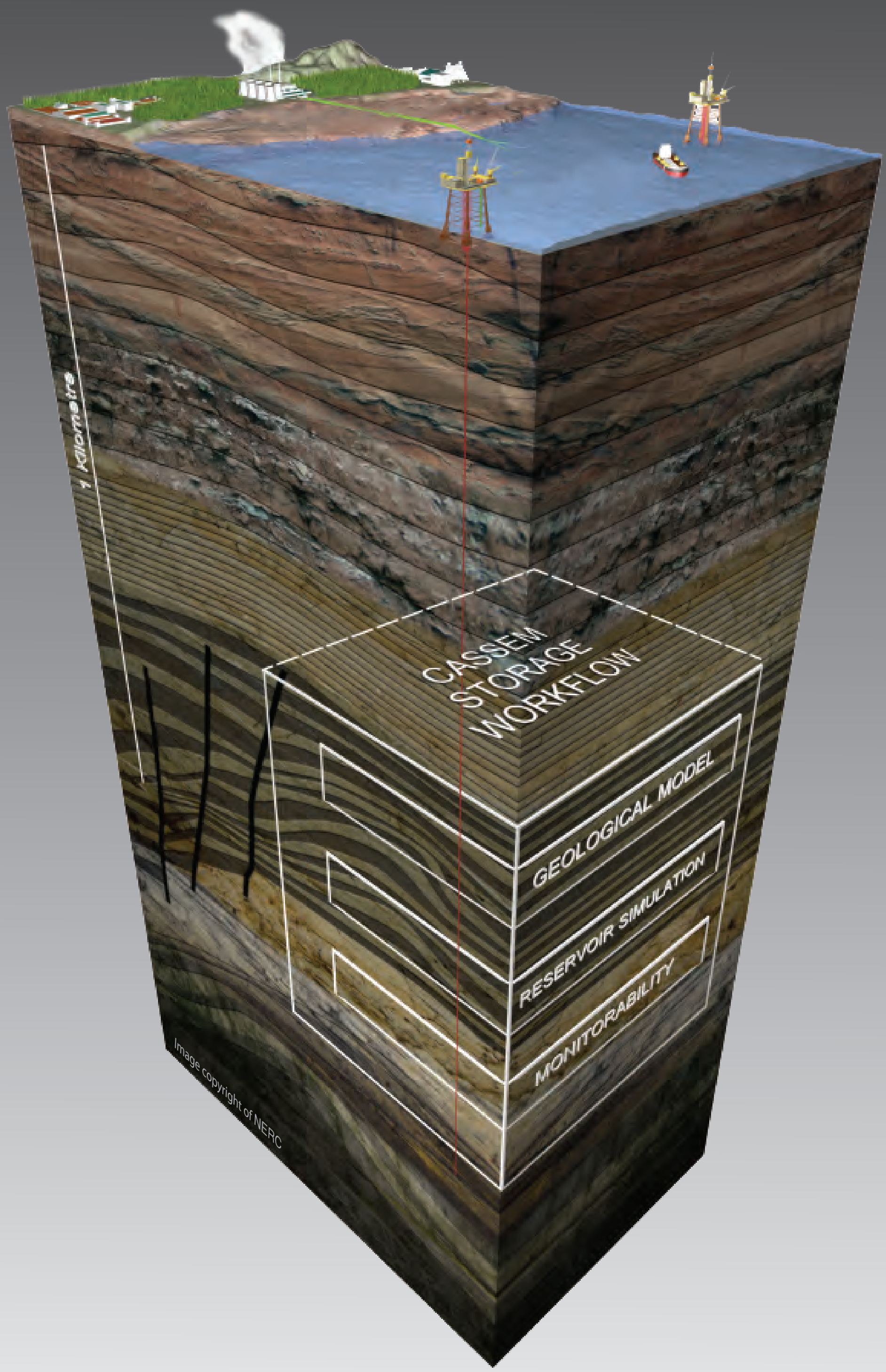
CO_2 AQUIFER STORAGE SITE EVALUATION AND MONITORING

Understanding the challenges of CO_2 storage: results of the CASSEM Project



Edited and compiled by Martin Smith, David Campbell, Eric Mackay and Debbie Polson

CO_2 *Aquifer storage site evaluation and monitoring*

*EDITED AND COMPILED BY**
MARTIN SMITH, DAVID CAMPBELL, ERIC MACKAY AND DEBBIE POLSON

** FOR A LIST OF PROJECT PARTNERS AND CONTRIBUTORS SEE OVER*

KEYWORDS: CO_2 SEQUESTRATION, STORAGE WORKFLOW, METHODOLOGIES, RISK, ECONOMICS, PUBLIC PERCEPTION

FRONT COVER: 3D GRAPHIC OF OFFSHORE CO_2 INJECTION

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Scottish Carbon Capture &Storage

PROJECT PARTNERS

AMEC plc is an international project management and services company that designs, delivers and supports infrastructure assets for customers across the public and private sectors. AMEC's headquarters is in the UK and employs more than 20,000 people. The section involved in CASSEM focuses mainly on the market sectors of electricity transmission, gas transmission, storage and distribution and process industries.

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The British Geological Survey (BGS), founded in 1835, is the world's oldest established national geological survey and the United Kingdom's national centre for earth science information and expertise. It is responsible for advising the UK government on all aspects of geoscience as well as providing impartial geological advice to industry, academia and the public. The BGS is a component part of the Natural Environment Research Council (NERC), which is the UK's leading body for basic, strategic and applied research in the environmental sciences. BGS is one of the main bases for SCCS.

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The University of Edinburgh is the premier research University in Scotland, and one of the top five in the UK. The science and engineering grouping is ranked as amongst the top 5 in Europe. The School of GeoSciences contains international quality research expertise ranging from the outer atmosphere, through the earth surface and oceans, geography, ecology, and geology and geophysics. UoE is one of the main bases for SCCS.

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Schlumberger is the world's leading oil and gas service and supply company: it helps oil and gas producers optimize their exploration and production performance. Schlumberger is addressing climate changes issues, recognizing CO_2 capture & storage (CCS) as a serious mitigation option where the company can significantly contribute by adapting existing technologies and developing new ones.

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Scottish and Southern Energy (SSE) is one of the largest energy companies in the UK. It is involved in the transmission, distribution, generation and supply of electricity; the storage, distribution and supply of gas; energy trading; electrical and utility contracting; energy services; and telecoms. SSE's portfolio of power stations is the second largest, and most diverse, in GB. It is also the leading generator of electricity from renewable sources in GB.

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FOREWORD

A large proportion of the UK's electricity generation will continue to be derived from fossil fuels for many years to come. It is needed to ensure the lights stay on and to provide critical dispatchable generation capacity to balance baseload nuclear and renewable generation. Carbon Capture and Storage (CCS) has the potential to significantly reduce CO_2 emissions from fossil fuel power stations and therefore is now an essential element of the UK energy and climate change strategy.

CCS will, however, require the co-ordination and connection of a number of new and complicated processes seen in utilities. Building carbon capture equipment at our power stations remains a challenge, but one that is similar to projects we have tackled in the past. By contrast, sub-surface exploration and reservoir engineering are new skills to most utilities and we do not have the same level of confidence. Whilst the oil and gas industry is used to these risks the economic challenges of CCS are different with expectations of utility level returns. Developing low cost ways to increase confidence will help us accelerate the development of CCS in the power sector.

While the first few CCS projects in the UK (and even Europe) seem likely to use depleted hydrocarbon fields as storage sites, aquifer storage will be important in the longer term and developing this option seems essential.

The CO_2 Aquifer Storage Site Evaluation and Monitoring (CASSEM) project research has focused on developing and understanding the best-value methods by which saline aquifers beneath the seas adjacent to the UK could be evaluated, with the intent to develop a low risk CCS "entry path" for potential new entrants including power utilities, engineering services companies and government.

The CASSEM project has produced both new scientific knowledge and brought wider insights to the CCS industry.

Firstly, it brought utilities like SSE and ScottishPower together with a sub-surface "asset-team" – demonstrating the effectiveness of a multi-disciplinary team of engineers and scientists working together, pooling their expertise in order to evaluate a particular storage target in detail.

Secondly, the methodical use of "FEPs" (Features, Events and Processes) to track experts' evolving perception of risk throughout the project is likely to be helpful in identifying where to invest resource to best reduce risk.

Thirdly, the open source full chain costing model that is both flexible and accessible to all should help industry, academia and government come to a common understanding on the true cost of CCS.

Finally, it is one of the first times that citizen panels have been used to assess public perception of CCS the UK. The public remain a powerful force in UK energy policy and we need to recognise and respect their views on CCS.

The UK needs a secure, affordable and decarbonised power system – this project ensures that CCS remains central to delivering that objective.

Ian Marchant, CEO Scottish and Southern Energy
May 2011.

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Schlumberger are thanked for use of Petrel and ECLIPSE software in this work, including use of ECLIPSE 300 with the CO_2STORE module.

CONTENTS

CHAPTER 1
FROM 'SURFACE TO STORE' – AN OVERVIEW OF THE CASSEM PROJECT

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1.1 INTRODUCTION

Carbon capture and storage (CCS) brings new entrants to subsurface exploration and reservoir engineering who require very high levels of confidence in the technology, in the geological analysis and in understanding the risks before committing large sums of capital to high-cost drilling operations.

Many of the subsurface techniques used for hydrocarbon exploration are capable of translation to CCS activities. Unfamiliarity may, however, lead new entrants to openly question their applicability in order to transform their current understanding to a level where large capital investment can be organisationally justified. For example, some may make the erroneous assumption that a good CO_2 subsurface store should resemble the pressure vessel type of containment that is prevalent with surface installations. Basic concepts such as utilising the rock structure and mineralogy to control fluid flow and securing the CO_2 by residual trapping (between the rock grains) or by dissolution, as a superior storage mechanism, are counter intuitive and challenging to communicate effectively.

To achieve success and reliable operation in CO_2 emission reduction for coal- and gas-burning electricity power generation, all elements of the CCS chain have to function. In 2008 the CO2 Aquifer Storage Site Evaluation and Monitoring project (CASSEM) was one of the first UK based projects to attempt integration and full-chain connectivity from, capture and transport to injection, storage and monitoring. Its research is aimed at development of workflows that describe a CCS entry path for a target audience of potential new entrants, i.e. power utilities, engineering sector and government.

In contrast to other studies, the CASSEM project has applied the specification of the full CCS chain, using two exemplar sites (coal-fired power plants) with contrasting geological conditions in the subsurface, to tailor storage site selection and analysis.

Centred on the Ferrybridge Power Station in Yorkshire (Figure 1.1), a ‘simple’ site underlain by a thick, uniform sandstone with diverse legacy information available was sought onshore in the English Midlands. The offshore extension of this (Bunter) sandstone has been highlighted as a large potential aquifer store for CO_2 captured from power plants in eastern and South East England.

A ‘complex’ site was sought offshore of eastern Scotland, centred on the Longannet Power Station on the Firth of Forth near Edinburgh (Figure 1.2). This site was intended to confront the difficulties of investigating subsea structures with sparse legacy and incomplete information from hydrocarbon investigations. The selected site is a faulted and folded geological structure and the issues of seismic reflection surveys, detection of faults and fractures, and quality of the target reservoir, are similar to those which challenge offshore hydrocarbon exploration beneath the North Sea.

To complement the published research that arose from the CASSEM project (see bibliography of outputs) this book presents an overview of the results as multi-authored papers.

Figure 1.1 Ferrybridge Power Station, Yorkshire ©webbaviation

Figure 1.2 Image courtesy of Scottish Power. Longannet coal fired power plant, Firth of Forth

1.2 BACKGROUND

Global perspectives

CCS requires the modification, upscaling and operationalisation of several existing technologies. The challenge for industries and government is to link these in a business which is credible, reliable, safe, trustworthy, profitable and can competitively attract commercial investment. CCS has emerged from a 1990s concept to become, in 2011, a rapidly growing suite of desk studies, pilot investigations and global test sites and plants.

There are numerous CCS-related activities around the world (see http://www.geos.ed.ac.uk/ccsmap), but to date, there are still only four commercial CCS projects operating globally (Figure 1.3). The first capture of CO_2 for storage was at the Sleipner field, offshore of Norway, which utilises amines to separate natural 9% CO_2 from condensate oil. Two drivers for this project were the $50 per tonne tax on offshore emissions and the required quality of saleable hydrocarbon. Since October 1996, Statoil has been injecting 1 Mt CO_2/year into the Utsira saline aquifer (Statoil, 2010). This project has proved that it is possible to inject CO_2 into a high-porosity deep reservoir.

Capture at industrial scale has been operated since 15 September 2000 by the Dakota Gasification Company at the Great Plains Synfuels Plant near Beulah, North Dakota. In 2010, about 3 Mt CO_2 per year is captured using methanol and transported 325 km by pipeline for use in enhanced oil recovery by miscible flooding in the Weyburn and Midale fields in Saskatchewan (Dakota Gas, 2010). This project has proved that it is possible to transport and inject compressed CO_2 in a 24/7 operation linked to a commercial chemical plant.

In July 2004 the In Salah onshore gas field in Algeria began to capture 5.5% CO_2 from natural gas, to achieve saleable pipeline quality. Like Sleipner, this field uses activated methyldiethanolamine capture, but differs in that injection is into the same reservoir from which the gas is extracted. In 2010, about 1.2 Mt CO_2/year was being emplaced through three horizontal boreholes, and this has become the most closely monitored and scientifically investigated CO_2 storage in the world (In Salah, 2010). This project has proved that it is possible to inject into a poor-quality storage reservoir and has developed monitoring techniques for onshore applications.

In April 2008 the Snøhvit field, producing liquefied natural gas offshore of Barents Norway, began injecting 700,000 Mt CO_2/year. This 5–8% CO_2 is separated from the hydrocarbons by processing onshore and returned by a dedicated 7-inch pipe to be reinjected into the Tubåen saline aquifer via a remotely operated seabed installation. The saline aquifer lies 2,500 m beneath the seabed and beneath the reservoirs at Snøhvit containing commercial gas (Statoil, 2010).

Finally, since 2007 the US Department of Energy has funded about 12 small-scale pilot injection projects (US DoE, 2010), and the results of about 20 significant injection tests have become available (SCCS, 2010-03).

In summary, three of the major commercial projects and numerous test sites currently exploit saline aquifers for CO_2 storage and demonstrate the importance of being able to identify, understand, develop and predict how these stores will perform.

UK perspectives

The CASSEM project was conceived in December 2005 at a time when several events had combined to bring CCS closer to reality. These events included the seminal 'wedges' publication of global

CO_2 reduction, prominently featuring CCS, by the Carbon Mitigation Initiative at Princeton (Pacala and Socolow, 2004); the 2005 proposition by BP and Scottish and Southern Energy to develop CO_2 capture at the Peterhead power plant in North East Scotland and link that to storage in a depleted North Sea oilfield; the G8 Article 14 statement on CCS at the 2005 Gleneagles meeting: 'We will work to accelerate the development and commercialisation of Carbon Capture and Storage technology.' (G8 Gleneagles, 2005) and the 2005 UK House of Commons Science and Technology Committee investigation of CCS (House of Commons, 2006).

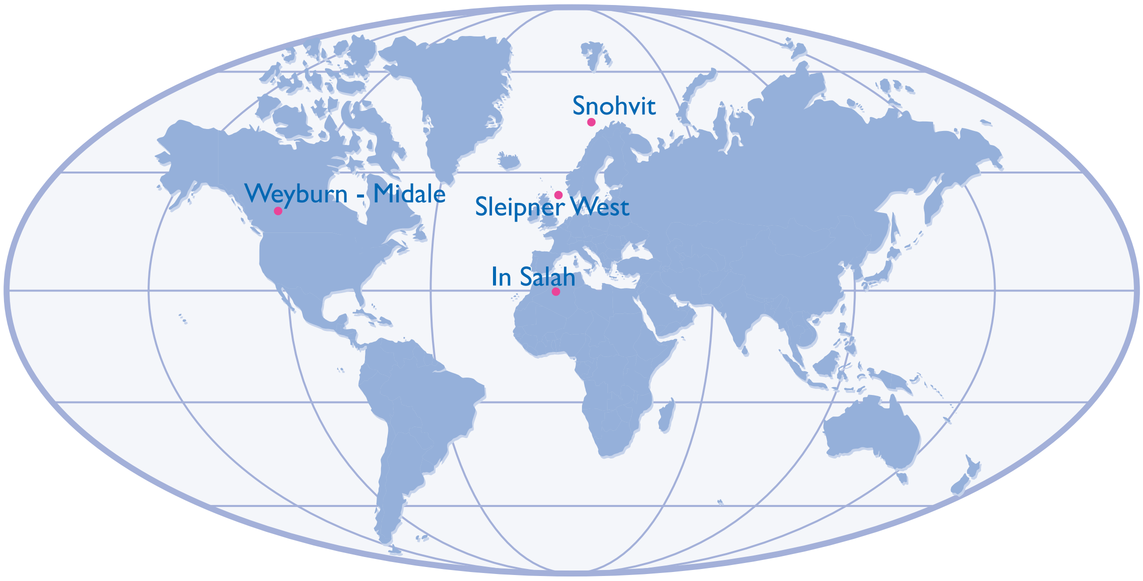

Figure 1.3 Map showing location of key commercial projects for CO_2 transport and storage. Map after www.geos.ed.ac.uk/ccsmap

In 2005 the UK government Department of Trade and Industry (DTI) produced the first formal Carbon Abatement Technology (CAT) strategy (DTI, 2005). It clearly stated that CCS would be vital to any decarbonisation of fossil-fuelled electricity generation in the UK.

By early 2006 these concepts crystallised and gained momentum in response to a funding call from the UK Department of Trade and Industry Technology Programme, as part of Low Carbon Technologies. At this time, working on the storage of CO_2 was uncommon. As a result, the process of garnering interest and financial support from business and industry (a requirement of many funding streams) was very challenging. Most large commercial companies were unconvinced that CCS would be necessary, or would even become mandatory. In 2006 the UK government published its Energy Review, which identified a clear role for CCS and was followed by the Energy White Paper in 2007. In 2007 the UK government also launched its competition for full-chain CCS demonstration.

These activities have incentivised the post-2008 landscape for UK CCS research funding. New opportunities were released by the Technology Strategy Board (TSB), the Research Councils Energy Programme (RCUK, 2010) and by the creation of the Energy Technologies Institute (ETI) and the Environmental Transformation Fund (ETF).

UK work on regulation and licensing has also proceeded apace. The UK government has made compulsory a 'capture-ready' specification for all new gas-fired and coal-fired power plant. This has been further augmented by a compulsory operation of CCS on at least 300 MW of any new coal-fired power plant. A funding mechanism, the UK electricity levy, was introduced in 2010 to enable the number of CCS demonstration plants to be increased from one in 2014 to a minimum of four within an undefined period around 2016. In 2011 this levy was cancelled and will being replaced by a premium price tariff for decarbonised electricity. There is active discussion of introducing an emissions performance standard, on new coal plant and on new gas plant.

The Committee on Climate Change has recommended a significantly more stringent CO_2 reduction target of at least 80% less than 1990 emissions by 2030. As part of this, the UK has an explicit vision that the electricity supply will be decarbonised to about 10% of its current emissions by 2030 (an average 500 g CO_2/kWh to less than 100 g CO_2/kWh; with coal plant reducing from 800 g CO_2/kWh to around 50 g CO_2/kWh). This will require CCS to work effectively. The economic climate has, however, become more challenging. Construction of a large coal power plant is a major undertaking for any utility; with the addition of CCS adding significantly to the capital cost. Government assistance is needed in a closely competitive 'free-market' economy like the UK.

In summary, CASSEM was conceived in a period when CCS was a 'proposition for visionaries'. It has now developed into a mainstream government and industry policy; if a CCS researcher had been incommunicado during the lifetime of the project, they would return now to an unrecognisable world of CCS policy and funding.

1.3 THE CASSEM PROJECT

Capture is essentially a process engineering activity where the effectiveness of the CO_2 removal from the flue gases is predictable in relation to proven capture technology and the sizes and operating conditions of the ancillary plant involved. Similarly, a pipeline transport solution is predictable in relation to the application of known engineering methods.

By contrast, the storage element, of injecting and storing CO_2 into subsurface water or oil-bearing structures, is fundamentally much less certain in the prediction of behaviour. It requires integration and understanding of the geological framework with the multiphase flow behaviour in the pore space of the reservoir rock over a large area (typically tens of km^2). Unlike a pipeline, to simply calculate capacity and flow determination in this pore space is a major technical challenge. Multiple natural processes are in operation, some poorly understood and quantified. Timescales of prediction are not minutes and hours, as familiar to power plant engineers, but tens of thousands of years into the future.

CASSEM is a predominantly desk-based study and design, involving laboratory modelling, experimentation and a social-science field study.

Over three years the CASSEM project has adopted a 'learning-by-doing approach' and evolved to derive a series of activity workflows and insights into the methods and techniques that will reduce uncertainty in the early stage (pre-drilling) characterisation of a CO_2 store in a saline aquifer (Figure 1.4). The project has not aimed to determine the eligibility of either site for a storage licence or permit.

The scope of the project includes five key elements (Figure 1.5):

- **Surface facilities:** focuses on handling and transport. These activities, researched mainly by the industrial partners, are described in Chapter 2.
- **The CO_2 store:** which provides an outline methodology for solving CO_2 storage via a series of process-orientated workflows covering geological modelling, reservoir simulation, monitoring and the assessment of uncertainty and risk. These activities, covered by the academic and research partners, are described in chapters 3, 4 and 5 and 7 and summarised in Figure 1.5.

- **Risk and uncertainty:** a basic understanding of uncertainty analysis and risk, covered by the academic partners, is presented in Chapter 6.

Injection strategies as an example of risk mitigation are described in Chapter 7.

The economics of CO_2: a transparent and accessible whole-chain analysis tool, developed by the industry partners, is presented in Chapter 8

Public perception: this comprises an early test and review of the public understanding of CCS in the regions of the exemplar sites. The work was completed by the Tyndall Centre, University of Manchester, and is presented in Chapter 9.

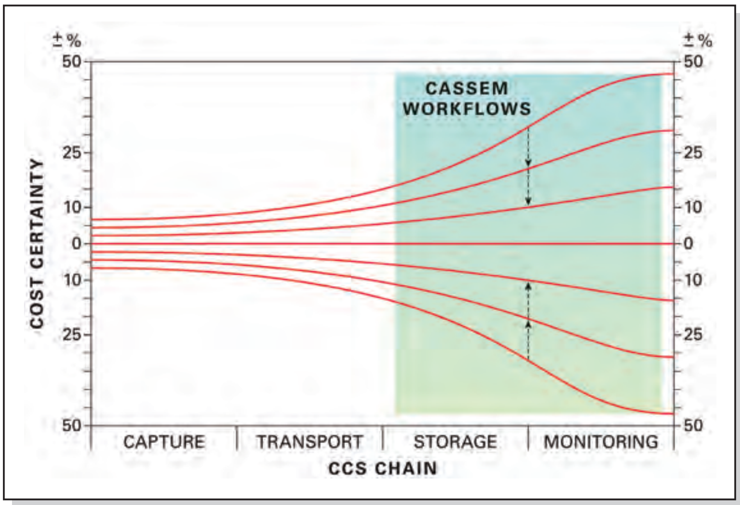

Figure 1.4 Graph of CCS chain versus cost certainty. Shaded area highlights main CASSEM project activities aimed at reducing uncertainty

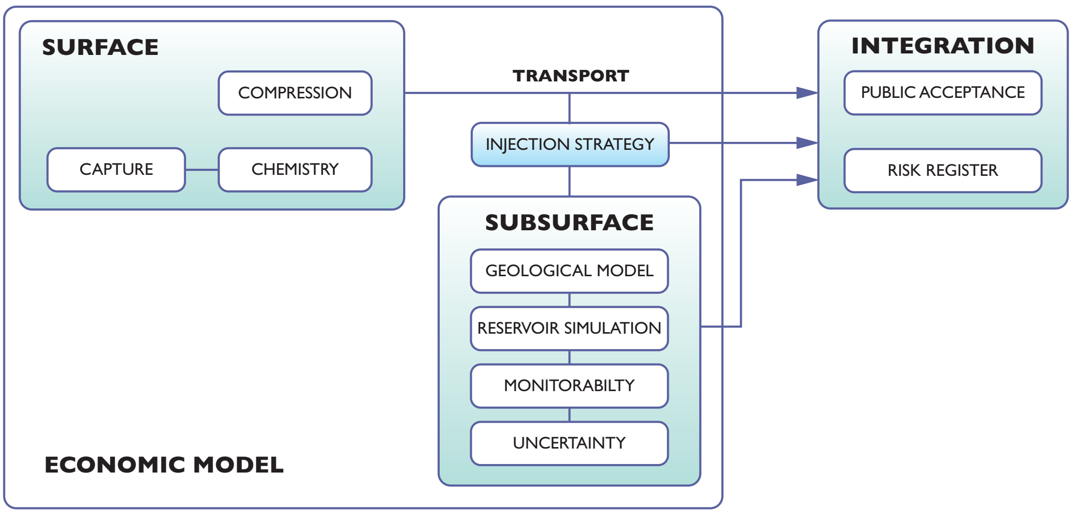

Figure 1.5 The CASSEM view of the CCS chain and connections between surface and subsurface.

1.4 SURFACE: FACILITIES AND TRANSPORT

Aspects of surface handling and transportation in a CCS scheme are considered in Chapter 2. The main industrial partners to the project (Scottish Power and Scottish and Southern Energy) provided summary data and know-how for the two exemplar sites used in the CASSEM project.

In terms of implementation, it is assumed that the source of the CO_2 feeding into the project will be a high-efficiency coal-fired power plant with a unit size of 800 MW. The capture plant would be post-combustion, using solvents (amines) to chemically absorb the CO_2 from the flue gas.

A 75 km radius limit was placed on a store site, which meant that predominantly onshore pipelines would be investigated as the transport option. This work, completed by AMEC, essentially tested the UK regulations and design practices, as applied to CO_2 pipelines, by examining the options and executing a high-level routing study. The exercise clearly demonstrated that both sites had various route options and that transportation by pipeline was achievable within current guidance and regulations.

1.5 TARGETING UNCERTAINTY: STORAGE AND MONITORABILITY

One of the key challenges in a CCS scheme is to address the inherent uncertainty surrounding the geological store. Data on the storage formation will always be comparatively sparse compared to the capture and transport components, thus making it the largest source of uncertainty in any CCS project. This is increasingly recognised as a major challenge to the regulatory process. The CASSEM project has therefore sought to target the reduction of uncertainty in the characterisation of a subsurface store. Our approach allows early application of low-cost methods to assess basic storage site requirements so that deficient candidate stores are rejected with minimum effort. Tracking the magnitude of key uncertainties throughout the CCS chain ensures that they lie within acceptable bounds when investment decisions have to be made.

Based on experiences gained during the project, we have developed a series of linked workflows that address the application of geological and petrophysical data to the modelling, interpretation and prediction of CO_2 behaviour when injected into a saline aquifer (Figure 1.6).

In Chapters 3 and 4 these workflows are described and illustrated with worked examples from the exemplar sites. The workflows, essentially iterative cycles of data assessment, encompass a range of activities, including site selection, geology and geomechanics of the aquifer formation and cap rock, followed by geochemistry and flow simulations of CO_2 under various injection scenarios, and then some consideration of geophysical techniques for monitorability (Chapter 5).

In both the geological modelling and reservoir simulation activities, model development is characterised by increasing levels of complexity, data analysis and cost. These levels are separated by gates at which an evaluation can be performed to make an informed decision on whether to invest further in data collection and refinement, forward data and results to other activities, or place the developing model on hold, in order to progress other models or sites being investigated in parallel.

Monitoring the physical properties of CO_2 in a subsurface store is another of the key challenges facing the nascent CO_2 storage industry. Monitoring is dependent upon the specific characteristics of the geology and the phase conditions of the injected CO_2; both will vary from site to site. The geophysical work undertaken within the CASSEM project is currently ongoing. For this publication we present preliminary findings (Chapter 5) which address our understanding of 'monitorability' and test the application of different geophysical techniques to the CASSEM sites.

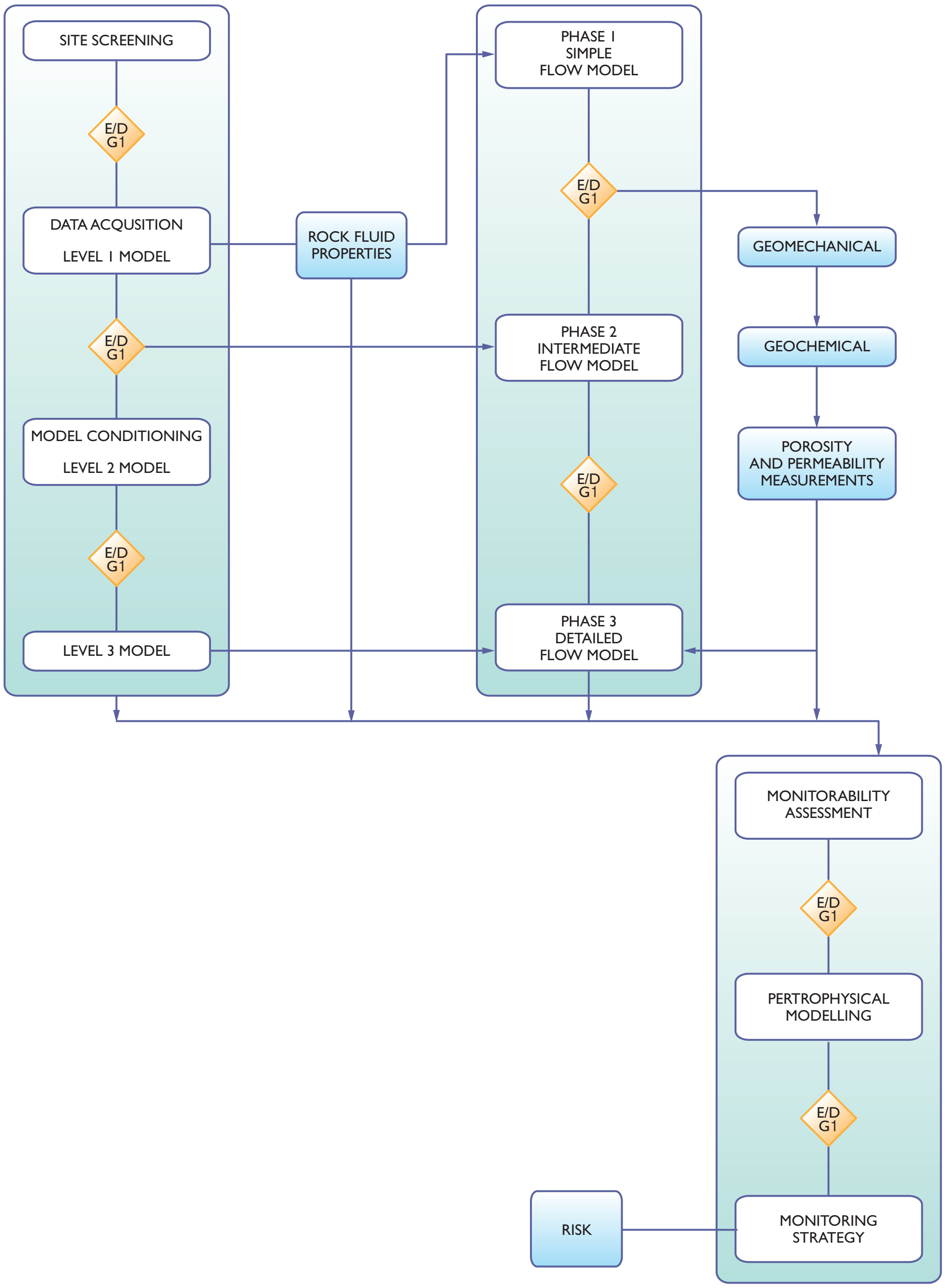

Figure 1.6 Simplified workflow model derived from the CASSEM project. Orange coloured diamonds represent evaluation-decision gates (E/D G1)

The inherent heterogeneity of the subsurface makes it impossible to know with 100% certainty whether a site will meet all the requirements for storage until long after injection of CO_2 has started. Thus, in Chapter 6, we focus our uncertainty analysis on the storage activity. The aim here is to investigate how we categorise a site as a good candidate site, in terms of capacity, security, injectivity and monitorability, within acceptable uncertainty bounds. Any measurement and modelling activity should be valued in the context of whether it will further reduce uncertainty on one of these key areas to the stage where a decision to accept or reject the site can be made. Combining these terms also highlights the tensions between the effects of different processes. For example, the dissolution of CO_2 in water is desirable from a security and capacity point of view, but will make it harder to monitor.

The criteria for site selection (Chapter 3) are therefore defined from the prior information regarding what makes a good storage site. These are global criteria, which provide an effective filter and do not, for example, take into account site-specific covariances. They ensure that likely sites potentially fall within acceptable storage uncertainty bounds.

Initial data collection and first response tools (Chapter 3) are the start of making the uncertainty assessment site-specific at a relatively low cost. These assessments generally reflect uncoupled processes and therefore make simplifying assumptions. This stage is key to informing on likely coupled processes that need to be explored in the reservoir simulations. The decision to progress to further investment should reflect that uncertainties are being favourably reduced.

Reservoir simulations (Chapter 4) allow the exploration of coupled processes in a physical and stochastic modelling framework. They produce posterior distributions on capacity, security and injectivity, with regard to the parameter space explored. Users must bear in mind that if a key control has not been included, the uncertainty bounds will be biased. The choice to move to more complex reservoir simulations is motivated by the expected information gain by doing so and the ability for this information to further reduce uncertainty. The monitorability assessment (Chapter 5) overarches these activities and is informed at all stages. It is mostly constrained by the results of the simulations, but can feed back into choosing the best injection strategies.

Similarly, any storage site must meet some acceptable limit of risk. Risk is usually defined as a combination of the probability and impact of some event. For example, the probability that CO_2 will leak to the surface and the scale of the impact on the environment. Hence, in assessing a site, consideration must be given, not only to the probability that the site will fail to perform as predicted, but also to the impact of failure. Using a risk register to assess and rank areas of risk, high risk factors can be identified and addressed through mitigation activities. In the CASSEM project a 'Features, Events and Processes' (FEP) based register was used to identify key areas of risk for both sites. Uncertainty is an influential factor on risk, and hence reducing uncertainty may be an important mitigation activity. The CASSEM methodology uses a structured decision process that explicitly includes uncertainty and risk, to identify, rank and select project activities. This is demonstrated with the selection of data acquisition activities based on the risk assessment results and the most up-to-date understanding of uncertainty.

Midway through the project a risk assessment identified the highest FEPs for both sites (Chapter 6) and led to specific mitigation activities being incorporated into the project. These activities are identified as case studies and are presented in Chapters 2, 3, 4 and 5 and 6.

A further three high-level generic FEPs were considered for their potential significance to reducing uncertainty and improving investor confidence. These included alternative strategies for injection of CO_2, whole-chain cost analysis and public perception.

1.6 INJECTION STRATEGIES

Alternative engineering strategies involving surface mixing of supercritical CO_2 are discussed in Chapter 7. Although still at a theoretical stage, these strategies offer the potential to significantly mitigate risk during injection and to provide storage solutions that are thermodynamically and environmentally stable and permanent.

For example, if the CO_2 can be immobilised by mixing with brine to reduce buoyancy, then it may remain underground indefinitely, even if the integrity of the cap rock is breached, thus reducing monitoring costs and decreasing uncertainty. These benefits are offset by the additional cost and scale of surface mixing facilities.

1.7 COSTING OF THE CCS CHAIN

Financial viability is the greatest risk to CCS. In Chapter 8 a transparent and open-source full CCS costing model is explained. The model highlights the importance of the underlying assumptions to the output presented and of such models. For example, one of the biggest challenges in a step-by-step approach to analysis of a CCS scheme is the way the rest of the CO_2 chain will react to large changes in CO_2 flow rate. Thus, the quality requirements of the subsurface store cascade back through the CCS chain and require assessment of the key design parameters and design variables at each step. Building this into a costing model is challenging.

1.8 PUBLIC PERCEPTION

Finally, fundamental to the acceptance of potential CCS storage projects is the ability to support the scientific and technological assessments with effective communication of the opportunities and risks to the public and policy makers. As recent experience in Europe has shown, CCS implementation can be blocked by public resistance and therefore needs to be communicated in a clear and transparent manner to all stakeholders.

Chapter 9 explains a process of using citizen panels at the two exemplar sites to investigate understanding and views on CCS before and after engaging with project experts. After the process, concerns on CCS technology were significantly reduced. Storage and the potential for leakage were viewed as the greatest concern, but, engaging with the experts generated sufficient trust such that the risks could be accepted.

The greater public concerns were around the wider political, financial and governance aspects of CCS and, ultimately, on the appropriateness of CCS as a climate change mitigating technology. How could safe monitoring be ensured over hundreds of years? What are the costs and benefits of developing CCS and how could these be distributed in a fair manner? Therefore, in any CCS project, early engagement and implementation of an effective communication plan with local stakeholders should be viewed as an essential element in developing CCS technologies.

CHAPTER 2
BETWEEN THE SOURCE AND THE STORE

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2.1 INTRODUCTION

Carbon capture and storage (CCS) schemes require complex integrated solutions combining a number of elements. These elements can be considered as CO_2 producer, capture, transportation and long-term storage, the latter three being the additional requirements for CCS when compared to conventional power generation. Within each element there are a number of technology options with their own characteristics and requirements. Whilst integration of some of the elements has occurred previously, for example, transport and sequestration in the form of enhanced oil recovery (EOR), the entire chain from emission to store remains unproven at a commercial scale.

To understand the viability of a CCS scheme there are a large number of variables to consider, including scientific, technical, economic and practical aspects. Early understanding of the issues and particularly the risks is critical for informed business decision making, as well as technology development.

The CASSEM methodology is focused around the subsurface geological aspects of CCS, however, it is recognised that the surface plant aspects of the CCS chain including volumes, pressures and purity of CO_2, all impact on subsurface design. This chapter introduces the surface aspects of CCS that were built into the CASSEM project. It does not provide a detailed assessment of capture technologies, but instead gives consideration to aspects of transportation, health and safety and impact of effective project implementation as exemplars for industry to consider.

2.2 HOW IMPORTANT ARE DECISIONS TAKEN AT THE CONCEPT STAGE?

In any project early decisions potentially have the greatest impact on the final outcome, with CCS being no exception. Conversely, poor decisions or poor performance in the early phases are difficult to recover from without exceptional performance in latter stages, extensions of time or increased capital cost. The ability of each project stage to affect the outcome is shown graphically in Figure 2.1 as a simple plot of the ability to influence project costs and the expenditure. At the early stages, for relatively low costs, the project can be shaped appropriately. Poor initial phases are the most difficult to recover from as subsequent phases start below the line of optimal performance or value.

When considering CCS schemes, the critical elements are different depending on which part of the chain the decision makers reside. For power utilities the issues tend to be around the impact on electricity sales, flexibility of operation, impact on assets and the cost. Technology providers are concerned with the scale-up issues and the effect of other elements on their process. Storage providers need to understand the storage site behaviour, how its capacity can be defined and the behaviour of the store.

Five cross-cutting issues, fundamental to inform basic decisions in all activities are:

- Technology options
- System Integration
- Physical, health and safety issues
- Implementation of the systems
- Outline costs

Early consideration of these issues allows decisions to be based on common understandings. In the case of the CASSEM project we have included aspects of some of these issues across the CCS chain in order to build a more informed approach to assessing storage requirements. In the following sections we discuss system integration, the capture plant and transport. CCS economics are discussed in Chapter 8.

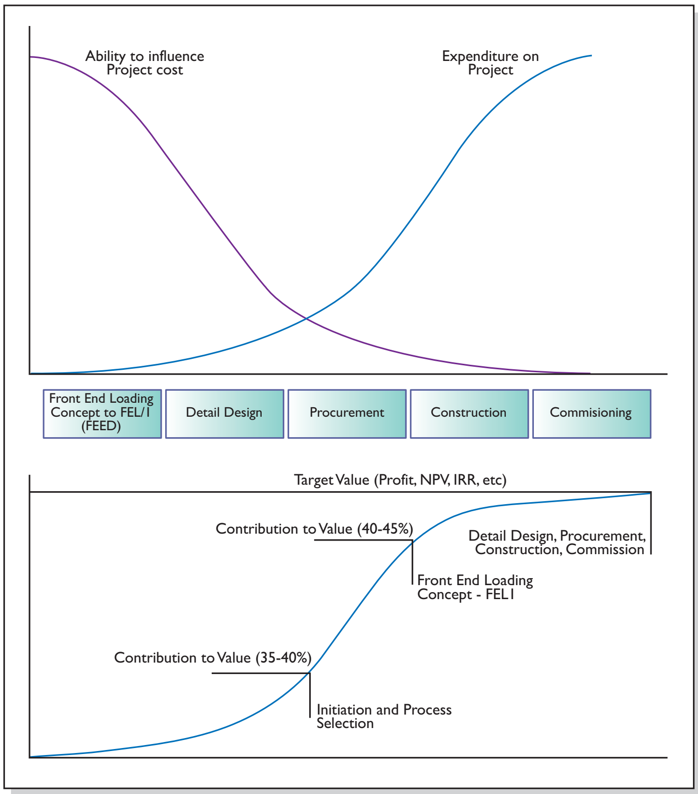

Figure 2.1 Plot of the ability to influence a project and the expenditure

2.3 CCS SYSTEM INTEGRATION

The CASSEM project adopted the use of two exemplar sites to constrain the parameters and operating factors of surface activities that influence subsurface analysis of CO_2 storage.

The project exemplar sites are Longannet Power Station in Fife and Ferrybridge Power Station in Yorkshire. The CCS scheme utilised by the project includes the CO_2 emitted, the capture plant, transportation infrastructure, injection facilities and storage. The exemplar sites are modelled to include a new power plant, post-combustion capture plant, pipeline transportation and a store located within 75 km of the site. This section describes the exemplar sites and the information that has been provided to, and utilised by, the CASSEM methodology.

Full Scheme Integration

What is a CCS system? What are the constituent parts and how do they integrate? All of the questions that highlight the full extent of such schemes are not widely understood and appreciated. In simple terms, the basic structure of the CCS chain consists of an emitter, capture plant, transport and a store. Figure 2.2 shows that this chain, even at a basic level, is complex, with numerous process units. In addition, when considering power generators as the CO_2 producer, the influence of the electricity market on plant operation cannot be ignored.

A more complex structure is shown in Figure 2.3. Here the chain is shown in the constituent unit operations, where a single process may affect downstream and/or upstream processes.

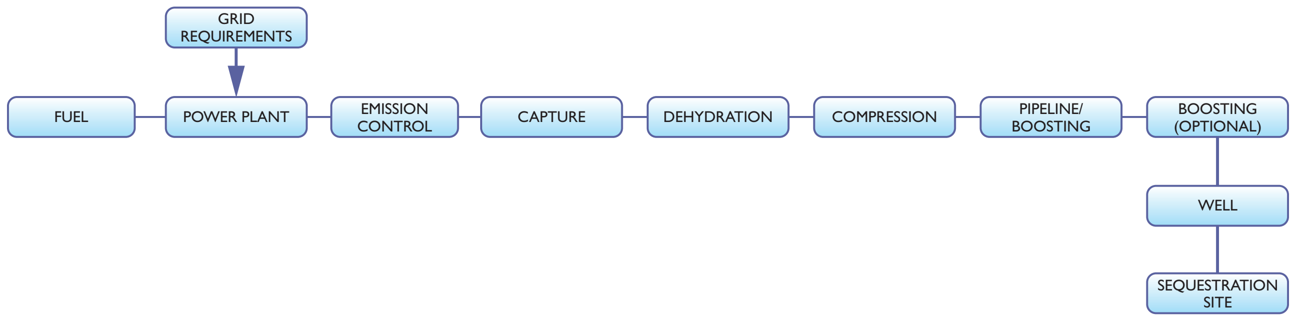

Figure 2.2 Simple Block Diagram of Typical Power based CCS Scheme

The block diagram is a simple statement of the operational units; what is not clear is how they influence each other. To examine the constraints or design criteria of each unit it is necessary to track and understand the issues across units. This leads to a step-by-step consideration of the scheme, from fuel entering the system, to the storage site and back again. In determining at each step, the key design parameters and design variables at a high level, it enables the issues and information to be identified. In addition, it highlights where key bottlenecks may occur, where flexibility is available and an indication, therefore, of the risks in the design process.

Consider, for example, the high-level design parameter from the storage site and the feedback down the CCS chain. Whilst flow rate of CO_2 dictates the required number of wells, the delivery temperature and pressure supplied by the pipeline are determined, not by the pipeline or compressor, but by the requirements or tolerances of the storage site. This feedback into the system also raises the issue of the quality of the CO_2 fluid. In effect, the quality requirements of the store will cascade back through the system. Thus, rather than the capture plant achieving a fixed removal point it must encompass subsurface geology storage requirements, alongside air quality, control systems and fuel composition.

Power and Capture Plant

The CASSEM project has assumed that the source of the CO_2 will be a high-efficiency coal-fired power plant. These plants, which are now being constructed around the world, operate at high temperature and pressure, typically 620°C and 280 bar. At these temperatures and pressures the steam is in the supercritical phase. Consequently, these power plants are generically referred to as supercritical plant. Typical thermal efficiencies for supercritical plant are between 40 and 45%.

The two exemplar sites, Longannet and Ferrybridge, have operating power plants that were commissioned in the 1960's/70's. They are of an older design, operating in the subcritical steam phase with efficiencies in the range of 35–40%. It is likely that electrical power generation will continue on some of these sites due to their grid connection and the configuration of the UK grid system around concentrations of power generation. To develop new sites will require modification of the UK grid system, with an associated requirement for capital investment. The cost of building CO_2 pipelines to suitable storage sites will also influence location decisions.

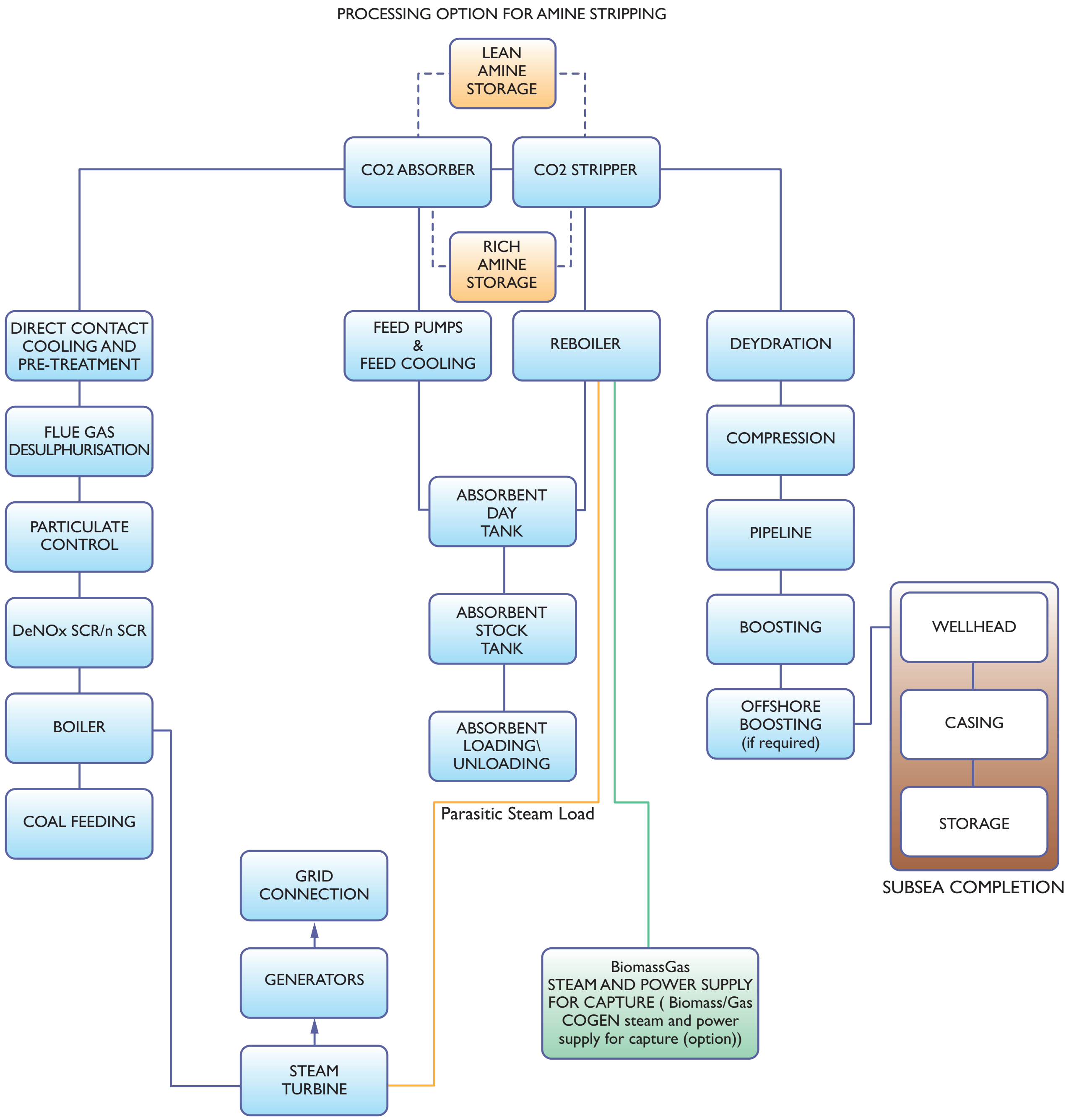

Figure 2.3 Expanded Power based CCS system

Currently, power plant manufacturers concentrate on specific sized plant rather than offer bespoke plant for individual locations, with 800 MW being a common size. Given the existing grid connection and assuming a unit size of 800 MW, the exemplar CCS deployment schemes have been sized at three units for Longannet and two units for Ferrybridge. The CO_2 capture plant will reduce the net output of the power plant, however, there may be occasions when the capture plant is not fully utilised for short periods of time to meet peak demand, hence the number of units selected to match grid connection.

It is assumed that the capture plant will be post-combustion as this is assessed as closest to commercial operation. Post-combustion capture plant use chemical solvents (amines) that absorb the CO_2 from the flue gas. The CO_2 is separated from the amines in a desorber, with the remaining flue gas (essentially nitrogen, oxygen and water vapour) being vented to atmosphere and the CO_2 being compressed for transportation. The process of desorption requires significant energy as heat for the CO_2-rich amine to release the CO_2. There is significant work taking place globally to reduce this energy burden and this issue is not further considered here.

Capture Plant Flexibility

Typically unrecognised in CCS discussions is the need to respond to the operational requirements of the power plants that produce CO_2. As electricity cannot be easily stored, it is produced to meet instantaneous customer demand. The UK power demand varies by approximately a factor of three on most days, with low overnight demand and very high demand during the early evening. Consequently, to maintain security of electricity supply, it is important that the UK has additional generation capacity that can be turned on or off safely and rapidly according to the needs of the market. This is usually referred to as 'flexibility'.

While hydroelectric and pumped storage schemes play an important part in grid stability, the bulk of flexible generation in the UK is currently fossil-based. By 2030 it is expected that the nuclear fleet will have been replaced and there will be substantially more wind capacity, thus the need for fossil-based generation plant to be flexible may actually be amplified.

For a given level of CO_2 emissions it will be cheaper for CCS developers to build a small number of very large carbon capture schemes that operate 'baseload' and allow other fossil plant to run for fewer hours as 'peaking plant'. However, it is not clear yet how the legislation or incentives that drive CCS will be written and it may be a requirement to have a large number of flexibly operated fossil plant with CCS (albeit at much higher cost per tonne of CO_2 abated).

It is believed to be technically possible to add flexibility to a post-combustion plant by partially decoupling electricity output from CO_2 output. However, this has not yet been demonstrated, even at the 100 te/day pilot scale.

The principle of flexibility in CCS capture is straightforward; to achieve flexibility the carbon capture plant is equipped with two additional storage tanks to hold the capture solvent. The 'lean solvent tank' contains solvent substantially free of CO_2 while the 'rich solvent tank' holds solvent laden with CO_2. During the evening peak in electricity demand the CO_2 stripper column and the CO_2compressor are turned off – redirecting the substantial heat and electricity penalty from these to the grid. This helps grid stability and increases plant revenues. The CO_2 capture column continues to run, so no additional CO_2 is released to atmosphere. This gradually empties the lean solvent tank and fills the rich solvent tank.

Once the evening peak has passed and the demand for electricity falls, the power plant is turned down to its minimum capacity and the stripper column and CO_2 compressor are turned back on at full capacity. This gradually empties the rich solvent tank, regenerates the whole solvent inventory and fills the lean solvent tank.

However, one of the biggest challenges in this approach is the way the rest of the CO_2 chain will react to large changes in CO_2 flow rate. Therefore, studies of full-chain integration are crucial to realising a CCS project.

2.4 IMPLEMENTATION: TRANSPORTATION

The implementation aspect of early decision making is the understanding of the 'how' behind a project. To achieve CCS you need a capture and storage solution, but also a transport path. It is this issue which the CASSEM project developed as an exemplar of implementation.

For the project the two power stations were examined, route options plotted and a test of the current UK regulations and design practices as applied to CO_2 pipelines carried out; essentially executing a high-level routing study. The study utilised a methodology that is common across all pipelines, but there are gaps where CO_2 does not fit into the existing regulations.

Application of UK pipeline regulations

In Europe, the regulations around pipelines are well established, as are the design codes. These regulations do not consider carbon dioxide as a specific named substance in the more prescriptive manner of the US federal regulations. However, in the UK, the Health & Safety Executive (HSE) have classified carbon dioxide from CCS as both a 'dangerous fluid' under the Pipeline Safety Regulations (PSR) and a 'dangerous substance' under Control of Major Accident Hazards (COMAH).

In order to comply with PSR the guidance used is set out in BS PD 8010-1, Steel pipelines on land. Under this guidance, CO_2, normally a Category C fluid, when compressed and transported as a dense liquid phase, i.e. a supercritical fluid, is defined as a Category E fluid, the most stringent fluid category.

For a Category E fluid, what amounts to a quantitative risk assessment is required. The code specifies separation distance parameters in most cases, but not for CO_2. Therefore, until such guidance is provided, full dispersion models for CO_2 pipeline operation and leakage scenarios will be required as part of any pipeline design or design statement. Such pipelines are prohibited in Class 3 locations, including areas such as the centre of towns, high population and building densities, multi-storey buildings, dense traffic and areas with high densities of underground services.

Pipeline Design

The initial design of a pipeline occurs in stages, as shown below:

- Route definitions
- Definition of process conditions.
- Design criteria
- Material selection
- Topography assessment
- Route identifications
- Crossing identification
- Route selection

These stages generally apply to all pipeline design. There are specific considerations and differences for CO_2 transportation, much as the same pipeline rules apply, but special attention is paid to certain areas for crude oil, natural gas or ethylene transportation.

Carbon Dioxide Specific

For carbon dioxide specific pipelines, the primary factors in design are already addressed in established regulations and international standards. Codes such as BS PD 8010 and literature such as Mohitpour (2007) go further in highlighting that there are more primary factors, as well as highlighting in detail the considerations at each step. The pipeline design factor chosen will also influence chosen routing as the design factor will influence proximities to normally occupied buildings, e.g. under BS PD 8010-1.

Risk contours for the pipeline should therefore be developed to determine safe limits and proximities as part of the design process.

In addition, and specifically for CO_2, special attention must be shown to the topography of the route; the change in height of the pipeline must be carefully configured for hydraulic and pressure responses. Also, the pipelines should be run such that the dispersion of any rupture or leakage plume will avoid the build-up of dangerous concentrations of the CO_2 gas. As a gas, CO_2 is denser than air and a low momentum release or cloud of CO_2 will follow terrain changes and lead to an accumulation. Therefore, the routing must also consider this possibility and, where appropriate, deviate from low-lying depressions that might see accumulation. As with all elements of routing there are economic considerations as route change may add distance to the pipeline (Gale and Davison, 2004).

As part of the CASSEM project, a review of the regulations and current methodologies was performed. This confirmed them to be entirely adequate for designing CO_2 service pipelines. Whilst there are gaps, critically in the separation distance allowed, these may be overcome by risk assessment and, where necessary, executing dispersion modelling.

2.5 APPLICATION TO THE EXEMPLAR SITES

To test the application of pipeline design the two project sites were considered and a pipeline solution applied to each, to a hypothetical storage target 30 km offshore. In each case the routes were plotted and sea landing locations considered and assessed.

In the Ferrybridge example, the pipeline is required to cross a large area of land to access an offshore storage site. Figure 2.4 shows the preliminary route options, assuming storage is to be 30 km east of the Theddlethorpe gas terminal.

In the Longannet example there are again a number of options that exist to access the North Sea. Here the routing is more complex, due to a more scattered population, although over a much shorter distance. Longannet can, unlike Ferrybridge, immediately access the coastline as it is on the shoreline of the Firth of Forth. Other options take a pipeline overland through Fife to access the sea from the south or north coastlines.

This exercise demonstrated that both exemplar sites had significant route options and that transportation by pipeline was achievable within current guidance and regulation.

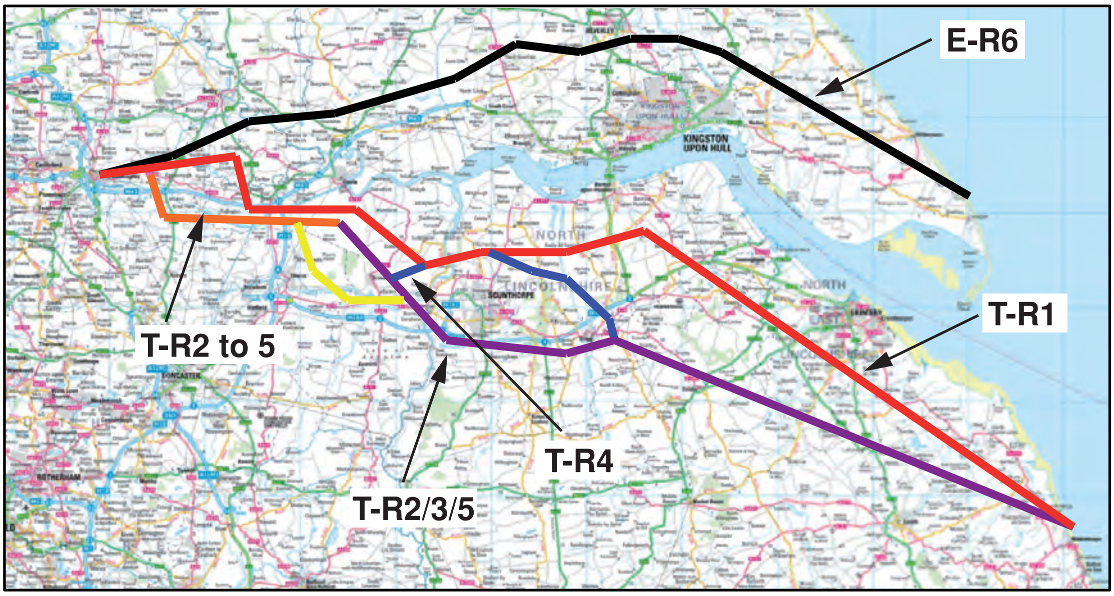

Figure 2.4. Preliminary pipeline route options pipeline routes for Ferrybridge

CASE STUDY 1: CARBON DIOXIDE PROPERTIES, HEALTH AND SAFETY

The properties of CO_2 and the associated health, safety and environmental considerations are not unique to CCS projects; they are common to all industrial gas plant and the chemical industry in general. Because the physical properties of CO_2 vary widely, depending upon the phase relations, a discussion of their potential impact was included within the CASSEM project.

Properties

The phase diagram, Figure 2.5, shows the phase boundaries for CO_2. Whilst all materials have similar phase diagrams, CO_2 is complex because it straddles the operating envelope of a CCS system. Capture occurs with the CO_2 in vapour phase, but transportation and storage will, under current technologies, occur in the dense liquid phase, i.e. above critical pressure. The phase envelope transcribes atmospheric conditions such that variation in temperature can cause a phase change, i.e. rapid depressurisation can lead to solid formation and cold temperatures. This understanding is further complicated by the influence of impurities on the CO_2 stream, introducing more potential challenges in pipeline design.

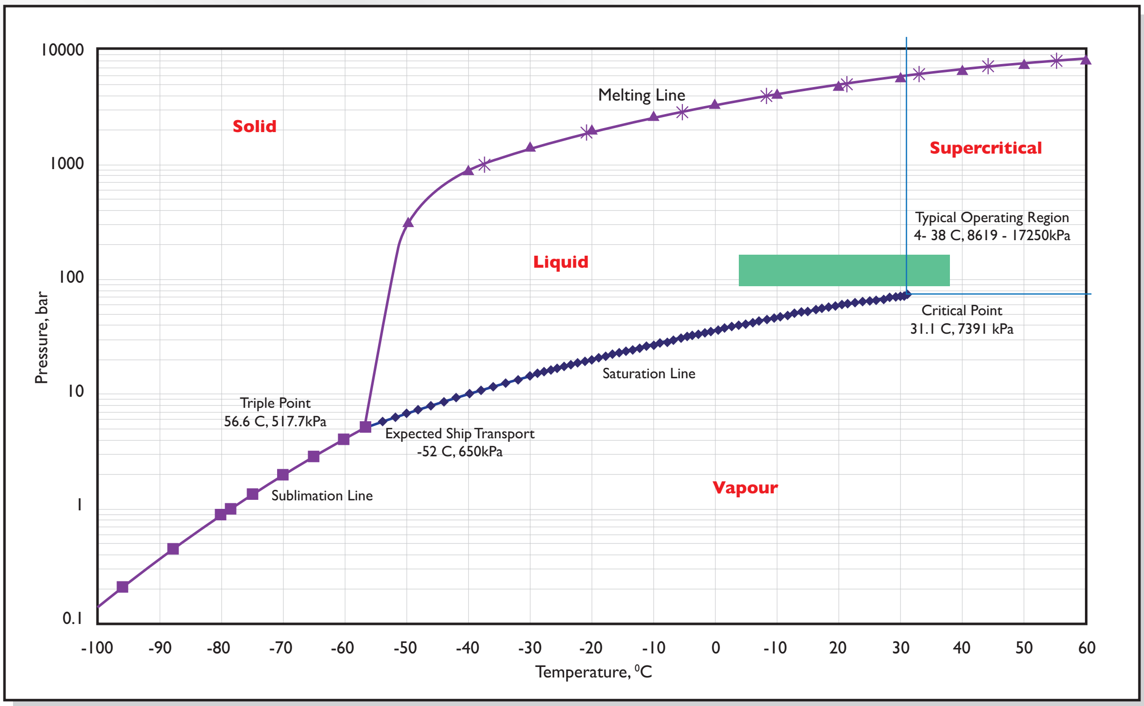

Figure 2.5 Carbon Dioxide Phase Diagram

Human Health

Carbon dioxide is a critical chemical and a fundamental building block in biology and, as such, we are very used to it. Carbon dioxide exists in the atmosphere at around 350–390 ppm (0.035/0.039%) by volume; we exhale it, ingest it in beverages and generally are aware of the role it plays in climate change. It has no colour and is effectively odourless, thus detection by humans is not assured, making it easy to forget that it has a detrimental effect at high concentrations. The impact of an industrial scale leakage are not widely known.

Nevertheless, industrial levels of CO_2 are handled on a daily basis by a number of gas companies for the drinks, pharmaceutical and chemical industries, for a variety of purposes. The body of knowledge needed to support safe operation exists and has demonstrated over decades that such volumes can be controlled and managed safely.

Increased levels of carbon dioxide cause:

- Anoxia (asphyxiation) due to reduced oxygen concentration. Air normally contains 21% oxygen and asphyxiants interfere with the body's oxygen uptake mechanisms. Oxygen deficiency in inhaled air, e.g. due to the presence of nitrogen, argon, or carbon dioxide in a confined space, depending on the concentration and duration, may affect the body and ultimately cause death. Oxygen levels below 19.5% can have detrimental effects if the body is already under stress, e.g. at high altitudes. Exposures below 18% should not be permitted under any circumstance.

- Reduced bloodstream pH, triggering effects on the respiratory, cardiovascular and central nervous systems.

Typical human health effects of increased carbon dioxide content at various concentrations are given in Table 2.1. Effects at low concentrations are reversible, but higher concentrations are toxic and damaging. The individual may not be aware of these symptoms, especially at higher concentrations.

Concentration	Effects
1 - 1.5%	Slight effect on chemical metabolism after exposures of several hours. Slight increase in breathing rate.
2%	Breathing rate increased by 50%. Prolonged exposure can cause headaches, tiredness.
3%	Breathing rate doubled and becomes laboured.. The gas is weakly narcotic at this level, giving rise to deeper breathing, reduced hearing ability, coupled with headache, and an increase in blood pressure and pulse rate.
4 – 5%	Stimulation of the respiratory centre occurs resulting in deeper and more rapid breathing. Signs of intoxication (vomiting, dizziness, disorientation, breathing difficulties) will become evident after 30 minutes exposure.
5 – 10%	Headache, vomiting, dizziness, disorientation, vis ual impairment, loss of judgement, ringing in ears, breathing difficulties after short exposure. Loss of consciousness within minutes.
10%	Headache, vomiting, dizziness, disorientation, unconsciousness. Death after a few minutes.
Over 10%	Concentration affected. Unconsciousness in less than 1 min. Death.
Over 25-30%	Narcotic effect, stops respiration within several breaths, even if sufficient oxygen is present. Death.

Table 2.1 Typical human reactions to carbon dioxide in the local atmosphere at various concentrations.

Exposures to carbon dioxide may involve mixtures of physical form: solid, liquid, mists, aerosols, or gases in any combination. Quantification of exposure is then difficult. Contact with liquid, solid or a cold gas jet may induce freeze burns or frostbite. In response to these hazards, the HSE in the UK has set workplace exposure limits of (Health and Safety Executive, 2005):

5,000 ppm (0.5%) for long-term exposure (8-hour TWA)
15,000 ppm (1.5%) for short-term exposure (15-minute TWA)

They have also specified Dangerous Toxic Load (DTL) for Specified Level of Toxicity (SLOT) and Significant Likelihood of Death (SLOD) (Health and Safety Executive, 2008) for use in land use planning. SLOT DTL has been set at 1.5×10^{40} ppm^8.min and is defined as the level of toxicity causing severe distress to almost everyone in the area, a substantial fraction of exposed population to require medical attention, serious injury that requires prolonged treatment for some people, and death for highly susceptible people. SLOD DTL has been determined as 1.5×10^{41} ppm^8.min and is defined as the level of toxicity causing death to 50% of the affected population. Both SLOT and SLOD values take into account exposure duration and concentration in air. Expanded concentration data is given in Table 2.2.

Time (min)	1	3	5	10	20	30	40	60	90	120	180	240	360	480
SLOT %	10.5	9.2	8.6	7.9	7.2	6.9	6.6	6.3	6.0	5.8	5.5	5.3	5.0	4.9
SLOD%	14	12.2	11.5	10.5	9.6	9.2	8.8	8.4	8.0	7.7	7.3	7.1	6.7	6.5

Table 2.2 SLOT/SLOD data for carbon dioxide.

Environmental Impact

Carbon dioxide has an effect on animals, similar to that seen in humans. Biota may experience both toxic and physical effects. Carbon dioxide has historically been used as an insecticide at levels of a few percent. It can also inhibit the growth of bacteria.

Plant growth and yield can be stimulated:

- Increased carbon dioxide concentration around the leaves gives an increased rate of diffusion of carbon dioxide through the stomata of leaves and enables the plant to grow faster and larger with a greater crop yield.
- Carbon dioxide solution in groundwater acts on soil material to produce fertilising materials beneficial to plant life.

Although beneficial in small quantities, larger amounts are toxic. In addition, cold CO_2 can cause frost damage to vegetation. Chronic effects are summarised in Table 2.3.

Animals		Plants		Insect/ behavioural Effects		Risk ratios		
Level	Type	Level	Type		Type	Animals	Plants	Insect/ behavioural effects
1000	Respiratory stimulation	380	Increased growth Biomass	0.5	Moth, butterfly olfactory sensation	0.06	0.2	120
10000	Insect spiracle aperture regulation	700	Increases/ decreases in plant respiration	10	Mosquitos ticks, fire bugs olfactory activation	0.006	0.09	6
50000	Respiratory poisoning	10000	Fungi, abnormal growth	1000	Mosquitos ticks, fire bugs olfactory locomotion	0.001	0.006	0.06
				5000	Ants, bees, termites, beetles, nematodes olfactory sensation	-	-	0.01

Table 2.3 Chronic effects of carbon dioxide on biota (US Department of Energy, 2007)

Around the globe many communities live in close proximity to CO_2 discharges or systems, and the effects can be managed and mitigated. This brief summary highlights that a comprehensive health and safety assessment which considers both human and environmental impacts is required before a transportation system can be implemented.

CHAPTER 3
DEFINING THE STORE; GEOLOGICAL INTERPRETATION AND STORAGE MODELLING

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3.1 INTRODUCTION

The identification of a suitable storage site for CO_2 is fundamental to a viable CCS methodology. In this chapter we describe a workflow for the process of identification, interpretation and geological modelling of a potential aquifer storage site.

The construction of a valid and testable geological model is an essential pre-requisite to carrying out any reservoir simulation of CO_2 flow and storage capacity modelling.

A well constructed model enhances confidence in the numerical simulations and monitorability assesment and importantly, also delivers a visual understanding of the sub-surface to the non-geologist.

Geologists visualise geology in 3D and previously have translated this onto 2D maps and sections. Modern technology now permits the routine construction of digital models at all scales and for these to be exported to other software packages. The construction of models based on limited data is, by necessity, open to multiple interpretation; and one of the key outcomes of our investigation has been to recognise the importance of the development and early application of a set of first response tools for geological interpretation and storage modelling. Use of this methodology and tool set should lead to best available data analysis, improved decision making and confidence in reservoir simulation (see Glossary for a full definition of terms used in this chapter).

3.2 WORKFLOW

Workflow design

The workflow (Figure 3.1), based around an asset team approach, was developed from an evaluation of the geological characterisation of two areas defined by the CASSEM project. The two areas (Figure 3.2) differ markedly in geological complexity, volume and quality of data and in potential environmental impacts (onshore vs near-shore), and thus provide complementary information for methodological development and contrasting outcomes and insights into aspects of CO_2 aquifer storage.

The geological modelling workflow described here encompasses site screening and selection, data acquisition, evaluation and compilation, leading to storage characterisation and the construction of 3D geological framework models. These models and data underpin primary estimates of (1) storage capacity and (2) the spatial behaviour of CO_2 and are applied to numerical simulations of dynamic flow and monitorability in Chapters 4 and 5. An additional aim has been to explore the quantification of uncertainty and improve our understanding of risk at each stage in the workflow (Chapter 6).

The workflow comprises four main stages separated by Evaluation/Decision gates (E/D G1 etc.) (Figure 3.1) that define a critical path approach to informed decision making. The use of E/D gates ensures that sufficient data are in place at critical stages, and, importantly, are visible to all members of the asset team. With a significant emphasis on the testing and validation in the early stages, this workflow aims to identify the key challenges early in the assessment process.

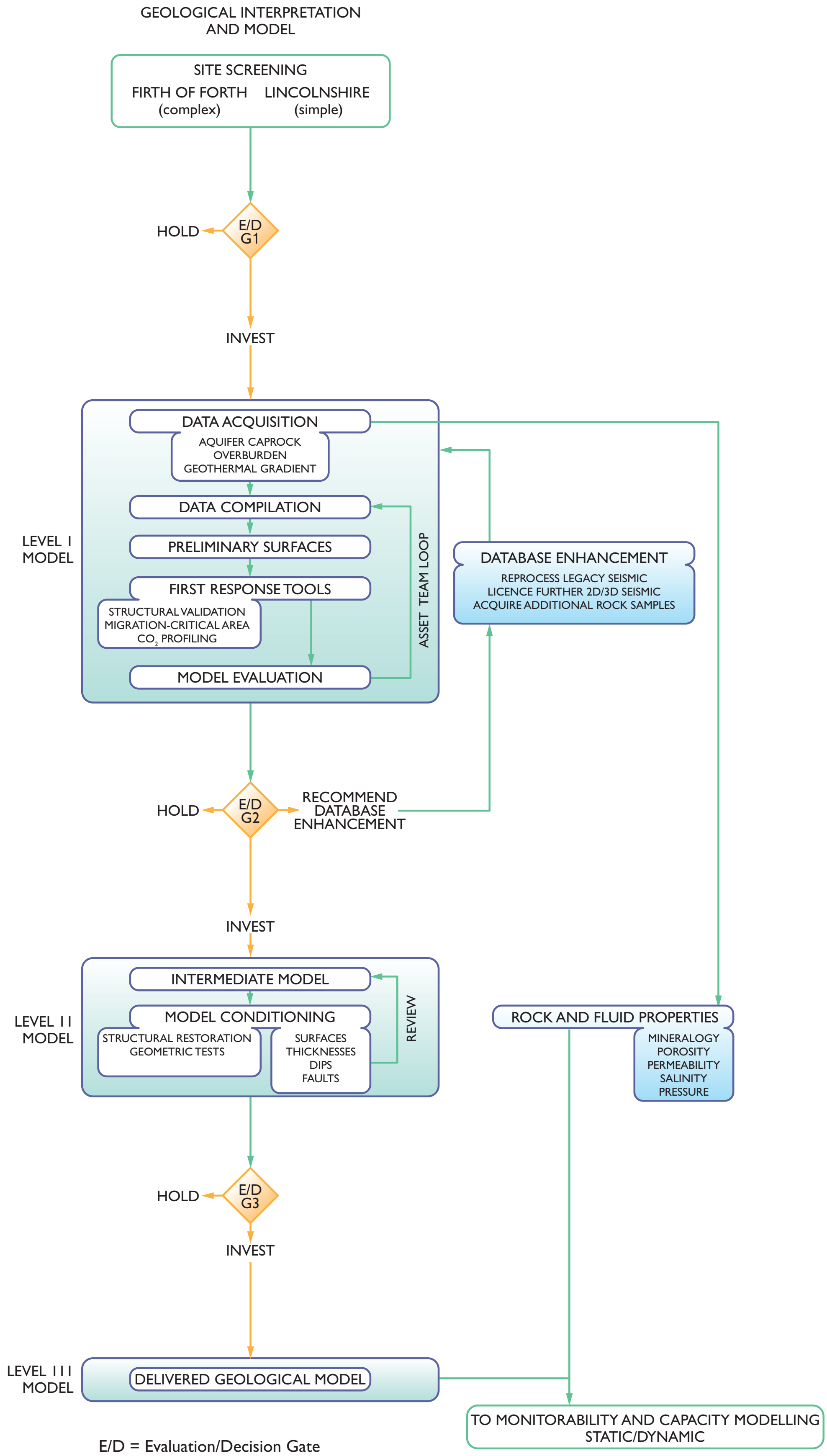


Figure 3.1 Workflow diagram for geological interpretation and modelling of a potential CO_2 store.

The four stages are:

- Site screening (geological scoping within the designated area; evaluate, rank and select potential sites based on agreed criteria).

- Level I: the basic geological model (data compilation, assessment, initial surfaces proposed and risk evaluated by the asset team, with iterative workflow loop between seismic-picking and geological interpretation via first response tools).

- Level II: the intermediate model (completed geological surfaces and faults, structural restoration, evaluation, migration and geometric testing).

- Level III: the high-level model (final geological model, attributed and validated).

The storage workflow builds on published methodologies and best practice, including Chadwick et al. (2008), the EU GeoCapacity project, and parallels the methodologies for '…the realisation of a CO_2 storage operation', as described as part of the CO2ReMoVe Project (Groenenberg et al., 2008). The steps outlined below broadly correspond, in part, to the basin-scale assessment and structural and stratigraphic modelling steps of Kaldi and Gibson-Poole (2008) and to the Phase 1 screening and part of Phase 2 site investigation of Groenenberg et al. (2008).

A key element to success and efficiency is the early establishment and resourcing of an asset team to complete a rapid analysis of data quality. Effective communication and feedback loops during initial model surface construction (Figure 3.1) are essential. As data and the models are progressively refined, they are delivered to other workflows (e.g. reservoir simulation and monitorability assessment), either at an E/D gate, if early assessment is required, or at the Level III geological model stage. Examples from the two exemplar sites of how the methodology works are presented below.

3.3 DATA AND WORKFLOW TOOLS

A wide range of commercial software tools are available to manipulate geological data and construct spatial 3D models. For the CASSEM project work, geological models were built using GOCAD® (Paradigm) and Petrel (Schlumberger) software. 2D and/or 3D baseline seismic data were rendered using Geographix® Seisvision, WellBase and Landmark™, and incorporated with other data from wells, fault pattern information, underground mine records and surface outcrops. The first response tools for geological interpretation and storage modelling implement features and algorithms of the commercial software suites: Move (Midland Valley Exploration Ltd) and MPath (Permedia Research Group Inc). Additional original code (termed CO_2 Depth Profile, University of Edinburgh) was compiled for specific tasks.

Other considerations: model equivalence

Where the geology is complex and/or interpretation of the data equivocal, then the final Level III model presented is but one representation of the available data. Other equally valid interpretations may be identified and result in parallel workflows for two or more other model outcomes. This model equivalence would commonly be identified during the Level I stage of initial risking and structural validation of surfaces but, theoretically, could occur at any stage.

Clearly, not all models of a single parent can be correct. Where there is no consensus on which is most likely, a quantification of uncertainty and risk should be allocated to each initial model. This is complicated by the fact that the risk metrics of each parallel workflow are not independent as they would be, for example, for competing, separate storage sites. Whilst acknowledging the issue of model equivalence, this is not discussed here.

3.4 SITE SCREENING AND GEOLOGICAL SCOPING

Initial site selection

A basic requirement for the subsurface storage of CO_2 is the identification of candidate porous saline aquifer formations (the hydraulic unit) at depths greater than c.800 m below mean sea level, with sufficient knowledge of the geometry and areal extent of the lithological and geomechanical properties of the aquifer, overburden, cap rock, and surrounding stratigraphies. Combined, these data permit calculation of potential storage capacity and predictions of CO_2 behaviour.

Using GIS functionality, the criteria for site selection (Table 3.1) are combined with an assessment of parameters (including tolerances on porosity, thickness, cap rock, capacity, etc) to be met by the modelling and sampling protocols. The sites can then be objectively scored and ranked, e.g. Bachu (2003). A ranking approach based on capacity and injectivity (e.g. Kaldi and Gibson-Poole, 2008) is beyond the scope of the workflow at this stage, although these metrics have pivotal roles elsewhere in the CASSEM project (Chapter 5). Risk strategies and parameterisation of input to a features, events and processes (FEP) register (e.g. Maul et al., 2004) is undertaken at this stage.

Criteria	Positive indicators	Cautionary indicators
Saline aquifer present	Salinity >100 gl -1	Salinity <10 gl -1
Aquifer depth	> 800 m <2500 m	<800 m >2500 m
Trap geometry exists		Accepted at start of workflow that no major trap structures exist
Caprock exists	>100 m thick	<20 m thick
Availability of geological data	3D seismic data, uniform coverage	Old 2D seismic data, variable coverage
Proximity to powerplant	<75 km	>100 km
Suitable porosity	>20%	<10%
Suitable permeability	>500 mD	<200 mD
Stratigraphy	Uniform	Complex lateral variation and complex connectivity
Aquifer volume	>100 m thick sandstone over 5.5 km^2 or for a 30m thick sandstone 10 km^2	<20 m thick sandstone
Igneous rocks	An appreciation of their existence, geometry and effect on surrounding rock	Little knowledge of geometry and effect on surrounding rock
Containment	Knowledge of minimal routes to surface/high level from saline aquifer/ caprock – faults, boreholes, mineworkings etc.	Little knowledge of routes to surface, including faults and boreholes

Table 3.1 CASSEM initial area and site selection screening criteria

For CASSEM, saline aquifer targets were identified within a 75 km radius of two clusters of major CO_2 emitters: Drax/Ferrybridge (Lincolnshire) and Longannet/Cockenzie/Grangemouth (Firth of Forth) (Figure 3.2).

(a)

(b)

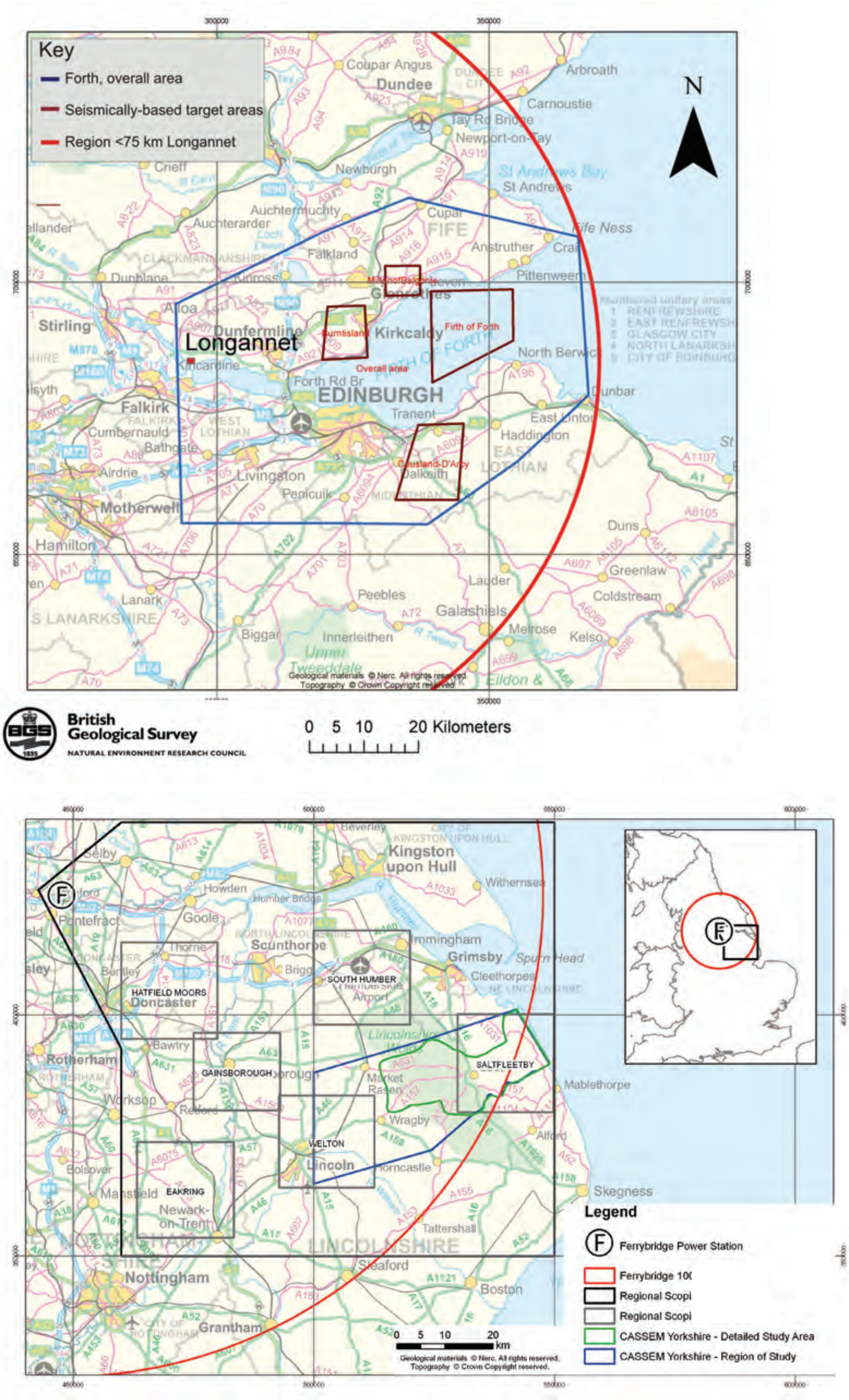


Figure 3.2 Location map for CASSEM target sites (a) Firth of Forth and (b) Lincolnshire

Firth of Forth – site screening

Targets within 75 km of the Longannet Power Station best matched to the CCS criteria extend around the Firth of Forth from West to East Fife and Edinburgh to East Lothian (Figure 3.2a). However, the area has relatively sparse, vintage 2D seismic data constrained by a single offshore well, and a complex stratigraphical sequence and structural pattern. The primary saline aquifer targets are the fluvial and aeolian sandstones of the Kinnesswood and Knox Pulpit formations of early Carboniferous to late Devonian age. The primary cap rock is the Ballagan Formation of Carboniferous age. Minor saline aquifers and seals occur throughout the overlying Carboniferous succession (Figure 3.3).

Whilst the primary target aquifer and cap rock meet some of the CCS criteria presented in Table 3.1, Cawley et al. (2005) concluded that the key stratigraphic targets for aquifer storage were less than ideal due to low to medium porosity (up to 20%), very low primary permeability and any secondary fracture permeability probably being too low at target depths for CCS storage. Nevertheless, in terms of aquifer volume and depth criteria, these rocks form the best saline aquifer target in the Midland Valley of Scotland and provide a potential test of Central and Northern North Sea scenarios for aquifers with complex structural traps and minimal hydrocarbon reserves.

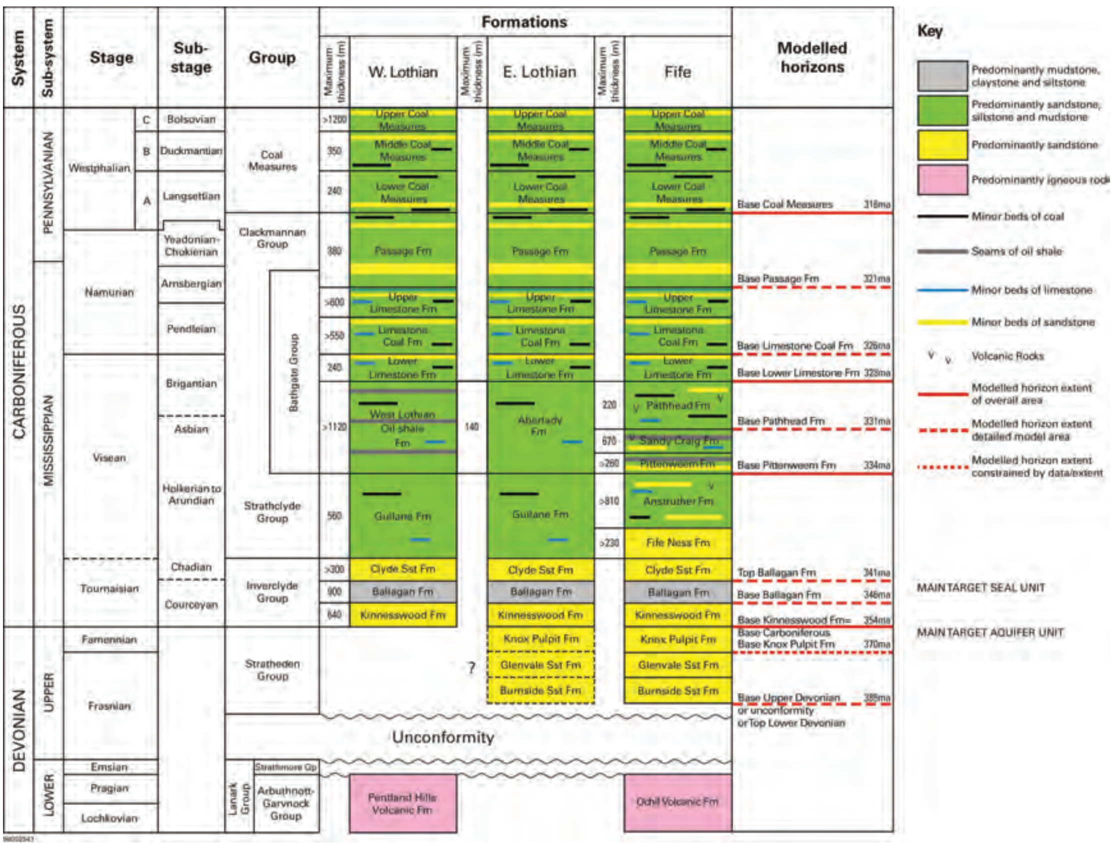


Figure 3.3 Simplified stratigraphy for the Firth of Forth site

Lincolnshire – site screening

The Lincolnshire area extends from Saltfleetby on the coast to Lincoln in the west (Figure 3.2b). In contrast to the Firth of Forth, this area has abundant modern, good quality data (2D and 3D seismics, wells and core samples) that describe a relatively simple and predictable eastward dipping geological succession with limited structural complexity. The primary target saline aquifer in this area is the Sherwood (or Bunter) Sandstone Group (SSG) and the corresponding cap rock is the Mercia Mudstone Group (MMG), both of Triassic age (Figure 3.4). A secondary target saline aquifer/ cap rock pair exists at greater depth, as represented by the sandstone-dominated Permian Rotliegendes Group sealed by the Marl Slate, Cadeby and succeeding evaporite rich cap rock formations.

Period	Geological Unit	Age (Ma)	Saline aquifer/ caprock/ overburden classification	Approximate depth below ground level at Saltfleetby
Cretaceous	Upper Cretaceous (Chalk Group)	90	Primary overburden	Base = 180 m (not modelled)
	Lower Cretaceous	100	Primary overburden	Base = 200 m (not modelled)
Jurassic	Upper Jurassic	151	Primary overburden	Base = 560 m (not modelled)
	Middle Jurassic (inc. Lincolnshire Limestone Fm)	164	Primary overburden	Base = 600 m (Top Lincolnshire Limestone modelled)
	Lower Jurassic (Lias Group)	179	Primary overburden	Base = 860 m (not modelled)
Triassic	Penarth Group	200	Primary overburden / caprock	Base = 870 m
	Mercia Mudstone Group	204	Primary caprock	Base = 1160 m
	Sherwood Sandstone Group	242	Primary saline aquifer	Base = 1490 m
Permian	Roxby Formation Equivalents	251	Primary bottom caprock	Base = 1560 m
	Brotherton Formation	253	Secondary overburden	Base = 1600 m (not modelled)
	Edlington Formation Equivalents	254	Secondary overburden / caprcock	Base = 1775 m
	Cadeby and Marl Slate formations (undifferenti-ated)	256	Secondary caprock (see details)	Base = 1780 m
	Rotliegendes Group	258	Secondary saline aquifer	Base = 1840 m
Carb.	Pennine Coal Measures Group	307	Underlies modelled succession	Base =2360 m (not modelled)

Figure 3.4 Simplified stratigraphy for the Lincolnshire site

These saline aquifer and seal pairs meet many of the selection criteria, with the major exception being that there are no significant structural traps. This site provides an opportunity to study dynamic trapping within a key target aquifer, the Sherwood Sandstone Group, with offshore equivalents in the southern North Sea that represent major oil and gas reservoirs with substantial saline aquifer potential (DTI 2006).

The Lincolnshire area is also important in that it includes the onshore continuation of a major offshore aquifer that is exploited for other human activities. As the geological succession is traced westwards and up-dip (Figure 3.5), the aquifer is utilised extensively for water abstraction. This presents an opportunity to examine the impact of CO_2 injection pressure effects on ground and surface water systems. At the outset, this was perceived as a significant risk. A hydrogeological model (Bricker et al., 2010) was produced (Case Study 2 below) and the results integrated with the dynamic flow simulation modelling (Chapter 4).

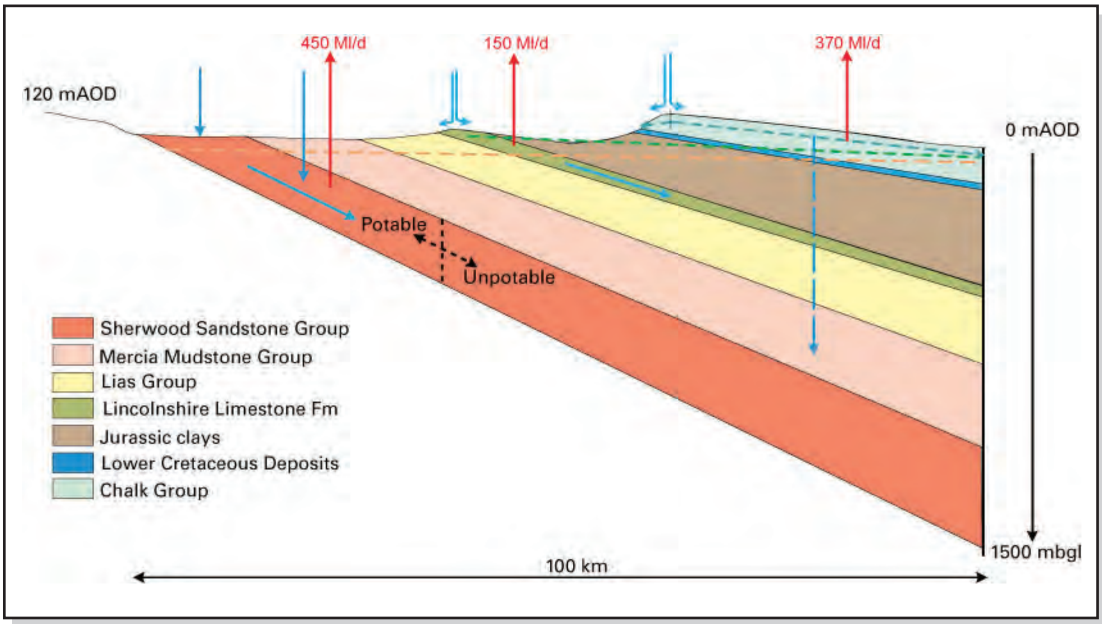


Figure 3.5 Schematic geological cross-section (west to east) of the Lincolnshire study area with regional groundwater flow and abstraction. Abstraction from the Sherwood Sandstone Group is approximately 85% unconfined, 15% confined. Blue arrows represent the flow of recharge, red arrows are abstraction in megalitres per day (Ml/d).

3.5 EVALUATION-DECISION GATE 1 (E/DG1)

At this gate an assessment and ranking of the target sites is carried out. This process should include an assessment of the uncertainty and potential challenges presented by the geology to inform data acquisition and best approach to modelling.

Geological knowledge, data availability and approximate depth to the saline aquifer/cap rock and presence of a structural trap (Firth of Forth only) are the key variables to enable an area to be selected for initial modelling. In summary, both CASSEM sites satisfy the basic geological criteria (Table 3.2) and provide sufficient data desirable for an initial characterisation exercise relevant to basin-scale assessments. They do, however, fall short on the requirements (e.g. 3D seismic data) for full site characterisation and prospective storage capacity, as described by Kaldi and Gibson-Poole (2008).

Criteria	Forth. Primary saline aquifer/cap rock (Knox Pulpit; Ballagan)	Forth. Minor aquifer/seal (e.g. sand bodies in Lower Carboniferous)	Lincs. Primary aquifer/seal (Sherwood Sstn./Mercia Mudstone)	Lincs. Secondary aquifer/seal (Rotliegendes/ Cadeby Marl Slate)
Saline aquifer present	Not known	Not known	Not known	Not known
Saline aquifer depth (elevation of top surface)	Ranges from -1300 to -3000 m OD in parts of the study area with anticlinal traps. Synclinal areas deeper. Comes to outcrop at margins of overall area.	Lower Carboniferous ranges from -400 to -2000 m OD in parts of the study area with anticlinal traps. Synclinal areas deeper. Comes to outcrop within overall area.	Ranges from 700 to -1555 m OD; < -800 m in 60% of the region of study	Ranges from -860 to -1955 m OD; i.e. all < -800 m in the region of study
Trap geometry exists	Several anticlinal trap structures identified	Several anticlinal trap structures identified	Not identified in region of study	Not identified in the region of study
Cap rock exists	Cap rock thought to be present in all areas south of Ochil Fault system, likely >100 m thick	Mudstone/siltstone 'seal' present throughout variable character overburden	Seal >200 m thick, locally transitional base	Cap rock>100 m thick over 40% of the region of study (CDFu + EDT)
Availability of geological data	Patchy, variable quality 2D seismic data with no well control at saline aquifer/ cap rock level	Patchy, variable quality 2D seismic data with limited well control	Good 3D seismic data in part	Good 3D seismic data in part
Suitable porosity	Up to 26% (Milodowski & Rushton, 2008)	Up to 17% (Passage Fm, Milodowski & Rushton, 2009) but very limited data	25% (approximate)	16% (approximate)
Suitable permeability	Mean 70-80 mD assumed, some up to 1000 mD, from previous work	Permeability not yet known	Limited knowledge assumed 500 mD	Permeability not known at time of E/DG1 (later HWU results gave permeability)
Stratigraphy	Likely lateral variability of aquifer rock types. Cap rock shows some lateral variability but moderately well known.	Likely lateral variability of aquifer rock types. Seals likely more continuous.	Uniform aquifer and seal	Fairly uniform saline aquifer, variable seal

Table 3.2a Summary of geological evaluation at E/DG1 for CASSEM sites

Saline aquifer volume	Assume >150 m thick sandstone for Knox Pulpit Fm over part of area and Kinnesswood Fm >100 m over whole area	Volumes of minor aquifers likely to be very small as maximum thicknesses of c.20 m and lateral extent not known.	>170 m thick sandstone throughout region of study	>40 m thick sandstone over approximately 200 km^2, >60 m thick sandstone over 150 km^2, >80 m thick sandstone over approximately 15 km^2,
Igneous rocks	Commonly cross-cutting in study area, geometry poorly defined	Commonly cross-cutting in study area, geometry poorly defined	Not identified in the region of study	Not identified in the region of study
Containment	Risks to containment include existing boreholes/wells, faults of unknown character, routes provided by igneous bodies	Risks to containment include existing boreholes/wells, faults of unknown character, routes provided by igneous bodies	Locali sed clusters of deep hydrocarbon wells	Localised clusters of deep hydrocarbon wells

Table 3.2b Summary of geological evaluation at E/DG1 for CASSEM sites

3.6 BUILDING THE GEOLOGICAL MODEL – LEVEL I

Construction of the Level I model is a key step in the workflow. It involves the compilation and assessment of the available data, followed by a series of iterative steps and feedback loops. These deliver a preliminary interpretation, test the validity and suitability of the geological data (Figure 3.1) and identify any shortcomings in data quality and sufficiency. The asset team will then make recommendations on dataset enhancement (e.g. is reprocessing of seismic data beneficial or necessary?) at the decision gate (E/DG2).

Data acquisition

For each selected site all publicly available geological data, including seismic data, underground mining, borehole, well data, isopach and sub-crop maps should be acquired, assessed and compiled in GIS format, and key datasets licensed and prepared for preliminary analysis using appropriate software (e.g. Geographix® Seisvision, WellBase and Landmark™). Combined with knowledge of the regional geological framework and local geological expertise, preliminary stratigraphic surfaces can be generated to honour geological reference points, e.g. wells, outcrop and seismic data. These geological surfaces are then assessed and gaps in seismic data and quality addressed by licensing and purchase of additional infill data.

Rock and fluid property data

All rock and fluid property data, including mineralogy, porosity, permeability, petrophysical metrics (e.g. Young's modulus, Poisson's ratio, etc.) and in situ metrics (e.g. fluid salinity, pressure and temperatures, and the historic and modern stress field) for key horizons, including target aquifer and cap rock, should be compiled and combined with a listing of rock sample availability from existing drill cores obtained during ground investigation (e.g. for coal, geothermal, oil and gas).

Where drill core material and/or well coverage is sparse, other regional drill core and surface outcrops may be a significant supplement providing (1) indications of vertical and lateral lithological heterogeneity in the geological model, (2) reservoir simulations and capacity estimates with information on stratigraphic architecture where heterogeneity is below the resolution of the main model, and (3) analogue samples for laboratory analysis.

Firth of Forth – data acquisition

In the example of the Firth of Forth, the geological framework and model is based on an interpretation of third-party 2D seismic data, limited downhole borehole/well data, subsurface mining data and BGS onshore mapping (Figure 3.6). At the depth of interest, the configuration of the proposed store is poorly constrained by the available data. Only the BGS Glenrothes borehole (Brereton et al., 1988), onshore in the north of the area, reached the target aquifer, the Knox Pulpit Formation. No boreholes penetrate the target aquifer or cap rock in the favoured sites, introducing considerable uncertainty in the geological interpretation. Five wells, shown in Figure 3.6, provide accessible time-depth information and were used in controlling the position of seismic picks; all of the wells terminate above the Ballagan Formation cap rock. Borehole core samples were collected from the Glenrothes borehole where the primary saline aquifer/cap rock are at depths >200 m, with additional primary saline aquifer/cap rock material from shallow depths (<70 m) and from outcrop.

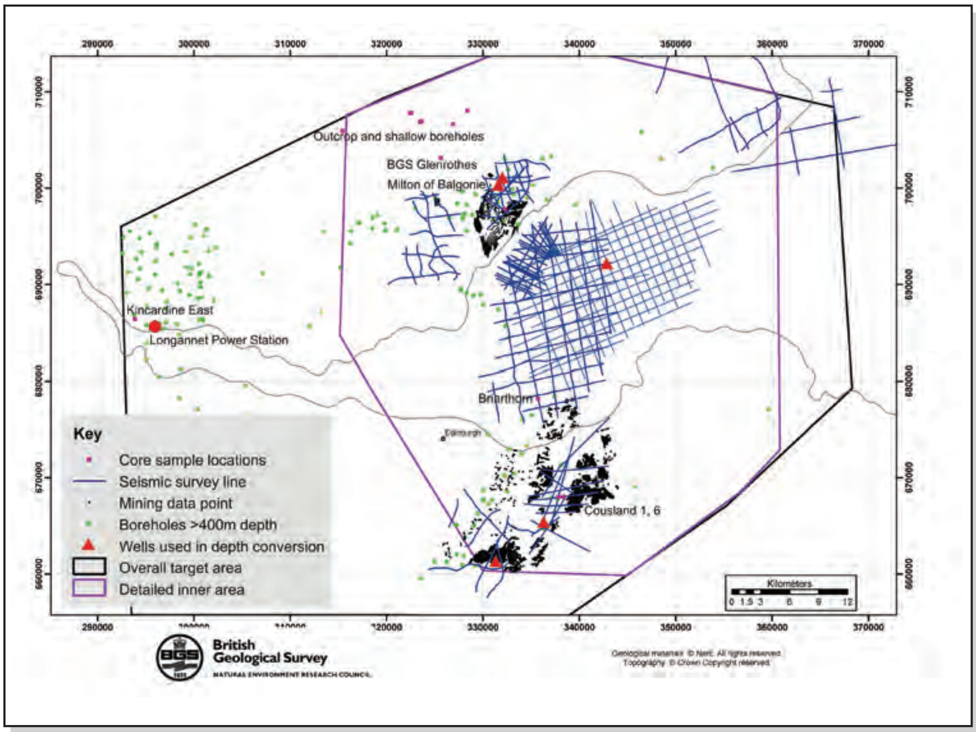


Figure 3.6 Data types and distribution in the Firth of Forth

Lincolnshire – data acquisition

In contrast, in the example of Lincolnshire, a data-rich site, the geological framework and model is based on an extensive interpretation of good-quality third-party 2D and 3D seismic data, geological borehole/well data and existing BGS geological mapping (Figure 3.7). The seismic picks were controlled using well data and mapped surface outcrop. Eighteen wells were used to depth-convert the geological horizons and faults.

In general, the wells penetrated through the entire Permo-Triassic succession to terminate in the underlying Carboniferous rocks. Borehole core samples were provided from the BGS Cleethorpes No.1 borehole (Downing et al., 1985) where the primary aquifer and secondary saline aquifer/cap rock were at depths from 1100–1190 m. Additional core material, including that from the primary cap rock, was available from boreholes of shallower depths to the west of the modelled area.

Asset team loop: data compilation, first response tools and initial model evaluation

After integration of known fixed points (e.g. well ties and, if near-shore, surface outcrop and mine maps), interpretation of seismic data allows preliminary surfaces and faults to be proposed and risk assessed (Chapter 6). These initial surfaces are built using a standard interpolation workflow in a package such as GOCAD (e.g. Ford et al., 2009b) or Petrel. For efficiency, seismic interpretation typically selects conspicuous surfaces that are then auto-picked into weaker signal portions with additional mimicking algorithms into deeper or shallower horizons. While still in the preliminary stage, some or all of the surfaces are tested using the first response tool set that was developed during the CASSEM project.

These tools address three key areas: (1) structural validity, (2) surface regions and pathways for CO_2 migration, and (3) depth critical regions for CO_2 phase behaviour:

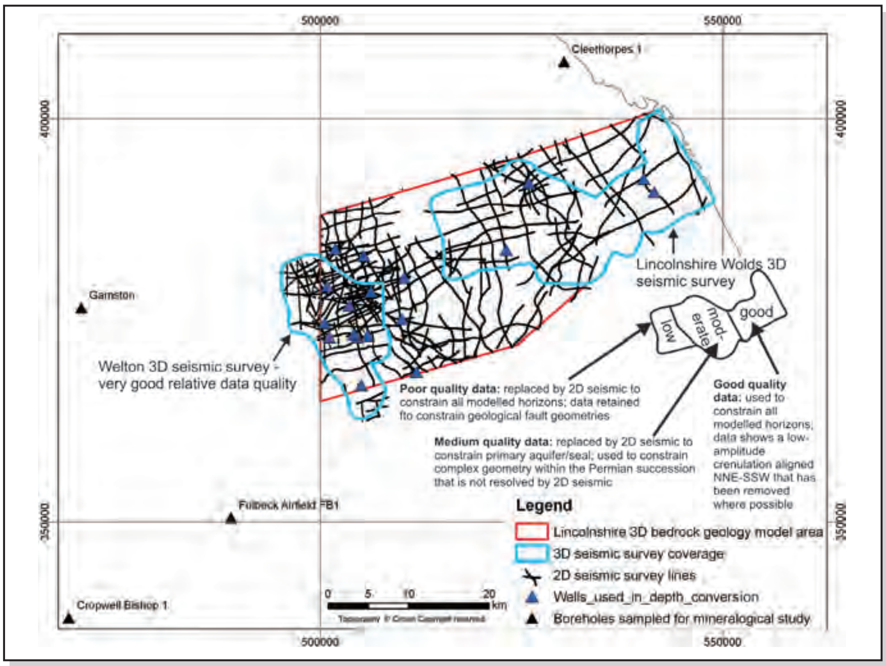


Figure 3.7 Data types and distribution in Lincolnshire

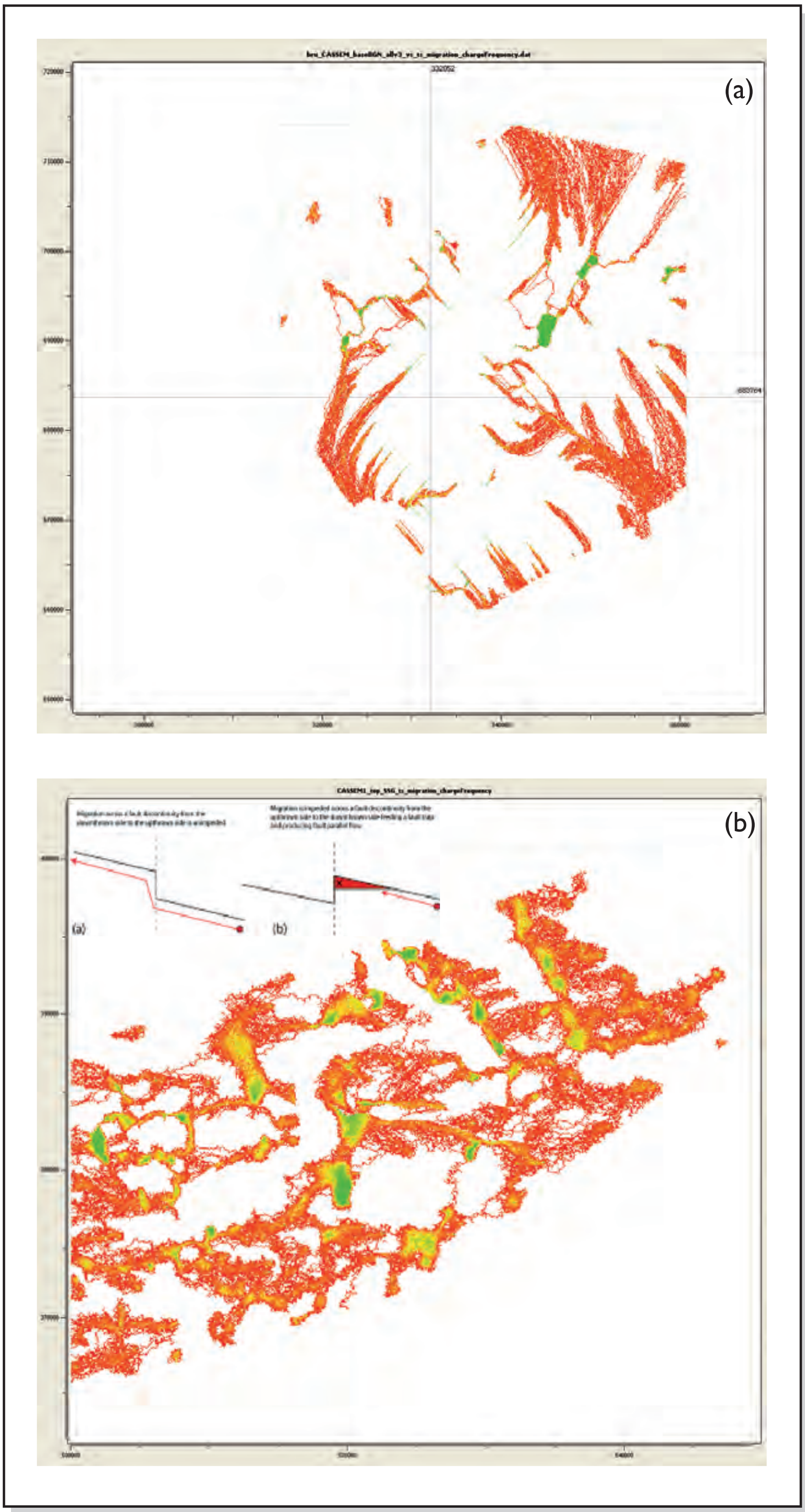


Figure 3.8 Mpath Single Map Migration output for saline aquifer/cap rock boundary based on 100 simulations with 20 iteration (±10 m uniform uncertainty) per well; wells represented as single dots: (a) Firth of Forth, base of Ballagan Formation showing structural traps (green polygons) and predicted CO_2 migration pathways (red polygons); (b) Lincolnshire, top of Sherwood Sandstone Group – green polygons identify structural highs and linear patterns identifying NW–SE trending faults.

(1) Structural validation used 2D-Move (Midland Valley Exploration Ltd) and provides a key early test where structural complexity is present. Indicators of structural complexity are: major faults (i.e. faulting with displacements >15% of the fault length at the slip-surface mid-point), folds with large amplitudes, or multiple fold sets with differing geometries. Precise structural validation is a lengthy iterative process (see Level II below); an initial quick test of whether preliminary surfaces are geometrically viable is the aim here. This validation is achieved through either reverse modelling ('restoration') techniques or forward modelling of a simple initial geometry (e.g. horizontal layers). Both invoke a suite of algorithms that describe deformation of rocks. Portions of the preliminary surfaces which are geometrically invalid or where there is large uncertainty, i.e. where minor differences in position or geometry would have a large impact, are highlighted.

(2) Pathways for migration of buoyant CO_2 below the seal of the target aquifer may be assessed using a single map migration technique such as Mpath (Permedia Research Group Inc). This geometric technique samples preferential migration directions for the surface investigated. Multiple (typically tens to hundreds) up-dip migration simulations, subjected to stochastic uncertainty, are run for a range of injection points to reveal likely migration pathways and traps. This provides an early opportunity to target further data collection activities in regions where CO_2 is likely to migrate, to integrate subsurface geometry and uncertainty, and identify likely target sites for injection wells.

Examples of the contrasting style in predicted migration directions of buoyant CO_2 between the two case study areas are shown in Figure 3.8. A relatively homogeneous dispersal pattern is predicted for Lincolnshire whilst the Firth of Forth displays a strong heterogeneity. The absence of an obvious structural (static) trap is a notable feature of the Lincolnshire saline aquifer site. Of interest in this study are the numerous (20–50) small structurally high areas ('traps') that are filled (up to 'spill') by the ongoing CO_2 flux that further enhances the 3D reservoir architecture dynamic trapping.

(3) Reservoir modelling and monitoring also requires an assumption or prediction of the density, viscosity and solubility of CO_2 under initial depth conditions. For example, does the adoption of the depth criteria (i.e. >800 m depth below mean sea level) for a uniform phase change guarantee that CO_2 remains in the dense phase as it migrates? Where geothermal and hydrostatic gradient data allow, using CO_2 Depth Profile (Dr. M. Naylor and University of Edinburgh) indicates where simple or complex multiphase behaviour is likely. For preliminary model surfaces with significant uncertainty that encompass critical depth regions, this tool will highlight regions where further work is required to improve data quality, confidence and interpretation.

This suite of initial tests allows the asset team to respond with a spatial re-evaluation and reinterpretation as a feedback loop around the Level I workflow. After a series of iterations, depending upon structural complexity and data quality, a Level I 3D model can be defined, comprising a series of interpolated digital surfaces (geological layers and some faults), or recommendations made for further database enhancement before a model can be built.

3.7 EVALUATION - DECISION GATE 2 (E/DG2)

At E/D2 the geological model is considered for an invest or hold decision and may be ranked against alternative storage sites identified by the client/operator. In the case of less favourable ranking, the asset team may make recommendations for database enhancement. Implementation of these recommendations forms a key part of a broader cost-risk-invest business decision.

At this stage, the preliminary Level I model may be released to inform planning and decisions on approaches to capacity modelling and monitorability. Similarly, a coarse static capacity estimate (see Jin et al. (2010) may be included to further advise the invest/hold decision.

Firth of Forth

From the initial work at the Firth of Forth site an assessment of the model results against basic geological criteria (Tables 3.1 and 3.2) indicates that over much of the investigated area, the saline aquifer/cap rock depth, trap geometry, distance from power plant, and porosity, all positively meet the geological criteria with relatively high confidence. Known complexity of stratigraphy, presence of igneous rocks, existing permeability measurements and containment issues negatively meet the geological criteria. Critically, the existence, thickness and volume of the saline aquifer/cap rock and salinity are unknown due to the lack of well data at appropriate locations. On this basis, the Firth of Forth site would be negatively ranked and held at E/D Gate 2. However, in order to further test the workflow, this site was progressed through to the Level II intermediate model with the Forth Anticline as the target recommended for further study.

Lincolnshire

In contrast, the Lincolnshire area has relatively simple and predictable geology and good data coverage (Table 3.2). The modelled horizons for the Lincolnshire site could be built with a greater degree of confidence and show a simple easterly dipping succession of layered strata cut by a series of relatively minor faults. Recognised issues with minor fault displacements and differing permissible options for fault continuity were considered to have only minor effects (Ford et al., 2009). Lincolnshire was cleared for advancement at E/D Gate 2 by all of the first response tools, with no major recommendations for data enhancement.

CASE STUDY 2: DATABASE ENHANCEMENT, FIRTH OF FORTH

Many of the potential offshore storage targets for UK CCS are covered by relatively old seismic data acquired during the early days (1970s and 80s) of hydrocarbon exploration and licensing. Modern reprocessing techniques now offer the opportunity to improve poor quality data, and confidence in data interpretation and the geological model. As part of the CASSEM methodology, a reprocessing test was performed on a grid of original offshore 2D seismic data with modern industry-standard (Schlumberger) processing techniques.

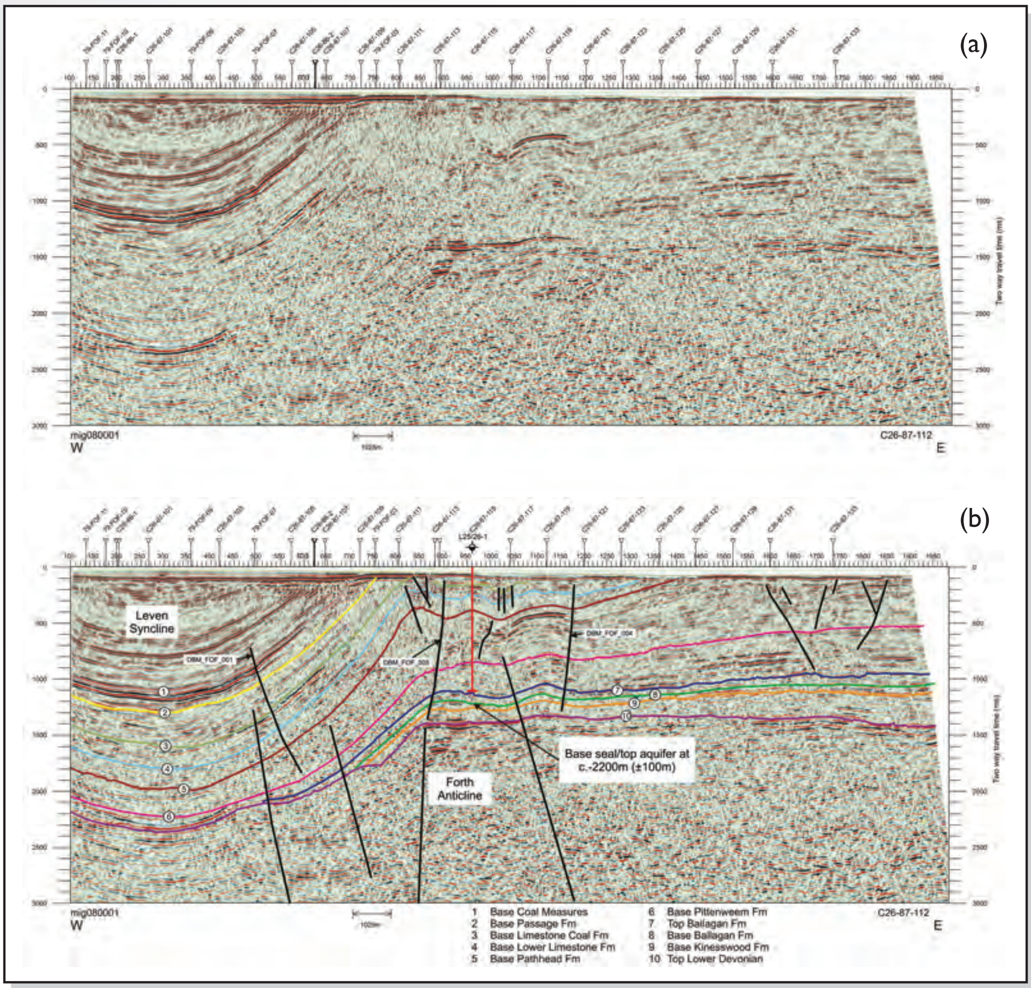


Figure 3.9 Example of the best seismic data from the Firth of Forth area. Line C26_87_112 oriented SW–NE through the Forth of Forth-1 (25/26-1) tied well. Shown with permission of Phoenix Data Solutions: (a) primary data and (b) interpreted geology and regional structure. Only the labelled faults were included in the 3D geological model.

In the Firth of Forth, the geological succession is folded into a series of NNE- trending anticlines and synclines and cut by steep to vertical faults of varying orientation (e.g. Figure 3.9). First response tool analysis highlighted an unsatisfactory compromise in the interpretation of the seismic data, most critically in the Leven Syncline with a ‘downlap’ scenario with multiple pinching out of units at the saline aquifer/cap rock level. This is important as the catchment area within the trap is interpreted to be limited. Up-dip single map migration runs (assuming buoyant CO_2 behaviour) for a range of stochastic uncertainties and wells showed dramatic tendency for migration away from the target antiformal structural trap (see Figure 3.8a). In addition, the irregular discontinuous nature of some of the key stratigraphic horizons was initially interpreted as due to faulting. Much of this faulted data is located around the Forth Anticline on the eastern side of the Leven Syncline, which was predicted to host the target aquifer within the critical depth interval.

Database enhancement was recommended. Reprocessing of the 2D seismic data set comprised 30 lines totalling approximately 500 km. The technical details, described in Sansom (2009), involved pre-stack noise attenuation, pre-stack demultiple, offset migration and post-stack processing.

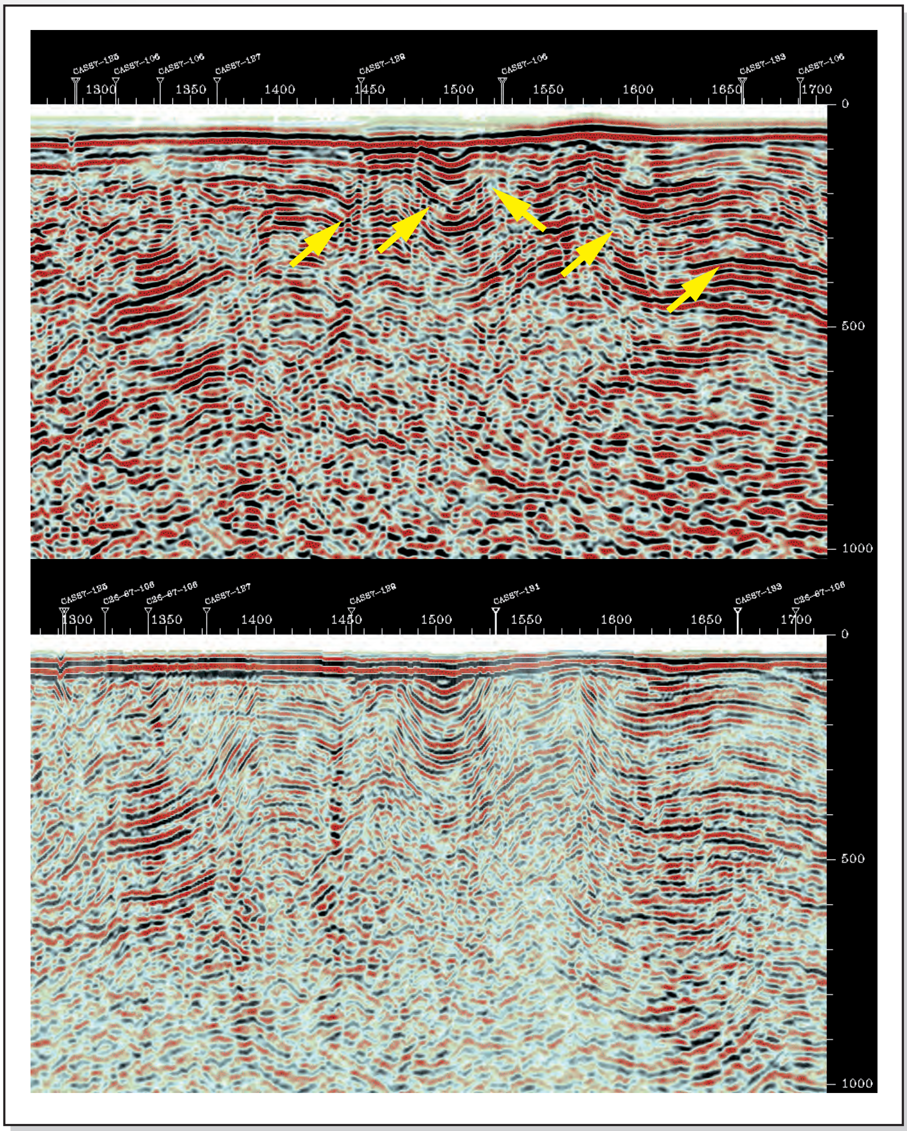


Figure 3.10 Example of original seismic data (top) compared to reprocessed data (below) for part of Conoco 87 Line 106, showing the improvement in the imaging of a series of near-surface folds. The poorly imaged folds in the original data were previously, and incorrectly, interpreted to be a series of faults (highlighted by yellow arrows). Vertical scale is TWTT (Two Way Travel Time) in milliseconds.

Interpretation of the reprocessed data (McInroy and Hulbert, 2010) revealed the following:

- Areas with incoherent reflectors in the original dataset, often interpreted to be faults, now revealed as coherent steeply dipping and tightly folded reflectors. Several faults were removed from the original interpretation (Figure 3.10).

- Better imaging in the trough of the Leven Syncline led to reinterpretation of seismic picks and corrected geological interpretation from lateral pinch-outs to through-going (sub)parallel synformally folded layers.

- Change in depth of key picks over the Forth Anticline (up to 200 m upwards) and the Leven Syncline (up to 1000 m downwards) (Figure 3.11).

- Removal of many of the deep reflections (artifacts?).

This work clearly illustrates the added value and cost benefit that early reprocessing brings to confidence in geological interpretation.

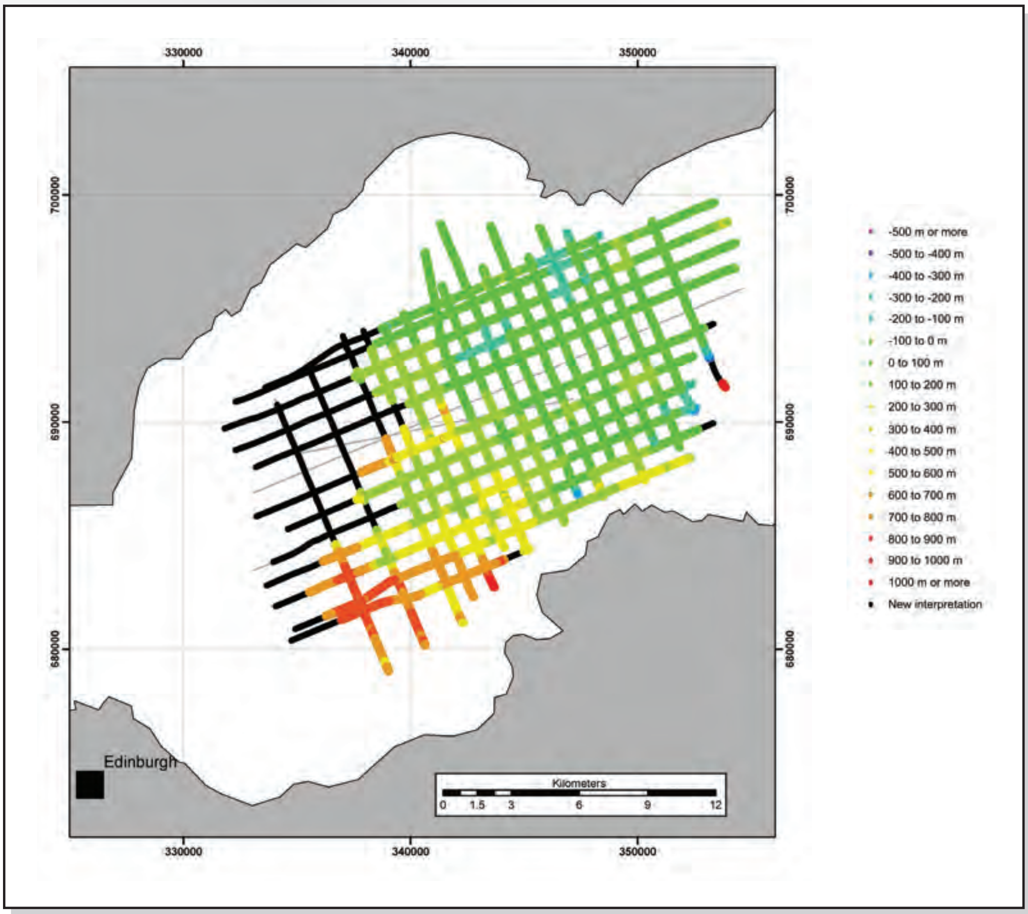


Figure 3.11 Example of difference between original and reprocessed interpretations of depth difference to base of the Ballagan Formation (cap rock).

3.8 BUILDING THE GEOLOGICAL MODEL - LEVEL II

Level II Model

At this stage a full geological model is constructed comprising key stratigraphical surfaces and faults of the target saline aquifer and cap rock and surrounding stratigraphies. Model conditioning includes further application of structural restoration techniques and geometric tests on the surfaces.

Depending upon the degree of structural complexity, there may still be significant changes to local elements. For example, where faults are associated with large displacements and/or more intense surface curvature, then limiting their position at depth is problematic. This requires best estimates of thickness, dip and fault geometry. Confidence in surface curvature is also the starting point for strain analyses and modelling of discrete fracture networks. MPath may also be redeployed at this stage for locating injection wells in the reservoir simulations (Chapter 5).

The two CASSEM project sites provide contrasting illustrations of this workflow stage.

Firth of Forth Level II model

The data, construction methods and limitations of the full 3D geological model are described in Monaghan et al. (2008b). Representative images are shown in Figure 3.12.

Model limitations include:

- Scale of use 1:250,000 to 1:50,000, locally higher in certain areas.
- Igneous intrusions and vents not modelled.
- In target storage area, no wells reach suitable depths and saline aquifer/cap rock location is highly uncertain: constrained by geologists' interpretation only.
- Faults are generalised as discrete planes of movement; in reality, they typically occur as complex zones of deformation and brecciation, including multiple fracture surfaces, and may act as a barrier (if sealed) or a pathway (if open) for fluid migration.
- Complex sub-seismic stratigraphy (e.g. alternating, interleaving mud and shale layers) in reservoir and cap rock are indicated in neighbouring area well logs.

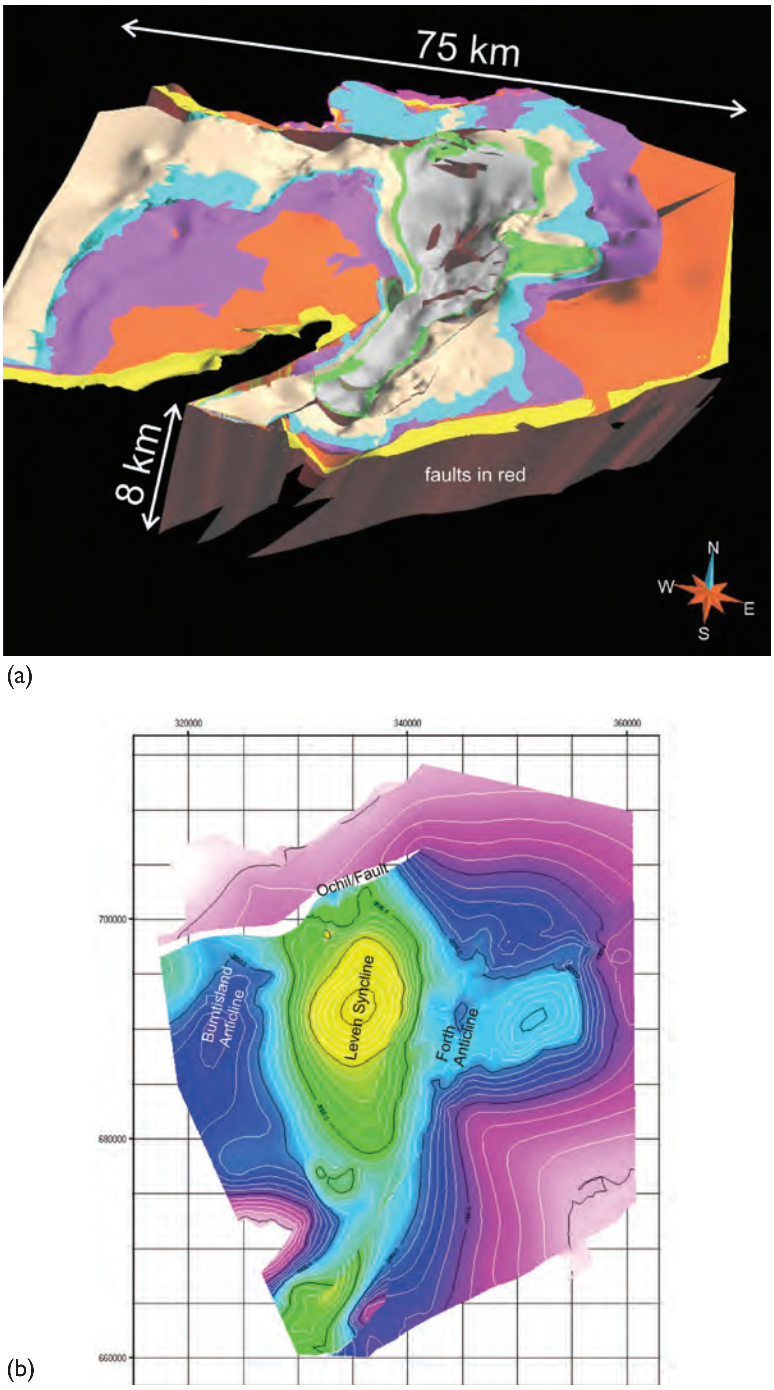


Figure 3.12 (a) Level II 3D geological framework model for Firth of Forth; (b) Contour map plot of the base Ballagan Formation (base cap rock/top saline aquifer).

Figure 3.12 illustrates the Midlothian-Leven Syncline structure (black contours every 1000 m, so deepest part of syncline: 5200 m) and the Forth and Burntisland anticlines.

The Firth of Forth level II model was significantly revised following the reprocessing of legacy seismic data (Case Study 2 above). Conditioning and validation of the complexity present in the new model included revising surface curvature and reducing uncertainty in the depth and position of surfaces by applying unfolding and backstripping techniques.

Unfolding

As the Firth of Forth folds are modelled as concentric structures affecting the complete geological succession, then a flexural slip unfolding algorithm can be applied to validate the model. The algorithm works on the limbs of a fold by de-rotating them back to a horizontal datum (reference line in 2D, a surface in 3D) or an assumed regional reference line/surface and then removes the displacements between the separate rock layers.

Backstripping

Backstripping is a commonly applied reverse modelling technique that tests the relationship between variations in sediment thickness and timing of movements on individual faults within a geological section. It effectively steps backwards in time, sequentially removing the current uppermost rock layer for the given period, migrating the corresponding lower layers upwards and applying various corrections (for decompaction and isostasy). In the Firth of Forth model where these surfaces no longer exist (i.e. eroded away), they were reinstated above the present day surface, honouring the geometry of the geological structure preserved at depth (see difference in Figure 3.13a, b and c). This tested for and excluded the complication that the folding which formed the Leven Syncline occurred during the main sedimentation (Carboniferous).

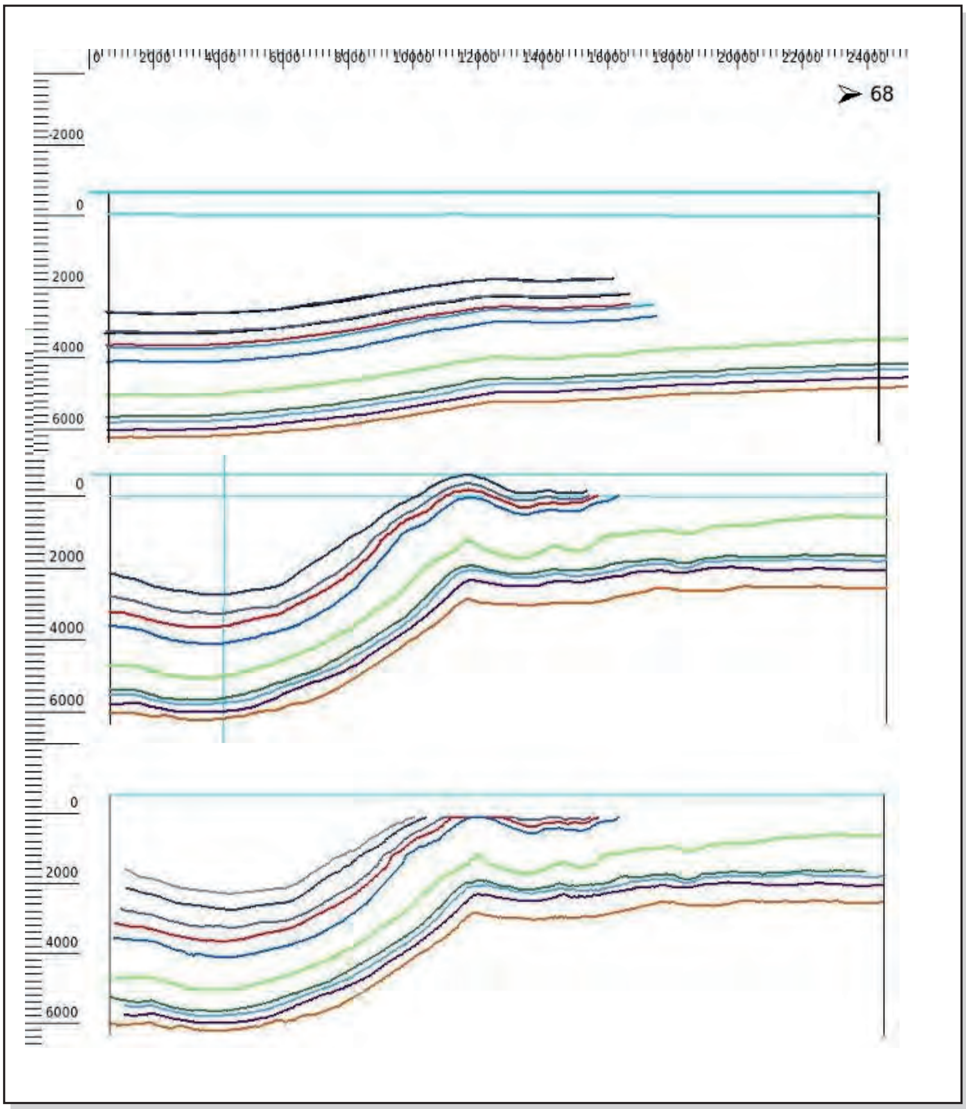


Figure 3.13 Example from bottom to top of (a) smoothing, (b) eroded surface rebuilding and (c) 80% flexural slip unfolding to -6000 m datum about a 05 degree SW pin line in the Leven Syncline, as applied to Firth of Forth modelled surfaces. Backstripping model validation not shown.

Lincolnshire level II model

The data, construction methods and limitations of the 3D geological modelling are described in Ford et al. (2009b). Maximum error on depth of modelled surfaces is interpreted as ±30 m, with ±15 m for the aquifer top surface as illustrated in Figure 3.14. The faults shown are those identified from the seismic reflection data and where an offset or disturbance is observed. Faults with a vertical displacement of >10 m are resolvable, many cross the interpreted horizons and potentially provide vertical high permeability pathways.

The models confirm a high level of data-fitting, with a GOCAD model confidence showing 95% of the seismic data points are honoured by the initial surfaces to a tolerance of less than 20 m. Such confidence permits the construction of uncertainty maps and reliable surface elevation maps for each horizon (Figure 3.15). Thus, further structural analysis of the relatively simple structure of the Lincolnshire model is unlikely to significantly refine the depth and thickness errors.

As the target aquifer is also utilised for up-dip groundwater abstraction (Case Study 3 below) then an assessment of the potential CO_2 migration pathways is important at this stage.

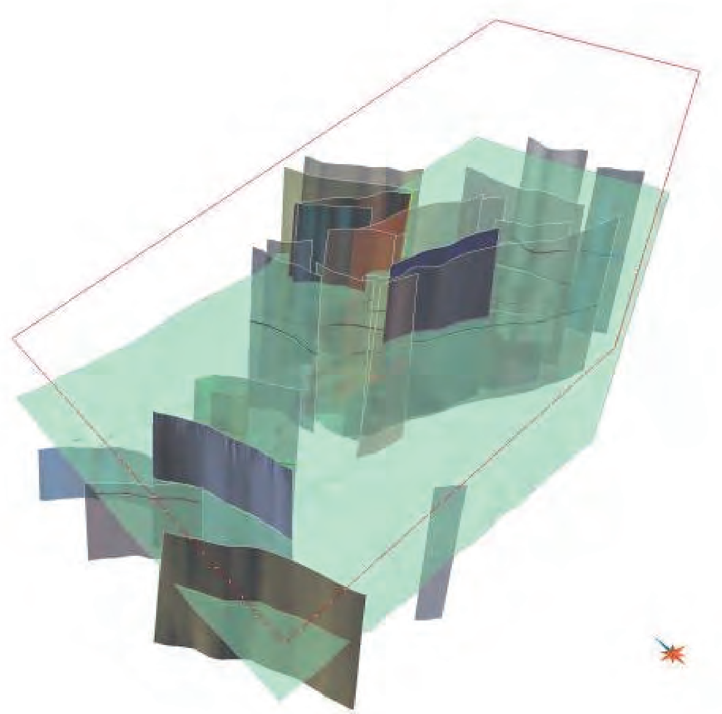


Figure 3.14 3D geological framework model for Lincolnshire faults intersecting top Sherwood Sandstone Group – view to NE.

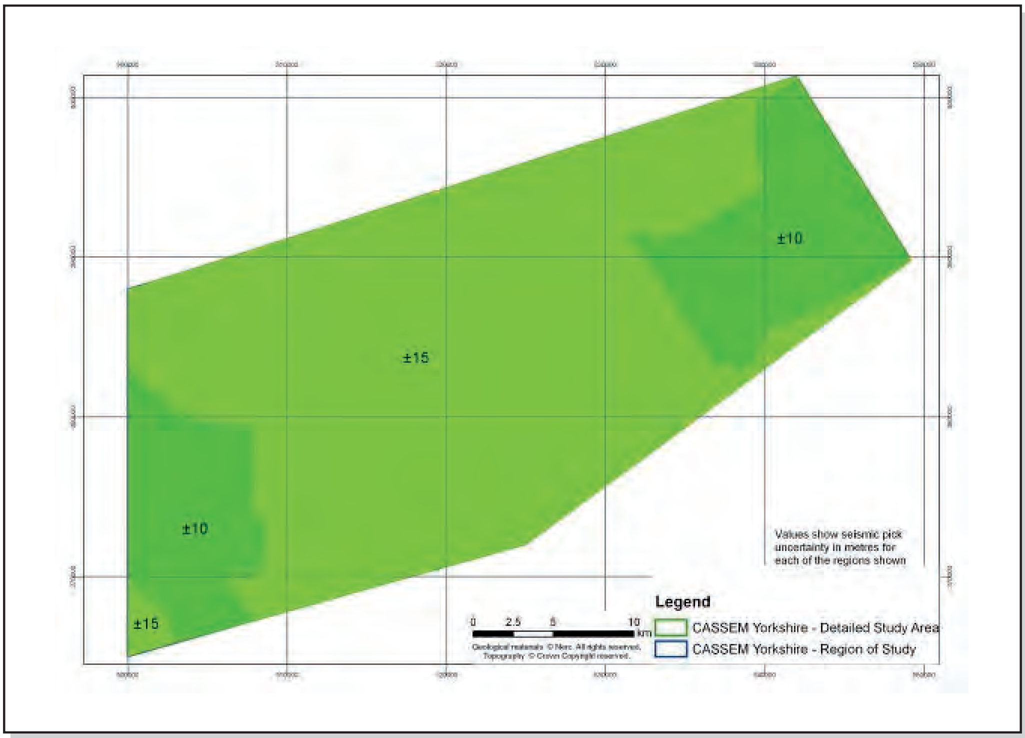


Figure 3.15 Seismic pick uncertainty map for the top Sherwood Sandstone Group.

The simple pattern of lineation in migration pathways due to flow that is parallel to faults on the up-dip side (Figure 3.8) results in the distribution of fetch areas and structural closures shown in Figure 3.16. The interpreted faults in the model may act as conduits and facilitate the rise of CO_2 to stratigraphically higher lithologies, or act as impermeable barriers and compartmentalise any westward migration (thereby limiting storage capacity). Further database enhancement is recommended to mitigate this uncertainty.

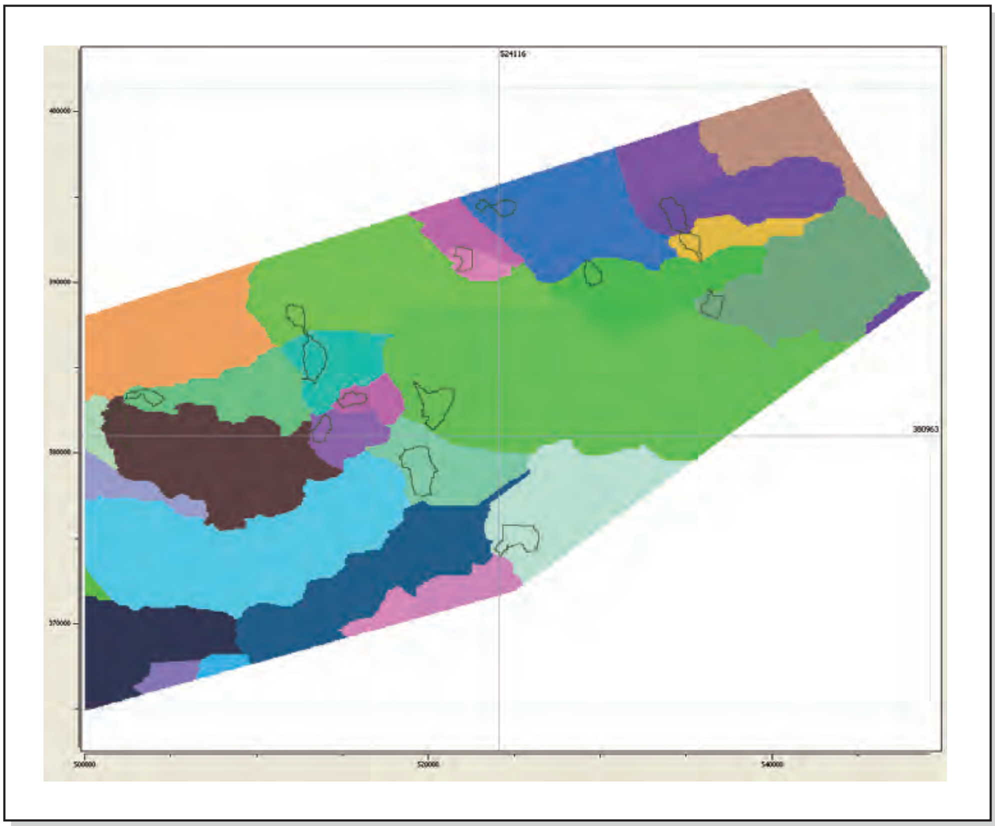


Figure 3.16 Mpath Fetch and Closure Analysis on the Lincolnshire Sherwood Sandstone Group. Note 15 principal structural closures (black outlines). Colours to differentiate fetch areas ('catchments') are arbitrary. Area is likely to be scalable and be well suited for dynamic trapping (see Chapter 4).

CASE STUDY 3: A HYDROGEOLOGICAL ASSESSMENT OF CO_2 INJECTION IN EAST LINCOLNSHIRE

The impact of CO_2 injection on shallow groundwater systems is a key issue for onshore storage options (e.g. Nicot, 2008; Birkholzer et al., 2009 and Yamamoto et al., 2009). Injection of CO_2 has the potential impact of raising groundwater pressures and changing groundwater flow in aquifers many tens of kilometres distant from the injection site. In the eastern part of the Lincolnshire model, saline fluids within the Sherwood Sandstone aquifer (SSG) pass up-dip into fresh groundwater, which is extensively extracted for public supply. The chalk aquifer which overlies the SSG at the injection site is also used extensively for public water supply (Figure 3.5). Thus, an examination of the hydrogeological implications of deep CO_2 storage on shallow groundwater systems has relevance to any wider environmental and impact assessments.

The potential impact of onshore to near-shore injection of CO_2 on the hydrogeology of the SSG freshwater aquifer has been modelled by Bricker et al. (2010). This work evaluates the hydrogeological properties of the geological formations which form the aquifer, the cap rock and the overburden, and numerically simulates the injection of CO_2 and its potential impact on the shallow (up-dip) groundwater systems.

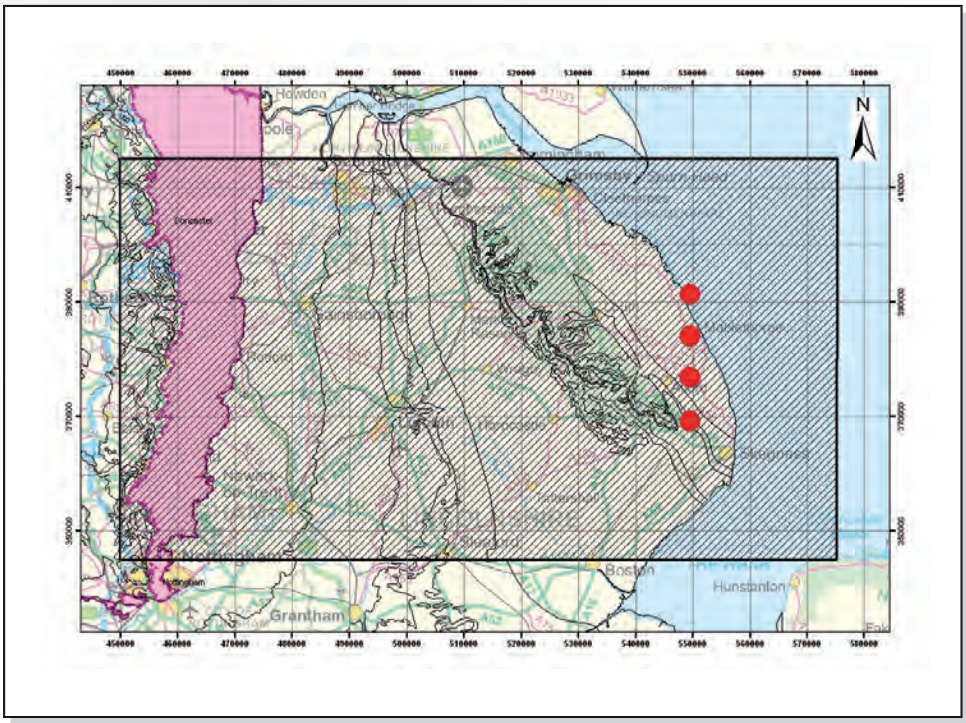


Figure 3.17 Area covered by the CASSEM numerical groundwater model. The SSG outcrop area is shown in pink, and injection sites in red.

A dual approach was adopted. Firstly, to create a hydrogeological conceptualisation of the system and, secondly, to perform a groundwater modelling exercise. The hydrogeological task, using shallow aquifer property data derived from the BGS aquifer properties database and the Environment Agency, sought to characterise the hydrogeological system at depth and to identify the potential leakage routes that might occur due to increased pressure caused by CO_2 injection. Drawing on this, a groundwater model was then developed to evaluate groundwater heads pre- and post- injection, leakage through the seal formation, water balance calculations and potential impacts on groundwater abstraction and river flows.

Key findings from the hydrogeological study are listed below:

- Three major aquifer units are present in the area, supporting licensed abstraction ranging from 150 to 450 Ml/d.
- Four key transport routes identified: laterally up-dip along the Sherwood Sandstone, through the cap rock (Mercia Mudstone Group), through deep boreholes, and through faults.
- Groundwater at an injection zone some 80 km into the confined aquifer is expected to be brine with values typically between 35–80 g/l.
- The main Sherwood Sandstone aquifer becomes less permeable and less productive with depth as fracture flow decreases.
- Transmissivity at depth is estimated to be 40–135 m^2/d (28–95 Dm) but permeability may be reduced by less dissolution of cements and presence of fibrous clays.
- Based on regional analyses, the intrinsic permeability of the SSG may vary over four orders of magnitude.
- The cap rock is lithologically heterogeneous and subject to geochemical weathering at depths <400 m below ground level.

The dynamic effects of CO_2 injection were then approximated using a 3-layer ZOOMQ3D numerical groundwater model which represented the spatial variation of the geological and hydrological properties of the Sherwood Sandstone. CO_2 injection was simulated at a rate of 15 Mt/yr distributed across eight injection wells.

Regionally, the Mercia Mudstone Group (MMG) is heterogeneous with varying proportions of mud to sand, and, therefore, and the model assumes that the cap rock does not have a perfect seal. A vertical hydraulic conductivity of 10^{-6} m/day for the MMG was applied within the groundwater model. Under this leakage scenario, groundwater heads in the shallow confined SSG aquifer, where it is used for potable water supply, increase by between 0.01–10 m. Groundwater levels within the unconfined aquifer increase by <0.01 m to 1 m, with a corresponding increase in river flows of approximately 1.7%.

Results from the model highlight two important points. Firstly, that the degree of impact on shallow groundwater systems is highly sensitive to the vertical leakage assigned to the cap rock. Reducing the vertical hydraulic conductivity of the MMG by one order of magnitude to 10^{-7} m/day has the effect of increasing groundwater heads in the shallow confined aquifer by 0.1–50 m and increasing river flows on the unconfined aquifer by approximately 9%.

Secondly, the response of groundwater heads in the deep confined part of the aquifer to injection, is rapid, with groundwater heads approaching their maximum limit within the first five years of injection (Figure 3.18). Recovery of groundwater heads to baseline conditions post-injection is equally rapid within the deep saline aquifer, with near complete recovery occurring within the first five years. Recession of groundwater heads in the shallow confined aquifer occurs less quickly, with groundwater heads still elevated by up to 1 m ten years after injection ceases.

The approach adopted in this study provides a preliminary assessment of CO_2 impacts. To improve the model requires a better understanding of facies variation in the SSG and geomechanical modelling of faults, such that preferential flow paths within the storage formation can be accounted for.

At the interface between the deep and shallow confined aquifer, particle tracking shows on a small movement (c.6 m) of water over a 20-year injection period. Lateral movements of water interface are more strongly influenced by ongoing surface abstraction, rather than CO_2 injection and migration, assuming intergranular flow.

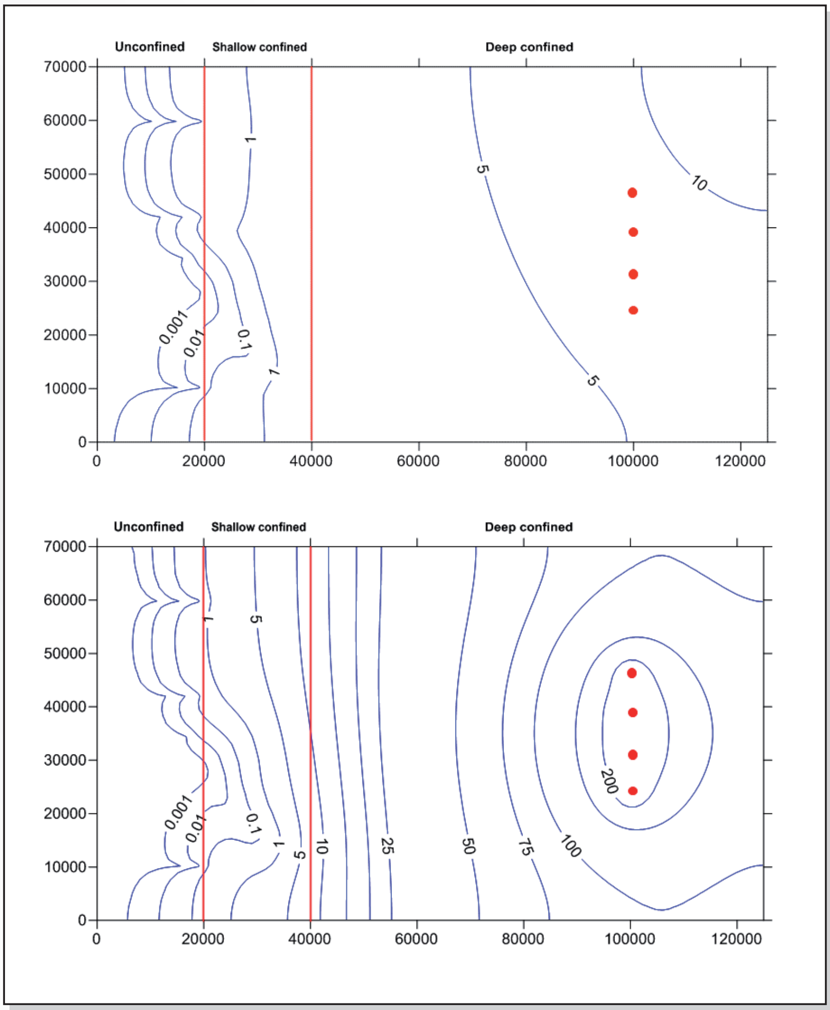


Figure 3.18 (a) Difference in groundwater pressure heads between the baseline and injection scenarios. Continuous CO_2 injection for 20 years was modelled using a vertical hydraulic conductivity of 10-6 m/day for the MMG cap rock. (b) Recovery of groundwater pressure heads. The difference between baseline and five years after injection has stopped is illustrated. Continuous CO_2 injection for 20 years was modelled using a vertical hydraulic conductivity of 10-6 m/day for the MMG cap rock.

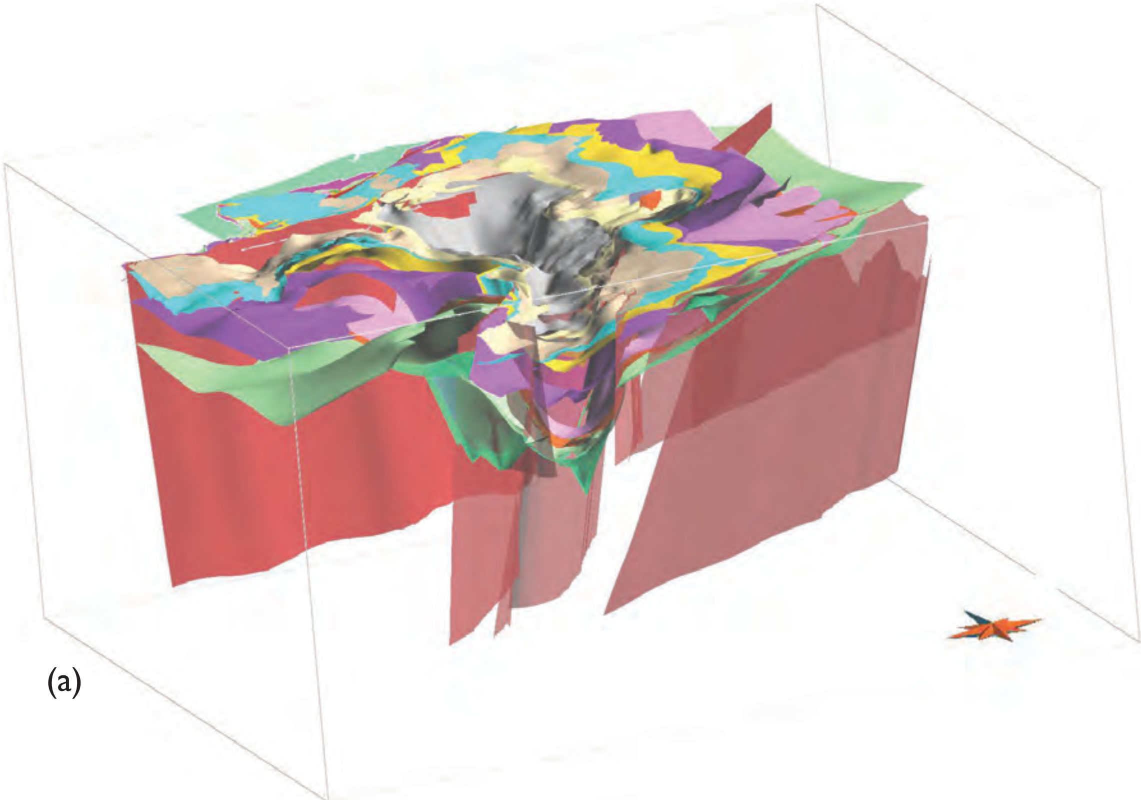
3.9 EVALUATION-DECISION GATE 3 (E/DG3)

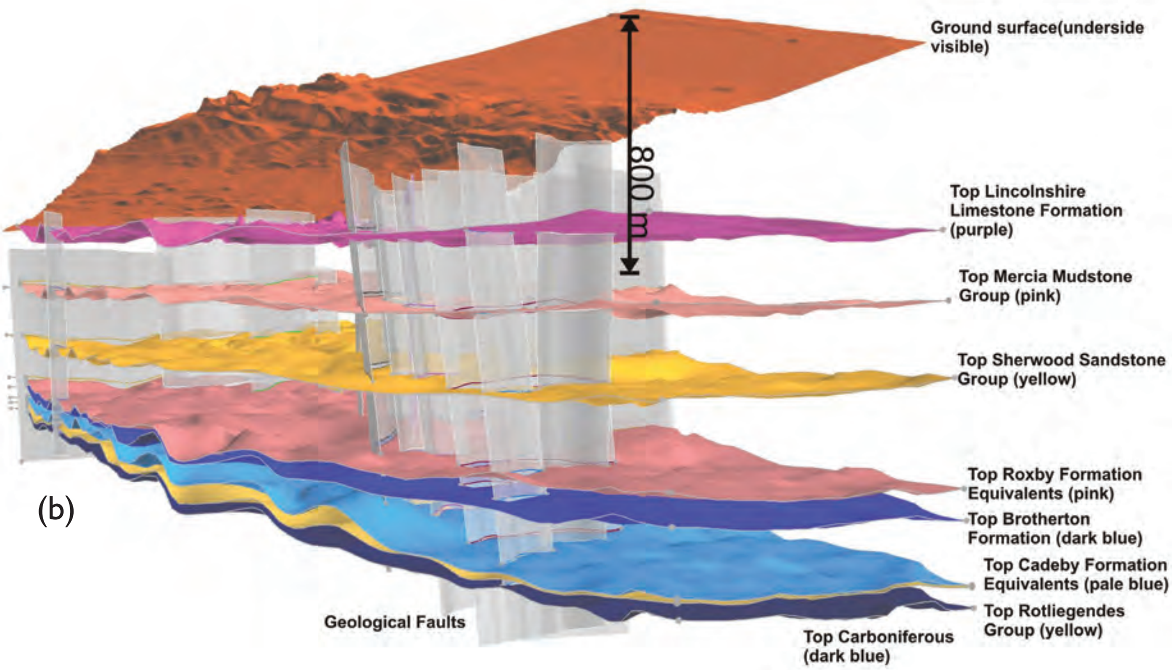
At this gate all of the previous model iterations and data refinements are combined and compared to determine the best model version that will progress to Level III and ultimately provide the framework for storage capacity modelling.

An assessment of the model uncertainties is required to inform the decision-making process and to make recommendations to hold for further analysis or invest and progress to the final delivery stage.

3.10 BUILDING THE GEOLOGICAL MODEL - LEVEL III

The chosen Level III geological model is now refined and the data sets quality-assured. The surfaces are exported from the modelling package in suitable formats (e.g. ASCII grids) for wider use. It is important to confirm maximum and minimum scales of use so that the models are utilised appropriately in a range of reservoir simulations. The final released geological framework models for the Firth of Forth and Lincolnshire are shown in Figures 3.19a and 19b.


(a)



(b)

Figure 3.19 Final geological framework models for CASSEM sites: (a) Firth of Forth (3x vertical exaggeration) and (b) Lincolnshire (10x vertical exaggeration).

3.11 SUMMARY

The quality of available data and range of geological histories creates an inherent variability of natural CO_2 stores. The geological interpretation and modelling workflow derived through the CASSEM project work is an attempt to address this natural variability. The workflow is flexible and will derive validated geological frameworks. Large uncertainties and biases are inevitable, but can be mitigated by targeted data collection and critical path analysis of data interpretation. It is anticipated that this workflow will, through application, evolve and become better fitted to CCS exploration targets.
Key findings:

- Establishment of an asset team, with frequent interaction and communication of data limitations and uncertainty issues with others parts of the storage methodology, is fundamental to the timely identification of major hurdles and difficulties.
- Use of structural restoration techniques (first response tools) will provide early assessment of site suitability and highlight inconsistencies in the geological interpretations that require further detailed modelling and risking for capacity estimates.
- Early reprocessing and reinterpretation of data (e.g. seismic) will reduce uncertainty in the geological model, with improved resolution of fault structures and constraining depths of key surfaces.
- For a relatively simple geological site with good data quality (e.g. Lincolnshire), the model is easily understood and utilised by other partners and a definition of initial conditions in the saline aquifer reservoir can be estimated with confidence.
- For a geological site with complicated geometries and structural features (e.g. Firth of Forth), communication of the geological uncertainty and estimates of reservoir conditions is consequently more challenging.

CHAPTER 4

FATE OF CO_2 IN THE STORE; ROCK MECHANICS, GEOCHEMISTRY AND FLUID FLOW

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4.1 INTRODUCTION

When CO_2 is injected into a saline aquifer, we know in general what processes will occur. Firstly, the pressure in the saline aquifer will increase. Then, because CO_2 is less dense than saline water (brine), it will rise, and there must be an impermeable cap rock above the aquifer to trap the CO_2. There are additional trapping mechanisms which act to contain the CO_2: dissolution, pore-scale trapping and geochemical trapping. These are complex linked processes, and to be able to predict the outcome of a CO_2 storage project it is necessary to perform flow simulations. Moreover, there are many uncertainties in the subsurface, both in the structure and in physical properties.

The benefit of simulations is that we can assess a range of models in order to understand the effects of uncertainties in the data. This helps inform decisions around what data needs to be collected and what calculations need to be performed to progress in the decision-making process. Also, the results from the reservoir simulations may be used as input for other studies being conducted as part of the saline aquifer assessment, as shown in Figure 4.1.

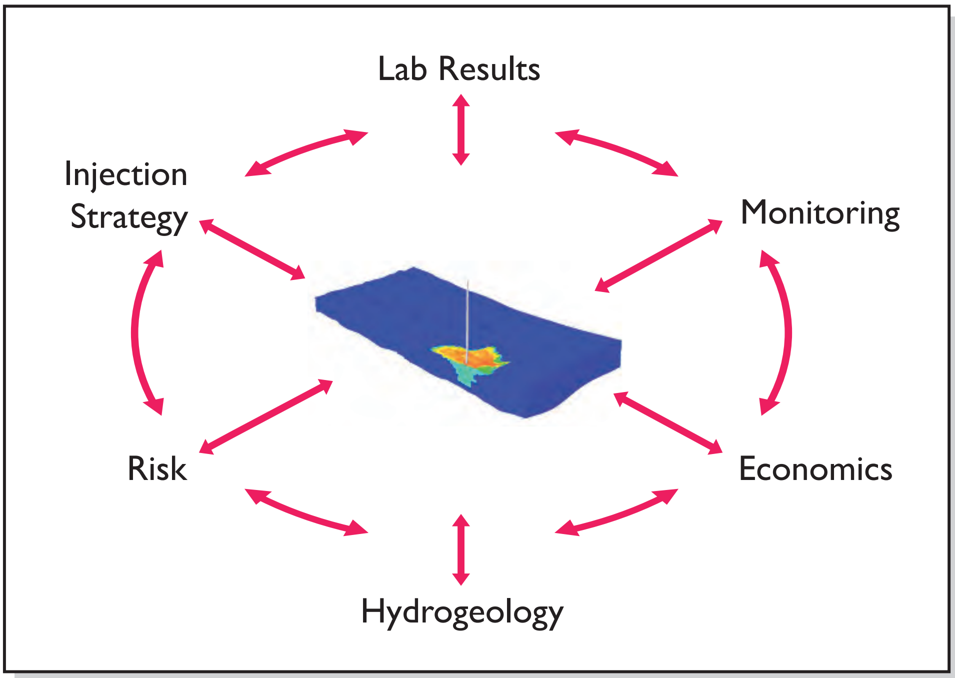

Figure 4.1 Schematic to show links between reservoir simulation and other aspects of the overall saline aquifer assessment.

4.2 RESERVOIR SIMULATION

In the oil and gas industry, reservoir flow simulations are routinely used to estimate how much oil or gas they are likely to produce, or to evaluate different production scenarios. This includes the simulation of gas injection to improve oil recovery. The codes developed for simulation of fluid flow in oil and gas reservoirs are readily adapted to simulate CO_2 injection into saline aquifers. The basic requirements for fluid flow simulation are:

- A geological model
- Rock properties
- Fluid properties
- Well information

Geological model

The basic framework for the geological model consists of interfaces (horizons and faults) between different types of rock. This has been described in Chapter 3. For flow simulation, the model is subdivided into grid cells, which are assigned different rock properties, depending on the geology. The simulation code tracks the fluid masses in each grid cell as a function of time. A description of how the boundaries of the model are defined is included in the Glossary.

Rock properties

The key properties for flow simulation are porosity and permeability. Porosity is the fraction of the bulk volume which is pore space, and therefore determines how much fluid may be stored in a rock. Permeability determines how fast a fluid can flow under a given pressure gradient. The rock compressibility is also important, because this determines the change in the porosity as the fluid pressure changes (see the Glossary for a full definition of these and other terms used in this chapter).

Fluid properties

For reservoir simulation, we need to know the density and viscosity (i.e. the resistance to motion) of each fluid. These quantities depend on temperature and pressure. In addition, we need to know what phase (liquid, gas or supercritical) a fluid is in: this also depends on temperature and pressure. For a saline aquifer these properties are also a function of the salinity. Carbon dioxide is soluble in brine, and so we need to know the solubility of CO_2 in brine as a function of temperature and pressure. All of these fluid properties have been measured in laboratories, and the required data may be entered as inputs in the simulation software used for CO_2 flow modelling, or indeed may already be included within the software's database.

When two fluid phases (e.g. gas and water) are flowing in a rock, they interfere with each other, so that the total flow rate is less than the rate for a single phase. This is taken into account using relative permeabilities, which are dependent on the fraction of the pore space occupied by that phase – commonly termed fluid saturation (see Glossary). The concept of relative permeability is critical in calculations of CO_2 injectivity and migration. Another factor to be taken into account is that, because of capillary forces at the pore-scale, the pressures in the two fluids are different, the difference being known as capillary pressure (see Glossary). As an illustration, if an open straw is put into a bowl of fluid, the fluid may rise up the straw due to capillary pressure; the narrower the straw, the further the fluid will rise. Porous rock contains millions of interconnected narrow capillaries, and so capillary pressure is very important. Quantities such as relative permeability and capillary pressure are measured in laboratories. However, there is always a lack of data, since only a few samples are usually measured and, typically, reservoirs are very heterogeneous systems. The results of reservoir simulation calculations have a degree of uncertainty associated with them due to the issues that arise from this lack of data. However, to identify these uncertainties and minimise their impact, multiple realisations may be run that test the dependency on the input assumptions, as discussed in Chapter 6.

Well information

In a reservoir simulation model, we can specify the location of wells and how they are connected to the grid cells. We can also specify the injection rate (m^3/day) and a maximum allowed bottom hole pressure – which will be determined by the requirement not to fracture the rock.

4.3 WORKFLOW AND TOOLS

Workflow design

As with the other aspects of an aquifer site evaluation, there are different stages at which decisions need to be made, and dynamic flow modelling may be used to contribute data to this decision-making process. Typically, as the project plans develop, more data becomes available, and hence more complex modelling activities may be undertaken. Some decisions around suitability of sites will be taken before any modelling work begins: it will be evident from available data whether sites may or may not be possible storage locations just by considering basic volumetric and geographical information, without conducting any flow simulations. This type of decision making at the start of the process is described in Chapter 3.

Once a candidate or candidate sites have been identified, we define three stages of flow modelling, which we term ‘phases’. The basic idea is to start with a very simple model at minimal cost (in terms of data, time and money), and then move through in stages to more complex levels of modelling, using more complex simulation tools and techniques, and acquiring more site-specific data to better constrain the modelling. The objective is that by the third stage a detailed model will be available that may be used to provide reliable input for the risking process, as described in Chapter 6.

The Phase 1 modelling considers primarily volumetric and simple rock property data. This will give an indication of whether adequate storage volume exists, generally assuming the rock type is suitable.

We then proceed to an intermediate phase, which includes the Level 1 geological model (Chapter 3). This second phase simulation activity will include more complex geomechanical and geochemical processes, although site-specific data may not yet be ready to provide as input, and so values from analogue sites may be required at this stage. The second phase simulation will tell us whether there may be sufficient injectivity and what the likely migration path of the CO_2 would be. This calculation can then be compared with the migration path identified using MPath, which is conducted on a much finer resolution model, but which does not account for the effect of dissolution.

This is then followed by a third and final phase of modelling, which includes laboratory data derived from site-specific samples (from tests conducted concurrently with the second phase of reservoir flow calculations), and incorporates the most advanced and final geological model (developed during the third level of geological model building). From this third phase of modelling we identify the impact of site-specific data, such as relative permeability, mechanical rock strength and mineralogy, and brine composition. Combined, these factors are used to calculate storage capacity for the site. These models should be used as the most accurate input for the uncertainty analysis (as described in Chapter 6).

Figure 4.2 summarises this approach of using three phases of simulation. The results of the three stages may then be compared to determine the level of detail required and the cost effectiveness of each activity. When following through the process, there is a stage gate after each phase of activity, in which a decision is taken whether to invest in moving to the next stage, or to put the project on hold, or indeed stop it.

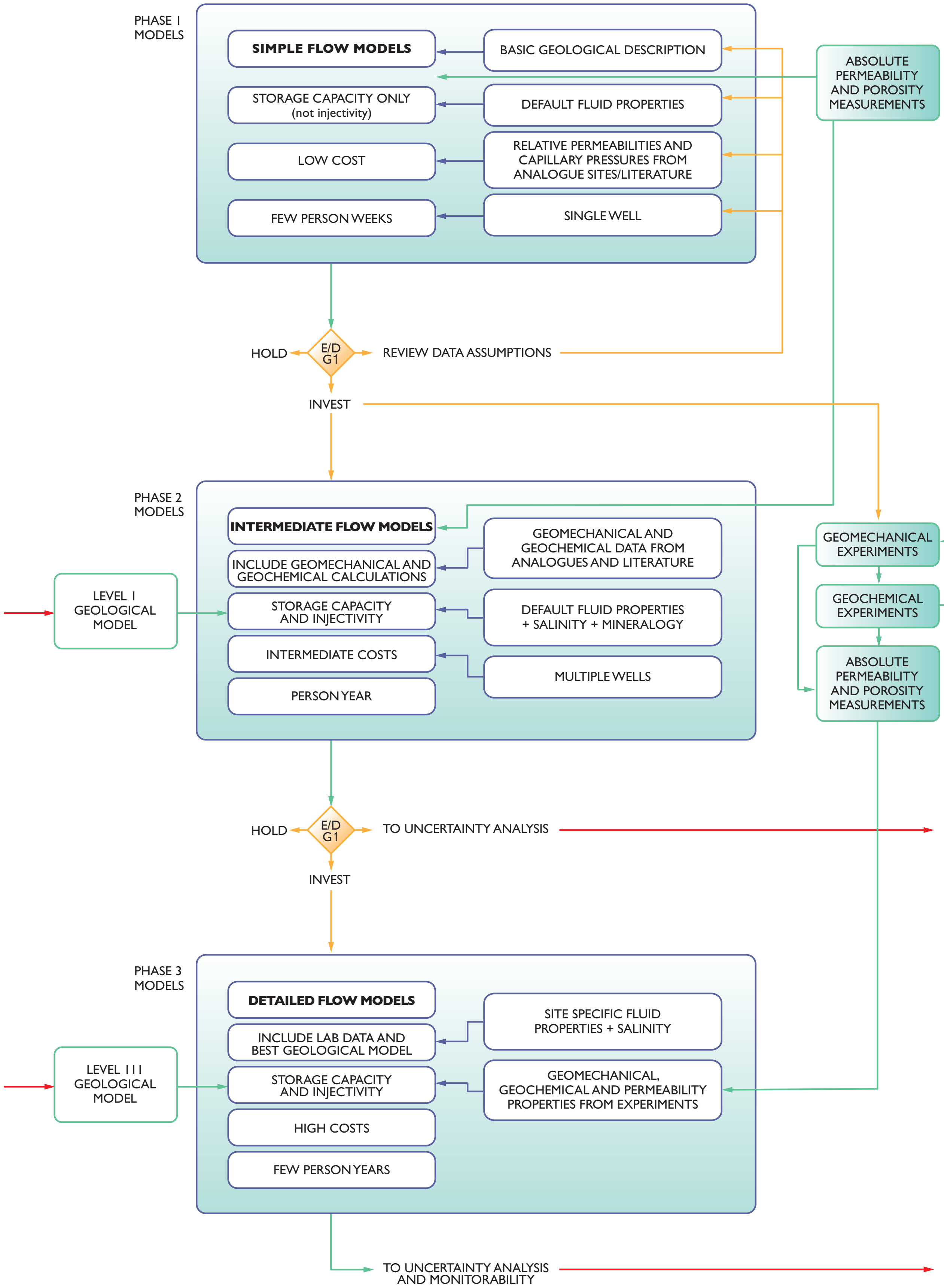

Figure 4.2 The three phases of modelling used for reservoir simulation.

Examples of how this three-stage approach works in practice will now be presented, with specific reference to the two project sites introduced in Chapter 1, in Lincolnshire and under the Firth of Forth. Not only did the two sites have differing geographical and geological settings, there were also substantial differences in the data available: from the outset there was greater resolution of geological information for the Lincolnshire site and rock core samples from wells were available, whereas seismic data were much more limited for the Firth of Forth Site and only outcrop rock samples were available, no well having been drilled into the target formation. The impact of this data availability on the experimental work and reservoir simulation activity will be apparent throughout the rest of this chapter.

Workflow tools

As is the case for geological model building, there is a wide range of commercial software tools available to perform dynamic flow simulations. Some operating companies also use their own in-house software. The preliminary step is to discretise the geological model, dividing the system into discrete grid blocks, each being assigned petrophysical properties such as permeability and porosity, derived from the geological model. Petrel (Schlumberger) was used to discretise the models for all three phases of dynamic simulation. The flow calculations were performed using the compositional simulator ECLIPSE 300 (Schlumberger) with the CO2STORE option for CO_2 storage in saline aquifers. This enables calculation of the injection of CO_2, its displacement through the rock away from the well, its buoyant rise and trapping under the cap rock, residual trapping and the dissolution of the CO_2 in brine. The dissolution calculation uses the Spycher and Pruess model for CO_2 solubility in brine, which may be applied to chloride/brine mixtures in the temperature range 12–100^{o}C and up to 600 bar pressure (Spycher and Pruess, 2005). The calculated solubilities tend to give a close match with the best experimentally derived solubility data, such as by Duan and Sun (2003), as reported in Gundogan et al. (2010).

Geomechanical modelling was carried out using VISAGE (Schlumberger). This is an integrated package of pre- and post-processing programs developed for coupled reservoir simulation. It is primarily designed for use in the oil industry with the black oil ECLIPSE 100 simulator, but was used here with the CO2STORE module of ECLIPSE 300. VISAGE Modeller is used to condition the ECLIPSE flow model by setting up suitable mechanical embedding with appropriate boundary conditions, initial stress conditions and geomechanical properties. Geochemical modelling was carried out using GEM-GHG (Computer Modelling Group), which models the free CO_2 phase with an equation of state, and the CO_2 solubility in the brine phase using Henry's law, corrected to take account of pressure and salinity effects. GEM has an internal database of equilibrium constants for the reactions involving chemical species in the aqueous phase and the primary and secondary minerals. Activity corrections are based on the B-dot model.

Data requirements for simulation

The framework for the geological models was supplied by BGS (see Chapter 3) and the rock properties for the grid cells were based on data from boreholes, where available. The properties for individual fluids (pure CO_2 and brine) were already coded into the simulation software. Some relative permeability and capillary pressure data were taken from the literature (Bennion and Bachu, 2005). Before the CASSEM project started, it was recognised that there is a general lack of data for simulating CO_2 storage in general, and with respect to the two specific sites in particular, and it was decided to include laboratory measurements within the scope of the project. Four types of measurements were made:

- Petrophysical properties: to determine permeability and porosity of supplied core plugs.
- Rock mechanics: to determine impact of stress changes induced by pressure changes arising when CO_2 is injected.
- Geochemistry: to determine impact of disturbing the chemical equilibrium that existed before CO_2 injection began, and impact of changes in brine composition on CO_2 interactions.
- Relative permeability: to determine impact of rock-fluid behaviour on CO_2 migration and retention.

4.4 BUILDING AND RUNNING THE RESERVOIR SIMULATION MODEL – PHASE 1

Phase 1 simulation development

Phase 1 activity should only take a matter of weeks. During this phase only desktop tasks will be completed. Data available to the project are reviewed, and a pre-processor such as Petrel is used to create and discretise a geological model. This allows a static estimate of CO_2 storage capacity to be made and the dynamic simulation model can be defined. The model may be used to calculate volume of CO_2 that may be injected and the potential injection rates. However, there is little value in estimating the proportion of CO_2 that is dissolved, mobile or capillary trapped, as the input data quality would not warrant this level of investigation. Neither are geomechanical or geochemical considerations addressed at this stage.

Although Phase 1 should be relatively short, it is appropriate to begin acquisition of samples and other data, and to identify an appropriate test laboratory to conduct experiments that will be performed if the decision is made at the first stage gate to proceed with the project. If samples are available and a test laboratory can be contracted in time, it may be possible to conduct initial porosity and permeability measurements using available core.

Part of the objective of study was to identify the incremental value to the decision-making process that each phase of additional data and modelling brought. The work undertaken in the three phases of activity for the two sites is described. However, a more detailed description of the results is kept to the comparative discussion at the end.

Firth of Forth Phase 1 dynamic simulation

During Phase 1 there was very limited geological data to constrain any dynamic simulation. Indeed, Petrel was not used for this task, but a simple 3D rectangular model was constructed. Other than the effect of CO_2 dissolution in brine, which is dependent on interface contact area, the calculations could have been performed analytically, and thus the principal value of building this model was to provide a starting point for subsequent modelling activity. Therefore, while the geometric and geological inputs would need to be redefined once these data become available, the generic fluid properties could be included in the model at this stage.

Lincolnshire Phase 1 dynamic simulation

The Phase 1 models used were provided by BGS, based on existing information from the Lithoframe 1M model of the UK (Monaghan, 2008a). This included some surfaces and, thus, Petrel was used to develop the geological model and create a grid. However, detailed information on faults could not be incorporated. Rock samples representative of the Sherwood Sandstone Group were available at this stage and permeability measurements were conducted on these to provide inputs for the Phase 2 modelling.

4.5 BUILDING AND RUNNING THE RESERVOIR SIMULATION MODEL – PHASE 2

During Phase 2 the outputs of the geological description work carried out in Level 1 of the geological model building, as described in Chapter 3, are used. Whereas the Phase 1 models are constructed with minimal geological input, Phase 2 adopts much more of an asset team approach. Flow modellers interact with the geologists building the models, to help define the data requirements, and the geologists, in turn, quality control the flow models, once constructed, to ensure that these models accurately reflect the geological understanding developed thus far.
At this time, geomechanical and geochemical calculations are also introduced. However, no site specific data are available, so these calculations use generic correlations as input. The results should thus be treated with caution – the objective is to identify the type of behaviour that might occur, to identify the input data requirements that will have to be satisfied by the experimental activity and to initiate the detailed model building so that experimental data may be more readily assimilated into the calculations during the Phase 3 activity.

Geomechanics

When CO_2 is injected into a porous and permeable formation, it will be forced into pores at a higher pressure than the surrounding rock. This causes changes to the stress state of the rock, which leads to deformation and possible failure of the reservoir and/or cap rock. Pre-existing fractures or faults may be opened up and/or new fractures or faults created, potentially providing conduits for leakage. The conditions under which this may happen are site-specific and depend on the injection pressures the characteristics of the host formation, the in situ stress regime and the previous pressure history of the site.

The most immediate risk of leakage in CO_2 geological storage is posed by breaching the cap rock. As injection progresses the storage formation pressure increases and the cap rock may be subjected to hydraulic fracturing and/or shear failure. These modes of rock failure may provide openings through the reservoir cap rock, allowing contained fluids to migrate to other formations. The shear failure may be manifested by the creation of new fractures or the reactivation of pre-existing faults within and transecting the reservoir. It should be noted that geomechanical effects may take place in locations not directly associated with the CO_2 migration pathways, so it is important to predict both the fluid flow and the geomechanical behaviour. Some geomechanical effects may not pose risks to storage integrity.

Experiments are performed to determine the rock properties, which are required as input for the geomechanical simulations. Plugs of 1.5” diameter are cut at various selected depths to honour progressive changes in rock type, i.e. a selective sampling rationale is applied. Once cut, the plugs are tested at ambient stress conditions for porosity, permeability and bulk density.

On completion of the ambient tests, electrical strain gauges are bonded to the outside of the plugs to determine the change in plug dimensions during the tests. Ultimately, the changes in dimensions during the elevated stress tests are used to calculate the static elastic constants required for simulation. The plugs are tested at elevated stress conditions, to simulate those found in the reservoir, in a Hoek cell, which provided a means of applying a confining pressure to the plugs with a servo-controlled stiff testing machine applying the axial load to the plugs. Figure 4.3 shows a schematic diagram of the apparatus and Figure 4.4 presents a detailed diagram of the Hoek cell. At each of the chosen stress levels the compressional (P) and shear (S) seismic wave velocities were determined and these were used to calculate the dynamic elastic constants. Figure 4.5 shows a flow chart to summarise the rock mechanical testing procedure.

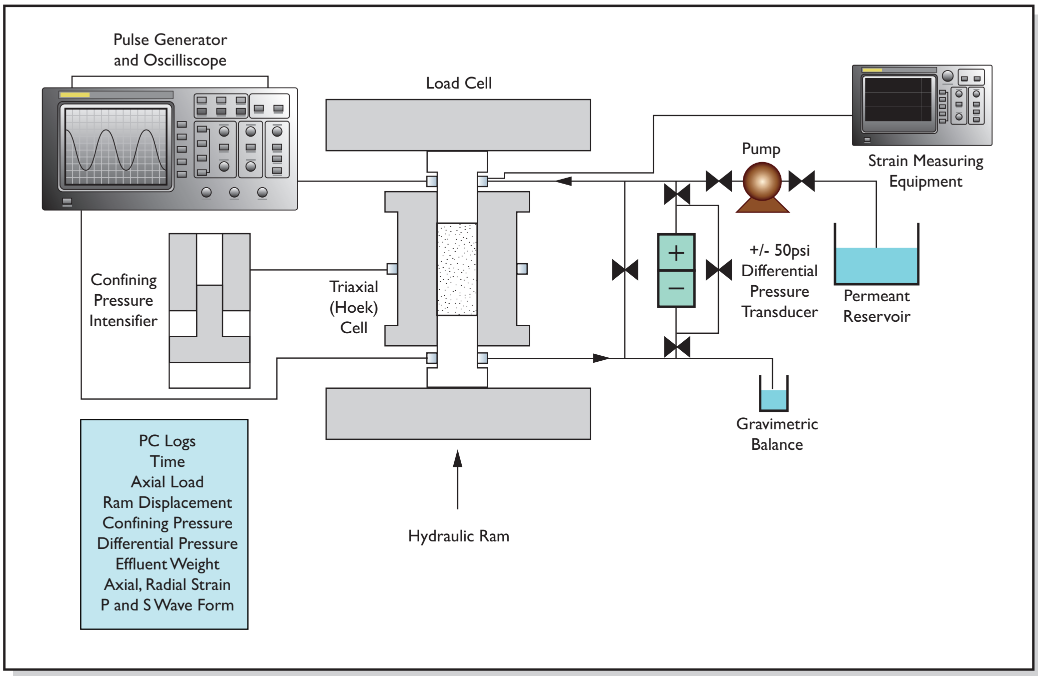

Figure 4.3 Schematic diagram of the rock mechanics experiments.

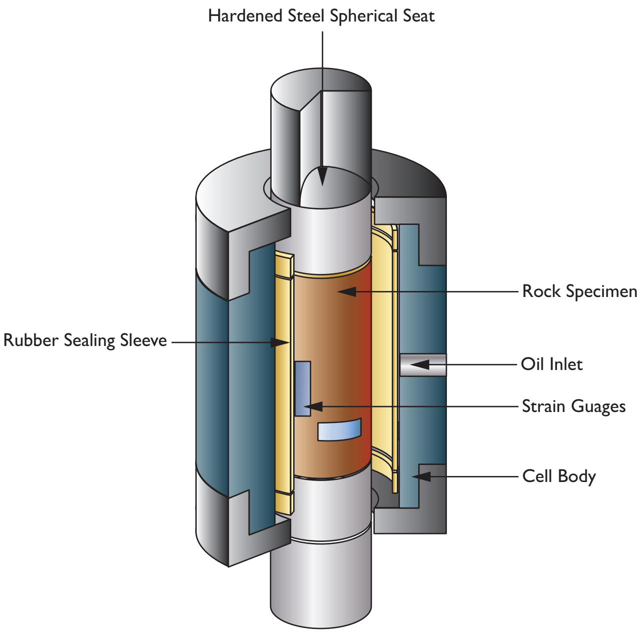

Figure 4.4 The Hoek Cell.

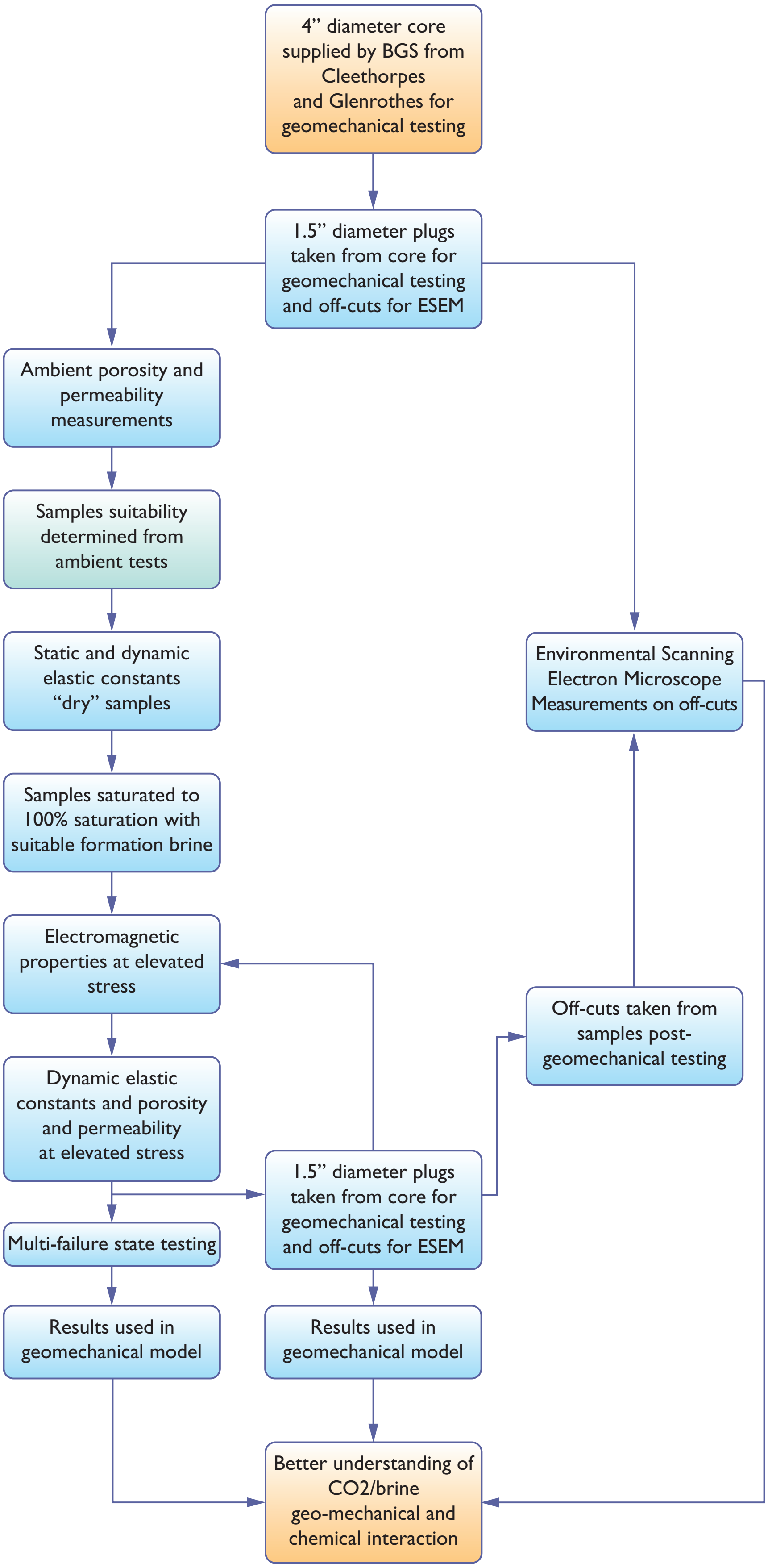

Figure 4.5 Flow chart of the test procedure.

Formation brine is prepared for each of the boreholes and the samples saturated to 100% brine saturation before testing at the stress levels used in the 'dry' tests. The 'wet' plugs are placed in the Hoek cell and the stress increased to 3.5 MPa effective stress, with the volume of effluent produced being measured. This volume of effluent is then used in the calculation of the pore volume compressibility and, ultimately, the sample porosity at elevated stress. Sample permeability and P and S wave velocities are also determined. This process is repeated at each of the stress levels and the sample unloaded and stored until required for multiple failure state (MFS) testing. MFS is used to determine the failure criteria, describing the change in the sample strength with increasing confining pressure, up to the point where the rock breaks apart. The Mohr-Coulomb failure parameters, cohesive strength and angle of internal friction describing the rock failure envelope are derived from this data (see Glossary).

There are various approaches to reservoir simulation incorporating geomechanical effects. A coupled analysis in which there is feedback from the geomechanical model to the flow model is now considered the preferred method. The stress and strain state of the geomechanical model is used to modify the hydraulic properties (porosity and permeability) of the flow model. The exchange of data between the two sets of calculations can be scheduled to take place at different times, according to the magnitude of the pore pressure changes taking place.

Geochemistry

When CO_2 dissolves in brine, the brine becomes weakly acidic:

$$CO_2+H_2O \leftrightarrow H_2CO_3 \leftrightarrow H^+ + HCO_3^-$$

It can then interact chemically with the rock, dissolving some minerals and precipitating others. Such reactions could have important consequences for CO_2 storage. For example, calcite (calcium carbonate) may be dissolved:

$$CaCO_3+CO_2+H_2O \leftrightarrow Ca^{2+}+2HCO_3^-$$

In rocks containing carbonate minerals, these reactions may occur relatively rapidly. However, the rocks involved in this study are silicate rocks (sandstone and mudstone), and the reactions with CO_2 are relatively slow. Metal ions, such as calcium, magnesium and iron in the silicate minerals may react with the bicarbonate ions to precipitate carbonate minerals. This is mineral trapping, which is the most secure type of trapping for CO_2. One example of a mineral trapping reaction is the dissolution of anorthite, followed by the precipitation of calcite.

$$2H^+CaA1_2Si_2O_8+H_2O \rightarrow Ca^{2+}+A1_2Si_2O_5(OH)_4$$

$$Ca^{2+}+HCO_3^- \rightarrow CaCO_3+H^+$$

While the precipitation of calcite is a mechanism by which CO_2 will be very effectively immobilised, the prior dissolution of minerals that makes this reaction possible may have consequences for injectivity. On the one hand, dissolution of minerals may increase the porosity and permeability of the rock, making flow easier. On the other hand, if the minerals are acting as cements that hold the rock fabric together, their removal may release fine grains that then lodge in pore throats downstream, reducing permeability and restricting flow.

To measure these effects, CO_2-saturated brine is displaced through core samples and the composition of the effluent brine is analysed to identify the presence of certain ions. The effluent brine composition may then be compared with the injected brine composition to identify evidence of changes occurring in situ. The pressure differential across the core is also measured. An increase in pressure differential would correspond to damage to the rock, resulting in a reduction in the permeability.

CASE STUDY 4: RELATIVE PERMEABILITY

When two or more fluids are present in a rock, they interfere with each other. For example, the presence of one fluid in a narrow pore may block the flow of another fluid. At larger scales, this phenomenon is referred to as relative permeability. The relative permeability of the rock to a given phase is dependent on the saturation of that phase – the higher the saturation of the phase, the higher the relative permeability. Thus, the higher the proportion of the pores that are filled with a given phase, the more readily that phase will flow.

When calculating the flow that will result from an induced pressure gradient across a piece of rock, the flow rate is proportional to the product of the absolute permeability (measured in mD, say) and the relative permeability (which is dimensionless). Thus, halving the relative permeability at a given saturation would have the same impact as halving the absolute permeability. Relative permeability is therefore very important in determining how fast CO_2 will migrate, and also in identifying the injectivity of a well.

However, relative permeability is also very important in determining how far CO_2 will migrate. If the saturation of a phase is below a certain threshold, that phase will stop flowing altogether. This is referred to as the critical saturation. Thus, if CO_2 is present in the rock at a saturation lower than or equal to the critical CO_2 saturation, it will be immobile. This is residual trapping. The higher the critical CO_2 saturation, the more CO_2 that can be trapped by this mechanism. This leads to a retardation effect. As the plume of CO_2 advances, it is continually leaving behind a residual saturation of CO_2, so that the plume gradually decreases in size and eventually runs out of mobile CO_2, at which point all the CO_2 is trapped.

However, as CO_2 is injected, there will also be a critical water saturation, at which point the water stops flowing, and so the CO_2 saturation cannot increase further unless the water evaporates. The relative permeability to CO_2 at the critical (or irreducible) water saturation is lower than if the pore space were completely occupied by CO_2. This relative permeability value is referred to as the endpoint CO_2 relative permeability. The more water that is trapped, the lower the endpoint CO_2 relative permeability value, and thus the harder it will be for CO_2 to flow or be injected.

Finally, the shape of the relative permeability curves will depend on whether the water saturation is decreasing or increasing. Initially, the pore space will be entirely filled with water (water saturation Sw = 1). As CO_2 is injected, the water saturation will decline. This is referred to as a drainage process, since the rock generally is preferentially water-wet, which means the water will be retained in the smallest pores and the CO_2 will advance preferentially through the largest pores it has access to.

Once the irreducible water saturation has been reached, the water saturation cannot decrease further. If CO_2 injection stops and the CO_2 plume migrates away, the water saturation at the tail of the plume will start to rise again, as water starts to invade pores previously occupied by CO_2. In a water-wet system it is the smallest pores that fill with water first, and this process is called imbibition. The fact that while CO_2 is advancing it tends to fill the largest pores first, whereas while water is replacing CO_2, the water tends to fill the smallest pores first, leads to hysteresis in the relative permeability curves.

An example of a CO_2-brine relative permeability curve which highlights these various issues is shown in Figure 4.6.

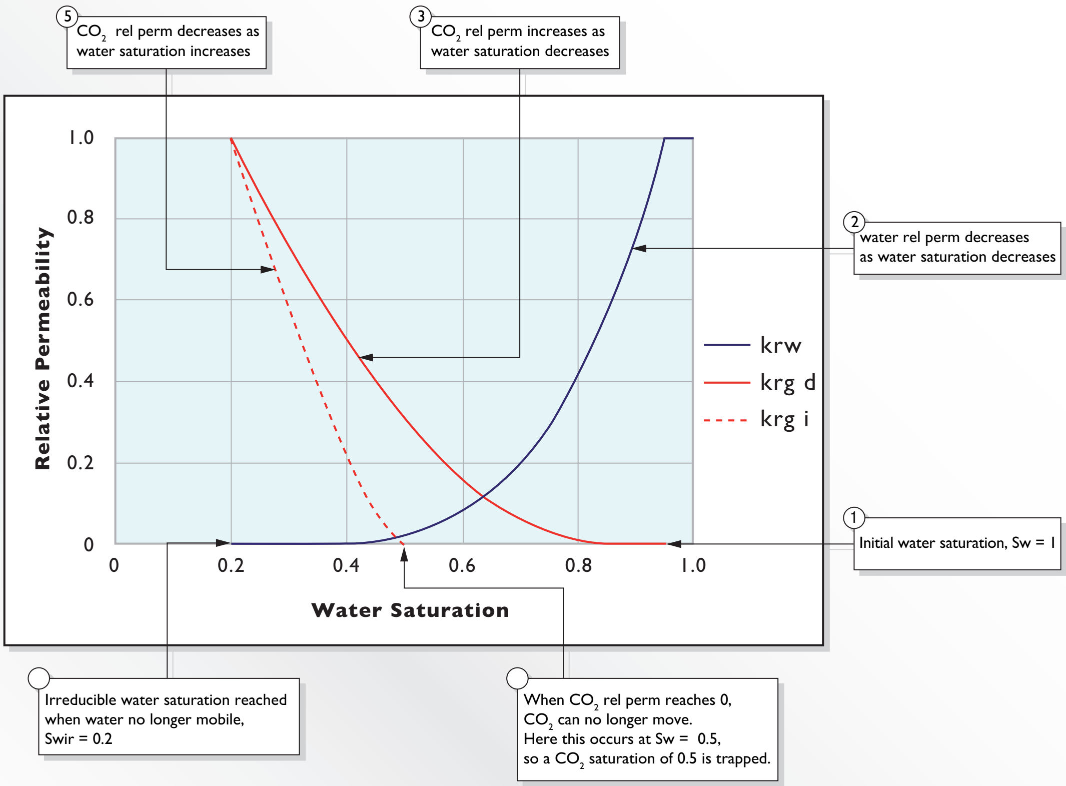

Figure 4.6 CO_2 (red) and brine (blue) relative permeability curves, as a function of water saturation in the rock, and showing hysteresis in the CO_2 relative permeability curves.

Points to note are:

- The rock is initially filled with water (Sw = 1).
- The relative permeability is always less than one, meaning that the flow rate of one fluid is adversely affected by the presence of another fluid; the relative permeability decreases as the saturation of that phase decreases.
- Conversely, the relative permeability of the second phase increases as the saturation of the first phase decreases.
- When CO_2 is injected into a formation, it does not displace all of the brine. Water can adhere strongly to the surface of the rock grains, so there is an irreducible water saturation, labelled Swir.
- After injection has stopped, CO_2 continues to rise within the aquifer, and water moves into the region vacated by the CO_2. As the water saturation increases again, the relative permeability to water declines.
- The escaping CO_2 can become disconnected and unable to continue flowing. Thus, the water can trap CO_2 at the pore scale, and this is referred to as pore trapping, or residual trapping.

An important aspect of relative permeability measurements conducted in the laboratory is the appropriate selection of cores. The composition of rock is site-specific and even within a single storage site there may be considerable variation in rock properties such as mineralogy, porosity and permeability, each of which will impact relative permeability. Since the tests themselves are complex and time-consuming, it is expensive to conduct tests on a large range of core samples. The selection process should then take account of how representative of the system the given cores are. There is no point in only conducting a core test on a sample that is only representative of a short section of the well, or that has a very low permeability, since very little CO_2 would actually flow through that rock type.

Figure 4.7 shows an example of the relative permeability results obtained for a sandstone core from the Sherwood Sandstone Group. As can be seen, as CO_2 is injected in the brine-saturated core, the water saturation decreases (drainage) and so does its relative permeability. The water relative permeability eventually becomes zero and further water displacement out of the core is not possible. In this case, this irreducible water saturation is 33%. The CO_2 relative permeability is at its maximum at irreducible water saturation (end-point relative permeability). One important and common feature of the relative permeability measurements carried out in the CASSEM project was the very low CO_2 end-point relative permeability. As can be seen from Figure 4.7, the CO_2 end-point relative permeability is less than 0.05. That means that, in this case, the effective permeability of the rock when it is as saturated as it can be with CO_2 is 20 times lower than it was initially when just water was present. As a result, CO_2 injection will be met with much greater resistance than when just water was flowing.

When CO_2 rises due to buoyancy and the pore space starts to refill with water (imbibition), the water saturation can only increase to 73% before the CO_2 becomes isolated and immobile. Thus, 27% of the pore space will contain residual trapped CO_2.

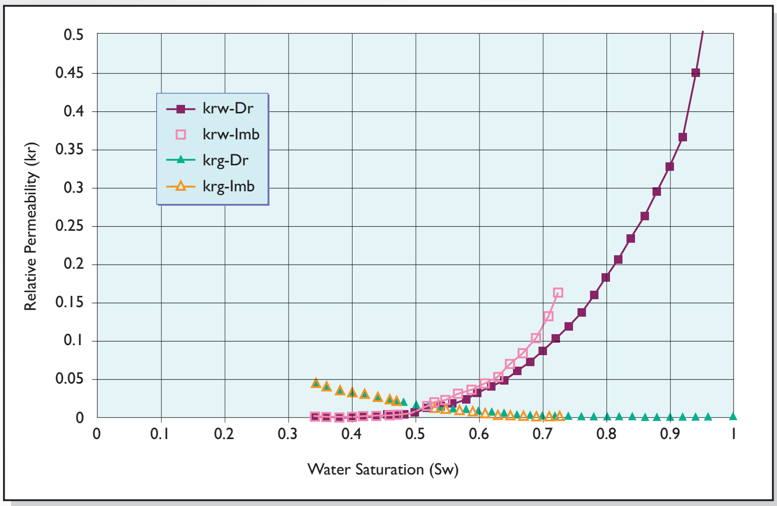

Figure 4.7 Example of relative permeability results: krw is relative permeability to water, and krg is relative permeability to CO_2. Drainage (Dr) curves correspond to decreasing water saturation, and imbibition (Imb) curves correspond to subsequently increasing water saturation.

These experimentally derived relative permeability functions are used as direct input to the reservoir simulation models. Since they determine how readily CO_2 will flow, and also how much CO_2 is residually trapped, they are one of the most sensitive input parameters in the simulation model.

Firth of Forth Phase 2 dynamic simulation and experiments

The introduction of a more realistic geological model with representative topography and layer thicknesses meant that much more accurate account could be taken of buoyancy and dissolution effects. However, at this stage only generic relative permeability data were available and layer thicknesses were still to be refined after seismic reprocessing, so accurate injectivity calculations could not be performed and a single injection point was still being used at this time.

The BGS supplied Heriot-Watt with whole core from a borehole at Glenrothes, Fife, to be used as an analogue for the Firth of Forth site. Porosity, permeability and rock strength tests were conducted on this core.

The results of these calculations and tests are described in the comparative summary at the end of this chapter.

Lincolnshire Phase 2 dynamic simulation and experiments

The change in the geological model from Phase 1 to Phase 2 was not as significant for the Lincolnshire model as it was for the Firth of Forth site, as data relating to surfaces had previously been made available. Again, the results of the modelling work are described in the comparative section.

With regards to the experimental test work, the first step was to identify the mineralogy of the rock and the composition of the in situ brine. The brine, having been in contact with the rock over geological time frames, would be in geochemical equilibrium with the rock. The Sherwood Sandstone Group was identified as consisting of red-brown sandstone with calcareous mudstone and mud-flake conglomerate. The overlying Mercia Mudstone Group contains red-brown calcareous mudstone and siltstone with anhydrite and gypsum (Milodowski and Rushton, 2009). In each case, the rock substrate contains calcium-rich minerals. This means that reactions, such as the one described above, in which calcium is dissolved and then re-precipitates as calcite, are possible.

The BGS supplied Heriot-Watt with whole core from the Cleethorpes borehole, to be used for tests to provide input for the Lincolnshire models. Sample SSK2450, from the Sherwood Sandstone formation, underwent stress testing, but not to the point of failure. Instead, CO_2-saturated brine was subsequently flowed through the sample, as part of the geochemical test work, which is described in more detail below. Once the flow test was completed, the sample was returned to the rock mechanics laboratory for post-geochemical stress testing. The results of both suites of tests, i.e. pre- and post-geochemical testing, are shown in Figure 4.8. It can be seen that the permeability has decreased after geochemical testing and that the dynamic elastic constants have all also decreased.

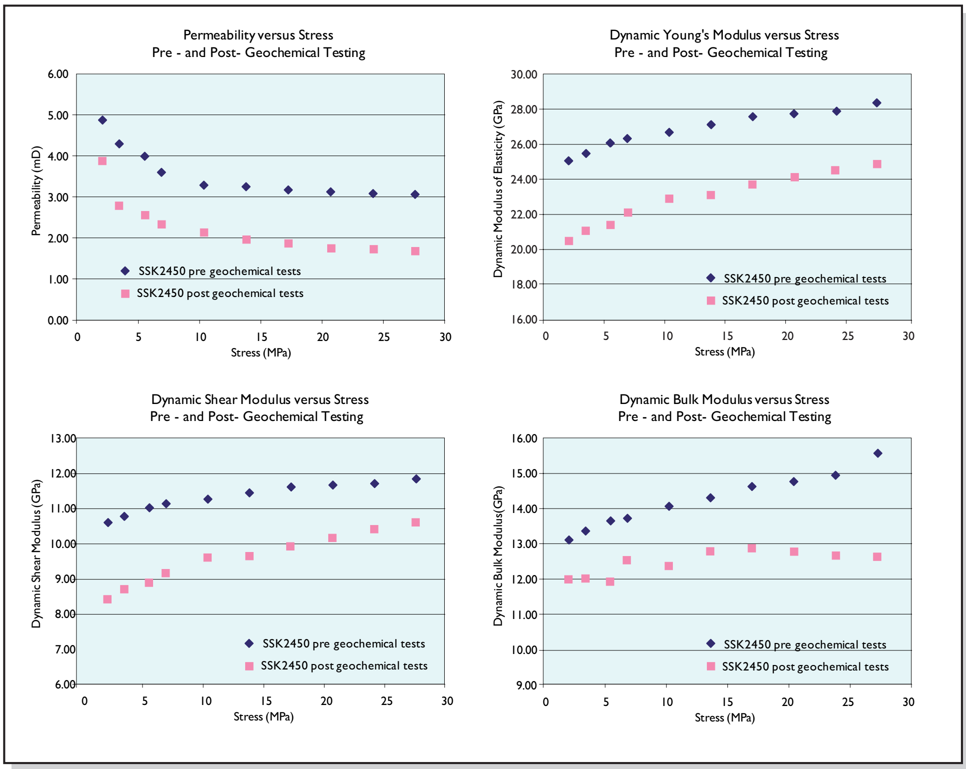

Figure 4.8 The results of the pre- and post-geochemical tests for the Lincolnshire sample.

Offcuts from the samples were tested using the environmental scanning electron microscope, both pre- and post- geochemical testing, and were used to further understand the CO_2/brine geomechanical and geochemical interaction seen during these tests.

The data derived from these tests were used as input to the geomechanical simulation activity in Phase 3, as described below. Two important observations from this work are that:

- It is imperative to test not only rock samples from the formation in which the CO_2 will be stored, but also the cap rock, since the integrity of this cap rock is critical to ensuring secure CO_2 storage.
- The brine composition used in the tests must initially be in equilibrium with the minerals present in the core samples. Various brine compositions were supplied, some of which were in equilibrium, but some of which resulted in immediate precipitation of salts or dissolution of primary minerals. Thus, a thermodynamic calculation should be carried out to ensure the brine initially in situ in these tests is properly equilibrated.

The results of the geochemical testing on sample SSK2450 are presented in Figure 4.9. The graph shows the concentration of various elements in the effluent relative to their concentration in the input brine. The gap in the data at around 12 pore volume throughput corresponds to the time when there is switch from injecting brine which is in equilibrium with the minerals in the rock (corresponding to initial formation brine) to injecting brine saturated with CO_2. The main effect is the increase in mineral reactivity that occurs because of the introduction of CO_2. In particular, magnesium (Mg) concentration in the effluent increases; this is due to the dissolution of the mineral dolomite in the sample. A decrease in strontium (Sr) is also significant, indicating a possible precipitation of strontium sulphate. DP (differential pressure) can be seen to be increasing when injection of CO_2-saturated brine started. This implies reactions are taking place between the rock and ions in the brine during the time frame of the laboratory test.

We emphasise the timescale of the observation (days to weeks) because much of the literature relegates geochemical interactions to the time frame of millennia. We consider long time frames may be appropriate for some of these reactions for groundwater conditions. However, under conditions of elevated temperature and pressure differential, familiar from subsurface hydrocarbon extraction, these reactions may take place over periods of hours and days. The increase in DP in this test points to a reduction in core permeability caused by precipitation or blockage of pore throats due to fine particle movement within the core.

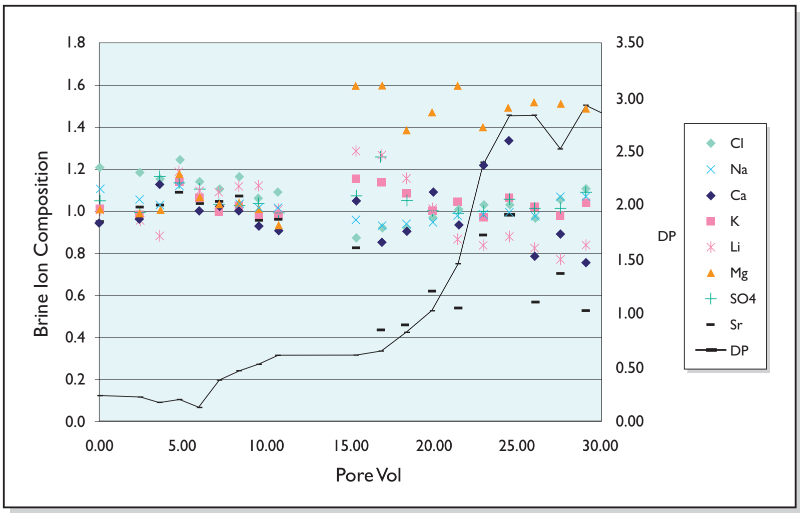

Figure 4.9 Example of geochemical results. The left-hand vertical axis shows the relative change in ion concentrations. Values greater than one correspond to an increase in the concentration of that ion due to mineral dissolution, values less than one indicate precipitation, and values close to one mean no reaction is taking place. The right-hand vertical axis shows pressure differential across the core – the higher the DP, the lower the permeability. Pore volume throughput, shown on the horizontal axis, is a dimensionless way of representing volume of fluid injected.

4.6 BUILDING AND RUNNING THE RESERVOIR SIMULATION MODEL – PHASE 3

The significant changes introduced in the Phase 3 modelling activity are:

- To include the most developed (Level III) geological model (as described in Chapter 3).
- To include the site specific experimental results from Phase 2 to constrain geomechanical effects, geochemistry and relative permeability.

Depending on the generic correlations used previously and the specific details of the sites, there may be a significant change in the results going from Phase 2 to Phase 3, or there may not. For instance, general geomechanical correlations can often be applied to different rocks from similar formations with a similar degree of accuracy. However, geochemical reactions tend to be much more sensitive to specific mineralogies and water compositions, and so tend to be much more site-specific. Whether or not there is a significant change in the results from Phase 2 to Phase 3, the benefit comes from having used site-specific data that validates the results and reduces the risk of the site behaving in an unexpected manner. It is anticipated that no developer would proceed to CO_2 injection without having conducted site-specific tests such as these, to ensure, at the very least, that the required injectivity can be achieved.

Firth of Forth Phase 3 dynamic simulation

For the Firth of Forth site, the geological model was developed from the reprocessed and reinterpreted seismic data. Separate calculations were performed using the low-resolution grid to identify when and where rock failure would be most likely to occur, and using the high-resolution grid to identify injectivity and number of wells required, the CO_2 migration pathway and the eventual fate of the injected CO_2. Parameters form the rock strength testing on the core from the Glenrothes bore were used to constrain the geomechanical model. Relative permeability curves for this core were not available, so curves from the Lincolnshire core were used instead as proxy. Explicit geochemical calculations were not performed, although brine salinity effects were taken into account.

The data derived during Phase 2 activity suggested lower permeabilities should be used and this led to an increase in the number of wells required to provide sufficient injection capacity, as discussed below.

Lincolnshire Phase 3 dynamic simulation

The geological model for the Lincolnshire site used for Phase 3 was the same as that for Phase 2.

The initial permeabilities in the flow models were determined mainly by values measured in core plugs from the Cleethorpes borehole, supplemented using well log data. However, these values were reduced to account for the stress induced by the overburden rock. Figure 4.10 shows an example of the data available from tests conducted in the rock mechanics laboratory that were used to recalculate these in situ permeabilities.

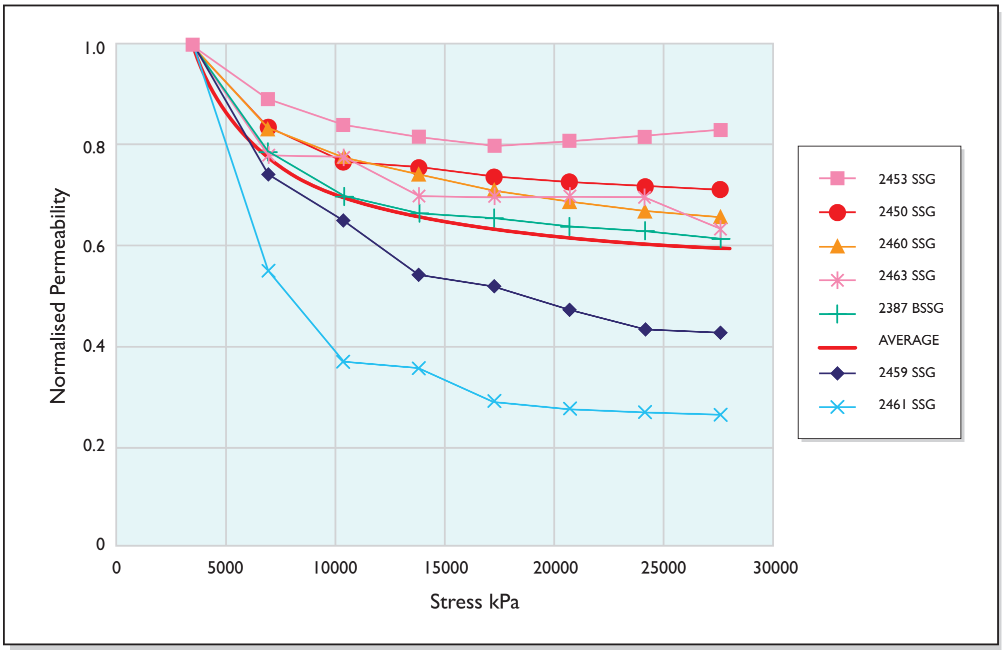

Figure 4.10 Example of impact of stress due to overburden rock on permeability.

After setting up both the ECLIPSE and VISAGE models for coupled analysis, suitable time steps throughout the simulation were chosen at which the stress steps were performed. These were chosen where significant pressure changes were expected to occur – more frequently during injection and less so post-injection. Once the analysis was complete, the results were reviewed in order to make observations about the potential for rock failure, either through fracture (shear failure) of the intact rock, or reactivation of existing faults.

4.7 COMPARISON BETWEEN DATA-POOR FIRTH OF FORTH AND DATA-RICH LINCOLNSHIRE MODELS, AND BETWEEN PHASE 1, 2 AND 3 ACTIVITIES

Comparative results for laboratory data

As examples of laboratory results, the permeability, porosity and bulk density measurements are shown in Figure 4.11 for both sites. It is evident that while the bulk density measurements are similar, the permeability and porosity values are much lower for the Firth of Forth site compared to the Lincolnshire site. This translated directly into a lower calculated injectivity for the Firth of Forth model.

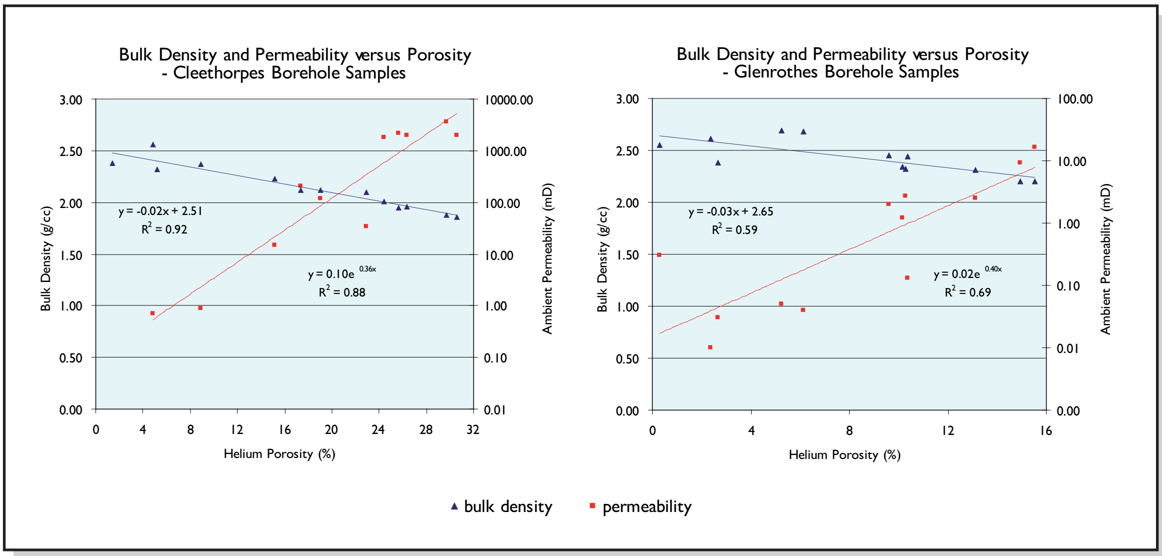

Figure 4.11 Plots of bulk density and permeability as a function of porosity for the samples from the Cleethorpes and Glenrothes boreholes.

Comparative results for geological models

Figure 4.12 illustrates the three phases of development of the geological models for the two sites. In each case, the aquifer formation, the layer above (cap rock) and the layer below were modelled.

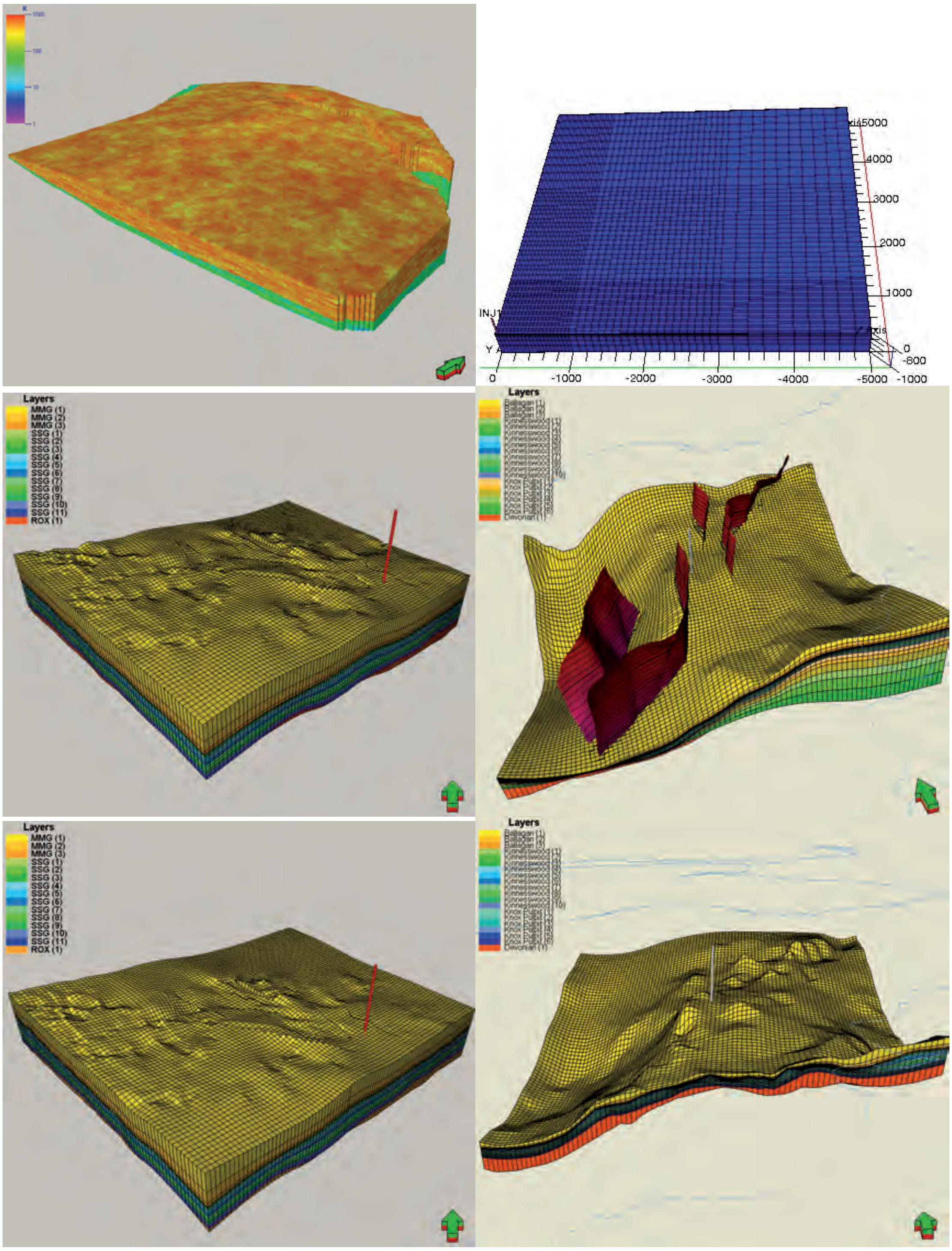

Figure 4.12 Models used in each of the three phases (top to bottom, Phase 1, 2 and 3): on the left is the Lincolnshire site and on the right is the Firth of Forth site.

Table 4.1 lists the model properties for the Firth of Forth site and Figure 4.13 shows the porosity distribution for the Phase 3 base-case model.

Features	Phase 1	Phase 2	Phase 3
Geological structure	Simple box model	CASSEM model	CASSEM model, reinterpreted seismic
Rock properties (porosity and permeability)	Const. based on Glenrothes borehole	Stochastic, based on Glenrothes borehole	Stochastic, based on Glenrothes borehole
Model area (km x km)	10 x 10	20 x 19	17.6 x 15.8
Model thickness (m)	200	1000	1000
Grid block size in horizontal (m)	50–200	200	200
Range of grid block sizes in vertical (m)	5–80	3–200	0.043~570.0
Average porosity			
Aquifer	0.2	0.1179~0.1509	0.1179~0.1509
Cap rock	-	0.0683	0.0683
Average permeability (mD)*			
Aquifer	50	51.6~73.1	12.6
Cap rock	-	0.007	0.0048
Ratio of vertical to horizontal permeability	1	0.1	0.1
Net-to-gross ratio	1	0.5~0.9	0.8

Table 4.1 Properties of the Firth of Forth model. *The permeability distribution was log-normal. We give the geometric average here.

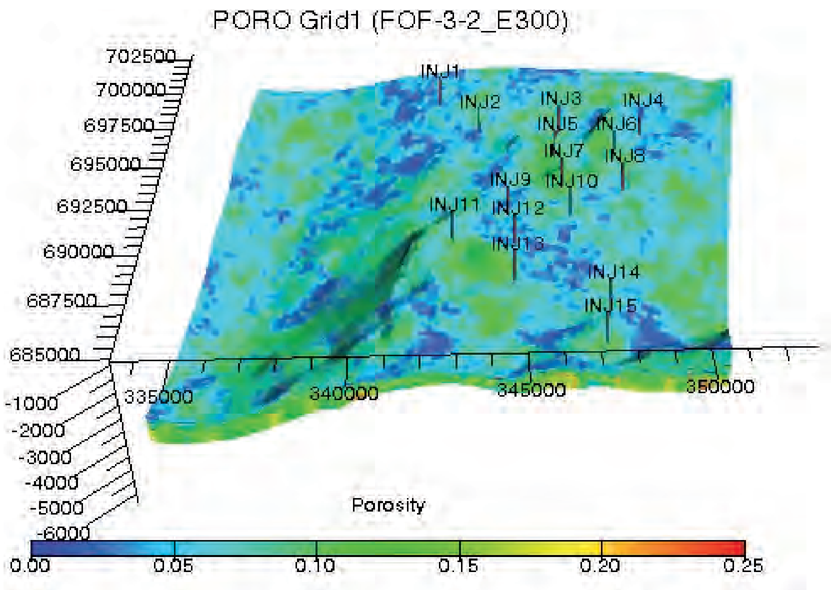

Figure 4.13 Porosity distribution in the Phase 3 Firth of Forth model.

Table 4.2 gives information on all of the Lincolnshire models. We focus on the Phase 3 model, and show the porosity distribution in the model in Figure 4.14.

Features	Phase 1	Phase 2	Phase 3
Geological structure	Lithoframe 1M model of the UK	CASSEM Model	CASSEM Model
Rock properties (porosity and permeability)	Stochastic, based on Cleethorpes borehole	Stochastic, based on Cleethorpes + other boreholes	Stochastic, based on Cleethorpes + other boreholes Phase 2 data was modified
Model area (km x km)	105 x 90	30 x 43.2	30 x 43.2
Model thickness (m)	600	600	600
Grid block size in horizontal (m)	500	450	450
Range of grid block sizes in vertical (m)	0.0004~160	0.032~200	0.032~200
Average porosity			
Aquifer	0.2	0.215	0.215
Cap rock	0.1	0.1	0.1
Average permeability (mD)*			
Aquifer	500	500	500
Cap rock	-	0.005	0.005
Ratio of vertical to horizontal permeability	1	0.1	0.1
Net-to-gross ratio	1	0.5~0.9	0.9

Table 4.2 Properties of the Lincolnshire model. *The permeability distribution was log-normal. We give the geometric average here.

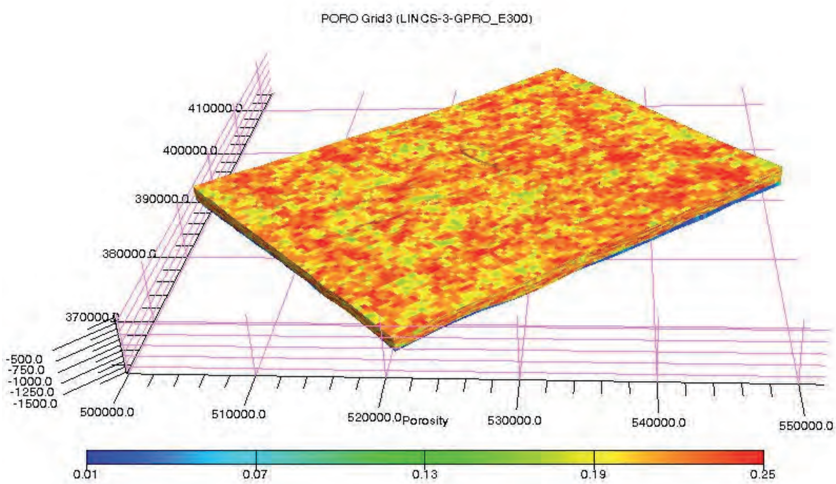

Figure 4.14 Porosity distribution in the Phase 3 Lincolnshire model.

Comparative results for flow models

In the basic simulations supercritical CO_2 was injected at the rate of 15 Mt/year for 15 years. In the Phase 1 and 2 models, a single well was used, and injectivity issues were not considered in detail. With the results of laboratory tests available, and with the greater resolution of the Phase 3 models, we used 15 wells, each injecting 1 Mt/year. After 15 years, the wells were shut in and the simulations were continued for a further 7000 years. Table 4.3 gives details of the simulations at each of the three stages.

Features	Phase 1	Phase 2	Phase 3
Temperature	Cleethorpesborehole for Lincolnshire model, Glenrothes borehole for Firth of Forth model		
Salinity	Zero	Borehole data	Borehole data
Relative permeability	From literature*	From literature	CASSEM lab data & from literature
Capillary Pressure in aquifer	From literature	From literature	From literature
Capillary Pressure in cap rock	As in aquifer	As in aquifer	Higher values
No. of wells	1	1	15
Well orientation	vertical	vertical	horizontal
Rock compressibility (1/MPa)	7 x 10-4	7 x 10-4	5 x 10-4

Table 4.3 Difference between the simulations at the different phases of the project.

The simulations enabled monitoring of the build-up of pressure in the wells and the surrounding regions. The distributions of supercritical CO_2 and CO_2 dissolved in brine were also examined throughout the simulations. Figure 4.15 shows examples of the distribution of supercritical CO_2 and dissolved CO_2 at the end of injection and the end of the simulation (7000 years) for models of the two sites and for all three phases. Figure 4.16 shows the proportions (by mass) of the CO_2 which has dissolved or remains in a supercritical phase – either mobile or trapped at the pore scale.

When comparing models, focus is placed here on the Phase 2 and Phase 3 models. When the Phase 1 models were constructed, data on the geological surfaces were very limited, so the models were approximate. Including the geological surfaces in the Phase 2 models had a very significant impact on the storage calculations.

There were a number of differences in the Phase 2 and Phase 3 models for both sites, and in order to understand the effect of these differences the models were altered in steps, one parameter at a time. The main differences between the Phase 2 and Phase 3 models were that laboratory data were used in the Phase 3 models. This included the relative permeabilities and results from the geomechanical tests such as the rock compressibility and the effect of in situ stress on permeability. Also, after examining the laboratory permeability measurements of the Glenrothes borehole (Firth of Forth site), it was decided to lower the average permeability in the Firth of Forth geological model.

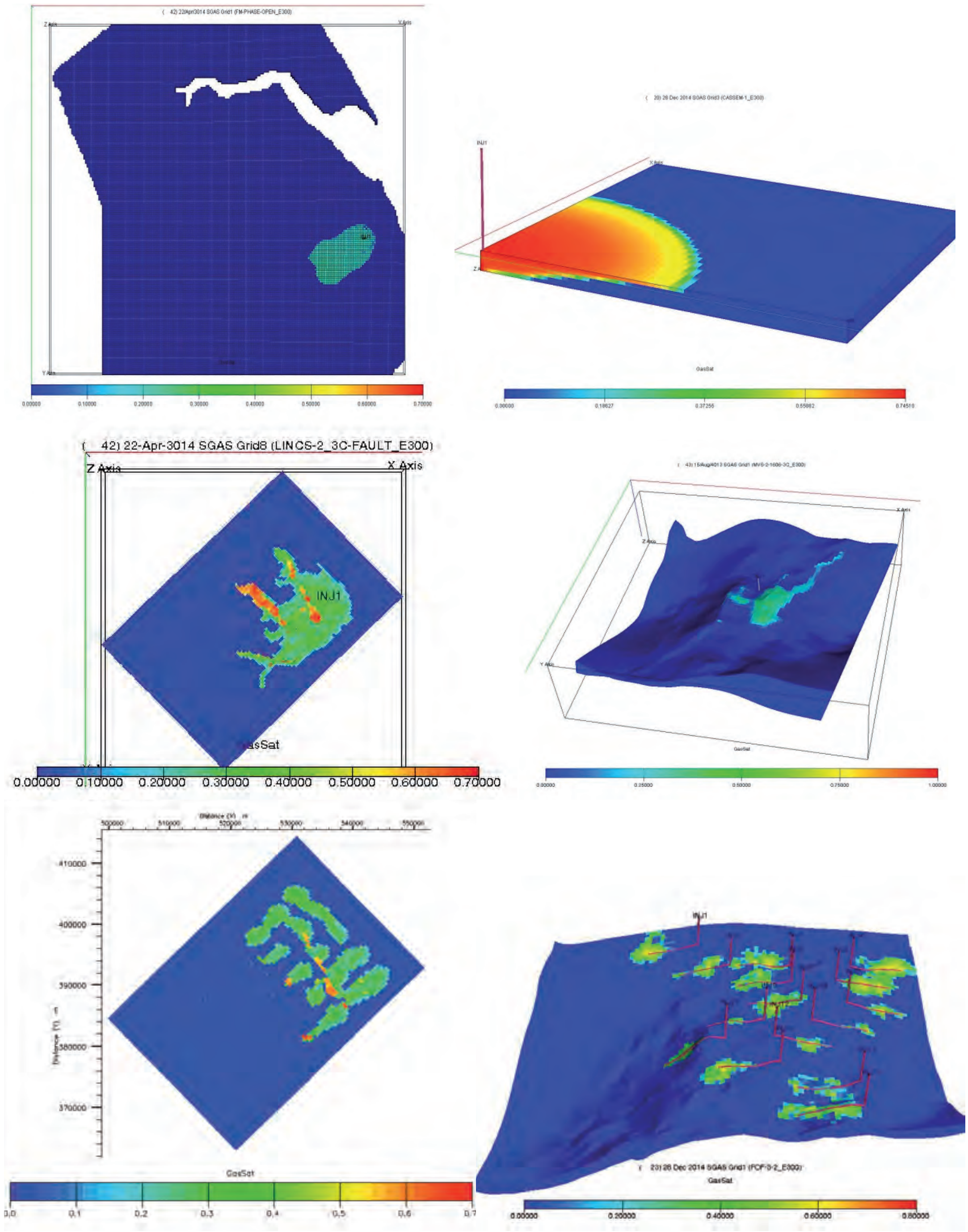

Figure 4.15 The distribution of supercritical CO_2 at the end of the injection period for the Lincolnshire (left) and Firth of Forth (right) models. Phases 1 to 3 are shown from top to bottom.

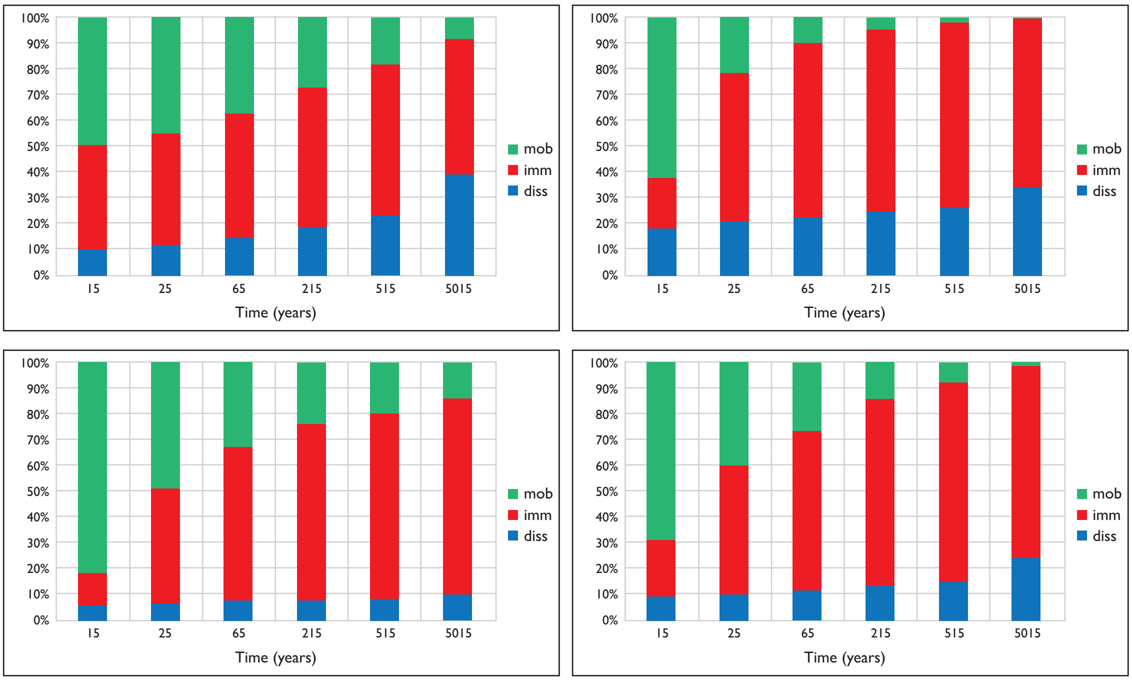

Figure 4.16 The proportion of CO_2 in different states at different times for the two sites. Blue represents the proportion of injected CO_2 that has dissolved in brine, red the proportion that is immobile (below irreducible saturation) and green the proportion that is mobile (above irreducible saturation, although potentially trapped by stratigraphy). The top row plots are for the Lincolnshire model and the bottom row plots are for the Firth of Forth model. The left plots are for the Phase 2 and the right for the Phase 3 simulations.

The steps used when progressing from Phase 2 to Phase 3 were:

1. Increase the number of wells from 1 to 15.
2. Change the structure of the model based on an updated geological model (for the Firth of Forth model).
3. Alter the compressibility.
4. Change the distribution of the petrophysical properties (porosity, permeability and net:gross).
5. Correct the permeability for the effect of increasing stress with depth.
6. Apply the laboratory relative permeabilities.
7. Increase the capillary pressure in the cap rock.

In the Lincolnshire model, the most significant impact was observed during step 6, where the laboratory relative permeabilities were applied for the first time. As discussed above, the CO_2 relative permeability is much lower than the generic curve that was used previously. The CO_2 became less mobile, leading to a larger pressure build-up around the wells, a higher CO_2 saturation near the wells and an increase in the proportion of mobile supercritical CO_2.

In the Firth of Forth model, the change in the structure was not the most significant effect, although the different topography of the new model gave rise to different CO_2 migration paths. The biggest difference for this model was the change in petrophysical properties due to the lowering of the permeability. The pressure in some wells built up to the limit (1.5 times the initial pressure) and the rate had to be reduced so that the pressure did not exceed the limit. This reduced the total amount of CO_2 that could be injected over the 15-year period.

The sensitivity studies which were performed on the Phase 3 model were:

(a) The use of different realisations of the stochastic petrophysical properties (see glossary)
(b) Increasing the vertical permeability
(c) Decreasing the net-to-gross ratio
(d) Using the Phase 2 relative permeabilities.

In the Lincolnshire model, the use of different porosity and permeability realisations had a negligible effect because, overall, the injectivity in the model was good (due to high average permeability). There was a significant effect on the average pressure in the wells, which varied over a range of about 20 bars (2 MPa). There were also minor changes in the proportions of CO_2 dissolved and trapped at the pore scale.

The use of different porosity and permeability realisations in the geological model had a significant effect on the Firth of Forth model. This was again due to the low average permeability in the model. Wells situated in regions where the permeability was lower than average reached the maximum pressure, and so the injection rate was reduced. Therefore, in different realisations, the wells behaved differently and the CO_2 distribution changed. This indicates that in heterogeneous systems well location is very important to ensure good injectivity.

Comparative results for geomechanical simulations

An example of one of the geomechanical model grids is shown in Figure 4.17. The initial stress conditions for the models were based on information gathered from the World Stress Map (http://dc-app3-14.gfz-potsdam.de/) and analysis of other tectonic features known about the proposed storage sites. The geomechanical property correlations used in Phase 2 of the project were based on published data and are shown in Figure 4.18.

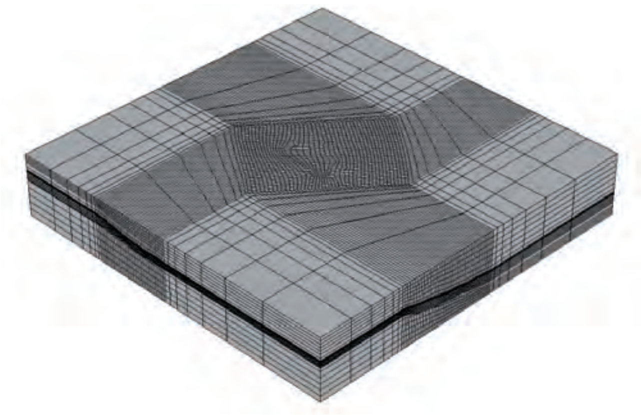

Figure 4.17 Phase 2 example of geomechanical model grid for the Lincolnshire site.

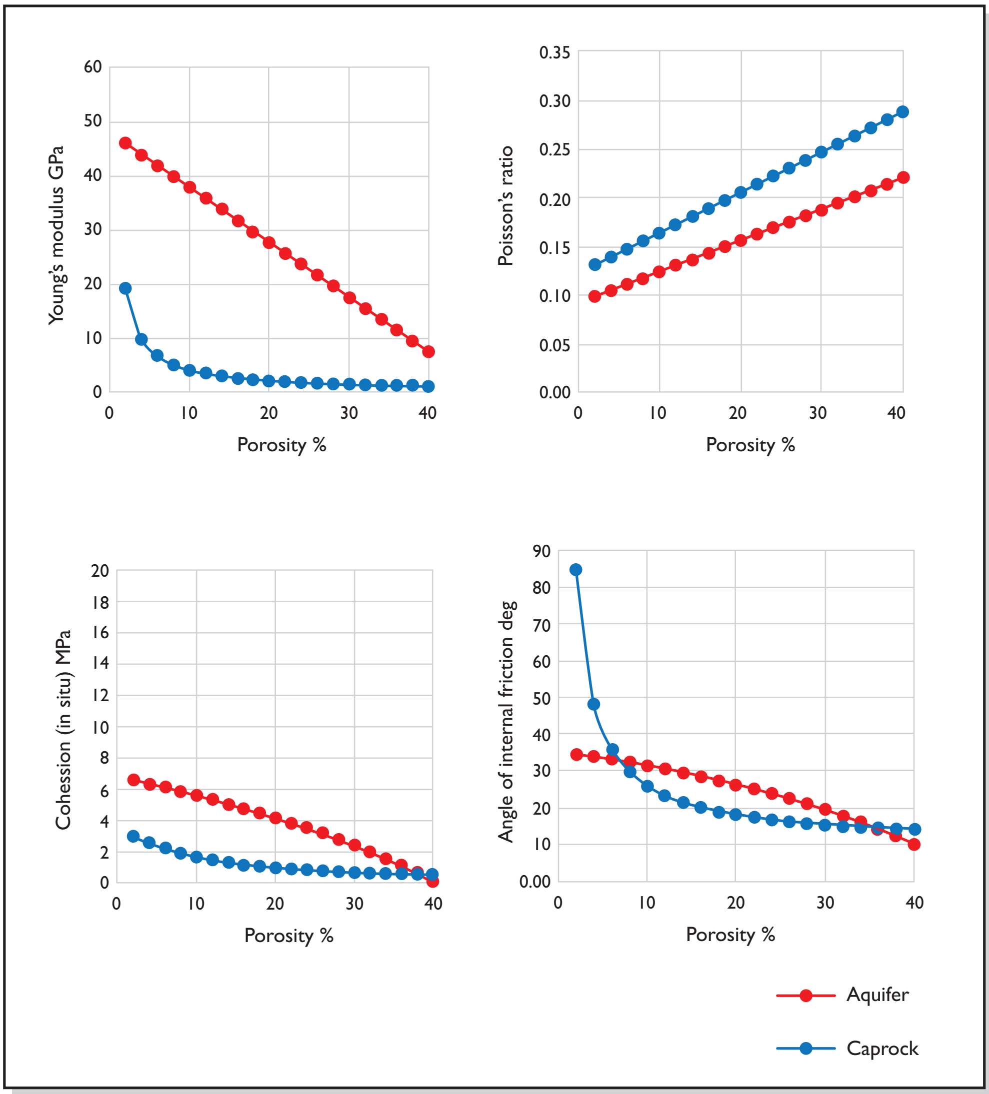

Figure 4.18 Phase 2 geomechanical property correlations.

Figure 4.19 shows an example of results from the geomechanical modelling in Phase 3 of the project. A time sequence of the intact rock failure parameter and the fault slip parameter are plotted for layers of both the cap rock and the aquifer at the Firth of Forth site. In this example, owing to low permeabilities and high injection pressures, the model predicts failure of the cap rock and the potential for fault reactivation in both the cap rock and the aquifer during injection. Compared to modelling in the earlier stage of the project, these results demonstrate the importance of accurate pressure predictions when assessing geomechanical effects. Changes made to the permeability and porosity realisations in the flow model, together with the effect of regional aquifers, made significant differences to the geomechanical modelling results, affecting both the locality and timing of adverse effects. In certain circumstances, changes in the cap rock were observed that persisted at timescales long after injection ceased, as pressures equilibrated in the aquifer-cap rock storage system. In the case of the simulation shown in Figure 4.19 for a single injector, the geomechanical effects were considerably ameliorated when the injection was carried out using multiple wells.

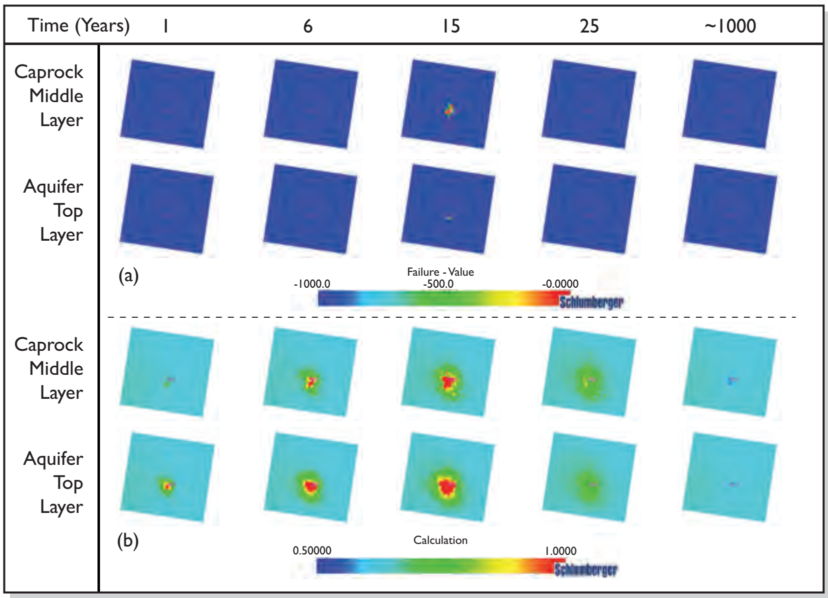

Figure 4.19 Example of geomechanical modelling results for the Firth of Forth site showing (a) potential for failure of intact rock and (b) reactivation of faults.

The rock mechanics testing of core samples from the proposed storage sites largely confirmed the validity of geomechanical property correlations that were available from previously published data. It also demonstrated how the data could be tuned for site specificity at a reservoir scale. The testing also provided the permeability stress sensitivity, which enabled in situ permeabilities to be derived from core plug and well log data. However, ideally a larger range of samples from the cap rock would be tested, since cap rock integrity is vital for CO_2 storage security.

The geomechanical modelling of the storage sites showed that the prediction of adverse geomechanical effects depends on the accurate prediction of the pressure regime, both spatially and temporally.

Comparative results for geochemical simulations

A large number of geochemical reactions can take place when CO_2 displaces brine through rock. The tendency for reactions to occur increases if the brine becomes acidic, as will occur when CO_2 is dissolved in it. It is often stated that geochemical reactions will take place over time frames of thousands of years. While this may be true at ambient conditions, at elevated subsurface temperatures, and where significant pressure gradients are applied, mineral reactions, including those involving CO_2, can take place in a matter of days. This will be confirmed by any oilfield production engineer who has lost an electrical submersible pump or subsurface safety valve to calcite scale.

Calculations conducted during Phase 2 showed the potential for reactions to take place over periods of days and weeks (e.g. dissolution of calcite cements) and over periods of decades and centuries (e.g. precipitation of dolomite). However, these reactions tended to lead to mineral trapping of less than 5% of the injected CO_2, as shown in Table 4.4.

Amount of CO_2 in different phases	Percentage %
Supercritical phase	53.1
Dissolved in water	38.0
Present in aqueous ions	4.2
Present in mineral precipitate	4.7

Table 4.4 Amount of injected CO_2 in different phases after 500 years in Phase 3. Lincolnshire model.

This suggests that the importance of geochemical reactions may be limited to two principal areas. The first is the impact on injectivity, if cements in the near-wellbore area are dissolved. The evidence from the coreflood work carried out on sample SSK2450 was of a decrease in permeability due to release, migration and blocking of fine rock grains. The second impact is the potential for calcite precipitation where pressure decreases and CO_2 evolves out of the brine solution. This release of CO_2 from the brine will lead to a reduction in the acidity of the brine, and therefore a reduction in its capacity to retain minerals such as calcite or dolomite in solution. Pressure decrease will tend to be slow during the post-injection period, being caused primarily by CO_2 dissolution into brine elsewhere in the formation. Thus, mineral precipitation will, indeed, tend to be slow. However, should there be a significant decrease in the pressure of the fluid, as might occur during leakage from the store; then the resulting rate of calcite precipitation might lead to a self-healing mechanism in which the leakage path becomes blocked.

To conduct accurate geochemical calculations, accurate compositional analysis of the rock and the brine are required. Some of the formation brine compositions supplied turned out not to be in geochemical equilibrium with the corresponding rock samples. In some cases, the rock gradually disintegrated when in contact with the brine, indicating the brine was undersaturated with respect to cements present in the rock, which duly dissolved. In other cases, the brine, when made up, was oversaturated with respect to certain salts, and after a period there was evidence of precipitates forming.

This illustrates the importance of performing thermodynamic equilibrium calculations when initialising a geochemical model for CO_2 injection, as the supplied brine compositions may be in error, depending on how the sampling and analysis were performed.

4. 8 STORAGE EFFICIENCY CALCULATION

The amount of CO_2 that may be stored in a saline aquifer can be estimated using a number of different methods, as discussed in Jin et al. (2010). In this project, the following methods were considered:

The compressibility method, which assumes that the amount of CO_2 that may be stored depends purely on the compressibility of the brine and the pore space and on the pressure build-up allowed. This method assumes that the saline aquifer has closed boundaries.

The semi-closed saline aquifer method (Zhou et al., 2008), which is similar to the compressibility method described above, but which allows for brine displacement out of the target formation through the cap rock and the underburden. However, it is a basic assumption that the injected CO_2 remains within the target formation. Numerical simulation may treat the system as having closed or open boundaries.

A storage efficiency, E, is often calculated as part of the site evaluation process before results of dynamic simulations are available. This is defined as the pore volume containing CO_2 divided by total pore volume. In Phase 2, the results of these three methods were compared. If a certain mass of CO_2 is injected for 15 years, we may not reach the maximum limit, so we refer to this as the actual storage efficiency, not the absolute efficiency. Table 4.5 summarises the efficiency values obtained where 't15yr' is the actual storage efficiency and 'tmax' is the maximum that can be stored. Also given is the time to reach the maximum, assuming constant injection rate. Note that the maximum storage efficiency in the Firth of Forth model is much higher than in the Lincolnshire model, because the site is deeper and so at higher pressure. Therefore, the Forth saline aquifer can undergo a larger absolute pressure increase before it reaches the limit of 1.5 times the initial pressure. The Phase 3 model for the Lincolnshire site had a similar value for the actual storage efficiency. However, in the Firth of Forth Phase 3 model, the reduction in permeability meant that some wells reached the pressure limit, and the actual storage efficiency was reduced from 0.25% to 0.17%.

	Lincolnshire Model					Firth of Forth Model				
Storage efficiency	Closed system	Semi-closed system		Numerical simulation		Closed system	Semi-closed system		Numerical simulation	
	tmax	t15yr	tmax	t15yr	tmax	tmax	t15yr	tmax	t15yr	tmax
tmax (yr)	27.1		64.1		53	98.6		(155)[1]		155
E (%)	0.46	0.26	1.04	0.27	1.00	1.60	0.25	(2.59)[1]	0.25	2.75

Table 4.5 Storage efficiencies for the two sites (from Jin et al., 2010). The maximum pressure was not reached in this case, so the time for the numerical simulation was taken.

We conclude that storage efficiencies should be estimated using numerical simulation, where possible, as the simulation model uses more information and takes more processes (e.g. dissolution) into consideration.

4.9 SUMMARY

Reservoir simulation is a powerful tool for predicting the behaviour of CO_2 in the subsurface. Data can readily be generated to provide input for other engineering calculations. These data may include:

- Potential storage capacity or storage efficiency
- Well injectivity, well numbers and completion types, and pressure requirements to pump CO_2
- CO_2 migration paths, including potential for CO_2 to migrate to higher risk locations
- Impact of changing reservoir stress state on likelihood of containment failure
- Potential for CO_2 to be retained away from higher risk locations – by local stratigraphic trapping, residual trapping, dissolution or mineral trapping.

In general, the physical and chemical processes are well understood and captured in the models. For example, well characterised laboratory tests can often be reproduced with a high degree of accuracy.

However, there are three principal limitations when simulating processes at the field scale, especially in the context of CO_2 injection:

(1) Numerical errors due to insufficient grid resolution, leading to averaging inaccuracies. The most significant errors here will arise from calculation of CO_2/brine immiscible displacement and from calculation of CO_2 dissolution into brine (Pickup et al., 2010). The former error may be addressed by appropriate manipulation of the relative permeability curves. The latter error can only be addressed by appropriate grid resolution, which poses a computational resource challenge.

(2) Unavailable or inaccurate input data. Reservoir description poses a challenge, particularly since data acquisition is relatively expensive (drilling wells, seismic, etc.). There are two complimentary approaches to addressing this challenge. One is to ensure good integration within the asset team. An example would be the benefit demonstrated of regular interaction between the geoscientists preparing the geological models (described in Chapter 3) and the engineers performing the flow simulations. During the model construction phases the engineers should gain an understanding of the geological background and they should specify the parameters they will need to use to populate their models. During the development of the base-case dynamic models, the geologists should be involved to ensure that assumptions made are realistic. A second example of integration is between laboratory specialists performing experiments and the flow modellers who need to identify and interpret the relevant data to provide meaningful input for their models. This can be an iterative process, as it is sometimes in the running of a model that it is identified that additional laboratory data are required.

(3) Inability to monitor a real system and validate models. A simulation is only valuable if it informs and if it provides a testable prediction. Monitoring CO_2 storage in saline aquifers will almost certainly prove to be challenging. Some of the issues will be technical, some economic. However, there is an opportunity for reservoir simulation to be used to inform the monitoring programme of potential outcomes. This is illustrated in Chapter 5.

As well as expending effort in collecting relevant and accurate data to provide inputs for the dynamic models, a crucial approach is to run multiple scenarios and generate a range of possible outcomes. If a single calculation is performed, all that can ever be said about it is that, to some degree of accuracy, it is wrong. However, if a range of calculations is performed, and if the range of input values is based on defensible criteria, then a range of outcomes should be generated that cover the range of possible real outcomes. This type of sensitivity analysis has been presented to a limited extent in this chapter. It is significantly extended in Chapter 6 and then used in evaluating risk in a systematic fashion in that chapter.

So, the question may be asked, what value is derived from moving up through the various phases of complexity in dynamic modelling?

The Phase 1 modelling should, perhaps, be conducted as part of the initial site evaluation process described in Chapter 3. Data was very limited at this point, particularly for the Firth of Forth site, and thus it would not have been of benefit to allocate significant resource to this phase of activity. However, caution does need to be taken that potential sites are not excluded at this phase due to inaccurate data. A conservative approach should be considered, and sites only excluded if there is clear and verifiable data that suggests they are inappropriate or that alternative sites will definitely be more favourable.

The Phase 2 modelling was based on a more sound geological interpretation. By this stage it is possible to define the storage capacity more accurately than by assigning some arbitrary storage factor, and thus data can be generated that may be used as input for other engineering calculations being conducted.

The value of Phase 3 modelling is clearly that site-specific laboratory data is incorporated. Every site has specific characteristics, and these will affect the capacity for and the security of CO_2 storage. In hydrocarbon recovery, an accurate estimate of recoverable reserves can only be made once fluids and fluid-rock interactions have been analysed in the laboratory. The same is true for CO_2 storage. The challenge for CO_2 storage is to make use of what will almost necessarily be sparser data to constrain a model that will often encompass a much larger, but much less well defined asset. Therein lies the challenge for CO_2 geological storage risk evaluation.

CHAPTER 5
HOW DO WE KNOW WHERE THE CO_2 IS? – DEVELOPMENTS IN GEOPHYSICAL MONITORING

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5.1 INTRODUCTION

In order to reduce the risks associated with CO_2 stored in geological subsurface formations, monitoring of the CO_2 is fundamental to the operation and management of the storage site. Generally, monitoring is the continuous or repeated observation of a situation to detect changes that may occur over time. To be able to monitor a given CO_2 store, we must be able to observe and track changes in the 3D distribution of CO_2 during injection, post-injection site management and post-closure stewardship.

Objectives of monitoring are therefore, (1) to enable optimal reservoir engineering by repeated or continuous assessment that informs on the evolving physical conditions in the store, and (2) to allow operation of the storage site within regulatory monitoring requirements and agreed industry practices. With the scarcity of established regulation and active CCS storage during the life cycle of CASSEM and of other pioneering CCS-demonstration R&D, the second objective includes providing assurance to (would be) regulators and stakeholders that unexpected or undesired migration in the storage can be tracked and mitigated, informing well in advance of any 'leakage', 'escape' or 'emission', in the public parlance. Correspondingly, the monitoring strategy is 'proactive' (DET NORSKE VERITAS, 2010).

5.2 MONITORING METHODS

Several methods have been proposed for monitoring stored CO_2, including geochemical, geomechanical and geophysical methods. Geochemical methods use direct sampling of subsurface fluids or escaping gases and have limited spatial resolution. Geomechanical methods such as comparing satellite measurements repeated over time to monitor earth surface movements (e.g. uplift) as a mechanical response to a large amount of injected CO_2 are only viable (1) for onshore reservoirs and (2) where the target geological layers are sufficiently shallow to impact the earth's surface. Geophysical monitoring methods have a much broader scope; they remotely measure subsurface changes by sending signals like seismic (i.e. acoustic) waves into the ground, measuring them either at the surface or in boreholes after propagation through the subsurface, and analysing the data for subsurface information. The application of geophysical monitoring methods to subsurface exploration and monitoring is well developed in the hydrocarbon industry and other resource storage and waste disposal sectors. They are, therefore, the most likely methods to be used to monitor stored CO_2. The remainder of this chapter considers only geophysical monitoring methods.

A range of geophysical methods have been used to monitor major CO_2 storage sites around the world, such as Sleipner in the Norwegian North Sea, Weyburn in Canada and In Salah in Algeria. Repeated seismic monitoring is currently the key method providing most information about the subsurface. However, gravity and electromagnetic methods at Sleipner (e.g. Alnes, 2008) and microseismic monitoring at Weyburn (Verdon et al., 2010) have also been deployed. In the case of In Salah, time-lapse (repeated) satellite imagery (monitoring ground surface displacement) has proven to be informative (Mathieson et al., 2009). This site in particular is well-suited to satellite imagery because it is situated in the desert (this technique is more efficient when the earth surface is covered with bare rock). The most applicable and informative suite of monitoring methods is therefore site-dependent.

5.3 MONITORABILITY

The suite of geophysical monitoring techniques employed should be able to detect where some minimum threshold volume or saturation of CO_2 has been exceeded within a subsurface reservoir or after migration into the overburden. Moreover, the saturation (and hence volume) of CO_2 must be estimable within some predefined or characteristic spatial volume, with some minimum degree of accuracy. Defining these minimum thresholds is equivalent to defining the term 'monitorable'. To date, no standard definition of what is required for a site to be monitorable has been agreed.

This chapter contributes new insight and information towards this definition. Particular attention is paid to offshore geophysical methods, but many of the conclusions are also valid for onshore monitoring. Whether or not monitorability requirements can be met depends essentially on the geology and geography of the storage site. Site geology dictates the magnitude of the change in CO_2 saturation that is measurable in any given injection scenario. Pertinent geological information is obtained from the geological model, rock properties and lab petrophysical data (see Chapters 3 and 4). Site geography limits the range of applicable geophysical monitoring methods (dictated by whether the site is offshore, mountainous, remote wilderness, etc).

To assess the detectability of petrophysical changes in storage reservoir rocks, the expected magnitudes of corresponding changes in geophysical signals are calculated by petrophysical and geophysical modelling. Petrophysical modelling comprises constructing mathematical relations that predict geophysically monitorable parameters such as the velocity of primary (P) waves and shear (S) waves propagating through the rocks, from estimated rock properties such as permeability, porosity, clay content and saturations of different fluids. Geophysical modelling involves predicting the magnitude of the measurable signal based on those modelled values of geophysical parameter changes and on the site geology. When a monitoring survey is carried out, the real geophysical signals are measured in the field, from which critical rock properties (e.g., fluid saturations) are estimated by applying the reverse form of the above mathematical relations. This technique is called 'inversion'.

For the purposes of the CASSEM project we propose that 'site monitorability' is defined by a combination of the following factors:

- Survey practicality/cost.
- Geophysical spatial resolution.
- Petrophysical detectability.
- Petrophysical parameter resolution.

Thus, a site is assumed to be monitorable, if geophysical monitoring is possible from a practicality and cost point of view; if there is sufficient spatial resolution to image potential positions of subsurface CO_2; if changes in geophysically measurable signals due to CO_2 injection are detectable; and if there is sufficient resolution or uncertainty-reduction in petrophysical and fluid parameter estimates to fulfil monitoring objectives such as detecting leakage, or exceeding the volume and saturation thresholds.

Figure 5.1 shows the workflow for assessing monitorability of a site and designing a corresponding monitoring strategy, and the linkages to other work packages in the CASSEM project. In the following sections, detectability, petrophysical resolution and, to some extent, geophysical spatial resolution components are explained. It is assumed that there are no practical or cost barriers to geophysical monitoring.

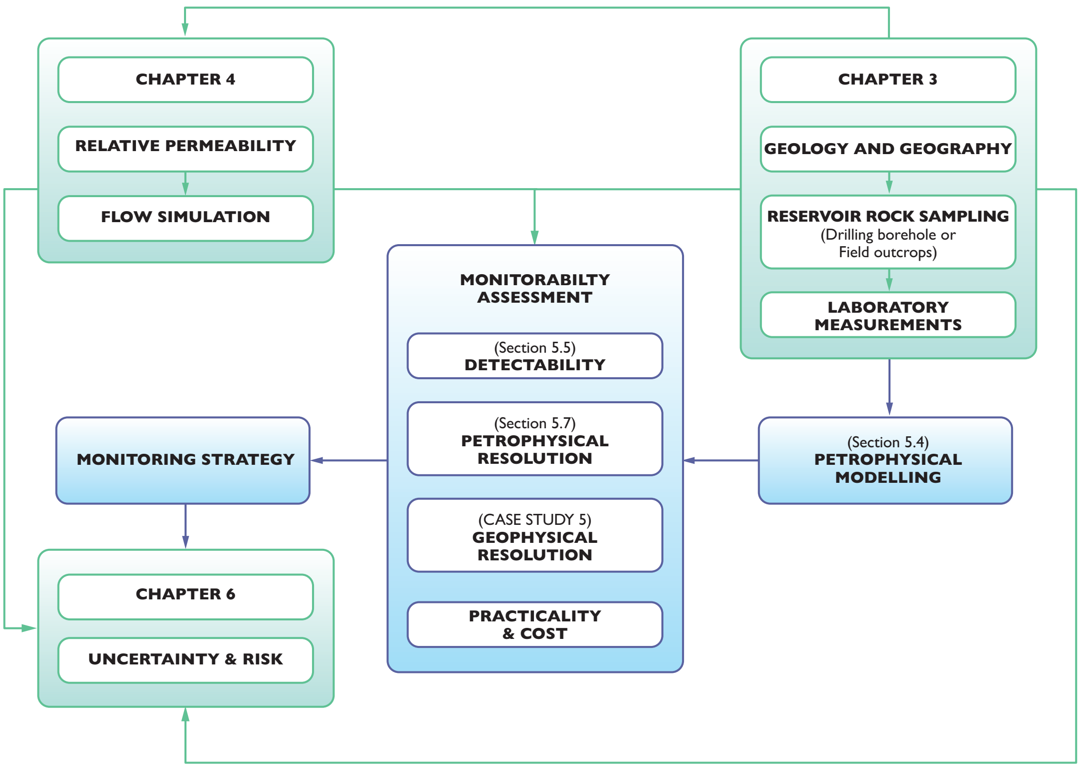

Figure 5.1 Monitorability assessment workflow. Blue boxes represent work carried out in this chapter. Section numbers refer to sections in this chapter. Yellow boxes indicate information derived from other chapters.

5.4 PETROPHYSICAL MODELLING (PREDICTING GEOPHYSICAL PROPERTIES OF CO_2-BEARING ROCKS)

The main physical parameters of rocks to which various geophysical methods are sensitive are:

- Bulk and shear moduli, corresponding to P- and S-wave seismic velocities.
- Density.
- Electrical conductivity.
- Magnetic permeability.

Each of these may have apparent variation with the direction of measurements (this property is called anisotropy). All of the geophysical methods are sensitive to one or more of these parameters. The physical parameters of rock pre- and post-CO_2 injection depend on the mineralogical composition, porosity, pore fluid content (including the saturation of CO_2), and in situ pressure and temperature of the rock, as well as on the physical parameters of the injected CO_2. Rock and fluid physics measurements and theoretical modelling show that the presence of CO_2 may affect the bulk and shear moduli, the density and the electrical resistivity of the reservoir (more details on this are given in Chapter 4). No change is expected in magnetic properties of rocks due to CO_2 injection.

There are a range of petrophysical models that are used to investigate the effect of CO_2 saturation (S_{CO2}) on geophysical parameters of the reservoir rocks, such as the models proposed by Pham et al. (2002), Pride and et al. (2003) and also the Archie (1942) model to calculate electrical resistivity of reservoir rocks. Figure 5.2 shows calculated P-wave velocity (the subsurface equivalent of acoustic speed of sound in the air) and electrical resistivity of a reservoir rock with 22.6% porosity and 5% clay content (for information about the other material parameters used in the petrophysical model see Table 6.1 of JafarGandomi and Curtis, 2010), with respect to a range of S_{CO2} (1–99%) and frequency in the case of P-wave velocity. Because the fluid content of rock has no effect on the shear modulus, any variation of the shear or S-wave velocity with S_{CO2} occurs primarily due to density changes.

Figure 5.2a implies that in terms of monitoring CO_2 storage sites using seismics, the purpose of monitoring has a significant effect on selecting the appropriate monitoring methods. For example, if the purpose of monitoring is simply to detect the presence of CO_2 in the storage formation or to detect CO_2 migration or leakage into the surrounding rocks, time-lapse (repeated) reflection seismics with a low-frequency content may be appropriate because it will show significant changes in the recorded signals, even with a small amount of CO_2 in the brine. However, if the purpose of monitoring is to evaluate the amount and spatial distribution of injected CO_2 (i.e. to estimate S_{CO2} in the brine), low-frequency methods such as time-lapse reflection surface seismics may not be appropriate since their sensitivity is minimal to saturations beyond about 10–20%; higher frequency techniques such as sonic logging in wells, or cross-well methods may have to be applied. Nevertheless, in many injection scenarios one may expect up to ~5% CO_2 dissolved in brine over the majority of the reservoir volume, in which case surface seismic methods may well suffice.

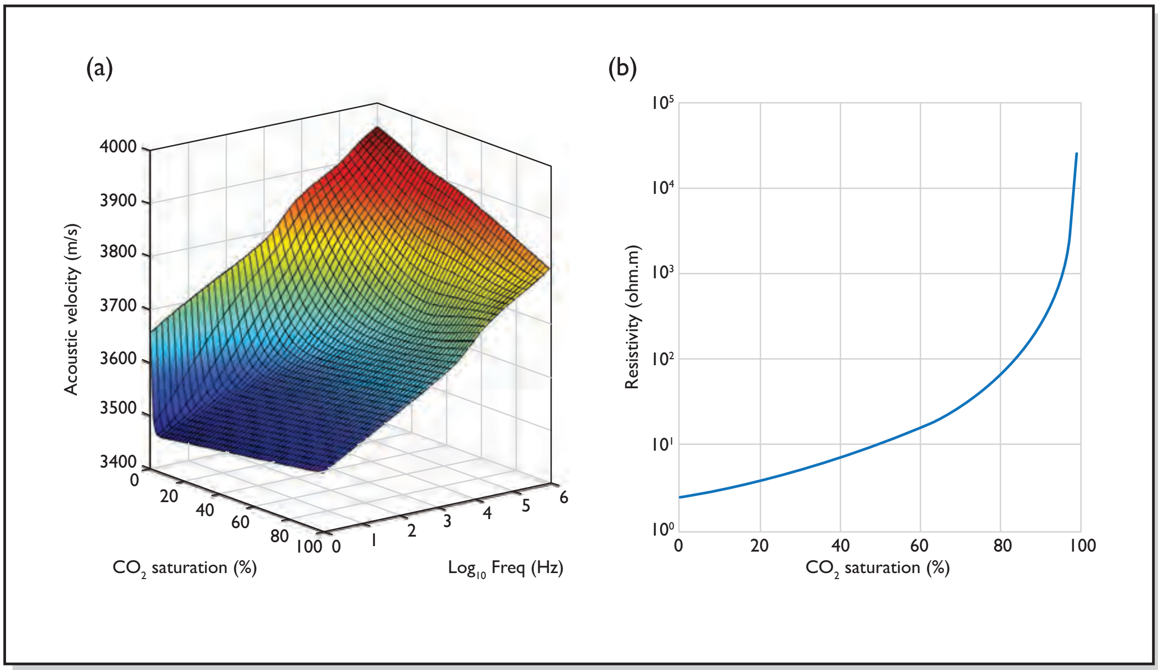

Figure 5.2 Variation of (a) acoustic velocity and (b) electrical resistivity against S_{CO2} and seismic wave frequency for the reservoir rock. Colours reflect the height of the surface in (a). Low, intermediate and high frequencies correspond to the marine reflection seismic method, well-based seismic measurements, and laboratory measurements, respectively. Note the strong nonlinearity of acoustic velocity variation with respect to CO_2 saturation at lower frequencies and its linearity at higher frequencies.

5.5 DETECTABILITY

As mentioned earlier, any geophysical monitoring method employed should at least be able to detect where some minimum threshold volume or saturation of CO_2 has been exceeded within the reservoir. This minimum threshold is used to define the detectability. In this section a set of diagnostic parameters are defined for three geophysical methods:

- Gravimetry (sensitive to the density of rocks).
- Controlled source electromagnetic (sensitive to electrical resistivity of rocks).
- Seismics (sensitive to (an)elastic properties of rocks).

Each method is used to assess the detectability of changes in geophysical parameters of reservoir rocks due to increased S_{CO2} for one geophysical model. These changes are calculated by comparing expected or modelled geophysical responses of the reservoir before and after injecting CO_2.

Detectability parameters

The following general form for the detectability parameters is introduced:

$$\delta x = \frac{X - X_0}{std(X)} \tag{5.1}$$

where X_0 and X are values of geophysical parameters measured with a particular geophysical method before and after injecting CO_2, respectively, and *std(X)* is the uncertainty or noise level involved in estimating X, which dictates the minimum required changes in geophysical parameters to produce distinguishable geophysical signals. Equation 5.1 is used to evaluate the different geophysical methods. In the rest of this section two examples of the application of detectability parameters to gravimetry and controlled-source electromagnetic (CSEM) measurements are shown. The seismic method can quickly be used to detect P-wave velocity changes to about 1–2% accuracy, so the detectability of a particular saturation change at different frequencies can be inferred from Figure 5.2a. Further investigation of seismic detectability based on seismic amplitude variation with offset is given in JafarGandomi and Curtis (2011).

Gravity survey (gravimetry)

Once CO_2 is injected into brine-saturated rocks (saline aquifer reservoirs), it will partially replace the brine and consequently change the bulk density of reservoir rocks. Studies have shown that it is possible to detect the presence of CO_2 in the storage formation by gravimetry, which is sensitive to the density changes in the reservoir (e.g. Alnes et al., 2008). The depth of storage formation and inherent resolution of the technique has significant impact on the feasibility of gravimetric detection of CO_2 migration. As the depth of the storage formation increases, the amplitude of changes in gravity measurements at the surface decreases rapidly.

To design a gravimetry survey to detect CO_2 migration, modelling is necessary to see whether the expected amplitude of signals generated on the surface are sufficiently large to be detected using current technology. The current accuracy of time-lapse gravity measurement is around 5 $^{\mu Gal}$ (e.g. Stenvold et al., 2008). In this chapter a simplified CO_2 plume shape (a vertical cylinder) is used to estimate its detectability by repeated surface gravity measurements. The gravity signal is calculated on the axis of this vertical cylinder of homogeneous density perturbation.

The gravimetric detectability is calculated for a range of reservoir rock porosities and S_{CO2} and is shown in Figure 5.3. In this figure, the coloured area highlights the detectable zone using surface gravity measurements for storage formations with thickness (cylinder height) of h = 20 m, 100 m and 200 m, and cylinder radius-to-depth ratios of 0.2, 0.5 and 1.0, in a matrix form. Any value of corresponding detectability parameter greater than one falls within the detectable zone of gravimetric measurements. This figure shows how the area of the detectable zone, with respect to porosity and saturation, increases either with plume thickness or with its radius-to-depth ratio.

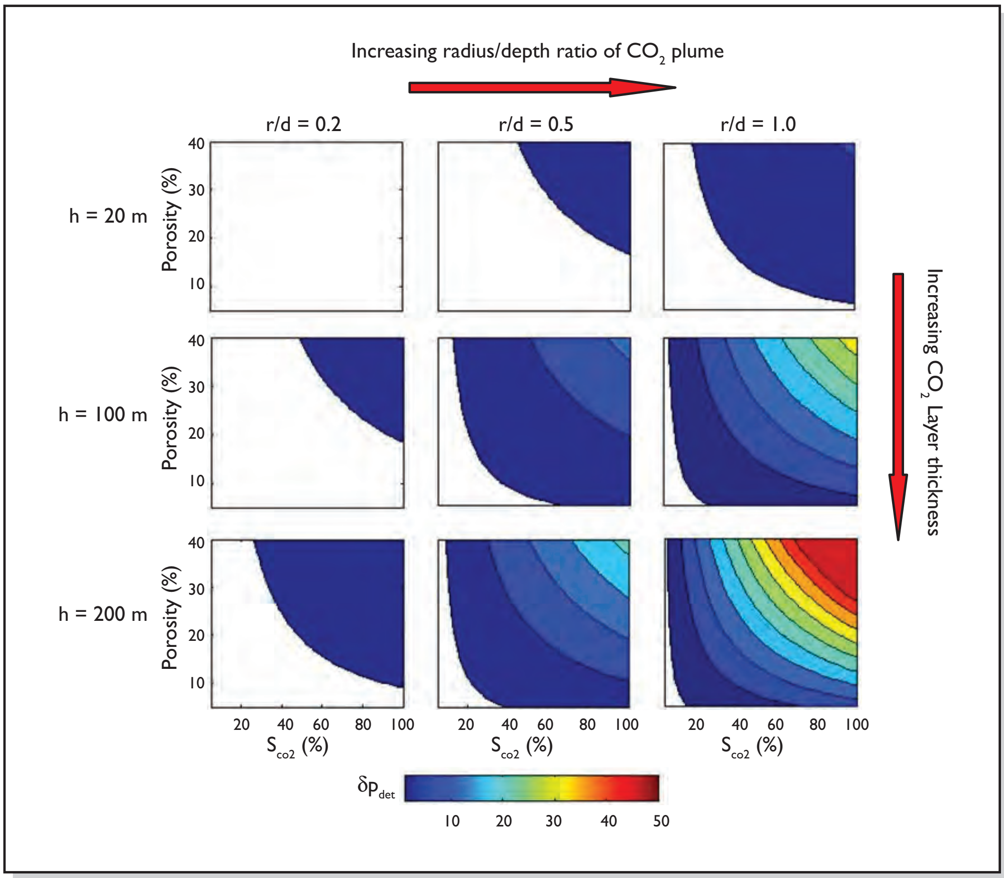

Figure 5.3 Density detectability parameter versus S_{CO2} and rock porosity for different values of thickness and radius-to-depth ratio of the CO_2 plume within the storage formation. Coloured areas represent detectable plumes. In this figure, moving from left to right corresponds to increasing the CO_2 plume size and/or reducing its depth. Moving from top to bottom represents increasing the CO_2 layer thickness.

Applicability

The above calculations for simple cases confirm that gravimetry has the potential to be used to detect subsurface stored CO_2, particularly for higher porosity reservoirs, for higher saturations and when the lateral extent of the plume is comparable to its depth. Calculating the gravimetry detectability parameter for each individual storage site and the expected plume shape will help to design an appropriate and efficient monitoring strategy. However, while gravity can be used to detect the presence of a plume, it will not constrain its shape or its internal saturation heterogeneity because the spatial resolution offered by surface gravity is generally very low.

5.6 CONTROLLED-SOURCE ELECTROMAGNETIC METHOD

Even though CO_2 injection into brine-saturated sandstones significantly increases the resistivity of rocks (Figure 5.2b), detectability of these changes remains a challenge, particularly in the case of offshore storage sites. Controlled-source electromagnetic (CSEM) data typically result in far lower spatial resolution than reflection seismic data. There have been several studies on the feasibility of monitoring CO_2 storage by electrical methods (e.g. Gasperikova and Hoversten, 2006). For offshore monitoring, the marine controlled-source electromagnetic method has recently been tested.

Um and Alumbaugh (2007) demonstrated that the efficiency of marine CSEM for detecting high-resistivity relatively thin layers (e.g. hydrocarbon and CO_2 reservoirs) at depth is strongly dependent on the source-receiver configurations and on the site characteristics, and is only possible within a certain source-frequency range. In particular, the thickness and depth of the storage formation and electrical structure of the overburden have a profound effect on detectability. This limits the ability to draw general conclusions about the electromagnetic detectability of SCO_2 stored in a saline aquifer.

The standard strategy to design a CSEM experiment or survey is to make the received signal as large as possible for the shortest possible transmitter-receiver offset, in order to increase the lateral resolution while maintaining an appropriate signal-to-noise ratio (e.g. Constable and Weiss, 2006). To illustrate this we consider a simple model of a storage formation with initial (pre-storage) resistivity of 1 ohm-m and thickness of 100 m at a depth of 1000 m below the seabed, within a background medium consisting of a lower half-space with the resistivity of 1 ohm-m. We model the CSEM responses for a single receiver located on the seabed for a series of inline electric dipole transmitters from 0–20 km horizontal offset from the receiver and at 50 m above the seafloor. We use the OCCAM1DCSEM code of Key (2009) to calculate the synthetic responses. It is assumed that the resistivity of the storage reservoir increases to 20 ohm-m after injecting CO_2. To see the effect of CO_2 injection on the CSEM measurements, the CSEM responses of the model are calculated before and after injecting CO_2, for a range of frequencies from 0.1–100 Hz, and for transmitter-receiver offsets from 1–20 km (Figure 5.4a), and use the corresponding detectability parameter (equation 5.1) to assess detectability of resistivity changes in the reservoir.

In order to investigate the effect of the overburden and underburden on CSEM monitoring, a high-resistivity layer with 20 m thickness and 200 ohm-m resistivity (corresponding, for example, to a basalt layer) is moved vertically from just below the seabed to 4000 m depth below the seabed, in 200 m steps, and at each step the detectability parameter is recalculated. Different values of uncertainties (noise level) for horizontal and vertical components of recorded electrical fields (1×10^{-15} V/Am^2 and 5×10^{-15} V/Am^2, respectively) are considered because the vertical field measurements on current systems are generally more contaminated by instrumental noise than horizontal components (Constable et al., 2006). Figure 5.4b shows variation of the detectability parameters for each component, versus the depth of the high-resistivity layer. The variation of detectability indicates that in the overburden, as the high-resistivity layer gets closer to the reservoir, its effect decreases, while this is the opposite when the high-resistivity layer is in the underburden. The detectability parameter converges to the corresponding values for the homogeneous background at about 1000 m below the reservoir (3000 m depth).

Applicability

The significant effect of the underburden as well as overburden on the monitorability of reservoirs with the controlled-source electromagnetic method has been investigated for the first time in CASSEM. The main lesson to be learned, however, is that the potential effectiveness of the controlled-source electromagnetic monitoring method must be assessed on a site-by-site basis. This will require significant prior information about the electrical resistivity structure of the reservoir, overburden and underburden. This is significant since exploration wells tend not to be drilled into the underburden in current exploration practice. Of course, performing electromagnetic monitoring from borehole wells may reduce the susceptibility of these methods to surrounding high-resistivity layers, but this susceptibility will never be completely removed, particularly if such layers are close to (above or below) the reservoir (e.g. Um & Alumbaugh, 2007).

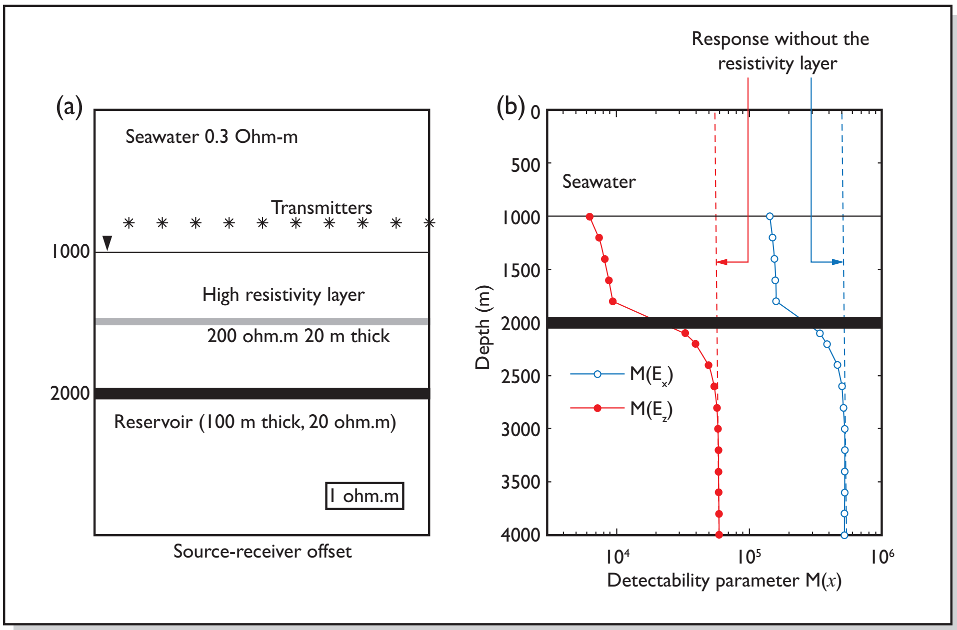

Figure 5.4 (a) Resistivity structure model and transmitter-receiver configuration (*=inline electric dipole transmitter). (b) Variation of the detectability parameters for horizontal and vertical components of the electric field with respect to the depth of the thin (20 m thick) high-resistivity (200 ohm-m) layer. Vertical dashed lines represent the detectability parameter in the absence of the high-resistivity layer. Note that the high-resistivity layer affects the detectability parameter even when it is in the underburden.

Large dolerite sills (with high resistivity) are characteristic of the geology of the Midland Valley of Scotland. It may be anticipated that such volcanic bodies/layers are present in the overburden and underburden of the Firth of Forth target aquifer reservoir and are indicated in the well-log of the Firth of Forth-1 borehole and seismic sections. Thus, further detailed geological and geophysical investigation of the overburden and underburden of the Firth of Forth site would be required before an appropriate monitoring strategy can be designed.

5.7 COMPARISON OF DIFFERENT GEOPHYSICAL PARAMETERS FOR CO_2 MONITORING

The purpose of geophysical monitoring of subsurface stored CO_2 has a significant effect on the selection of appropriate monitoring technique(s). Some of the most desirable goals of monitoring are: detecting the presence of CO_2 at different locations in the storage formation, and estimating the spatial distribution of S_{CO2} within the brine-filled aquifer and monitoring seal integrity. Based on the effect of S_{CO2} on the petrophysical parameters of rocks, and on their corresponding detectability parameters constructed in previous sections, the utility of each of the rock properties can be derived for different purposes of monitoring.

The detectability of stored CO_2 is strongly dependent on site characteristics (not only for electrical methods). For example, site geography (onshore or offshore), and the depth of the storage formation have first-order effects on the applicability (and cost) of all monitoring methods. In the following, the relation between the petrophysical parameters of rocks and their utility to detect CO_2 presence, migration, saturation, and seal integrity of a typical offshore storage site is discussed.

Based on the methods described above it is possible to summarise the results by assigning a qualitative ranking to each of the physical parameters of rocks for the various different purposes of monitoring the subsurface stored CO_2. The scale A, B and C is used where these are defined as follows. A: when geophysical monitoring is highly sensitive to the parameter with few limitations. B: when the parameter is only conditionally detectable, depending on the specific site or reservoir. C: when the parameter represents either very low sensitivity to S_{CO2}, or if current geophysical technology is not usually able to detect the corresponding petrophysical changes. Table 5.1 gives the ranking of each petrophysical parameter for each of four monitoring purposes. Such a ranking table is useful in the sense that it captures the overall likelihood that a parameter could be monitored by a surface geophysical method to detect the four types of changes due to CO_2 injection.

	Density	Vp	Vs	Qp	Qs	Resistivity
Presence	B	A	C	B	B	B
Migration	B	A	C	B	B	B
Saturation	B	B	C	B	B	B
Seal integrity	C	A	A	C	C	C

Table 5.1 Relative ranking of geophysical parameters for different monitoring purposes (Presence: detecting existence of the CO_2 plume regardless of the saturation. Migration: detecting lateral or vertical movement and growth of the plume. Saturation: quantitative estimation of exact CO_2 saturation. Seal integrity: detecting cap rock quality and leakage of CO_2 into it).

While we suspect that most entries in Table 5.1 will be correct for a number of sites based on the methods of analysis herein, the results given in Table 5.1 cannot be directly used for any particular storage site. For each specific site, the table must be updated using modelling methods similar to those used above, and using petrophysical models tailored to represent specific reservoirs or overburdens.

5.8 PETROPHYSICAL PARAMETER RESOLUTION

In Sections 5.5 and 5.6 the detectability of expected changes in petrophysical parameters due to CO_2 injection in each geophysical measurement was examined. We now examine petrophysical resolution: the ability to distinguish between different potential values of inverted petrophysical parameters such as SCO_2 in the reservoir. In this section, an inversion approach is used to investigate the effect of petrophysical resolution on the monitorability of changes in petrophysical parameters of saline aquifer rocks, in order to estimate SCO_2. This is particularly important to estimate the volume of migrated CO_2, either within the reservoir or leaked into the overburden. Such information will be used to assess associated risks.

Technical details

Recently, inversion using the Monte Carlo method has been widely used for estimating hydrocarbon reservoir parameters (e.g. Bosch et al., 2007). The method estimates expected uncertainties in key petrophysical parameters, which assists in operational decision-making, given various qualities of geophysical parameter estimates. This in turn identifies key contributions to uncertainty and allows an appropriate selection of targeted geophysical monitoring technique(s) to reduce overall uncertainty on petrophysical parameters. To quantify the information in post-inversion probability density functions (pdfs) of S_{CO2}, Shannon's information concept is used (for details see Curtis, 2004a, b; Guest and Curtis, 2009; JafarGandomi and Curtis, 2010). Here, Shannon information is a measure of how much information about S_{CO2} can be obtained from the inversion of geophysical parameters.

Petrophysical parameters are calculated, corresponding to the reservoir rock used in Section 5.3, for a range of S_{CO2} (1–99%). Figure 5.5 shows the post-inversion histograms of inverted S_{CO2} from P-wave impedance (IP) (top row) at low frequencies (30 Hz) that may typically be measured from reflection seismics, with three different values for the uncertainty in estimated IP (1%, 2%, and 3%) and their corresponding calculated Shannon information (bottom row). Both are plotted against the true value of S_{CO2}. The higher values of information at very low and high S_{CO2} are due to the hard boundary conditions at 0% and 100% saturations (these boundaries can not be exceeded, which is a form of additional, definitive information). This is very important because, in principle, the higher hard boundary condition can even be moved to lower values by conditioning the process of S_{CO2} estimation by the prior relative permeability estimates of the reservoir rock. According to relative permeability measurements the S_{CO2} in the reservoir rocks cannot exceed a certain value. This value depends on the characteristics of the reservoir rock, but generally it may vary between around 30% to around 60%. The same information curves have been calculated for density and electrical resistivity (not shown here).

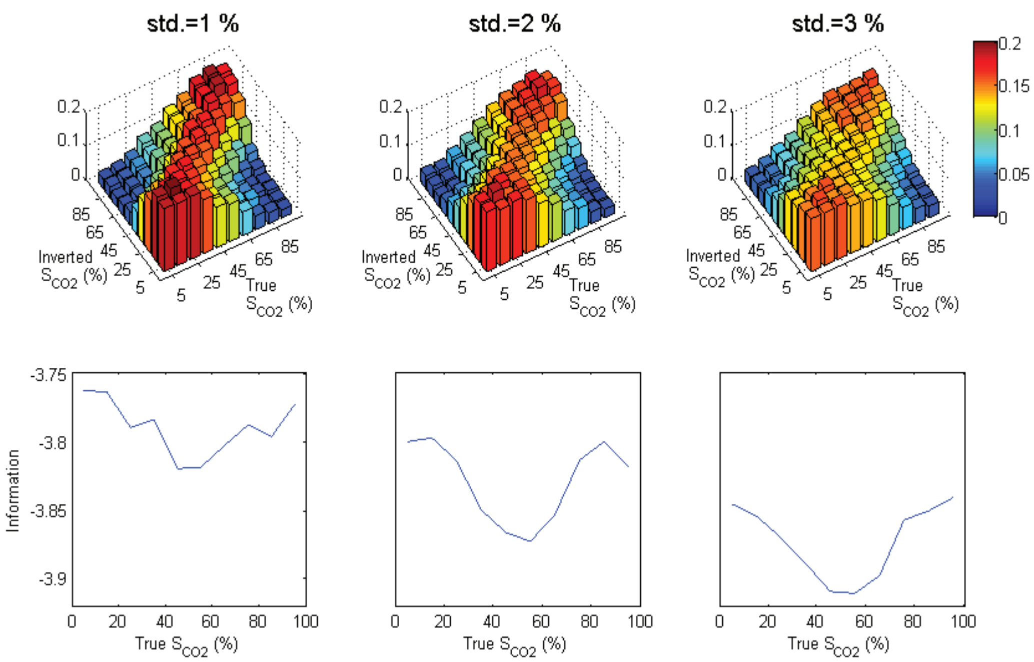

Figure 5.5 Posterior histograms (top row) and information values (bottom row) for Ip measurements as a function of S_{CO2}, with I_P uncertainties of 1%, 2%, and 3%, and seismic frequency of 30 (Hz). Note the higher values of information that can be obtained near the highest and lowest CO_2 saturations. In the top row tighter histograms represent higher monitorability.

Information interpretation

As expected intuitively, increased uncertainty in the geophysical parameter estimate increases the uncertainty and decreases the information obtained about S_{CO2}. The same analysis for different geophysical parameters at three different frequencies, representing reflection seismics, borehole and lab measurements, shows that borehole measurements can significantly increase the level of information obtained. Compared with the other geophysical parameters, the information from electrical resistivity presents far higher values. This indicates that electrical resistivity has the potential to aid S_{CO2} monitoring, if it can be estimated reasonably accurately across the reservoir. The negligible sensitivity of electrical resistivity to the frequency of electromagnetic measurement over the frequency range of interest in geophysics may also be an advantage. Joint inversion of electrical resistivity and elastic parameters may significantly reduce the uncertainty in inversion results and improve monitoring capability.

Laboratory measurements

Repeated seismic and electromagnetic methods are two of the geophysical techniques to be used to monitor CO_2 movement and saturation in a variety of reservoirs. In contrast to hydrocarbon-bearing reservoir rocks, there are very few data available for seismic and electromagnetic responses of the CO_2-bearing reservoir rocks. Most available laboratory measurements on rock samples are for low CO_2 saturations (e.g. Lei and Xue, 2009). In practice, very high CO_2 saturations may occur near the wellbore, or in highly fractured zones, which may act as potential leakage pathways.

In order to better understand the monitoring potential of the seismic and electromagnetic techniques, a range of laboratory experiments have been carried out to measure the ultrasonic and electromagnetic properties of the reservoir sandstones of the CASSEM analogue storage sites, while saturating the samples with a range of different proportions of brine versus supercritical CO_2, and under a range of stress conditions (Fisher et al., 2010). These experiments are conducted on four sandstone samples: two from the Clashach Quarry (CL1 and CL2), which is considered to be geologically analogous to the reservoir formation expected at the Firth of Forth site, and two samples from the Sherwood Sandstone formation (SSK2451 and SSK2454), which is the reservoir formation at the Lincolnshire site.

The elastic parameters of the reservoir sandstones were measured for a wide range of CO_2 saturations (0–100%). These measurements, especially for high CO_2 saturations, provide some of the basic data for monitorability assessment. The measurements indicate that the elastic parameters of the Sherwood Sandstone samples present a greater sensitivity to CO_2 saturation than the Clashach Quarry samples. This implies that (neglecting the effect of the overburden for the moment) the seismic monitorability potential of the former is greater than the seismic monitorability potential of the latter.

CASE STUDY 5: MONITORABILITY OF THE FIRTH OF FORTH SITE

In the CASSEM project, two representative UK North Sea saline aquifer near-shore storage sites were used as case studies to develop corresponding methodologies. In this section, monitorability of S_{CO2} in the Firth of Forth site is assessed. A description of this site is given in chapter 3 and in Jin et al. (2010).

In order to assess monitorability of S_{CO2}, the petrophysical model has to be calibrated to the reservoir rocks. Ideally, rock samples taken from boreholes intersecting the reservoir will be used for this purpose. However, since no borehole was drilled into the Firth of Forth reservoir, measurements from the two rock samples, CL1 and CL2 above, were used for calibration, to estimate acoustic and electromagnetic properties of the reservoir rocks. Calibration of petrophysical model

Figure 5.6 shows the variation of measured P-wave and S-wave velocities with respect to S_{CO2} at different effective pressures on sample CL1 (Fisher et al., 2010). The expected range of pressure in the Firth of Forth around the injection point is approximately between 3500 psi to 4000 psi. Laboratory measurements indicate that while S-wave velocity does not change significantly with S_{CO2} there is more than 200 m/s drop in the P-wave velocity once the sample is fully saturated with CO_2, indicating a high sensitivity of the P-wave velocity of the sample to S_{CO2}. The electromagnetic measurements (not shown here) indicate that electrical resistivity of the brine-saturated samples is about 3 ohm-m.

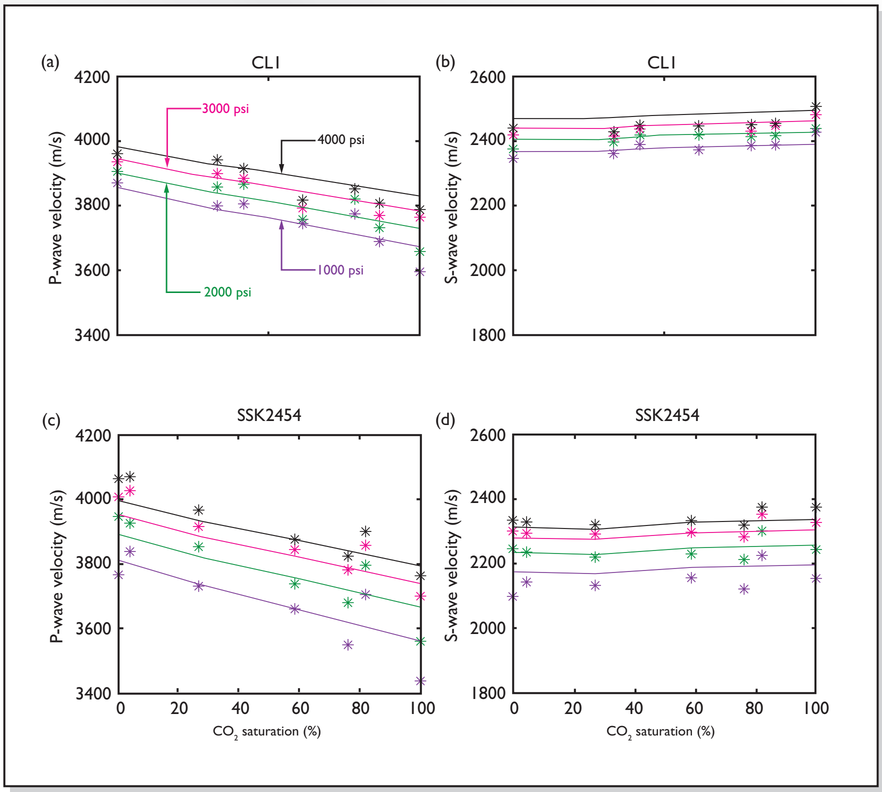

Figure 5.6 Variation of measured P-wave (a and c) and S-wave (b and d) velocities of samples SSK2454 and CL1 at different effective pressures and values of S_{CO2}, and the corresponding petrophysical model fitted to the measurements (solid lines).

We now assume that time-lapse reflection seismics and CSEM surveys have been deployed over the reservoir. Synthetic cross-sections of geophysical parameters (Density, Ip, Is, Qp, Qs, resistivity) along the reservoir interval based on CO_2 flow simulation results for a single injection well after ten years of injection are estimated. CSEM data typically result in far lower spatial resolution than reflection seismic data. To represent these different resolutions the CSEM data are spatially averaged: a smoothing function is applied to the porosity and saturation values by averaging them over many surrounding cells. Then, for each cell, the petrophysical model is used to calculate resistivity from the averaged porosity and saturation. The overall average porosity and permeability of the aquifer are about 0.135 and 60 mD, respectively. More details about the injection scenario and reservoir are given in Chapter 4 and in Jin et al. (2010).

The geophysical parameters are inverted using the Monte Carlo approach (Section 5.3) to estimate S_{CO2} in the reservoir. In time-lapse (repeated) geophysical monitoring strategies, the reservoir is characterised by a benchmark survey (pre-injection) from which reservoir parameters such as porosity, permeability and clay content are known with some level of uncertainties (in this case assumed to be 1%). We assume an optimistic approach and assign 4% and 2% uncertainties to the corresponding CSEM and seismic geophysical parameters, respectively. This assumption may not be far from reality because in time-lapse monitoring, reservoir parameters, except saturation, are constrained by pre-injection surveys.

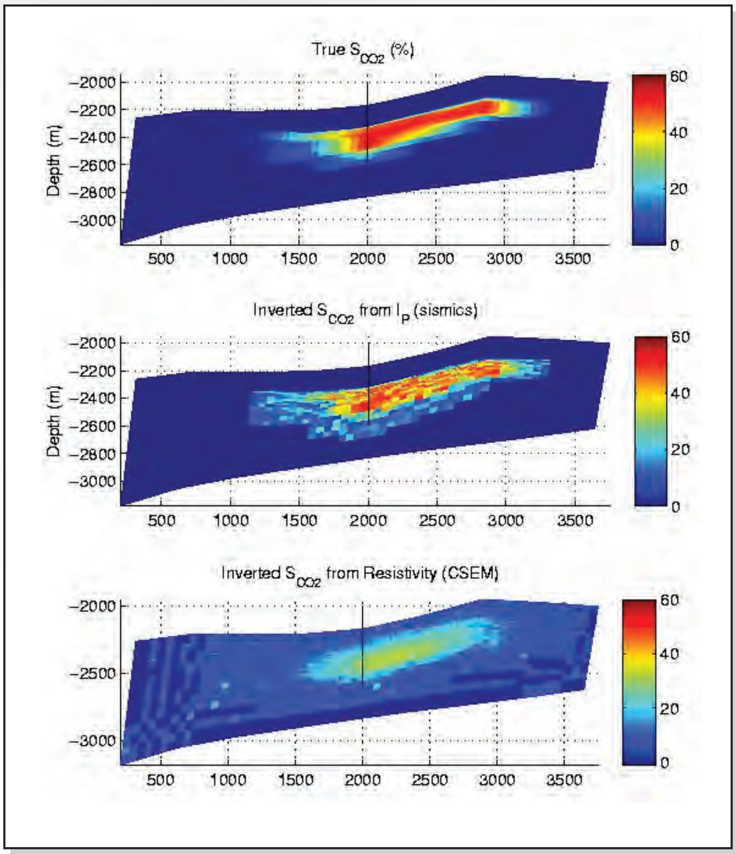

Figure 5.7 Distribution of true S_{CO2}, calculated from a flow simulation along an East–West slice of the Firth of Forth model (top), and MAP estimates of S_{CO2} from the inversion of IP (middle) and of resistivity (bottom). Note that while electrical resistivity is very sensitive to CO_2 saturation, low spatial resolution of the CSEM method significantly diminishes its applicability. In such cases, well-based EM measurements are recommended.

A uniform pre-inversion (a priori) probability distribution between 0% and 100% is used for S_{CO2}. This means that we assume we have no previous knowledge about S_{CO2} in the reservoir before the survey. It is common to use maximum a posteriori (MAP) values as the optimal representative values of the post-inversion (posterior) probability distributions. The MAP value at each grid cell is the post-inversion value of S_{CO2} that has the highest likelihood of being true given the measured geophysical data. Figure 5.7 depicts inverted S_{CO2} from Ip and from resistivity, over the reservoir. For comparison, the true S_{CO2} values in the reservoir are also shown. This figure shows the information that we might expect from seismics and CSEM surveys (with current technology) after ten years of injection.

It is known from laboratory measurements of two-phase (CO_2 and brine) relative permeability that once CO_2 is injected into brine-saturated reservoir rocks, it can not fully replace the brine. Based on the relative permeability measurements on the representative reservoir rock samples of the Firth of Forth (see previous chapters), the prior distribution of S_{CO2} can be constrained to be between 0% and 60%. Figure 5.8 indicates the effect of applying this constraint on the monitorability of S_{CO2}. In this figure, probability density functions (pdfs) of the true S_{CO2} and inverted S_{CO2} from IP (seismics), with and without this additional constraint, are shown, where the pdfs are histograms of S_{CO2} values over the entire section in Figure 5.7. The pdf of the constrained inversion is much closer to that of the true S_{CO2}. This implies that integrating auxiliary data, such as lab measurements and flow simulation modelling, with geophysical data can significantly improve monitoring capabilities.

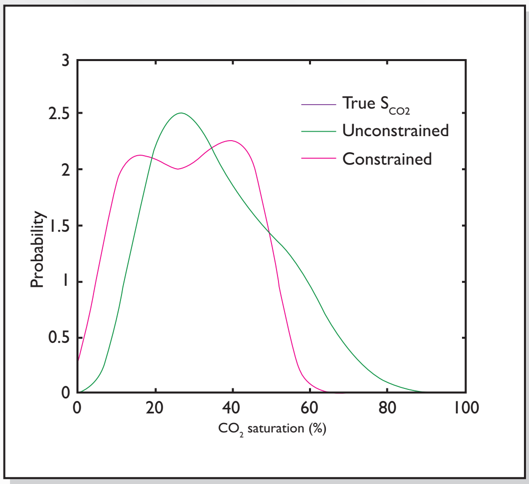

Figure 5.8 Probability distribution (normalised histograms) of S_{CO2} across the cross-section in Figure 5.7 (blue curve), and of inverted S_{CO2} from IP (seismics) with and without relative permeability constraints (red and green curves, respectively). Integrating relative permeability data with geophysical data significantly improves the distribution of estimated CO_2 saturations.

Interpretation

The information of the marginal post-inversion probability distributions of S_{CO2} is calculated in each cell (not shown here). As shown in the previous sections, information for low S_{CO2} is greatest. This indicates that inversion of IP near the CO_2 plume boundaries (where S_{CO2} is the lowest) gives a relatively high level of information. In addition to the true value of S_{CO2}, other reservoir parameters such as porosity and permeability have significant effects on the information obtained. Overall, marine reflection seismics is found to be an appropriate method to map the extent of the CO_2 plume, while, because of the low spatial resolution, CSEM is not an appropriate method for that purpose. The high sensitivity of reflection seismics to low concentrations of CO_2 is also a valuable characteristic that results in the applicability of this method to detection of leakage and of plume migration. However, the low sensitivity to higher CO_2 concentrations may be a significant issue that limits its application to S_{CO2} estimation, particularly if pure CO_2 is injected – see Eke et al. (2009) – and highlights the need for borehole resistivity or EM measurements in such cases.

5.8 SUMMARY

Monitorability is a major investment uncertainty to be quantified as far as possible in the early stages of site selection and evaluation, in order to inform business decisions regarding site development. An efficient monitoring strategy must address the degree to which changes in the 3D distribution of CO_2 can be observed and tracked in a given store: insufficient storage site monitorability is a potential showstopper.

The CASSEM project has developed a workflow for geophysical methods of assessing monitorability of S_{CO2} in a saline aquifer. A site is considered to be monitorable, if geophysical monitoring is possible from practicality and cost points of view, if there is enough geophysical spatial resolution to identify the spatial extent of subsurface CO_2, if geophysical changes due to CO_2 injection are detectable, and if there is sufficient resolution of petrophysical parameters of interest.

The effect of S_{CO2} on the geophysical parameters of rocks (density, P- and S-wave velocities and attenuations, and electrical resistivity) is investigated by applying existing petrophysical models that include poroelastic effects. Variation of P-wave velocity and attenuation of rocks is strongly dependent on the frequency of measurements. This frequency dependence has a significant influence on selecting appropriate monitoring techniques (e.g. choosing between well-based or surface measurements). A set of detectability parameters are defined for different geophysical methods (seismics, electromagnetics and gravimetry), to assess the detectability of changes in the geophysical properties of reservoir rocks due to changes in S_{CO2}. This analysis shows that the detectability of expected geophysical changes depends on the porosity and clay content of the rock and on S_{CO2} in the brine, as well as on the thickness and depth of the storage formation. In particular, the density and resistivity changes are detectable only above a certain threshold saturation that increases significantly with increasing depth and decreasing thickness of the storage formation

To assess petrophysical resolution, a Monte Carlo inversion scheme is developed. The results show that the monitorability of S_{CO2} is strongly dependent on the level of geophysical uncertainty and on the true value of S_{CO2}. In the case of seismic measurements, it is also dependent on the frequency of measurements. The seismic attenuation may contribute significantly to the overall information obtained. Combining different geophysical parameters and methods (e.g. seismics and electromagnetic) may significantly increase the overall information obtained, improving monitorability and quantification of S_{CO2} in saline aquifers. This can be achieved by designing an optimal combination of borehole and surface measurements; borehole measurements are recommended to increase both spatial and petrophysical resolution near to and potentially between pairs of wells, while surface measurements provide relatively lower spatial resolution, but over a more comprehensive and meaningful rock volume for reservoirs of large areal extent.

Overall, the following comments are made on geophysical monitorability of CO_2 storage sites:

- Monitorability of CO_2 storage sites is a site-specific problem and strongly depends on the overburden and underburden structure of the particular reservoir.
- The purpose of monitoring (e.g. leakage detection, S_{CO2} estimation, detection of plume migration, etc.) has a significant impact on selecting an appropriate geophysical monitoring method.
- A combination of seismic and non-seismic (e.g. electromagnetic, gravimetry, etc.) methods from the surface and from boreholes may have to be applied.
- While the comprehensive spatial coverage required to map laterally large CO_2 plumes might be achieved by surface measurements, borehole measurements may have to be used to achieve higher petrophysical and spatial resolution.
- In principle, electromagnetic measurements have the potential to estimate CO_2 saturation accurately. However, with current technology their spatial resolution is of major concern.
- Integration of auxiliary data, such as flow simulation and laboratory measurements, with geophysical data significantly improves the results of geophysical inversion and ultimately improves the site monitorability.

CHAPTER 6
RISK AND UNCERTAINTY

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6.1 INTRODUCTION

Ultimately, any storage site is required to have appropriate capacity, injectivity, security and monitorability. If the storage formation fails or does not perform within expected bounds in one of these features then there could potentially be severe impacts. Leakage of CO_2 and displacement of the formation fluids may result in acidification and/or contamination of groundwater and near-surface deposits, with uncontrolled leakage posing a risk to surface ecosystems, either onshore or offshore. Furthermore, there is a large financial risk in rolling out geological CCS on a major scale, with significant investment required both in improving technology and in identifying and characterising potential storage sites. Risk analysis therefore forms a vital part of any carbon storage project.

Typically, risk is defined as a combination of likelihood of occurrence and magnitude of the potential impact. Using a quantitative or semi-quantitative approach, it is possible to rank areas of potential risk to a project, for example, faults in the storage site that may provide leakage pathways for CO_2, petrophysical properties that may not allow for the required injection rates or volumes, or public opposition that may cause a project to be suspended.

A key factor in risk analysis for geological storage of carbon dioxide is uncertainty: the successful storage of CO_2 requires that it remains within the target formation far into the future. Given the large uncertainties associated with any work in the subsurface, it is impossible to know with 100% certainty what the fate of the injected CO_2 will be in the subsequent decades and centuries. Therefore, it is important that uncertainty in the properties of the subsurface and in behaviour of CO_2 in the formation are considered when assessing the suitability of a potential storage site. In this way we can quantify our uncertainty in the likely fate of the CO_2 in the system and make probabilistic assessments regarding the behaviour of CO_2 in the long term.

In this chapter we describe processes for assessing risk and uncertainty and show how these can feed into the decision-making process within a project. While assessment of risk and uncertainty are separate processes, they are closely linked, with uncertainty strongly influencing the risk and risk informing important decisions regarding future data acquisition aimed at better understanding uncertainty. Both are iterative processes that take place throughout the project lifetime, allowing changes to be tracked and the impact of individual activities to be assessed.

The chapter is divided into two sections: the first section describes the sensitivity and uncertainty analysis process used to identify key properties of the site, required to both model the behaviour of CO_2 in the storage formation and assess uncertainty in the models. The second section describes an assessment process used to quantify and rank areas of risk and to show how these feed directly into project decisions.

6.2 GEOLOGICAL UNCERTAINTY

Numerical simulations are the primary tool for predicting the fate of injected CO_2. These simulations aim to model true properties of the storage site and accurately simulate the behaviour of the system. However, the properties of the subsurface will always be uncertain (as highlighted in Chapters 3, 4 and 5) and, therefore, no simulation will be able to make completely accurate predictions. To properly assess a storage site will therefore require that these uncertainties are propagated through a simulation in such a way as to allow the uncertainty on the outputs to be estimated.

Given the large number of parameters in such models, identifying the key parameters controlling uncertainty on the model output is important for the prioritisation of resources for data acquisition.

This process is called sensitivity analysis. Quantifying the uncertainty in the input parameters and propagating these through the models, in order to estimate the uncertainty on key model outputs, is called uncertainty analysis.

Figure 6.1 shows how sensitivity and uncertainty analysis fit into the overall workflow, where the ultimate aim is to make a probabilistic assessment of security, capacity, injectivity or monitorability. However, the techniques used for this analysis can be applied to any model where uncertainty estimates are required

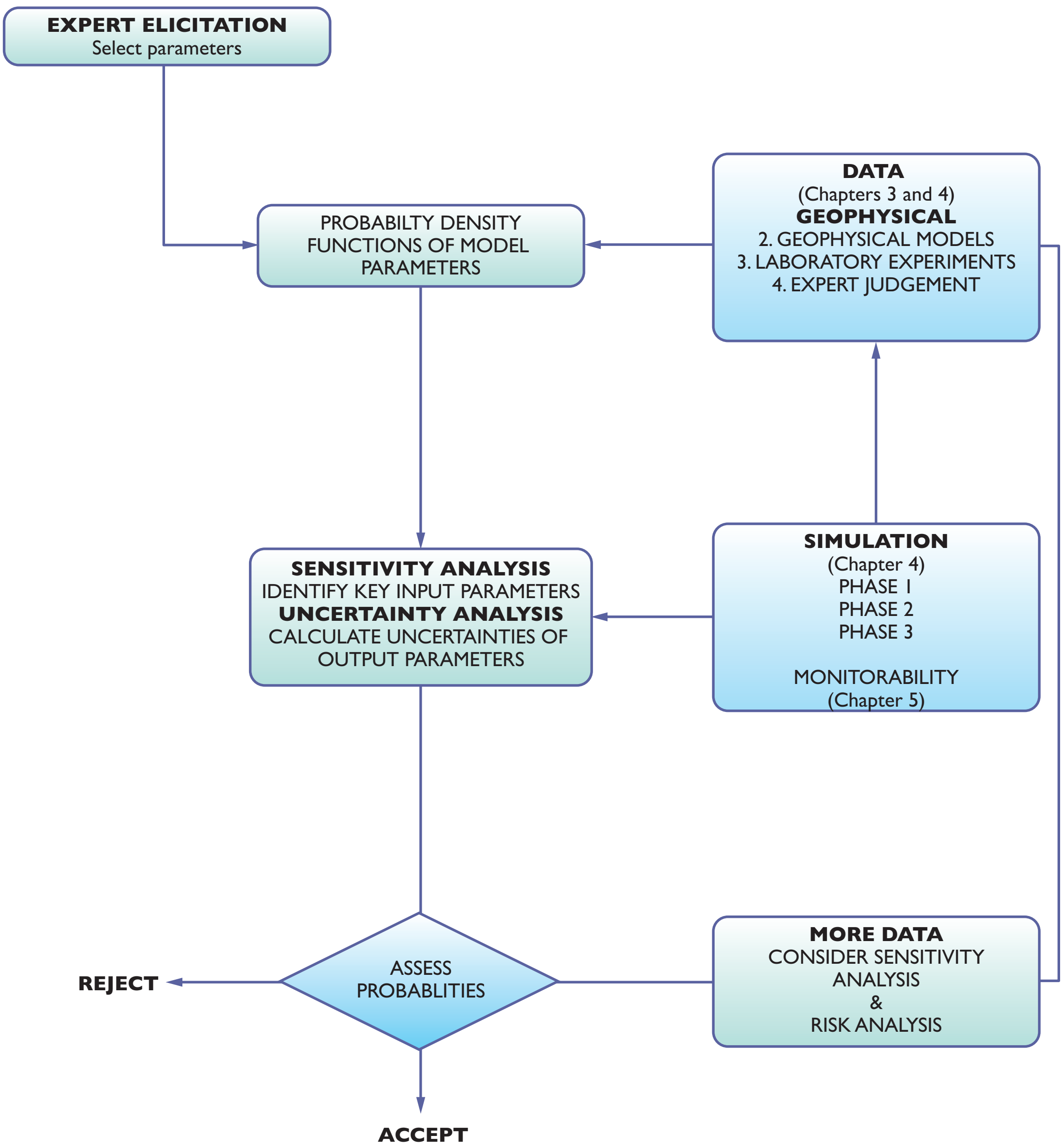

Figure 6.1 Workflow for sensitivity and uncertainty analysis.

Expert elicitation

The first step is to identify the particular model outputs for which uncertainty and sensitivity are to be assessed and the input parameters that are likely to influence these model outputs. Ideally, all input parameters would be included in the sensitivity and uncertainty analysis. However, this is likely to be impractical for many computer simulations and, therefore, a subset of parameters may be selected based on the judgement of experts. This is done using expert elicitation, where the experts consider the influence of the parameter and its associated uncertainty.

Care must be taken when eliciting expert opinion. All individuals, experts included, are subject to certain well-known cognitive biases which will affect their judgement in situations of uncertainty (Kahneman et al., 1982). These biases are the result of heuristics or rules of thumb that are used to simplify what are often extremely complex tasks. Types of bias include over-confidence, anchoring and adjustment, availability, and motivational bias (see Glossary). Explaining these biases to the experts at the start of the process and using a well-managed elicitation process can help to minimise the impact of bias on the results (Polson and Curtis, 2010a). However, expert judgement should be treated with caution and the effects of bias considered when interpreting results.

In the CASSEM project the sensitivity and uncertainty analyses were applied to the reservoir flow simulations described in Chapter 4, to quantify the uncertainties in the simulation predictions. An elicitation session with the set of experts responsible for constructing the flow simulations was used to decide which input and output parameters to investigate. The set of input parameters investigated are listed in Table 6.1 (details of their pdfs can be found in Polson et al., 2010b). The simulation outputs investigated were immobile and mobile CO_2 in the gas phase, dissolved CO_2, average pressure and bottom hole pressure, all as a function of time and, where relevant, space. It is important to know the state of CO_2 in the reservoir, as dissolved or immobile CO_2 should be trapped while mobile CO_2 remains free to potentially migrate to the surface. The pressure within the reservoir is important as it relates, not only to injectivity, but also to security, with higher pressures making it more likely that the cap rock may be damaged and hence provide migration pathways for CO_2. The pressure at the bottom of the injection well is important for the injectivity.

Input parameter
Depth of surfaces/interfaces between layer
Potential existence of lateral no-flow boundaries
Heterogeneity within each layer
Porosity of reservoir and caprock
Permeability of reservoir and caprock
Fault locations
Fault transmissivity
Relative permeability of carbon dioxide and water

Table 6.1 Input parameters investigated in sensitivity and uncertainty analysis.

Deriving probability density functions

Having selected the set of input parameters for investigation, probability density functions (pdfs) are estimated for each. The pdfs describe the range of possible values the input parameters could take and are estimated using a combination of data, expert judgement and, potentially, other modelling work. Work in the subsurface is inherently uncertain due to the natural variability in the geology and the comparative lack of information compared to other fields. Expert judgement is therefore often relied upon where data is lacking to fully constrain any particular property or characteristic of a storage site. As expert judgement is influenced by cognitive bias, as described above, real data should be relied upon, as much as is possible, to estimate the pdfs of the input parameters. However, it is inevitable that expert judgement will play some role in any such study and, therefore, efforts must be made to minimise the impact of bias in the interpretation of the results, using careful elicitation. In addition, the uncertainty should be estimated conservatively (i.e. as large as is reasonable) and, where possible, the extremes considered.

An example of the parameter uncertainty is shown in Figure 6.2, which shows the estimated uncertainty in the surface depth of the Sherwood Sandstone Group for the Lincolnshire site. This represents the range of depths the geologist responsible for building the geological model (Chapter 3) believes the top of the layer could take in reality. It is based on a range of factors, including the seismic data, borehole data, geological complexity and expert judgement. This range is used to construct a pdf for the input parameter surface depth, assuming a Gaussian distribution with the mean value taken from the final geological model.

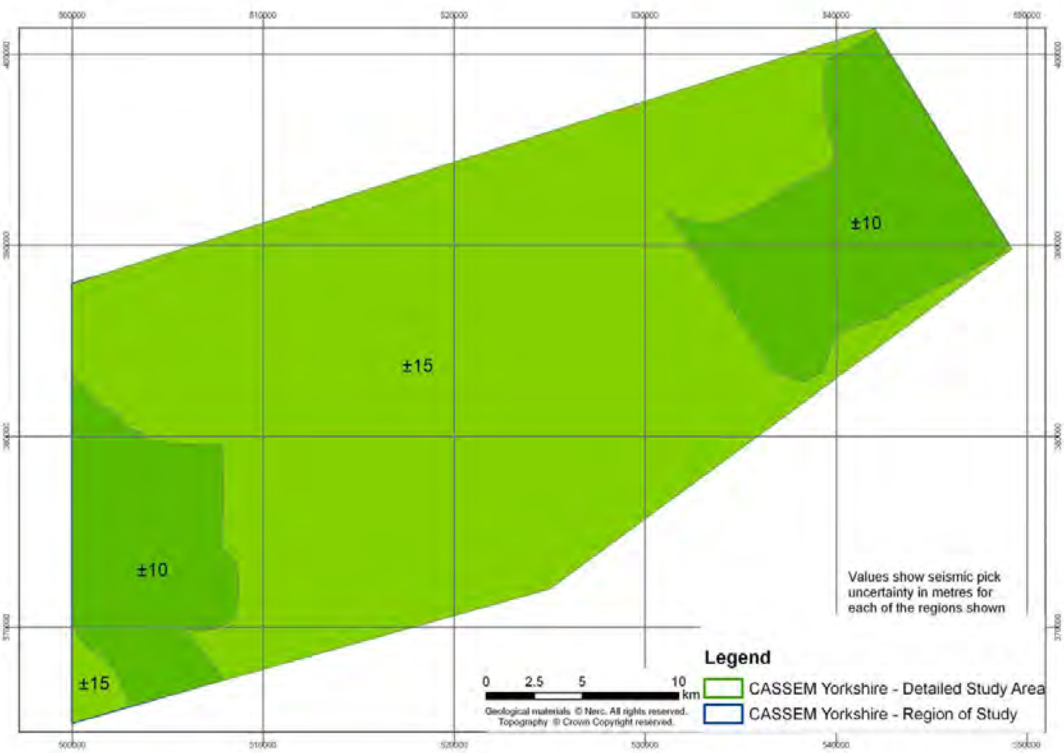

Figure 6.2 Seismic pick uncertainty map for the top Sherwood Sandstone Group.

Sensitivity and uncertainty analysis

The final step is to apply the sensitivity and uncertainty analysis to the simulation. Here, the analysis should be applied to the Phase 1, 2, and 3 reservoir flow simulations and the Phase 2 geomechanical and geochemical simulations and monitorability assessments. Applying the sensitivity analysis to the Phase 1 flow simulation identifies the key input parameters to the model. Data acquisition should be prioritised to reduce uncertainty in these parameters. The uncertainty analysis applied to the Phase 1 simulation should be used to validate the volume estimates of these models. Applying the uncertainty analysis to the Phase 2 simulations will show the impact of the final geological model on the simulation predictions and show the impact of the geomechanical and geochemical modelling. Applying the uncertainty analysis to the Phase 3 flow simulation will produce the final pdfs for the simulation outputs. Given the predicted behaviour of CO_2 in the formation, monitorability also needs to be considered with uncertainty analysis applied here also, to assess the likelihood of being able to detect and monitor CO_2 in the future. Based on these predictions, a decision should be made as to whether the site meets the minimum requirements (i.e. the probability of having the required security, capacity, injectivity and monitorability exceeds some minimum acceptable limit) and, hence, whether to accept or reject the site for progression to the next stage of development. Alternatively, more data may be required, iterating around the workflow until some acceptable level of certainty is reached, to allow a decision to be made.

Monte Carlo techniques are widely used for uncertainty analysis. In this approach, the pdfs of the input parameters are defined, randomly sampled and used to drive different simulations. This approach requires thousands of simulations to be performed for different combinations of input parameters, to ensure that the pdfs of the input parameters are well sampled. The output from all runs can then be plotted as a histogram to give the pdf and the most likely value and uncertainty of the simulation output. The problem with this approach is that each simulation is usually extremely computationally costly; running thousands of simulations is usually infeasible. Using a metamodel (i.e. a model of the model) can allow the simulation output to be predicted in a fraction of the time and also allows us to easily identify which input parameters are most influential.

A metamodel is usually a function that approximates the behaviour of a numerical simulation. One well-established technique used in this study is response surface methodology (RSM) (Myers and Montgomery, 1995). However, a number of alternative metamodels do exist. The complexity of the simulation will dictate the form of the response function; although, typically, a quadratic polynomial, as shown in equation 6.1, which includes linear terms for each input parameter plus parameter interaction terms, is sufficient.

$$y = a_0 + \sum_{i=1}^{n} a_i x_i + \sum_{i=1}^{n} \sum_{j=i}^{n} a_{ij} x_i x_j + \varepsilon \qquad (6.1)$$

Here y is the simulation output (the response), which might be, for example, CO_2 saturation in a particular sub-volume of the earth at a fixed time in the future. Terms x_i and x_j are any two input variables out of a total of n variables considered, a_0 is the so-called intercept term, and a_i and a_{ij} are coefficients associated with linear and quadratic interaction terms, respectively. The term ε is an error term representing higher-order sources of variability not accounted for in equation 6.1.

The coefficients for each term are calculated using a least-squares fitting technique. A carefully selected subset of simulations is run for different permutations of the input parameters. These runs are referred to as experiments, and the selection of runs is referred to as the experimental design. Different families of design exist, which allow the response function to be fitted accurately, using a minimal number of experiments. In the case of the CASSEM project, a composite design was chosen, which ran experiments using combinations of the minimum, maximum and mean of the input parameter distributions (Polson et al., 2010b).

Generally, the larger the magnitude of the coefficient, the more influential the term. However, as linear and interaction terms cannot be compared directly, the student t-values for the coefficient of each term are used instead.

$$t_i = \frac{a_i}{s(a_i)} \qquad (6.2)$$

Here t_i is the student t-value of input parameter i, a_i is the value of the coefficient estimated by the least-squares fitting, and $s(a_i)$ is the estimated standard deviation associated with the coefficient. For each model output of interest and each time of interest, a unique response function is constructed and, hence, the influence of each input parameter for different outputs can be tracked over time. From this, the key parameters for the uncertainty in the simulations can be identified and recommendations made as to which properties of the site should be targeted with data acquisition activities.

CASE STUDY 6: RESULTS FOR FIRTH OF FORTH AND LINCOLNSHIRE

This study describes the results of a sensitivity analysis of flow simulations of the Firth of Forth and Lincolnshire sites at a range of times up to 1000 years post-injection, for the simulation outputs: total dissolved CO_2, total immobile CO_2, total mobile CO_2, average pressure and bottom hole pressure. The student t-values for the coefficient of each term in the response function are used to rank the influence of each term and, hence, the parameters in that term. It was found for the CASSEM sites that the first two or three most influential terms in the response function were generally much more influential than the remaining terms. Figure 6.3 shows the number of times each input parameter appeared in one of the three most influential terms in the response function for all five outputs and all times. Figure 6.3a shows the input parameters, itemised by site and injection and post-injection phases and Figure 6.3b shows the input parameters, itemised by simulation output. Thus, we can distinguish which input parameters are most influential for each site and at different phases of the storage and which input parameters are most influential for each simulation output.

The results show, importantly, that the most influential parameters are similar for both sites despite their distinct geologies and locations. Overall, the reservoir permeability, reservoir thickness (i.e. surface depth) and relative permeability are the most influential input parameters. Perhaps surprisingly, reservoir and cap rock porosity, cap rock permeability, faults location and transmissivity and heterogeneity are found, in comparison, to have negligible influence. It is important to note that this finding is dependent on the simulation outputs investigated and the pdfs defined for each input parameter; had these been different then input parameters, which were not found to be significant here, may well be found to be very influential.

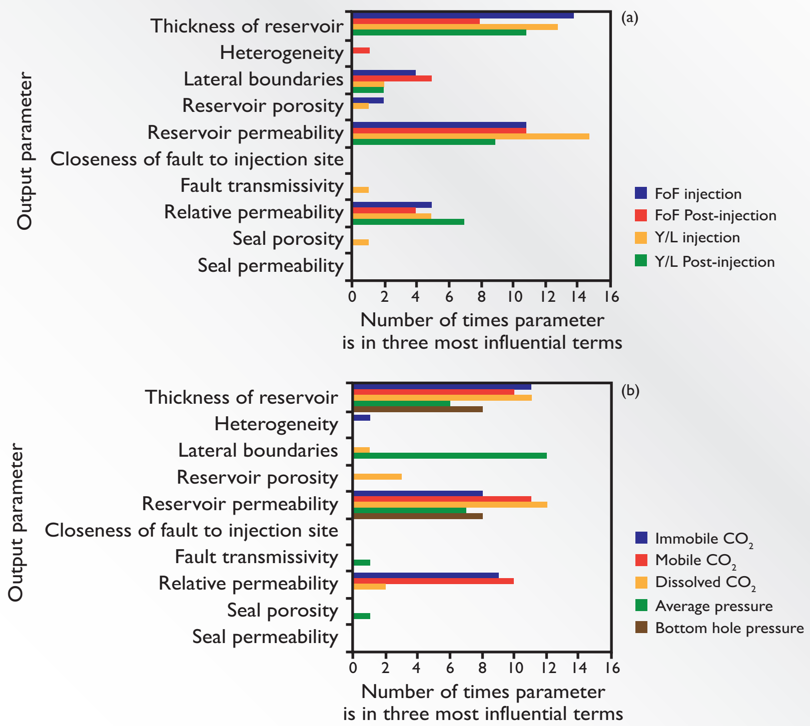

Figure 6.3 Number of times each input parameter appears in one of the three most influential terms in the response functions for the five simulation outputs: (a) for output times for injection (inj) and post-injection (post-inj) phases for the Firth of Forth (FoF) and Yorkshire/Lincolnshire (Y/L) sites and (b) for each of the five simulation outputs for both sites.

CASSEM CASE STUDY RESULTS: UNCERTAINTY ANALYSIS

Figure 6.4 shows the results of the uncertainty analysis of the flow simulations for total immobile CO_2, total mobile CO_2 and total dissolved CO_2 for both sites, using the Phase 2 simulations at 100 years post-injection. For both sites the pdfs are approximately Gaussian, with the median (50th percentile) value for the Lincolnshire site consistently higher than the value for the Firth of Forth site. Comparing the relative uncertainties, where relative uncertainty is taken to be the 10th to 90th percentile as a percentage of the median value, we can show that the relative uncertainty is similar for both sites.

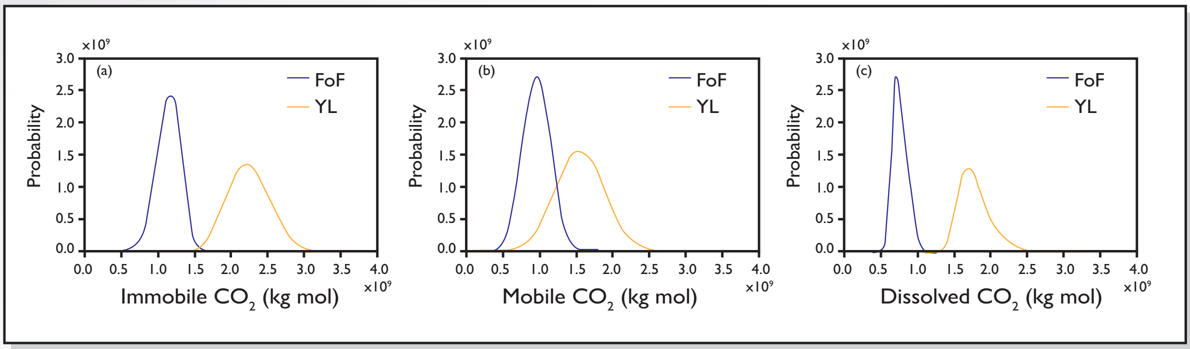

Figure 6.4 Probability density functions for (a) total immobile CO_2 in the gas phase (kg mol), (b) total mobile CO_2 in the gas phase (kg mol) and (c) total dissolved CO_2 (kg mol) for both sites at 100 years post-injection for the Phase 2 flow simulations

Uncertainty analysis performed on the Phase 1 simulations found that the results for the Lincolnshire site were consistent with those of the Phase 2 simulations, that is the pdfs of the two models for the various outputs tended to overlap significantly. However, for the Firth of Forth site, the Phase 1 and Phase 2 simulations could not be made consistent, even when extreme uncertainties were applied to the input parameters in the Phase 1 simulation. The Phase 1 simulation of the Firth of Forth was a simple box while the Phase 1 simulation of Lincolnshire contained detailed parameterisation from real data. This suggests that the simple form of the Phase 1 simulation for the Firth of Forth site can not capture even the most basic, critical aspect of behaviour of the CO_2 in the system, even allowing for very large uncertainties in the properties.

CASSEM CASE STUDY RESULTS: MIGRATION OF CO_2 INTO CAP ROCK

One of the key components of site assessment is security, i.e. the potential for leakage of CO_2. In this section we describe a methodology for assessing the probability of CO_2 migrating upwards through the subsurface. To properly assess the risk of leakage we need to consider how the likelihood of leakage changes in time and space, as well as the impact of leakage (Vivalda et al., 2009). However, this may be computationally expensive, potentially requiring the whole subsurface to be modelled, as well as modelling of the impacts. Assuming that the cap rock is the primary barrier to upward migration of CO_2, assessing the migration of CO_2 into and up through the cap rock should be a first step in assessing the security of the site. Should CO_2 be found to migrate through the cap rock, more detailed modelling of the subsurface, including the overburden, will be required to show whether additional seals may prevent further upward migration or whether CO_2 is likely to continue migrating to the surface.

We can apply the uncertainty analysis techniques to estimate the pdfs of the amount of CO_2 moving into the cap rock rather than being trapped within the reservoir. The probability of leakage to the top of the cap rock can be assessed by partitioning the top layer of the cap rock into regions and calculating the leakage rate of CO_2 into these regions at different times.

Figure 6.5 shows the median value from the probability density functions of total CO_2 in the cap rock in each phase over time, for the Firth of Forth site and the Lincolnshire site. These show that for the Firth of Forth site there is expected to be some CO_2, in all states, in the cap rock at virtually all times. For the Lincolnshire site there is expected to be some dissolved CO_2 in the cap rock at all times, while the median values for immobile and mobile CO_2 do not significantly exceed zero at most times. However, there is expected to be some CO_2 in both phases in the cap rock by 1000 years post-injection.

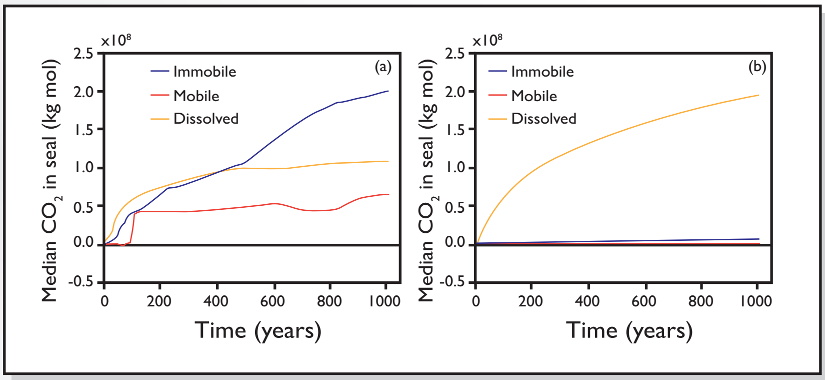

Figure 6.5 Median value (50th percentile) of probability density function of CO_2 in each phase (kg mol) in the cap rock at all times up to 1000 years post-injection for (a) the Firth of Forth site and (b) the Lincolnshire site.

Figures 6.6 and 6.7 show the median leakage rate (i.e. the 50th percentile from the pdfs) into the top layer of the cap rock for a range of times for the Firth of Forth and Lincolnshire sites, respectively (note the difference in scales between the two figures). Here the top layer of the cap rock is divided into four regions so that the spatial variation of the probability of leakage can be assessed, as well as variation with time. Figure 6.6 shows that leakage into all four regions at the top of the cap rock of the Firth of Forth site is expected in the decades and centuries following injection. For the Lincolnshire site, leakage is only expected in region 2 and the leakage rate is very low, never exceeding 10 kg mol year-1. Results for mobile CO_2 show that for the Firth of Forth site there is a high probability of some leakage to the top of the cap rock. For the Lincolnshire site there is no mobile CO_2 in the upper cap rock, as all CO_2 in this region is dissolved in the formation fluids.

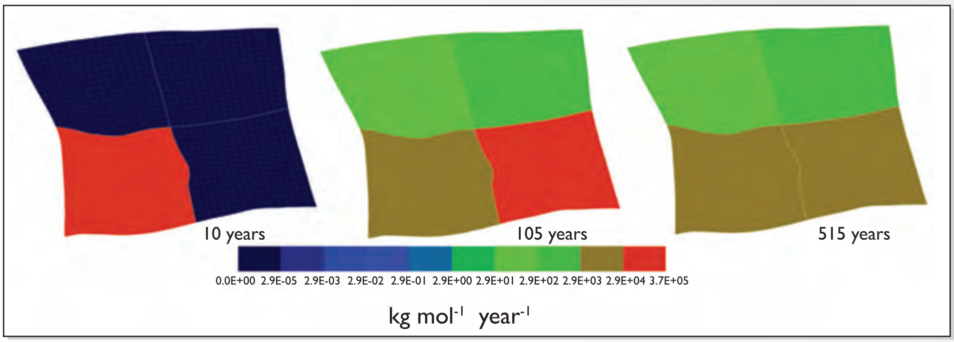

Figure 6.6 Median (50th percentile) leakage rate of total CO_2 (kg mol year-1) in regions 1, 2, 3 and 4 (anticlockwise from bottom left) at the top of the cap rock of the Firth of Forth site.

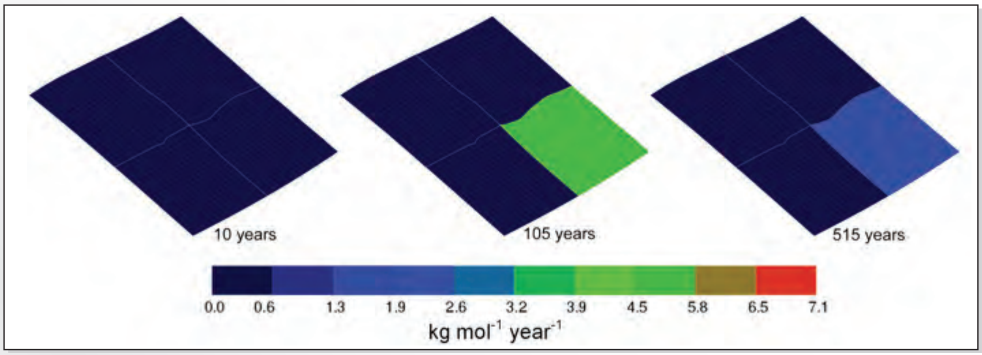

Figure 6.7 Median (50th percentile) leakage rate of total CO_2 (kg mol year-1) in regions 1, 2, 3 and 4 (anticlockwise from bottom left) at the top of the cap rock of the Lincolnshire site. Note the different scale compared to Figure 6.6.

These results are for the Phase 2 flow simulations, not the final Phase 3 simulations, and hence should not be considered a conclusive assessment of these sites; they are presented here to demonstrate a methodology. Assuming these were the results for the most advanced simulations, the Firth of Forth site is unlikely to be suitable for storage, as mobile CO_2 is likely to be able to migrate into and upwards through the cap rock. The Lincolnshire site is likely to be more suitable, as although CO_2 does appear in the cap rock, it is mostly trapped in the dissolved and immobile form and therefore unlikely to migrate to the surface. Furthermore, only trace amounts of CO_2 reach the top of the cap rock and this is entirely dissolved in the formation fluids.

6.3 RISK ANALYSIS

In any CCS project there are many potential areas of risk which could impact on the success of a project. These impacts may be environmental or health and safety related, or they could be financial. In this chapter we describe step-by-step the risk assessment process, summarised in Figure 6.8, used in the CASSEM project to rank areas of risk, and describe how these assessments were used within the decision-making process within the project. The work described here is a scaled-down version of the type of process that would be required in a full-scale CCS project.

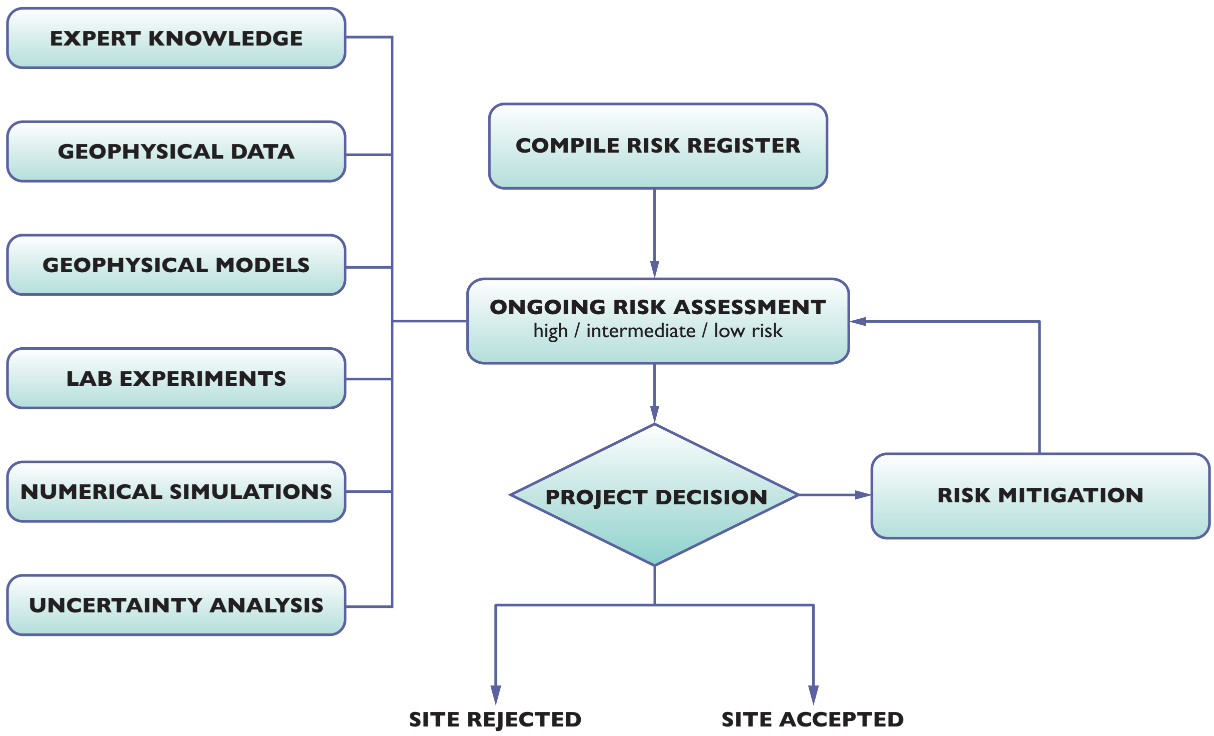

Figure 6.8 Workflow for risk analysis.

All CO_2 storage projects will require some form of register that can be used to quantify, rank and track risk. One such recommended approach is the use of 'Features, Event and Processes' (FEPs) (e.g. Maul et al., 2004; DET NORSKE VERITAS, 2010), which includes an exhaustive list of all relevant possible scenarios and behaviours of CO_2 in the storage site which may impact on the project. These FEPs are assessed by experts for their likelihood and scale of impact on the project. Related FEPs are organised into categories, and for each individual FEP there is an expanded description, including relevance to performance and safety.

A six-step process is then used to compile the risk register in the initial months of the project:

- Step 1. List construction. Obtain a comprehensive list of all known possible FEPs that might conceivably pose a risk to the project, and construct preliminary likelihood and severity scales.

- Step 2. Initial group elicitation. Carry out elicitation of lower and upper bounds of likelihood and severity of each FEP affecting the potential storage sites, using all available experts. For each FEP also elicit the level of expertise of each participating expert.

- Step 3. Individual consultations. Discuss with project partners to ensure all areas of potential risk are included in the risk register and define any project-specific criteria for likelihood and severity scales.

- Step 4. Propose register. Based on the results of steps 2 and 3, a risk analyst produces a draft risk register of project-specific FEPs and draft likelihood and severity scales to be used consistently for all FEPs. The draft risk register takes the form of each of the original FEPs categorised as to keep, to remove, or for discussion by group.

- Step 5. Group discussion. Meeting of partners, to discuss the proposed list of FEPs to be kept, and to produce a finalised register.

- Step 6. Reflection and validation. After a pre-agreed period of reflection, all project partners agree on a final risk register.

Once the register is finalised, groups of experts are assigned to individual categories of FEPs. These experts are responsible for completing risk assessments at regular intervals, according to a structured elicitation process. In this way it is possible to track how the experts' perception of risk changes.

For each FEP, the expert scores the likelihood (L) and severity (S) on a scale of 1 to 5. These scales should be compiled during the consultation process with experts in the project. The severity scale is used to score impacts in different areas and care should be taken to ensure that the scores are equivalent. When completing the risk assessment, the expert should assess which is the highest impact across all areas and score the FEP accordingly. As experts are unlikely to be able to perfectly quantify their perception of risk, or will themselves be uncertain, they are directed to give lower and upper bound scores, in addition to their 'best guess'. This provides a range incorporating the experts' perception of their uncertainty into the risk assessment. As discussed in section 6.2, experts are subject to cognitive biases which affect their judgements in situations of uncertainty, and, therefore, care must be taken to minimise their impact (Polson et al., 2009).

To calculate the actual risk, the score for likelihood is multiplied by the score for severity. This gives a total score somewhere on the risk matrix (L x S) shown in Table 6.2. In this case, a score of 1 is defined as negligible risk, a score of 2 to 4 is defined as low risk, a score of 5 to 9 is defined as moderate risk, a score of 10 to 19 is defined as high risk and a score of 20 to 25 is defined as very high risk. The purpose of any risk assessment is to identify areas of unacceptably high risk and, where possible, determine suitable mitigation activities. Ideally, through the implementation of mitigation activities, the risk score for the FEP should decrease, moving from the bottom right of the risk matrix towards the top left. The regular assessments of risk allowed us to ensure the level of success of these mitigation activities.

For the CASSEM project, a project-specific risk register was developed, based on that of Jammes et al. (2006) and the Quintessa CO_2 FEP register, which was extended during the consultation process to include additional FEPs related to this particular project. When FEPs are referred to below, it is by title only, but each has a more detailed definition and description to avoid ambiguity. For the CASSEM project, two separate severity scales were used. Health and safety was assessed separately to other types of impact. The second severity scale included financial, environmental, research and industry impacts, and is referred to hereafter as the FERI scale. The likelihood, health and safety, and FERI severity scales are shown in Tables 6.3, 6.4, and 6.5, respectively.

		Likelihood				
		1	2	3	4	5
Severity	1	1	2	3	4	5
	2	2	4	6	8	10
	3	3	6	9	12	15
	4	4	8	12	16	20
	5	5	10	15	20	25

Table 6.2 Combine likelihood and severity (L x S). Blue = negligible, green = low, yellow = moderate, red = high, black = very high.

Likelihood		If there were 100 similar projects, impact related to this risk element (FEP) would occur:
Improbable	1	Probably not at all, never
Unlikely	2	Fewer than three times among the100 projects
Possible	3	5 to 10 times among the100 projects
Likely	4	In around half of the100 projects
Probable	5	In most or nearly all of the projects

Table 6.3 Likelihood scale for the project.

Severity of impacts		Project values
		Health and safety
Light	1	Minor injury or illness, first aid
Serious	2	Reversible health effect, lost time injury less than 3 days
Major	3	Irreversible health effect, lost time > 3days
Catastrophic	4	Life-threatening health effect, fatality
Multi - Catastrophic	5	Multi -fatality

Table 6.4 Health and safety severity scale for the project.

Risk mitigation and data acquisition

The results of the risk assessments are used to inform decision makers in the project as to how to proceed in such as way as to reduce the risk. For each high risk FEP, mitigation activities should be identified and the results should be used to help prioritise future project activities, using a transparent and comprehensive assessment process. For example, a key component in risk is uncertainty and, hence, risk should be explicitly included in decisions regarding allocation of resources when acquiring new data. A structured process is used to optimise additional knowledge expected to be gained, given the time and cost constraints and ensure that all options are given equal consideration. The results of the risk assessment will feed into this process as a key component in value of information. The selection criteria used in the CASSEM project were:

Severity of mpiacts		Project values Financial	Environment	Research	Industry viability
Light	1	< £500k	No modification to initial state	Little to no progress to 1 of 4 goals	Project lost time > 1 day. Minor citations e.g. moving vehicle citations.
Serious	2	£500k–£5m	Modification to initial sta te within acceptable limits	Little to no progress to 2 of 4 goals	Project lost time > 1 week. Regulatory notice without fine. Local allegations of unethical practice or mismanagement
Major	3	£5m–£25m	Modification to initial state above acceptable limits b ut without damage	Little to no progress to 3 of 4 goals	Project lost time > 1 month. Permit suspension. Major local opposition or substantial negative local media coverage
Catastrophic	4	£25m–£50m	Modification to initial state above acceptable limit with repairable damage	Little to no progress to 4 of 4 goals	Project lost time > 1 year. International media coverage of law violations, questionable ethical practices or mismanagement.
Multi - Catastrophic	5	>£50m	Considerable modification to initial state which is not repairable with existing technologies	No gain in understanding applicable to future projects	Negative public experience results in legal ban on similar projects

Table 6.5 Financial, environmental, research and industry viability severity scale for the project. Categories are assessed together and the highest ranking category used to rate severity.

1. Information value. Significance of the gap in knowledge (the uncertainty) in the current geological model. Generic value of testing the action to gain information for future CCS projects. Criticality of associated risks to be mitigated, as identified in the risk assessment exercise.

2. Cost.

3. Timescale to completion.

4. Likelihood of failure of technique to provide new information.

Each potential activity is scored according to the categories shown in Table 6.6 and the highest scoring activities selected, given the cost and time constraints and likelihood of failure.

Score	Information value		
	Gap in existing model	Generic value of information (very site specific vs any subsurface application)	Criticality of risk (from FEP s)
5	Complete absence of information 0%	Widely applicable	Addresses multiple high risks
4	Mainly absent 2 5%	Applicable to majority of sites	Addresses one high risk
3	Reasonable information available, but many also absent, 50%	Applicable to some sites	Addresses multiple moderate risks
2	Mainly complete for site, 75%	Unique to one site	Addresses one moderaterisk
1	Complete information on site 100%	Not applicable to any site	Addresses no risks

Table 6.6 Information value scoring scale used for data acquisition optimisation.

CASSEM Initial Risk Assessment Results

The FEPs which scored 10 or more (high risk) in the first risk assessment are shown in Figures 6.9 and 6.10 for the Firth of Forth and Lincolnshire sites, respectively. The scores shown are the average best guess, lower bounds and upper bounds from all experts assigned to each FEP, multiplied to give the combined L x S scores, with only the highest score from the health and safety and FERI severity scales shown for each site. Alternatively, the scores for each expert can be used to construct a triangular distribution, which is then averaged and the resulting average distributions for likelihood and severity then multiplied and the median of this distribution used to rank the FEP.

For the Firth of Forth site, the FEPs that were perceived as high risk at the start of the project were:

- Financial viability.
- Construction of pipeline.
- Geological heterogeneities.
- Fractures and faults.
- Undetected features.
- Formation pressure.
- Effects of pressurisation of reservoir on cap rock.
- Lithology.
- Construction and site logistics.
- Hydrogeology.
- Hydrological regime and water balance.
- Near-surface aquifers and surface water bodies.

For the Lincolnshire site, the FEPs that were perceived as high risk at the start of the project were:

- Financial viability.
- Construction of pipeline.
- Effects of pressurisation on cap rock.
- Construction and site logistics.
- Hydrogeology.

- Hydrological regime and water balance.
- Near-surface aquifers and surface water bodies.
- Storage concept.
- Public perception and security.

There is a correlation between the perception of risk and the uncertainty with which that risk can be assessed by experts: the range of the lower and upper bound increases significantly with perception of risk. This link was confirmed when experts were asked to explain why they assessed FEPs as high risk. In particular, the quality and quantity of the geological data associated with the Firth of Forth site and the complexity of the geology in the region led to significant uncertainty in the characteristics of the reservoir and cap rock formations in that region. This resulted in the higher scores for geological FEPs for this site than for the Lincolnshire site.

The most important contributor to the specific risks associated with the Lincolnshire site relate to the lack of full geometrical closure by the cap rock and the fresh water within the saline aquifer formation up-dip; the potential for leakage of formation fluids from the storage system to the shallower fresh water section of the aquifer in the near-surface is considered high risk, with three FEPs assessed as high risk relating to the hydrology. Overall, financial viability is the highest ranked FEP for both sites. Financial viability is not particularly site-specific compared to the other high risk FEPs, but it is clearly the greatest cause for concern amongst experts.

Mitigation activities

Table 6.7 shows the results of the data acquisition prioritisation exercise. The key activities for the risk mitigation informed a series of case studies, including the reprocessing of the relatively old seismic data for the Firth of Forth site, which aimed to reduce uncertainty in the structure of the subsurface (Case Study 2, Chapter 3); a hydrogeology study (Case Study 3, Chapter 3) of the Lincolnshire site, which aimed to predict the impact of CO_2 injection into the saline aquifer; a series of flow experiments on rock core (Case Study 4, Chapter 4) to derive measurements of relative permeabilities aimed at…; and use of analogue rock samples to derive combined acoustic velocity and relative permeabilities (Case Study 5, Chapter 5), aimed at constraining seismic monitoring. It is unlikely that any of these activities would have been carried out were it not for the early use of risk analysis.

Final risk assessment results

Also shown in Figures 6.9 and 6.10 are the final risk assessment results from the end of the project, for the high risk FEPs from the start of the project. The highest ranking FEP at the start of the project, 'financial viability', is a combination of a number of factors and in order to get a better handle on the risk associated with this area it was decide to divide this FEP into several individual FEPs. Hence, there is no overall score for financial viability at the end of the project, only for the individual FEPs. All of the financially related FEPs are perceived as high risk at the end of the project, except one, highlighting the high level of financial risk associated with CCS.

Comparing the site-specific high risk FEPs from the start of the project to the end of the project, we find that for a number, the scores have decreased from the start to the end of the project. The major risk mitigation activity for this site was the reprocessing of seismic data in order to reduce uncertainty in the characteristics of the subsurface. The major impact of this work was to decrease the perception of risk for the 'fractures and faults' FEP from high risk to moderate risk, based on the 'best guess' value. This is a result of the improvements to the quality of the data, which resulted in less uncertainty, but also in fewer faults being interpreted in the reprocessed data. Other FEPs that have also moved from the high risk banding are: 'hydrogeology', which has gone from high risk to low risk; 'hydrological regime and water balance' and 'near-surface aquifers and surface water bodies', which have gone from high risk to moderate risk. This change is most likely the result of lessons learned from the hydrogeology study of the Lincolnshire site (Chapter 3).

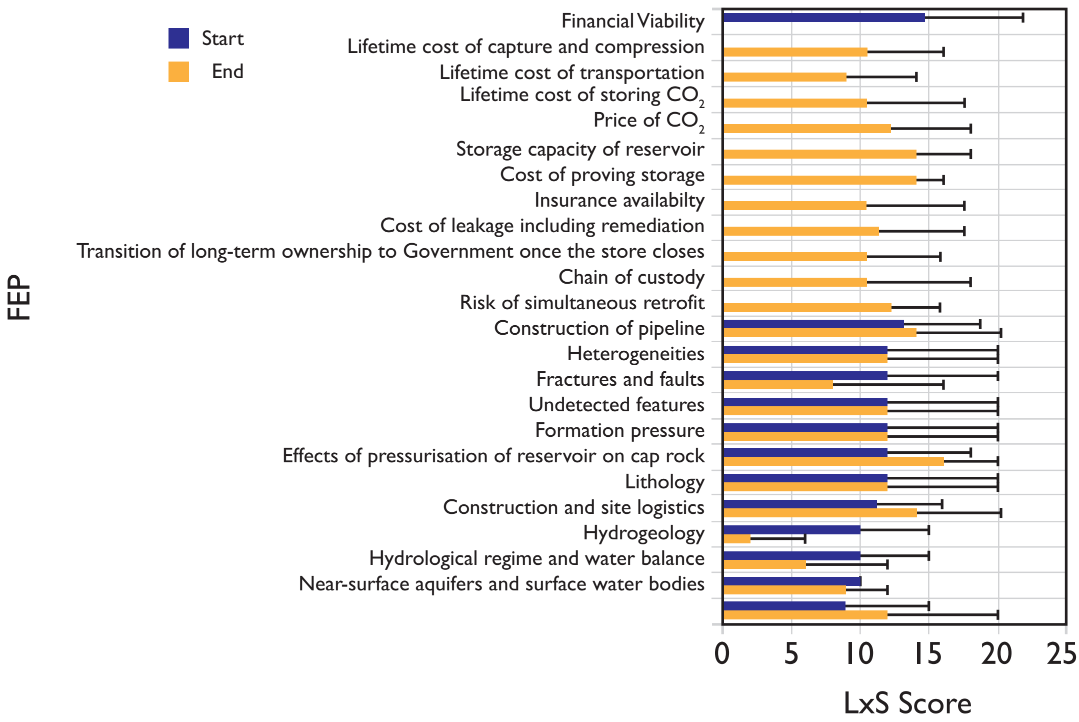

Figure 6.9 Likelihood (L) x severity (S) score for FEPs for the Firth of Forth site at the start and end of the project, for FEPs that score 10 or more in the first risk assessment. Solid bar shows 'best guess' value and line shows the upper bound. Only highest values from the health and safety and financial, environmental, research and industrial viability severity scales are shown. FEPs are ordered according to their ranking at the start of the project. The financial viability was divided into a range of individual FEPs after the first assessment, and consequently there is no final overall score for financial viability at the end of the project, with only the individual financial FEPs shown in orange.

A number of FEPs remained in or have moved into the high risk banding. It was not possible within this study to address all high risk areas, however, potential mitigation activities have been identified for all high risk FEPs for both sites (Polson et al., 2010c). For any potential mitigation activity, a careful estimate of the costs involved should be weighed against the potential reduction in risk. For example, a potential mitigation step for the 'buoyancy-driven flow' FEP (which is high risk for both sites) is to use a CO_2-brine surface dissolution strategy (Chapter 7).

The work that has been done demonstrates the type of process that should be applied in a full-scale CCS project and has shown that the mitigation activities implemented within the CASSEM project have been able to reduce the perception of risk in the targeted areas. For full details of results see Polson et al. (2010c).

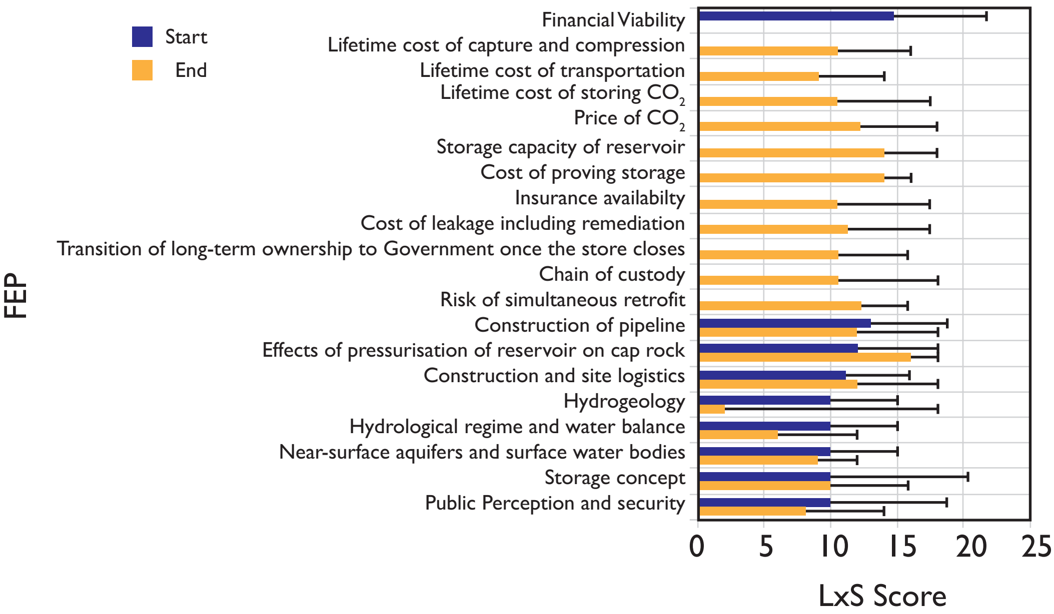

Figure 6.10 Likelihood (L) x severity (S) score for FEPs for the Lincolnshire site at the start and end of the project, for FEPs that score 10 or more in the first risk assessment. Solid bar shows 'best guess' value and line shows the upper bound. Only highest values from the health and safety and financial, environmental, research and industrial viability severity scales shown. FEPs are ordered according to their ranking at the start of the project. The financial viability was divided into a range of individual FEPs after the first assessment, and consequently there is no final overall score for financial viability at the end of the project, with only the individual financial FEPs shown in orange.

Data acquisition technique
Seismic reprocessed for Firth of Forth site
Proxy boreholearchive (using existing samples from boreholes or outcrops as proxy for new borehole)
Hydrogeology study for Yorkshire/Lincolnshire site
Relative permeability
Monitorability assessment

Table 6.7 Data acquisition activities implemented to reduce uncertainty and risk.

6.4 SUMMARY AND CONCLUSIONS

In this chapter we described methods to assess risk and uncertainty associated with the geological aspects of CCS projects and applied this methodology to the flow simulations (Chapter 4) of the CASSEM case study sites. Using sensitivity analysis we demonstrated how to identify the key controlling properties of the storage site, allowing resources to be targeted on those factors that most influence uncertainty in the long-term fate of the injected CO_2.

Results for the two sites show that the key properties tend to be the same despite the differences in the two storage sites. Applying uncertainty analysis to the same flow simulations allowed this uncertainty to be calculated and compared for different sites. Thus, we were able to demonstrate a methodology for probabilistic assessment of leakage of CO_2 into and through the cap rock and showed how this could be tracked in space and time.

Using regular (quarterly) risk assessments, we were able to quantify and rank the experts' perception of risk and track this as it developed throughout the project. This allowed risk mitigation activities (case studies) to be identified and implemented and the impact of these activities to be assessed. The results show that the key factor influencing the experts' perception of risk at the start of the project was uncertainty, and that by reducing the uncertainty associated with particularly influential properties and characteristics of each site, the experts' perception of risk could be decreased. It does not necessarily follow that reducing uncertainty will decrease perception of risk, as was generally the case here. However, it is clear that unless the uncertainty associated with a storage site can be brought to within some acceptable limit, perception of risk is likely to remain high.

The overall results from the risk and uncertainty analysis work show that the Firth of Forth site is perceived to be much riskier than the Lincolnshire site, with many geological features, in particular, perceived to be high risk. This is primarily due to fewer data, poorer quality data and more complex geology for this site, which ultimately makes the uncertainty associated with the Firth of Forth site greater than that of the Lincolnshire site. The risk and uncertainty analysis has shown that at this stage the Lincolnshire site appears to be potentially more viable as a long-term storage site for CO2, however, neither site would yet meet all the criteria for storage.

Overall, the two largest perceived generic risks for CCS identified by the CASSEM project are financial viability and pressurisation of the cap rock. Public perception and security, although reduced in risk during the study, has the potential to stop a CCS project in its tracks. These three activities are the subject of the following chapters.

CHAPTER 7

RISK MITIGATION: ENGINEERING STRATEGIES FOR CO_2 INJECTION INTO SALINE AQUIFERS

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7.1 INTRODUCTION

The technologies for capturing, transporting and injecting carbon dioxide from industrial facilities draw upon a large body of existing research and field experience in the energy industry, which are generally well understood (Gale and Kaya, 2003; IPCC, 2005). A central challenge of both scientific and regulatory interest is how to ensure secure long-term CO_2 sequestration. Currently, successful storage of CO_2 in geological formations such as the Utsira aquifer (for the Sleipner field) (Korbøl and Kaddour, 1995) and enhanced oil recovery at Weyburn (Malik and Islam, 2000) relies on an impermeable cap rock at the top of the formation to trap the fluid CO_2 (Jessen et al., 2005). This storage mechanism can be considered reliable in well-characterised oil and gas fields where hydrocarbons have been trapped over geological time. However, assuring containment is more difficult in less-known aquifer formations with uncertain cap rock properties (Bruant et al., 2002; Bachu, 2008).

Although CCS is viable from a technical perspective, a number of important scientific uncertainties remain. One of these is around the stability of CO_2 in deep saline aquifers. The upward buoyancy of dense-phase CO_2 in deep reservoirs requires that sites are chosen with a methodology which has carefully evaluated details of performance during and after the injection process. Surface leakage would undermine efforts to stabilise atmospheric CO_2 concentrations, and could, in a worst-case scenario, pose environmental and human health safety risks (IPCC, 2005). The concern over the potential risk of CO_2 leakage has already contributed to local opposition to CCS implementation (Pearce et al., 2005; Evans et al., 2004; Haszeldine et al., 2005).

Long-term storage costs are expected to be a trivial percentage of a CCS project (Herzog et al., 2005), however, the cost of leakage in a worst-case scenario may be very large. Current regulations for underground injection primarily address the operational phase (when the injection takes place), but are not yet clear about the time frame for monitoring and risk management issues (Wilson and Gerard, 2007). New technologies are required to reduce or even eliminate the cost of the long-term monitoring and risk management issues and guarantee that the injected CO_2 will remain stable underground over an extended period of time. In this chapter we explore and present innovative strategies to improve our options for long-term secure CO_2 storage and to mitigate risk.

This work takes a speculative, non-conventional approach to injection, linking risk mitigation to economics. It focuses on investigation of various injection strategies, including those that do not rely entirely on an impermeable seal, in an attempt to enhance long-term CO_2 storage and improve the reliability of storage.

7.2 SEQUESTERING CO_2

Injected carbon dioxide is typically less dense than aquifer formation water and, therefore, will migrate laterally and upwards if the cap rock is not completely impermeable. Conversely, the efficiency of CO_2 storage in geological media will rise with increasing CO_2 density (Brennan and Burruss, 2003). Therefore, the stability of sequestered CO_2 in saline aquifers is more certain if the CO_2 is dissolved in the liquid, as brines with dissolved CO_2 have a greater density than that of CO_2-free brines (Eke et al, 2011), or precipitates as a carbonate in the geological formation (IPCC, 2005; NAP, 2003). An improved understanding of dissolution may facilitate the selection of saline aquifers as disposal sites, by reducing the requirement for a mechanically strong and impermeable cap rock, thereby expanding the number of possible disposal reservoirs (NAP, 2003).

Recent research suggests that solubility trapping makes the bulk of CO_2 sequestered in a well-chosen saline aquifer unlikely to escape on timescales appropriate for geo-sequestration (Benson and Cole, 2008; Gilfillan et al., 2009). However, very long timescales are required for the CO_2 injected into saline aquifers to eventually dissolve into the brine, before it could then pose a significantly reduced environmental risk. Current research suggests that CO_2 storage integrity will improve over time, as natural mechanisms (trapping in rock capillaries and geochemical reactions) dissolve CO_2 in formation waters (centuries), and eventually convert it to minerals (millennia), thus decreasing buoyancy-driven flow (Pruess et al., 2004; IPCC, 2005). As with natural weathering, the natural dissolution of CO_2 in brines is too slow to be a practical storage solution for a large-scale CO_2 operation. Engineering approaches that enhance the dissolution of CO_2 in brines or water are key to addressing this issue.

In the CASSEM project, conceptual process engineering design and simulation studies of four CO_2 injection systems downstream were performed using Aspentech and Schlumberger's commercial simulation packages. Surface equipment to handle a hypothetical injection flow rate of 15 million tonnes CO_2 per annum for 15 years was designed and evaluated for the four strategies. The study has identified the principal methodologies that could enhance CO_2 immobilisation in the subsurface formation by surface process engineering. The workflow incorporates sensitivity analysis of the surface and subsurface process interface.

7.3 THE SURFACE AND SUBSURFACE PROCESS INTERFACE

The interface design work linked downstream pipeline transport to surface process injection facilities and from the wellhead to injection at the 'rock face' in the storage reservoir. This section highlights the interface conditions required for the proposed injection methodologies and provides the underlying application of the processes to the two exemplar sites selected for the project.

We assume that the captured supercritical CO_2 is transported via pipeline to the process and injection platform or manifold for off/onshore storage. The designed injection facilities then include downstream pipelines and pumps for pressure boosting, distribution piping between the terminus of the upstream CO_2 trunk line and the wellheads, CO_2 flow control equipment and equipment to monitor the well condition and wells for injection. The surface and subsurface specifications and parameters used in the design were estimated for both sites and are presented in Table 7.1.

Parameters Unit	***Unit***	***Lincolnshire***	***Firth of Forth***
Injection rate	Mt/well/ yr	1	0.7~1
Injection wells	N	15	15~22
Extraction wells (water/brine)	N	8~74	8~74
Extraction rate	b/well/d	70000	70000
Total injection rate	Mt/yr	15	15
Injection Period	Yr	15	15
Wellhead Pressure	bar	~90	~100
Bottom hole Pressure	bar	~150	~250
Maximum Bottom hole pressure	bar	~225	~375
Bottom hole Temperature	°C	~55	~81
Injection depth	M	1190~1360	2100~2800

Table 7.1 A summary of input parameters and design specifications for two project scenarios.

Nodal analysis was carried out to estimate pressures at both the wellhead and reservoir wellbore. The pressure required to inject CO_2, as shown in Figure 7.1, is a function of reservoir parameters such as permeability and zone thickness and the bottom hole pressure exerted by the column of CO_2 in the wellbore. The injection pressure must exceed the formation pressure for the CO_2 to fill the permeable pore space within the sedimentary rocks, essentially trapped by less permeable rock layers which impede fluid migration. Taking reservoir conditions of the two sites into consideration, the following were the basis of the simulations: maximum bottom hole pressure in the well is assumed to be 1.5 times that of the initial reservoir pressure (van der Meer and van Wees, 2006; van der Meer and Egberts, 2008) and CO_2 is above the supercritical condition.

Two completion options have been considered: 7″ monobore and 4.5″ tubing completions after 9 5/8″ production casing. The prediction results indicate that the completion options that use 7″ tubing offer a slight injection advantage (lower head pressure) over 4.5″ tubing. Minimum wellhead pressure is calculated to be about 90 to 100 bar for the Lincolnshire and Firth of Forth sites, respectively, as shown in Figure 7.1.

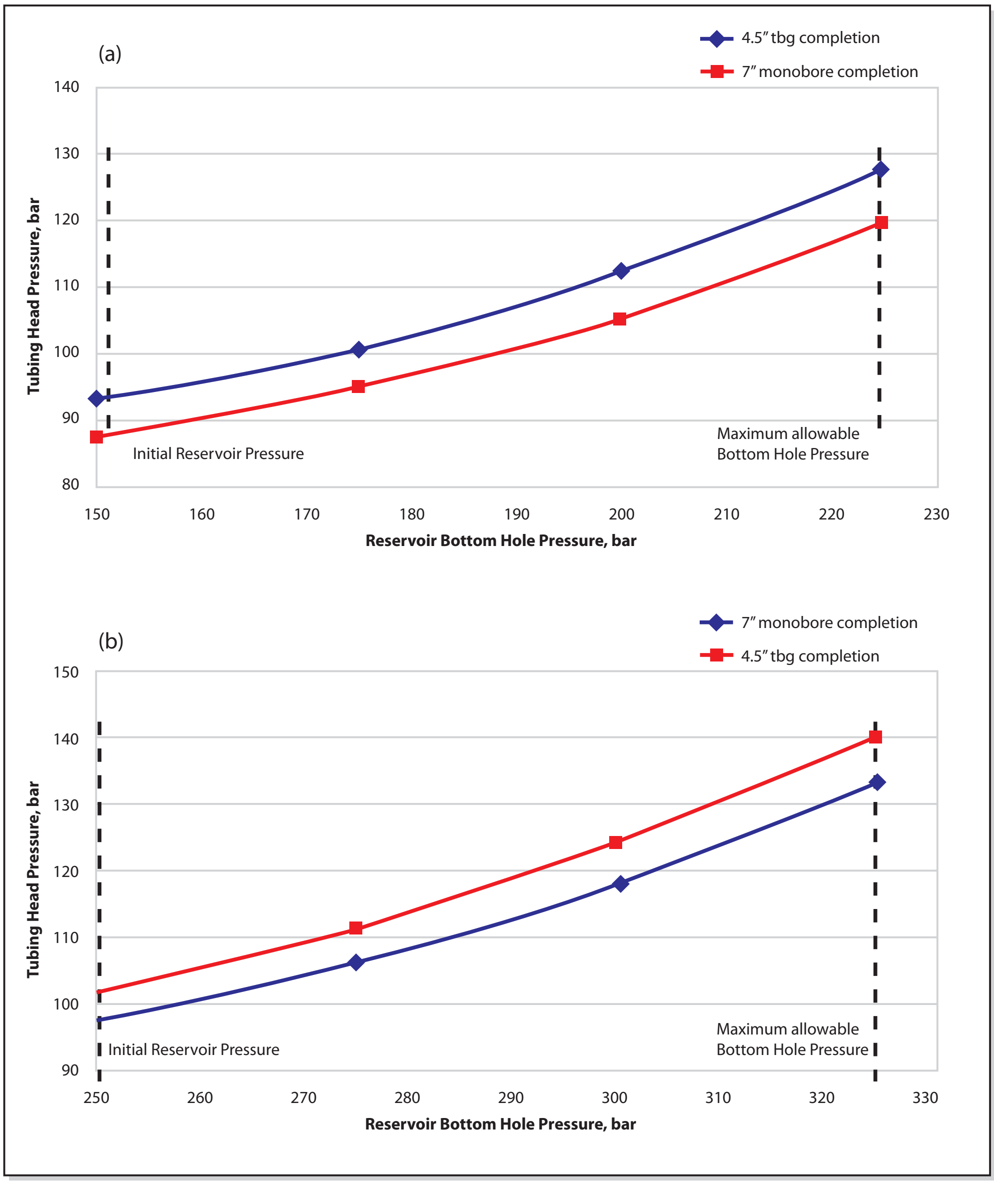

Figure 7.1 Nodal analysis showing: (a) Lincolnshire wellhead pressure and (b) Firth of Forth wellhead pressure conditions.

7.4 CO_2 INJECTION STRATEGIES

High-level process engineering studies and analysis were performed to investigate four different strategies for CO_2 injection. Investigations were conducted on CO_2 stream behaviour on the process facilities within applicable thermodynamic conditions. Key components and conditions governing whether large volumes of supercritical CO_2 can be safely, reliably and securely injected into and stored within a saline aquifer, were investigated by modelling various injection processes. The strategies studied were:

- Standard CO_2 injection.
- CO_2-brine surface mixing and injection.
- CO_2-water surface mixing and injection.
- CO_2 alternating brine (CAB) injection strategy.

These four strategies were then applied to the two sites investigated, resulting in eight scenarios.

7.5 STANDARD CO_2 INJECTION

This method involves injection of compressed CO_2 in a dense supercritical phase. The process model was constructed using Aspen HYSYS version 7.1. Peng Robinson equations of state (Peng and Robinson, 1976) are applied in all strategies unless otherwise stated. A booster pump is used at the injection sites to raise the wellhead injection pressure to ~90 bar, and ~100 bar prior to distribution to an individual wellhead via the distribution manifold, as shown in Figure 7.2.

The injection and extraction wells designed for the injection of CO_2 and extraction of brine are characterised as consisting of two basic elements:

1. The wellbore, that is the penetration into the earth consisting of casing, cement and wellhead, whose purpose is containment of reservoir pressure and isolation of groundwater resources from contamination.

2. The mechanical completion equipment, consisting of valves, tubulars and packers used to inject fluids into or to produce fluids from a formation.

Wellbore designs are similar in all four options, as presented in Figures 7.2, 7.5, 7.8 and 7.9. A process flow diagram (PFD) of the standard injection is connected to the schematic well, modified from previous work by McCoy (2008), as shown in Figure 7.2.

The simulation results indicate that dense-phase CO_2 has a density of ~700 kg/m^3, leaving a density difference between the CO_2 and formation fluids of ~300 kg/m^3 (Eke et al., 2011), which drives the buoyant migration of CO_2 towards the top of a reservoir layer. This technique is reliant on the presence of a cap rock with a capillary entry pressure sufficient to hold the CO_2.

7.6 CO_2-BRINE SURFACE MIXING

The CO_2-brine dissolution approach involves dissolving supercritical CO_2 into brine at a surface facility. This was modelled using Aspen Plus version 7.1 with an electrolyte package to account for brine-CO_2 properties and reactions. Physical and chemical parameters that favour the dissolution of CO_2 into brine are optimised and controlled in the surface process facilities referred to as 'ex-situ CO_2-brine dissolution'. Conceptually, the process model is based on the formation brine being extracted from the reservoir, but sea water could be used, where necessary. The design involves various calculations, including an estimation of the amount of brine required for surface CO_2 dissolution and CO_2 solubility (Eke et al., 2011). Brine used for the surface mixing is produced at a rate of 70,000 barrels/well/day, and due to the low solubility of COv, large volumes will be required to accommodate the CO_2 produced at the CASSEM sites.

The model was then used to predict the sequestration potential and long-term behaviour of the CO_2-saturated brine in the two saline aquifers studied. The relevant calculated composition properties of CO_2-saturated brine were solubility, density, pressure and temperature, at applicable depths, as presented in Figures 7.3, 7.4, 7.6 and 7.7. The simulation outputs for the two sites show that greater pressure and lower temperature increases solubility (Figures 7.3 and 7.4). The basic process optimisation challenge is thus identified as the operating temperature and pressure of the mixing equipment, which has a strong link with the CO_2-brine solubility. Hence, lower temperatures in the brine stream would need to be optimised against high pressure to maximise CO_2-brine dissolution in the mixing vessel.

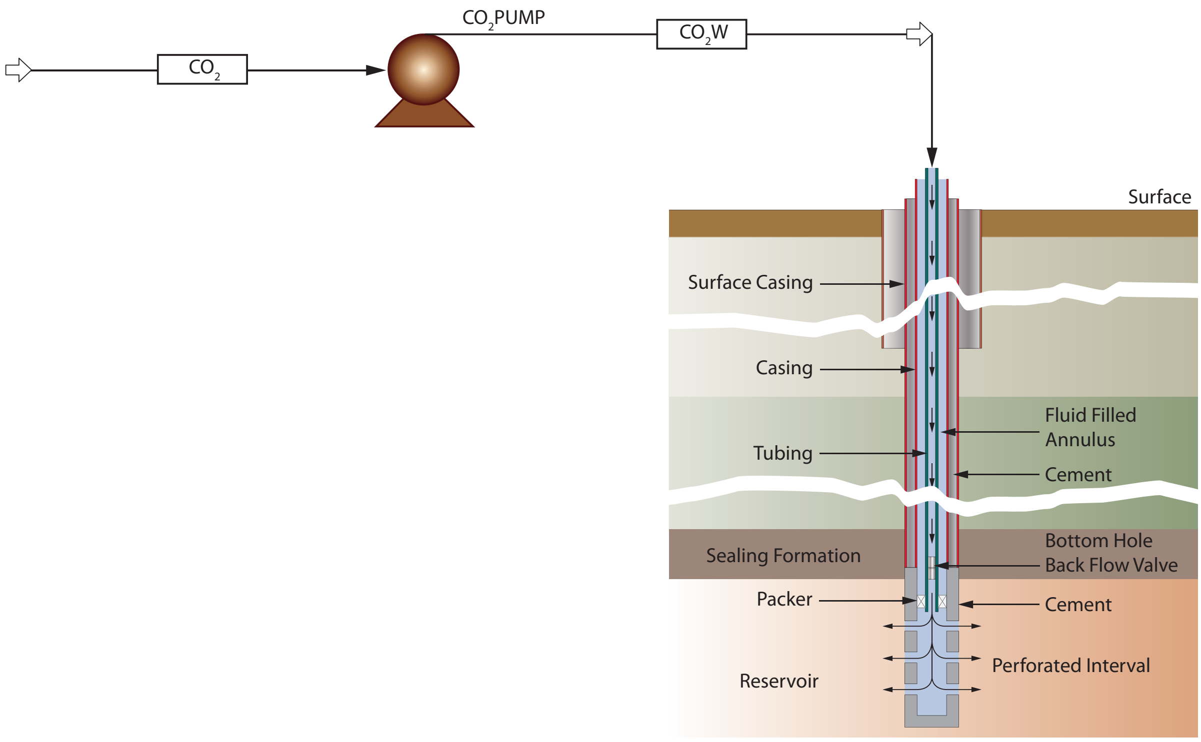

Figure 7.2 Standard injection process simulations PFD.

The pressure mixing vessel where the material streams (CO^2 and brine) are combined is an important unit operation in this process (Figure 7.5).

The feasibility of this strategy is investigated by comparing the CO_2-saturated brine density to the density of the native brine without CO_2. The simulation results for the two CASSEM sites indicate that the CO_2-saturated brine is slightly denser (Figures 7.6 and 7.7) and hence has a downwards buoyancy drive.

This strategy provides a significant advantage since it mitigates the need for a sealing cap rock and CO_2 can potentially be injected safely at depths of <800 m, as required for pure CO_2. In addition, the production of brine from deeper depths within the reservoir would induce a pressure drawdown and enhance the migration of the CO_2-saturated brine away from the injection site and help regulate the reservoir pressure. This approach results in chemically stable CO_2-saturated brine that is denser than supercritical CO_2 and, therefore, poses substantially less long-term leakage risk. The above ground CO_2-brine dissolution process also reduces the need for long-term monitoring of the sequestered CO_2.

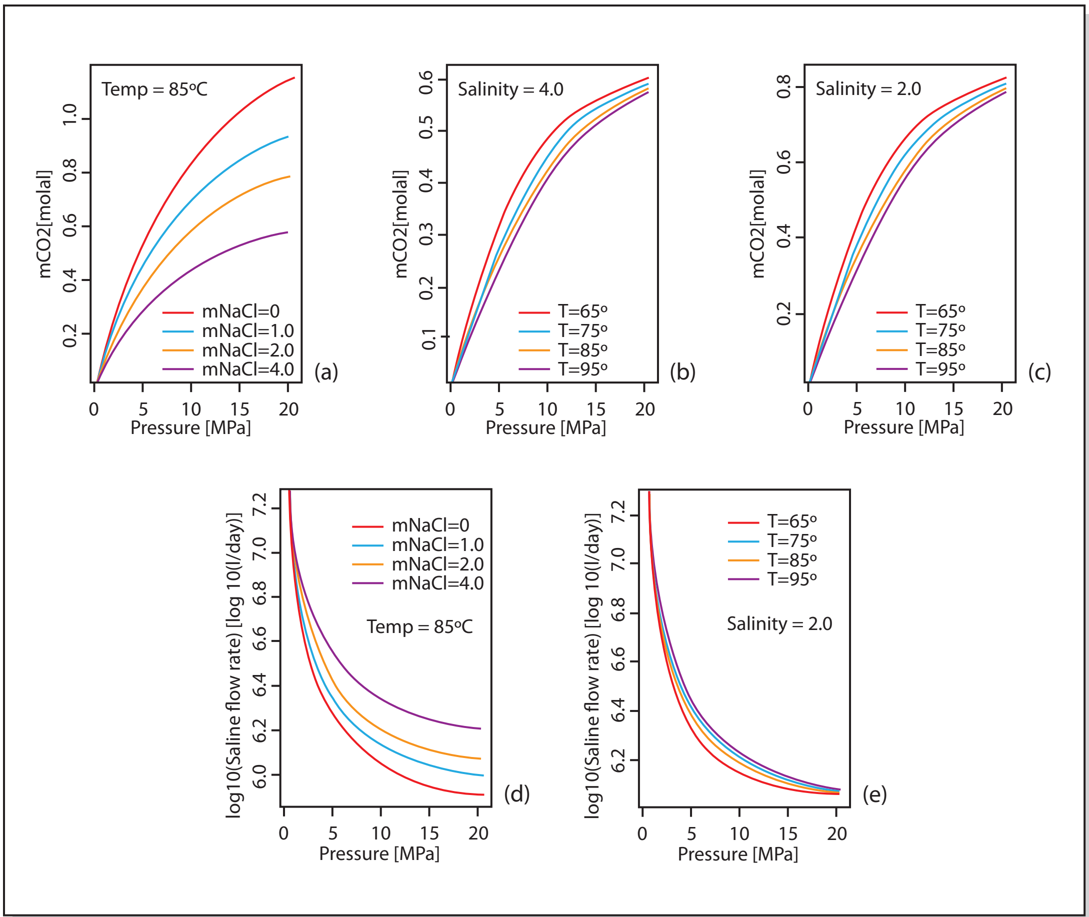

Figure 7.3 Firth of Forth solubility of CO_2 in brine as a function of pressure, temperature and salinity of NaCl, showing: (a) solubility of CO_2 in brine of various ionic strengths with a constant temperature of 85ºC, (b) solubility of CO_2 in brine of various temperature with a constant salinity of 4, (c) solubility of CO_2 in brine of various temperature with a constant salinity of 2, (d) log solubility of CO_2 in brine of various ionic strengths with a constant temperature of 85ºC, (e) log solubility of CO_2 in brine of various temperature with a constant salinity of 2.

However, this approach does involve additional costs due to the large fluid volumes involved. These costs include extra injection wells, extraction wells to supply the brine, high-pressure mixing vessels, as well as other process facilities (Eke et al., 2011). Further studies on mixing and reaction technology indicate that an inline mixer or blender is key to optimising the process facility (Eke et al., 2011).

In terms of risk mitigation, we must also consider cost implications of leakage, as the likelihood of leakage using the CO_2-brine strategy would be effectively zero (the mixture would be more dense than existing pore space brine and, hence, would sink rather than rise) compared to a CO_2-only injection strategy, in which the likelihood of leakage could never be reduced to zero. A simple calculation of the minimum downside costs associated only with those FEPs (Chapter 6) related to impacts of leakage gives a lower-bound estimated cost of approximately £500m. This is a conservative minimum as it uses the minimum value from the multi-catastrophic severity banding (Table 6.5) and it does not include a range of other FEPs, which could potentially also be mitigated using the CO_2-brine strategy. For example, FEPs related to costs associated with characterising the reservoir and cap rock. A CO_2-brine strategy would remove the need for a cap rock, allowing reservoirs to be used for CO_2 storage which would not otherwise be viable. These could include sites much nearer shore or in shallower water. Furthermore, other FEPs related to storage security, such as open fractures and faults, would no longer be such a concern; while this strategy may also reassure the public and reduce public opposition to CCS. Similarly, we can compare the costs associated with alternative monitoring strategies or data acquisition activities with the potential cost implications of the associated FEPs for which risk could be reduced.

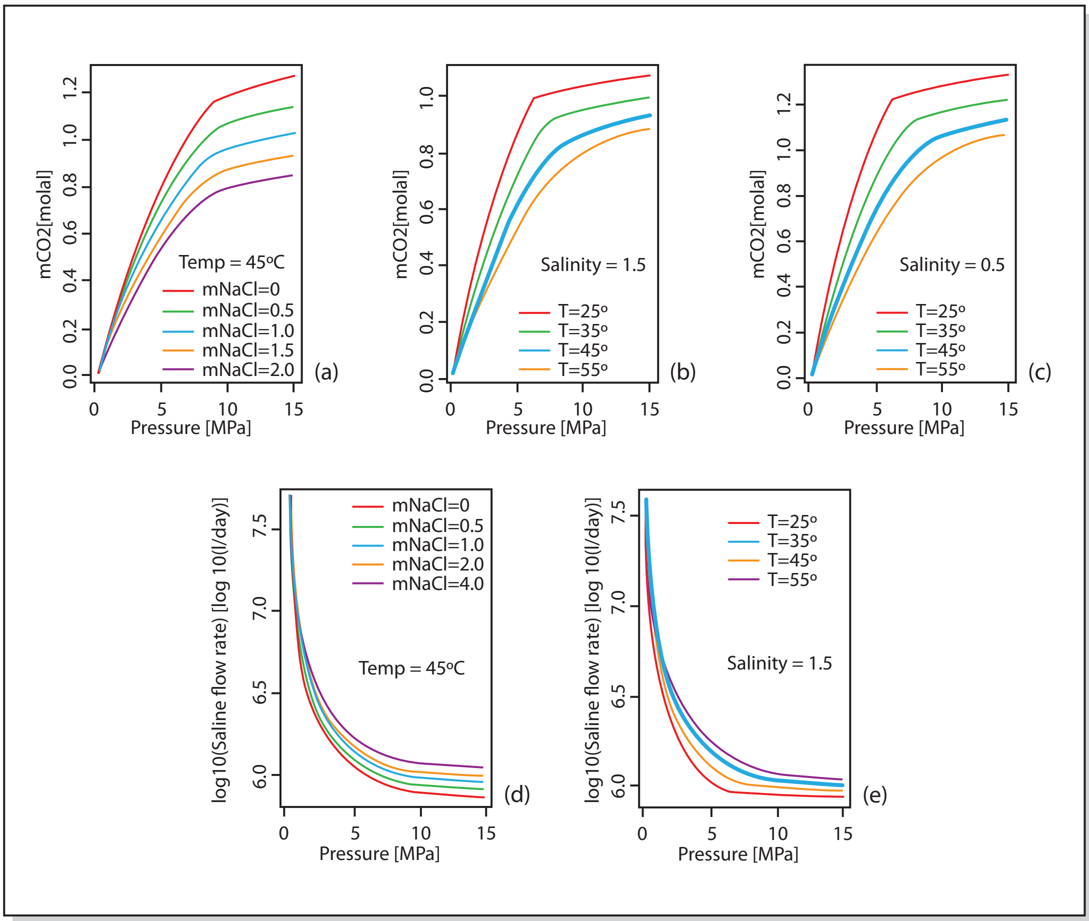

Figure 7.4 Lincolnshire solubility of CO_2 in brine as a function of pressure, temperature and salinity of NaCl, showing: (a) solubility of CO_2 in brine of various ionic strengths with a constant temperature of 45°C, (b) solubility of CO_2 in brine of various temperature with a constant salinity of 1.5, (c) solubility of CO_2 in brine of various temperature with a constant salinity of 0.5, (d) log solubility of CO_2 in brine of various ionic strengths with a constant temperature of 45°C, (e) log solubility of CO_2 in brine of various temperature with a constant salinity of 1.5.

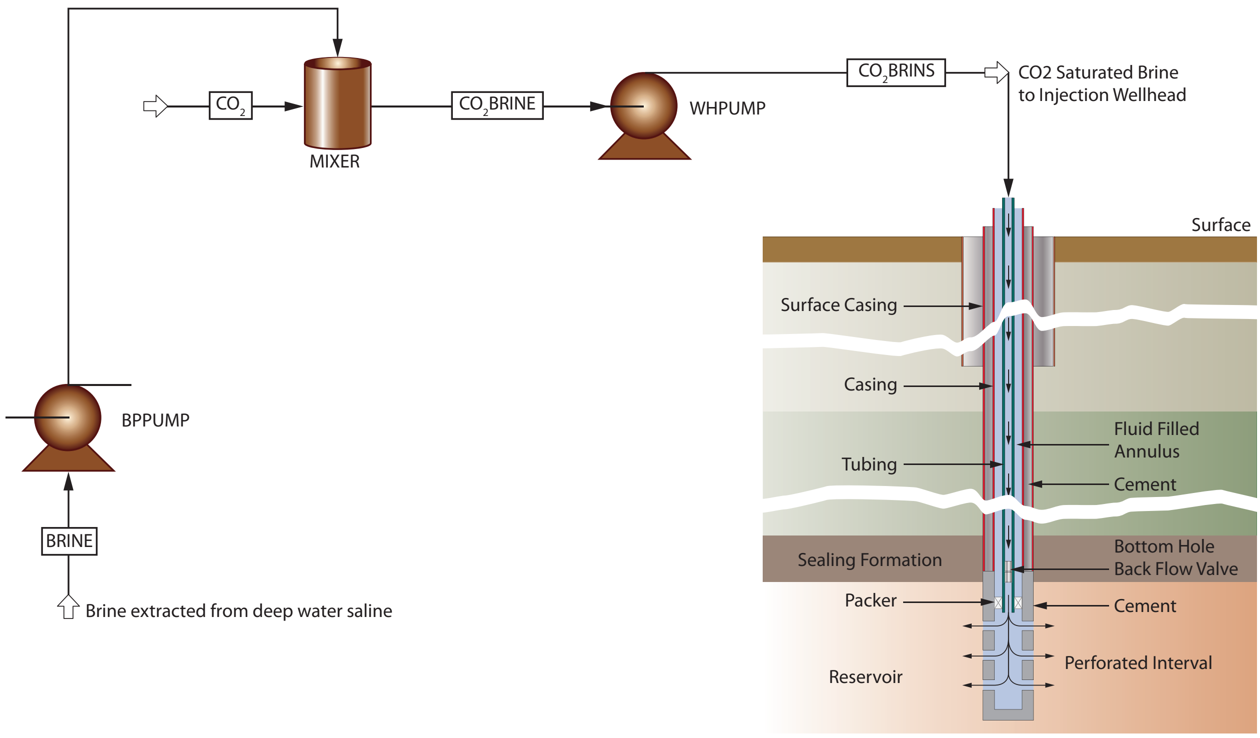

Figure 7.5 CO²-brine surface mixing process simulations PFD.

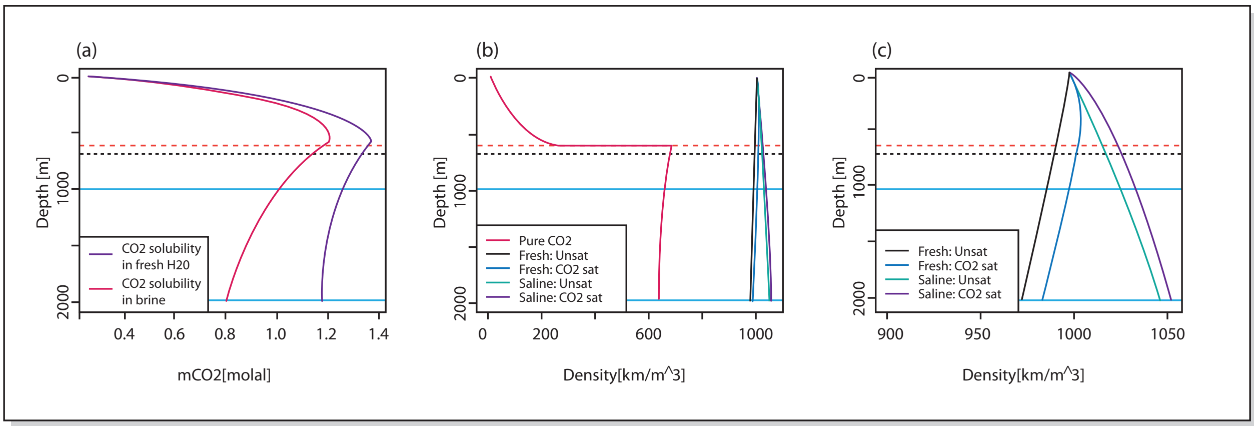

Figure 7.6 Firth of Forth properties of pure CO_2, pure fresh water, brine, CO_2-saturated fresh water and CO_2-saturated brine. (a) Solubility of CO_2 in fresh water and brine, (b) density of pure CO_2 and fluids (c) zoom in on the fluid densities. Salinity increases with depth at 1 mol/l/km.

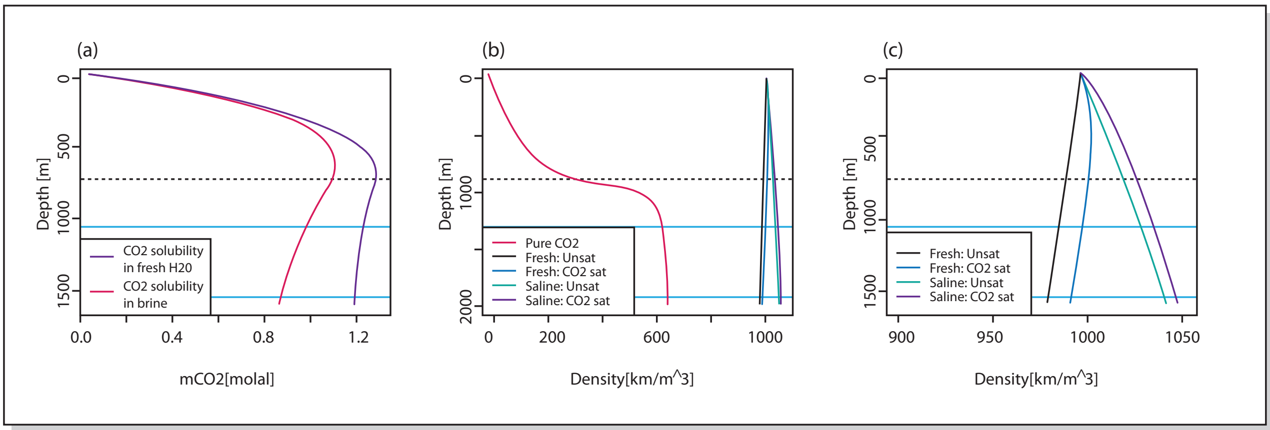

Figure 7.7 Lincolnshire properties of pure CO_2, pure fresh water, brine, CO_2-saturated fresh water and CO_2-saturated brine. (a) Solubility of CO_2 in fresh water and brine, (b) density of pure CO_2 and fluids, (c) zoom in on the fluid densities. Salinity increases with depth at 1 mol/l/km.

7.7 CO_2-WATER SURFACE MIXING

This injection strategy investigates the possibility of enhancing the process of dissolution of CO_2 into water by mixing at the surface facilities.

A process flow model for mixing dense CO_2 with water in surface facilities prior to injection into the saline aquifer (Figure 7.8) was developed and used to predict the sequestration potential and long-term behaviour of the carbonated water in the two saline aquifers studied.

The technical motivation behind this methodology is that when CO_2 dissolves in water, it forms a carbonic liquid, which, while less dense than the expected ambient saline formation fluid (by ~50 kg/m^3 for the parameterisations chosen here and at reservoir depths (Figures 7.6 and 7.7 and Eke et al., 2011)), has a density difference of an order of magnitude less than supercritical CO_2. While the use of sea water or formation brine rather than pure water would help to reduce this buoyancy drive, it does so at the expense of lower CO_2 solubility. Dissolved CO_2, when stored in a saline aquifer, will assist transformation into carbonate minerals and, therefore, permanent storage (Gunter et al., 2004).

A major limitation with this strategy is that it requires the injection of significant volumes of water (at least an order of magnitude greater than for the standard injection of pure CO_2) into the saline aquifer. Since the CO_2-saturated fresh water is buoyant, it also requires the presence of a cap rock to retain it. The performance of a capillary cap rock in a water-wet reservoir/cap rock system is likely to be low. The simulation results show that free water is found in the carbonated water stream and hydrate is formed at the moderate temperature of 10°C. Corrosion preventive actions should be evaluated and implemented; these include choosing correct operating conditions and corrosion resistant materials.

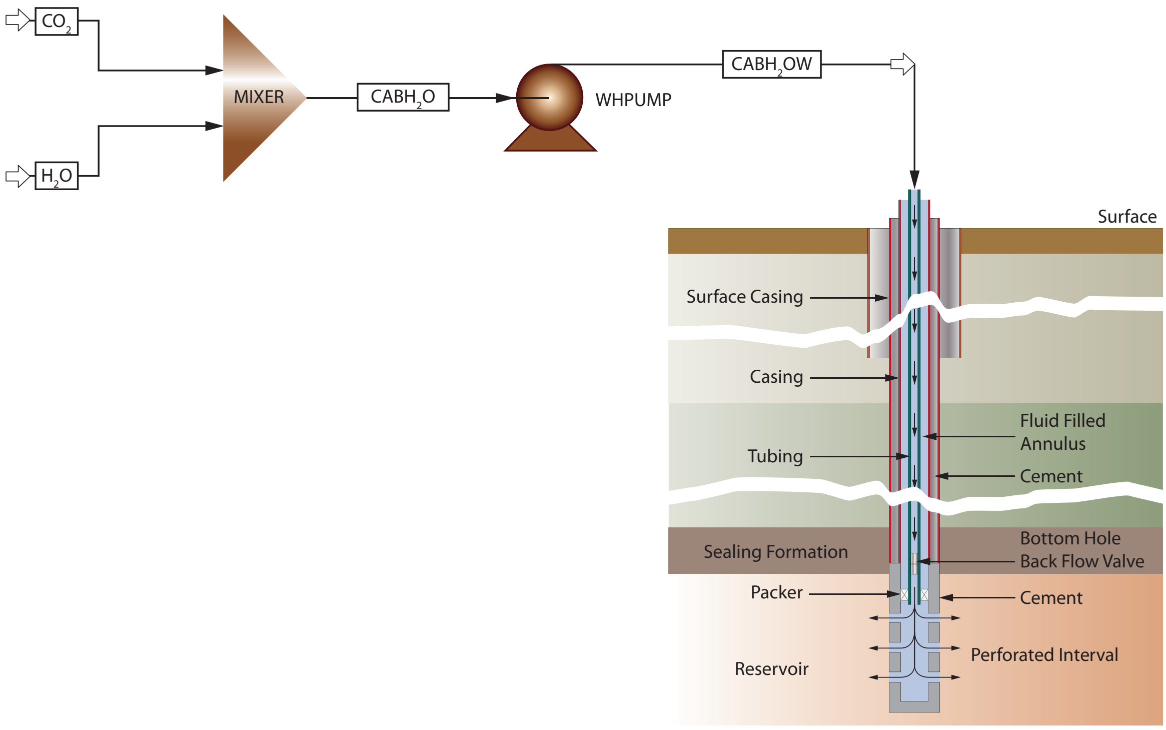

Figure 7.8 CO_2-water surface mixing process simulations PFD.

7.8 CO_2-ALTERNATING-BRINE (CAB) INJECTION

This injection strategy involves alternating the injection of supercritical CO_2 with brine (Figure 7.9). The technical and scientific principle behind this strategy is based on a water-alternating-gas (WAG) process. The model designed consists of two standard injection facilities, one injecting a CO^2 stream and the other a brine stream to the wellhead where the alternating injection schedule is operated. CAB injection operations therefore require flow controls that occur sequentially rather than simultaneously, for extended periods of time. As an additional safety practice, flow isolation is practised; a blind flange is inserted on the line of the non-flowing phase to assure its complete isolation. This procedure assures that, should a valve not seal properly, no backflow can occur, which could induce corrosion and over-pressurisation. This injection strategy is predicted to reduce CO_2buoyancy migration and immobilise CO_2 in the formation by enhancing the dissolution rate of CO_2 in brine. It has the potential to be an effective solution to rendering the CO_2 immobile in a residual phase, in the absence of dissolution.

The science behind this strategy lies in capillary or pore-scale trapping, which is an important and rapid mechanism to render the CO_2 immobile in geological formations. Previous studies have shown that WAG CO_2 injection into a saline aquifer can trap more than 90% of the CO_2 injected as an immobile phase (e.g. Qi et al., 2009). Using the lessons learned from studies on water-alternating-gas as a starting point, ongoing research is targeted at simulating the process facilities and economics to assess the feasibility of CAB as strategy to optimise trapping.

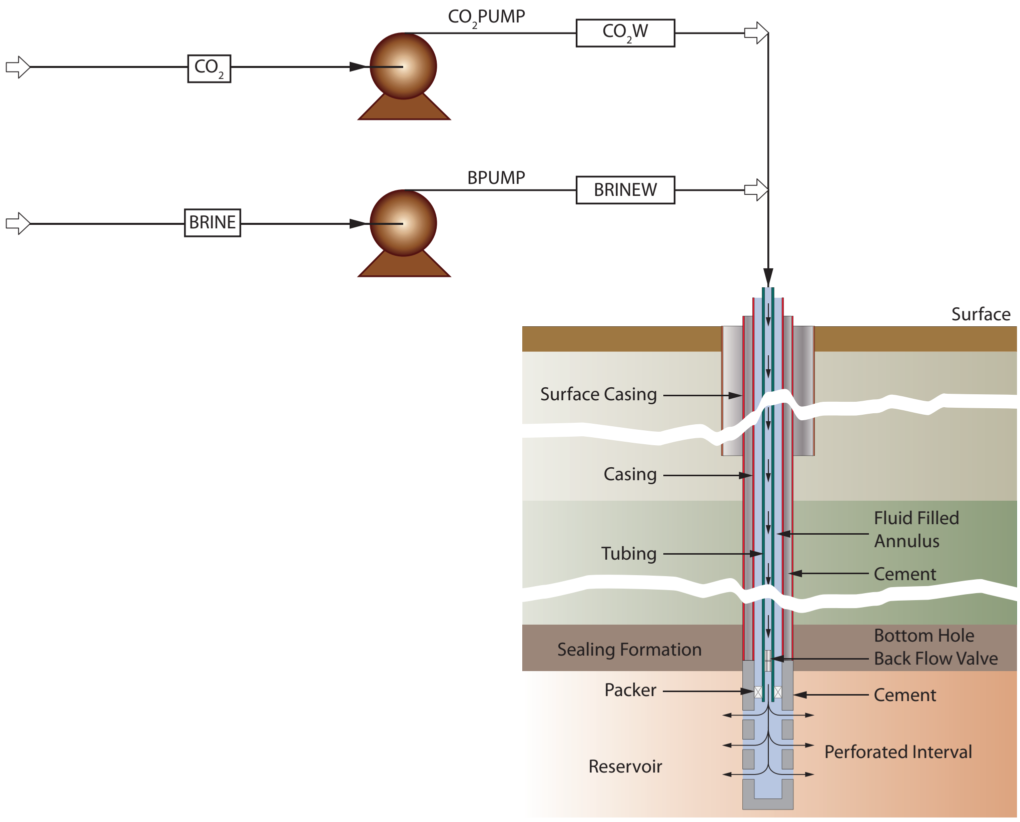

Figure 7.9 CO_2-alternating-brine process simulations PFD.

7.9 SUMMARY

In summary, surface mixing of supercritical CO_2 has the potential to significantly mitigate risk during injection and for long-term storage. The alternative engineering strategies studied here can be directly linked to storage solutions that are thermodynamically and environmentally stable and capable of enhancing permanent storage in the geological formations.

Application of the various process models to the two CASSEM sites indicates that the CO_2-brine surface mixing and injection methodology is an important and perhaps an essential step, as it removes the tendency for buoyant upward migration in the reservoir. Crucially, if the CO_2 can be immobilised, then it will remain indefinitely underground, even if the integrity of the cap rock is breached. This research contributes to the reduction of a major risk (Chapter 6), addresses the long-term CO_2 storage uncertainties which are a major public concern (Chapter 9) and has the potential to reduce monitoring costs (Chapter 5).

The principle disadvantage of the alternative injection strategies is the additional costs from the surface infrastructure, operational costs and from the additional wells required for injecting the equivalent volumes of CO_2 and, potentially, extraction of aquifer brine. These should therefore be carefully weighted in the risk register, as described in Chapter 6. For example, a CO_2-brine strategy would remove the need for a cap rock, allowing assessment of reservoirs otherwise considered unsuitable for CO_2 storage. These may include sites nearer shore, in shallower water and those affected by open fractures and faults.

Further work is required to develop these concepts. A scaled demonstration program that addresses the issues of CO_2-water/brine-rock reaction kinetics, the operational realities of mixing fluids and the impact on the whole CCS chain (Chapter 2) is needed. Outcome from this will make it possible to compare and optimise the technologies in detail, select the optimal one and provide more precise cost estimates.

CHAPTER 8
FINANCIAL MODELLING OF A CCS SCHEME

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8.1 INTRODUCTION

There is still significant uncertainty around estimating the cost of CCS, and financial viability was the highest risk identified in Chapter 6. This is principally because CCS has not yet been implemented at full scale on any commercial power plant. Estimates are based on scaling up smaller demonstration schemes or with reference to similar processes and technologies.

There have been various studies conducted over recent years to estimate the cost of industrial scale CCS, based on a range of scenarios and different estimation basis. However, up until now, very few have provided fully transparent access to the underlying calculations and source data, instead relying on the reader to accept the output of the 'black box' calculations. This chapter aims to open up the debate on how CCS costs are calculated. We provide users with the ability to see into the 'black box' and come to their own conclusions about the cost of CCS, and thereby better understand the various ways in which costs are represented.

With this in mind, a fully open and transparent Microsoft Excel-based model has been developed, along with a discussion paper which expands on some of the topics in this chapter. Both are freely available for download from www.sccs.org.uk/cassem . The model covers the entire CCS chain, including the power plant, onshore and offshore transport, storage and monitoring. It demonstrates that a common set of inputs can produce a range of different 'costs' depending on the units and measurements used. In addition, it is hoped that the cost basis for existing studies can be clearly identified, and to highlight that not all publicly quoted 'CCS costs' can be compared on a like-for-like basis.

The aim of this work has not been so much to produce a 'cost', although the model can do this, but to stimulate the conversation around how the costs are produced. We encourage users to run the model and to provide constructive feedback on how the model can be improved. Please feedback your findings to www.sccs.org.uk.

8.2 WHICH COSTS ARE WE INTERESTED IN?

Fitting CCS to a commercial power station, whether integrated into a new-build plant or retro-fitted to an existing plant, incurs additional capital and operating costs. In assessing the cost of CCS, we are only interested in the incremental cost over and above a non-CCS plant with equivalent electrical output (see below). These are incurred in the following main areas:

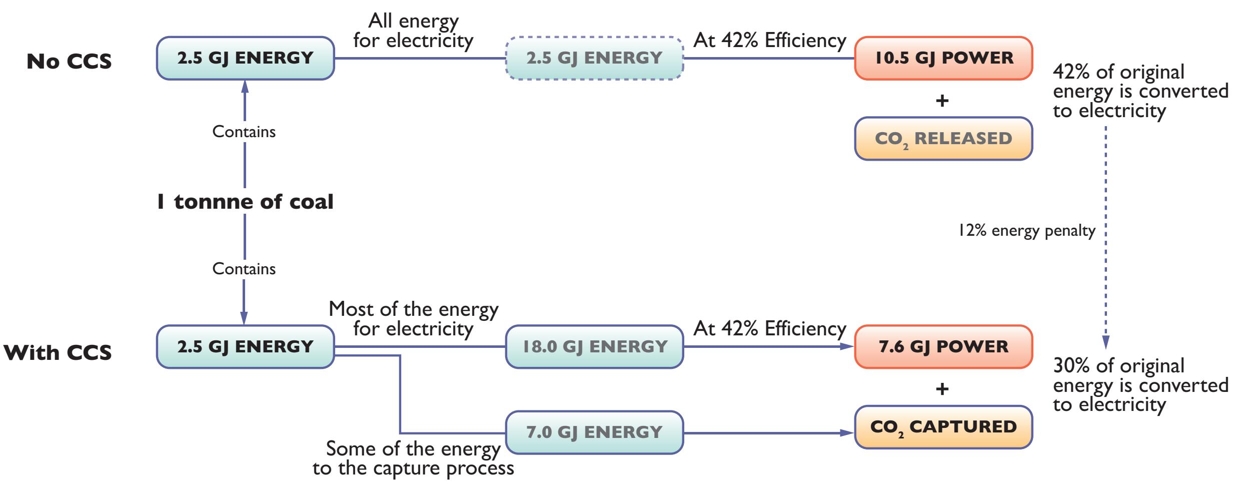
- CapEx: additional cost to scale-up the power plant, equipment for capturing CO_2 from the exhaust gases, compressors, CO_2 conditioning equipment, transport pipelines, wellhead infrastructure, and injection and storage infrastructure.

- OpEx: as well as the additional operating and maintenance costs for the capital items noted above, the single largest operating cost is the energy required to capture the CO_2 from the exhaust gases. This is provided by diverting some of the steam from the power station, which would otherwise be used to drive electricity-generating turbines, to the capture plant. This reduces the amount of electricity available for sale to the grid and is known as the efficiency penalty.

Efficiency penalty

The issue of efficiency penalty is easier understood with reference to an example:

One tonne of coal contains approximately 25 GJ of energy and produces approximately 2.2 tonnes of CO_2 when burned. The energy released from the coal is either fully sent to steam turbines and electricity generators (if no CCS is fitted), or split between the electricity generators and the capture plant (if CCS is fitted). In this example, fitting CCS reduces the electrical output of the station from 42% of the input energy in the coal, to 30%: a 12 percentage point efficiency penalty. See Figure 8.1 below.



Assumptions: 1 tonne of coal contains 25 GJ of energy and produces 2.2t CO_2 when burned. The CO_2 capture process requires 3.2 GJ / tCO_2 which equates to 7.0GJ / t coal.

Figure 8.1 Example of efficiency penalty for CCS

8.3 HOW DO WE DEFINE COST?

As with all major projects, the question of cost is not always straightforward. In the case of CCS, the way in which it is calculated depends on how the question is asked. In practice, this can be reduced down to two main scenarios:

Scenario A. 'As a power generator, I am planning to build a power station with a certain electrical output to the grid. What is the incremental cost I need to incur to fit CCS?'

or

Scenario B. 'As a power generator, I am planning to build a power station with a certain electrical output to the grid. By diverting steam and power to the capture process, I will reduce the amount of electricity I can send out to the grid. How much revenue will I lose?'

Scenario A requires additional capital costs to 'oversize' the plant and increased coal burn to produce the additional steam and electricity for the capture process; it is an 'additional cost' basis. This perspective is likely to be appropriate where CCS is legally required and the cost is an integral part of the investment case, i.e. a mandated solution.

In this case of Scenario B, the cost is the 'lost revenue' of not selling the power to the market. This perspective is appropriate where CCS is not legally required and it is purely an economic decision whether to fit CCS or not.

The query which naturally follows from (B) is: 'What would the carbon price have to rise to in order to persuade me to install CCS on this power station?', i.e. the free-market solution. It will only be financially worthwhile fitting CCS when savings can be made. More specifically, the market will choose to include CCS when the cost of emitting CO_2, based on the market price of carbon, is greater than the lost revenues.

For example, we assume that a power company is considering building a new coal-fired supercritical power station and requires a net electrical output to the grid of 1,150 MW. We also assume that the station efficiency is 42% without CCS, 30% with CCS, resulting in a 12% energy penalty, equivalent to 450 MW of power for the capture process. Whether we ask the question using scenario A or B above, we want to end up with identical stations in terms of electrical output to the grid, in order to isolate the incremental cost of CCS:

Scenario A: CCS is assumed to be legally mandated, so the station must be oversized by 450 MW. The cost of CCS is an additional 450 MW of capital and operating costs (including the fuel requirement and CO_2 permits) and the associated return on capital required for the investment.

Scenario B: CCS is assumed to be optional, so the decision to fit CCS is driven by the value of sacrificing 450 MW of revenue. This will be compared to the value of carbon emission permits (EUAs) saved, in order to determine whether fitting CCS is economically viable.

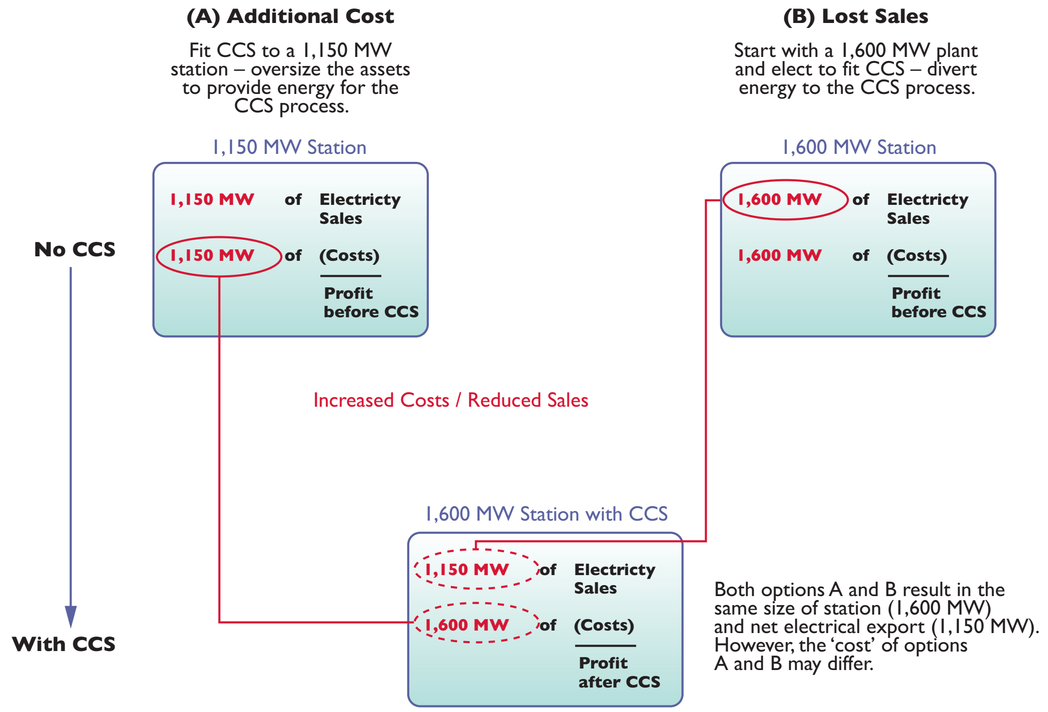


Figure 8.2 Costs of CCS for Scenario A (CCS is legally mandated) and Scenario B (CCS is optional)

Whilst the increased costs in option A may be similar in value to the lost sales in option B, this is not assumed. Additionally, the timing between additional costs (A) and lost income (B) differentiates the two options, resulting in significantly different cash flow profiles. As such, the choice of how to view the 'cost' of CCS is critically dependent on which option is selected.

8.4 MEASUREMENT UNITS

Once the cost basis (A or B above) has been established and the individual costs collated, there are a number of ways in which the total cost can be represented. The main variations to note, which may be implicit, or explicitly stated, in existing cost studies, are:

CO_2 captured vs CO_2 abated

These two terms are key in assessing and comparing the CO_2 benefit of CCS schemes. It is not as straightforward as saying that fitting CCS to a power station will capture, say, 90% of its CO_2. This ignores the fact that we have had to use a significant amount of additional energy to power the capture process. This energy comes from burning more coal, which produces additional CO_2. So fitting CCS actually increases the amount of coal (and therefore CO_2) required for each unit of electricity sent out to the grid, however, the bulk of the CO_2 is subsequently disposed of. The term 'abated' refers specifically to the net benefit to the atmosphere between: (1) a power station with no CCS, and (2) a CCS-fitted station with the same net electrical output to the grid as option (1). See Figure 8.3.

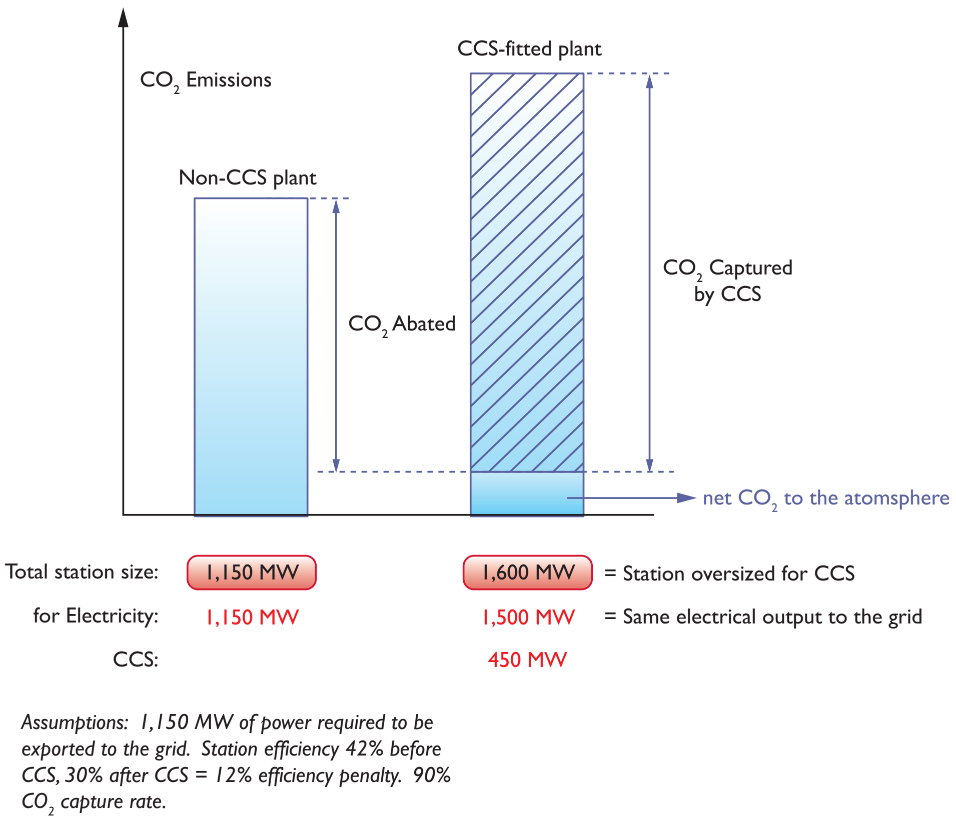


Figure 8.3 CO_2 captured vs CO_2 abated

Real vs nominal

Costs are generally expressed in today's money, without the effects of future inflation ('real costs'), so as to compare various different projects on a consistent basis. However, costs can also be shown including inflation, which will show the actual cash flows required for the project ('nominal costs') and are more commonly used for internal business plans and cash flow projections.

CCS cost per unit of electricity

CCS costs are generally quoted in £ per tonne of CO_2 (whether captured or abated), but are most relevant to consumers when linked to the price of electricity. The additional electricity 'cost' will be the incremental CCS costs in real terms divided by the volume of power produced. Alternative calculations may be used, but it is important to clearly identify these differences when comparing studies from different sources.

'Cost' vs price

It is worth noting that the cost of the additional items for CCS is not necessarily the same as the price which must be charged by a commercial operator. The principal reason is that a return on investment will be applied to the funding used to pay for the incremental costs. This will always be the case, as an investment decision to pursue CCS, in the context of building a new coal power station, is likely to be one of many different investment propositions competing for the same limited pool of capital. Thus, capital will not be diverted unless it satisfies the same return as other projects demand.

8.5 THE MODEL

As noted in the introduction to this chapter, a financial model has been developed to explore the cost of CCS in power generation. This model is designed to take a single set of input parameters, model as many of the scenarios and options discussed as possible and illustrate the range of different outputs, depending on which cost definition is used.

The model follows the general CASSEM project criteria, and as such is defined by the following core assumptions:

- A supercritical coal-fired power station with a post-combustion, fully integrated capture plant.
- Pipeline transportation, onshore and offshore.
- A single saline aquifer storage site, offshore in the North Sea.
- Point-to-point basis (single emitter, dedicated transport route, single storage site).

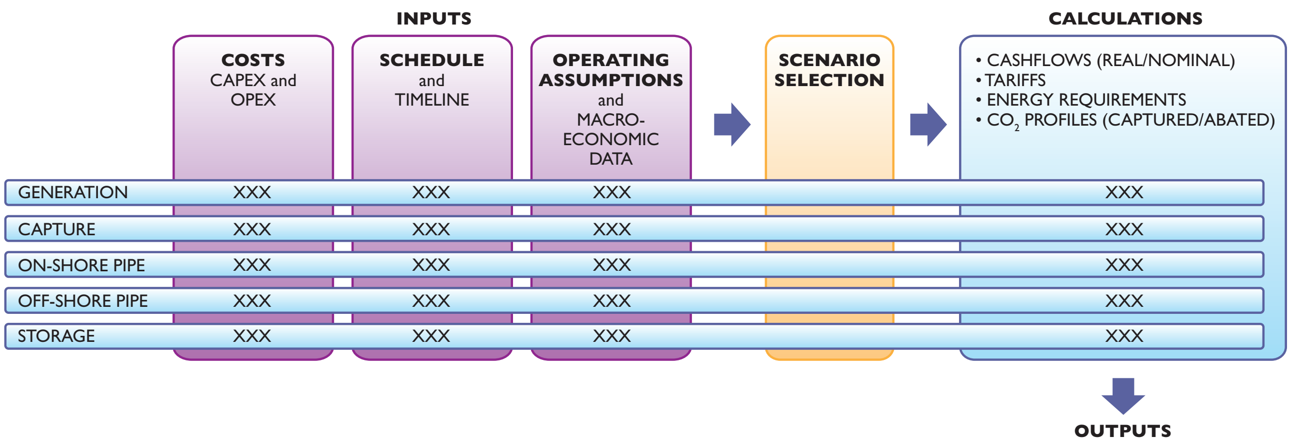


Figure 8.4 High-level structure of the financial model

No account is made of economies of scale which could be generated from networked transportation or storage.

As with all models, there are a number of assumptions inherent within the structure of the model, the way in which calculations are performed and the inclusion or exclusion of certain model drivers from the input and data schedules. Downloading and exploring the model is the best way to highlight these assumptions, so a detailed description will not be provided here.

High-level structure

The model is constructed in Microsoft Excel, is free from macros and is unlocked and unhidden. It is fully transparent and is designed to calculate the incremental cost of CO_2 capture, transport and storage using two principal costing bases (A and B, as noted above) and represent the outputs using a range of commonly quoted bases. The high-level structure is shown in Figure 8.4.

Discounted cash flows

The model is a discounted cash flow (DCF) model, in line with most corporate investment appraisal methodologies. Various macroeconomic factors are applied to the incremental costs of CCS to create a set of cash flows, inflation is added and a discount rate applied to these cash flows to take account of the required investment return. The resulting discounted cash flows will sum to give the net present value (NPV) of the project. All values are pre-tax and shown in £real (i.e. in today's money, excluding inflation) and £nominal terms (actual cash flows, including inflation).

Tariffs

Tariffs are calculated for each element of the CCS chain to determine the level of income required to cover all costs, including the cost of finance, for that element. The total of all tariffs is effectively the total price of implementing the full CCS scheme and is probably the most realistic basis for 'cost', as delivered by the private sector.

The income in each year is calculated as follows:

$$\text{Income} = \text{Tariff} \times \text{Inflation factor (if CPI-linked)} \times CO_2 \text{ volume} \qquad (8.1)$$

When this discounted income stream exactly equals the discounted cost profile, there will be a zero NPV. This indicates the tariff required for the project to achieve the target rate of return (being the discount rate input to the model). This is effectively the hurdle rate which a developer would need in order to take on the capital project.

Data sources

The purpose of the model is to stimulate the debate around 'how' the cost of CCS is calculated, not necessarily to produce a definitive number. However, in order to provide a starting point, the model has been pre-populated with some publicly available data. The sources are noted in detail in the model and accompanying paper. The principal items are:

- Commodity price forecasts from the Ofgem 'Project Discovery – Energy Market Scenarios paper', 'Green Transition' scenario, published Oct 2009.
- Capital Costs from the Mott MacDonald 'UK Electricity Generation Costs Update', June 2010.
- Discount rate assumed at 10%, and inflation at 2%, in line with the Bank of England target.

Key drivers and uncertainties

There are a number of areas which pose particular challenges, either in terms of absolute cost, or in terms of cost uncertainty. The two key areas are:

Energy requirement for capture. This is the largest operating cost in the full CCS chain and is dependent on the efficiency of the amine in the capture process. The industry base case is generally regarded to be 4.2 GJ per tonne of CO_2 captured, based on a widely available 'MEA' amine. However, developments over the last few years have brought the energy requirement down and research is continuing to develop even more efficient chemicals. The energy requirement also determines the extent to which the station must be 'oversized' to provide the capture plant with its power, so improvements in amine efficiencies not only reduce the operating costs, but also reduce the upfront capital requirement and ultimate power station and capture plant size.

Storage CapEx. It appears that one of the areas of highest cost uncertainty is in offshore operations. The drilling of test and production wells in the North Sea is an expensive business and total CapEx is likely to stretch into hundreds of millions of pounds for a fully operational storage site. Each target saline aquifer has specific characteristics which determine the flow rate that each well is capable of receiving. Whilst estimates for total flow rates can be made, there is a risk that these cannot be fully verified until injection actually begins. The results of initial injection could result in a number of additional wells being required, further impacting capital costs.

Application

As the model is fully unlocked and editable, the user can input whatever values are believed to be appropriate. Thus, the model can be used to estimate the cost of CCS, using data for technology available today, or to prepare estimates based on assumptions about how those costs and factors will develop into the future. For example, future amines could reduce the energy requirement for capturing CO_2 and simply updating this input value will illustrate the effect on the entire CCS chain.

CHAPTER 9
PUBLIC PERCEPTIONS OF CARBON CAPTURE AND STORAGE

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9.1 INTRODUCTION

Carbon capture and storage (CCS) is widely mooted as a key technology in the fight against climate change and one which will be widely deployed. That said, there has yet to be a commercial-scale demonstration plant which links CO_2 capture from a fossil-fuelled power station with the transport and long-term storage of the CO_2.

The assessment of public perceptions of CCS will form a vital part of any future development of CCS and was identified as having a moderate risk score (Chapter 6). For example, Vattenfall's Schwarze Pump project in Spremberg, northern Germany, was planned to be the first fully operational CCS plant, but has failed to obtain a storage licence for the captured CO_2 due to substantial local opposition. This demonstrates to those looking to deploy CCS, or develop the policy framework within which deployment will take place, the impact of social opposition on the implementation of CCS and the important role that public perceptions of the technology will play.

The CASSEM project research sought to assess the lay public's reaction to CCS and how perceptions change as they learnt more about the technology and the wider issues around energy and climate change. Continuing with the CASSEM focus on distinct geographical assessments, the research explored public perceptions of CCS in Dunfermline on the Firth of Forth and Pontefract, West Yorkshire. Both locations are in the vicinity of coal-fired power stations, which in the future could be fitted with CCS technology, as well as being located in regions of the UK that are at the forefront of the UK CCS agenda.

Approach

Anticipating the social response to a technology such as CCS, which currently has a low level of public awareness, is difficult; CCS is a relatively technical and remote concept with few points of connection for lay people to use as a frame of reference. Perceptions of CCS are very much dependent on how much people know about CCS and their wider understanding of the climate change contexts within which CCS is being discussed (Shackley et al., 2004; van Alphen et al., 2007). Consequently, research through traditional social science methods such as interviews and questionnaires is unlikely to provide an accurate picture of public perceptions. To overcome this, this study used a series of citizen panels to explore public opinions and provide participants with information about CCS and the wider context for its deployment.

Participants met for a total of ten hours, over the course of which experts from the CASSEM consortium presented information on CCS; they also received written briefing notes (Figure 9.1). The presentations focused on climate change and energy generation, CCS technology, CO_2 storage and risks associated with CCS. Plentiful opportunities were provided for participants to discuss CCS with the experts, and small facilitated discussion groups ensured that everyone had the opportunity to be heard. In addition, the participants were asked to give feedback on the information they had been provided and comment on the citizen panel process.

Specifically, the study aimed to:

- Establish how much knowledge members of the public had about CCS prior to taking part in the citizen panel process. This was assessed through a pre-workshop questionnaire.
- Gauge initial reactions to CCS when people first hear about the technology. Such reactions would be similar to those felt by someone reading of CCS in the newspaper, for example.
- Explore in more detail specific concerns the participants have about the technology and how these change as they are provided with more information, both about CCS, and the wider energy and climate change context for deployment. Of interest were concerns related to each element of the CCS chain, namely capture, transport and storage.

- Identify the factors that are the most influential in shaping the participants' perceptions of the technology.
- Identify strategies which could be applied in the future to address public concerns about CCS.

The chapter will now present the results of each element of the research, focusing on each area in turn.

Figure 9.1 Public engagement at Pontefract

9.2 RESEARCH PARTICIPANT'S PRE-WORKSHOP KNOWLEDGE OF CCS

The results from the questionnaires strongly supported the findings of other studies and demonstrated that awareness of CCS amongst our sample was very low. Prior to taking part in the citizen panels, the majority of respondents had little or no knowledge of CCS. This is to be expected, given that CCS was not prominent in the local media and people generally had little contact with their local power station. Furthermore, when first introduced to the idea of CCS and without any further information, 60% of the participants in both case studies didn't feel they knew enough about CCS to be able to form an opinion (see Figure 9.2). However, it was clear that the participants were interested in the subject, keen to learn and to be consulted on proposals related to CCS.

The results of other studies into public perceptions of CCS highlight the important relationship between public acceptance of CCS and their perceptions and knowledge of climate change. Thus, Shackley et al. (2006) conclude that for people to accept CCS, they have to accept the need to take action to mitigate carbon emissions. The pre-workshop questionnaire also sought, therefore, to assess how much our participants knew about climate change and suggested that a high proportion of the participants accepted that humans were having an impact on the climate (85% were either concerned or very concerned). That said, subsequent discussions revealed that opinions were much more divided. Although there was an overall consensus that the climate was changing, many participants questioned both the extent to which this was a consequence of human activities and the reliability of the evidence, with many people feeling that they were extremely ignorant about the issues involved.

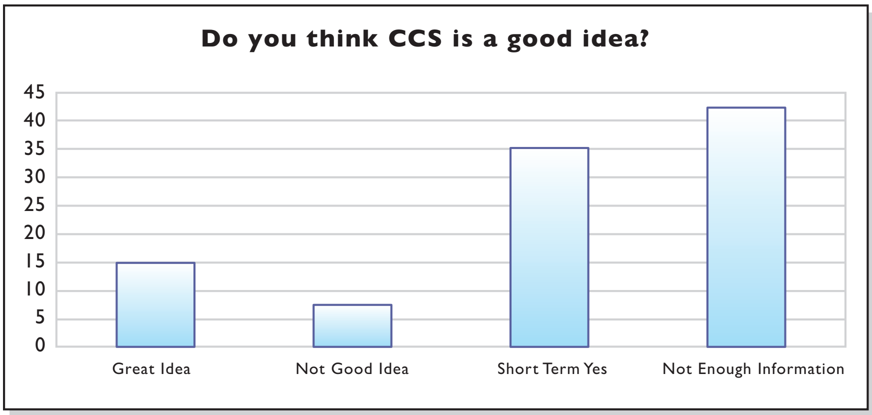

Figure 9.2 Initial thoughts about CCS

Another strong theme which emerged in both panels was the extent to which people are tied in to high-carbon lifestyles, which they are unwilling to give up, particularly to avoid uncertain impacts. The participants were, however, able to identify changes they perceived as happening as a result of climate change, the most cited examples were more extreme weather, e.g. storms or higher temperatures, and seasons becoming less defined weather-wise. However, there was a consensus that these changes were not yet having a major impact on people's quality of life so they were unwilling to act upon them. Furthermore, a number of participants questioned whether people would be willing to make big changes to their lifestyles, even if the effects of climate change were more obvious. That said, the respondents in Pontefract, in particular, appeared to recognise that they might have to change their behaviour as a result of the effects of climate change. For example, the recent floods in parts of Yorkshire had prompted people to think about the flood vulnerability of their homes.

9.3 HOW DID THE PARTICIPANTS REACT WHEN FIRST INTRODUCED TO THE IDEA OF CCS?

Many authors describe how we are now living in a 'risk society' where we are becoming more preoccupied with the future (and safety); the perceived risks of a new technologies are often a far greater threat, financially, politically and socially than the original physical threat (see, for example, Giddens, 1999; Beck and Kropp, 2007). Consequently, people's initial response to a new technology or phenomenon is often dominated by concern, and this was the case for the citizen panel participants when first introduced to CCS.

It was very clear that the participants' initial reaction to CCS was one of scepticism and they were unable to offer their support or otherwise to the technology before they understood more about it. At this stage, the vast majority of questions related to the risks associated with CCS, and in particular the implications of CO_2 leakage, either during transport to the storage sites or once it had been injected. The participants were keen to know more about what would happen if the CO_2 leaked? Would it be a danger to human health? How can we be sure it won't leak? What happens if there is an earthquake? How do we know the CO_2 will remain stable for thousands of years? Reservations about the long-term storage of CO_2 also sparked off debates about the ethics of long-term storage, with a number of people expressing the view that we would be storing up problems for future generations.

Although, as described, the majority of questions were highly rational, others were less so and demonstrated the participants' lack of understanding of the science behind the technology and the nature of CO_2. For example, a number of participants independently asked 'what happens if it explodes?' or 'why can't we just send it into space?' Furthermore, participants made reference to more familiar technologies to use as a starting point from which to construct their ideas about the risks associated with CCS. For example, the comparison was made between the storage of CO_2 and the disposal of nuclear waste, without considering the difference between the two substances.

In addition to the concerns about the physical risks associated with CCS technology, the participants appeared to be as concerned (and in some cases more concerned) about the financial, regulatory and governance implications of deployment. In particular, they were highly sceptical of the government's ability to put in place a regulatory framework to ensure both the safety and financial viability of the industry in the long term.

It is interesting to note that the questions about the risks associated with CCS came up at such an early stage of the process with many of the participants questioning the safety of the technology before they asked more detailed questions about how it worked and why it was necessary. That said, this initial reaction is not unexpected given society's concern over risk and safety, and highlights the importance of the provision of transparent, accessible and comprehensive information about CCS.

9.4 WHAT SPECIFIC CONCERNS DID THE PARTICIPANTS HAVE ABOUT THE TECHNOLOGY AND HOW DID THEY CHANGE AS THEIR KNOWLEDGE INCREASED?

The initial concerns outlined above formed the basis of the expert presentations, to ensure that panel participants were given information that answered their questions. The technology presentation was focused on the locality, thus CCS technology was placed in the context of the local coal-fired power station, including safety, scale, employment and so on. CCS was also set within the UK's current generation mix and the need to meet challenging climate change targets whilst maintaining energy security and affordability.

Once concerns about safety had been addressed by the experts, the participants started to ask questions about why the technology was necessary. There was little disagreement with the need to develop low-carbon energy technologies; however, several people asked why we couldn't just rely on renewable technologies. This line of discussion indicated that the participants were struggling to get to grips with the extent of the emissions cuts required to meet climate change targets and the current capacity of renewable technologies. This suggests that if the public is to accept that CCS represents a viable option for reducing CO_2 emissions, it has to be set within the context of climate change and our current and future energy needs. The importance of framing low-carbon technologies, particularly the more controversial technologies such as nuclear, or the emergent ones, such as CCS, within a broader picture of climate change has been highlighted in a number of recent studies. Fears about climate change have persuaded many people who were previously anti-nuclear to reluctantly accept the need for the technology in light of the challenges posed by climate change (Bickerstaff et al., 2008; Poortinga et al., 2006).

The risks associated with new technology are usually characterised by high complexity, uncertainty related to the technology and a confused regulatory system, which can easily lead to the public making assumptions and developing perceptions with little basis in scientific fact. The more obvious it becomes to the lay public that there is a level of uncertainty associated with a new technology, the more influence accrues to the perception of risk and, eventually, the distinction between real risks and the perception of risk disappears (Beck and Kropp, 2007). Lay perceptions of a particular risk are also highly influenced by the level of understanding of the technology concerned and level of trust in the sources providing information. Thus, when we consider public perceptions of CCS, we must not forget that these may be influenced by factors other than scientific information; in particular, the extent to which that information is trusted, and how useful and necessary the technology is judged to be.

The results from the citizen panels showed that as the participants learnt more about CCS their concerns evolved; these changes can be clearly seen in the flow chart (Figure 9.3). As previously highlighted, their initial questions related to the potential risks associated with the technology. The majority of these concerns were addressed by the experts through their presentations and the question and answer sessions. However, the concerns related to the government's ability to establish an appropriate financial and regulatory structure, within which CCS would be governed, remained.

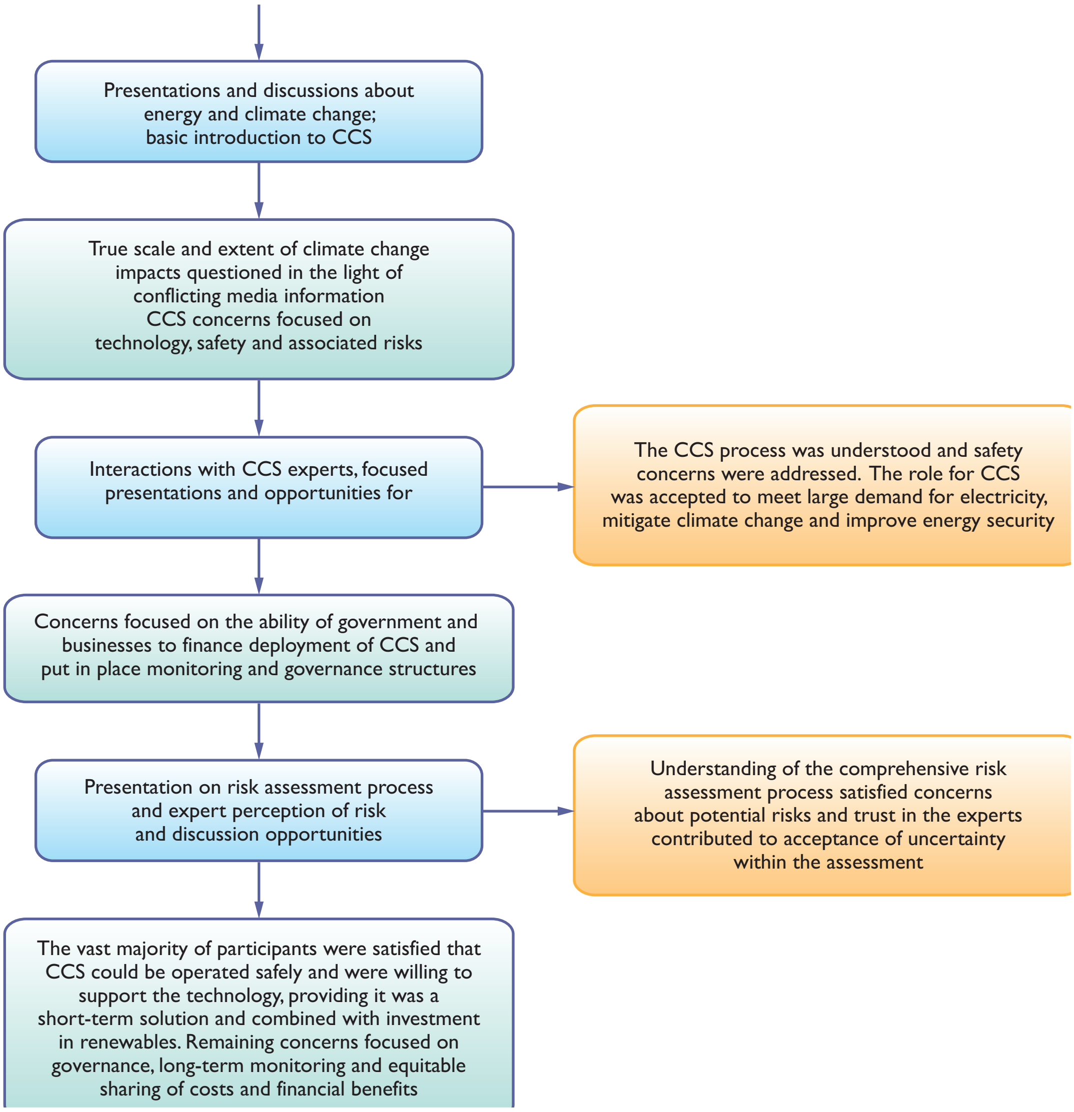

Figure 9.3 Evolving perceptions of CCS

It appeared that although participants were willing to trust the information provided by scientists and those directly responsible for implementation of the technology, they were less willing to trust the government to oversee implementation. The trust in the engineers and managers from within the CASSEM consortium, showed the importance of the interactions between panel participants and the experts. The pre-workshop questionnaire suggested that participants were highly suspicious of information produced by the government and industry. Prior to the start of the process, only 20% of respondents trusted or strongly trusted the government and even less, 12.5%, trusted industry, compared to 57.5% who said they trusted or strongly trusted scientists, and 80% trusted or strongly trusted academic articles.

A further issue, of particular importance in the Scottish case study, was the need to ensure that local people benefitted from the deployment of CCS in their locality. Using the example of the development of the offshore oil industry, there was disagreement amongst participants as to the extent to which Scotland had benefited from the resource, and a determination that CCS should benefit the locality.

The participants made it very clear, both in the post-workshop questionnaire and the discussions, that they found the presentations and particularly the opportunity to ask questions far more useful to help them form an opinion on CCS than the printed material. Their lack of knowledge about the technology meant that they found it difficult to evaluate the latter as they did not have either the expertise or resources to verify its accuracy. However, the opportunity to meet experts face to face and question the information they were given, allowed them to ask for clarification on areas of concern and enter in to a two-way dialogue with the experts. Through this process they were able to assess the level of competence of the experts and, importantly, evaluate whether they thought they were a trustworthy source of information.

The question and answer sessions which followed the presentations on the different aspects of the technology, capture, transport and storage, highlighted the impact of uncertainty on public perceptions of CCS. As previously discussed, the emergence of a 'risk society' has led to concerns about safety dominating public perceptions. Furthermore, as Beck and Kropp (2007) note, the consequences of the perceived risks increase when there is a high level of uncertainty associated with the risk in question. Many of the participant questions were focused on the level of certainty that various aspects of the technology, particularly related to storage and monitoring of the CO_2, were safe and would actually work.

The small group discussions which followed the presentations revealed that by and large the experts had successfully built up a good rapport with the participants, who felt they were experts in their fields and a trustworthy source of information. Participants were reassured by learning more about the frameworks used to evaluate risk from storage of CO_2 in saline aquifers, although it was unclear to what extent the participants were able to evaluate the technical information related to specific risks from CO_2 storage. However, they were able to see that the process was highly rigorous and comprehensive. A few concerns did remain about the level of uncertainty associated with CCS, especially in relation to the storage aspects and over who would make the final decision concerning an acceptable level of risk.

9.5 WHAT SHAPES PERCEPTIONS OF CCS?

Two factors appeared to be particularly important in the development of public perceptions of CCS. Firstly, the extent to which the participants deemed the technology to be useful and necessary and, secondly, the extent to which they trusted the information provided on the potential risks associated with the technology.

Studies exploring public perceptions of new technology reveal a direct correlation between how useful or necessary the technology is deemed to be and the level of risk associated with it (Frewer et al., 1998). In terms of climate change mitigation technologies, this suggests that if the public accepts the notion that human activities are causing climate change and that there is a need to find alternative low-carbon technologies, they are likely to form a more generous perception of the potential risks associated with CCS.

Moving on to consider the second point, the evidence from the present study, and others, into public perceptions of CCS highlights a lack of understanding amongst many members of the public regarding both climate change and CCS. Consequently, it has to be assumed that due to the lack of knowledge, most people will not directly assess the risks and benefits associated with CCS, but will rely on information provided by experts. However, experts are not necessarily a homogeneous group and will often differ in their assessments of the technology (see, for example, Sjöberg, 1998 or Siegrist and Cvetkovich, 2000). Since people will not necessarily be able to assess the pros and cons of different sources of information, on the basis of the information itself, judgements are likely to be made on the basis of social trust (Earle and Cvetkovich, 1995; Luhmann, 1989). Essentially, social trust refers to the processes people use to reduce the complexities surrounding the formation of a perspective on new technology or other potentially risky innovation.

Siegrist et al. (2000) argue that social trust simultaneously influences both perceived risks and perceived benefits. For technologies such as CCS the associated risks and benefits are not directly visible; therefore, people rely on information provided by experts, and ultimately will make a decision on the basis of how much they trust that expert. Consequently, it is necessary to consider the way the public make decisions regarding what they consider to be a trusted source of information.

Since the 1950s psychologists have been investigating the factors which make people trust or distrust risk, regulatory or other institutions. In very general terms, Rousseau et al. (1998:395) argue that trust, as conceptualised across a number of disciplines, can be defined as 'a psychological state comprising the intention to accept vulnerability based upon behaviour of positive expectations of the intentions of or behaviour of another'. In many studies exploring trust in the context of new technology, the perceived competence of the expert was reported as the most important factor in determining the extent the public trust experts (see, for example, Renn and Levine, 1991 or Kasperson et al., 1992). During the citizen panels it was clear that the initial concerns about the technology were, by and large, addressed by the experts through the presentations and question and answer sessions. This suggests that the participants perceived the experts to be competent and therefore should be trusted. It was very apparent from the small group discussions that the participants' willingness to trust the experts had primarily developed from the opportunity to interact with them face to face. It would have been significantly harder for the experts to demonstrate their expertise and develop the trust of the participants through other mediums such as printed material.

9.6 WHAT ARE THE KEY PUBLIC CONCERNS ASSOCIATED WITH CCS AND HOW MAY THESE BE ADDRESSED?

By the end of the citizen panel process there remained few concerns focused on CCS technology itself. Storage emerged as the part of the CCS chain which raised the most concerns, with the potential for leakage the greatest concern. That said, the trust in the experts was such that the risks would be accepted.

The greatest areas of concern focused on the political, financial and governance aspects of CCS. How could safe monitoring be ensured over hundreds of years? What are the costs and benefits of developing CCS and how could these be distributed in a fair manner? Interestingly, the post-workshop questionnaire revealed that 75% of people now thought that the costs of CCS should be shared between industry, the public and government, compared to 55% before the workshop. Furthermore, 67% of people would also be prepared to pay between £3 and £5 per month more on their electricity bills to fund CCS.

There also remained lingering unease over the appropriateness of CCS as a climate change mitigating technology, primarily because it is an 'end-of-pipe' solution. People had a more instinctive acceptance of renewable energy which did not create CO_2 in the first place, and were worried that CCS research would take resources away from renewables. The last point highlights the importance of CCS being set in a wider climate change and energy context, particularly the scale of the emissions reduction needed. This also brings to the fore the confusion many people experience when trying to decide for themselves the extent to which man influences the climate, and the potential impacts. With little direct experience of climate change and much conflicting information, particularly on the internet or in the media, it is very difficult for some panel members to know what to believe or who to trust. The participants appreciated the honest approach taken by the experts, who willingly acknowledged the uncertainties related to the potential impacts of climate change.

The results from the post-workshop questionnaire demonstrated that the citizen panel process was an effective way to communicate information about CCS to the public. As Figure 9.4 shows, after taking part in the citizen panels all of the participants had an opinion on CCS, whereas prior to the workshops over 40% didn't feel that they had the necessary information to form an opinion. Furthermore, the vast majority agreed that CCS was at least a good idea as a short-term solution until alternatives to fossil fuels can be brought on stream. The citizen panel format, with experts on hand to answer questions in small discussion groups, was a crucial factor in the assessment of CCS. Due to the low levels of knowledge about CCS it is clear that any wide-scale deployment of CCS has to be accompanied by a programme of public engagement, particularly in areas which will be impacted first hand by the technology. The acceptance of CCS demonstrated from the CASSEM work is in contrast to other studies where a short documentary about CCS was used to structure focus group discussions on CCS. Experts were not on hand to answer questions and many of the participants appeared confused about CCS and left with generally negative opinions of the technology. Consideration needs to be given to appropriate approaches to public consultation and engagement which move beyond the simple provision of information in a pamphlet or public meeting.

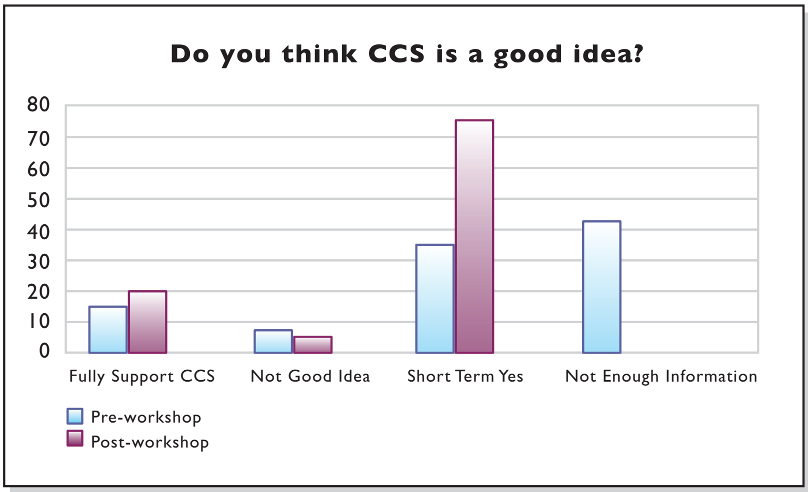

Figure 9.4 Opinion on CCS

It is crucial that information provided to the public should be as clear as possible and without bias. One example of where we could have provided clearer information to the participants related to the description of CCS in the questionnaire as 'a short-term solution', without properly clarifying how we defined 'short-term'. This highlighted that while the experts defined CCS as a short-term solution to be used for the next 100 years, many of the participants defined the impacts of climate change as long-term, even though the timescale is shorter than 100 years. There was also some concern from the participants that we were not providing all the available perspectives on CCS as none of the expert witnesses represented environmental NGOs.

The participants felt that CCS was a topic on which they should be consulted and appreciated the opportunity to voice their opinion. They responded well to the bottom-up – public engagement approach – rather than a top-down public relations exercise. There was a general consensus that they appreciated being informed about CCS and asked for their opinion rather than simply being told what was going to happen.

The results from both the discussions and the post-workshop questionnaire showed that the participants particularly valued the opportunity to engage with the experts and ask questions, while they were less keen on the written material. Although it is clear that embarking on a large-scale public consultation process through face-to-face interaction with CCS experts presents significant challenges, the approach shouldn't be completely dismissed. The post-workshop questionnaire revealed that the vast majority of the participants planned to discuss the information they had received at the workshops with friends, family and work colleagues, providing significant opportunities for the social transmission of knowledge. Furthermore, providing adequate resources are available, deliberative processes such as citizen panels can be organised for several hundred people at a time.

9.7 SUMMARY

This chapter has outlined the public perceptions work undertaken by Tyndall researchers as part of the CASSEM project. CCS is an emergent and unfamiliar technology, so a citizen panel format was used to familiarise people with the technology whilst gaining an understanding of their perceptions of CCS through facilitated discussions. Given the low levels of awareness of CCS, it is not surprising that people have yet to have defined views of the technology. However, the participants made it clear that climate change and energy generation were issues which they considered to be important and about which they should be kept informed and consulted upon. When first introduced to CCS the participants' initial concerns focused upon safety and risks, particularly from the storage of CO_2. The research demonstrated, however, that through discussions with experts many of these concerns can be overcome. Furthermore, it was also revealed that trust in the experts represents the most important factor in the acceptance of risk.

Harder to allay are concerns related to governance, regulatory and financial aspects of CCS deployment; particularly as many of these concerns were brought about by the participants' perceptions of the government's ability to manage large projects unrelated to energy generation. However, these issues may be overcome through mechanisms which distribute the benefits, as well as the costs, of the technology fairly, to ensure that there is local benefit as a result of CCS deployment.

Climate change and energy policy often seems remote to people's lives, and given that emissions reduction is the primary motivation for deployment of CCS, it is crucial that schemes are set in the wider context of energy and climate change, and that this is made real to people. Trust in government and institutions is generally low, particularly at national and international scales, thus, an appropriate monitoring and regulatory regime, implemented independently of government, is also an important aspect of acceptance of CCS.

Although the citizen panel format was used for research purposes, it successfully disseminated information on CCS and allowed local voices to be heard. Rather than relying on top-down public relations exercises, those looking to deploy the technology should focus on participative and deliberative engagement, which can help to build acceptance of CCS.

CHAPTER 10
CONCLUSIONS

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By 2020 over half of the UK's electricity generation will continue to be fuelled by coal and gas. CCS technology has the potential to significantly reduce CO_2 emissions from fossil-fuel power stations and is therefore now a crucial element of the UK government's energy and climate change agenda.

The methodological approach adopted by industry and the regulators to CCS storage is strongly influenced by the level of knowledge of the subsurface. Whereas existing oil and gas operators and hydrocarbon service companies have extensive knowledge of the subsurface, new entrants to CCS, such as power companies and transport operators, do not. One of the defining differences is the acceptance of uncertainty.

A power company which operates surface assets will have well-established project development processes that feed into investment decisions based on their acceptance of uncertainty. For example, they will have very high levels of confidence that a new-build power plant will deliver the power output required. This view of uncertainty is fundamentally different from existing subsurface operators where their project development cycle accommodates for high levels of uncertainty. Hydrocarbon operators will typically accept that boreholes are drilled, with costs in excess of tens of millions (£, $ or €), which will not result in producing hydrocarbons. Given that a power company will operate at one end of the CCS chain and a subsurface operator at the other, this highlights the need for entry paths and understanding along the whole CCS chain.

The CASSEM project was therefore funded to develop a pathway to inform and de-risk investment decisions for new entrants to CCS in the subsurface and in the identification of suitable formations to store CO_2.

The value of interaction within a workflow and, ultimately, the uncertainty of subsurface operations is well illustrated, for example, by the work that was carried out on the Firth of Forth. The initial geological interpretation indicated that there was a small but usable storage structure and the CO_2 flow modelling that had been carried out in Phases 1 and 2 of the flow simulations supported this view. However, doubt remained with regard to faulting from the seismic interpretation. The original seismic data was reprocessed using current processing tools and then reinterpreted. The improved seismic data changed the interpretation of what had been assumed to be faults to be more confidently identified as tightly folded layering. This reinterpretation increased confidence in the site and follow-up testing of the relative permeability of the aquifer rocks was carried out. This testing, however, revealed very low relative permeability values, impacting on the injectivity and making it an unrealistic storage proposition. This information would have been invaluable to a new-entrant store developer in halting further investment in an unsuitable formation

The CASSEM project combines a 'conventional' geosciences approach to CCS, sets this in context and recognises external influences (e.g. costs, transport, etc.) on CCS deployment. The approach can be summarised in the following three questions:

- Will there be sufficient public support for the CCS deployment?
- How can the risk and uncertainty be framed?
- How should this deployment be costed?

To address the issue of public support, the CASSEM project included work on public perception; unsurprisingly, this work identified that the public understanding of CCS, and of climate change, was very low. Significantly, it demonstrated that by providing the public with unbiased information on climate change and how it could be mitigated, and providing access to credible experts that they could discuss the issues with, people could understand where CCS fitted and through that understanding were supportive of the potential of having a CCS scheme relatively close to where they lived.

Many projects contain an element of risk management; the CASSEM project went beyond that, using a risk and uncertainty work package to manage our own project risk. Within the project there was a budget allocated to obtain data for the other work streams, and it would have been simple and uncontentious to allocate those funds to each of the work packages on a pro rata basis to carry out the additional experimental work. Instead, the risk and uncertainty FEPs approach was used within the project, for each of the exemplar sites, and, using this approach, the areas of greatest uncertainty were identified and a data acquisition activity undertaken to reduce that uncertainty.

There are several cost models produced for a CCS deployment. The CASSEM project has produced a financial framework to allow that costing of a CCS deployment. The CASSEM financial model is not just intended to produce a cost per tonne of CO_2 emitted, but rather proposes a transparent method for calculating that cost. This model has been published with the expectation that it will be challenged, and through that, develop into a web resource available to the wider CCS community. We hope that this will allow CCS to be judged on an equal footing with other climate change mitigation strategies.

Through the development of the CASSEM project, new insights and scientific knowledge have been gained. The real benefit, rather than the sum of the constituent parts, lies in the linkages between the work streams and the application of an 'asset team' approach to subsurface development.

The individual insights and new knowledge that has been created as a result of the CASSEM project are summarised below as a series of value headlines.

HEADLINE OUTPUTS OF THE CASSEM PROJECT:

- Provided an interface between process facilities design and the reservoir
- Demonstrated the importance of an 'asset team' style approach
- Identified a first response toolkit for the evaluation of geological structures for their suitability to store CO_2
- Demonstrated the benefit of reprocessing and reinterpreting vintage seismic data
- Was the first UK hydrogeological assessment of CCS impact on multiple-use saline aquifers
- Defined well locations and numbers – for given injection volumes, the work accounts for the impact of rock mechanics in determining the number of wells required
- Demonstrated the benefit of using natural analogue samples as proxies for a saline aquifer at depth. One site used actual cores and the other natural analogues; this allowed a discussion of relative merits and disadvantages of the two approaches
- Experimentally derived relative permeability measurements from analogue samples – these were fed into the geomechanical modelling and proved to have a significant impact on injectivity
- Defined the benefit of mobile CO_2 resulting in greater residual trapping and dissolution
- Identified the key sensitivities for flow simulations for both sites and confirmed that they were the same, despite significant geological contrasts between the two sites
- Reinforced the importance of obtaining cores from cap rock (not only from the target reservoir formation) for laboratory characterisation studies
- Confirmed that the topography of the top of the saline aquifer has a significant effect on the migration of CO_2, and thus highlights the need to have a reliable geological model.
- Produced a definition of 'monitorability' of a storage site
- Demonstrated that the use of electromagnetics for monitorability requires knowledge of the resistivity of the underburden as well as overburden
- Carried out assessment of the monitorability of the site using different geophysical methods, and used this information to design an optimal suite of monitoring methods
- Used Features, Events and Processes (FEPs) risk assessment to track experts' evolving perception of risk for each site
- Used FEPs to identify additional tasks (case studies), most critical to reduce risk. The FEP analysis was used to select a number of tasks that were then carried out to reduce the uncertainty around exemplar sites
- Developed integrated injection strategies suitable for use in enhancing sequestration of CO_2 in deep geological formations
- Produced, for the first time, an open-source CCS costing model that is both flexible and accessible
- Pioneered the use of citizen panels to assess public perception of CCS around locations which may be used for CCS in the future

Next steps

The CASSEM project partners now plan to apply and develop the derived methodologies to test the viability of a multi-user store offshore of the UK. This will be the intended CASSEM 2 project and will aim to take a CCS storage prospect up to the stage where high-cost offshore activity can be undertaken with an understanding of the associated risk. This offshore activity will then form the final stage, CASSEM 3, proving a CCS store by drilling.

CASSEM PROJECT LISTING OF OUTPUTS

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GLOSSARY

A

Activated methyldiethanolamine capture: is a chemical engineering process licensed by BASF that is used to separate CO_2 from a natural gas stream.

Aeolian sandstone: sandstones produced by the movement of sand grains by wind power.

Anchoring and adjustment bias: is the tendency for people to 'anchor' a numerical judgement to some initial estimate of its value. In the light of new information they tend to adjust their initial estimate, rather than re-evaluate the situation from scratch, resulting in a bias towards the initial 'anchor' value where they do not adjust sufficiently.

Angle of internal friction: the slope of the Mohr-Coulomb envelope. A measure of the ability of a unit of rock or soil to withstand a shear stress. It is the angle (φ), measured between the normal force (N) and resultant force (R), that is attained when failure just occurs in response to a shearing stress (S). Its tangent (S/N) is the coefficient of sliding friction. Its value is determined experimentally.

Anticline: a folded formation of stratified rock that is convex up and has its oldest beds at its core.

Aquifer: an underground layer of water-bearing permeable rock or unconsolidated materials (gravel, sand, silt, or clay) from which groundwater can be usefully extracted using a water well.

Attenuation (1/Q): inverse of Q. The loss of energy or amplitude of waves as they pass through media.

Availability bias: results from the use of heuristics to judge the likelihood of an event. Instead of using the recollection of the number of similar events and their frequency to judge the probability of a future event, people tend to use ease of recollection as a short-hand for frequency. This can lead to bias with more recent or memorable events judged as more likely than more distant or hard to recall events.

B

Blind flange: this has no bore, and is used to close the ends of piping systems. There is no opening for the passage of fluid (water or brine).

Borehole Total Measured Depth: the actual distance measured along the axis of the borehole from the rig kelly bushing to the depth of maximum penetration of the well.

Bottom hole pressure: the pressure of the reservoir or formation at the bottom of the hole or well.

Boundaries: the boundaries of the model will depend on what data is available, and on what the region of influence of the proposed CO_2 injection will be. Because the boundaries must be defined early in the process, perhaps before the region of influence is identified, a conservative approach of gathering data over a wide area should be adopted. During the latter phases it may be possible to focus in on the zone of interest, if required, whereas expanding the region to be modelled would prove much more difficult. The model boundaries may be quite different during the construction of the static geological model, compared to the dynamic flow simulations. Since pressure calculations do not need to be made using the geological model, it is expected that the static geological model will always be greater than or equal to the dynamic model in extent.

Geological model boundaries
There are a number of reasons for discontinuities in physical features of the subsurface, and these may be used as boundaries for the geological description. They include:

- Available geological data (e.g. seismic)
- Potable aquifer
- Hydrocarbon field
- Outcrop to land surface or seabed
- Impermeable overburden
- Impermeable underburden
- Faults
- Pinchout

In general, the available geological data will contain information on most of the other features listed.

Dynamic simulation model boundaries
When building dynamic flow models, choices have to be made about grid size and resolution. The edge of the grid is classed as the boundary of the model. By default, this boundary will be treated as a barrier to flow, i.e. an assumption is made that the model is surrounded by impermeable rock. However, if in reality there is permeable rock in pressure communication with an edge of the model, flow across the boundary can be simulated by a number of approaches:

- By attaching a numerical or analytical 'aquifer'. A single permeability and a single volume can be defined for this notional aquifer. Darcy's law is then used to calculate the flow between the aquifer and the grid blocks on the edge of the model.
- By modelling a well that is completed in the grid blocks on the edge of the model, thus allowing flow into or out of the system at the edge.
- By associating a much larger pore volume with grid blocks on the edge of the model than is actually the case. The additional pore volume would represent the rock accessible beyond the edge of the model.

For large systems where there may be multiple injection locations, it may be possible to subdivide the formation into more local units. The boundaries would be defined by the location where the influence of the well under investigation is approximately equal and opposite to the influence from the neighbouring well, i.e. the tendency for fluid to flow away from the current well is countered by the tendency for it to flow towards the current well as a result of injection in the neighbouring well. Under such circumstances, a no-flow boundary is appropriate at this location. However, this depends on the relative timing of injection in the neighbouring wells.

Grid size and resolution
To model the pressure response accurately, all the connected pore volume should be accounted for. To avoid numerical errors when modelling the CO_2 displacement, the grid resolution should be as high as possible in zones that may at some point contain CO_2. Thus, the greater the number of grid blocks, the more accurate the model. However, the larger the number of grid blocks, the greater the computational resource required to perform the calculation, i.e. greater memory and longer run times are required. Other factors that affect run times, and hence allowable grid resolution, include the number of phases and components modelled, whether or not geophysical or geochemical processes are included in the model, etc.

The overall size of the grid selected will depend on the process that is being modelled and the geological data that is available, as discussed in Chapter 4. As noted above, high grid resolution should be employed in areas where CO_2 and brine will share pore space. Low grid resolution would cause an overestimate of mixing of CO_2 and brine, which, in turn, would result in too much dissolution of CO_2. Where only brine is present, a much lower degree of resolution is acceptable.

The following is a list of processes that are modelled and the appropriate grid requirements:

- Injectivity: near-well model – order 10–100 m.
- CO_2 (free phase) migration: reservoir-scale model – order 1–100 km, with high grid resolution at top but low resolution elsewhere.
- CO_2 (free phase and dissolved) migration: reservoir-scale model – order 1–100 km, with high grid resolution at top and intermediate resolution underneath CO_2 'tongue'.
- Pressure footprint: reservoir- or basin-scale model – order 10–1000 km, with low grid resolution required.

Firth of Forth
The Firth of Forth model covered a rock volume of 17 km x 16 km x 300 m. For the general fluid flow calculations, it was possible to use 139,040 grid blocks to model this volume. However, for the geomechanical calculations this was restricted to 21,760 grid blocks. No flow boundaries were assumed on all sides, except for calculations of the potential for CO_2 migration through the cap rock.

Lincolnshire
The Lincolnshire site covered a wider area, and the model had dimensions of 43 km x 33 km x 300 m. The general model consisted of 96,480 grid blocks, while the coarser model for geomechanical modelling consisted of 21,285 grid blocks. Because the Sherwood Sandstone Group outcrops to surface to the west of the Wolds, this boundary of the system was considered open. This was modelled by use of an infinite acting aquifer attached to the westerly row of grid blocks. Although the formation extends to the north and to the south of the area under investigation, it was considered that there might be other injection locations in these directions, and so no flow boundaries to the north and south were appropriate.

For both the Firth of Forth and Lincolnshire models, a finite permeability and porosity was associated with the cap rock, and hence the upper boundaries of the models were the top of the cap rock layers. The underburden was assumed impermeable in both cases.

Bulk modulus (K): is a measure of a substance's resistance to uniform compression. It is defined as the pressure increase needed to cause a given relative decrease in volume. Its base unit is the pascal.

C

Capillary pressure: the pressure difference between two immiscible fluids, resulting from the fact that one fluid (brine in this case) is attracted to the surface of the grains of rock more than the other fluid (CO_2).

Cap rock: a layer of low permeability rock overlying a sandstone saline aquifer. Owing to the high capillary entry pressure for CO_2 in such a rock, CO_2 is prevented from entering it and remains trapped in the saline aquifer. Commonly is it shale, anhydrite, mudstone or salt.

Carbon capture and storage (CCS): an approach to mitigating global warming based on capturing carbon dioxide (CO_2) from sources such as fossil-fuel power plants and storing it deep underground instead of releasing it into the atmosphere

Claystone: sedimentary rock that is composed primarily of clay-sized particles (less than 1/256 mm in diameter.

Concentric folds: folds whose shape curvature is the same for all folded beds; shapes like half-ripples radiating from a drop in water.

CO_2 stream behaviour: the phase behaviour of CO_2 and its component mixtures including contaminants in process facilities.

Cohesion: the intercept of the Mohr-Coulomb envelope with the shear axis.

Compressibility: the fractional change in the density of a rock or fluid per unit change in pressure.

Conceptual process engineering: is basic process engineering words that involve generation of ideas for possible solutions to the problem. It is often used to identify and systematically narrow down, the possible technical options for a given process goal. This is the creative stage and at this point a conceptual design can be done that includes preliminary process flow diagrams, mass and energy balances, and a list of major equipment. A very rough order of magnitude cost estimate can be provided as well.

Controlled source electromagnetic (CSEM): is an offshore geophysical technique, employing electromagnetic remote-sensing technology. The CSEM survey uses a dipole source that is towed just above the seafloor to transmit a time-varying electromagnetic field into the earth. This field is modified by the presence of subsurface resistive layers and these changes are detected and logged by an array of receivers placed on the seabed.

D

Dangerous Toxic Load (DLT): describes the exposure conditions for a particular substance, in terms of airborne concentration and duration of exposure, which would produce a particular level of toxicity in the general population.

Discounted cash flow (DCF) analysis: is a method of valuing a project, company, or asset using the concepts of the time value of money. All future cash flows are estimated and discounted to give their present values (PVs) – the sum of all future cash flows, both incoming and outgoing, is the net present value (NPV), which is taken as the value or price of the cash flows in question.

Dissolution: the process by which a solid or liquid forms a homogeneous mixture with a solvent (solution).

E

Enhanced oil recovery (EOR): is a generic term for techniques for increasing the amount of crude oil that can be extracted from an oil field.

Equation of state: an equation relating the pressure, temperature and volume of a fluid.

EU GeoCapacity Project: involves 25 European partners and one Chinese partner, and has the objective to assess the European capacity for geological storage of CO_2.

F

Fault: a fracture surface or zone of fractures in earth materials along which there has been vertical and/or horizontal displacement or movement of the strata on opposite sides relative to one another.

Flexural slip-unfolding: typically applied to folds formed due to layer-parallel deformation.

Flow isolation: a technique in which a blind flange or other isolation tool is inserted on the line of the non-flowing fluid to assure its complete isolation or separation.

Fluid saturation: a measure of the gross void space in a reservoir rock that is occupied by a fluid.

Fluvio-lacustrine: sedimentary deposits formed by a combination of fluvial (river) and lacustrine (lake) conditions.

Formation: a basic rock unit distinctive enough to be readily recognisable in the field and widespread and thick enough to be plotted on a map. It describes the strata, such as limestone, sandstone, shale, or combinations of these and other rock types.

G

Gaussian (or normal) distribution: a theoretical frequency distribution for a set of variable data, usually represented by a bell-shaped curve, symmetrical about the mean.

Geographic Information Systems (GIS): is a set of tools that captures, stores, analyses, manages, and presents data that are linked to location(s). In the simplest terms, GIS is the merging of cartography, statistical analysis, and database technology.

Gravimetry: is the measurement of the strength of a gravitational field.

H

Heuristics: refers to experience-based techniques for problem solving, learning, and discovery. Heuristic methods are used to come to an optimal solution as rapidly as possible. Part of this method is using a 'rule of thumb', an educated guess, an intuitive judgment, or common sense. A heuristic is a general way of solving a problem.

Hoek cell: is apparatus used to measure the strength of cylindrical rock specimens which are subjected to triaxial compression.

I

Immobilisation: the act of limiting movement or making incapable of movement: trap or freeze.

Intergovernmental Panel on Climate Change (IPPC): is the leading body for the assessment of climate change, established by the United Nations Environment Programme (UNEP) and the World Meteorological Organization (WMO).

Isopach: a contour line joining points of equal thickness in a rock layer.

Isostatic correction: numerical compensation for the lithosphere (crust plus mantle) sinking/rising due to (un)loading (a bit like the rise/fall of the load line of a container ship).

L

Layer-parallel folding deformation: folding whose axial plane is orthogonal to the layer and in which a folded line along any part of the fold profile is the same length as the line before folding.

Layer-parallel shear: displacement of material parallel to a layer, typically a rock formation bed.

Limestone: a sedimentary rock composed largely of the mineral calcite (calcium carbonate: CaCO3).

Lithology: description of rocks on the basis of colour, structure, mineral composition, and grain size; the physical character of a rock.

Lithostratigraphic: a body of rock forming a discrete and recognisable unit, of reasonable homogeneity, defined solely on the basis of its lithological characteristics.

M

Marl: a calcareous clay.

Maximum a posteriori (MAP): a maximum a posteriori probability estimate is a mode of the posterior distribution.

Migration: the movement of one atom or more, or of a double bond, from one position to another within a molecule.

mOD: metres relative to Ordnance Datum (sea level).

Mohr-Coulomb: a common mathematical model used to describe the brittle failure response of rock to normal and shear stress.

Monte Carlo methods: or Monte Carlo experiments are a class of computational algorithms that rely on repeated random sampling to compute their results. Monte Carlo methods are often used in simulating physical and mathematical systems. Because of their reliance on repeated computation of random or pseudo-random numbers, these methods are most suited to calculation by a computer and tend to be used when it is unfeasible or impossible to compute an exact result with a deterministic algorithm.

Motivational bias: occurs where an expert is not completely independent and their judgement is influenced by some conflict of interest. A common example is where an employee believes that a confident answer, or one consistent with a company view, is more desirable.

Mudstone (also called mudrock): a fine-grained sedimentary rock whose original constituents were clays or muds. Grain size is up to 0.0625 mm (0.0025 in), with individual grains too small to be distinguished without a microscope.

Multiple failure state testing (MFS): a method whereby the triaxial test factor can be obtained by testing a single rock sample.

N

Net present value (NPV): in finance, the net present value (NPV) or net present worth (NPW) of a time series of cash flows, both incoming and outgoing, is defined as the sum of the present values (PVs) of the individual cash flows. NPV is a central tool in discounted cash flow (DCF) analysis, and is a standard method for using the time value of money to appraise long-term projects.

Net to gross: the ratio of the volume of porous permeable rock in a formation to the total volume.

Nodal analysis: a useful design method for determining the conditions between points where facilities or branches connect in a single well or more complex systems.

O

Operationalisation: is the process of defining a fuzzy concept so as to make the concept measurable and to understand it in terms of empirical observations. In a wider sense it refers to the process of specifying the extension of a concept – in other words, describing what is and is not a part of that concept.

Outcrop: referring to the appearance of bedrock or superficial deposits exposed at the surface of the earth.

Over-confidence bias: occurs where the belief in a judgement does not reflect its true uncertainty. Tends to manifest as bounds or ranges that are too narrow.

P

P-wave impedance (IP): product of density and P-wave velocity.

P-wave velocity (VP): travelling speed of P-waves. A P-wave is an elastic body wave or sound wave in which particles oscillate in the direction the wave propagates. P-waves are the waves studied in conventional seismic data.

Permeability: the ability, or measurement of a rock's ability, to transmit fluids, typically measured in darcies or millidarcies. Formations that transmit fluids readily, such as sandstones, are described as permeable and tend to have many large, well-connected pores.

Poisson's ratio: The ratio of transverse to axial strain for an elastic material.

Porosity: the percentage of pore volume or void space, or that volume within rock that can contain fluids

Probability density function: a function that describes the relative likelihood for a random variable to occur at a given point in the observation space.

Q

Quality factor (Q): is the ratio of the peak energy of a wave to the dissipated energy.

R

Relative permeability: is the ratio of the permeability of a fluid in the presence of another fluid, to the permeability when the rock is completely saturated with the first fluid. The value is less than one, and increases as the saturation of the fluid increases.

Response surface methodology (RSM): explores the relationships between several explanatory variables and one or more response variables. The method was introduced by G. E. P. Box and K. B. Wilson in 1951. The main idea of RSM is to use a sequence of designed experiments to obtain an optimal response. Box and Wilson suggest using a second-degree polynomial model to do this. They acknowledge that this model is only an approximation, but use it because such a model is easy to estimate and apply, even when little is known about the process.

Reservoir: a subsurface, porous, permeable rock body in which water, oil and/or gas is stored.

S

S-wave impedance (IS): product of density and S-wave velocity.

S-wave velocity (VS): travelling speed of S-waves. An S-wave is an elastic body wave in which particles oscillate perpendicular to the direction in which the wave propagates. S-waves, or shear waves, travel more slowly than P-waves and cannot travel through fluids. Recording of S-waves requires receivers coupled to the solid earth.

Sandstone: a sedimentary rock composed mainly of sand-size mineral or rock grains.

Saline aquifer: a deep underground rock formation composed of permeable materials and containing highly saline fluids.

Seal: see cap rock.

Sedimentary rock: formed by deposition and consolidation of mineral and organic material and from precipitation of minerals from solution.

Seismic data: acoustic waves sent into the ground that are analysed for subsurface information.

Significant Likelihood of Death (SLOD): a level of toxicity used by the HSE in relation to the provision of land use planning (LUP) advice. It is defined as a toxicity level that would result in the death of 50% of an exposed population.

Siltstone: a sedimentary rock which has a composition intermediate in grain size between the coarser sandstones and the finer mudstones and shales.

Stochastic modelling: rock properties are highly variable and, due to a lack of data, there is much uncertainty. It is customary in the oil industry to generate stochastic models for the porosity and permeability throughout a reservoir, based on data from wells. In order to take account of uncertainty, multiple realisations of the models are often generated, i.e. models which have the same statistical properties (mean and standard deviation), but are created using a different set of random numbers.

Stratigraphy: a branch of geology that studies rock layers and layering (stratification).

Syncline: a downward-curving fold, with layers that dip toward the centre of the structure.

T

Trap: any feature or characteristic of a formation which will allow the accumulation, but not the escape, of oil or gas.

Triaxial stress factor: the linear slope of the axial stress versus confining stress at failure for a rock (multiple samples) tested in triaxial compression.

TWTT: Two Way Travel Time

U

UCS: uniaxial compressive strength – a basic measure of rock strength derived from uniaxial compression of an unconfined rock sample.

Uncertainty: lack of information with which to fully describe the existing state or future events. May arise due to natural, unpredictable variation in the behaviour of a system or lack of knowledge about the behaviour of a system.

Unconformity: a surface of erosion or non-deposition that separates younger strata from older strata; most unconformities indicate intervals of time when former areas of the sea bottom were temporarily raised above sea level.

V

Viscosity: viscosity is a measure of the resistance of a fluid to flow.

W

Water-alternating-gas (WAG): is an enhanced oil recovery process whereby water injection and gas injection are alternately injected for periods of time to provide better sweep efficiency and reduce gas channelling from injector to producer. This process is used mostly in CO_2 floods to improve hydrocarbon contact time and sweep efficiency of the CO_2.

Wellbore: a hole drilled or bored into the earth, usually cased with metal pipe, for the purpose of injection of CO_2, exploration for or extraction of natural resources such as water, brine, gas or oil.

Wellhead: a general term used to describe the component at the surface of an oil, gas or CO_2 well that provides the structural and pressure-containing interface for the drilling, production and injection equipment.

Wellhead pressure: the pressure exerted by the fluid at the wellhead or casinghead.

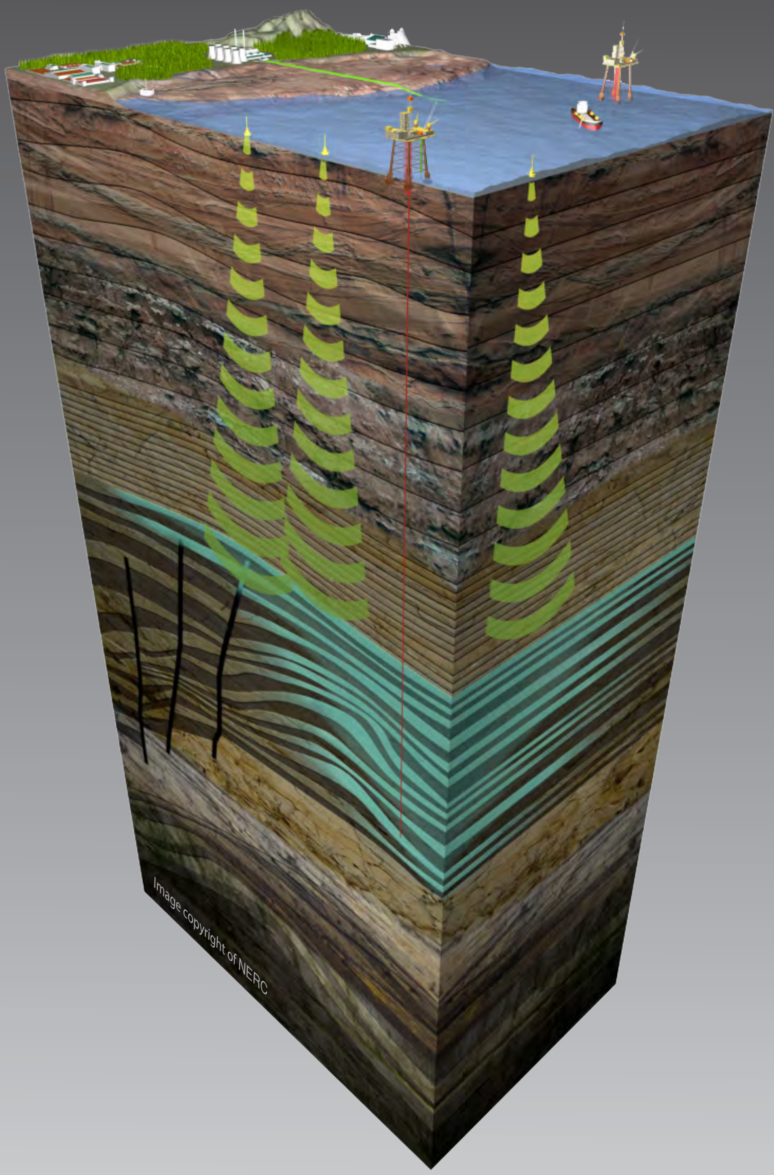
World Stress Map (WSM): is the global compilation of information on the present-day stress field of the earth's crust with 21,750 stress data records in its current WSM database release 2008. It is a collaborative project between academia, industry and government that aims to characterise the stress patterns and to understand the stress sources.

V

Vent: an igneous body related to a (an ancient) volcano.

Y

Young's modulus: The ratio of uniaxial stress over uniaxial strain for an elastic material – a measure of its stiffness.



CO_2