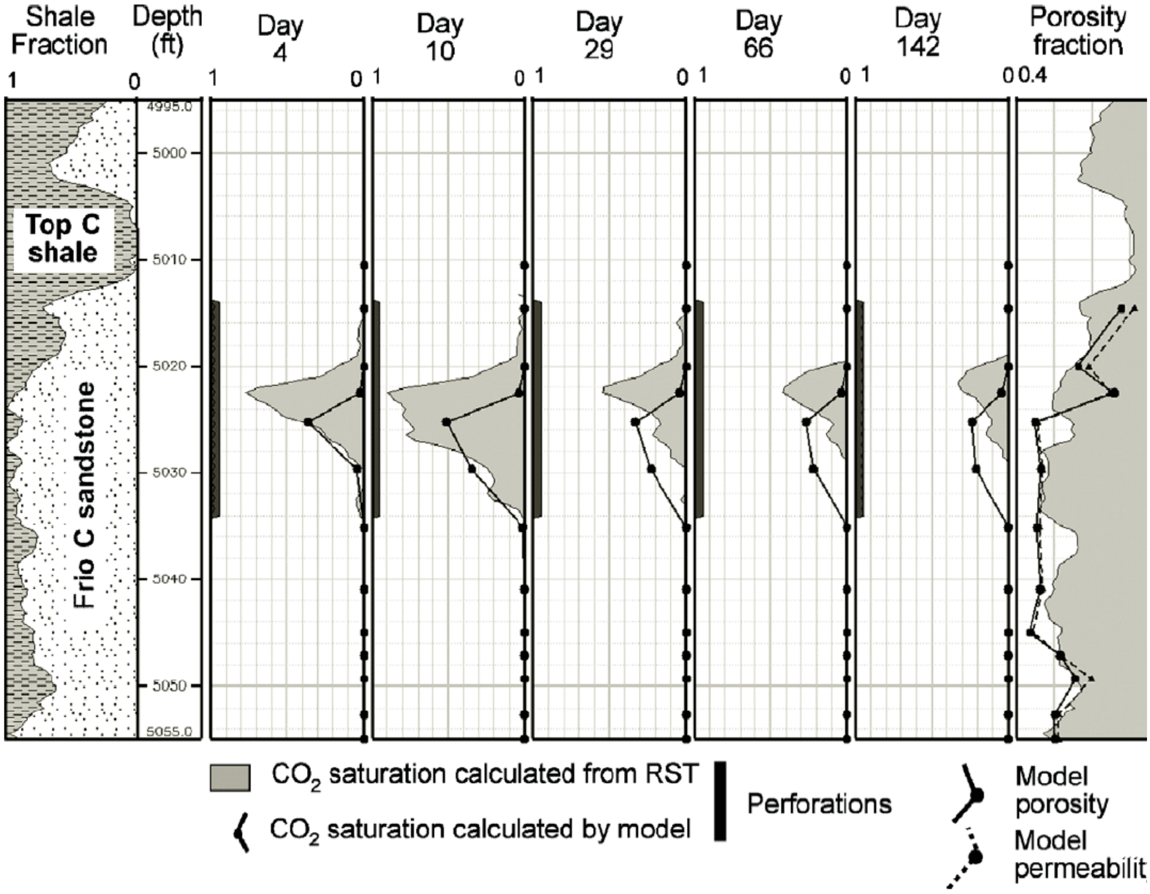

Figure 10-42: RST logs collected during the Frio Brine Pilot test. CO_2 saturation at the observation well is compared with modelled changes in saturation per layer plotted at layer midpoint (Freifeld et al, 2009, reproduced with permission of Elsevier).

10.4.2 Downhole pressure/temperature

In addition to standard geophysical logs, pressure and temperature can be recorded downhole. Wellhead, bottom–hole and annular pressure are key monitoring tools and can provide early evidence of CO_2 migration and pressure build–up and cement integrity. Excessive pressure build–up can result in fracture dilation or reactivation and damage to caprock integrity. Pressure reduction can indicate CO_2 migration, dissolution into groundwater or sensor drift. As pressure changes can have a number of causes, it is useful to consider pressure and temperature in conjunction with other measurements.

Pressure and temperature sensors could be deployed in an observation well to continuously monitor changes in pressure and temperature at varying depths within the reservoir and caprock, before, during and after injection.

Permanent downhole pressure and temperature gauges are available, with data transmitted to the surface through optic fibre cable. Current pressure sensor drift is less than 1% over 20 years (Pearce et al., 2005). Temperature sensor lifetime is currently 5 – 10 years (Carlsen et al., 2001). Measuring pressure and temperature is an established technique used in other industries but has not yet been proven for use with CO_2 monitoring.

The Schlumberger Unigage tool is designed to acquire temperature and pressure readings for up to a year under harsh borehole conditions (e.g. the presence of hydrogen sulphide) with a temperature resolution of 0.001 ºC, an accuracy of ± 0.3 to 1 ºC and a pressure resolution of 0.07 to 1.03 kPa and accuracy ± 17 – 69 kPa (Schlumberger 2009c).

10.4.2.1 CASE STUDY (CO_2): PEMBINA CARDIUM, CANADA

Penn West Energy Trust, the Alberta Research Council (ARC), the Alberta Energy Research Institute, Western Economic Diversification Canada, Natural Resources Canada and Alberta Environment are conducting a CO_2–EOR pilot in Pembina Cardium, in Alberta, Canada (Alberta Research Council et al., 2009). One of the work packages involves downhole logging. The Pembina Oilfield covers an area of about 140,000 km^2 and produces from several horizons of Devonian to Tertiary age at depths of 1600 – 1650 m. Average core porosity and permeability ranges from 8% and 31 mD in the conglomerate to 16% and 21 mD in the middle and upper sandstone units. The reservoir temperature is 50°C and current pressure about 18 – 19 mPa. An existing well was chosen for use as an observation well. Pressure and temperature sensors were installed and data is received at the surface using a remote cellular phone link. Due to influx of downhole fluids during cementing, a small channel was created permitting fluids to flow to the surface, this was stopped by circulating dense brine between the tubing and the casing, which damaged some of the sensors. The remaining pressure–temperature sensors have transmitted data to the present (2009).

10.4.2.2 CASE STUDY (CO_2): KETZIN

At the Ketzin pilot–injection project, a fibre–Bragg–Grating based pressure sensor has been installed in the injection well Ktzi 201 at the saline aquifer injection pilot site. The sensor operates as a single point optical pressure gauge, it is temperature compensated and designed to have a long–life at high temperatures (Giese et al., 2009). Bottom hole temperatures are also recorded (Figure 10–43).

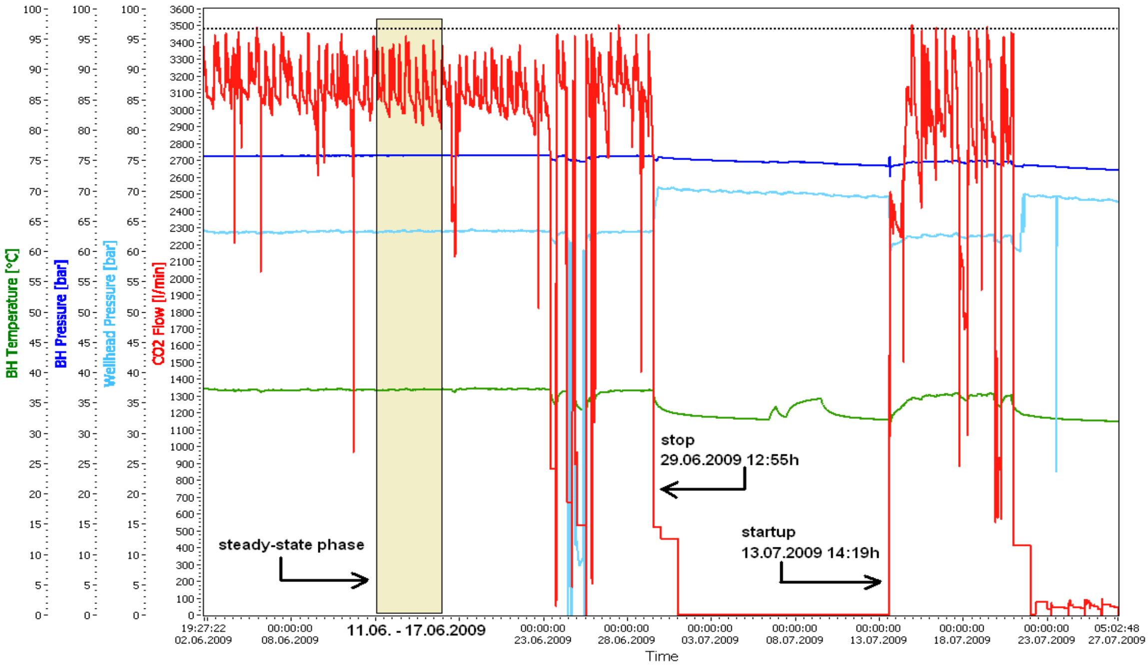

Figure 10-43: Bottom–hole (BH) temperature and pressure, wellhead pressure and CO_2 flow measurements at Ketzin, showing changes associated with stop and startup of injection (image courtesy C. Schmidt–Hattenberger, German Research Centre for Geosciences).

10.4.3 Continuous downhole temperature measurements

Temperature is recorded continuously at regular spacing along the borehole using fibre optic sensor cables connected to the processing computer at the surface. In contrast to standard downhole tools, these permanently mounted fibres offer continuous data for the whole well during borehole operations.

The Schlumberger WellWatcher Ultra DTS offers accuracy of 0.01 °C, calibration accuracy of ±1.8 °C or better and can measure 15 km of fibre at metre–resolution and update data in a few seconds (Schlumberger, 2009d)

10.4.3.1 CASE STUDY (CO_2): KETZIN

At the Ketzin pilot injection project continuous downhole temperature measurements have been made using a DTS (distributed temperature sensor), mounted outside the injection tubing. It serves as an additional safety monitoring tool in combination with the deployed bottom–hole pressure–temperature point gauge at the end of the injection string.

Permanent temperature profiling helps to ensure that the injected CO_2 will stay in its highly dense phase (as specified for the injection process) in order to avoid a two–phase system in the reservoir (Figure 10–44).

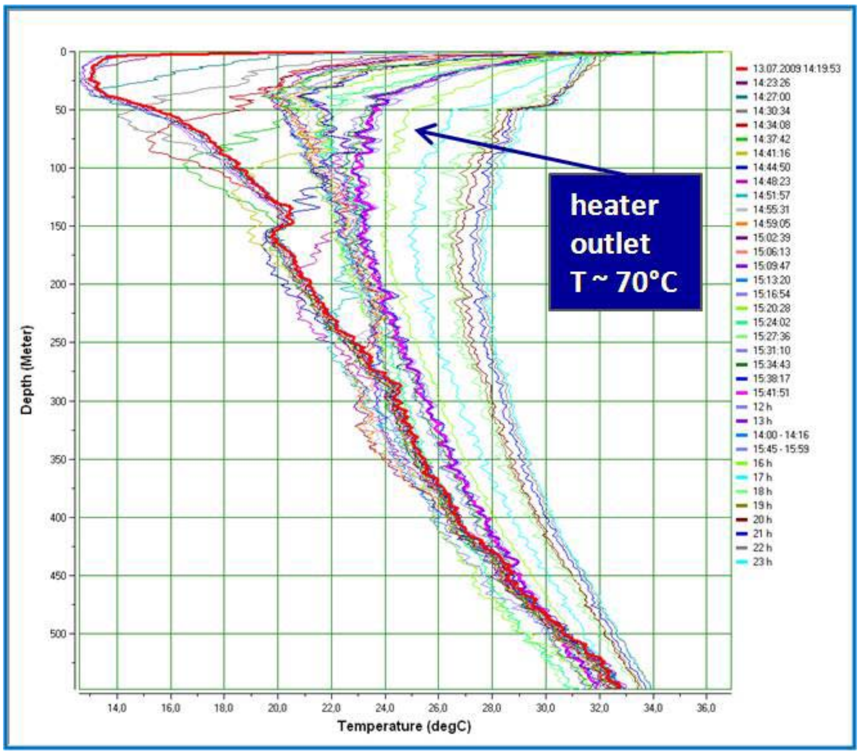

Figure 10-44: DTS measurements outside the injection tubing from Ketzin showing changes in temperature profile of the CO_2 column in the hours following startup of injection (image courtesy C. Schmidt–Hattenberger, German Research Centre for Geosciences).

DTS optic fibre cables mounted behind the borehole casing with sensors allow long–term temperature monitoring in the borehole. At Ketzin they were also used for better control of casing cementation, which is critical for proper sealing of the boreholes for secure storage. The temperature has been monitored constantly since CO_2 injection began. Temperature changes of up to about +25 ºC were observed close to the wellhead of the injection well. Those in the injection zone were around 5 – 10 ºC. In the two observation wells, temperature variations of up to about 1.5 ºC were observed. In the observation well, Ktzi 200, a temperature increase of 0.5 ºC was detected prior to CO_2 breakthrough being detected in the wellbore using the gas membrane sensor (Giese et al., 2009) (Figure 10–45**.**).

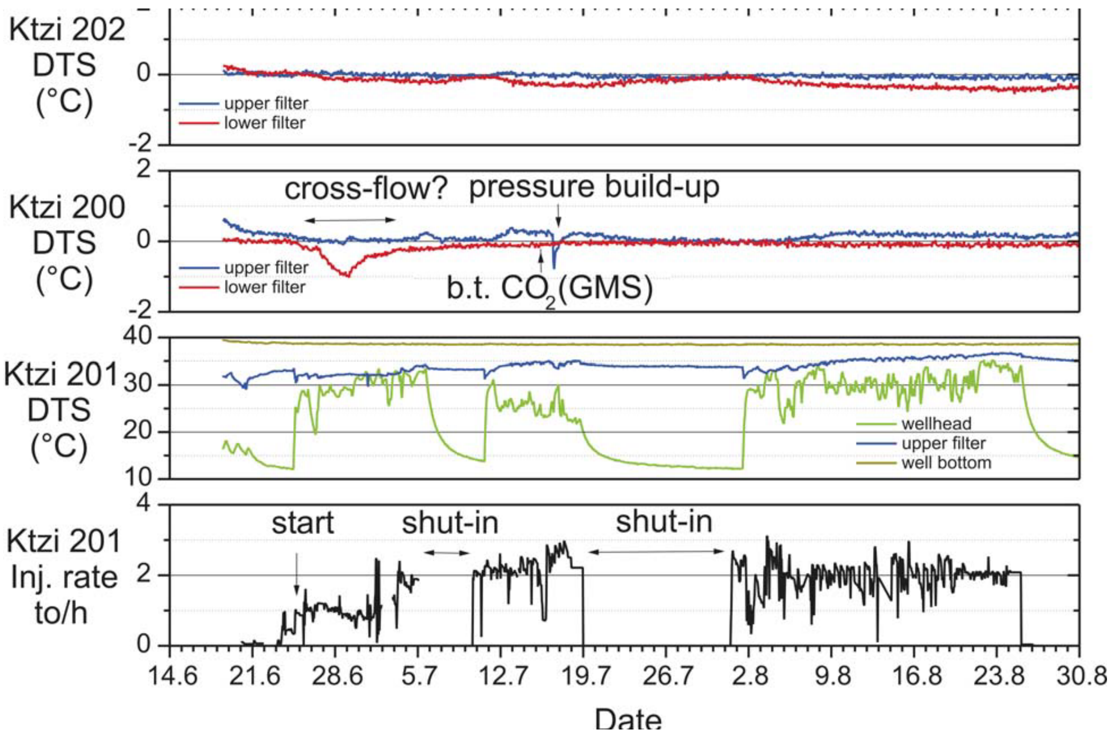

Figure 10-45: Injection rates and measured DTS (outside casing) temperatures in the injection well (Ktzi 201) and observation wells (Ktzi 200 and Ktzi 202). Time of breakthrough (b.t.) detected using the gas membrane sensor is marked (Giese et al., 2009, reproduced with permission of Elsevier).

10.4.4 Dynamic downhole temperature testing

Thermal conductivity measurements can be used to monitor CO_2 saturation. The equipment consists of an electrical resistance heater cable running the length of the borehole, to which constant heating is applied. The heater is then switched off and the thermal decay is measured using the fibre optic distributed temperature sensor (DTS), described in the continuous downhole temperature measurements (section 10.4.3**.**).

CO_2 has a low thermal conductivity compared to water and rock and so increased CO_2 saturation causes a decrease in formation thermal conductivity. This allows a calculation of CO_2 saturation.

10.4.4.1 Case study (CO_2): Ketzin

At the Ketzin pilot–injection project distributed thermal perturbation sensing (DTPS) equipment has been successfully used to estimate CO_2 saturations. The electrical heater cable providing approximately 20 Watts per metre along the wellbore was activated for 48 hours,. CO_2 saturations were calculated from estimates of thermal conductivity based on inversions of the temperature decay measured by the DTS system at a 1m vertical resolution (i.e. the DTS resolution). Preliminary results (Figure 10–46**.**) matched well with measurements on core samples. It is anticipated that the increase in CO_2 saturation as injection continues will result in a measurable drop in thermal conductivity using this monitoring method.

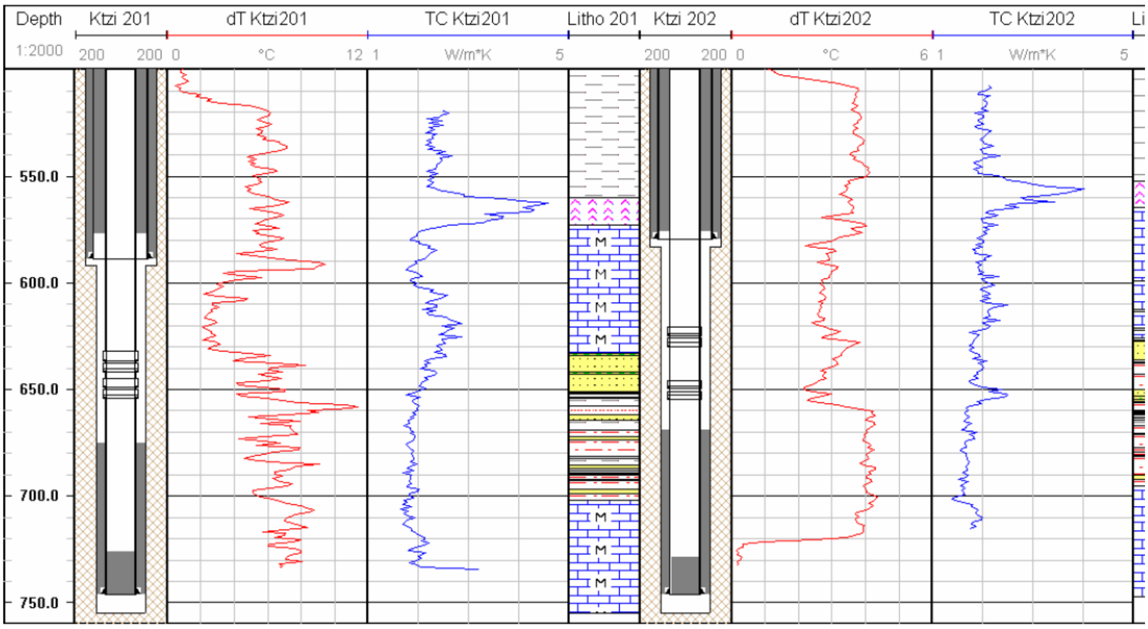

Figure 10-46: Well logs for the injection well (Ktzi201) and monitoring well (Ktzi202) showing temperature changes (dT) during DTPS heating and calculated thermal conductivities (TC) along with well layouts and lithologies (Freifeld et al, 2009, reproduced with permission of Elsevier).

10.4.5 Well integrity logs

Wells are generally recognised as a weak spot in CO_2 storage, where containment could break down. This is because cement, steel and elastomers can be corroded by CO_2, and the ageing process will be accelerated by any defects in the cement sheath (e.g. Loizzo et al., 2009). To ensure proper behaviour, different monitoring (logging) tools exist (**Figure 10–47**). These monitor the quality of the casing(s) and the occurrence of corrosion. Incidences of corrosion may signify a potential breach of well integrity, but could also represent CO_2 migration occurring on the outside of the casing that would lead to corrosion of the steel (Carey et al., 2010). Furthermore, measurements focus on the bonding of the annular cement to the casing and the observation of channels behind the casing.

The multifinger caliper tool provides information on the internal radius of the wellbore casing or tubing. The caliper can detect small changes in the inside wall of the casing or tubing that may be indications of corrosion, casing wear or other deformation. Multifinger caliper tools cannot assess the condition of the outside or the thickness of the casing. The tool is equipped with a large set of arms or fingers that radially extend from the tool in 360º. Typical multifinger calipers have between 20 to 80 fingers, the larger number being applied in pipes with larger diameters. Multifinger caliper tools can be used in pipes with diameters between 1 3/4 and 13 3/8 inches (4.4 to 34.0 cm) and have an accuracy of up to ±0.05 inches (1.27 mm) (Duguid and Tombari, 2007). The tool does not impose requirements on logging fluids, but is limited to measure only the inner radius.

A cement bond log or cement evaluation log evaluates the integrity of the cement job, i.e. the quality of the bonding between cement and casing, between cement and formation and the density of the cement. The log is acquired through a sonic tool that transmits an acoustic signal to the casing and formation, measuring the magnitude and transit time of the refracted signal. The tool's output consists of two parameters, i.e. the bond index and the variable density log. The first provides a quantitative estimate of the cement–to–casing bond, based on attenuation of the transmitted sound waves, while the latter gives qualitative information on the bonds between casing and cement as well as between cement and formation (Duguid and Tombari, 2007).

The interpretation of the results may not be unequivocal as the measurements are sensitive to fast formations, tool eccentricity, liquid–filled microannuli and contaminated cements. While cement bond logs return radially integrated and averaged bonds and do not identify specific locations of poor bonding, newer versions – called cement evaluation logs – along with the associated processing software, provide 360° representations of the cement bonding with high azimuthal resolutions. Recent generations of ultrasonic logging tools (like the UltraSonic Imager Tool or USIT) measuring acoustic impedance, present enhanced information on the next interface (cement–formation interface or another casing cement interface). This is the result of the combination of classic pulse–echo techniques with new flexural wave imaging. Furthermore, ultrasonic tools measure casing anomalies, such as corrosion pits, both on the inside and outside of the casing surface. Its accuracy goes down to 0.3 inches (7.6 mm). The application of ultrasonic techniques enables differentiation between materials behind the casing (e.g. cement, microdebonded cement, liquids or gas) as well as identification of channels and defects in the annular isolating material (Duguid and Tombari, 2007).

The Isolation Scanner is a tool combining the pulse echo technique as used in the CBL logs with the measured attenuation of an induced flexural wave. It provides maps of acoustic impedance (Z) and flexural attenuation (α) with a resolution of 10° and 1.5 inches (approx. 15.5 mm around the azimuth and 38.1 mm along the depth of the well); it also provides a measured wave speed in the annular medium at each depth. Interpretation is done by comparison of the results with a laboratory measured database to identify the material immediately behind the casing.

		CBL	USIT	Isolation Scanner
Good, well bonded cement		☺ 0.5 measures	☺ 1 measure	☺ 2+ measures
Mud channel	Good cement	☹	☺	☺☺
	Weak cement	☹	☹	☺☺
Solid-solid channel		☹	☹	☺☺
Vertical cracks	Thin (~10 µm)	☹☹	☹☹	☹☹
	Thick (~10 mm)	☹☹	☹	☺
Gas chimney	At casing	☹	☺	☺☺
	In cement	☹☹	☹☹	☺
Debonding	At casing (wet)	☹	😐	☺
	At casing (dry)	😐	☹	☹
	At formation	😐	☹☹	◷
Cement radial variations		☹☹	☹☹	☺

☺ Unambiguous measure
😐 Some measure
☹ Affected, ambiguous
☹☹ No effect

Figure 10-47: Overview of available logging tools to detect flow pathways at steel–cement–rock interfaces (courtesy Laurent Jammes, Schlumberger Carbon Services). Note, that USIT stands for UltraSonic Imager Tool, considered as a specific CBL tool and generally used in combination with more conventional sonic CBL logging tools.

Other than acoustic tools, electromagnetic tools scan both the inner surface and the thickness of a production casing. This enables identification of casing corrosion or grooves and splits. The quantitative measurements show the severity and nature of corrosion. Time–lapse runs of the tool even provide corrosion rate estimates. Multifrequency electromagnetic measurements are related to casing wall thickness and inside diameter. The measurements are based upon the phase shift of alternating magnetic fields as a result of interaction with the casing. The resulting parameters give averaged values around the casing circumference. Different tools are designed for smaller and larger defects. The tool is insensitive of the type of logging fluid and measures the casing radius behind scale.

A final set of techniques that can be deployed to investigate CO_2 migration or well integrity comprises sampling and testing tools. These include vertical interference tests, where a well is perforated across a 10 ft (3 m) interval. Subsequently the lower perforations are sealed and pumped from the annulus to analyze the sample in real–time and determine an equivalent annular permeability. Disadvantages are that it remains unclear what the measurements actual represent and that the technique is destructive. In that respect cased–hole mobility tests are more advanced, since here the hole drilled through the casing and cement (up to 6 in (15 cm) deep) is sealed off after monitoring of pressure and retrieval of a formation sample. Cased–hole coring is also a destructive method, yet valuable as samples of casing, cement and formation can be obtained and studied (e.g. Carey et al., 2007; Crow et al., 2009).

In contrast to wireline sampling and testing tools, permanent installations are also available for semi–continuous downhole monitoring. A u–tube manometer can be used for measuring fluid densities. In addition, the so–called Westbay completion enables measuring pressure, temperature and sampling. This technique involves a tube with valved ports to the annulus, which is divided into separate, isolated zones. Measurements are operated using a wireline tool. The last technique is developed for shallow reservoirs and not suitable for repeated sampling.

10.4.5.1 CASE STUDY (CO_2): KANIOW, POLAND

On the site of Kaniow (Poland) a new well was used to inject supercritical CO2 into coal seams over a two year period. The injection was part of an experiment on Enhanced Coal–Bed Methane recovery. Both integrity of the casing and of the cement have been evaluated using CBL (UCI–tool) and Isolation Scanner (IS) logging tools (Loizzo et al., 2009).

Basically time–lapse logs, in May 2006 and Oct 2007, could detect no casing corrosion over the 17 month period.

Figure–48 shows an increase of the average thickness of the casing between the two logs along the whole well, although the magnitude of change (about 0.5% corresponding to 50 µm for a 10 mm thick casing) is far below measurement precision (estimated at 2% for the IS, 4% for the UCI). The trend between the thickness measured by the IS and the UCI shows a good correlation, although the exact values are an order of magnitude higher.

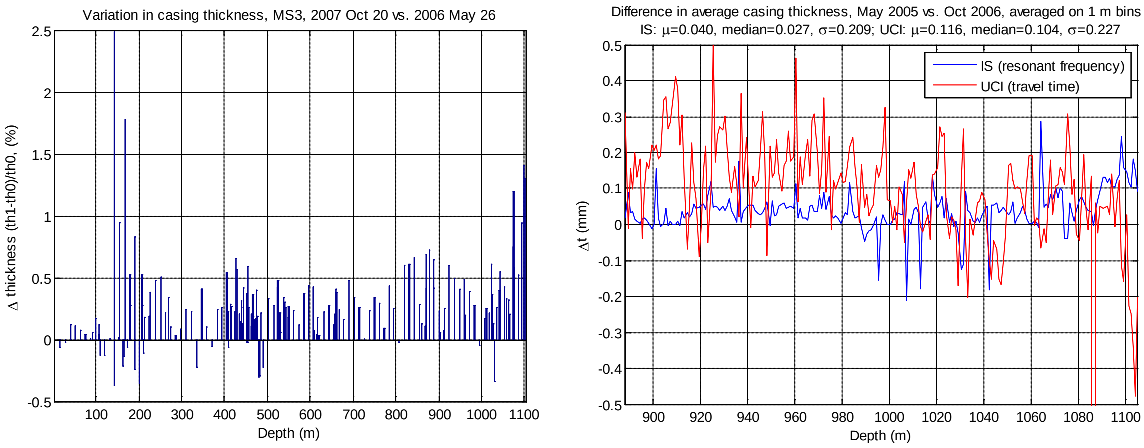

Figure 10-48: Distribution of casing percent thickness changes between logging runs measured by the IS and averaged at each casing joint (left plot), and comparison of IS and UCI absolute thickness changes for a section at the bottom of the well (right plot) Image from Loizzo et al, 2009 reproduced with permission of Elsevier.

It is highly likely that all the thickness changes, far below published tool precision, are due to the effect of increasing cement acoustic impedance. The additional effect of a fluid–filled microannulus on the UCI may also help explain the larger thickness increase measured by the tool, as well as the seemingly different behaviour of thickness below and above the packer.

Concerning the cement integrity, the evolution of Z and α between the two logging runs shows a clear increase in values about four times higher than the resolution. The difference is therefore considered meaningful. So far the interpretation has been speculative and could be attributed to contraction of a fluid–filled micro–annulus between cement and casing, or to carbonification of the Portland cement leading to a higher impedance.

A combined interpretation of all the logs suggests indeed superficial cement carbonation along the whole well: the carbonation was probably caused by a ballooning fluid–filled microannulus, in turn caused by the high injection pressure. The evidence also confirms that the microannulus shrank back in size after the end of injection and that coal creeping/swelling provides a good hydraulic seal.

10.5.1.1 CASE STUDY (CO_2): COLORADO, USA

Crow et al. (2009, 2010) present a study in the framework of the CCP–2 project on the well integrity of a 30–year old well from a natural CO_2 production reservoir. The wellbore was exposed to a 96% CO_2 fluid from the time of cement placement. This site is unique for two reasons: it represents a higher, sustained concentration of CO_2 compared to enhanced oil recovery fields and the reservoir and caprocks are clastic materials that will possess less buffering capacity than carbonate reservoirs.

The well has been producing CO_2 for 20 years, with an increased water production over the last 7 years. The pH of the produced water varied from 3.1 to 6 in recent years. Besides an extensive sampling program of solids and fluids outside the casing, well integrity logging (USIT, multi–arm mechanical caliper and pulsed neutron) has been carried out.

Cement samples taken in and near the CO_2 reservoir have been almost completely converted to calcium carbonate. Even samples at the top of the caprock showed some minimal alteration. Cement evaluation log information given by raw acoustic impedance indicates generally good cement quality with the highest quality near the top of the shale. Visual observation of the cement interfaces with casing and with caprock show apparently tight contacts with no debris or other indications of porosity and only very thin deposits (< 0.1 mm) of calcium carbonate. All 20 carbon steel casing samples recovered were in excellent condition with limited corrosion. The measured formation pressure suggest that wellbore system provides hydraulic isolation between the CO2 production zone and the upper caprock intervals based on the 1000 psi pressure difference across the shale.

The Ultrasonic Imaging Tool (USIT) was run to provide an indication of the cement quality and its bond to the casing measured by attenuation of the acoustic signal. The general trend is consistent with a decrease in cement core hydrologic properties from the top of the caprock (1μD permeability, 25% porosity) to theCO2 interval (21μD permeability, 41% porosity). For this well, the USIT log measurement seems capable of detecting differences in the quality of the cement that is attached to, and surrounding the casing. Acoustic impedances show a correlation with the cement porosities and permeabilities consistent with the observed cement alteration zones.

A multi–arm mechanical calliper indicated minimal wall thickness loss between the perforations and packer where the casing was exposed to CO_2 and produced water, consistent with actual casing samples collected.

The pulsed neutron log indicated no gas saturation evident in the caprock or other overlying layers. This indicates no migration along the barrier system.

Finally a Vertical Interference Test Analysis was conducted between two perforated zones. The results from this test indicate the extent of hydraulic communication along the exterior of the well casing between the two perforations and are a measure of the effective permeability of the wellbore system. The permeability calculations from the VIT data are 1 to 2 orders of magnitude greater than the cement core permeability. This indicates that the cement interfaces with casing and/or formation are the primary path for CO_2 migration as shown by cement carbonation.

In summary, the authors interpreted the data as CO_2 originating from the reservoir migrating along defects (primarily cement–caprock and cement–formation interfaces) within the wellbore system and leading to carbonation of cement and acidification of fluids adjacent to the caprock

Furthermore they conclude, that current technologies can be used to determine barrier conditions. Logging results from this survey correlate with the performance measurement of the large scale vertical interference test (VIT) and the small scale cement core properties.

10.5.1.2 CASE STUDY (CO_2): OTWAY, AUSTRALIA

Contraires et al. (2009) present a case study on well integrity where the integration of 3D ultrasonic imaging together with an advanced understanding of cement petrophysical properties brings about a detailed picture of the cement sheath. The CO2CRC Otway pilot project aims to inject 0.1 million metric tons (Mt) of CO2 over 2 years in a depleted

sandstone gas reservoir in the South–East of Australia to demonstrate the feasibility of geological storage. Injection has started on 2008 Apr 2. This paper introduced the presence of solid–in–solid channels in the cement of the CO2CRC CRC–1 well. It is a contamination of the tail CO2 resistant cement by some much more porous lead cement. These channels have been observed on acoustic impedance logs, and characterized using a Bayesian joint inversion of the impedance and the flexural attenuation to determine the parameters of the blend composition used to model the best fitting data.

10.6 CHEMICAL METHODS

Monitoring dissolved and free CO_2 in the subsurface sediments and in the water column is a developing technology. Typical CO_2 saturations in groundwater vary, but away from CO_2 sources are likely to be low. Establishment of baseline conditions should be used for comparison with samples taken after CO_2 injection has begun. Sampling in deeper formations requires specialist equipment and care must be taken to maintain the pressure and temperature conditions of the sample to avoid degassing. Water samples can be taken downhole or at the wellhead in boreholes (Pearce et al., 2005; Benson et al., 2004).

Calculating the CO_2 content requires measurement of several factors as the total inorganic CO_2 content will be a composite of CO_2(aq), H_2 CO_3(aq), HCO_3^- and CO_3^{2-}; temperature, pH salinity, total dissolved inorganic carbon, total alkalinity, fugacity of CO_2 in equilibrium with fluid (fugacity is a measure of the partial pressure of CO_2) and total hydrogen ion. At present there are no downhole tools to directly monitor the presence of CO_2 in the formation water, the CO_2 content is evaluated using laboratory results or the effects of CO_2 (e.g. pH).

10.6.1 Headspace gas

Samples of seabed surface sediments are obtained using box– or vibro–corers from depths of up to few metres. A box–corer is suitable for use with soft sediments; the box can obtain a sample of up to 30 by 30 by 60 cm and a depth of penetration of up to 50 cm. The box and containing frame are lowered from a wire to the seabed and the box is deployed vertically (bgs.ac.uk 2009a). A vibro–corer with containing frame is lowered on a wire and uses a twin motor housed in a pressure vessel, driving a core barrel with a vibration force of 6 tonnes at 50 Hz to obtain a core at up to 6m depth with diameter 83 mm (bgs.ac.uk 2009b). Subsamples of this primary sample are then extracted by pushing in plastic sampling tubes and allowing the sediment to settle. Samples of gas are collected in the 'head space' above the sediment, these gas samples are then geochemically analysed, to determine parameters such as its origin (thermogenic or biogenic), composition and stable isotopic content.

This technique could be used to check for the presence of CO_2 in shallow seabed sediments. This technique is well established in the hydrocarbon (for methane) and packaging (for CO_2) industries amongst others, but has not yet been used in relation to monitoring stored CO_2.

A limitation of this technique is that it requires the access to the seabed, which is more difficult in deeper waters.

Costs would be expected to be low to moderate.

Headspace gas is often analysed using gas chromatography. A case study given on the Agilent technologies website (chem.agilent.com 2009) used a G1888 headspace sampler and 6890N and 5975 inert MSD to monitor hydrocarbons in a water sample (The 5975 has been replaced with the 7975 with accuracy 0.01 ppb). The 5975 can also be used to monitor CO_2 content.

CO_2 monitoring devices are available for the packaging industry, but it is uncertain how well these would survive field conditions at the wellhead.

10.6.1.1 Case study (non–CO_2): Netherlands

As part of the Nascent project, seabed samples were obtained in and around a pockmark in Block A11, offshore Netherlands (Schroot and Schüttenhelm, 2004, Schroot et al., 2004). Seven cores were obtained of length 2.5 – 3.4 m. Each one metre length was then sub–sampled and the gas analysed. The majority of samples had background levels of methane varying between 6.5 and 13.7 ppm, however, one sample had a high methane content (122.6 ppm), indicating a site of active methane leakage (Figure 10–49**.**). Water depth was about 33 m.

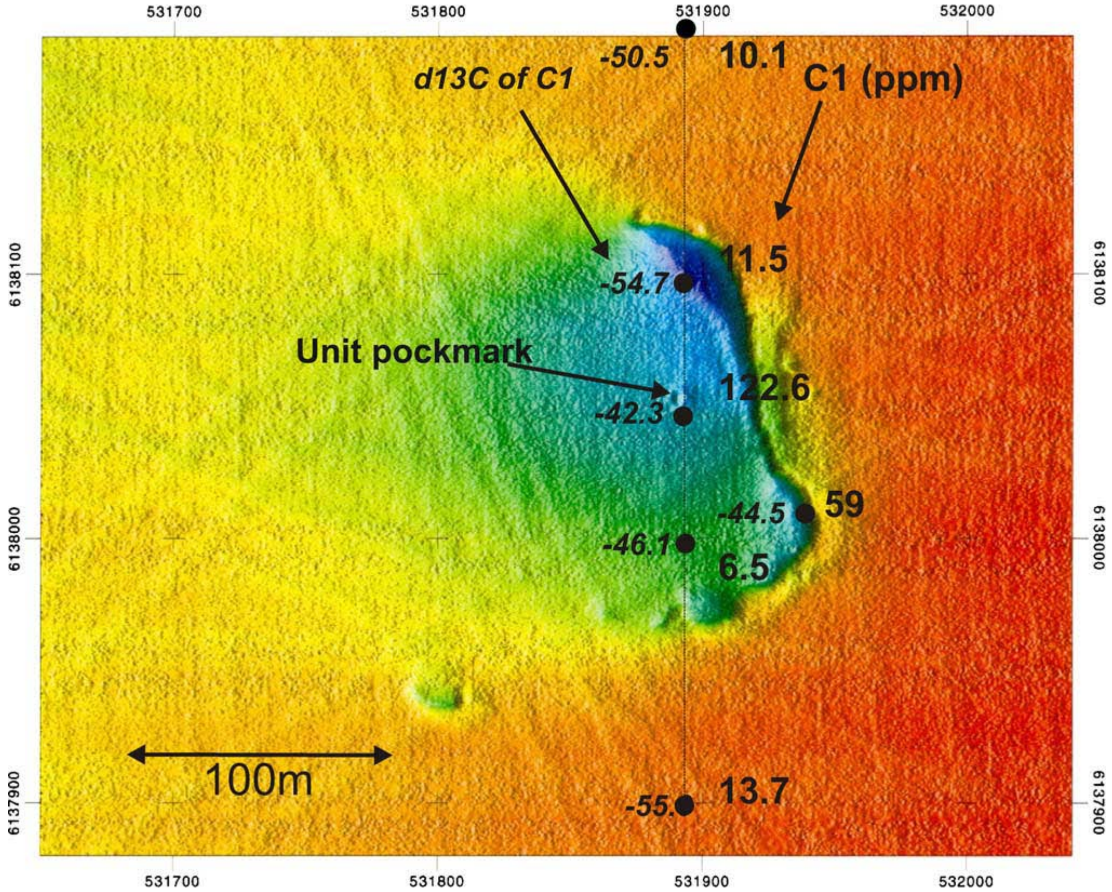

Figure 10-49: Multibeam echo sounding image of a pockmark with vibro–core number (266 – 270) and methane gas headspace gas content (ranging from 6.5 – 122.6 ppm) (Schroot et al., 2004, image reproduced with permission of Elsevier).

10.6.2 Seawater chemistry

To determine the amount of CO_2 in seawater, the following factors are measured; temperature, pH salinity, total dissolved inorganic carbon, total alkalinity, fugacity of CO_2 in equilibrium with seawater and total hydrogen ion. The total inorganic content will be composite of CO_2(aq), H_2 CO_3(aq), HCO_{3-} and $CO_{3\,2-}$ As the samples collected to test for CO_2 leakage will most likely be collected at depth, care must be taken to maintain the pressure and temperature of the sample to avoid degassing.

Technologies to monitor surface seawater geochemistry are well developed and widely used. Monitoring CO_2 concentration

The U.S. Department of Energy (DoE) handbook (Dickson et al., 2007) details recommended operating procedures for sampling and analysis, calibration, procedures for computations and quality control for determining CO_2 content of seawater. A sensitive pH monitor has recently been developed in the UK, which could potentially be useful for measuring decrease in pH caused by CO_2 leakage.

A limitation of this technique is that surface sampling would also not indicate the location of the leak and so deeper sampling would be required. Additionally, deep sampling requires specialist equipment to maintain the pressure and temperature of the sample.

10.6.2.1 Case study (CO_2): North Atlantic

The CDIAC (Carbon dioxide information analysis center) operates under the U.S. Department of Energy. Data on CO_2 concentration in the ocean was collected and collated for the Global Ocean

Data Analysis Project (GLODAP), a collaborative project involving the National Oceanic and Atmospheric Administration (NOAA), the U. S. DoE and National Science Foundation (NSF). Figure 10–50 shows the total concentration of CO_2 from data collated since 1990.

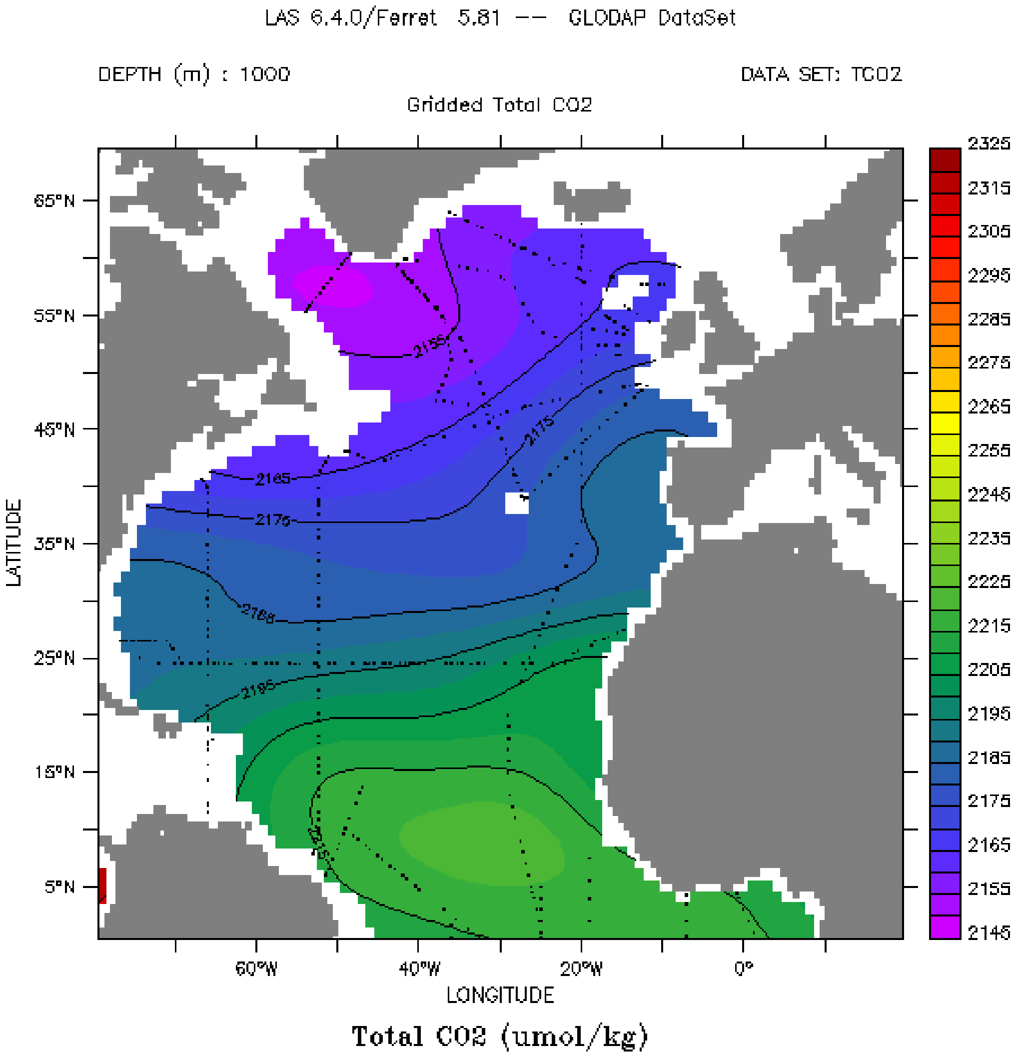

Figure 10-50: Total CO_2 at 1km depth in the North Atlantic from the CDIAC website through CDIAC GLODAP LAS (CDIAC website 2009, reproduced with permission of CDIAC,).

10.6.3 Bubble stream chemistry and seabed sampling

Bubbles of gas escaping into the water column can be sampled by divers using inverted funnels to collect gas into sealed containers. The chemical composition of the samples can then be determined in the laboratory and used to infer the origin and flux rate of the gas.

This is an established technique, which has been used to sample natural CO_2 seeps (CO_2GeoNet).

A limitation of this technique is that for offshore applications, additional techniques will be needed to locate the bubble stream (see above). Experiments were carried out using gas collection on a buoy to monitor CO_2 natural CO_2 leakage for the CO_2GeoNet project, however, this would also require the leak to be located before the buoy could be deployed. Using divers also limits the depth at which samples can be collected and increases cost.

For continuous seabed gas sampling, the CO_2ReMoVe project aims to develop an automatic, buoy–mounted continuous CO_2 seep monitoring tool, most likely using chemical and infrared sensors in combination with gas selective membranes for sampling and phase separation (co2remove.eu 2009)

10.6.3.1 CASE STUDY (CO_2): GULF OF TRIESTE

The COSTE group (Coastal Oceanography and Engineering group) at OGS (National Institute of Oceanography and Experimental Geophysics) operates buoys in the Gulf of Trieste where there are local natural methane and CO_2 seeps. OGS, Bundersanstalt fur Geowissenschaftern und Rohstoffe (BGR) and the Sapienza Università di Roma Fluid Geochemistry Group (URS) worked in collaboration to collect and analyse gas samples collected on an OGS buoy using a BGR–developed gas monitoring device. URS developed sensors for detecting dissolved CO_2. Gases, collected as bubbles at the buoy passed through a flow sensor to determine flow rate using infra–red optical sensors. The funnel was dropped to the sea bottom in 2006, it remained connected to the buoy by tubing and the collected gas was analysed for flow rate and CO_2 and methane gas concentration (Figure 10–51) and dissolved methane and CO_2 concentration (Viezzoli et al., 2008). Maintenance of the underwater systems was required, as biofouling affected the equipment. The sea conditions were also shown to affect the results, for example, ocean swell moved the buoy, changing the water level inside the tube which changed the volume inside the sensors.

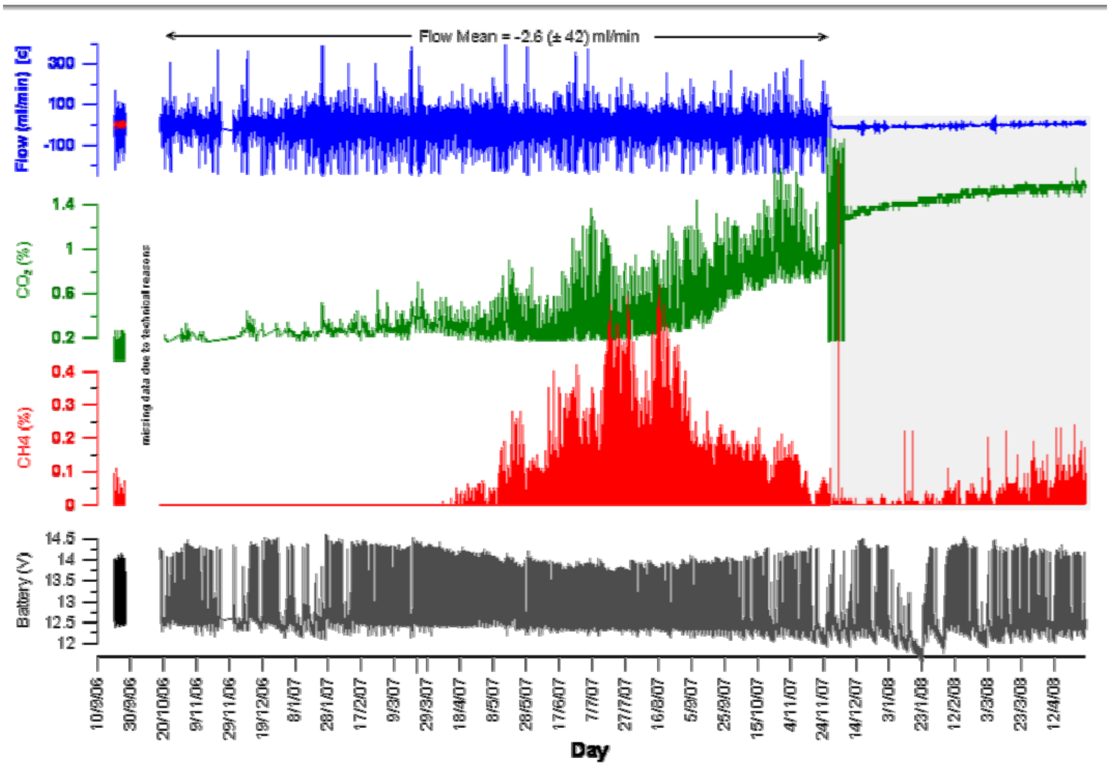

Figure 10-51: Flow rate, CO_2 and methane concentration data from the buoy (Faber et al., 2009, reproduced with permission of BGR)
N.B. This diagram may not be reproduced by ETI without separate permission from BGR.

10.6.4 Downhole Fluid Chemistry

Changes in downhole fluid chemistry can provide valuable insights into plume movement and any leakage. This would require regular sampling from pre– to post–CO_2 injection. Measurements could include, pCO_2, pH, HCO_3^-, alkalinity, dissolved gases, hydrocarbons, cations and stable isotopes. A Wireline logging tool for downhole fluid analysis is available, however, the technique mainly applied at present is on–site and laboratory testing of fluid samples.

The Schlumberger live fluid analyser can analyse the CO_2 content of fluids using a filter array spectrometer, pH is accurate to 0.1 units and CO_2 content is accurate to within a few wt%. The instrument brochure states it is difficult to obtain an accurate CO_2 level in the reservoir due to the high reactivity of CO_2 with water and potential drilling mud contamination (Schlumberger 2009e)

10.6.4.1 CASE STUDY (CO_2): NAGAOKA, JAPAN

At the Nagaoka test site, 10400 tonnes of CO_2 were injected into a sandstone saline aquifer over an 18 month period. Baseline samples were collected from the injection well during pump tests. Breakthrough of CO_2 was detected on wireline logs in two of the three observations wells. About a year after cessation of injection, formation waters were sampled again using a cased hole dynamic formation tester (CHDT), which drills a small hole in the casing and measures pressure, temperature and collects samples, the hole is then plugged and the tool retrieved (Figure 10–52). Three formation samples were taken at each site, above, below and within the CO_2 plume. No evidence of leakage to the surface was detected.

The samples were tested for pH and conductivity on site. Gas chromatography was used to analyse the gas composition. Baseline analysis indicated the downhole fluid to be enriched in Na, Cl and HCO_3^- and depleted in Mg and SO_4^{2-} compared to seawater. Laboratory tests to show how the pore fluid would be expected to react with CO_2 were conducted, which indicated that most minerals except quartz and K–feldspar would dissolve. After cessation of injection, the samples from within the CO_2 plume were mostly gas with only 7% liquid, the gas comprises 98.8% CO_2. Fluid conductivity increased for the sample underneath the plume (from 1.2 to 2.4 – 3.6 Sm^{-1}) (Mito et al., 2008).

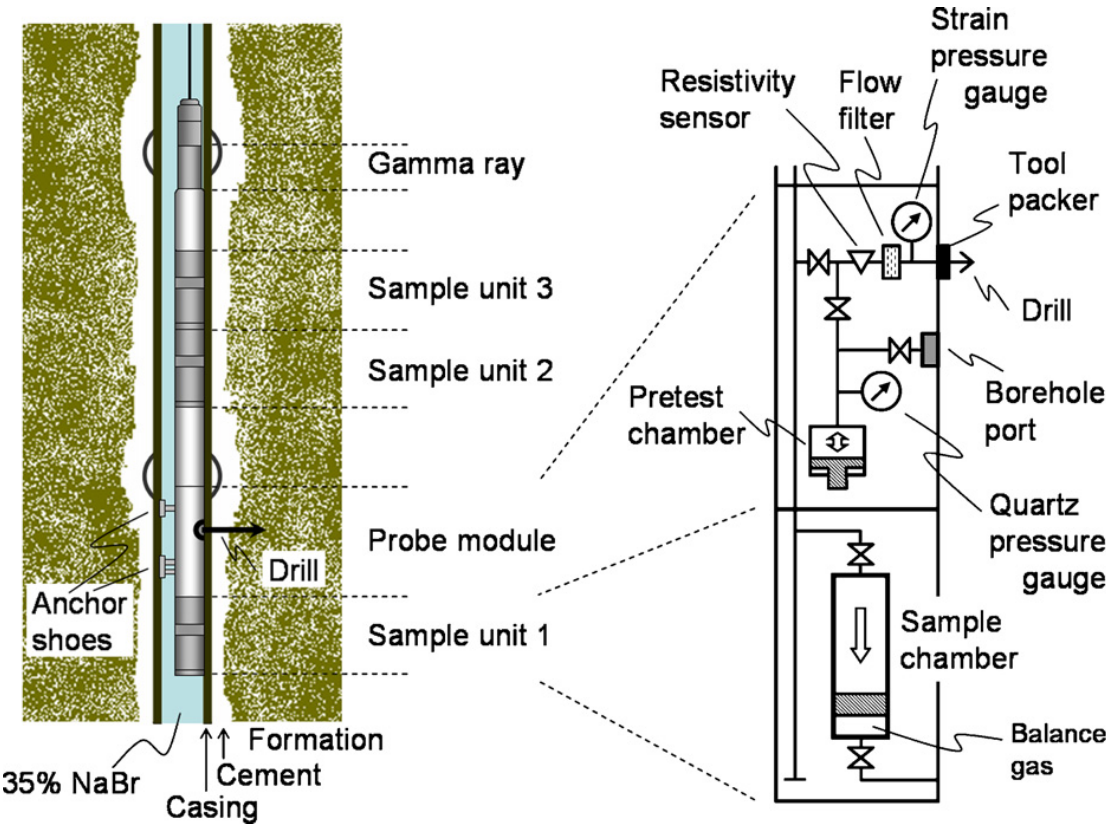

Figure 10-52: Downhole CHDT tool used at Nagaoka to sample pore fluids (Mito et al., 2008, image reproduced with permission of Elsevier)

10.6.4.2 CASE STUDY: FRIO

Approximately 1600 tonnes of CO_2 were injected at Frio, Texas at a depth of 1500 m into a sandstone reservoir. . Downhole samples were collected using evacuated Kuster samplers or the Schlumberger MDT (Modulation formation Dynamics Tester) tool. During CO_2 injection, samples were collected using a U–tube system developed for this project (Friefeld et al., 2005). Fluid samples obtained from the injection and observation wells show a Na–Ca–Cl brine with 93000 mg/L TDS (total dissolved solids) and near saturation of methane at reservoir conditions. As CO_2 reached the observation wells, sharp drops in pH were observed and an increase in HCO_3 alkalinity, Ca, Fe and Mn and significant shifts in the isotopic composition of H_2O and DIC (Dissolved Inorganic Carbon) were observed. Post injection, the brine gradually began to return to its pre–injection state (Kharaka et al., 2006).

10.6.5 Long–term downhole pH

Long–term downhole pH can play an important role is site monitoring as it can indicate the proportion of CO_2 dissolving into the formation water or indicate CO_2 migration or leakage. As a large number of geochemical processes can influence pH, other monitoring tools are required for accurate geochemical monitoring.

Commercially, pH sensors for use in boreholes are available, they tend to be expensive compared to other borehole tools and only employed on a short–term basis. Tool development, including improvement in the length of time that sensors retain their calibration, would be required for long–term use. Laboratory–based testing of sensors under simulated reservoir conditions is required with the aim of developing a reliable downhole tool.

A tool developed by Schlumberger can be used to measure downhole fluid properties including pH, colour, fluorescence and resistivity. It comprises a pump–out system to avoid contamination of drilling mud, a grating spectrometer (for hydrocarbon composition and gas: oil ratio), a filter–array spectrometer (for CO_2 content, pH, and colour), a fluorescence and gas detector and devices to measure formation fluid density and viscosity, water resistivity and fluid pressure temperature (O'Keefe 2009). The Schlumberger tool can measure pH (short term) to within 0.1 pH units (Schlumberger 2009e).

An alternative which has been tested is to measure pH of deep samples at the wellhead, though care must be taken to avoid the samples degassing.

Costs are expected to be moderate to high as even current short–term sensors are expensive.

10.6.5.1 CASE STUDY (NON–CO_2): OFFSHORE NORWAY

The Schlumberger tool mentioned above injects pH sensitive dyes into the formation fluid being pumped through the tool, and an optical detector is used to record the dye signal and calculate the pH with 0.1 unit accuracy. The test well is an appraisal well drilled into a gas/condensate field (Figure 10–53). A mixture of oil and water was sampled, and the pH was calculated from the water/dye colour to range from 5.82 – 6.26 at depths of 8.5 – 49.9 m. These results compared well with model results which used numerical simulation and laboratory techniques (Raghuraman et al., 2007).

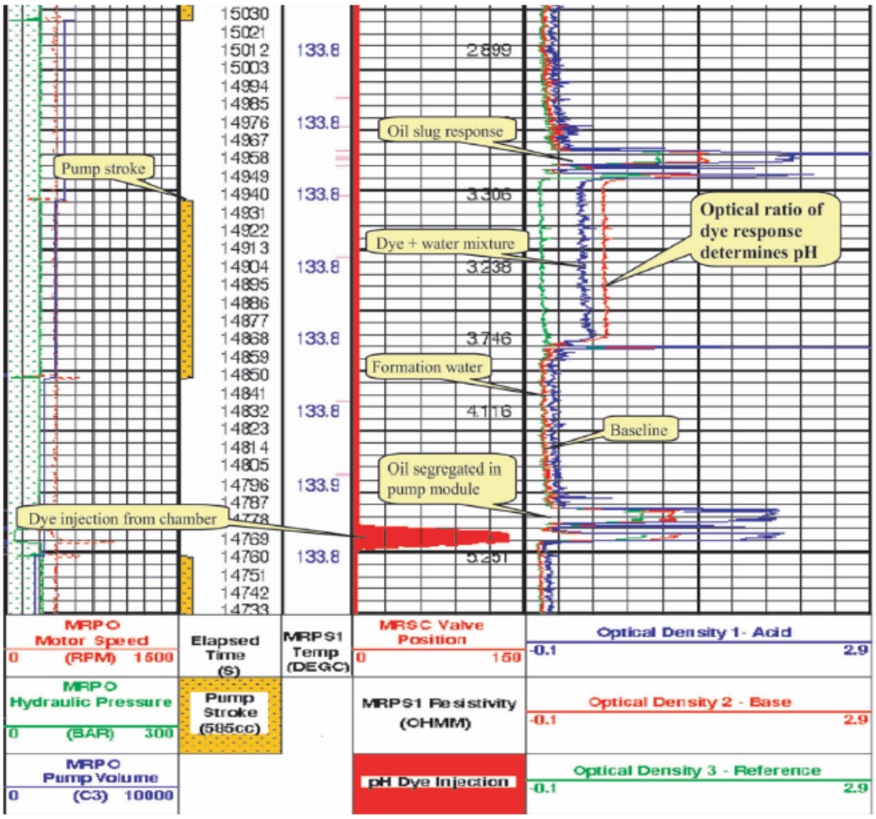

Figure 10-53: section of a Norwegian offshore well with oil and water flow, the dye mixes only with the water phase, pH can be determined by analysing the optical spectra of dye in the water slugs (Raghuraman et al., 2007, Copyright (2007), Society of Petroleum Engineers. Reproduced with permission of the copyright owner. Further reproduction prohibited without permission)

10.6.6 Casing logging

Casing logging is a mature technology and is trusted by both oil companies and regulators internationally as sufficient for establishing whether an effective bond exists between casing and cement and the cement and surrounding formation. There is no indication that a new step change in technology for this assessment is in development at this time, though companies are incrementally improving such tools on a regular basis. For instance, it is increasingly common for cement bond logs to define bonding around the whole circumference of the casing. These technologies must therefore be considered as sufficient.

10.7 ELECTROMAGNETIC METHODS

Electromagnetic (EM) methods detect the conductive and magnetic properties of the subsurface. Free CO_2 has a high resistivity so introduction of it to the pore fluid should be detectable through observable changes in the EM properties of the subsurface. Conversely, dissolved CO_2 has a lower resistivity than low salinity water so again may be detectable. Fractures in the rock can be a migration pathway for CO_2 and may be detectable by EM methods (Arts and Winthaegen 2005). There are passive and controlled source EM methods, which respond to natural electro–magnetic properties of the subsurface and the response of the subsurface to artificially induced EM fields respectively.

Electrical (DC) methods map conductivity of the relatively shallow subsurface and are often used for ore prospecting, or to map palaeochannels or cavities. Electro–magnetic methods map the response of the subsurface to an induced EM field.

The response to electrical methods to CO_2 is not yet well understood so further research is needed.

10.7.1 Electrical Self Potential

Horizontal electrode dipoles (negative charge on one end and positive charge on the other) are towed a few metres above the sea bed. The dipole measures the difference in natural electrical potential between two points in the ground. These voltages can arise from the presence of ore bodies or groundwater flow.

There are some advantages of ESP in marine conditions compared to land ESP, including greatly reduced contact resistance at electrodes, and generally stable temperature and salinity of seawater over the timescale of a typical experiment. Additionally, meteorological changes induce noise for land–based surveys. However, waves and swell and induction from ocean currents induce noise in marine surveys. For both land and marine surveys, noise from the Earth's magnetic field and drift of potential difference between any pair of electrodes need to be removed during processing. The resulting signal is used to model depth and size of the mineral body.

Repeated surveys could identify changes in self potential, which could potentially be a response to CO_2 migration into the shallow subsurface pore fluid. However, the response of ESP due to CO_2 has not yet been characterised. The coupled flow equations relating self potential to fluid flux require development if this technology is to be used to monitor CO_2 storage sites. The main limitation of this technique is that it is not yet proven for use with CO_2.

10.7.1.1 CASE STUDY (NON–CO_2): EYRE PENINSULA, AUSTRALIA

Self potential measurements were made in water depths of up to 100 m south of Eyre Peninsula, South Australia (Heinson et al., 1999). A series of electrode dipoles were towed close to the seafloor to investigate mineralisation. The height of the tow fish above the seabed, water depth and location from GPS were recorded during the survey. A magnetometer was also towed at the surface and these results compared with the ESP results which confirmed that the bodies detected by ESP were non–ferrous minerals. An electric field anomaly with magnitude 100 μV/m and peak to trough width was 2 km, this was inferred to be a result from the presence of graphite bodies or fluid flow through a fissure (Figure 10–54).

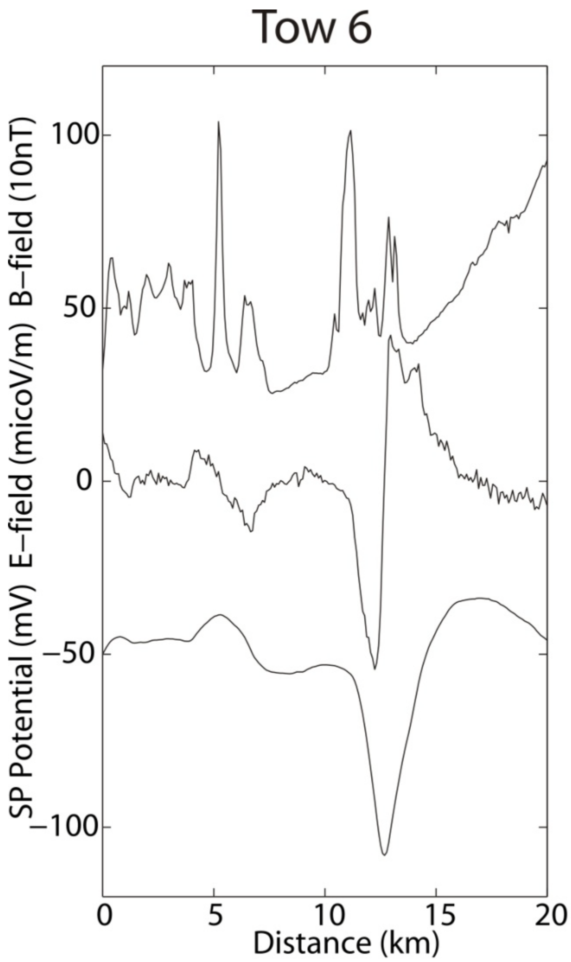

Figure 10-54: ESP integrated electrical potential (lower trace), ESP field (middle trace) and magnetic field intensity (top trace) for a single profile. To scale the magnetic profile, multiply values by 10. Note that the magnetic fields have a uniform baseline of around 59000nT and for plotting purposes the magnetic intensity trace has been shifted up by a uniform 500 nT and the SP potentials have been shifted down by 50 mV. The ESP data were processed to remove the ocean swell signal (Image reproduced with permission of the Society of Exploration Geophysicists from Heinson et al., 2005).

10.7.2 Seabottom controlled source electromagnetic monitoring

Seabottom controlled source electro–magnetic (CSEM) surveying can be used to detect subsurface electrical properties, which may be influenced by the introduction of highly resistive CO_2. An EM source towed behind a boat induces electrical currents in the sub–surface sediments. The secondary induced electrical and magnetic fields are monitored by a series of seabed receivers. In conductive sediments, the energy is attenuated rapidly. In high resistivity strata such as CO_2–saturated filled sands, the EM energy is attenuated less and at a critical angle of incidence (the angle at which it intersects the boundary where EM properties change), is guided along the layers and refracted back to the seafloor EM receivers.

Developments of CSEM systems have led to ‘direct–detection–of–hydrocarbons’ tools, including seabed logging (SBL) and offshore hydrocarbon mapping (OHM).A horizontal electrical dipole, towed behind a tow fish emits a low frequency EM signal into the underlying seabed. This source is towed over an array of receivers which measure two or three orthogonal components of the induced electric field.

This technique is sensitive to thin resistive anomalies at depths of several tens of metres and several kilometres. Theoretically, thin layers of resistive zones of CO_2 should be detectable.

This technique is being developed for the hydrocarbon industry and has been tested for use with CO_2 at Sleipner. A limitation of this technique is that deployment has so far been restricted to deep water (greater than 300 m) as airwave interference has hindered data quality in shallow waters (Chadwick et al., 2009a). However, as data processing techniques improve, this issue is being gradually overcome.

Acquisition costs are usually high, for example, two 2D profiles at a storage site would cost about 500000 GBP.

10.7.2.1 CASE STUDY: NORWEGIAN NORTH SEA

Seabed logging has been successfully used to image gas fields in the North Sea, including the Troll gas reservoir (Figure 10–55). An ultra–low frequency source was towed close to the seabed, which was recorded by stationary seabed receivers.

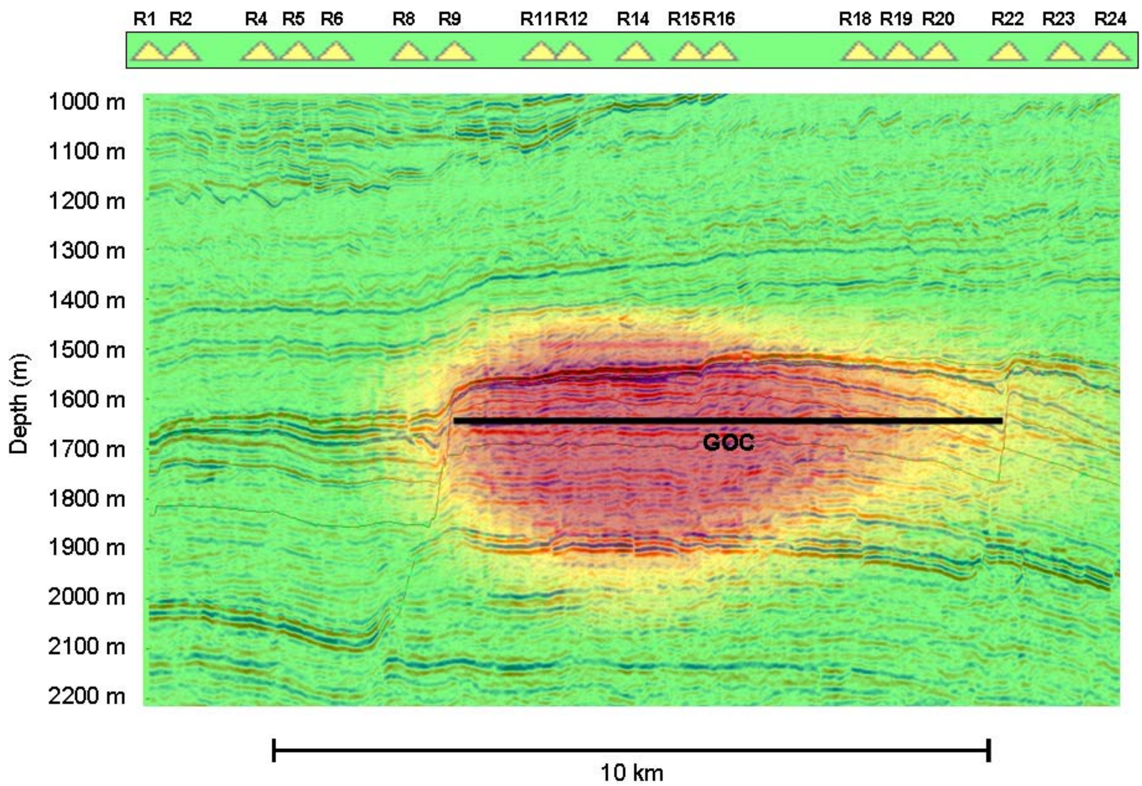

Figure 10-55: SBL imaging of the Troll gas field in the North Sea gas reservoir. The Gas–oil contact (GOC) and seismic section through the field are shown with an overlay indicating the region of high conductivity (in red) (image Courtesy of Ketil Hokstad (Statoil)).

The Troll field complex is the largest gas discovery on the Norwegian Continental shelf and is located in water depths of 300 – 360 m. The complex is divided into three separate compartments, Troll West Gas Province was selected for the SBL survey as it has well defined edges and a strong contrast between high resistivity of the hydrocarbon–saturated sands (200 – 500 Ωm) and the low, relatively constant resistivity of the overburden (0.5 – 2 Ωm). The reservoir interval lies at a depth of about 1400 m bmsl (below mean sea level) and comprises Jurassic sandstones with a gas column of 160 m (Johansen et al., 2005).

Two surveys were collected, one over the gas field, and one, for baseline data, nearby over a non–hydrocarbon bearing region. Data were collected using 24 EM receivers across the field, which were deployed by being dropped from a ship and sinking freely to the sea floor. Acoustic ultra short baseline communication was used to establish the exact location of the receivers. The horizontal dipole antenna consisted of two electrodes separated by approximately 230 m with electrical contact to the seawater. The source was located on a tow fish which was maintained at about 40 m above the seabed. The source was electrically connected to electrodes on a streamer which was pulled behind the tow fish. The source transmitted a continual square pulse at 0.25 Hz, with current varying from zero to almost 1000 A. Antenna depth below the ship and position were monitored. The data were processed and agreed well with the forward model, which supported this technique in having potential for determining fluid content of reservoirs (Johansen et al., 2005).

10.7.2.2 CASE STUDY: SLEIPNER

Controlled source EM was undertaken at Sleipner in 2008 as part of the CO_2ReMoVe project. The data is still being analysed and no results have been published.

10.7.3 Permanent borehole electromagnetic field monitoring

Changes in formation resistivity are measured using semi–permanent downhole sensors and transmitters. CO_2 has low conductivity, so migration of CO_2 into the pore fluids should produce a response in the measured EM (electromagnetic) field. This technique should be able to monitor long–term, fine–scale changes in CO_2 saturation.

Data is acquired using a downhole tool comprising a two receivers and a controlled EM source. The source dipole contains a coil which induces an EM field in the rocks surrounding the borehole, penetration depth is typically only a few metres around the borehole. The receivers detect the induced secondary field. The induced field will be at an angle to the primary field produced by the source. The angle between these two fields and the strength of the secondary field are used to model the conductivity of the rocks. Data needs to be processed to remove transient noise and the background EM field.

Permanent borehole EM equipment is not available; the expected lifetime of current systems is about five years. Another major limitation of this technique is that it is not normally viable in a steel cased hole, so deployment in long–term monitoring wells may not be feasible.

10.7.3.1 CASE STUDY (CO_2): CALIFORNIA

An example is given here of repeated short–term EM measurements at a CO_2–EOR pilot. Water flooding has been employed in this Chevron Oilfield in California for enhanced oil recovery (EOR) since 1995, and the area was selected for a CO_2 injection pilot, injection of CO_2 began in 2000. Four water injection boreholes were adapted for use with CO_2 (including re–completion where necessary), two of these (observation wells OBC1 and OBC2) with fibre–glass casing were selected for monitoring CO_2, these boreholes lie less than 25 m from the injection well 11–8WR. Cross–hole data were collected before CO_2 injection and a single borehole survey, including EM data, was collected in May 2001. The vertical time–variant source had a frequency of 6 kHz and the source–receiver distance was five metres. EM data were collected 422 – 559 m depth. The EM field was recorded in all 3 axial planes. Inversion of the data took 26 hours and 11 iterations (Tseng and Lee 2004). The measured induced EM field, compared well with the inversion model results. A major lateral conductivity variation is observed at depths between 507 – 525 m, in the horizontal plane at 513 m, the conductivity is lower on the north–east side of the observation well, indicating that CO_2 has replaced some of the more conductive injected water (Figure 10–56).

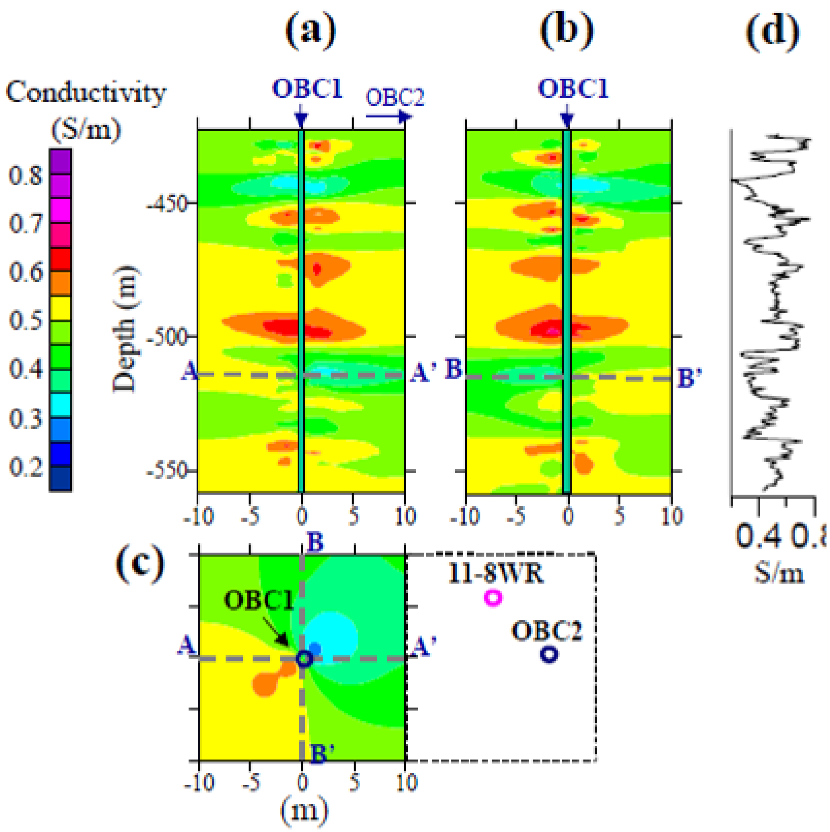

Figure 10-56: Inversion results; (a) in the vertical plane containing both observation wells, (b) an east–west vertical slice centred at OBC1, (c) horizontal slice at 513 m centred around OBC1, showing lower conductivity on the side facing the CO_2 injection borehole, (d) induction logging for OBC1 at the start of CO_2 injection (Tseng and Lee 2004, image reproduced with permission of Stanford University).

10.7.4 Crosshole electromagnetic logging

Crosshole electromagnetic (EM) logging requires two boreholes located near the CO_2 plume; time–variant EM sources are deployed in one borehole and receivers in another and tomography is used to map the conductivity structure between the wells. Distance between wells is typically small, maybe a few tens of metres. Tomography uses the moving source and receivers to image the region between the wells section by section to build up a 2D image of the conductivity. CO_2 is a resistant fluid and would be expected to reduce conductivity where the pores contain CO_2–saturated fluid. Cross–hole EM is particularly useful when used in conjunction with seismic methods.

This technique monitors CO_2 saturation by detecting the reduction in conductivity when the native pore fluid is invaded by more resistive CO_2. The Schlumberger DeepLook EM is stated to work between wells that are 1000 (open hole receiver well) to 450 m (steel casing receiver well) apart (Schlumberger 2009f).

This technique is widely used for the hydrocarbon industry and has been field tested with CO_2, however, in the field test, the results were more difficult to interpret in oilfields than in saline aquifer sites due to the similarity of the resistive properties of oil and CO_2 (see case studies below).

A limitation of this technique is that it requires extensive processing to model the sub–surface.

10.7.4.1 CASE STUDY: LOST HILLS CALIFORNIA

Repeated cross–hole seismic and EM logs were collected at the Chevron operated Lost Hills Oilfield in California in fibre–glass cased observation wells OBC21 and OBC2. Cross–well EM and seismic surveys were acquired in September 2000 before CO_2 injection, and a repeat seismic survey was conducted in late May 2001 and the repeat EM survey was conducted in early July 2001. The temperature and pressure of the reservoir are such that injected CO_2 forms an immiscible flood in the reservoir in its gas phase. The aim of these field tests was to use the seismic and EM data to model the changes in the reservoir. Assuming porosity to be constant, the change in conductivity was attributed to change in water saturation. These data were used to calibrate the seismic results. The cross–well EM survey showed that the largest decreases in conductivity occurred in alignment with the fractures created during water injection. This was attributed to the fact that the water injection undertaken for more than six years produced a high permeability damage zone which proved a better conduit for fluid flow than the new CO_2 injection fracture (Figure 10–57).

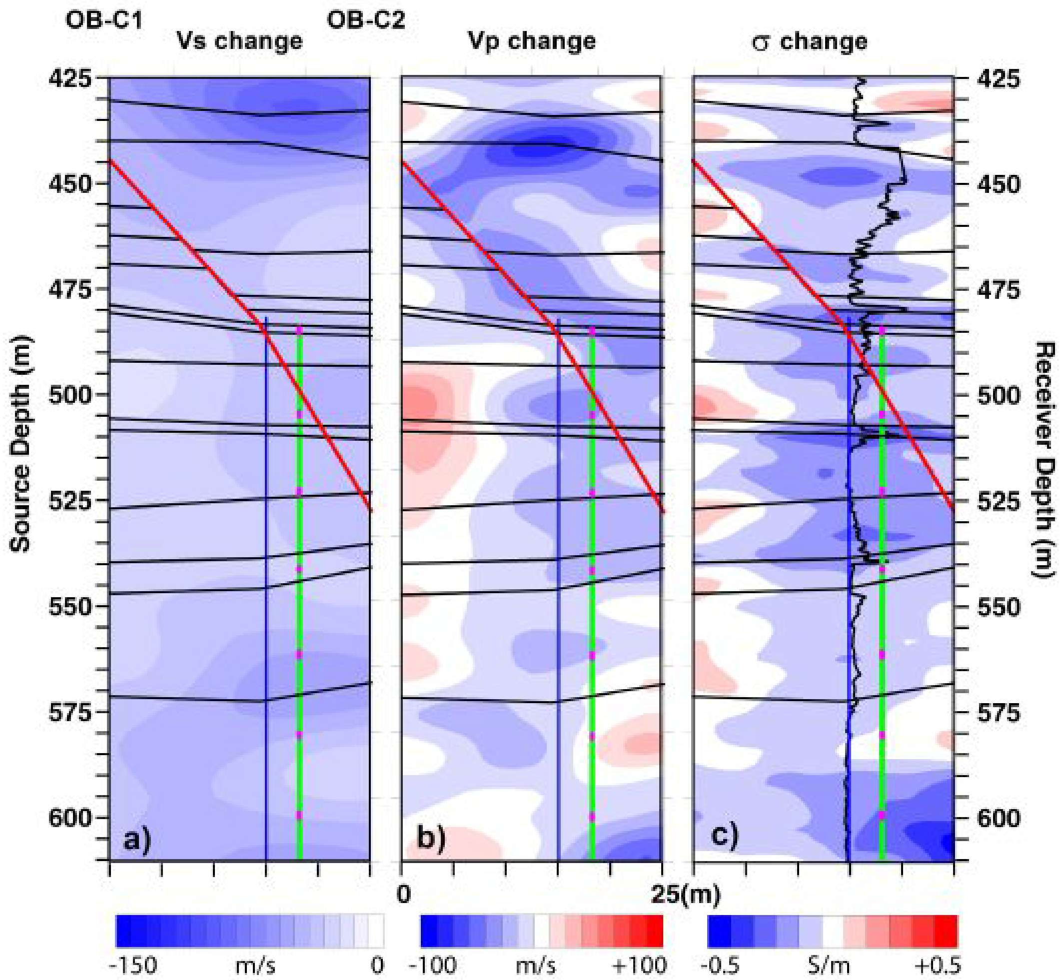

Figure 10-57: Time–lapse data; changes in (a) Shear wave velocity, (b) P wave velocity and (c) conductivity. The CO_2 injection points are shown as purple ticks, the new CO_2 fracture is shown as a vertical green line, location of a fault zone is shown as a red diagonal line (Hoversten et al., 2003, image reproduced with permission of the Society of Exploration Geophysicists).

The change in conductivity was used to predict the change in water saturation. This result, in conjunction with the observed changes in velocity and borehole logs (to take into account the observed hydrocarbon gas in the reservoir) was used to estimate CO_2 gas/oil ratio. The predicted maximum error in this calculation was 10 – 15%. The maximum predicted changes in CO_2 saturation were aligned with the CO_2 injection points, and the estimated gas/oil ratio showed better alignment with the injectivity properties recorded in the injection borehole than the individual geophysical logs (Figure 10–58) with the exception of one of the injection points where the match was relatively poor (recorded injectivity was lower than the model predicted).

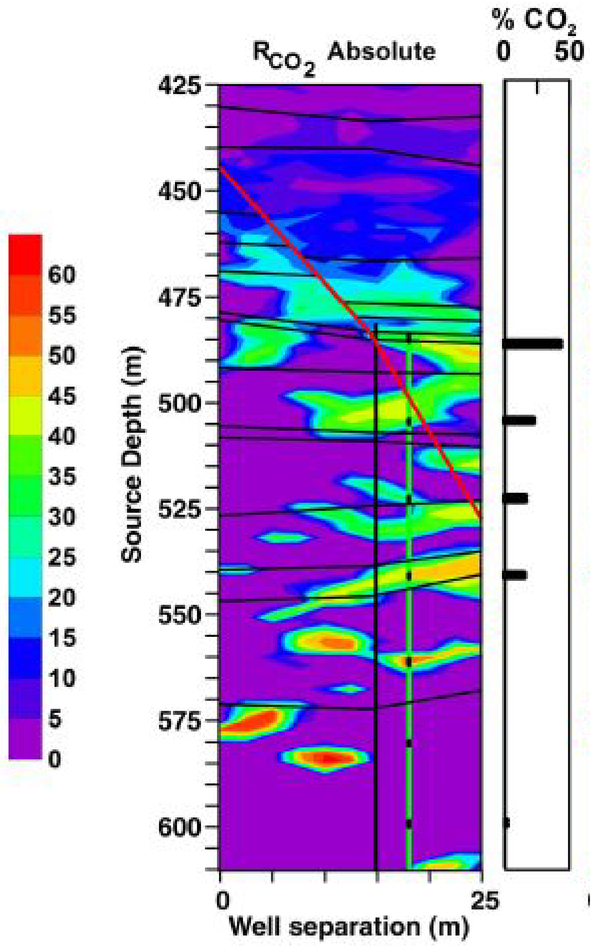

Figure 10-58: CO_2/oil ratio predicted from borehole geophysics and cross–hole experiments. The CO_2 injection points are shown as black ticks, the new CO_2 fracture is shown as a vertical green line, location of a fault zone is shown as a red diagonal line (Hoversten et al., 2003, image reproduced with permission of the Society of Exploration Geophysicists).

10.7.4.2 CASE STUDY; FRIO, TEXAS

Approximately 1600 tonnes of CO_2 were injected at depths of around 1500 m over a period of 10 days into the Frio Formation aquifer at the test site. The change in conductivity was monitored using cross–well electromagnetic survey using wireline–deployed equipment in the two steel–cased wells, which are approximately 35m apart. Between 40 and 44 stations were used, at a spacing of 2.4m, between the approximate depths of 1435m and 1550m. A pre–injection survey was carried out in August 2004 and a post injection survey in December 2004. The close proximity of the two wells meant that the direct signal from the transmitter was much stronger than the formation signal and also suffered from high magnetic noise. However after processing, the negative conductivity change caused by the injected CO_2 could be observed (Figure 10–59; Dodds, 2005).

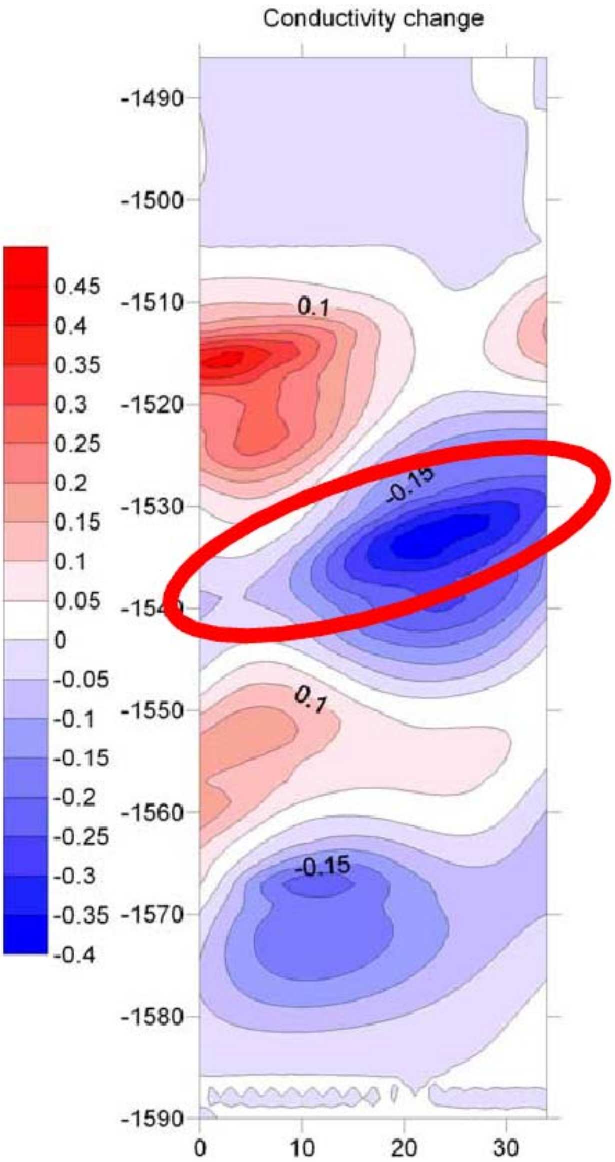

Figure 10-59: Change in conductivity at the Frio site (Hovorka 2005) (image reproduced with permission of G. M. Hoversten, Formerly Lawrence Berkeley National Laboratory (LBNL), presently Chevron. Image produced from work undertaken by G. M. Hoversten while at LBNL)

10.7.5 Crosshole electrical resistance tomography

Crosshole electrical resistance tomography (ERT) involves the measurement of resistivity in the subsurface between wells. If the wells are cased, then the well casings can be used as electrodes, or specific electrodes can be mounted behind the casing, and in open holes, electrodes can be mounted downhole. The results are used to build up a 3D image of the sub–surface resistivity. This does not physically image the plume, but rather gives a bulk indication of the changes in resistivity of the sub–surface, potentially indicating where conductive CO_2 has infiltrated the pore space, but not quantifying the amount of CO_2 in the pore space.

As carbon dioxide is a resistive fluid, it would be expected that an increase in CO_2 saturation in the pore fluid would result in an increase in resistivity. However, a limitation of resistivity monitoring is that the signature of hydrocarbons is similar to that of CO_2. For storage in oilfields therefore other monitoring techniques are required in collaboration in order to distinguish the fluids.

ERT is being developed for use in the hydrocarbon industry and has been tested for CO_2 detection at the Ketzin pilot injection site in Germany (Giese et al., 2009). A limitation of this technique is that it requires two monitoring wells located close to the injection site. If the entire lengths of the borehole casings are used as electrodes then the technique can only detect lateral change in conductivity, not changes with depth. However, the equipment is relatively easy to deploy and operate and may have a better sensitivity at high gas saturation (>20%) compared to seismic methods, although the results are lower resolution (Kiessling et al., 2009).

Expected costs are low to moderate.

10.7.5.1 CASE STUDY (CO_2): VACUUM OILFIELD

Repeated electrical resistivity measurements were recorded at the Vacuum Oilfield, New Mexico as part of an EOR operation. The well pattern uses 9 wells, spaced over approximately 36400 m^2. Baseline data were collected in May 2002, repeated surveys were collected in September and December 2002 (Figure 10–60) (Daily et al., 2004**).**

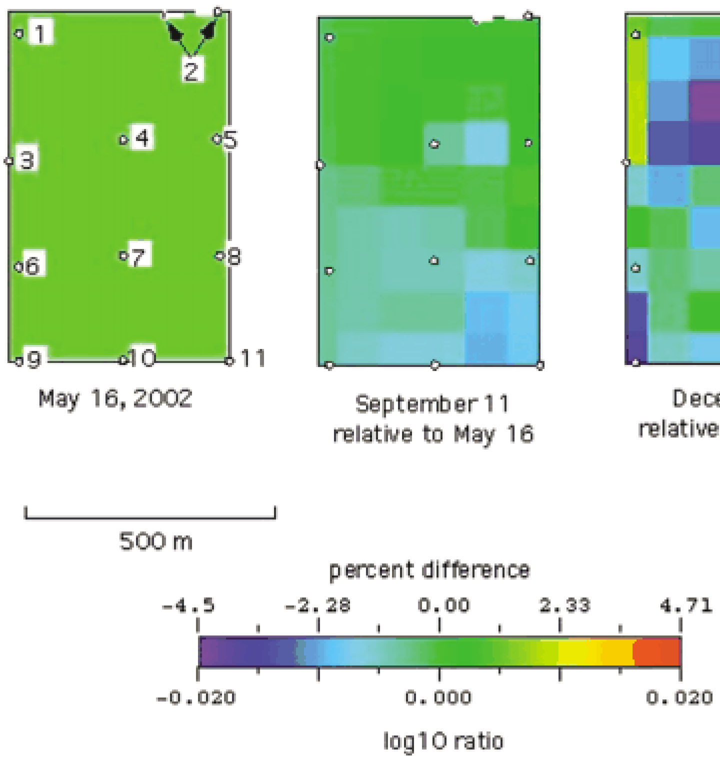

Figure 10-60: ERT results for Vacuum Oilfield, on the left is the well layout, the central panel shows the difference between the September and May surveys, the right hand panel shows the difference between the December and May surveys (Daily et al., 2004) (image reproduced with permission of the Society of Exploration Geophysicists).

10.7.5.2 CASE STUDY (CO_2): KETZIN, GERMANY

At the CO_2SINK test CO_2 injection site near Ketzin in Germany, around 16 000 tonnes has been injected to date. The injection well and the two monitoring boreholes have been equipped with behind–casing Vertical Electrical Resistivity Arrays (VERA) in order to monitor the distribution of the CO_2 plume using the ERT method. The wells are 50m to 100m apart and each has 15 permanently installed electrodes at 10m spacing between the depths of 590–735m. A baseline survey was carried out in June 2008 and measurements have been gathered continuously (one measurement cycle per hour) since the start of CO_2 injection. Surface measurements were combined with the downhole measurements to increase the area of observation to a hemisphere about 1.5km radius around the wells. Preliminary results match the expected reservoir behaviour and the results from other monitoring techniques employed at the site (Figure 10–61).

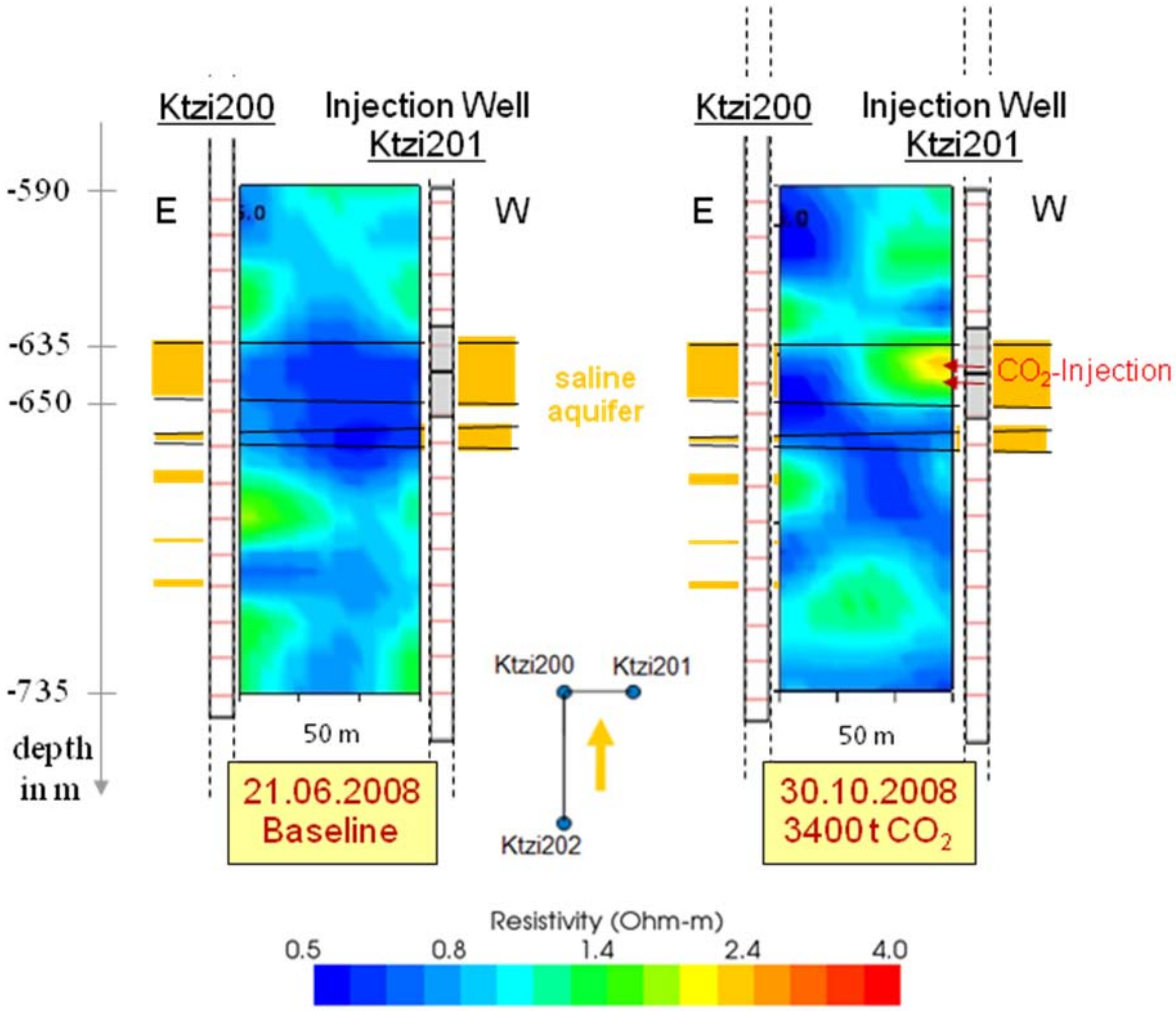

Figure 10-61: Preliminary results of the crosshole ERT measurements from the Ketzin site after 3400 tonnes of CO_2 injection. The increased resistivity indicating the presence of the CO_2 plume can be seen on the right–hand site, close to the injection point (in well Ktzi201) as it migrates towards the observation well Ktzi 200 (From D. Kiessling, H. Schuett, C. Schmidt-Hattenberger, F. Schilling, E. Danckwardt, K. Krueger, B. Schoebel, and CO_2SINK Group. Geoelectric Crosshole and Surface-Downhole Monitoring: First Results. 5th Monitoring Network Meeting, Tokyo Japan, June 2009).

10.8 GRAVIMETRY

Microgravimetry involves repeated high precision gravity measurements at the surface or seabed to detect changes in density of the subsurface. The size of the gravity anomaly is mainly determined by the subsurface volume/density, and the spatial variation in gravity by the lateral distribution of density. The main limitation of this technique is the lack of resolution in terms of depth of the anomaly. Although of much lower resolution than surface seismic, the two methods can be complementary; gravity methods can provide independent verification of changes in the sub–surface mass, and could potentially be used to estimate the amount of dissolved CO_2 (dissolved CO_2 is invisible on seismic data). The accuracy of gravity measurements depend strongly on the site properties.

10.8.1 Surface gravimetry

Repeated gravity surveys are used to detect changes in sub–surface mass, the injected CO_2 would be expected to displace denser native pore fluid, reducing the gravity readings. Offshore, the gravimeter is positioned at permanent concrete benchmarks by a remotely operated underwater vehicle (ROV). Gravimetry can indicate sub–surface mass changes and can be used to estimate how much CO_2 has dissolved into pore water. In some circumstances, CO_2 density can be derived, which can be useful for constraining seismic monitoring when reservoir temperature is uncertain or when the pressure/temperature conditions are close to the CO_2 phase change boundaries. Repeat surveys could be used to monitor changes in mass and potentially to detect accumulations of CO_2 in shallow overburden traps if it migrates from the deep reservoir.

Gravity is an established technique in other industries, including mineral exploitation. It has also been used to monitor CO_2. A limitation of this technique is that resolution of depth to the anomaly is not high and that the technique is unsuitable for deep reservoirs. A further limitation is that gravimetry is quite expensive to deploy in a marine environment compared to an onshore environment.

Recent work from Sleipner suggests measurement accuracy in marine surveys may be around 3 – 5 μGal. Detection thresholds and measurement accuracy are highly site specific. Under favourable conditions, accumulation of CO_2 in the gaseous state as small as 0.5 – 1 Mt may be detectable at 500 m depth. For general mass verifications within a typical storage reservoir, masses of at least 2 Mt would need to be injected to produce an identifiable response (Chadwick et al., 2009a.).

10.8.1.1 CASE STUDY (CO_2): SLEIPNER

The first gravity survey was acquired in 2002, when around 5.19 $MtCO_2$ had been injected. Each gravity station was visited at least three times to better constrain instrument drift and other errors. Single station repeatability was estimated to be 4 μGal. For the repeat measurements, it was estimated there was 1 – 2 μGal uncertainty in the reference null level, therefore the final detection threshold for Sleipner was estimated to be about 5 μGal for individual stations for the first survey. A repeat survey was conducted in September 2005 when 7.76 $MtCO_2$ had been injected and a second repeat survey acquired in 2009. Each station was visited at least twice during the survey and the measurements were corrected for tides, instrument drift, temperature, tilt and drift (Figure 10–62). The uncertainty for these surveys was estimated to be 3.5 μGal. One of the concrete benchmarks had been moved, most likely by trawler fishing, before the repeat survey. Two iterations of modelling have been carried out to estimate CO_2 density. Nooner et al., (2007) calculated an average value of 530 ± 65 kgm^{-3}. Alnes et al. (2008) using revised data corrections and processing calculated an average value of 760 Kgm^{-3} (Figure 10–62Figure 10–63). This significant discrepancy arising from the application of revised data corrections and a different modelling approach illustrates just how close the measurements are to the limit of viability. It is anticipated that the 2009 time–lapse changes, arising from on a greater change of CO_2 mass, will be significantly more robust.

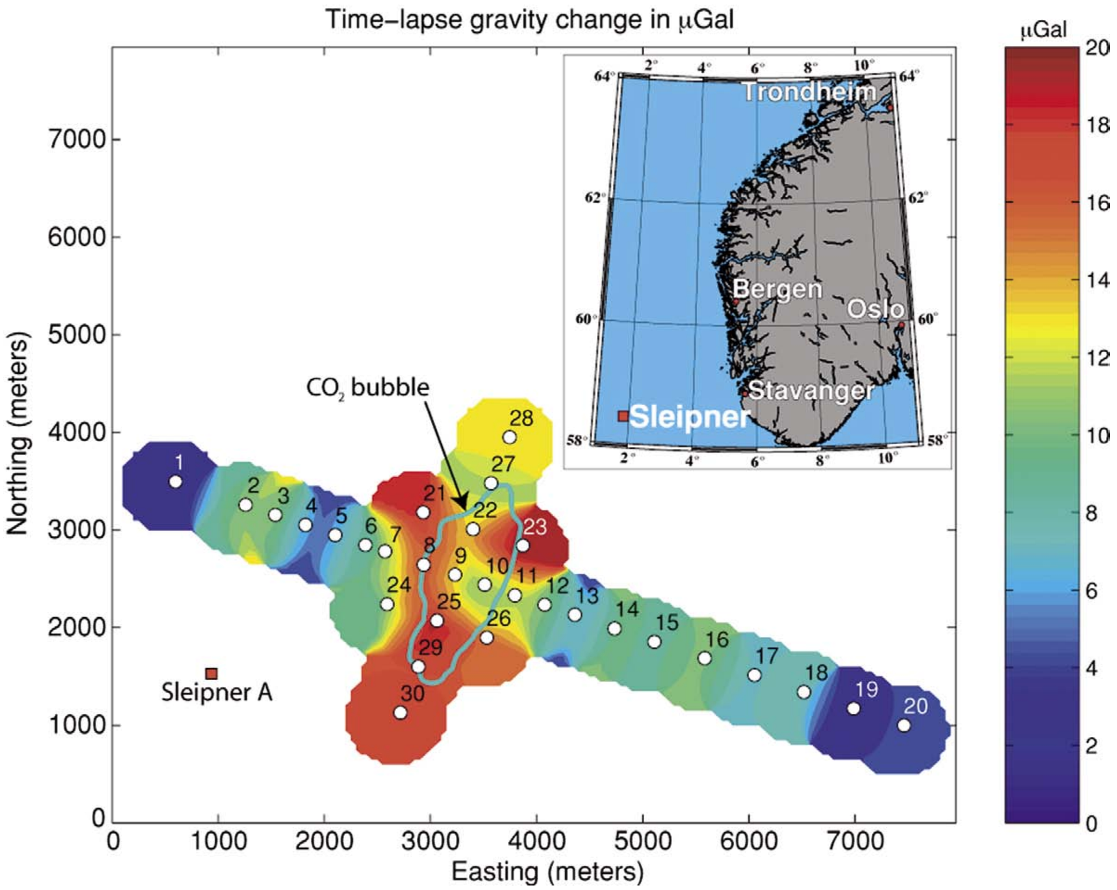

Figure 10-62: Change in gravity response over the Sleipner site from 2005 with the 2002 survey results subtracted. The outline of the CO_2 plume as identified from seismic in 2001 is identified. The numbered white circles show the gravity bases. The effects of gas extraction at Sleipner East were compensated. The gravity survey shows a decrease in mass around the CO_2 plume (Arts et al., 2008, image reproduced with permission of the European Association of Geoscientists and Engineers).

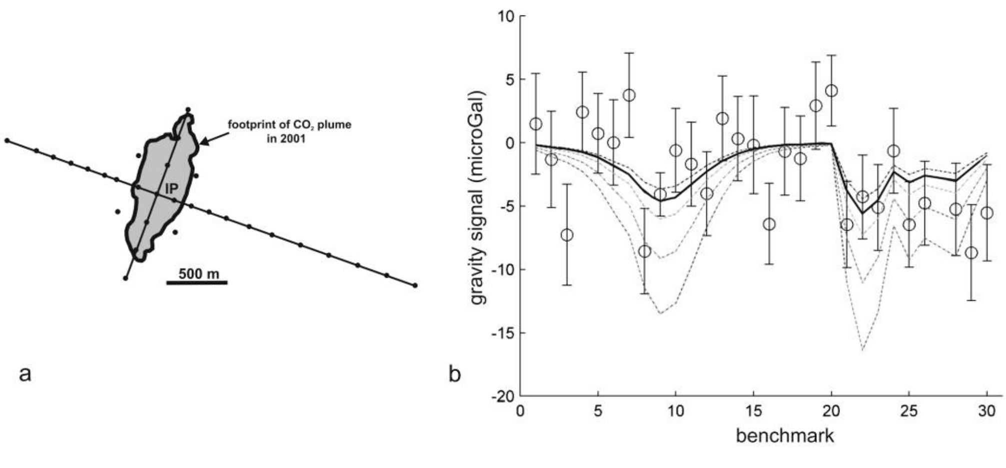

Figure 10-63: a) Map of the gravity survey layout at Sleipner showing location of seabottom benchmarks b) modelling results – dashed lines indicate modelled gravity with CO_2 densities from 500 to 800 kgm^{-3}, solid line shows best fit for a CO_2 density of 760 kgm^{-3} (adapted from Alnes et al., 2008, image reproduced with permission of the Society of Exploration Geophysicists).

10.8.2 Well gravimetry

Downhole gravity measurement acquires higher resolution gravimetric data, interrogating the layers close (typically less than one layer thickness) to the monitoring well. As less–dense CO_2 replaces native pore fluid, it would be expected that repeated gravimetry surveys would show a response to the decrease in mass. Limitations of the method include the fact that it can only be acquired in near–vertical, large diameter wellbores and it takes several minutes to collect a single data point (Chapin and Ander 1999).

Borehole gravimetry can also be used to detect changes in density resulting from different rock types, porosity and fluid tens to hundreds of metres from the borehole, depending on the geological environment and size of anomalous density body (Herring 1990).The borehole gravity meter (BHGM) is lowered into the wellbore and readings are taken at discrete intervals. Two different depths are required and the difference in the gravitational field detected at the two sites is used to obtain the apparent density measurement.

The most common type of gravimeters (LaCoste–Romberg) use a mass suspended from a spring. Tiny changes in position of this mass are detected using a reflected light beam. The gravimeter must be levelled at each site. Temperature must also be accurately recorded, as thermal expansion/contraction will affect the spring. The mass position changes are caused by variations in the gravity field resulting from different rock and fluid densities. Accuracy of gravimeters is typically in the range of 1 – 3 mgal (for comparison, the typical gravity field at the surface is around 980 gal). Repeatability of results can be within a standard deviation of 3 µgal (Adams and van Popta 1992).

In the hydrocarbon industry, borehole gravimetry has been used to calculate oil saturation and locate gas–saturated sands in open and cased boreholes. In boreholes around a CO_2 injection site, theoretically as higher density CO_2 fluid replaces pore fluid, the change in density should be detectable.

10.8.2.1 Case study: Cranfield Oilfield, Mississippi

The Cranfield Oilfield in Mississippi was discovered in 1943 and oil was extracted until the watercut became such that further extraction was uneconomic. Almost all wells were plugged and abandoned by 1966. Water drive from interconnected aquifers has returned the reservoir to near hydrostatic pressure. Injection for CO2–EOR began in July 2008 in the reservoir in the lower Tuscaloosa Formation at depths greater than 3000 m. Rate of CO2 injection reached 0.5 Mt/year by the end of 2008 (Hovorka et al., 2009, Hovorka 2009). A baseline survey was acquired by BP at the Cranfield SECARB Regional partnership site in September 2009 from two wells separated by approximately 30 m. A repeat survey is planned for Q3 2010 at which point it is expected that approximately 750000 tonnes will have been injected into two stratigraphic intervals. It will be evaluated and reported as part of CCP activities and through regional partnership.

10.8.2.2 Case study (non–CO_2): Natih Oilfield, Oman

Borehole gravity measurements have been used to determine gas saturation in the Natih field, northern Oman. This is a fractured limestone reservoir where gas is injected above the oil to lower the gas–oil contact and maintain reservoir pressure producing oil through gravity drainage. The gas flushes the oil out the reservoir, encouraging flow into the fracture system such that oil continues to be produced at the oil rim. Porosity and depth were measured accurately around the four selected open–hole boreholes, to allow estimation of gas saturation. Before each measurement, the EDCON BHGM (Borehole Gravity Meter) was allowed to settle for several minutes and repeated readings were sometimes taken at each station. Typically 15 – 20 gravity sample points were selected in each well in each well from 20 m below the gas–oil contact (GOC) to 20 m above the reservoir. The gas saturations estimated from the BHGM readings compare well with the reservoir model results. They are higher than those predicted by the earlier neutron log which is interpreted as showing the effect of drilling fluids on the neutron log (Adams and van Popta 1992).

10.8.3 Gravity gradiometry

In regions where seismic data is ineffective for imaging the subsurface (e.g. in regions of extensive salt bodies), gravity gradiometry may be considered in conjunction with geological data and other geophysical methods. Gradiometry data may be collected using aeroplanes or shipborne equipment. It measures changes in the earth's gravity field in three dimensions; x and y in the horizontal direction and z in the vertical direction as opposed to conventional gravity meters which detect the vertical field only. The full tensor gravity field is measured, which comprises five independent tensors and the gravity field (nine tensors are measured, e.g. how the x component of gravity changes in the y direction, Txy, but only five of these tensors are independent). The change in the vertical field can be interpreted to indicate depth and, with wavelength–based filtering, the basin structure and basin fill. The horizontal components mainly indicate the edges of the anomaly, the dominant structural pattern and the central axes of the body. Gravity gradiometry can be used to remove noise from the data and obtain a higher resolution survey of density features than conventional gravity surveys. The additional data can provide a better approximation of the shape of the density anomaly and the centre of mass.

Two pairs of opposing accelerometers are mounted orthogonally on a continuously rotating platform to form a rotating accelerometer. The Bell Geospace 3D Full Tensor Gravimetry (FTG) system uses sets of four rotating accelerometers mounted on a stabilised platform. Extensive processing is required to obtain the final density survey results, for example, to remove the effects of vehicle movement and to wavelength filter the data to infer geological data at different scales. Forward modelling is used to describe the expected response based on the geological model and the gravity gradiometry survey is then used to iteratively to confirm and improve this model. The gravity gradient can be related to anomalous density bodies, such as low density CO_2 fluid in the pore space. Seismic and magnetic surveying are commonly used to support gravity gradiometry.

10.8.3.1 Case study (non–CO_2) marine gravity gradiometry survey of low density sediments in the Judd Basin, Faroe–Shetland region

The region around the Faroe–Shetland Islands is potentially prospective for hydrocarbons. The Judd Basin was surveyed from 1999 – 2002 with a 750 m spacing along lines orientated NW–SE to follow the dominant geological trends. The results show a low in the vertical tensors over the successful well drilled in the basin. Frequency filtering was used to separate out the long wavelength signal (greater than 20 km which can be interpreted to show the basin–scale structure) from the shorter wavelength (3 – 10 km) and intermediate (10 – 30 km) wavelength signals associated with basin fill. Lineaments interpreted as basin–forming structures were identified from the long–wavelength signal. Shorter wavelength anomalies interpreted as low density sedimentary rocks were identified within the Judd Basin, one of which was penetrated by the successful well (Figure 10–64). Other wells drilled outside the gravity lows have shown minor traces of oil and gas only. Most of these regions interpreted as low density sedimentary fill are located on the basement ridge flanks.

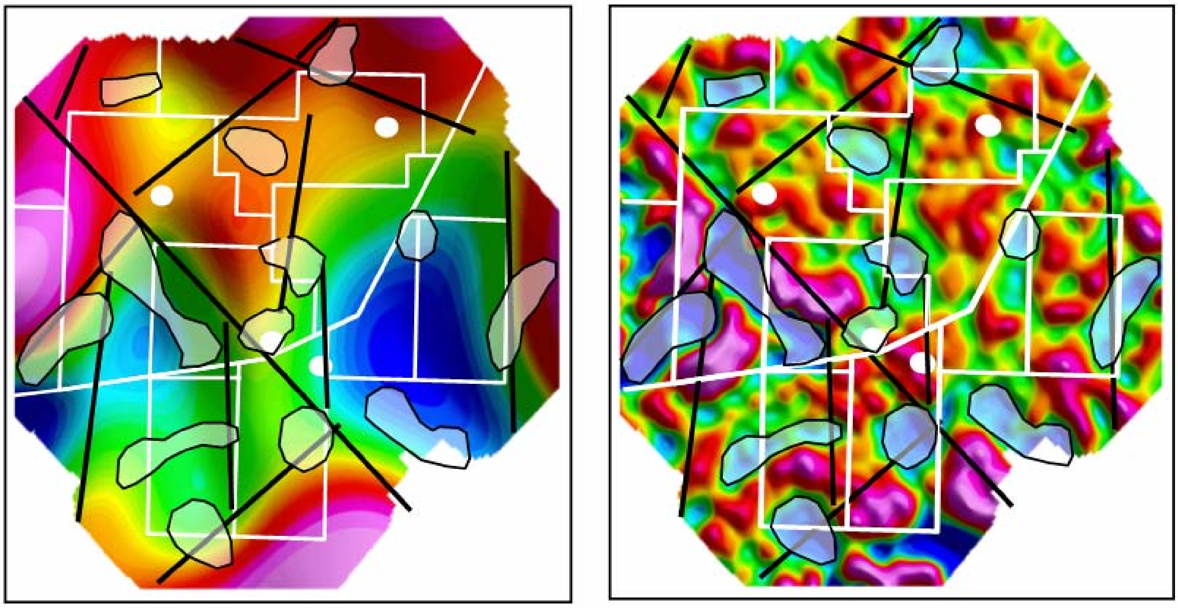

Figure 10-64: Frequency filtering results for the Judd Basin showing change in the vertical gravity tensor (Tzz), which is dependent on two of the horizontal gravity tensors (Txx and Tyy). Blue shows lows, pink shows highs. The black lineaments show basin–scale structures, the filled polygons low density material, the white dots show wells drilled in the basin up to 2004 and the white polygons the exploration licences (Murphy and Mumaw, 2004). The left hand image shows the long–wavelength basin–scale structures, the large eastern low is the Foinaven sub–basin. The right hand image shows the intermediate to high frequency changes in the vertical tensor interpreted as low density sediment fill, one of which contains the successful well. Image Copyright © Bell Geospace reproduced with permission of CSIRO Publishing.

10.9 OTHER MONITORING TECHNIQUES

Other monitoring techniques are also under development for monitoring CO_2 migration and leakage, including ecosystem studies, tiltmeters and tracers.

10.9.1 Ecosystem studies

If CO_2 leaks to the surface, it may affect ecosystems it comes into contact with. The impacts and their significance may be assessed using a variety of microbiological, macrofaunal, botanical and biogeochemical techniques. Baseline surveys would be required to observe the ecosystem, including seasonal variation, so that effects of leaking CO_2 could be identified. Marine surveys to date have focussed primarily on the impact of decreased pH. There has also been some observation of the ecosystem at natural CO_2 seeps as part of CO_2GeoNet and tank–based studies of the response of marine organisms to increased CO_2 levels.

Ecosystem monitoring is under development for providing information on CO_2 leakage. Identification of early bio–indicators such as response of particular species to elevated CO_2 levels and tolerance levels are being undertaken onshore (e.g. West et al., 2005) and offshore (e.g. Langenbuch and Portner 2004, Ishida et al., 2005), also in the North Sea as part of the CO_2ReMoVe project.

Such studies include recovery and examination of physical samples collected by divers or camera guided devices. Other samplers are more randomly selected such as box corers and grabs that are not guided to points of interest. There are also non–invasive techniques where video and stills cameras are used to survey the fauna of the seafloor.

Research on the response of specific marine organisms has also been undertaken, including laboratory–based aquarium experiments (e.g. Langenbuch and Portner 2004). Using a benthic–chamber (designed to penetrate sea–bed sediments to a certain depth), following injection into the chamber of CO_2–rich water and monitoring the response of the contained organisms, Ishida et al., 2005 concluded that calcium–carbonate organisms are likely to be the worst affected by elevated CO_2 levels. Ishida et al., 2005 also noted an increase in bacterial activity above 20000 ppm, which was believed to be an increase of bacteria adapted to high CO_2 levels.

A limitation of studying areas with natural CO_2 seeps is that the ecosystem has already adapted to increased CO_2 levels, so some early bio–indicators may not be obvious. Additionally, this technique does not quantify the amount of CO_2 leakage. Marine observation requiring divers is also likely to be expensive and will have limitations on water depth.

Although changes in ecosystems have the potential to detect smaller changes in the environment due to gas seepage compared with the identification of physical changes (such as pockmarks) it is likely to be difficult to detect these biological markers as analysis of video/stills or physical samples can take a long time, with great uncertainty over the range and tolerance of marine species identified.

10.9.1.1 Case study (non–CO_2 and CO_2): North Sea

Ecosystem studies in the North Sea of a couple of active pockmarks seeping methane concluded that the epifauna is enriched within the pockmarks but this was thought to be due to the presence of cemented hardgrounds[1] rather than the gas seepage (Dando et al, 1991). It was also suggested that the infauna was impoverished compared with the seabed outside the pockmark. There was, however, evidence for symbiont–hosting species associated with methane seepage. It is not clear if these characteristics of cemented hard ground and symbiotic fauna could be expected if the seeping gas was CO_2 rather than CH. However a study in the Aegean where the escaping gas is dominated by CO_2 showed a large diversity of microbial species with several new taxa documented. The epifauna abundance and diversity was also high compared with sites away from the seepage location though no vent–specific species were found (Dando et al., 2000). Examination of a large North Sea pockmark attributed to a CO_2 blow out noted increase biological abundance and diversity but attributed that to the geomorphology of the structure rather than the formerly escaping gas (Thatje et al. 1999). Many methane seepage sites have extensive bacterial mats that provide a conspicuous seafloor feature (Figure 10–65**.**).

[1] hardgrounds are regions of sea floor which have been lithified in situ. They may support organic life fixed to the hard seabed

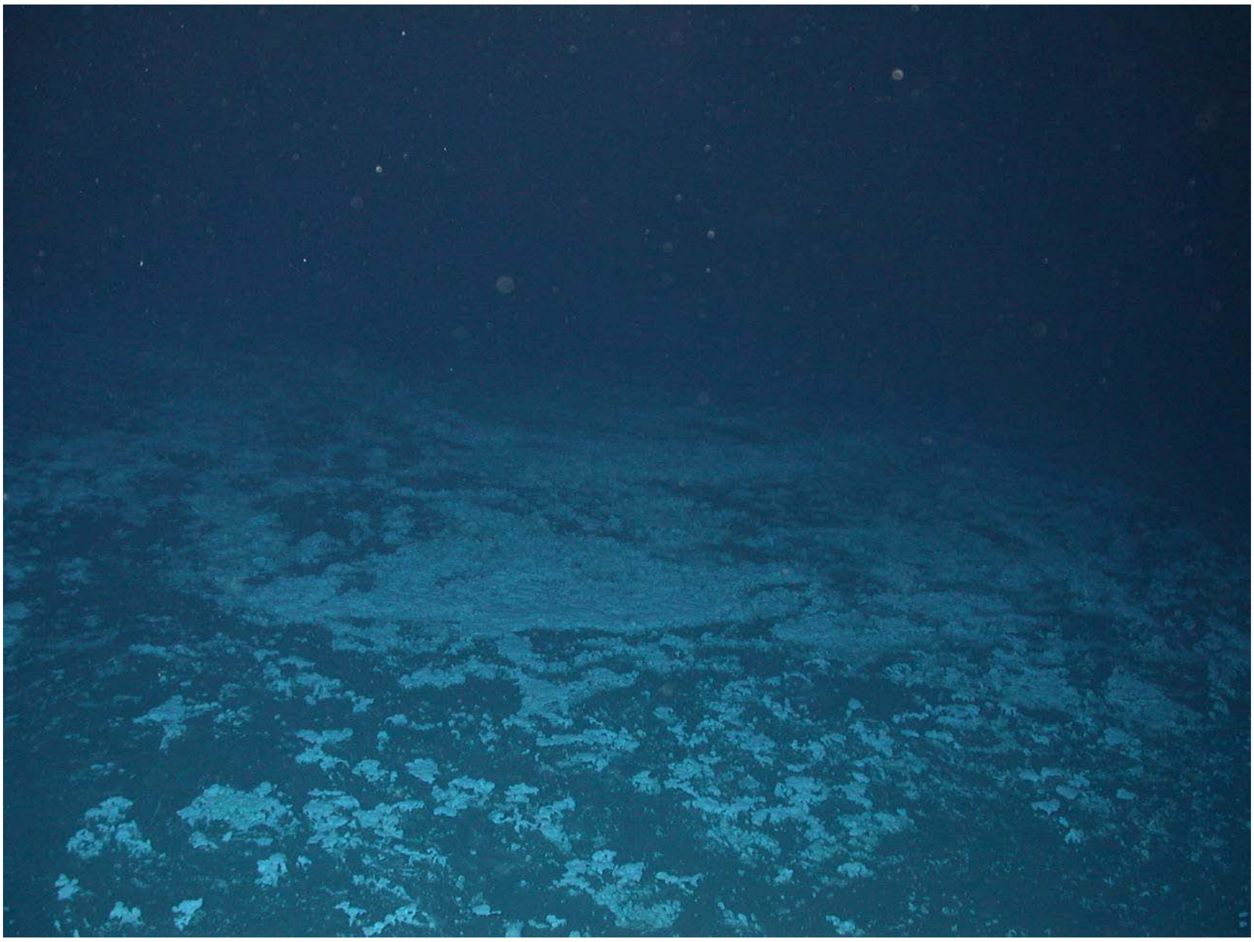

Figure 10-65: Gigantic bacterial mat associated with methane seepage. Image reproduced with permission of MARUM – Center for Marine Environmental Sciences from http://www.mpi–bremen.de/Background_Chemosynthetic_Ecosystems.html.

It is possible the formation of hardgrounds due to methane oxidation may be replicated during the escape of CO_2. Hanor (1978) demonstrated that CO_2 degassing in the vadose zone caused the precipitation of aragonite and the formation of beachrock (carbonate–cemented sediment layers within unconsolidated sediments on beaches). If this also occurs in deeper water with CO_2 seepage the presence of cemented hard ground at the seafloor is likely to increase biological activity and diversity and could be monitored.

10.9.1.2 Case study (CO_2): Ischia Island, Italy

East of Ischia Island, Italy, cold CO_2 is naturally venting from the seabed at a rate of 1.4 million litres per day (across a region 3000 m^2) as a result of volcanic activity. Ecosystem surveys and pH, alkalinity and salinity measurements were carried out by scuba divers over three field seasons. Overall, near the vents, there was a reduction in macro–organism species, particularly those with calcareous shells, there were no juvenile shellfish and additionally, adult shellfish displayed weakened and pitted shells. Plant surveys showed an increase in the presence of non–calcareous algae (>60% coverage) and sea–grass (<30% increase in population density) near the vents (Hall–Spencer et al., 2008).

10.9.1.3 Case study (CO_2): Ketzin, Germany

At the Ketzin CO_2 injection pilot project, rock and fluid samples have been collected from the reservoir rock to determine the microbial community of the sub–surface. Further samples will be collected during the pilot study to monitor for changes in the deep biosphere community (Giese et al., 2009).

10.9.2 Tiltmeters

Tiltmeters can be deployed either at the surface or downhole to monitor small changes in strain in the reservoir, caprock or overburden. This technique can be used to monitor the geomechanical integrity of the system: small changes in strain signifying a response to elevated injection pressures. Monitoring changes in strain may be particularly useful where geomechanical models indicate that there is a risk of induced faulting or ground movements. As CO_2 is injected, the pressure in the pore space will increase, this can result in small ground movements which could be detected using a sensitive tiltmeter (onshore, in low vegetation areas this centimetre–scale movement can be measured using satellite interferometry as used at the In Salah site, Algeria). This ground movement could indicate the areal extent of the pressure footprint, which will be larger than the injected CO_2 footprint.

A tiltmeter generally consists of an arched tube, containing a conductive electrolytic fluid with an air bubble, and electrodes either side and underneath the air bubble. As the tiltmeter tilts, the bubble covers more of the electrodes next to it, and the change in voltage precisely locates the bubble. Two orthogonal tiltmeters on the same base can be used to effectively monitor ground movement. Measurements as fine as 0.0001 degree are claimed by manufactures.

This is an established technique for other fields, such as monitoring volcanic sites and dams, but is not yet proven for use with CO_2. Gas extraction has been known to cause ground subsidence, so it is logical that CO_2 injection may cause ground movement (Winthaegen et al., 2005). Tiltmeters are currently being deployed at the In Salah CO_2 storage site in Algeria.

Costs for downhole or marine tiltmeter surveys will be higher than land–based monitoring.

10.9.2.1 Case study: Mid Atlantic Ridge

Long term seabed deformations in the Logatchev Hydrothermal Vent Field at the Mid–Atlantic Ridge were monitored using a Bremen Ocean Bottom Tiltmeter (OBT) from May 2005 until June 2006 in water depth of 3035 m (Figure 10–66). The tiltmeter records tilt in two perpendicular horizontal directions. A vertically aligned accelerometer was used to distinguish between true tilt and transient horizontal motion of the OBT which can cause a fake signal. It was noted that the acceleration steps correlate well in time with the tilt steps, but amplitude is different, and the reason for this mismatch was unclear as it was not observed in laboratory tests. In this region, the ground movement was related to movement along fractures and faults and possibly to downhill debris slides.

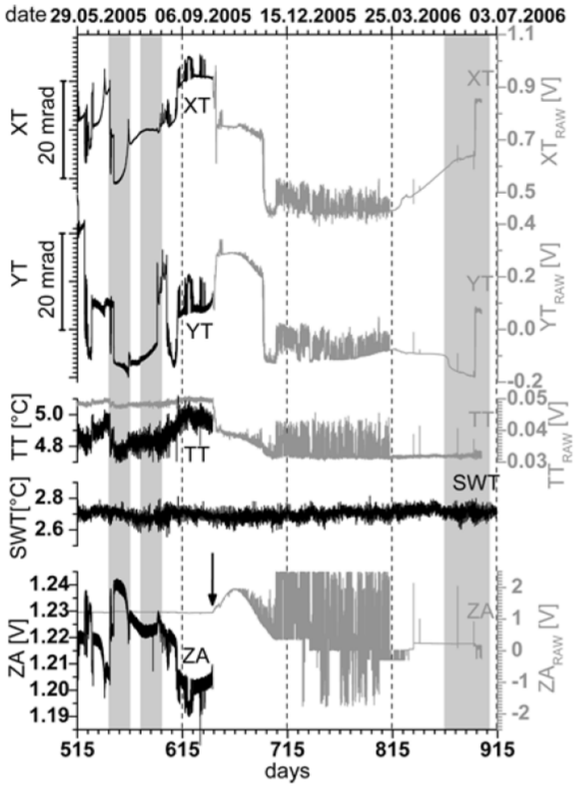

Figure 10-66: Tiltmeter data (XT and YT), seawater temperature (SWT), sensor temperature (TT) and vertical acceleration (ZA) from the Logatchev hydrothermal vent area. Axes on the right hand side show raw data in volts. The black arrow on day 643 indicates battery failure, plots in black show uncorrupted data, plots in grey show the remaining data (Fabian and Villinger, 2008, Copyright 2008 American Geophysical Union, image reproduced by permission of American Geophysical Union).

10.9.3 Tracers

Tracers are made up of extremely fine particles, soluble gas or liquid samples of exotic compounds which can be added to the injected CO_2 to give it a unique ‘fingerprint’. The main purpose of adding tracers would be to monitor migration of CO_2, to estimate the volume and flow rate (Benson et al., 2004; Winthaegen et al., 2005) and to identify the CO_2 input source. Tracers could also potentially be useful in identifying if the CO_2 had leaked from a storage site, rather than a natural source, and also potentially, if disputed, tracers could identify from which storage site CO_2 detected at the surface had leaked.

A number of tracers with very low detection limits such as perfluorocarbons (detectable at concentrations of 10^{-12}, Benson et al., 2004) are currently available and others are under development. Noble gases, such as helium and radon, which occur naturally in the subsurface, can also provide indications of potential gas movement. Examination of isotope ratios (e.g. C isotopes) can help to discriminate the source of CO_2. This depends on there being a contrast between the isotopic signature of the injected CO_2 and that being produced biogenically in the shallow subsurface. In some cases this appears to work well in discriminating the deep injected CO_2 from shallow sources (e.g. Klusman, 2003a, b), but in other cases the isotopic signatures overlap (e.g. at Weyburn) making identification more difficult. Very detailed work has been necessary to separate deep and shallow CO_2 components onshore, such as Klusman’s sampling in shallow boreholes to depths of up to 10 m. Such an approach would be much more difficult and expensive to adopt offshore. Phase partitioning tracers can also be used to determine the amount of different phases (e.g. residual oil in the reservoir).

A suitable amount of tracer material can be injected together with the CO_2 to generate a pulse of tracer in the CO_2 plume. Depending on the tracer's partitioning coefficients into the water and gas phases, its breakthrough into observation wells may not coincide exactly with that of the CO_2. However adding more than one type of tracer allows study of the relative breakthrough times to provide information on the fluid flow through the reservoir. For example, sulphur hexafluoride (SF6) and the noble gas Krypton (Kr) have been used among others as tracers at the pilot injection sites at Frio (in 2004) and Otway (in 2008). The Otway site is also investigating the use of perdeuterated methane (CD4) as a tracer in the depleted gas field (Stalker et al, 2009). Different tracers have been added at each of the three injection wells at In Salah (Algeria) to aid in understanding fluid migration.

10.9.3.1 Tracers case study: Frio

Perfluorocarbon tracers were added in three paired intervals at the Frio site, at the start and in the middle of the injection phase. Samples were collected from an up–dip monitoring well, 31m from the injection well (Figure 10–67). The four tracers injected each time were perfluoromethylcyclopentane (PMCP), perfluoromethylcyclohexane (PMCH), perfluorodimethylcyclohexane (PDCH), and perfluorotrimethylcyclohexane (PTCH). These samples were later analysed in a laboratory to determine the concentration of perfluorocarbons. Breakthrough peaks had an average travel time of 51 hours. The duration of each peak varied between tracers.

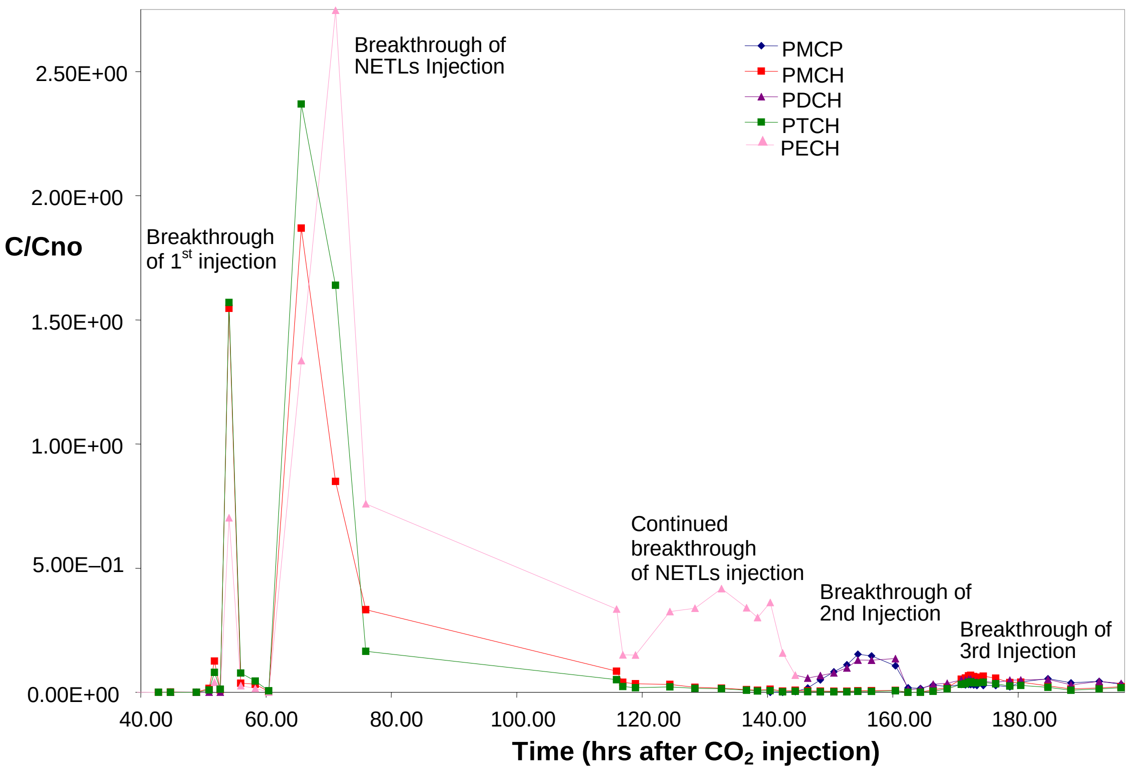

Figure 10-67: C/Cno data for all major injected perfluorocarbons during the breakthrough period (image courtesy T. J. Phelps, Oak Ridge National Laboratory)

As Perfluorocarbons are more soluble in CO_2 than in water, their dilution could indicate that additional CO_2 dispersed the injected perfluorocarbons (McCallum et al., 2005). An important point to note is that around 48 – 55 hours after the first CO_2 injection, a lot of small particulates arrived at the sub–sampling needles with the CO_2, clogging the needles and as a result, the accuracy of measurements is likely to have been affected around this time. Comparison of these results with the analysed downhole U–tube sampling results (Freifeld et al., 2005), suggests the

C/Cno peak should have been greater for the first breakthrough. The needles were subsequently removed and tracer sampling continued successfully (T. J. Phelps, pers. Comm.).

10.9.3.2 TRACERS CASE STUDY: K12–B

At K12–B, CO_2 is being injected into an almost depleted gas field in the Dutch sector of the North Sea. Around 60 000 tonnes of CO_2 has been injected for storage and enhanced gas recovery.

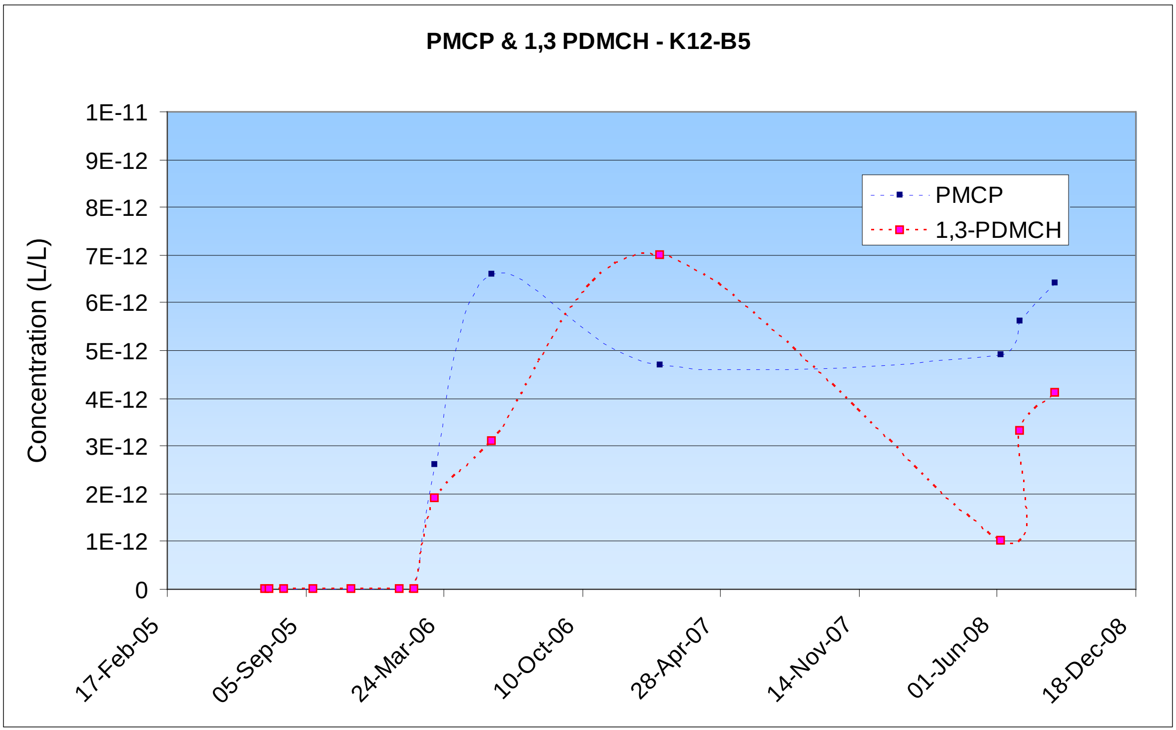

Figure 10-68: Tracer concentration measured in the producing gas stream of K12–B1 (420m from the injector well) (top) and K12–B5 (1000m from the injector well) (bottom) (courtesy TNO/GDF Suez - Vandeweijer et al., 2008).

In March 2005, two tracers (1kg each) were injected in 10 minutes into the injection well (K12–B6) together with the CO_2. The tracers used were 1,3–Perfluorodimethylcyclo–hexane (1,3–PDMCH) and Perfluoromethylcyclo–pentane (PMCP). Samples were taken weekly from the two producing wells (K12–B1 and K12–B5). K12–B1 is 420m from the injector and tracer breakthrough occurred in July 2005. K12–B5 is about 1000m from the injector well and tracer breakthrough was detected in April 2006 (TNO 2006) (Figure 10–68).

10.9.3.3 PRESSURE CORE SAMPLING

Pressure sampling provides a means of recovering sediment cores held at in–situ pressure. This aims to avoid sediment disturbance that often occurs when gas bearing sediment are brought to the surface. Large volume changes disrupt the core changing the physical structure making a core analysis uncertain as representative of in situ conditions. This is particularly important when gas is held within hydrates and large volume changes occur as it sublimates. In recent years EU funded projects HYACE and HYACINTH have led to the development and deployment of two systems to fit within shallow drillings systems, the Fugro pressure corer (FPC) and the HYACE rotary corer (HRC). These were developed to support studies of methane hydrates. The FPC uses a hammer driven by mud circulation to drive a sampler into the sediment and seal it. The HRC uses a mud motor to drive a cutting shoe into lithified sediments. Both systems have been used in programmes in the Gulf of Mexico (Chevron–DOE JIP programme), offshore Cascadia (IODP Leg 204), Bay of Bengal (Indian hydrates study) etc. The former has been used more frequently. The latter has been modified into the Fugro Rotary Pressure Corer (FRPC). The systems are designed to hold the cores under pressure within an autoclave before transfer to a logging system including, magnetic, gamma, resistivity, X–ray (Schultheiss et al., 2006). The recovered cores have been logged to show the location of the hydrates within the core and how it changes as the cores are depressurized. This has generally shown that methane is located in distinct layers or along fractures within the cores rather than disseminated throughout. This could also be expected for CO_2 within sediments.

These technologies may be important in measuring the amount and location of CO_2 gas with the shallow sediment sequence (approx less than 500m sub-seabed depth).

10.10 ABANDONED WELLS: MONITORING OPPORTUNITY OR LEAKAGE RISK?

Structures that have been exploited for oil and gas will have abandoned wells, as will many similar areas that have been explored with no subsequent development for production. Such wells may provide an opportunity for re–use as monitoring observation wells if the structure is developed for CO_2 storage; however they also present a significant risk as potential leakage conduits. Similar issues may arise with non–hydrocarbon wells, e.g. water wells in an aquifer.

Abandoned wells are not usually completed with re–use in mind and completion may not have been undertaken carefully, particularly in dry wells or in wells with few shows where there was low–risk of hydrocarbon release. Re–entering such wells to run wireline logs or to install CO_2 storage monitoring instrumentation constitutes a risk, as disturbing the sealing between casing and cement could create a leakage pathway.

During storage project planning the quality of the abandonments of any existing wells needs to be assessed, taking into consideration: the history of the field and any failures during production; the risk of new failures due to injection of CO_2 and its effect on cement and casing. This requires an audit of the abandonments based on the completion reports for wells drilled in the field or structure. Information is needed about the position and type of cement plugs, packers, casing and casing bonds. The CDA (Common Data Access Ltd) well database should include much of this data for the UK offshore fields.

The next step would be to investigate the condition of the cement and casing using wireline logs. Conventional casing bond log (CBL) and ultrasonic imager tools, both used routinely for oil wells, are adequate for assessing the state of any existing wells provided that the well sections are accessible. However, this operation presents a risk of damage to the well completion under assessment, and any such damage would require a fresh completion and abandonment of the well. For this reason Schlumberger’s view is that all old wells should simply be re–opened and re–abandoned on safety grounds. They regard this as essential in a field where a significant proportion of the wells have a history of leakage during production, or where old wells are to be used as observation wells.

The accuracy of well locations is an additional factor in the case of old offshore wells. Subsea well heads were often only located to accuracies of tens of metres, which greatly increases the difficulty of identifying them for monitoring and, especially, re–entry.

A pragmatic resolution would be to accept that a certain amount of leakage from old wells is inevitable, and to work with regulators to define limits based on the location of wells, the scale of leakage and where the gas is leaking to. Exceeding these conditions then triggers work to re–enter and re–complete a leaking well.

It would be ideal if instrumentation could be installed as part of original well abandonments in future. However, there would be no point in fitting sensors if a well was unlikely to be used for

CO_2 monitoring. For this to be practicable there would need to be a regulatory change so that planning for CO_2 storage was considered as part of the oil and gas field shutdown process.

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British Geological Survey holds most of the references listed below, and copies may be obtained via the library service subject to copyright legislation (contact libuser@bgs.ac.uk for details). The library catalogue is available at: http://geolib.bgs.ac.uk.

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Appendix 1 Treatment of FEPs in the Scoping Calculations

This appendix specifies, unless otherwise stated, how each FEP in Quintessa's On–line CO_2 FEP database will be treated in the development of a systems model for the present MMV project. In a few cases, a FEP will not be represented within the systems model, but will be treated explicitly or implicitly during the project by some other means. These cases are indicated in the tables.

The colour coding used in the first column of each table is as follows:

- Blue indicates that a FEP will be treated explicitly.
- Yellow indicates that a FEP will be treated implicitly.
- Red indicates that a FEP has been screened out and will not be considered.

An "explicit FEP" is one that is represented directly within a model, by a combination of system discretisation, parameters and equations.

An "implicit FEP" is one that is not represented directly within a model, but which has effects that are bracketed by those of "explicit FEPs".

Table A–1: FEP Audit for FEP Category 0, Assessment Basis.

FEP number	Description	Audit
0.1	Purpose of the assessment	The primary aim is to bound values of parameters that can be measured and that indicate whether or not a storage system is behaving as expected (or values of proxies for these parameters).
0.2	Endpoints of interest	The magnitude and timing of fluxes of CO_2 in the sub–surface and to the accessible environment, and the areas over which fluxes occur, are of primary concern. Also of concern is possible acidification of formation waters and effects on pressures.
0.3	Spatial domain of interest	The region that must be monitored to demonstrate that the storage system is behaving as expected is of primary interest. This region includes the sub–region over which injected carbon dioxide may conceivably be transported. The region is entirely offshore.
0.4	Timescale of interest	The timescales relevant monitoring. The primary focus is on timescales up to a few hundred years, though longer timescales will be considered for comparative purposes.
0.5	Sequestration assumptions	The rate of injection of CO_2 and the total amount injected are model inputs.
0.6	Future human action assumptions	Future human actions are treated implicitly and concern monitoring activities
0.7	Legal and regulatory framework	Primarily the EU CCS Directive 2009/31/EC
0.8	Model and data issues	Simplified algorithms will be used in order to represent complex processes at the systems level.

Table A–2: FEP Audit for FEP Class 1.1, Geological Factors.

FEP number	Description	Audit
1.1.1	Neotectonics	Implicit. No significant effects are expected over the short timescales considered. Any effects of neotectonics on the storage site would lie within the ranges of calculated outcomes for other phenomena.
1.1.2	Volcanic and magmatic activity	Screened out. Not relevant since no volcanic or magmatic activity occurs.
1.1.3	Seismicity	Implicit. No significant effects are expected over the short timescales considered. Any effects of neotectonics on the storage site would lie within the ranges of calculated outcomes for other phenomena.
1.1.4	Hydrothermal activity	Screened out. Not relevant since no volcanic or magmatic activity occurs.
1.1.5	Hydrological and hydrogeological response to geological changes	Implicit. Significant changes in the geology are not considered. Any small effects would lie within the ranges of calculated outcomes for other phenomena.
1.1.6	Large scale erosion	Screened out. Not relevant since no large–scale erosion is expected.
1.1.7	Bolide impact	Screened out on the basis that bolide impact is highly unlikely on the considered timescale and in any case the adverse effects of bolide impact would render monitoring irrelevant.

Table A–3: FEP Audit for FEP Class 1.2, Climatic Factors.

FEP number	Description	Audit
1.2.1	Global climate change	Implicit. No significant effects are expected over the short timescales considered. Any effects of global climate change on the storage site would lie within the ranges of calculated outcomes for other phenomena.
1.2.2	Regional and local climate change	See 1.2.1.
1.2.3	Sea level change	Implicit. Any changes in sea level over the relatively short timescales considered are considered to be insignificant. The small effects of any such changes and would lie within the ranges of calculated outcomes for other phenomena.
1.2.4	Periglacial effects	Screened out. No periglacial effects are expected during the relatively short timescales considered.
1.2.5	Glacial and ice sheet effects	Screened out. No glacial or ice sheet effects are expected during the relatively short timescales considered.
1.2.6	Warm climate effects	Screened out. No warm climate effects are expected during the relatively short timescales considered.
1.2.7	Hydrological and hydrogeological response to climate changes	Implicit. No significant responses are expected during the relatively short timescales considered. The small effects of any such changes and would lie within the ranges of calculated outcomes for other phenomena.
1.2.8	Responses to climate changes	Implicit. See descriptions for 1.2.1, 1.2.2, 1.2.3 and 1.2.7.

Table A–4: FEP Audit for FEP Class 1.3, Future Human Actions.

FEP number	Description	Audit
1.3.1	Human influences on climate	Implicit. No significant effects are expected over the short timescales considered. Any effects of climate change on the storage site would lie within the ranges of calculated outcomes for other phenomena.
1.3.2	Motivation and knowledge issues	Screened out on basis of assessment context.
1.3.3	Social and institutional developments	Screened out on basis of assessment context.
1.3.4	Technological developments	Screened out on basis of assessment context.
1.3.5	Drilling activities	Implicit. Any effects of drilling on the storage site would lie within the ranges of calculated outcomes for borehole leakage.
1.3.6	Mining and other underground activities	Screened out since would not occur in any of the considered storage environments.
1.3.7	Human activities in the surface environment	Screened out on basis of assessment context.
1.3.8	Water management	Screened out on basis of assessment context.
1.3.9	CO_2 presence influencing future operations	Implicit. The nature of the storage site and the expected behaviour of CO_2 will influence MMV operations.
1.3.10	Explosions and crashes	Screened out on basis of assessment context.

Table A–5: FEP Audit for FEP Class 2.1, CO_2 Storage Pre–Closure.

FEP number	Description	Audit
2.1.1	Storage Concept	Explicit. The model is applicable to a range of different offshore storage concepts.
2.1.2	CO_2 quantities, injection rate	Explicit. The injection rate and total amount of CO_2 injected are model inputs.
2.1.3	CO_2 composition	Explicit. Pure CO_2 is specified.
2.1.4	Microbiological contamination	Explicit. Pure CO_2 is specified.
2.1.5	Schedule and planning	Any effects are implicit in the specification of the storage scenario.
2.1.6	Pre–closure administrative control	Any effects are implicit in the specification of the storage scenario.
2.1.7	Pre–closure monitoring of storage	Any effects are implicit in the specification of the storage scenario.
2.1.8	Quality control	Any effects are implicit in the specification of the storage scenario.
2.1.9	Accidents and unplanned events	Any effects are implicit in the specification of the storage scenario.
2.1.10	Over–pressuring	Explicit. Initial over-pressuring will be specified in some calculations. In other cases, over–pressures due to the amounts of CO_2 injected (FEP 2.1.2) or CO_2 phase changes will be calculated by the model.

Table A–6: FEP Audit for FEP Class 2.2, CO_2 Storage Post–Closure.

FEP number	Description	Comment
2.2.1	Post–closure administrative control	Any effects are implicit in the specification of the storage scenario.
2.2.2	Post–closure monitoring of storage	Any effects are implicit in the specification of the storage scenario.
2.2.3	Records and markers	Screened out on basis of assessment context.
2.2.4	Reversibility	Screened out on basis of assessment context.
2.2.5	Remedial actions	Screened out on basis of assessment context.

Table A–7: FEP Audit for FEP Class 3.1, CO_2 Properties.

FEP number	Description	Audit
3.1.1	Physical properties of CO_2	Explicit. Simplified algorithms are used to represent the variation of CO_2 viscosity with pressure and temperature.
3.1.2	CO_2 phase behaviour	Explicit. Simplified algorithms are used to represent the variation of CO_2 density with pressure and temperature.
3.1.3	CO_2 solubility and aqueous speciation	Explicit. Dissolution in water is represented explicitly. Dissolution in oil is not considered.

Table A–8: FEP Audit for FEP Class 3.2, CO_2 Interactions.

FEP number	Description	Audit
3.2.1	Effects of pressurisation of reservoir on caprock	Implicit in the specification of caprock properties.
3.2.2	Effects of pressurisation on reservoir fluids	Explicit. Induced groundwater flows will be calculated.
3.2.3	Interaction with hydrocarbons	Implicit in the specification of CO_2 migration properties.
3.2.4	Displacement of saline formation fluids	Explicit. Calculated by the model.
3.2.5	Mechanical processes and conditions	Included implicitly in some process algorithms.
3.2.6	Induced seismicity	Screened out since considered of limited value for monitoring.
3.2.7	Subsidence or uplift	(Explicit) Not treated in the systems model but bounded by "off-line" calculations based on systems model outputs.
3.2.8	Thermal effects on injection point	Screened out since not considered relevant to monitoring.
3.2.9	Water chemistry	Explicit. Will affect CO_2 solubility and thus included in some process algorithms.
3.2.10	Interaction of CO_2 with chemical barriers	Explicit. Chemical reactions that remove CO_2 can be represented.
3.2.11	Sorption and desorption of CO_2	Screened out since considered to be insignificant compared to other processes.
3.2.12	Heavy metal release	Screened out since it is considered not to be feasible to monitor heavy metals or that it would be more appropriate to monitor other proxies (e.g. pH).
3.2.13	Mineral phase	Explicit. Mineral trapping of CO_2 can be represented.
3.2.14	Gas chemistry	Will affect CO_2 solubility and thus included implicitly in some process algorithms.
3.2.15	Gas stripping	Screened out since considered to be insignificant compared to other processes.
3.2.16	Gas hydrates	Screened out since considered to be insignificant compared to other processes.
3.2.17	Biogeochemistry	Implicit. Any biogeochemical effects on the storage site would lie within the ranges of calculated outcomes for borehole leakage. Potential biogeochemical effects will be discussed based on other model outputs.
3.2.18	Microbial processes	Implicit – See FEP 3.2.17
3.2.19	Biomass uptake of CO_2	Implicit – See FEP 3.2.17

Table A–9 FEP Audit for FEP Class 3.3, CO_2 Transport.

FEP number	Description	Audit
3.3.1	Advection of free CO_2	Explicit. Represented directly in the equations for MPF
3.3.2	Buoyancy–driven flow	Explicit. Represented directly in the equations for MPF
3.3.3	Displacement of formation fluids	Explicit. Could result from induced groundwater movement.
3.3.4	Dissolution in formation fluids	Explicit. Dissolution of CO_2 in groundwater is represented.
3.3.5	Water mediated transport	Explicit. Advection of dissolved CO_2 in groundwater is represented.
3.3.6	CO_2 release processes	Explicit. Transport to the surface through wells and other features is represented in the model.
3.3.7	Co–migration of other gases	Screened out – see 3.2.15.

Table A–10: FEP Audit for FEP Class 4.1, Geology.

FEP number	Description	Audit
4.1.1	Geographical location	Explicit. The model can be adapted to represent any of the four kinds of storage site considered.
4.1.2	Natural resources	Screened out on the basis of assessment context.
4.1.3	Reservoir type	Represented explicitly.
4.1.4	Reservoir geometry	Represented explicitly.
4.1.5	Reservoir exploitation	Represented implicitly in the system description.
4.1.6	Cap rock or sealing formation	Represented explicitly.
4.1.7	Additional seals	Represented explicitly.
4.1.8	Lithology	Properties of all rocks in the system domain are represented explicitly.
4.1.9	Unconformities	Represented explicitly in rock properties.
4.1.10	Heterogeneities	Explicit. Represented by varying properties of model compartments.
4.1.11	Faults and fractures	Explicit. Represented in rock permeabilities or explicitly as model features.
4.1.12	Undetected features	Implicit. The importance of undetected features can be assessed by varying the representation of the system geology.
4.1.13	Vertical geothermal gradient	Represented explicitly.
4.1.14	Formation pressure	Represented explicitly.
4.1.15	Stress and mechanical properties	Included implicitly in some process algorithms.
4.1.16	Petrophysical properties	Represented explicitly.

Table A–11: FEP Audit for FEP Class 4.2, Fluids.

FEP number	Description	Comment
4.2.1	Fluid properties	Represented explicitly.
4.2.2	Hydrogeology	Represented explicitly, but approximately.
4.2.3	Hydrocarbons	Implicit. Represented by appropriately parameterising the model to take into account the possible effects of hydrocarbons.

Table A–12: FEP Audit for FEP Class 5.1, Drilling and Completion.

FEP number	Description	Audit
5.1.1	Formation damage	Implicit. Any effects relevant to the initial conditions will be included in the specification of well properties.
5.1.2	Well lining and completion	Implicit. Any effects relevant to the initial conditions will be included in the specification of well properties.
5.1.3	Workover	Implicit. Any effects relevant to the initial conditions will be included in the specification of well properties.
5.1.4	Monitoring wells	Implicit. Any effects relevant to the initial conditions will be included in the specification of well properties.
5.1.5	Well records	Screened out on the basis of assessment context.

Table A–13: FEP Audit for FEP Class 5.2, Borehole Seals and Abandonment.

FEP number	Description	Audit
5.2.1	Closure and sealing of boreholes	Implicit. Any effects relevant to the initial conditions will be included in the specification of well properties.
5.2.2	Seal failure	Implicit. Any effects relevant to the initial conditions will be included in the specification of well properties.
5.2.3	Blowouts	Screened out on the basis of assessment context.
5.2.4	Orphan wells	Implicit. Any effects relevant to the initial conditions will be included in the specification of well properties.
5.2.5	Soil creep around boreholes	Screened out on the basis of assessment context.

Table A–14: FEP Audit for FEP Class 6.1, Terrestrial Environment.

FEP number	Description	Audit
6.1.1	Topography and morphology	Screened out on the basis of assessment context.
6.1.2	Soils and sediment	Screened out on the basis of assessment context.
6.1.3	Erosion and deposition	Screened out on the basis of assessment context.
6.1.4	Atmosphere and meteorology	Screened out on the basis of assessment context.
6.1.5	Hydrological regime and water balance	Screened out on the basis of assessment context.
6.1.6	Near–surface aquifers and surface water bodies	Screened out on the basis of assessment context.
6.1.7	Terrestrial flora and fauna	Screened out on the basis of assessment context.
6.1.8	Terrestrial ecological systems	Screened out on the basis of assessment context.

Table A–15: FEP Audit for FEP Class 6.2, Marine Environment.

FEP number	Description	Audit
6.2.1	Coastal features	Screened out since the storage site is considered to be entirely offshore and to have no on–shore influence.
6.2.2	Local oceanography	Explicit. The seabed and seawater above the seabed is represented.
6.2.3	Marine sediments	Implicit. The effects of marine sediments are taken into account in the specification of properties for the shallowest lithologies in the model.
6.2.4	Marine flora and fauna	(Explicit). Not included in the systems model, but comment is made on the ecological effects based on calculated fluxes of CO_2 to the seabed in some scenarios.
6.2.5	Marine ecological systems	(Explicit). Not included in the systems model, but comment is made on the ecological effects based on calculated fluxes of CO_2 to the seabed in some scenarios.

Table A–16: FEP Audit for FEP Class 6.3, Human Behaviour.

FEP number	Description	Audit
6.3.1	Human characteristics	Screened out on the basis of assessment context.
6.3.2	Diet and food processing	Screened out on the basis of assessment context.
6.3.3	Lifestyles	Screened out on the basis of assessment context.
6.3.4	Land and water use	Screened out on the basis of assessment context.
6.3.5	Community characteristics	Screened out on the basis of assessment context.
6.3.6	Buildings	Screened out on the basis of assessment context.

Table A–17: FEP Audit for FEP Class 7.1, System Performance.

FEP number	Description	Audit
7.1.1	Loss of containment	Represented explicitly.

Table A–17: FEP Audit for FEP Class 7.2, Impacts on the Physical Environment.

FEP number	Description	Audit
7.2.1	Contamination of groundwater	Explicit. The effects of CO_2 dissolution are calculated.
7.2.2	Impacts on soils and sediments	Screened out on the basis of assessment context.
7.2.3	Release to the atmosphere	Screened out on the basis of assessment context.
7.2.4	Impacts on exploitation of natural resources	Screened out on the basis of assessment context.
7.2.5	Modified hydrology and hydrogeology	Represented explicitly.
7.2.6	Modified geochemistry	Explicit. A very simplified representation of geochemical reactions is included.
7.2.7	Modified seismicity	Screened out because it is not amenable to scoping calculations.
7.2.8	Modified Surface Topography	Implicit – see FEP 3.2.7.

Table A–18: Illustrative FEP Audit for FEP Class 7.3, Impacts on Flora and Fauna.

FEP number	Description	Audit
7.3.1	Asphyxiation effects	Screened out on the basis of assessment context.
7.3.2	Effect of CO_2 on plants and algae	(Implicit) Not represented in the systems model, but qualitative deductions will be made based on systems model outputs.
7.3.3	Ecotoxicology of contaminants	(Implicit) Not represented in the systems model, but qualitative deductions will be made based on systems model outputs.
7.3.4	Ecological effects	(Implicit) Not represented in the systems model, but qualitative deductions will be made based on systems model outputs.
7.3.5	Modification of microbiological systems	(Implicit) Not represented in the systems model, but qualitative deductions will be made based on systems model outputs.

Table A–19: Illustrative FEP Audit for FEP Class 7.3, Impacts on Humans.

FEP number	Description	Audit
7.3.1	Health effects of CO_2	Screened out on the basis of assessment context.
7.3.2	Toxicity of contaminants	Screened out on the basis of assessment context.
7.3.3	Impacts from physical disruption	Screened out on the basis of assessment context.
7.3.4	Impacts from ecological modification	Screened out on the basis of assessment context.

Appendix 2 Questionnaire used as a basis for discussions with contacted third parties

The aim of this questionnaire is to guide the process of exploring for the latest developments in monitoring tools for underground CO2 storage.

Article 13 from the EU–Directive 2009/31/EC states the rationale for monitoring. Monitoring, then, is to be invoked in order

To compare actual and modelled CO_2 behaviour and formation water behaviour.
To detect significant irregularities.
To detect CO_2 migration
To detect CO_2 leakage
To detect adverse effects for the environment (in particular drinking water), for human populations, for users of the surrounding biosphere.
To assess effectiveness of any corrective measures taken.
To update the assessment of safety and integrity of the storage complex in short– and long term, including assessment of whether CO_2 will be completely and permanently contained.

Keeping the above goals in mind a number of questions have been formulated relating to a new ("new") technology T. It is important to keep in mind what a particular technology might achieve on any of the aforementioned points.

The questions have been used as a guideline in targeting users, manufacturers, developers of novel technologies in possibly different stages of development.

Questions

Q0: What technologies, not already established or in later stages of development and demonstration, do you anticipate could be needed to monitor CO_2 storage?

Q1: What is the general use of T in terms of monitoring goals?

Q1a: Are developments in T mainly *theory–driven / technology–driven / requirement driven*?

Q1b: Are the significant strides in the area of *hardware / processing / interpretation / new application of existing technology for CCS*?

Q1c: Does T result in information pertaining to strictly local conditions, or does it inform about a more global condition (Δx, Δy, Δz)?

Q2: Does T solve any of the above questions on its own, or is it an auxiliary technology?

Q2a: If auxiliary, what other tools must be supplemented to arrive at an answer?

Q3: Is the technology (routinely) used outside CCS?

Q3a: If so, is it commercially available?

Q3b: If so, could it be applied to CCS without further development?

Q4: Is T used in CCS–context?

Q4a: If so, is it deployed on a *research scale / pilot scale / industrial scale*?

Q4b: if not so, is there a clear and compelling reason why not?

Q4c: if not so, what should be changed to T to make it fit for purpose in CCS?

Q4d: If not, how much would these changes cost?

Q4e: If not, is there any need for further R and D?

Q4f: If not, how long would this development take?

Q5: Is the deployment method *permanent (e.g. seabed/well/platform/buoy)/ non–permanent (e.g. ship, ROV, AUV, diver)*?

Q5a: If permanent, what are the power and data communication requirements?

Q6: Does employing T have adverse environmental impacts?

Q7: Are there limitations on the deployment?

Q7a: If so, are these limitations of a technical or legal or societal nature?

Q7b: Are so–called competent authorities to be notified of its deployment?

Q7c: If Q7b is answered in the affirmative, are these notifications required on each separate occasion of its deployment?

Q8: How many different pieces of equipment are involved in T?

Q9: Is T used in surveys or continuously?

Q9a: If used in surveys, what is their frequency?

Q9b: if used in surveys, what is their typical duration, rate of coverage (e.g. points/lines/km2 per day)?

Q10: Which are the *data / time / modelling / power /* requirements for arriving at conclusions upon T's output?

Q11: How robust is T in adverse operating conditions?

Q12: Is there potential for T for deployment in the post–closure phase?

Q13: Does T have the potential to make some other technologies superfluous?

Q13a: If not so, does T have the potential to boost (the use of) other technologies?

Q14: Is the addressee aware of any other ongoing R and D–attempts closely related to T?

Appendix 3 Monitoring techniques applicable in offshore storage projects, their degree of maturity, examples of detection and limitations

	Parameter/ Technique	Overview	Maturity	Detection Examples	Limitations
Seawater	Bubble stream detection and flow rate measurement	Bubble streams can be detected by very high resolution acoustic imaging, but this provides only 2D coverage. Multibeam echo sounding and sidescan sonar have been demonstrated to be capable of detecting bubble streams There is the possibility that ship–based sonar, designed for detecting shoals of fish, can also provide full volumetric sweeps for bubble detection at an offshore storage site..	An established but specialised technique, the use of which for CO_2 has yet to be demonstrated. Significant development may be required.	Continuous bubble streams of CH_4 visible, for the UK21/4 block, the bubble stream is 30 m wide at the surface and visible on multibeam echo sounding profiles. Detection limits not yet defined	CO_2 is more soluble than CH_4, so bubble streams may dissolve if water column is greater than 50 m. Quantification not possible.
	Seawater chemistry	For offshore storage, measurements of seawater properties may be needed to establish baseline conditions and if leaks were suspected. Measured properties can include chemical, physical and hydrographic parameters.	An established but specialised technique, the use of which for CO_2 is demonstrated in routine surface sampling.	Highly sensitive instruments are available.	A wide range of factors can influence seawater chemistry, would not indicate precise location of leak. Quantification not possible.
	Bubble stream chemistry	Bubbles of gas escaping into a water column, either seawater or freshwater, can be collected relatively simply using an inverted funnel. Locating the exact point of bubble escape may require the use of additional techniques, such as high resolution acoustic imaging.	An established but specialised technique that has been used to sample subsea CO_2 bubble streams.	Natural leakage sites such as Panarea (see CO_2ReMoVe project website).Detection varies with instrument type: lab types very sensitive (ppm), in situ less sensitive (0.1%)	Location of bubble stream needs to be determined before sampling.
Seabed and shallow subsurface	3D seismic seabed imaging	Shallow subsurface and seabed imaging capability, particularly in deep (>500m) water, utilising a higher frequency source, enabling topographic features to be observed.	An established but specialised technique used in other fields. Its use for CO_2 is as yet unproven.		Low resolution compared to dedicated seabed imaging tools.
	Boomer and sparker profiling	Boomer and sparker surveys are surface seismic techniques conducted offshore using high frequency seismic sources and receivers at or near the surface, that permit very high resolution 2D imaging of the shallow subsurface. Time–lapse datasets are required to identify changes that may indicate migration and leakage of CO_2.	An established but specialised technique used in other fields. Its use for CO_2 is as yet unproven.	In most conditions, sedimentary beds less than a metre thick can be resolved.	Time–lapse changes may be a result of processes other than leakage. Requires additional sampling. for verification
	High resolution profilers/pingers	Used particularly in soft sediments to image the seabed in a vertical profile.	An established but specialised technique used in other fields. Its use for CO_2 is as yet unproven.	Higher resolution (0.5m) than boomer/sparker but lower vertical penetration.	Time–lapse changes may be a result of processes other than leakage. Requires additional sampling to verify.
	High resolution acoustic imaging	Offshore, very high resolution surface seismic techniques can be used in time–lapse mode to detect changes to the seabed that may result from CO_2 leakage. Direct detection of bubble streams in the water column may also be possible in favourable circumstances.	An established but specialised technique in other fields, the use of which for CO_2 is as yet unproven.	Pockmarks less than 40 m in diameter can be identified	Time–lapse changes may be a result of processes other than leakage. Requires additional sampling to verify.

	Parameter/ Technique	Overview	Maturity	Detection Examples	Limitations
	Sidescan sonar	Sidescan sonar is one of the most accurate tools for imaging large areas of the seabed. Somewhat similar to side–looking airborne radar (SLAR), sidescan sonar transmits a specially shaped acoustic beam out to each side and perpendicular to the path of the towing vessel.	An established but specialised technique, the use of which for CO_2 is as yet unproven.	At Sleipner, gravity benchmarks at known locations can be identified (diameter 1.5 m).	Time–lapse changes may be a result of processes other than leakage. Requires additional sampling.
Seabed and shallow subsurface	Multibeam echo sounding, backscatter and bathymetry data	Multibeam echo sounding integrates acoustic bathymetric and backscatter information, permitting detailed mapping of seabed morphology and allowing inferences to be made regarding the nature of the sediment. In time–lapse mode the method could be used to detect slight changes in seafloor characteristics that might occur as a consequence of CO_2 leakage to the seabed.	An established but specialised technique in other fields, the use of which for CO_2 is as yet unproven.	Depending on equipment and survey design sub–metre resolution possible laterally and decimetre vertically	Time–lapse changes may be a result of processes other than leakage. Requires additional sampling.
	Headspace gas	Headspace gas analyses involve sampling the gas occupying the space at the top of subsamples taken from grab or core samples of seabed surface sediments. The gas is analysed geochemically to indicate its likely origin (thermogenic or biogenic).	An established but specialised technique in other fields, the use of which for CO_2 has yet to be demonstrated.	Highly sensitive instruments are available (0.01 ppb) however, their suitability for use with CO_2 storage has not yet been tested.	Not yet tested for CO_2 storage.
	Continuous seabed gas monitoring	Permanent instruments installed on the seabed, via a buoy–mounted continuous CO_2 seep monitoring tool.	A developing technique.	Gulf of Trieste, Panarea: dissolved and free CO_2 to fractions of 1%	Location of bubble stream needs to be determined before sampling, potential for biofouling.
	Ecosystems studies	Ecosystems monitoring, deploying biomarkers can be used to assess the potential impacts on ecosystems of CO_2 leaks in both terrestrial and marine environments. A baseline dataset is needed with which to compare subsequent survey results.	A developing technique that shows promise for CO_2.	Marker species (e.g. calcareous organisms) may be particularly sensitive	Does not quantify leak, change in ecosystem may be a result of many factors
Deep focussed including reservoir	Seabottom controlled source EM	Seabottom CSEM (Controlled Source Electro Magnetic) surveying is a novel application of a longstanding technique, currently at a quite early stage of development. It involves a towed electromagnetic source and a series of seabed receivers that measure induced electrical and magnetic fields. These can be used to determine subsurface electrical profiles that may be influenced by the presence of highly resistive CO_2.	A developing specialised technique in other fields, the use of which for CO_2 is as yet unproven.	Deployed at Sleipner, efficacy not yet demonstrated (water depth limitations).	High acquisition costs. Works best in water deeper than much of the North Sea.
	Surface gravimetry	Microgravimetry involves repeated high–precision gravity measurements at the surface (or seabed) to detect changes in gravity induced by fluid movements in the subsurface produced by injection of CO_2. The method is low resolution but it can provide inexpensive (at least onshore) information on subsurface mass/density distributions that complements other monitoring techniques such as the seismic methods.	An established but specialised technique in other fields, the use of which for CO_2 has yet to be fully demonstrated.	Site specific, in the range of few Mt CO_2 Sleipner suggest 3 – 5 µGal measurement accuracy and 0.5 – 1 Mt may be detectable at 500 m depth	Poor detection limit, poor depth resolution.
	Well gravimetry	Downhole gravity measurement offers the potential for higher resolution monitoring of CO_2 movement around the well, by measuring the gravity response of CO_2 layers in close proximity to the monitoring well.	A developing technique, the use of which for CO_2 has not been demonstrated.	Not known.	Not yet tested with CO_2
	Tiltmeters	Tiltmeters deployed either at the surface or downhole, measure very small changes in strain within the reservoir, caprock or overburden. This can be an early indicator of storage site deformation due to elevated injection pressures. May give general location of CO_2 at depth	An established but specialised technique in other fields, the use of which for CO_2 has yet to be demonstrated, but is about to be tested onshore at In Salah.	Current tiltmeters accurate to less than 1º	Not yet tested with CO_2, difficulty in deciding best location for tiltmeters

	Parameter/ Technique	Overview	Maturity	Detection Examples	Limitations
	Tracers	Tracers can be added to the injected CO_2 to monitor plume migration. Tracers are added to provide a unique fingerprint to the injected CO_2 and can have some benefits over simple detection and measurement of the CO_2 itself.	An established but specialised technique in other fields, which has been demonstrated for CO_2 .	Very sensitive. Tracers , such as perfluorocarbons can be detected at ppb levels	Potential for contamination during injection
	3D surface seismic	3D surface seismic is a sophisticated deep echo sounding technique utilising multiple seismic sources and receivers to produce full volumetric images of subsurface structure in both reservoir and overburden. A key application of surface seismic for monitoring purposes is in time–lapse (4D) mode, in which a number of repeat surveys are acquired, enabling changes in fluid distribution to be mapped through time.	Established and routine technique; use for CO_2 demonstrated. Easier and cheaper to deploy offshore than onshore, unlike most other methods	Estimated –2800 tonnes based on Sleipner aquifer project. Less for gaseous CO_2.	Dissolved CO_2 is essentially invisible on seismic. Expensive.
Deep focussed including reservoir	2D surface seismic	Conventional 2D surface seismic techniques can be used in time–lapse mode to detect any changes that may result from CO_2 injection. It can be deployed both in marine and non–marine environments. It would generally be cheaper than 3D surface seismic but lacks full volumetric subsurface coverage.	Established and routine technique – use for CO_2 demonstrated.	Inferior to 3D seismic with similar parameters	Cannot be used to verify CO_2 mass
	Multicomponent surface seismic	Multi–component surface seismic uses both compressive and shear waves to obtain a more complete characterisation of the subsurface, including improved imaging beneath gas accumulations, and improved discrimination of fluid pressure and saturation changes. It is expensive however compared to conventional surface seismic.	An established, but specialised technique that has a demonstrated use for CO_2.	Saturation changes similar to 3D seismic. Pressure detection sensitivity uncertain.	Complex processing required. Very expensive.
	Vertical seismic profiling (VSP)	Vertical Seismic Profiling (VSP) is a seismic technique in which multiple seismic sources are deployed around a well that has many receivers at intervals down the wellbore. This produces improved seismic resolution around the well and offers the potential to give early warning of well leakage.	An established but specialised technique in other fields, with promise for CO_2.	2D Section through 1600 tonnes detectable at Frio aquifer pilot	Coverage limited to vicinity of wellbore. Non–uniform sub–surface coverage.
	Microseismic monitoring	Microseismic monitoring involves the detection, measurement and triangulation of low–level seismic events using surface or downhole geophones. Induced seismicity may indicate fracturing of the reservoir due to injection or migration of the injected CO_2.	An established but specialised technique in other fields, the use of which for CO_2 is as yet unproven.	10 kt of CO_2 injected at Otsego aquifer site caused a response near the caprock possibly due to cracking	Requires monitoring well for deployment. Useful microseismic events may not be detectable.
	Cross–hole seismic	The cross–hole seismic technique measures velocity and attenuation characteristics in a 2D profile between wells, to measure CO_2 saturations and/or pressure changes during CO_2 injection. In time–lapse mode this can provide information on how the CO_2 is moving, as well as fine–scale data to help calibrate surface seismic data.	An established but specialised technique, with demonstrated applicability to CO_2 monitoring.	Detected CO_2 on 2D sections through1600 tonnes at Frio pilot and 3 kt at Nagaoka pilot.	Requires two boreholes close to storage reservoir
	Geophysical logs	Downhole geophysical logs are obtained from tools that are lowered down the well on a wireline. They measure the physical properties of the rocks that constitute the borehole walls, fluids in the rocks and downhole conditions such as pressure and temperature.	An established and routine technique, the use of which for CO_2 has been demonstrated.	Various, high resolution tools have been developed for the hydrocarbon industry which could be used/adapted	Limited depth of penetration away from well, requires wells near the CO_2 plume, can be expensive
	Downhole pressure	In addition to standard geophysical logging, dedicated downhole instrumentation for measuring pressure and temperature is strongly recommended. These parameters can be diagnostic of reservoir mechanical integrity, possible leakage from the reservoir or from a well and also the physical properties of CO_2.	An established but specialised technique in other fields; tested at Pembina Cardium and Ketzin	Various, high resolution tools have been developed for the hydrocarbon industry which could be used/adapted	Limited depth of penetration away from well, requires wells near the CO_2 plume, can be expensive

	Parameter/ Technique	Overview	Maturity	Detection Examples	Limitations
	Dynamic downhole temperature	Temperature is recorded continuously at regular spacing along the borehole, using permanently mounted fibre optic sensors	An established technique that had been used in pilot–scale CO_2 projects.	Minor changes (0.01°C) in temperature can be detected	Change in temperature is not definitive proof of CO_2 migration/presence
	Downhole fluid chemistry	Changes in downhole fluid chemistry can provide valuable insights into CO_2 plume movement, CO_2 solution into pore waters, fluid–rock interactions and well integrity.	A developing technique, the use of which for CO_2 has been demonstrated.	A few wt%	Difficult to obtain an uncontaminated sample
	Long–term downhole pH	Long–term borehole monitoring of in situ pH can play an important role in site monitoring. The pH of formation waters is an important geochemical parameter in the context of CO_2 storage, since it can indicate the proportion of CO_2 dissolving into the formation water and provide insights into the nature of fluid–rock interactions, including mineral trapping. It is also a potential early indicator of CO_2 migration in the overburden.	A developing technique the use of which using short term sensors for CO_2 is proven. Tool development is still required for long term downhole measurements.	Schlumberger tool to within 0.1 pH units short term, long term not known	Long term sensors not yet well developed
	Gas membrane downhole tool	Breakthrough at the monitoring well can be detected by using a silicone–based membrane which is permeable to gases.	A developing technique, the use of which for CO_2 has been demonstrated.	After injection of 531 t CO_2 at Ketzin, breakthrough was detected at observation well 50 m away	Early stage of development

Appendix 4 Summary of the detection capabilities of different monitoring techniques

	Technique	Continuous or repeat	Coverage			Direct monitoring		Indirect detection	Maturity
			Point	Areal	Volumetric	Direct CO_2 detection	Direct CO_2 measurement		
Seawater	Bubble stream detection and flow rate measurement	Repeat surveys		Yes, plumes of bubbles can be mapped		Direct bubble detection in water column – not CO_2 specific and detection limits not defined			Established for bubble detection but limited test in CO_2 bubble detection. Requires further development for CO_2 and flow rates
Seawater	Bubble stream chemistry	Repeat surveys	Point–specific, requiring location of bubble stream first				Direct measurements		Established but not routinely used, more for research
Seawater	Seawater chemistry	Repeat surveys	Points along profiles within a repeatable area – mainly sea surface but sampling at depth possible				Direct dissolved CO_2	Indirect measurement including pH	Established for seawater monitoring – requires further development for preserving pressures from deeper samples for routine surveys.
Seabed and shallow subsurface	Boomer profiling	Repeat surveys			Yes to ~300m from seabed in vertical and horizontal profiles	Direct gas detection in seabed sediments and bubbles in water column – not CO_2 specific		Seabed topography and shallow gas in vertical and horizontal profiles	Established but resolution for CO_2 to be determined
Seabed and shallow subsurface	Sparker profiling	Repeat surveys			Yes to ~1000m from seabed, with ~1m resolution, in vertical profiles			Seabed topography and shallow gas in vertical and horizontal profile	Established but resolution and applicability for CO_2 to be determined

	Technique	Continuous or repeat	Coverage			Direct monitoring		Indirect detection	Maturity
			Point	Areal	Volumetric	Direct CO_2 detection	Direct CO_2 measurement		
	High resolution profilers/ pingers	Repeat surveys			Yes to limited depth from seabed, with ~0.5m resolution, in vertical planes			Seabed topography and shallow gas in vertical profile	Established but resolution and applicability for CO_2 to be determined
Seabed and shallow subsurface	High resolution acoustic imaging	Repeat surveys			Yes to <100m depth from seabed, with <1m resolution, in vertical planes	Direct gas detection in seabed sediments and bubbles in water column – not CO_2 specific		Seabed topography and shallow gas in vertical profile	Established but resolution and applicability for CO_2 to be determined
	Sidescan sonar	Repeat surveys		Yes, to 1m resolution		Direct bubbles in water column – not CO_2 specific		Seabed topography	Established and demonstrated for methane/water
	Multibeam echo sounding, backscatter and bathymetry data	Repeat surveys		Yes, to 0.1m resolution		Direct bubbles in water column – not CO_2 specific		Seabed topography	Established and demonstrated for methane/water
	Headspace gas	Repeat surveys	Points within a repeatable area			Direct CO_2 detection using GC onboard ship or in lab.			Established but not routinely used, more for research
	Continuous seabed gas sampling	Continuous	Point–specific, requiring location of bubble stream first				Direct measurement		Currently early prototypes being developed – requires further development

	Technique	Continuous or repeat	Coverage			Direct monitoring		Indirect detection	Maturity
			Point	Areal	Volumetric	Direct CO_2 detection	Direct CO_2 measurement		
	Ecosystems studies	Repeat surveys		Seafloor	Seawater			Indirect requiring identification and removal of changes due to other processes	Established for offshore and hydrocarbon industries but still experimental for CO_2, requiring further development (e.g. RISCS project).
Deep focussed including reservoir	3D, 2D and multi–component surface seismic	Repeat surveys			Yes			Plume	Established and demonstrated
	Microseismic monitoring	Continuous			Yes			Induced seismic activity	Established and demonstrated
Deep focussed including reservoir	Cross–hole seismic	Repeat surveys		Yes – in vertical plane between two wells				Plume imaging	Established and demonstrated
	Geophysical logs	Repeat surveys and some continuous	Confined to wellbore and small depth of penetration in formation (<0.5–1m)				CO_2 saturation (detection limits not known)	RST records C, O2 and thermal decay	
	Downhole pressure	Continuous	Confined to wellbore at specific locations					Schlumberger's Unigage tool: pressure resolution of 0.07 to 1.03 kPa and accuracy ± 17 – 69 kPa	Established for oil and gas and demonstrated in several CO_2 pilot tests
	Downhole temperature	Continuous	Confined to wellbore at specific locations					Schlumberger's Unigage tool: Temperature resolution of 0.001 ºC and an accuracy of ± 0.3 to 1 ºC	Established for oil and gas and demonstrated in several CO_2 pilot tests

	Technique	Continuous or repeat	Coverage			Direct monitoring		Indirect detection	Maturity
			Point	Areal	Volumetric	Direct CO_2 detection	Direct CO_2 measurement		
	Dynamic downhole temperature	Continuous	Confined to wellbore but can be set–up along length of wellbore, for long–term monitoring					The Schlumberger WellWatcher Ultra DTS accuracy of 0.01 °C, calibration accuracy of ±1.8 °C or better and can measure 15 km of fibre at metre–resolution and update data in a few seconds	Established for oil and gas and demonstrated in several CO_2 pilot tests
Deep focussed including reservoir	Downhole fluid chemistry	Repeat surveys	Confined to wellbore				Direct measurement to within few wt% with existing downhole tools, u–tube samplers used on pilot tests provide increased accuracy		Established tools available and U–tube samplers demonstrated on onshore plots only
	Long–term downhole pH	Repeat surveys	Confined to wellbore					Schlumberger tool available to 0.1pH unit accuracy	Long–term, continuous measurements not yet developed
	Gas membrane downhole tool	Repeat surveys	Confined to wellbore				Possible		Experimental
	Seabottom controlled source EM	Repeat surveys			Volumetric			Indirect – no information on sensitivity available	Established in oil industry and currently being tested at Sleipner
	Surface gravimetry	Repeat surveys			Volumetric for reservoirs			05–1Mt may be detectable in favourable conditions, but typically 2Mt	Established and demonstrated

Appendix 5 Summary of technology gaps and developments

No.	GAPS	REMARKS	KEY FUTURE DEVELOPMENTS	STATE OF DEVELOPMENT	RELEVANCE FOR UK TYPE SITES
1	**MONITORING STRATEGY**				
1a	Lack of integration of different methods (joint interpretation, joint inversion): need for model based inversion	Little experience for CO2 cases yet	Especially in research projects focussed around demonstration projects smart combinations of joint data inversion/interpretation are being developed and tested. Three key areas are: combining geophysical methods (e.g. EM-seismic), combine logging tools especially for well integrity (e.g. EMIT and caliper logs) and combine shallow methods (e.g. bubble detection and sampling techniques)	Partially in development, mostly in the phase of application to real data	Most suitable for type 3 & 4 reservoirs, less for type 1 & 2 reservoirs with "tank" behaviour
1b	Lack of strategy for shallow monitoring systems (where, when, how much).	Observations from naturally-occurring leakage sites show that in general the localities of active CO2 venting are small in relation to the total area over which CO2 emissions are being produced, coming from only a few percent of the total area. Thus monitoring techniques need to be designed to detect small features (10 m or less across) and, given the scale necessary for commercial CO2 storage, to be able to provide coverage over large areas (hundreds of square	The main developments for such a strategy are threefold: Combine deep geophysical methods to identify shallow risk areas and then do shallow sampling, combine shallow techniques scanning the sea bottom and do more detailed sampling at anomalous areas and finally improve continuous monitoring equipment to be permanently deployed in risk areas to detect seepages or leakages at the sea bottom.	Experience needed with CO2 demonstration sites	All types

No.	GAPS	REMARKS	KEY FUTURE DEVELOPMENTS	STATE OF DEVELOPMENT	RELEVANCE FOR UK TYPE SITES
		kilometres).			
1c	Lack of early warning systems	Here a clear distinction between gas fields and aquifer storage needs to be made: In gas fields pressure monitoring is a powerful tool to detect early irregularities, especially in the North Sea fields with little water influx. For aquifers the currently adopted strategy relies essentially on seismic methods.	The main new developments for early warning systems are sought in repeated geophysical methods other than seismic (such as ERT, EM or gravity based methods) to pick up unexpected migration, either from the seabottom or from wells. Alternative strategy development is sought in the permanent installation of seismic sensors in identified risk areas, both downhole and from the seabottom, that can be used in active and passive mode.	Sensitivity studies and initial testing under field conditions.	Most suitable for type 3 & 4 reservoirs, less for type 1 & 2 reservoirs with "tank" behaviour
1d	Lack of a standardised approach for monitoring strategies, each monitoring plan is case specific.	The location of the wells and also of the monitoring equipment, including fluid samplers, within the wells, requires very careful consideration to ensure they are located appropriately. In addition, the sampling frequency is also an important consideration, requiring close co-ordination	Developments for such guidelines are essentially focussing on type reservoirs, similar to the approach adopted in this report for typical North Sea reservoirs.	Parallel developments in different parts of the world.	All types

No.	GAPS	REMARKS	KEY FUTURE DEVELOPMENTS	STATE OF DEVELOPMENT	RELEVANCE FOR UK TYPE SITES
		with predictive modelling to optimise information retrieval (e.g. detection of the migrating plume front)			
2	**MONITORING LARGE AREAS WITH NON-INVASIVE METHODS**				
2a	Monitoring pressure (far) away from the injection and monitoring wells	Current solutions: Model driven approach (large models required), use monitoring wells (expensive and local measurement) and finally seismic inversion methods (large uncertainty, little experience),	Current developments for the model driven approach are essentially sought in improving the models and the modelling tools. In case of monitoring wells the lifetime of sensors is the main issue for pressure measurements. Furthermore detection thresholds in case of leakage need to be determined. The last option using seismics to invert for pressures comes from the oil- and gas industry, where time-lapse seismic data has successfully been used to invert for reservoir pressures (e.g. Gulfaks field) and for stress development around HPHT-fields (e.g. Shearwater field). A suitable field to test this methodology is Weyburn, where both saturation and pressure effects play a large role. Again the added value of	With respect to model and sensor development, continuous improvements are developed. With respect to seismic methods, application to CO_2 storage sites is required in combination with lab- and model calibration.	Most suitable for type 3 & 4 reservoirs, less for type 1 & 2 reservoirs

No.	GAPS	REMARKS	KEY FUTURE DEVELOPMENTS	STATE OF DEVELOPMENT	RELEVANCE FOR UK TYPE SITES
			using permanent (sparse) multi-component seismic arrays needs to be corroborated.		
2b	Monitoring risks related to potential significant lateral migration. Although the Storage Directive requires the storage complex to be defined as the area influenced by the CO2 injection, it is not clear how this would be managed in a large aquifer with multiple injection by different operators.	This is a regulatory issue that requires consideration of the types of monitoring technologies needed. For example the use of plume tracking and tracers to identify migration in aquifers used by multiple injection sites.	Not much future development expected other than the development of guidelines and threshold values that need to be monitored. This is strongly related to monitoring strategy developments.	Application of existing technology to CO2 storage fields. Potential for innovative ideas not identified yet.	Most suitable for type 3 & 4 reservoirs, less to not for type 1 & 2 reservoirs
2c	In general, the key deep-focussed monitoring technologies are very mature and it is not clear that specific technical gaps can be identified. It is clear however that continued deployment and testing in CO2 storage situations is necessary (limited number of cases available) and will lead	This requires more testing of existing technologies at a range of offshore storage sites.	Key developments are in demonstrating the added value and the threshold values for detecting CO2 migration in and out of the reservoir using (passive) seismics, EM, ERT and gravity based methods by deploying them over demonstration sites.	Testing at demonstration sites.	Especially relevant for type 4 and to a less extent for type 3. For type 1 & 2 only in case of unexpected migration out of the storage reservoir.

No.	GAPS	REMARKS	KEY FUTURE DEVELOPMENTS	STATE OF DEVELOPMENT	RELEVANCE FOR UK TYPE SITES
	to evolutionary improvements.				
2d	Monitoring brine displacement	No real solution other than monitoring wells, sampling, tracers yet. EM or ERT might provide local solutions, in case brine replaces fresh water.	The key developments will most likely move towards investigating the sensitivity of EM or ERT methods to brine displacement and to the use of tracers in combination with monitoring wells. Though the gap has clearly been identified, no other clear developments have been identified. The issue is expected to be addressed in the next FP7-EU call.	Sensitivity analysis of electrical based methods, both in the lab, numerically and in the field.	Especially relevant for type 4, not for underpressured depleted hydrocarbon reservoirs of type 1 & 2. For type 3 it depends on the pressure regime..
2e	Monitoring migration of dissolved CO2 in an aquifer	EM or ERT methods have a clear potential here, but testing has been limited . The best example of the effect is from the post-abandonment resistivity logging at Nagaoka (Japan).	The potential for EM or ERT methods from the seabed has not been tested yet. Threshold values still need to be determined. The issue is expected to be addressed in research projects. Joint inversion of seismic and EM/ERT data can potentially discriminate between free and dissolved CO2, as demonstrated by Hoversten () in the CCP-1 project in a crosswell setting. Developments move towards more field testing and improved joint inversion algorithms.	Sensitivity analysis of electrical based methods, both in the lab, numerically and in the field.	Especially relevant for type 4, and to a less extent for type 3.

No.	GAPS	REMARKS	KEY FUTURE DEVELOPMENTS	STATE OF DEVELOPMENT	RELEVANCE FOR UK TYPE SITES
2f	Permanent systems for continuous or intermittent monitoring at depth.	Potential for permanent systems (e.g. OBC) leading to cheaper repeated surveys and higher quality repeatability (often at the cost of lower coverage) for example at risk (or key) areas.	Developments in permanent or continuous seismic monitoring are focussed on further development of active sources, deployment and testing in different settings, interpretation of the data. The issue is addressed in different research and onshore demonstration projects like Ketzin and Aquistore.	Continuous sensor development, deployment at oil fields limited, experiments on land for CO2 storage, requires testing over CO2 storage site in offshore environment.	Especially relevant for type 4 & 3 or monitoring of risk areas (e.g. faults) in type 1 & 2 reservoirs.
3	**MONITORING IN AND AROUND WELLS**				
3a	Monitoring of well integrity of inaccessible abandoned wells.	This is widely recognised as a risk rather than a technology gap. Current onshore experience is limited to indirect geophysical methods such as seismics and direct surface measurements (such as sniffers), additionally offshore methods rely on seabottom monitoring such as bubble detection and sampling	No clear developments have been identified other than preventive measures (workover of the well, pancake plug)	No new developments identified.	Especially relevant for depleted hydrocarbon reservoirs (type 1-3) or aquifers (type 4) penetrated by wells.
3b	Detection thresholds for well integrity of operating/accessible wells.	Discussion with Schlumberger & BP/CCP indicates that tools are adequate to meet this requirement.	Key developments are in further testing of the available tools and joint interpretation of the tools in different wells. Activities are foreseen in the CCP-2 project.	Deployment and testing at CO2 storage sites. Parallel experiments under controlled conditions.	All types
3c	What is the worst case scenario in case a well fails.	There remains an unresolved question regarding the size of leak, i.e. the flux rate that might be expected from a failed well.	The issues is addressed in risk assessment studies.	Refinement of calculations.	Especially relevant for depleted hydrocarbon reservoirs (type 1-3) or aquifers (type 4) penetrated by wells.

No.	GAPS	REMARKS	KEY FUTURE DEVELOPMENTS	STATE OF DEVELOPMENT	RELEVANCE FOR UK TYPE SITES
3d	What are the implications of using multiple production strings for multiple CO2 injection.	Multiple production strings could be used for multiple CO2 injection, or possibly a combination of injection and monitoring. The feasibility for this should be further investigated. This is an area that may require further development – particularly establishing well integrity prior to, during injection and on abandonment.	No key developments have been identified in this area.	No new developments identified.	All types
3e	Downhole fluid measurements (PH and dissolved CO2).	A current technological gap is the capability to continuously monitor in situ pH in boreholes accurately. Key challenges are reliable and stable pH sensors and accurate and stable calibration.	Development of new sensors by various contractors.	Development of such a sensor for industrial deployment is estimated at 5 years.	All types
3f	Downhole fluid sampling systems for offshore environment	Recently downhole fluid sampling systems have been developed to allow samples at in situ conditions to be brought to the surface for offline chemical analysis (.e.g. CO2 concentrations, tracer analyses, chemical analyses to monitor CO2-reservoir interactions). These require further development for the offshore environment. Can U-tubes be used offshore ? Can the system be automated ?	Key developments are in applying onshore developed techniques to the offshore environment.	Application to CO2 storage sites.	All types

No.	GAPS	REMARKS	KEY FUTURE DEVELOPMENTS	STATE OF DEVELOPMENT	RELEVANCE FOR UK TYPE SITES
3g	Lifetime of current downhole (geophysical) sensors	The lifetime of geophones is roughly limited to 10 years. The potential for downhole electromagnetic techniques to monitor changes in CO2 saturation has been provisionally demonstrated (see Chapter 4). Current limitations are the lack of permanent borehole EM equipment and expected current lifetimes of around 5 years. In addition, it can not be deployed in wells with steel casings so is likely not be deployed in the North Sea. Experience so far suggests downhole deployments (especially outside casing) of sensors are very vulnerable to damage or degradation	Development of new more robust sensors by various contractors including fibre-optic technology.	Continuous development and improvement.	All types
3h	Size and impact of sensors (particularly downhole) on the sealing properties of a storage complex creating additional risks of migration out of it.	Single-well operation with older VSP equipment would require regular lengthy suspensions of injection for deployment of a receiver string in the well and acquisition of data. Seismic 'acquisition while producing' receivers are available for oil and gas wells, but current versions may not be suitable for use in CO2 injection wells due to the corrosive effects of CO2. Other potential is in developing cheaper, automated monitoring	Key developments are in the development of the sensors (mainly contractors) and in the deployment and testing in demonstration projects. Miniature geophone and fibre optic sensors now becoming available could be permanently installed in the casing annulus of an injection well permitting single-well operation with minimal interruption to injection – ideal for time-lapse surveys	Continuous development and improvement.	All types

No.	GAPS	REMARKS	KEY FUTURE DEVELOPMENTS	STATE OF DEVELOPMENT	RELEVANCE FOR UK TYPE SITES
		systems that allow direct monitoring of reservoir processes such as geochemical interactions.			
4	**ETS or SHALLOW MONITORING**				
4a	Quantifying rates of leakage to the seabed.	Our review to date indicates technologies for assessing and quantifying leakage require greater development. Only a limited experience at natural analogue sites is available.	To our knowledge the issues will be addressed partially in EU-FP7 projects like RISC and ECO2. Testing and deployment in the North Sea environment is required.	Start measurements at the seabed.	All types
4b	Detection thresholds for all monitoring methodologies.	Methods have been used sporadically, but only in a qualitative manner, not quantitative. For example, detection limits for bubble density have yet to be established and there are very few case studies in the use of the technique for CO2, although a simple fish finder was successfully used to detect CO2 bubbles in the Laacher See in southern Germany. Most case studies relate to releases of methane or water.	Key areas of development are in testing the different methodologies.	Testing under North Sea conditions.	All types

No.	GAPS	REMARKS	KEY FUTURE DEVELOPMENTS	STATE OF DEVELOPMENT	RELEVANCE FOR UK TYPE SITES
4c	Lack of commercially robust instruments to measure seabed CO2 concentrations and fluxes	In situ (seabed) measurement of CO2 concentration: Instrumentation under development, but not tested in North Sea environments; Data storage and transmission issues remain to be solved. There are a few commercial and research instruments capable of measuring CO2 concentrations and fluxes in sea water, which are currently being developed by research organisations.	Key areas of development are: fast-response pH, pCO2, and DIC sensors, which could be mounted on a wide range of platforms, and coupling of fast response sensors with instruments able to evaluate fluid dynamics at the micro-structural level, as is already done at the land-atmosphere interface using eddy covariance systems, would also be a major advance	Testing under North Sea conditions.	All types
4d	Lack of natural background flux and concentration measurements of CO2 in the water column.	These type of measurements have so far essentially been performed in areas with abnormal emissions such as volcanic areas to test the methodology.	To our knowledge the issues will be addressed partially in EU-FP7 projects like RISC and ECO2. Testing and deployment in the North Sea environment is required.	Start measurements at the seabed.	All types
4e	Identification of type of gas and gas concentrations using shallow acoustic techniques.	Shallow acoustic techniques, such as boomer, sparker or pinger, can detect surface features (e.g. pockmarks) along 2-D lines and may identify subsurface zones with gas that cause acoustic blanking. However, this effect can be caused by gas concentrations as low as 2% and currently these indirect methods cannot identify what gas is causing the effect.	To our knowledge the issues will be addressed partially in EU-FP7 projects like RISC and ECO2. Testing and deployment in the North Sea environment is required.	Development of interpretation/inversion algorithms based on test data to quantitatively interpret bubble streams.	All types

No.	GAPS	REMARKS	KEY FUTURE DEVELOPMENTS	STATE OF DEVELOPMENT	RELEVANCE FOR UK TYPE SITES
4f	How to detect gas emissions not associated with changes in sea floor morphology.	A limitation on the detection of gas emissions through seabed features is that not all gas escapes are associated with changes in sea floor morphology.	This topic is closely related to monitoring strategy developments.	No clear development expected.	All types
5	**MONITORING INJECTION AT THE WELL HEAD**				
5a	Uncertainty on the determination of mass of CO2 injected	Currently injection is pressure & temperature controlled, in combination with sampling from the flow line for composition. Conversion of the mass of CO2 injected is based on thermodynamics. Can fluctuations be properly accounted for? What about impurities?	This uncertainty has not got much attention so far. Some research initiatives are ongoing.	Testing under laboratory conditions to improve calibration.	All types
6	**ENVIRONMENTAL IMPACT ASSESSMENT**				
6a	Uncertainty on the environmental impact of CO2 leakage at the seabottom	An EIA will be obligatory for large scale CO2 storage. Currently little is known about the impact of CO2 leakage on the ecosystem.	This uncertainty has not got much attention so far. The research project ECO2 will deal with this issue. Furthermore the development of the Benthic Chamber Lander allows to do in-situ experiments.	Deployment under North Sea conditions.	All types

Colour in first column reflects perceived priority of gaps: high (red), medium (orange) and low (green)

Appendix 6 Novel technologies or technologies that are developed in other industries that have been identified as having potential application in CO_2 storage monitoring applications.

Short timescales are 1-2 years, intermediate timescales 3-5 years and long timescales more than 5 years

Monitoring objective	Technology	Areas for development	Value/impact	Storage type applicability	Time for development	Time for testing	Costs for development	Costs for deployment
					Short Intermediate Long	Short Intermediate Long	Low Medium High	Low Medium High
Shallow leakage detection	CO_2 bubble-stream detection	Ship-based sonar and integration with multibeam echo sounding	Significant – leading to established leakage detection technology	All	Short - Technologies already developed	Short	Low but requires a CO_2 bubble source	Low when combined with other ship-based surveys
		Detection limits for bubbles, in terms of size, density and gas composition	Major – leading to established leakage detection technology	All	Intermediate	Intermediate	Medium	n/a
		Microphonics	Minor – close range bubble detection – potential for monitoring wellheads	All	Intermediate – prototypes already used for CH_4 leak detection in pipelines	Short	Low	Low
Ecosystem impact assessment	Benthic chamber lander for EIA	Short- to long-term in situ benthic studies, quantify biological properties	Significant – leading to a thorough basis for EIA	All	Intermediate – Improvements expected on the current prototype	Short – First deployment already scheduled	Low	Low when combined with other ship-based surveys

Monitoring objective	Technology	Areas for development	Value/impact	Storage type applicability	Time for development	Time for testing	Costs for development	Costs for deployment
					Short Intermediate Long	**Short Intermediate Long**	**Low Medium High**	**Low Medium High**
	Biomarkers	Macro- or microbiological biomarker responses to CO_2 leaks	Significant – leading to a monitoring of leakage impacts and subsequent remediation	All	Intermediate – technology developed by some operators	Intermediate	Intermediate	Intermediate – requires ROV and sophisticated laboratory analysis
Emissions quantification	Quantify bubble streams	Acoustic characteristics to discriminate CO_2 from CH_4.	Major – leading to established leakage detection quantification (if gases can be discriminated)	All	Intermediate	Short	but requires a CO_2 bubble source	Low when combined with other ship-based surveys
		Direct remote quantification via acoustic methods	Major – leading to established leakage detection quantification at potentially reduced cost (if gases can be discriminated)	All	Intermediate	Intermediate	High??	Low when combined with other ship-based surveys
		Continuous seabed/seawater monitoring	Significant – leading to established leakage detection technology for leakage pathways such as abandoned and operational wells.	All	Intermediate	Intermediate	Low but requires a CO_2 bubble source	Low
		Marine eddy covariance technology needing fast CO_2 sensors	Major – leading to established leakage detection and measurement technology – essential for ETS MRG	All	Intermediate	Intermediate	Medium	Low
		Direct seabed flux measurement	Significant – leading to established leakage measurement technology – essential for ETS MRG	All	Intermediate	Intermediate	Medium	Low

Monitoring objective	Technology	Areas for development	Value/impact	Storage type applicability	Time for development	Time for testing	Costs for development	Costs for deployment
					Short Intermediate Long	**Short Intermediate Long**	**Low Medium High**	**Low Medium High**
		Development of stable, robust, cheap and accurate pH sensors for continuous seawater pH monitoring	Significant – leading to demonstration of site performance and containment	All	Short – some sensors are already being developed??	Intermediate to long (long-term robustness a key R&D objective)	Low	Medium for installation but low once installed
Long-term site stabilisation & long-term model calibration	Downhole pH	Development of stable, robust, cheap and accurate pH sensors for continuous pH monitoring	Significant – leading to demonstration of site performance and containment	All	Short – some sensors are already being developed??	Intermediate to long (long-term robustness a key R&D objective)	High – need access to a well	Medium for installation but low once installed. High if new well needed
	Downhole fluid sampling	Offshore deployment	Significant – leading to demonstration of site performance and containment	All	Short – already developed for onshore applications	Short	High – need access to a well	Medium-High for installation and medium once installed
Plume monitoring	Continuous monitoring for CO_2 plume or tracer breakthrough	Downhole sensors for CO_2 and tracer monitoring	Significant – leading to demonstration of site performance and containment	All – especially Type 1 where plume imaging is more difficult	Short – some sensors are already being developed	Intermediate to long (long-term robustness a key R&D objective)	High – need access to a well	Medium-High for installation but low once installed
	Cross-hole EM for plume detection	Integration with other techniques (e.g. seismic, gravimetry and ERT)	limited potential as need two observation wells	All – especially Type 1 where plume imaging is more difficult	Intermediate??	Intermediate	High – need access to a well.	Medium-High for installation and medium once installed

Monitoring objective	Technology	Areas for development	Value/impact	Storage type applicability	Time for development	Time for testing	Costs for development	Costs for deployment
					Short Intermediate Long	**Short Intermediate Long**	**Low Medium High**	**Low Medium High**
	Cross-hole ERT	Demonstration offshore	limited potential as need two observation wells	All – especially Type 1 where plume imaging is more difficult	Intermediate??	Intermediate	High – need access to a well	Medium-High for installation and medium once installed
	VSP	Ultra-high resolution travel-time applications	Application and demonstration in offshore storage	Types 2, 3 and 4 – especially 2 and 4 where new injection wells could be drilled at base of storage aquifer.	Short – technology already developed	Intermediate	High – need access to a well	High for installation and high once installed
	Permanent OBC	Demonstration for CO2 storage	Potential to improve resolution due to higher repeatability	Type 2, 3, and 4. Imaging of type 1 reservoirs is considered too difficult.	Short – technology already developed	Long – requires an offshore (large scale) storage	Low – essentially driven by large contractors	High
	Borehole gravimetry	Test borehole gravimetry in CO_2 storage applications	Potential to improve plume detection and monitoring, especially integrated with other techniques	All	Intermediate	Intermediate	Intermediate	High
In-borehole leakage detection	Noise Log	Direct measurement of CO_2 leakage in abandoned wellheads	Major – leading to established leakage detection	All	Intermediate	Intermediate	High – need access to a well & CO_2 bubble source	Medium for installation and medium once installed

Monitoring objective	Technology	Areas for development	Value/impact	Storage type applicability	Time for development	Time for testing	Costs for development	Costs for deployment
					Short Intermediate Long	**Short Intermediate Long**	**Low Medium High**	**Low Medium High**
	Electrochemical logs	Direct detection of borehole corrosion	Significant - leading to established leakage detection	All	Long – currently conceptual stage	Long – laboratory and then field testing needed	High – need access to a well & CO_2 bubble source	Medium