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Foreword

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Writing in the middle of 2013, the future for Carbon Capture and Storage (CCS) is not clear. Estimates of the world's future temperatures may vary somewhat but all point in the same direction – upwards. In contrast, 'weather forecasting' the implementation of CCS to help ameliorate global climate change is very much less certain. Why is this so? It is true that there are some uncertainties and challenges relating to the science and technology of carbon storage but there are research programmes which have already achieved major progress and point to successful approaches to achieve long-term, safe storage. Such topics form the first part of this book.

However, whether (rather than when) these approaches are put into use depends on the political, social and economic environment. In order to be effective, carbon storage has to comprise many very large-scale operations. This, in turn, requires a large economic investment and in common with all other investments needs a financial return. For companies this return may not be simply a profit but could also be a diminution of cost or even 'a licence to operate'. Carbon trading, or a market in emissions, seems to offer a plausible way forward since it applies an economic incentive to reduce emissions or at least puts a negative value on not doing so. Although there are some notable exceptions and especially in the current world economic situation, until recently there has been very little evidence of wide-scale, international political-will to apply carbon-trading regulations, which might put any single state's industry at a disadvantage relative to its competitors, unless universally implemented. Some of these aspects are dealt with in the second part of the book.

Thus, viewed from the perspective of the beginning of 2013, there was a spectrum of future possibilities. The most positive scenario would be global, large-scale carbon capture and storage as part of integrated programmes to reduce the concentration of carbon dioxide in the atmosphere while still using carbon-based fuels but where alternative energy sources also play an appropriate role. At the other end of the scale was the gloomy view that procrastination and 'business as usual' would continue to the greater detriment of the world's population. Then, earlier this year there was the surprise announcement that the government of China would institute carbon trading in its country, one of the world's largest industrial economies. Although the thinking behind the introduction of this policy is not really known, it seems likely that the widely publicised atmospheric pollution in many of China's large urban centres might have influenced the decision. Although only a start, this is an encouragement to think that the needle of the barometer of implementation of CCS is now swinging towards 'Fair' as opposed to pointing at 'Stormy' as it has done for so long. Inevitably, this has led to questions such as, how will CCS achieve what is required and will it really work?

Fortunately, around the world there are a number of CCS integrated projects, already in operation. They vary considerably in scale and objective and many, but not all, are intended as technical demonstrations and large-scale feasibility studies. The third part of the book describes a number of such efforts based in different countries.

So, looking into the future there is a possibility that CCS will become an integral part of the world's energy industry. The chapters of this book form part of the preparation for that future. The emphasis of most of the work presented here is on the geological aspects of CO_2 storage. It is clear why this should be the case. The knowledge base of how geological formations can trap hydrocarbons is immense; based on large investments in research made viable by the value of the resource being produced. Similarly, the processes of flow through and into geological formations are also integral to the everyday workings of those industries. Furthermore, understanding the technology and fundamentals of the reverse process, injection of fluids including CO_2 (to produce more resource) is also part of the toolkit of the hydrocarbon extraction industry. Nevertheless, the details of the processes for emplacement of CO_2 need to be evaluated and proven to be, fit for purpose, not just ported over from the hydrocarbons industry. Of even greater importance is the security of storage in the geological system. Unlike natural storage of hydrocarbons, which may have been emplaced over many millions of years, carbon dioxide will be introduced very rapidly to its storage environments. While leakage of natural hydrocarbons is known and accepted in the areas in which it occurs, similar leakage of CO_2 correctly would not be tolerated. Consequently, public acceptance of geological carbon storage has to be based on well-managed popular outreach coupled to an apposite regulatory regime for safe operation.

All of these aspects are covered in this very readable account, which will help document the current stage of progress from a worryingly uncertain recent past to the possibility of a brighter future for the world's population.

Introduction

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In 2011 the global emissions of carbon dioxide were 31.6 Gt with coal consumption accounting for 45%, oil 35% and natural gas 20% (International Energy Agency News 24 May 2012). The precise impact on climate change resulting from these emissions remains difficult to predict but 31.6 Gt is only just below the level of the modeled 32.6 Gt emissions peak (in 2017) from the IEA 450 Scenario and equated with less than a 50% chance that global temperatures will rise by no more than 2°C. Humankind will not easily give up using fossil fuels because of their high energy density!

Carbon capture and storage (CCS) is the only large-scale, industrial-scale process which can help reduce humankind's emissions of carbon dioxide into the atmosphere. However, deployment of CCS has been slow and to date the annual injected volume of carbon dioxide from burned fossil fuel sources is about 5 Mt; more than 6000 times less than would be required to achieve carbon neutrality. The barriers to large scale carbon capture, transportation, injection and storage are not technical; much of the technology is already known from the petroleum industry. Worldwide, there are over a hundred projects in which CO_2 is injected into oil reservoirs so as to extract more oil – so called enhanced oil recovery (EOR). It is an industry over 10 times larger than that of the carbon storage industry. EOR using CO_2 has a long history dating back to the 1970s when first tried by Shell in Texas in response to the oil crisis at that time. Well over half the CO_2-EOR projects are in Texas and although the CO_2 does not come from anthropogenic sources but from natural accumulation, transportation and injection are well-established processes. Similarly separation of naturally occurring CO_2 from methane is also a common and widespread process used to clean up natural gas production that is 'off-spec'.

The barriers that do exist are commercial and perceptual. Despite widespread recognition of the need to curb emissions the cost of first-generation capture and storage is estimated to be around a 30% energy penalty. In other words to capture, transport and inject the CO_2 produced from burning 1 t of coal would require an extra 0.3 t of coal to be burned. Translated into monetary terms this is an increased cost for those who choose to curtail their emission. In addition, some projects have been halted due to public opposition. Storage of CO_2 deep underground is not seen by some as safe, desirable or as a counter to consumption of fossil fuels and consequent emissions.

Despite the slow start the CCS industry is beginning to develop. The CO_2-EOR industry in Texas has functioned without a major safety incident in 40 years and this is exemplified by the monitoring of the long running SACROC CO_2-EOR project. Since 1972 over 175 million tonnes of CO_2 has been injected to the oilfield. An extensive monitoring campaign has shown the CO_2 not to be leaking from the site and 'no degradation of shallow drinking water resources as a result of more than thirty-five years of carbon dioxide injection into deep geological formations' (Smyth *et al.*, 2009). Similarly the long standing Sleipner CO_2 injection programme in the Norwegian North Sea has been running since 1996 with 1 million t of CO_2 injected annually and it too is free from leakage. The SACROC project is clearly driven by the value of the produced oil while the Sleipner project is economic because of the Norwegian CO_2 (emissions) tax. By not emitting CO_2 from the Sleipner gas field (32% CO_2, 68% CH_4) the operator Statoil can avoid some taxation.

While the Sleipner and SACROC projects have gone well, as indeed have many of the CO_2-EOR projects in Texas and elsewhere, there are at least two CO_2 disposal projects which have had technical issues. In the far north of Norway, the Snøhvit project ran into problems shortly after 1 Mt of injection with the reservoir pressure rising sharply in response to injection (Eiken *et al.*, 2011). The storage site may have a heavily compartmentalized reservoir though it is not yet clear. Another example is the In Salah project in Algeria. Here, as in Sleipner and Snøhvit, CO_2 is stripped from a natural gas stream prior to export and the CO_2 reinjected. For In Salah the reinjection occurs via three horizontal wells in the same formation from which the gas is produced. Injection itself was not an issue but careful monitoring of the ground surface demonstrated that it was elevating by as much as 5 mm per annum close to the injection wells – this despite the fact that injection was occurring 2 km below ground surface. The controlling issue proved to be one of permeability. At 10 mD the rock is not of sufficient permeability for the CO_2 dissipation (from the injection point) to keep pace with injection (Ringrose *et al.*, 2009).

These initial projects together with a handful of other well reported projects around the world (Great Plains Synfuel Plant and Weyburn-Midale Project North Dakota, USA/Saskatchewan, Canada; FutureGen, and Decatur, Illinois, USA; Otway, Australia, etc.) have set the pace for development. Norway aside, Europe has made a more hesitant start. The Netherlands has one project underway (K12-B) and Germany has a pilot site at Ketzin. At the time of writing (March 2013) the UK government has announced support for front-end engineering design work for two consortia of industrial companies that will capture CO_2 at power plants and ship via pipeline to storage sites in the North Sea. The Peterhead project in Scotland will store CO_2 in the depleted Goldeneye Gasfield while the White Rose project in England will exploit the storage capacity of a deeply buried saline aquifer.

The aim of this book is to capture both the state of the science and state of the art for CCS ahead of what could be rapid growth of the industry. The book is divided into three balanced sections. We begin with the state of the science in Part I, Fundamentals of the geological storage of CO_2. This part contains six chapters that take the reader from the link between CO_2 emissions and climate change through the basics of carbon geostorage (Freund) and then into exploring static and dynamic storage capacities (Pickup; Mackay), CO_2 migration in the sub-surface, the role of overpressure (Swarbrick *et al.*), monitoring (Hannis) and true sequestration (Bacon).

Part II, Environmental, social and regulatory aspects, deals with the state of the art. Three chapters examine the impact of long-term seepage and catastrophic leakage on the environment (Blackford *et al.*), risk assessment when planning for and constructing storage sites (Jagger and Drosin) and finally the legal framework for carbon capture and storage (Bell).

The final part of the book, Part III, Case studies, is just that, an examination of CO_2 storage in action. We begin with the long running Sleipner project (Chadwick and Eiken) which brings the story up to date with particular emphasis on the behavior through time of the CO_2 plume. Australia's Otway project has recently come to completion (Cook). Here too is an opportunity to examine both the successes and difficulties encountered during the project and the lessons learned from executing the injection trial. Two projects in Europe – Ketzin, Germany (Liebscher *et al.*) and K12-B, the Netherlands (van der Meer) have seen little published material to date and although modest projects in terms of injected CO_2 volume will have a huge impact on development of the industry in Europe. They target the Triassic and Permian respectively and both of these horizons have been identified as important storage intervals from Poland in the east to the North Sea in the west.

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1

Anthropogenic climate change and the role of CO_2 capture and storage (CCS)

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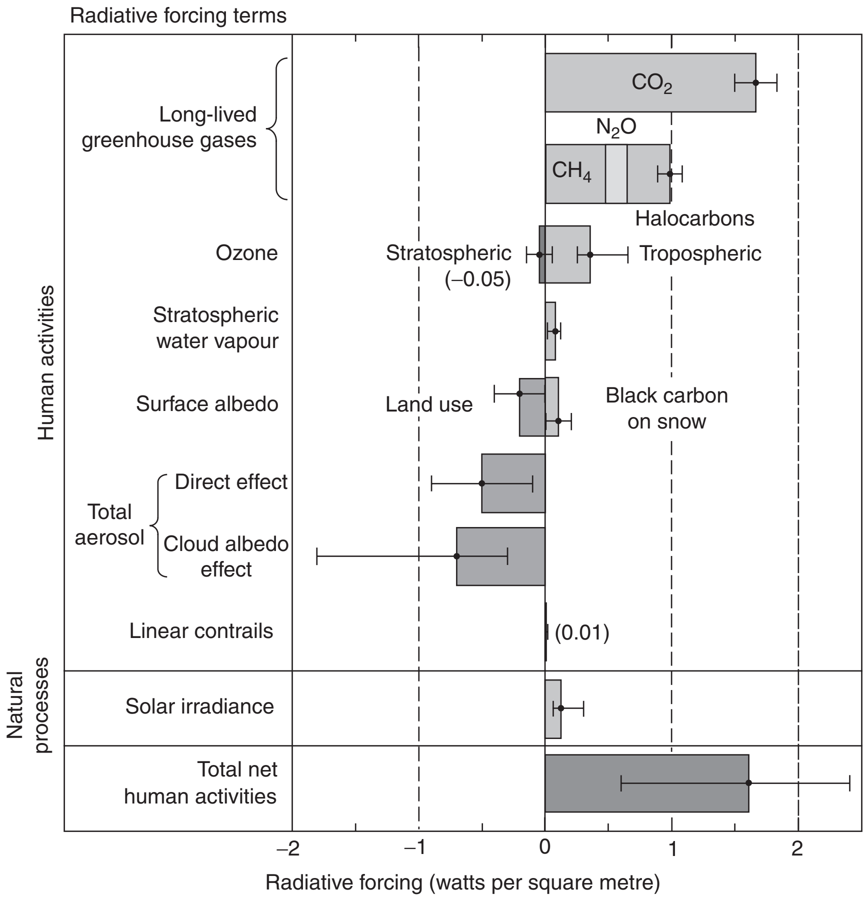
Abstract: Mitigating the effects of anthropogenic climate change will require use of a portfolio of measures – one of these is likely to be the capture and storage of CO_2 as it offers a means of significantly reducing the overall cost. In this process, CO_2 would be captured at large sources and then stored in geological formations. Several trends in the use of geological storage of CO_2 are identified – in the near term, depleted oil and gas fields are likely to be favoured; substantial capacity will also be available in deep saline aquifers but it is likely to take longer to gain approval for their use. Other developments that affect the financial and regulatory environment for CO_2 storage are also discussed in this chapter.

Key words: climate change, mitigation of climate change, CO_2 emissions, CO_2 capture and storage (CCS), electricity generation.

1.1 Climate change and anthropogenic emissions of CO_2

The surface of the Earth is about 33°C warmer than would otherwise be the case because of the greenhouse effect, the name given to the natural warming of the planet as a result of absorption of infra-red radiation in the atmosphere. Without the greenhouse effect, the planet would be largely uninhabitable by humans (Solomon *et al.*, 2007).

In recent years there have been many reports of changes in the Earth's climate – the increasing frequency of unusually warm years, rising sea levels, the melting of snow, ice and permafrost in areas normally regarded as permanently frozen. Many of these changes are now widely recognised to be the result of the enhancement of the natural greenhouse effect by increasing concentrations of carbon dioxide (CO_2) and other gases, a phenomenon that was first predicted by Arrhenius more than 100 years ago (Arrhenius, 1896). These gases are the products of human activities – for example, the main causes of the rising level of CO_2 in the atmosphere are the combustion of fossil fuels and deforestation (Peters *et al.*, 2011). The concentration of CO_2



1.1 The radiative forcing of climate due to various gases emitted between 1750 and 2005. (*Source*: Reproduced with permission from Climate Change 2007: The Physical Science Basis. Working Group I Contribution to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change, FAQ 2.1, Figure 2. Cambridge University Press.)

reached 392 ppm in December 2011 (Tans and Keeling, 2012), compared with 320 ppm in 1965 (Keeling *et al*., 1976); the corresponding level before the industrial revolution would have been around 270 ppm. The contributions of the various gases to changing the greenhouse effect (more specifically, to changes in radiative forcing) over the past 250 years are illustrated in Fig. 1.1. The emissions of many of these gases continue to increase so further changes are expected.

What may happen to the climate is deduced from use of complex mathematical models of the atmosphere, called Global Circulation Models, coupled with models of terrestrial ecosystems and, most importantly, with models of the oceans. With emissions continuing to grow (Boden and Blasing, 2011), these models predict that global temperatures might rise by 3–4°C by the year 2100 but there is considerable uncertainty in this figure, not only due to uncertainty about future emissions but also due to uncertainty about the sensitivity of the climate to increasing levels of greenhouse gases. After 2100, further change is expected and the rate of change may accelerate, something that provides even more cause for concern.

In order to avoid such changes in the climate, many actions have been proposed – to give some indication of what might be involved, calculations show that, if global emissions of greenhouse gases could be reduced by about 60% by 2100 compared with 1990 levels, the global temperature might be stabilised at 2°C above 1990 levels by 2100 (with uncertainty of +1/–0.7°C) (Eickhout *et al.*, 2003). However, global emissions have increased considerably since 1990 so it is now more realistic to consider that a target of 80% cut in current emissions might be needed to achieve such stabilisation. Although these figures are not at all certain, they help to illustrate the scale of the actions required if emissions are to be controlled sufficiently to halt the change in climate. Further reduction in emissions would be needed to reverse the changes in climate.

The models of the climate are hugely complex and, as indicated, are subjected to considerable uncertainty. Using them to make predictions about the future requires extrapolation beyond the range of data that has been used to build them which must add further uncertainty to the predictions. Further insight into how the climate may be changing, and a testing of the models, can be achieved by considering the state of the climate in prehistoric times.

1.1.1 The relevance of past geological periods for understanding climate change

Looking back to earlier periods provides information on the state of the planet when global temperatures and CO_2 concentrations were higher than they are now, or have been in recent history. This allows testing of the climate models over a wider range of conditions. In this way it may also be possible to understand better why the climate changed in the past, which could increase confidence in the predictions of future changes.

A prime source of information on past states of the climate is the analysis of air trapped in polar ice and of the ice itself; such measurements give information on the condition of the prehistoric atmosphere (from which temperature can also be inferred) up to 650 000 years ago (Solomon *et al.*, 2007). Before that time, other geological data can be used but there is greater uncertainty about such ancient atmospheric conditions. Nevertheless such data are important because they can be used to test climate models in conditions outside the range of the data from the ice measurements, in particular testing a key parameter, the sensitivity of the climate to CO_2, which is difficult to do in other ways.

Some understandings about the climate in the past (Jansen *et al.*, 2007) include:

- Recognition that average temperatures in the Northern Hemisphere during the second half of the twentieth century were higher than during any other 50-year period in the past 500 years. It is also likely that, in the Northern Hemisphere, the second half of the twentieth century was the warmest such period in the past 1300 years.
- The warming of the globe in the twentieth century has been about 10 times faster than any such change since the last period of maximum glaciation (21 000 years ago).
- There have been many other changes in the climate in the past, such as changes in the strength and frequency of El Nino-type events, abrupt changes in the strength of Asian monsoons, occurrence of droughts lasting for tens to hundreds of years in Africa and North America; these indicate that recent unusual events are not without precedent.
- Current atmospheric concentrations of CO_2, CH_4 and N_2O are higher than for the past 650 000 years. Over that period, Antarctic temperatures have been closely related to atmospheric CO_2 concentrations, although that does not prove which change caused what.
- In earlier periods (several million years ago) the Earth seems to have been warmer than at present. Indeed there were periods when it was mostly free of ice. The major expansion of Antarctic ice, which started around 35–40 million years ago, was likely due to declining CO_2 levels from the peak in the Cretaceous era.
- Around 55 million years ago there was an abrupt warming of the planet and a large release of carbon into the atmosphere; this event lasted about 100 000 years; it is being studied now because it has some similarity with the rapid release of CO_2 taking place at present.
- Going further back in time, the warmth of the Earth in the Mesozoic era (65–230 million years ago) was likely associated with high levels of atmospheric CO_2. Major glaciations occurred around 300 million years ago which likely coincided with relatively low concentrations of CO_2 (compared with the periods immediately before and after).

Such measurements show that the Earth's climate can change substantially. In some periods of warming, CO_2 levels have also been high but cause and effect is less clear. Nevertheless, the risk that changes due to human activities could happen so quickly as to make the planet very uncomfortable have stimulated many people and governments to take action to address the danger of anthropogenic climate change.

1.1.2 Mitigation of climate change

In 1992, at the Rio Conference, it was accepted by governments that the world needed to stabilise the concentration of greenhouse gases in the atmosphere. This would not undo the changes that had already taken place but would help to prevent further dangerous changes. Unfortunately the specific levels of emissions required to achieve these goals have never been agreed by all countries. Nevertheless some impression of the changes in emissions required may be obtained from various modelling studies – this discussion will focus on CO_2 but similar changes would be needed in the other greenhouse gases.

To stabilise atmospheric concentrations of CO_2 would require global cuts in emissions of at least 80% compared with current levels. This assumes that the oceans could continue to absorb about a third of anthropogenic emissions as at present. However, even that process ought not to continue for ever because it is leading to rising acidity in the oceans, a different form of environmental damage but one with enormous potential consequences. Nevertheless, as that is a slower process of change, the oceans may help to constrain the atmospheric levels of CO_2 at least in the short term.

In relation to this target of 80% reduction in emissions, the UK has already established legally binding emission reduction targets (through the Climate Change Act 2008); these require reduction of at least 34% in greenhouse gas emissions by 2020 (relative to 1990) and at least 80% reduction by 2050. The European Union has adopted a goal of emission reduction of 20% by 2020 and is discussing increasing this to 30% because of the extent of recent progress towards the original goal. Some other countries have set themselves similar goals but not everyone has – two of the largest emitters, the USA and China, have not yet agreed to such targets, which is indicative of a continuing problem in delivering large reductions in emissions on a global basis, 20 years after the Rio conference.

But if there was willingness to make such reductions, how could they be achieved? To provide some context for considering this question, it may be useful first to understand the causes of the emissions – these are examined next. Then methods of reducing emissions can be considered.

1.2 Emissions of CO_2

In 2009, global emissions of CO_2 as a result of fossil fuel combustion amounted to 29 Gt, an increase of 38% on 1990 levels (IEA, 2011). Electricity generation (including central production of heat) accounted for more than 40% of global CO_2 emissions (Table 1.1). Other industrial sources of CO_2, such as major energy-using industries including steel and cement, also played a significant role (these are included in manufacturing industries in Table 1.1). In

Table 1.1 World CO_2 emissions from combustion of fossil fuels by sector in 2009

Sector	Proportion of global emissions from fuel use (%)
Electricity and heat production	41
Other energy industries	5
Manufacturing industries and construction	20
Transport	23
Residential	6
Other	5

Note: The 'Other' sector includes commercial/public services, agriculture/forestry, fishing, etc.
Source: IEA, 2011.

addition oil refineries and other parts of the energy industry create significant emissions so that, in total, about half of CO_2 emissions come from large industrial sources. The other half is produced by dispersed sources, such as buildings, or by mobile sources, such as road vehicles.

1.2.1 Sources

CO_2 emissions come principally from burning solid fuels (coal and peat) and oil (see Table 1.2) but the use of solid fuels and natural gas is increasing much faster than that of oil – solid fuel and gas is mainly used by the energy industries and other large centralised facilities whereas oil is mostly used for transport.

Certain sectors of the economy have characteristics that make them more amenable to early action – for example, those sectors which own major plant (e.g. plant that has substantial emissions from a single site) and are dominated by large organisations with access to substantial funds for investment, and which are subject to central regulation. These sectors may be able to address the challenge of deep reductions in emissions by modifying their plant or by substituting a different type of plant. Such changes may not be easy but these industries have the tools to make the changes if required.

In contrast, the dispersed and mobile sectors typically involve many small sources of emissions, owned by millions of individuals who may not have ready access to funds for investment and are less easily addressed by regulation. These sectors may only be able to make deep reductions in emissions through changes to the energy carriers used to supply their buildings or vehicles – for example, substitution of petrol in cars by electricity or hydrogen (as long as such energy carriers have been made without CO_2 emissions). Such changes would require major changes in the fuel distribution system as well as in vehicle technology. Necessarily, making changes in

Table 1.2 World CO_2 emissions by fuel type in 2009

Sector	Proportion of global emissions from fuel use (%)	Increase over previous 10 years (%)
Coal and peat	43	50
Oil	37	21
Natural gas	20	52

Source: IEA, 2011.

millions of fuel-using systems would take longer and be more difficult to do than changes to a few thousand plants in the industrial sectors.

This discussion will now focus on tackling the centralised and major industrial sources of emissions.

1.2.2 CO_2 emissions from industry

A major source of CO_2 is the power generation and heat supply sector whose global CO_2 emissions were 10.5 Gt CO_2 in 2004 (Sims *et al*., 2007); it is estimated that emissions from this sector would rise to about 14.6 Gt CO_2 in 2030. Further to this, use of fossil fuels to provide energy in the general industrial sector resulted in direct CO_2 emissions of 5.1 Gt CO_2 in 2004. In addition there were emissions from non-energy uses of fossil fuels (e.g. production of petro-chemicals) and from non-fossil fuel sources (e.g. cement manufacture) that have been estimated to release 1.7 Gt CO_2 (Bernstein *et al*., 2007). By 2010, it is estimated these emissions may have grown by about 20%. Projecting to 2030, the emissions could be 20–30% higher still (depending on assumptions about growth and mitigation strategies). On this basis it is inferred that the general and industrial sector's emissions (from energy and non-energy uses) could be 9.8 to 10.6 Gt CO_2 in 2030. Developing nations accounted for 53% of the total industrial CO_2 emissions in 2004; this proportion is expected to grow in future.

1.2.3 Reducing CO_2 emissions

In order to achieve global reductions in emissions of 50% by 2050 and 80% by 2100, deep reductions are needed in all sectors but, as indicated above, some may be able to act faster than others.

Reduction in demand for energy and improvements in the efficiency of using energy will be able to make immediate and probably cost-effective reductions in emissions but, at best, these may amount to less than 40% of the cuts needed (IEA, 2010). Substitution of lower carbon fuels (such as natural gas) for high carbon fuels (such as coal) could achieve a halving of emissions at a particular power plant but in total such changes may only contribute about 15% towards the global goal. To achieve global reductions of 50% to 80% will need deeper reductions in some sectors and application of a wider range of technologies, approaching zero emissions in some cases.

Deep reductions in emissions may be achieved by substitution of fossil fuels by energy from nuclear power or renewable sources, which have close to zero net emissions. Among the main types of renewable energy, geothermal energy and hydropower have limited global potential but can be attractive in specific locations; ocean energy has largely unknown potential but is expected to be useful in some places; wind energy is generally regarded as being capable of making a significant contribution but there is more uncertainty about solar energy although some see it as potentially capable of a large contribution by 2050; a major source of renewable energy could be the use of biofuels which appears in most projections as making a significant contribution to global energy supply in 2050 (Arvizu *et al.*, 2011). In most cases, these sources are more expensive than conventional energy (including nuclear power), which is one of the factors limiting their application.

Another way of making deep reductions in emissions would be to capture and store the CO_2 from fossil fuel combustion; this technology would be applicable to large plants, such as fossil-fuelled electricity generation, and also in other industries that rely on use of fossil fuels, such as iron and steel, cement, petroleum refining and certain chemical processes. Use of CO_2 capture and storage (CCS) would enable the continuation of the existing electricity supply system, which is important since there is a large stock of established plant and much relevant knowledge and technological expertise. CCS could also help in the supply of alternative energy carriers for vehicles, i.e. electricity or hydrogen, both of which could be made from fossil fuels using CCS to avoid most emissions.

Several studies (e.g. Edmonds *et al.*, 2001; Stern, 2007) have shown that use of a significant proportion of CCS globally would help to reduce the overall cost of meeting the target of stabilisation of atmospheric concentrations of CO_2. Importantly CCS is a technology adapted from existing engineering, rather than having to be developed from first principles. It also has the attraction that it could be applied to several types of source of CO_2, not just electricity generation.

An analysis by the International Energy Agency (IEA, 2006) has shown that inclusion of CCS in the mix of electricity sources could play an important role in keeping down the overall cost of achieving deep reductions in emissions. More recent IEA analysis has shown that inclusion of CCS in their Blue Map scenario (which was designed to reduce emissions by 50% by 2050) resulted in a cut in the overall cost of electricity generation by 28% (IEA, 2010) compared with scenarios where CCS was not used (although emissions were slightly higher than in the base case).

The UK Committee on Climate Change (Committee on Climate Change, 2011a) described a scenario for power generation in the UK where renewables provided about 40% of electricity generation by 2030, with additional decarbonisation by use of nuclear power (also around 40%) plus 15% from use of CCS. This was based on cost assumptions (Committee on Climate Change, 2011b) that indicated that CCS would be more expensive than nuclear power, the other large-scale low-carbon technology, but less expensive than most of the distributed renewable technologies (i.e. solar, wave, tidal) except for onshore wind and several bioenergy technologies. However, it can be argued that this view of costs (especially capital costs) is significantly over-simplified.

A more sophisticated analysis of many low emission sources of electricity shows that the cost is not a simple, standard figure as has normally been used to represent fossil-fuel-fired power generation in the past – rather there are significant influences on the cost of electricity due to the geographic distribution of the sources (in the case of wind, solar, biomass) and on the size and distribution of the storage facilities (in the case of CCS). Allowing for these factors can make a significant difference to the cost of electricity but has only been attempted in a few studies to date, for example Davison (2001) for wind power and recent, as yet unpublished, work on CCS. It cannot be assumed that these influences on cost are either negligible or that they are similar for every type of system.

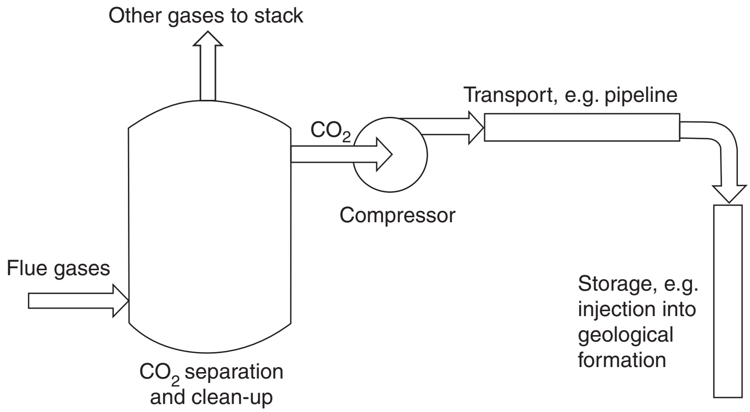
In conclusion it is worth repeating that the cost of CCS is no more than that of many other mitigation options and several studies have shown it could play an important role in keeping down the overall cost of a portfolio of mitigation options designed to achieve deep reductions in emissions. The cost of fitting CCS to individual power plants would be substantial, because typical power stations produce a lot of CO_2; to do the same by replacing the power stations with the equivalent effective capacity in wind or solar or other renewables would be even more expensive.

1.3 CO_2 capture and storage

The CCS process consists of three main stages – a plant for removing CO_2 from the exhaust stream of a power station or other large facility, followed by a method of transport, which delivers the CO_2 to the third stage, the storage site (see Fig. 1.2). These are examined in more depth to understand better how each stage contributes to the cost of the process.

1.3.1 The CO_2 value chain: from generation to capture to storage

All of the main items of equipment in the CCS process are based on established technology, already in use for similar purposes.



1.2 Schematic diagram of a system for capturing and storing CO_2 from power station flue gases.

At the heart of the capture plant is the separator, typically a solvent scrubber, although other methods of separation can be used and new systems are under development (IPCC, 2005). The stream of gases being scrubbed only contains a small proportion of CO_2 (between 3.5% and 14% depending on fuel type), most of which is removed by the solvent, which is then regenerated, releasing a stream of concentrated CO_2. After any necessary clean-up, the CO_2 is compressed for transport. The quantities of CO_2 produced by a single power station can be upwards of 2 million tonnes per year, for which the most appropriate method of transport is a high pressure pipeline (operating at 100 bar or more), although use of ships may also be considered in certain circumstances. The pressure in the pipeline is dictated by the physical properties of CO_2 – transporting the CO_2 in its 'dense phase' reduces the space required. Transport by ship, on the other hand, would require moderate refrigeration of the CO_2 rather than elevation to a high pressure. The energy required for capture and compression or capture and refrigeration can be substantial, which is one of the main costs of employing CCS.

A range of storage options for CO_2 have been considered but there is now consensus that storage in geological formations would be the most appropriate way of dealing with the quantities of CO_2 involved, in a safe and secure manner for a very long time (i.e. thousands of years). Other storage options are examined in the following section.

All stages of the CCS process will involve substantial capital investment, not least because of the sheer scale. The main expenditure will be on the capture plant, which, together with the compressor, incurs the main operating costs. The costs of all parts of the CCS system will show the effects of economies of scale. Typically, illustrative costs are quoted for a full size power station (e.g. 500 MW) but such a power station only produces 1 to 2 million tonnes/year of CO_2 and the economies of scale of pipelines are such that a capacity of 10–20 million tonnes/year could show useful savings, implying the amalgamation of CO_2 from several sources for transport (although this may not be the case in early projects).

For geological storage, the suitable scale of the facility will be determined by geological features but it may be that the CO_2 carried by a large pipeline would need to be distributed among several storage sites. It is likely that, in Northern Europe, such facilities will be offshore, under the North Sea. The cost of a storage facility will be dominated by the initial survey and by the work necessary to prove that the geological formation is suitable, plus the cost of establishing the facility (e.g. drilling of wells and construction of an offshore platform); there will also be ongoing expenditure on operation of the system and on monitoring. In the event of an unexpected failure of the storage system, the cost of remediation could be significant but it is expected that, by appropriate site selection and design, the chances of this happening will be very small. Capital costs will dominate the economics of transport and storage although the operating costs might be significant if pressure boosting were needed (as could be necessary for a long line).

In view of the established nature of the technologies involved in this process, it is relatively easy to estimate the costs of the various stages of the CCS process using standard engineering procedures. There are many published studies of the cost of capturing and compressing CO_2 and several generic studies of the cost of transport and storage (IPCC, 2005). Some impression of the balance of costs in the various parts of the system is shown in Table 1.3 based on a recent study of European costs (ZEP, 2011).

These figures indicate that perhaps 10% of the additional cost of using CCS may be due to the storage element but this may represent 20% of the additional capital cost of such a system.

How these costs translate into value (i.e. the potential profitability of the various stages) will not be clear until commercial operations are fully established. At present the value of CCS will be determined by how much subsidy will be available from public sources, or as a consequence of legal restriction on construction of power stations without CCS. In future, if the emissions from large sources are regulated and the permitted levels of emissions are reduced to a small fraction of current levels, then CCS plant could have value in its own right. Until it is clear when and how that situation will develop, the best that can be said of the relative value of the different elements of the CCS chain is to use the discounted costs (as shown in Table 1.3).

When CCS becomes a normal part of the business of electricity generation, it is likely that the rate of return expected from investment in the capture plant would be similar to that of the rest of the power plant; similarly for pipelines, the rate of return can be expected to match that allowed for typical common carrier pipeline assets. The analogous situation for geological

Table 1.3 The additional cost of a CCS network capturing, transporting and storing 20 million tonnes per year of CO_2

	Component parts	Capital cost (approx.)	Incremental contribution to cost of electricity
Power generation - base case	c.4 Pulverised fuel power stations	5.5 B€	–
Power generation - capture	c.5 Pulverised fuel power stations or c.4 IGCC power stations	8.5–10 B€	–
Capture and compression	Post-combustion or pre-combustion capture	Additional 3–4.5 B€	22–27 €/MWh
Transport	500 km offshore spine system	Additional 1.2 B€	5 €/MWh
Storage	Geological storage offshore:	Additional	2.5–5 €/MWh
	- either depleted oil/ gas fields	0.5 B€	
	- or deep saline aquifers	1.0 B€	

Source: Derived from ZEP, 2011.

storage is less clear but it is assumed that a similar rate of return would apply as to other parts of a CCS project. In that case the value of the storage part of the chain would be 10–20% of the value of the whole chain.

In a fully commercial CCS system, the different parts of the system may be owned and operated by different companies – for example, the capture plant would likely be owned by the power plant operator since it would be an integral part of that plant; the transport system might be owned by a pipeline company, much as gas pipelines are owned by dedicated pipeline companies in the UK and USA; the storage facility might be owned by a dedicated storage company that manages storage for a number of providers of CO_2; but other models of ownership could equally well develop.

1.3.2 The range of options for storing captured CO_2

The storage of CO_2, if it is to achieve significant reductions in global emissions, would eventually have to be able to handle thousands of millions of tonnes globally. For several reasons, including the availability of sites and the need to be able to regulate and monitor the storage of CO_2, only a limited number of storage facilities are likely to be used, each with capacity of up to hundreds of millions of tonnes of CO_2. Geological formations, especially ones that have previously held oil or gas, should be well qualified to perform this task, as the amounts of fluid removed from the formation during oil and gas production are typically similar to the volumes required. The fact that these reservoirs have held oil or gas over geological timescales gives confidence that they could hold CO_2 safely and securely, providing that the geological seal has not been compromised by the hydrocarbon extraction. Other geological formations, in principle, have even greater capacity, especially formations holding saline water since these have no other use. If the security of storage in such formations can be established, saline aquifers should make good stores for CO_2.

There are few other natural systems suitable for holding even a fraction of the vast quantities of CO_2 produced by the world's use of fossil fuels. One possible candidate is the deep ocean – if CO_2 can be injected at sufficient depth, it would have density greater than the surrounding ocean and so, in principle, should stay on the seabed (Ocean Storage, 1998). In practice, the CO_2 would react with the seawater forming hydrates; these solid-like materials have only limited stability which could lead to gradual dispersion of the CO_2 into the ocean waters, eventually compromising the storage. Just as significantly, such injection of CO_2 into the oceans is not allowed under international agreements such as the London Convention (Hendriks *et al.*, 2005).

Another option for dealing with the captured CO_2, which superficially has attractions, is to put it to use or make it into something else, for example a solid material or a chemical that could be sold.

An established way of using CO_2 is in enhancing oil recovery (EOR). This, and related newer uses in enhanced gas recovery and enhanced coal bed methane recovery, could provide a source of income to offset, partially, the cost of storage. However, the result of such injections would be to bring forward production and perhaps increase the overall extraction of hydrocarbons. This has caused some people to question whether CO_2 used in EOR (and the related techniques) should be accepted as a climate change mitigation measure. Nevertheless some countries have already recognised EOR projects as contributing to storage of CO_2.

Although developing a saleable product from CO_2 may be possible, for example as a building material, the size of the demand for any such product means it could not provide the whole answer to the huge quantities of CO_2 produced by global combustion of fossil fuels. In any system for utilising CO_2, or making it into something else, it is very important to consider fully all of the inputs and outputs in order to understand its true impact; to do this it is essential to select the appropriate system boundary for the scheme being studied (Freund *et al.*, 2005).

A related possibility is the production and disposal of a solid material made from CO_2 – this has attracted attention as a very secure method of storage. Natural minerals such as serpentinite and olivine have been identified as potential sources of Mg compounds that could be reacted with CO_2 to make such a stable material. To do this on an industrial scale, at a rate commensurate with the production of CO_2 by a power plant, would require a chemical engineering process. Typically such a process would have two stages – in the first, the rock would be decomposed, perhaps to make Mg $(OH)_2$; in the second stage, the CO_2 would be reacted with the products of the first stage to make the solid product (Fagerlund *et al.*, 2012). Although this second stage may be exothermic, the first stage is likely to require input of energy, so the process would involve heat recovery to minimise the energy demand of the plant. Even with the best integration, extra energy would likely be needed; an obvious source of this would be fossil fuels but the consequence of using such an energy source would be increased greenhouse gas emissions, which would tend to offset or even cancel out the emissions reduction arising from capturing the CO_2 in the first phase. A way of avoiding this problem might be to use energy from a renewable source but the cost of setting up such a system in order to convert captured CO_2 into a solid would likely make it more attractive to utilise the renewable energy directly (for electricity production or another purpose).

Another problem with this concept is that such a process of CO_2 mineralisation would require intermediate materials which would have to be recycled and any losses made good. In addition, the cost of the plant would be substantial (Gerdemann *et al.*, 2007), making the overall storage cost much greater than the cost of injection into geological formations. Finally, it must be recognised that the volume of material produced would be substantially greater than the volume of mineral mined, presenting a waste disposal problem.

For these reasons, conversion into solids is unlikely to be answer. The storage option that has attracted most attention is geological storage of CO_2, the subject of this book. Various steps have been taken in many countries to support the development and application of CCS using geological storage – demonstration projects have been monitored as the basis for learning, financing schemes have been put in place to encourage early application, regulations have been developed to ensure that CCS systems are safe and secure and achieve the goals that society requires. These and other developing trends are discussed below.

1.4 Trends in CO_2 capture and storage (CCS)

Since 1996, when CO_2 was first injected underground as a means of mitigating climate change, a great deal of experience has been accumulated about this method of dealing with CO_2 emissions. From this it is possible to distinguish a number of key trends in CO_2 storage technology.

1.4.1 Type of store

The first commercial injections of CO_2 underground (1972) were not for reasons of mitigating climate change but to enhance oil recovery (Han and McPherson, 2007). Several such facilities were constructed in the USA, at a time of high oil prices, which used CO_2 from natural fields or captured from low cost sources; the CO_2 was transported through pipelines, over distances of up to 800 km. There are now 114 CO_2 injections for EOR in the USA (Oil and Gas Journal, 2010) where there is a substantial body of expertise concerned with the handling and injection of CO_2. CO_2 has also been injected underground as a means of dealing with acid gas emissions in Canada, although the quantities involved are somewhat smaller than in the EOR projects. In the year 2000, an EOR project was initiated using CO_2 captured in the USA (at the Dakota Gasification plant in Beulah, North Dakota) and transported by pipeline to the Weyburn oil field in Canada – the first trans-national movement of CO_2 for injection. That project is also notable because it has provided an opportunity for extensive monitoring to learn about the behaviour of CO_2 in such a large-scale storage facility. Further EOR projects have been considered since then, with pilots being undertaken in Brazil, China and elsewhere.

The first storage of CO_2 in order to mitigate climate change was undertaken in 1996 by the Norwegian oil company Statoil and its partners in connection with production from the Sleipner natural gas field. This involved injection of CO_2 (separated from the gas stream) into a saline aquifer at more than 800 m depth. This injection has also been extensively monitored by an international research project (see Chapter 10). The Sleipner project has been followed by another that reinjected CO_2 extracted from the Snøhvit gas field into an overlying aquifer.

Another commercial gas production project, the In Salah project in Algeria, has reinjected CO_2 since 2004 when it was commissioned by BP and partners. In this case the CO_2, after removal from a natural gas stream, is reinjected into an outlying part of the gas field. Monitoring of the project has demonstrated how the CO_2 is moving and has investigated novel techniques for monitoring such storage facilities. A smaller reinjection project has been undertaken offshore the Netherlands (K12-B gas field – see Chapter 13) which has been used to examine the injection of CO_2 into compartments of the gas field as well as the potential for enhancing gas recovery in a depleted field. More recently an injection at Otway in Australia also made use of separated CO_2 which was reinjected nearby (see Chapter 11). All of these projects made use of CO_2 which had been separated for commercial reasons. They were relatively low risk and low cost and might be replicated by other countries wanting to build experience with geological storage of CO_2.

In addition to the commercial projects, several research and demonstration injections have taken place including at Nagaoka in Japan, at Ketzin in Germany (see Chapter 12), and at Frio and Mt Simon in the USA; these are relatively small projects (of order 10 000 tonnes of CO_2) because of the high cost of purchasing CO_2 specifically for injection. Larger injections are planned in the USA where 1 million tonnes of CO_2 will be injected into several deep saline aquifers or oil fields; two of these injections have already started. This represents the next step for many countries in establishing experience with CO_2 injection, although the US experience demonstrates that it can take quite a few years to establish and fund such projects.

Literally dozens of larger projects have been proposed but the likelihood of them taking place is closely connected with the availability of funding. In particular the source of CO_2 will likely have to be a capture plant in a power station or similar facility, implying large capital investment. A significant momentum has built up in many parts of the world to carry out further CO_2 injections in order to learn about the behaviour of CO_2, confirm models and test instruments. The extension of future activities into full-scale commercial injections is more problematic and depends strongly on the availability of funds and the level of interest of governments in making deep reductions in greenhouse gas emissions.

To summarise, it seems very likely that there will be continued interest in using captured CO_2 for EOR but this will be limited by the availability of cost-effective investment opportunities. As the environment improves for establishing full-scale CCS projects, injection into depleted gas fields, where available (followed by injection into depleted oil fields), is likely to be most of interest because gaining regulatory approval to use such fields in this way will be relatively faster than winning approval for use of deep saline aquifers, which are likely to need more investigation. Because of the longer period needed to gain approval for the use of aquifers, it would be important to initiate the process early but a major obstacle will be finding the funds for such preparatory work many years ahead of the CO_2 injection.

1.4.2 Location of the store

The preferred location for storage facilities varies depending on which region of the world is considered – in Northern Europe, onshore storage is being ruled out by governments and public attitudes, so storage under the sea (which is a feasible option for much of Northern Europe) is preferred. In North America it seems more likely that storage onshore will be used, not least because of experience with other onshore injections but also because, in most cases, the distances involved would make it too expensive to transport CO_2 to offshore locations. Similarly in China the rapidly growing interest in CCS focuses on use of CO_2 (for EOR) onshore. In Australia, although some of the largest potential stores are offshore, onshore locations have also been seriously considered.

1.4.3 Wells

One of the concerns raised about storage is the possibility of leakage in the short or long term. After injection has finished, the risk of leakage should decline as the excess pressure in the reservoir is dissipated through dissolution of the CO_2. But, especially during injection, the well is a potential source of leakage, one which could lead to rapid escape to the atmosphere; the same would be true for any monitoring wells in the formation, and any other wells passing through the reservoir. Purpose-made wells, such as for injection, are likely to be designed so as to minimise the chances of leakage but there is not yet sufficient experience with existing wells to demonstrate that their propensity to leak can be predicted; this will be one of the important issues facing developers of projects in established oil and gas production areas. Learning about the design of wells for CO_2 and the remediation of problems with existing wells is likely to be an area of increasing activity in future.

1.4.4 Monitoring

To date, CO_2 injection and storage has been monitored for reasons of research and demonstration. As CCS moves into a more commercial phase, the rationale for monitoring will change, as the primary focus becomes one of meeting the requirements of the regulations.

Many of the techniques for monitoring CO_2 now being deployed are based on oil and gas industry practice but instrumentation specifically to monitor stored CO_2 is also being developed and tested. Increasing experience is being gained with remote monitoring of the reservoir, the cap rock and its overburden using seismic techniques; other remote monitoring techniques, such as detection of micro-seismicity and satellite observation, are being investigated but have not yet shown the same wide applicability. In addition invasive techniques can be used that provide direct measurements of physical or chemical properties in the formation, typically via a well. These techniques can also help with management of the system but there is concern lest the use of extra wells could increase the risk of leakage. Indirect measurement, that is, monitoring the movement of any fluids that have left the reservoir, would seem to be attractive from the point of view of system management as it could be done without compromising security. Until monitoring plans have been agreed with regulators for commercial CCS projects it is not possible to be sure what balance will be struck between remote, invasive and indirect measurements.

Another type of monitoring is the detection of leakage by direct measurement of CO_2 at/close to the seabed at offshore sites, or close to the surface at onshore sites. Typically such technologies measure physical properties but chemical measurements would also be used to confirm that any gas detected was indeed escaping from the reservoir. Suitable techniques are available from the oil and gas industry but there is a need to establish a body of experience with their use in this new area. Because of the long time likely between injection and any leakage to surface (apart from through the wellbore), it seems likely that practical experience will have to be developed by use of simulated releases.

More novel means of monitoring the effectiveness of the injection and detecting possible failure of the security of storage, such as use of tracers, are being established but depend on large-scale projects to provide the means to demonstrate their effectiveness. Monitoring is an area where much remains to be done, and much will depend on the expansion of commercial-scale projects to provide the test beds for this learning.

1.4.5 Regulation

The need for monitoring is very much driven by the regulation of storage, which is an area where substantial progress has been made in recent years, especially in Europe. Regulation of the injection of CO_2 has been addressed in the USA. The requirements of the regulators are being clarified, something that is essential in order to encourage investment in CCS projects. As more experience is gained with practical injections, it can be expected that the regulations will evolve to incorporate the knowledge so gained. In Europe, a Directive on Geological Storage of CO_2 is being transposed into national laws in the member states. Continued dialogue between members of the industry and regulators can be expected but further developments in regulation of storage will now depend on gaining experience with practical projects.

1.4.6 Post-injection

After injection has finished, it is expected there will eventually be a transfer to government of responsibility for the store; although such an outcome is becoming accepted by government and industry, there must be a question as to whether it fully represents a consensus involving the public. In Europe, the Storage Directive dictates that a post-closure plan should be presented as part of the process of gaining a permit for storage but this plan can be amended when the site is ready for closure (which could be 20 or 30 years later). After the regulator has been satisfied that the storage is safe and secure for many years it should be possible to transfer the legal responsibility to the state. Only once experience has been gained with these regulations will the implications be fully understood, establishing whether this approach is fit for its purpose.

1.4.7 Operator

It is not yet clear who will own and operate the storage facilities – currently much of the relevant practical expertise is in the oil and gas industry who are leading on several projects. This seems likely to continue to be the case for the near term but, as the CCS industry achieves sufficient scale of operation, it would seem reasonable to expect that other companies, having acquired relevant sub-surface expertise, will also enter the field.

The European requirements, that the operator must provide a means of financially underpinning the future monitoring of the site after closure, suggests a style of regulation most appropriate for large organisations with substantial assets and ongoing business elsewhere. If this model is followed by other regulators, it seems likely this will have the effect of making it difficult for new/small companies to participate in CO_2 storage.

1.4.8 Finance

CCS projects will necessarily be large and have commensurate capital investment needs. At some point in the future, the market for emission reductions may be sufficiently large and the value of carbon sufficiently high that CCS projects can be funded in their own right but in the immediate future it seems more likely that interim funding arrangements will be necessary, such as those that the EU has put in place for European demonstration projects, and the USA is using to support Futuregen 2.0.

Until the 2011 Durban Conference of the UN Framework Convention on Climate Change, it had not been possible to win support from the Clean Development Mechanism (CDM) for CCS projects. The decision at that conference to accept CCS as one of the technologies that could be accepted in emission reduction projects (and thereby gain credits for the emissions avoided) may make it possible for developing countries to install CCS projects. The practical details of the implementation of this decision will only become clear in time but this could be an important development for CCS – probably the first projects to use this will be ones where CO_2 is separated from natural gas streams and reinjected nearby, as such projects have already been proposed for CDM funding. When and if this mechanism will be used for CCS in power generation projects is unknown at this time but it is likely that some decision makers in relevant industries in countries such as China will be looking into the possibilities (Reiner and Liang, 2012).

As with any other new technology, far more projects are being proposed than actually happen; many potential CCS projects around the world have come to a halt in the planning stage. At present pilot plants are being constructed or are operating in most continents but no full-scale power plants with geological storage are under construction anywhere. Especially disappointing in this respect are the failures of deliberate initiatives, such as the UK CCS Competition, the earlier version of the US Futuregen project and the Australian Zerogen project, to be translated into the construction of new power plant. It has to be hoped that this trend will be reversed in the near future.

1.4.9 Public attitudes and communication

The views of the public are important and can have a major influence on decisions about power plants, CO_2 storage facilities and pipelines. Several studies have been carried out over a number of years into the attitudes of stakeholders in industry and government and the public at large about CCS – these demonstrate the complexity of the influences on public opinion. One aspect that is worth mentioning is the finding that, as people become more aware of climate change and its potential, the more they seem to be prepared to accept CCS. This has been found in UK focus group work (Shackley *et al.*, 2004) as well as in a more recent survey of opinion formers in China (Liang *et al.*, 2011) – such a position is consistent with an understanding that the role of CCS would be to provide deep reductions in emissions.

But when it comes to decisions about specific installations, the attitudes of local people can be of crucial importance. When a research injection was proposed at Ketzin in Germany, local opinion was favourable, not least because of the potential for attracting energy industries to support research in the locality. On the other hand, a proposal to inject CO_2 into a disused gas field in the Netherlands was rejected by local people who did not want it done close to where they lived. The fact that CO_2 storage has technical similarities with other established technologies, such as natural gas storage, does not seem to be a good indicator of likely public reaction towards it. The design of communication campaigns to inform the public and enable them to influence decisions about CCS storage sites is an area that will have to improve if these schemes are to be developed widely. Until there is wider understanding of the value of CCS to everyone, and there is incontrovertible evidence of its safety, it seems likely that winning public acceptance will continue to require a long and patient process of communication and dialogue.

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2

CO_2 storage capacity calculation using static and dynamic modelling

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Abstract: This chapter outlines different methods used for estimating CO_2 storage capacity. The focus is on deep saline formations, which may provide a large storage capacity, but oil and gas reservoirs and unmineable coals seams are also discussed. Two types of method are described: static methods, such as volumetric estimates, and dynamic methods, including reservoir simulation. The chapter concludes with a description of a number of recent surveys of CO_2 storage, such as the US Department of Energy (DOE) CO_2 Sequestration Atlas and the UK Storage Appraisal Project.

Key words: CO_2 storage capacity, CO_2 storage efficiency, CO_2 geological storage, deep saline aquifers.

2.1 Introduction

Estimations of CO_2 storage capacity are of great importance for a number of reasons. Firstly, at national level, countries wish to assess how much CO_2 they will be able to store in the future and whether or not CO_2 storage can provide a feasible method for reducing the levels of CO_2 in the atmosphere. Initial estimates are bound to be uncertain, due to lack of data. However, at later stages, more detailed assessments may be carried out in promising regions, to match up CO_2 sources (e.g. power stations) with potential storage formations.

CO_2 may be stored in depleted oil and gas reservoirs, deep saline aquifers, or unmineable coal seams. Since deep saline aquifers have the greatest storage potential world-wide (e.g. IPCC, 2005), this chapter focuses initially on estimations of storage capacity in saline aquifers. A section on oil and gas reservoirs and on unmineable coal seams is presented later. Over the past two decades, a number of groups have developed methodologies for estimating CO_2 storage capacity. Similar approaches are based on the same physical principles, but differ slightly in their implementation. More recently, efforts have been made to standardise methodologies.

Table 2.1 Summary of methods for assessing CO_2 storage capacity

	Method	Summary
Static	Volumetric	• Calculate formation pore volume • Assume a storage efficiency • Simple approach
	Pressure build-up	• Assume a closed system • Estimate the maximum allowable pressure build-up • Calculate CO_2 volume from total compressibility and pressure increase
Dynamic	Semi-closed	• Similar to the pressure build-up method, but allows water to leak through the seals
	Pressure build-up at wells	• Assumes pressure at injection well is the limiting factor • Uses an analytical formula to estimate the injection pressure
	Material balance	• Similar to the pressure build-up method, but update calculations with time
	Decline curve analysis	• Monitor pressure build-up in a CO_2 injection site • Opposite of decline curve analysis in hydrocarbon reservoir
	Reservoir simulation	• Construct a detailed geological model • Perform fluid flow simulations • Requires most data and is the most time-consuming method

There are basically two types of method for assessing CO_2 storage capacity: static and dynamic. Static approaches are independent of time and include volumetric estimates and calculations based on pressure build-up. On the other hand, in dynamic methods properties vary with time, and these methods include a number of analytical approaches and numerical simulation. In all cases, the volume of CO_2 in the aquifer or reservoir is estimated first, and then knowing the density of CO_2, the mass capacity is calculated. Storage capacities are usually quoted in mega tonnes (10^6 t, denoted by Mt) or giga tonnes (10^9 t, denoted by Gt).

Table 2.1 lists the different methodologies, which are described in more detail below. In this chapter, the different methods for estimating storage capacity are outlined, and examples of results from a number of storage assessment projects are described.

2.2 Static methods for deep saline aquifers

Static methods of storage capacity are outlined first, because they are simpler to apply than dynamic methods.

2.2.1 Volumetric approach

Many deep saline aquifers are very extensive, so that large quantities of CO_2 may be injected without concerns for build-up of pressure. In this case the volumetric approach may be employed. The basic idea is very simple: in order to predict the mass of CO_2 which may be stored in an aquifer, you need to estimate the following:

- the total pore volume of the aquifer
- the proportion of the volume which the CO_2 will occupy and
- the CO_2 density.

If there is little data, the pore volume is calculated from estimates of the areal extent, the average thickness and the average porosity of the aquifer:

$$V_{\mathrm{p}} = A \times H \times \phi \qquad [2.1]$$

where V_{p} is the pore volume, A is the area, H is thickness and ϕ is porosity. Or, if more detailed information is available, the following calculation is performed:

$$V_{\mathrm{p}} = \iiint \phi \mathrm{d}x \mathrm{d}y \mathrm{d}z \qquad [2.2]$$

The CO_2 density depends on temperature and pressure, and can be calculated using an equation of state (e.g. Span and Wagner, 1996).

The estimation of the proportion of pore space which will be occupied by CO_2 is more complex though, and different groups have defined storage efficiency in slightly different ways. All of these methods, however, will ultimately arrive at the same value for the total amount of CO_2 stored. In this chapter, we initially follow the approach taken by the US DOE (2010) and then later compare this with the methodology set out by the Carbon Sequestration Leadership Forum (CSFL) (Bachu *et al.*, 2007). In the 2010 Carbon Sequestration Atlas of the United States and Canada (US DOE, 2010), the proportion of the pore volume which may be occupied by CO_2 is referred to as the storage efficiency, E, and defined as:

$$E = \frac{\text{Volume of CO}_2}{\text{Total pore volume}} \qquad [2.3]$$

Therefore the volume of CO_2 which is stored is:

$$V_{CO_2} = V_p \times E \qquad [2.4]$$

In the Atlas (US DOE, 2010), E is the product of several factors which take account of the fact that CO_2 will not be able to access all of the pore space. The first three factors take account of the proportion of the formation which is available for storage: the vertical and horizontal net-to-gross factors and the ratio of connected porosity to total porosity. The other four factors describe the proportion of the pore space which is contacted by the CO_2, and comprises horizontal and vertical sweep factors, a gravity factor which takes account of the fact that CO_2 is buoyant and rises to the top of an aquifer, and the microscopic sweep efficiency, which is equal to $(1 - S_{wirr})$, where S_{wirr} is the irreducible water saturation.

In the CSFL approach (Bachu *et al.*, 2007), the microscopic sweep efficiency is taken into account explicitly in the determination of the volume of CO_2 which may be stored, as shown in the following equation:

$$V_{CO_2} = C_c \times V_p \times (1 - S_{wirr}) \qquad [2.5]$$

where C_c is referred to as a capacity factor. The capacity factor is related to the storage efficiency:

$$C_c = \frac{E}{1 - S_{wirr}} \qquad [2.6]$$

Note that in the volumetric method, the storage efficiency or the capacity factor must be estimated. This may be done using numerical simulations (e.g. Gorecki *et al.*, 2009, as described in Section 2.5.3).

Volumetric approaches are very useful for making preliminary assessments of CO_2 storage over large regions – for example estimating the storage potential of a country.

2.2.2 Compressibility method

If an aquifer is of limited extent, the pressure will rise as CO_2 is injected, and there is a risk that the formation or caprock could fracture before the volumetric capacity is achieved. In this case, the amount of CO_2 which may be accommodated depends on the compressibility of the pore space and the brine, and the maximum average pressure build-up in the aquifer.

Compressibility, c, is defined as follows:

$$c = \frac{1}{V}\left|\frac{\partial V}{\partial P}\right| \approx \frac{1}{V}\left|\frac{\Delta V}{\Delta P}\right| \qquad [2.7]$$

where V is volume and P is pressure. The total volume which may be stored is estimated as:

$$V_{CO_2} = (c_r + c_w) \times V_p \times \Delta P = c_t \times V_p \times \Delta P \qquad [2.8]$$

where the subscripts r, w and t stand for rock (pore space), water (brine) and total.

The pressure increase, in this case, is the average pressure increase in the formation. Of course, the pressure build-up is greatest at the wells, but this simple approach does not take this into account. According to Zhou *et al.* (2008), the maximum injection pressure should be less than the fracture-closure pressure, and this should be estimated for each reservoir. They give examples of the fracture pressure gradient ranging from 130% to 180% of the hydraulic pressure gradient. More discussion on pressure build-up is given in Section 2.3.2.

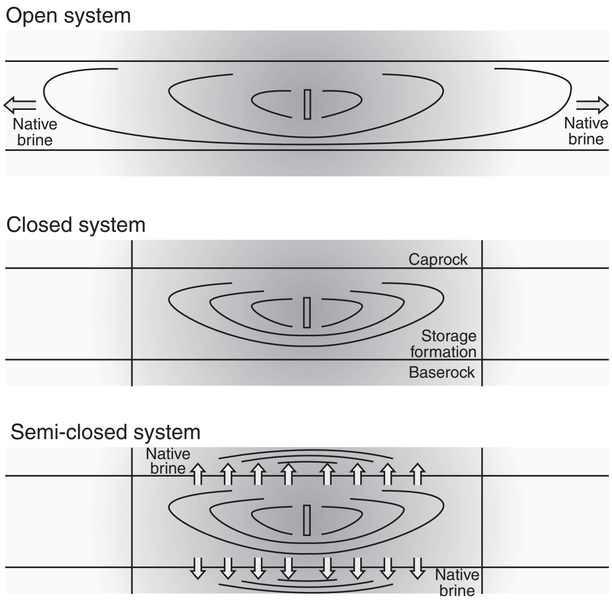
2.3 Dynamic methods for deep saline aquifers

In dynamic methods, the parameters for calculating storage capacity vary with time, and therefore the capacity estimate also varies with time. There are various methods, which range from analytical procedures to full numerical reservoir simulation (Table 2.1). The analytical approaches are described first. These methods rely on making simplifications, such as assuming a homogeneous aquifer, in order to be able to make a fast assessment of storage capacity.

2.3.1 Semi-closed aquifers

This method is related to the pressure build-up method, but it does not assume zero permeability for the seals. As CO_2 is injected into the aquifer, the rising pressure will force brine through the seal, providing more space for CO_2. It is assumed, however, that CO_2 will not leak out, because the capillary entry pressure in such low permeability rocks will be too high. The term 'seal' for the formations above and below the storage formation is therefore still appropriate. Figure 2.1 shows the examples of open, closed and semi-closed aquifers.

Zhou *et al.* (2008) consider a homogeneous cylindrical model which is closed on the lateral boundaries, and has top and bottom seals of equal



2.1 Schematic diagram of open, closed and semi-closed aquifers (Zhou *et al.*, 2008).

thickness, H_s. They derive the following formula for the volume of CO_2 in a semi-closed aquifer, at a particular time, t_I:

$$V_{CO_2}(t_I) = (c_r + c_w)\Delta p(t_I)V_f + 0.5(c_{rs} + c_w)V_s + \int_0^{t_I} \frac{2Ak_s\Delta p(t_I)}{\mu_w H_s}\,dt \quad [2.9]$$

where c is compressibility as before, with c_{rs} representing the pore compressibility of the seal. V is volume, with subscripts f and s standing for the formation (aquifer) and the seal, A is the area of the aquifer and k_s is the seal permeability. The equation may be discretised into a number of time steps in order to calculate the pressure as a function of time, and therefore to estimate the storage capacity as a function of time. Zhou *et al.* (2008) tested seal permeabilities of 10^{-17}–10^{-20} m^2 (10^{-2}–10^{-5} mD), and found that if the seal permeability is 10^{-17} m^2 or higher, the aquifer is effectively open.

2.3.2 Pressure build-up at wells

As stated in Section 2.2.2, the simple pressure build-up method assumes an average pressure build-up throughout an aquifer. A more accurate approach is to consider the maximum pressure build-up at a well in order to determine the maximum CO_2 storage capacity. Such a method has been developed by Mathias *et al.* (2009a, 2009b). Using certain simplifying assumptions such as a homogeneous aquifer, a sharp interface between the CO_2 and brine and no mutual dissolution, they derived a formula for the pressure build-up at an injection well. This equation allows the estimation of the pressure at an injector as a function of averaged properties for an aquifer, such as the permeability, the thickness, the fluid viscosity, the brine and rock compressibilities and the CO_2 density. Mathias *et al.* (2009a) assumed that the maximum pressure depends on the pressure for tensile failure, and set the limit as 90% of this pressure. They then showed how their method may be used as a screening tool for potential CO_2 storage sites.

More recently Mathias *et al.* (2011) have extended the calculations on pressure build-up to include mutual dissolution of CO_2 and brine. This work shows that the evaporation of water into the CO_2 can increase the relative permeability of CO_2, thereby reducing the pressure build-up.

2.3.3 Traditional engineering approaches

Frailey (2009) points out that decline curve analysis may be used to estimate how much CO_2 may be injected into an aquifer, in the same way as the total production from an oil reservoir may be estimated. If CO_2 is injected at a constant pressure, the rate will gradually decline as pressure builds up in the formation. It is assumed that the injection rate decreases exponentially with time, so that

$$q_{CO_2,t} = q_{CO_2,i} \exp(-Dt) \qquad [2.10]$$

where q_{CO_2} is the injection rate and subscripts t and i are for a particular time and the initial time, respectively. D is the decline coefficient. This method may be used when a certain amount of CO_2 has already been injected. A plot of $\log\ (q_{CO_2})$ vs. time will be approximately a straight line, the slope of which gives the value of D. It is assumed that there is a minimum economical rate for CO_2 injection, $q_{CO_2,A}$. Then (Equation [2.10]) may be integrated to calculate the total amount of CO_2 which may be injected.

$$V_{CO_2} = \frac{q_{CO_2,i} - q_{CO_2,A}}{D} \qquad [2.11]$$

This approach is different from other methods discussed so far, in that it is not a method for estimating the storage capacity in advance, but is a simple method for estimating the total amount of CO_2 which may be stored once a storage project is under way.

Frailey (2009) also suggests using the material balance equation for estimating storage capacity. This is a method used in the oil and gas industry to estimate the initial volume of oil or gas in place and to predict future recovery. In the material balance method, production is related to the change in pressure in a reservoir through the expansion of reservoir fluids, compression of the pore space and aquifer influx. The same equation may be used for relating pressure build-up in a reservoir with the volume injected, the compression of the existing brine and any efflux of brine from the storage site into surrounding formations. This method could be applied to a site where CO_2 is already being stored and some pressure measurements are available. The results could be used to estimate the amount of brine leaking from the storage site, and then could be used to predict the capacity for CO_2, assuming a maximum pressure limit.

2.3.4 Numerical reservoir simulation

Most of the methods considered above assume that the aquifer has a simple geometry and that it is homogeneous but, of course, aquifers may be irregular in shape and heterogeneous. Heterogeneities may be in the form of laterally continuous layers of shale within an otherwise high permeability sandstone (e.g. in the Utsira Formation at Sleipner), or the whole aquifer may consist of a complex arrangement of sand bodies within a low permeability mudstone. Whatever their nature, heterogeneities are likely to affect the migration of CO_2 – both vertically and laterally, and may also affect the pressure build-up near a well.

Analytical methods also usually neglect some of the physical processes which take place when CO_2 is injected into a formation, such as CO_2 dissolution in brine, evaporation of water in CO_2 and residual trapping of CO_2 at the pore scale. The dissolution of CO_2 in brine reduces the volume of free CO_2, thereby reducing the pressure, and so allowing more CO_2 injection. The residual trapping of CO_2 reduces the amount of migration. Therefore in a formation where the storage capacity is limited by seepage out of a specified region, the storage capacity may be underestimated if residual trapping is not taken into account.

In order to take account of reservoir heterogeneity and flow physics a dynamic simulation is required, using either a reservoir simulation software package which has been adapted for CO_2 injection, or purpose-built software. A description of various codes which may be used to simulate CO_2 injection is given in Class *et al.* (2009).

There are two purposes for building reservoir simulation models. Firstly, typical structures may be studied in order to calculate storage efficiencies to use in the volumetric estimate (Section 2.2.1), or to compare with the other storage capacity estimates. In this case, although it is useful to have some data on which to base a model to make it realistic, the models do not depend on having a lot of data. Secondly, a reservoir simulation model is essential for making a more informed estimate of CO_2 storage capacity at a chosen storage site. In this case, a lot of data is required, and considerable effort is needed to build a geological model.

Once a model has been constructed, wells are placed at chosen locations within the model and CO_2 injection is simulated. A number of criteria may be used to control the simulation, and assess when the maximum capacity is reached. In a typical simulation, CO_2 may be injected at a constant rate and the bottom-hole pressure (BHP) monitored. If the BHP reaches an unacceptable level (e.g. 90% of the fracture pressure at that depth), then the well rate may be cut back. The pressure may also be monitored in other locations in a model, such as under the caprock, and injection cut back if the pressure exceeds the maximum allowed at that point. At the same time the migration of CO_2 may be monitored, and when it reaches a spill point, injection may be stopped (e.g. Williams *et al.*, 2013). The capacity of an aquifer may be estimated as the mass injected until a stopping criterion is reached. The storage efficiency can then be calculated as:

$$E = \frac{M_{\text{inj}}}{\rho V_{\text{p}}} \quad [2.12]$$

where ρ is the density of CO_2 in the reservoir (e.g. Jin *et al.*, 2012). This method does not distinguish between free and dissolved CO_2. An alternative approach was employed by Gorecki *et al.* (2009). They computed the volume of the plume of free CO_2, assuming a cuboid shape (for simplicity), and then calculated the storage efficiency from this volume divided by the total pore volume.

2.4 Storage capacity in oil and gas reservoirs and unmineable coal seams

Sections 2.2 and 2.3 have focused on deep saline aquifers, because there is more storage potential in saline aquifers and more effort has been put into estimating the storage capacity of aquifers.

2.4.1 Oil and gas reservoirs

The storage capacity of a depleted oil or gas reservoir may be estimated more accurately than that of a saline aquifer, because more information is available on the extent of the reservoir and the rock properties. In addition, the fact that oil or gas has been trapped in a particular formation over geological time periods confirms the presence of a seal. It is usually assumed that the volume of CO_2 which may be stored in a reservoir is equal to the volume of oil or gas which has been produced, or will potentially be produced. For example, in an oil reservoir, the volume of CO_2 which may be stored is given by Bachu *et al*. (2007) as:

$$V_{CO_2} = R_f \times \text{STOIIP} \times B_o \qquad [2.13]$$

where STOIIP is 'stock tank oil initially in place' (i.e. volume at surface conditions), R_f is the recovery factor; and B_o is the oil formation volume factor, equal to the reservoir volume divided by the surface volume. If water has been injected into or produced from the reservoir, this must also be taken into account. The volume of CO_2 which may be stored may also be directly calculated from the volume of the reservoir as:

$$V_{CO_2} = R_f \times A \times H \times \phi \times (1 - S_{wc}) \qquad [2.14]$$

where A and H are the area and thickness of the reservoir, ϕ is porosity and S_{wc} is the connate water saturation (the proportion of the pore space which initially contains water).

Alternatively, the volume of CO_2 which may be stored may be estimated from produced and injected volumes. For example, for an oil reservoir, the following formula may be used (Gammer *et al*., 2011):

$$V_{CO_2} = N_p B_o + (G_p - N_p R_s) B_g + W_p B_w - W_i B_w - G_i B_g \qquad [2.15]$$

where N_p is the volume of produced oil (measured at the surface), W and G are the volumes of water and gas produced or injected, in surface units, R_s is the dissolved gas ratio and B is the formation volume factor (= reservoir volume/surface volume). The subscripts w, g, i and p stand for water, gas, injected and produced, respectively.

Note that this storage capacity may not be achieved for several reasons. For example this method assumes that when CO_2 is injected into the reservoir, the pressure can build up to the level before production started. However, this is not the case if the integrity of the reservoir or the seal has been damaged during depletion (Bachu *et al*., 2007). Also, if there is an aquifer associated with the reservoir, water may flow into the reservoir as the oil is produced. When CO_2 is subsequently injected, it will displace part of this water, but there will be residual water, which will limit the storage volume.

2.4.2 Unmineable coal beds

CO_2 may be absorbed onto coal, so unmineable coal beds may be used for CO_2 storage. An estimate of the storage capacity may be made using a volumetric method. According to US DOE (2010), the volume may be approximated as:

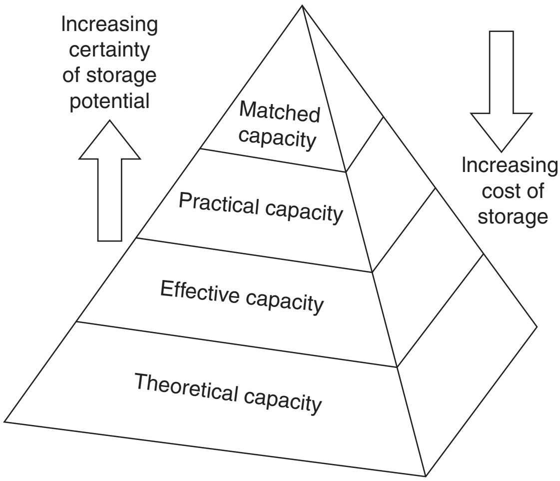
$$V_{CO_2} = A \times H \times C_{s,max} \times E_{coal} \quad [2.16]$$

where $C_{s,max}$ is the maximum absorption of CO_2 per unit volume of coal, and E_{coal} is a storage efficiency for coal seams. According to the US DOE (2010), the value for $C_{s,max}$ depends on the pressure and the type of coal. Values range from approximately 0.04 to 0.1 g/cc. The storage efficiency for CO_2 in coal beds is greater than in saline aquifers, due to the adsorption of CO_2. The US DOE (2010) quote a range of 21–48%. However, the total storage capacity in coal beds is low. According to the IPCC (2005), coal seams only have 1–2% of the storage capacity of saline aquifers.

Note that methane also is adsorbed onto coal, but not as strongly as CO_2. Therefore by injecting CO_2 into coal seams, methane which had previously adsorbed onto coal may be displaced. This is known as enhanced coal bed methane (ECBM) and is a proposed method for production of methane.

2.5 Examples of CO_2 storage assessment projects

There have been a number of studies to estimate CO_2 storage potential in various countries throughout the world. One of the first groups to draw up a systematic methodology for capacity estimation was the Carbon Sequestration Leadership Forum (CSLF) (Bachu *et al.*, 2007). They distinguish between 'resources', which in this sense means estimates of the total storage space for CO_2 including both proved and unproved volumes, and 'reserves', which refers to commercially viable storage capacity. Bachu *et al.* (2007) drew up a 'Techno-Economic Resource-Reserve Pyramid' to represent the way in which the storage estimates are reduced as more constraints are taken into consideration. See Fig. 2.2. The base of the pyramid represents the theoretical storage capacity which is the maximum possible capacity, ignoring any technical or economic limitations. The next level is the effective storage which is less than the theoretical capacity due to physical or technical limitations. Above this, is the practical capacity which takes account of technical, regulatory and legal constraints. Finally, at the top, there is the matched capacity, which is the part of the storage volume which can be matched up with large sources of CO_2 emissions, such as power stations.



2.2 CO_2 storage pyramid. (*Source*: After Bachu *et al.*, 2007.)

Note that the oil industry classifies reserves into 'proved', 'probable' and 'possible'. However, CO_2 storage has not developed sufficiently as an industry for these categories to be defined. At this stage, the term 'reserves' is still very uncertain for CO_2 storage.

2.5.1 The US Department of Energy (DOE) Carbon Sequestration Atlas

The third edition of this Atlas, which covers the USA and parts of Canada, was published in 2010. It includes a section on national perspectives for CO_2 storage, followed by more detailed estimates of storage capacity in different regions along with descriptions of current or planned pilot projects. Appendix B of this document (US DOE, 2010) outlines the methods used for estimating storage capacity in saline aquifers, oil and gas reservoirs, unmineable coal seams and also basalt deposits. They use the volumetric method, which has been summarised briefly in Section 2.2.1. However, since the Atlas aims to provide storage capacities on a regional scale, over which the rock properties are uncertain and are likely to be variable, a stochastic approach was taken, and the results were presented in terms of P10, P50 and P90. (A P10 value means that there is a 10% probability that the storage capacity is less than that value, and so on.) The final results for saline aquifers, in terms of storage efficiencies, are summarised in Table 2.2. In the section of the Atlas (US DOE, 2010), capacities in Mt are presented for each of the nine regions in the USA and Canada which were investigated.

Table 2.2 Storage efficiency estimates for deep saline aquifers, US DOE (2010)

Lithology	P10 (%)	P50 (%)	P90 (%)
Clastics	0.5	2.0	5.4
Dolomite	0.6	2.2	5.5
Limestone	0.4	1.5	4.1

2.5.2 Kopp, Class and Helmig's study of factors affecting CO_2 storage

Kopp *et al.* (2009a, 2009b) carried out a general study of factors affecting CO_2 storage. They pointed out that the storage capacity depends on the migration of the plume, which depends on the balance of forces (viscous, gravity and capillary) (Kopp *et al.*, 2009a). For example, the larger the ratio of gravity/viscous forces, the greater the effect of the buoyant rise of CO_2, and therefore the lower the storage efficiency. However, if the injection rate is higher, so that the gravity/viscous ratio is smaller, the plume has a more cylindrical shape, which leads to a higher storage efficiency.

They used data from the US National Petroleum Council public database, assuming that physical properties for saline aquifers are similar to those of hydrocarbon reservoirs. From this database, they identified properties (depth, temperature, permeability and porosity) for a 'median' reservoir, which they used as a base case. They also tested formations which were warmer, cooler, shallower and deeper; and with lower permeability, high capillary pressure and with a range of relative permeabilities. They performed a range of 1D and 3D simulations and calculated capacity factors after Doughty *et al.* (2001). These are similar to the CSFL factors (Bachu *et al.*, 2007), but they consider the volume of CO_2 relative to the total bulk volume, rather than the total pore volume. They presented storage capacities in terms of the mass of CO_2 stored, rather than the volume, because the density of CO_2 is different in different models – depending on the depth (and therefore the pressure) and temperature. Rather counter-intuitively, they estimated that a low permeability improves the storage efficiency. This is because low permeability decreases the gravity/viscous ratio. However, they did not take into account the build-up of pressure which could limit the amount of CO_2 stored.

One important aspect of their work is the recognition of the effect that relative permeability has on the storage capacity. There are very few measurements of relative permeability in CO_2-brine systems. Most studies make use of measurements by Bennion and Bachu (2008). Different types of rock have different irreducible water saturations, S_{wirr}, which determines the maximum CO_2 saturation. Also the shape of the relative permeability curves governs the saturation profile and the average saturation behind the CO_2 front. Kopp *et al*. (2009b) state that their results were more sensitive to relative permeability than to depth and temperature.

2.5.3 A study of CO_2 storage potential by the Energy and Environmental Research Center (EERC), University of North Dakota

Gorecki *et al*. (2009) of the Energy and Environmental Research Center (EERC) at the University of North Dakota carried out a thorough study of CO_2 storage potential, and the factors which affect it. They used the volumetric method, and calculated the efficiency, E, using the US DOE (2010) methodology and also the capacity factor, C_c, used by CSLF (Bachu *et al*., 2007). As mentioned above (Equation [2.6]), these two factors are related. They used geological and other data from the US DOE and the Average Global Database (AGD) which contains data for oil and gas reservoirs world-wide (assuming that data from the oil and gas reservoirs was appropriate for saline aquifers). In addition to making volumetric calculations, they also performed numerical simulations on a wide variety of models of varying structure (e.g. flat, tilted or dome-shaped) and internal heterogeneity to represent a wide variety of rock types.

An initial study focused on homogeneous models and investigated the sensitivity of E factors to various effects. They considered E in a homogeneous reservoir to be a product of two factors, the volumetric efficiency, E_V, and the microscopic displacement efficiency, E_d. E_V is the product of the areal sweep efficiency, the vertical sweep efficiency and the gravity factor, that is, the proportion of the formation thickness which is contacted by CO_2, on account of its buoyant rise. The DOE methodology (US DOE, 2010) separates these factors. However, E_V was treated as a single factor in the EERC project due to the difficulties in splitting these effects. As mentioned above (Section 2.3.4), Gorecki *et al*. (2009) computed the volume of the plume of free CO_2, assuming a cuboid shape, and then calculated the storage efficiency from this volume divided by the total pore volume. The microscopic sweep efficiency, E_d, in this case was calculated from the average gas saturation within the plume. The results of the study by Gorecki *et al*. (2009) provide insight into the effects which different factors have on storage efficiency. In a number of cases, factors affect E_V and E_d in opposite ways. For example, as the ratio of vertical to horizontal permeability (k_v/k_h) increases, the buoyancy effect increases and this decreases E_V. On the other hand, a strong buoyancy effect leads to a high concentration of CO_2 at the top of the aquifer, and a high average saturation within the plume, thereby producing a high E_d. In their simulations, Gorecki *et al.* (2009) found that the effect on E_V was dominant and a high k_v/k_h lowered the overall storage efficiency. Like Kopp *et al.* (2009a, 2009b), they also found that relative permeability has a significant effect on storage capacity.

To summarise the tests on homogeneous models, the highest storage efficiencies were obtained for deep, hot aquifers with high curvature (dome-shaped), with a low k_v/k_h and a high injection rate. Values of E ranged from 0.07 to about 0.25 (7–25%).

A range of heterogeneous models was also tested and the P50 results ranged from approximately 6% to 8%. The full range of efficiencies, from the lowest P10 to the highest P90, ranged from 4% to 17%. Note that these values are larger than the efficiencies quoted in the US DOE (2010). This is because they are site-specific values (i.e. determined from a model which is supposed to represent a storage site). At a specific site which has been chosen for CO_2 storage, the rock properties are better than the average rock properties over a whole formation, and so the proportion of the pore space available for CO_2 storage is higher. When Gorecki *et al.* (2009) took this into account the P50 storage efficiencies decreased to 2–3%, which is comparable to the P50 estimate from the DOE Atlas (2010).

The main results presented by Gorecki *et al.* (2009) are for open aquifers. They also give an example of a closed aquifer, using the pressure build-up method. In the case considered, the storage capacity (in Mt) for the closed system was only 1/25th of the capacity of an open system with identical properties.

2.5.4 The Energy Technologies Institute's UK CO_2 Storage Appraisal Project (UKSAP)

Gammer *et al.* (2011) describe the methodology which was used in the Energy Technologies Institute's UK CO_2 Storage Appraisal Project (UKSAP). The aim of this project was to provide a 'realistic, defensible and fully auditable estimate' (Gammer *et al.*, 2011) of the CO_2 storage potential of the UK offshore formations, using existing data from deep saline aquifers and hydrocarbon reservoirs. Offshore reservoir formations were divided into storage units with similar properties and the storage capacity of each storage unit was assessed. Since formation properties (e.g. areal extent, thickness and porosity) are uncertain the minimum, most likely and maximum values were stored. Saline aquifers were categorised depending on whether they were closed or open structures, and the open structures were further divided according to whether they were completely open, or were 'daughter units', such as domes which acted as partial traps. The storage capacity of the closed aquifers was calculated using the pressure method described above (Section 2.2.2). In the case of the open aquifers and daughter units, dynamic simulations were performed to estimate the storage factor (i.e. storage efficiency). The capacity of hydrocarbon reservoirs was estimated from the production, as described in Section 2.4.1. Monte Carlo simulations were performed to produce P10, P50 and P90 estimates the of storage capacity.

2.6 Conclusion

In summary, estimates of CO_2 storage capacity are highly uncertain, because of lack of data. The most difficult aspect of calculating storage capacity is the estimate of volumetric storage efficiency. This depends on a number of factors, not just geological parameters, such as thickness and extent of an aquifer, but also on petrophysical parameters, such as relative permeability. Moreover, the storage efficiency depends on a range of factors which have opposing effects (Gorecki *et al*., 2009), which makes it difficult to draw up general rules.

Physical properties in the reservoir also affect mass capacity estimates. The density of CO_2 depends on the pressure and temperature, which may be uncertain. In particular, the temperature may not be accurately known in a saline aquifer.

A figure of 2% is often used for regional estimates in open aquifers (see, e.g., US DOE, 2010). In specific sites, the value may be larger than this (Gorecki *et al*., 2009). For closed aquifers the value will be considerably smaller, depending on the size of the aquifer (Gorecki *et al*., 2009).

2.7 Challenges and future trends

The main challenge to estimating CO_2 storage capacity is the lack of data. Deep saline aquifers are thought to have a large storage potential (IPCC, 2005) but these have not been surveyed in detail. In recent years, many countries have undertaken projects to evaluate their CO_2 storage potential. These estimates are based on existing knowledge of aquifer extents and statistics of properties such as net-to-gross and porosity. Many surveys try to account for the uncertainty by quoting ranges of capacity (P10, P50, P90). Obviously these types of estimate are very rough, but they can assist companies and governments in making decisions for the future. Moreover, initial surveys are essential for identifying promising locations for future storage.

One problem with initial estimates of CO_2 storage was that different groups were drawing up slightly different methodologies and terminologies. Although these methods were broadly similar, using the volumetric approach, this was confusing for readers. The main methodologies drawn up in the USA were by the CSLF (Bachu *et al*., 2007) and US DOE (2010).

Gorecki *et al*. (2009) gives a useful comparison of methods. At the present time there is no standard approach.

Spencer *et al*. (2010) criticise current approaches, claiming that estimates are often too uncertain to be of use. The next challenge is therefore to start to make more reliable estimates of storage capacity, focusing on particular regions, and eventually on specific sites. It is crucial to obtain more data on aquifer extents (and pore volumes), because this affects pressure build-up during injection. It is also vital to learn more about the effectiveness of the caprock seal, which determines the limiting pressure. The simple capacity estimates described in previous sections either ignore rock heterogeneity or treat it using a net-to-gross factor. However, heterogeneity will be important when making site-specific estimates. At this stage, detailed geological models and numerical simulations become necessary.

2.8 Sources of further information and advice

Several useful reports on CO_2 storage capacity may be obtained from the internet.

- A description of the methodology developed by the Carbon Sequestration Leadership Forum (CSFL) may be found in Bachu (2007), and other CSFL publications. The web site is: http://www.cslforum.org/publications/index.html?cid=nav_publications?cid=nav_publications.
- The US Department of Energy methodology, which was used in the Atlas of the United States and Canada, is also available on the internet: http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlasIII/index.html. The methodology is described in Appendix B. In 2012, a new version of this Atlas, which also includes Mexico, was published (US DOE, 2012). This new version uses the same methodology as the previous version, but does not give so much detail. It is available on the internet at: http://www.netl.doe.gov/technologies/carbon_seq/refshelf/NACSA2012.pdf.
- Full details of the Gorecki *et al*. (2009) study are in an IEA-GHG Technical Report (2009): http://www.ieaghg.org/index.php?/technical-reports.html. The report is not downloadable, but may be obtained by emailing, as instructed on the website.
- Two additional storage atlases have recently been released: the Queensland Carbon Dioxide Geological Storage Atlas (Queensland Government, 2012) and the CO2 Storage Atlas, Norwegian North Sea (Norwegian Petroleum Directorate, 2012). The Norwegian Atlas may be downloaded from: http://www.npd.no/Global/Norsk/3-Publikasjoner/Rapporter/PDF/CO2-ATLAS-lav.pdf.

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3

Modelling the injectivity, migration and trapping of CO_2 in carbon capture and storage (CCS)

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Abstract: CO_2 injection into subsurface geological formations induces changes in the state of the system, as characterised by local pressure and saturation changes. Being able to understand, predict, monitor and manage such changes is critical to the successful development of carbon capture and storage (CCS) projects. Key to this is the ability to model injectivity, migration and trapping of CO_2. While injectivity can be understood using analytical models, migration and trapping calculations are generally carried out using numerical codes. A good understanding of the various trapping mechanisms can assist with developing engineering options to maximise storage capacity and security. The financial viability of CCS projects may be enhanced by consideration of CO_2-enhanced oil recovery (EOR).

Key words: injectivity, migration, trapping, simulation, storage capacity, storage security, aquifers, CO_2-enhanced oil recovery (CO_2-EOR).

3.1 Introduction

As noted in Chapter 2, storage of CO_2 may take place in a variety of subsurface scenarios. These include:

(a) salt water aquifers;
(b) depleted hydrocarbon reservoirs once they have reached the end of their productive lives;
(c) producing hydrocarbon reservoirs – as part of an Enhanced Oil Recovery (EOR) or Enhanced Gas Recovery (EGR, not covered here) project;
(d) unmineable coal seams – as part of an Enhanced Coal Bed Methane (ECBM, not covered here) project.

In all cases, one objective is evidently the safe storage of CO_2, such that it will never emerge from the subsurface in an uncontrolled fashion – that is, it will never leak out of the storage complex, however that may be defined. However, storage of CO_2 may not always be the only objective, and sometimes may not even be the primary objective; an example would be CO_2-EOR in scenarios where maximising oil recovery is the primary aim, or where the supply of CO_2 is constrained and production of CO_2 from the reservoir for reinjection may minimise the cost of importing CO_2. Nevertheless, in all scenarios the injection of CO_2 will alter the state of the subsurface system in two principal ways.

First of all, during the injection period there may be significant changes in pore *pressure*, particularly evident close to the injection locations, but depending on the connectivity of the porous medium, potentially having an impact kilometres or even tens of kilometres away. These pressure changes will in general be relatively rapid as the pressure wave diffuses away from the injection point. At the injection location itself, pressure changes will effectively be instantaneous as CO_2 starts to be injected, or as there are changes in the injection controls. Pressure changes away from the well will first be observed in a matter of seconds, minutes or perhaps days, depending on distance from the well. However, the pressure changes may not become fully established for periods of weeks, months or even years. The following simplified single phase compressible pressure equation describes how fast the pressure wave diffuses through the porous medium:

$$\left(\frac{\partial P}{\partial t}\right)=\left(\frac{k}{\mu\varphi c_f}\right)\left(\frac{\partial^2 P}{\partial x^2}\right) \qquad [3.1]$$

where the pressure, P, varies with time, t, and distance, x, and k is absolute rock permeability, μ is fluid viscosity, φ is rock porosity and c_f is fluid compressibility. The term $(k/\mu\varphi c_f)$ is known as the hydraulic diffusivity constant: the larger this constant, the faster the pressure wave will diffuse through the porous medium. In zones where there are multiple phases present, then the speed with which the pressure wave propagates is more complicated to calculate, and CO_2 compressibility in particular is sensitive to changes in pressure and temperature, and in turn the extent of CO_2 dissolution affects the compressibility of liquid phases present in the reservoir.

Secondly, during the injection CO_2 will be displaced away from the wellbore, and thus there will be changes in fluid *saturations* in the subsurface rock. However, even once injection has stopped, CO_2 migration may continue, primarily due to buoyancy effects, and saturation changes may continue for decades, centuries or even millennia. Not only may the migrating CO_2 displace the native formation fluids, but these fluids may re-saturate zones previously occupied by CO_2, should the CO_2 plume migrate up dip, say. The velocity at which a fluid is displaced through the porous medium is given by a form of the Darcy law:

$$u_i = \left(\frac{k \cdot k_{ri}}{\mu_i}\right)\left(\frac{\partial P_i}{\partial x} - g\rho_i \frac{\partial z}{\partial x}\right) \qquad [3.2]$$

where u_i is velocity of phase i, k is absolute permeability, k_{ri} is relative permeability to phase i, μ_i is viscosity of phase i, P_i is pressure of phase i, g is acceleration due to gravity, ρ_i is density of phase i, and x and z refer to distance in the horizontal and vertical directions, respectively. The higher the absolute permeability of the rock, or the higher the mobility of the fluid in the rock (k_{ri}/μ_i), or the higher the imposed pressure gradient, or the larger the density difference between phases and the greater the dip angle, then the faster the CO_2 will migrate away from the point of injection.

It is evident from these two equations that there are various parameters that affect CO_2 injection and migration. One parameter that is common to both is absolute permeability, k. A high permeability is beneficial in terms of enhancing pressure dissipation and hence reducing the risk of excessive pressure build-up in and around the injection well; however, a high permeability may also allow the injected CO_2 to migrate faster and further into the formation, with the attendant risk of it migrating out of the storage complex altogether.

In the case of salt water aquifers, storage will be the primary, and probably sole objective of the project, and indeed project sanction may be dependent on the ability to demonstrate that injected CO_2 will remain confined within the storage complex. Although in scenarios that entail hydrocarbon recovery, CO_2 storage capacity may not be the only or even the primary consideration as noted already, ensuring CO_2 storage security will nonetheless be important. As discussed in Chapter 4, the storage capacity of a complex is evaluated by considering the amount of CO_2 that can be injected securely – that is, without any escaping. Storage security can only be determined by considering the *pressure and saturation* changes that will arise due to CO_2 injection: they should not result in CO_2 migrating to a potential leakage pathway.

A leakage pathway may be induced by human activity during the CO_2 injection process, or may already exist somewhere in the system. Thus it is critical not to create new leakage pathways during a storage project, and to ensure that injected CO_2 does not migrate towards existing potential leakage locations. The former is achieved by appropriate *pressure* control, the latter by controlling *saturation* changes in the system. As noted in Chapter 3, both require a good knowledge of the geology of the target formation and enclosing strata, and how the rock and pore fluids will respond to changes induced by the injection of CO_2. These changes include pressure, temperature, fluid compositional and phase behaviour, and geochemical and geomechanical properties.

Since, as already noted, pressure variations tend to be fast acting, and since pressure changes dissipate away from the injection wells, pressure control tends to be an issue of overall system volumetrics and local well controls – location of wells and properties of the rock immediately around the well, completion type and length, and particularly the instantaneous flow rate. On the other hand, saturation changes and migration pathways are also impacted by well location, but are particularly dependent on rock properties away from the well and long term-injection volumes. Thus, managing pressure in the system is usually most important during the injection period, whereas monitoring and managing saturation changes will be an issue for as long as the CO_2 is mobile and migrating, possibly for decades to millennia after injection has ceased.

Prediction of pressure response and migration pathways is amenable to the standard reservoir engineering calculations regularly used in the oil industry. While allowable pressure changes may be calculated by either analytic or numerical methods, calculation of migration pathways tends to be carried out solely by numerical modelling, since the heterogeneity of subsurface formations tends to mean that identifying migration pathways cannot be solved analytically. Indeed, solution by numerical methods still entails a high degree of uncertainty, since it is very sensitive to the geological and fluid descriptions. Small changes in the permeability field, in the topology of surfaces such as at the interface between the storage formation and the cap rock, and in CO_2 mobility, particularly near the critical point, can influence migration quite strongly.

Simulation of CO_2 migration and dissolution into the brine phase are impacted by grid resolution. The calculation of the lateral extent of the migration is particularly influenced by the vertical grid resolution immediately below the cap rock. Furthermore, all the CO_2 that is calculated to have been displaced into a grid block during a given time step is assumed to be able to contact, and therefore dissolve into, all the brine in that grid block, and therefore coarser models will suffer from a significant over-prediction of the amount of CO_2 dissolved. Plate I (see colour section between pages 214 and 215) illustrates the simulation of a test injection of CO_2 at the Ketzin site.

Calculation of the pressure response of the system, and the impact on injection capacity, is addressed in Chapter 4, and is only discussed further here in terms of the impact that reservoir processes may have on wellbore pressure. Thereafter we concentrate on the issue of CO_2 migration routes, the potential impacts of various subsurface geological settings, and the engineering options for maximising storage capacity and security.

3.2 Reservoir processes and how they are modelled

As CO_2 is injected into a formation, the state of the system is altered, with pressure and saturation being two of the main parameters used to evaluate that change. The change in saturation is related to the change in pressure through material balance and the Darcy flow equation. Indeed, these are the two primary parameters that are calculated in every grid cell at every time step in all conventional finite difference reservoir simulation models. While during the prediction of hydrocarbon recovery it is the impact that these parameters have on the volume of fluids being produced that is often the focus of the calculations, in carbon storage calculations it is these parameters themselves that are of primary interest – that is, what is the fate of the CO_2, and what is the impact on the pressure distribution? While it is possible to run a simulation for hydrocarbon recovery in which the only output analysed in detail is the recovery of hydrocarbon, it is difficult to envisage a CO_2 injection simulation in which consideration is not at least given to the spatial distribution of CO_2, if not also to the pressure footprint.

In calculating pressure and saturation distributions throughout a formation, a simulator must take account of the various processes occurring in the reservoir that will impact these parameters. These processes are intrinsic to the flow of fluids in a porous medium, and include fluid phase behaviour, fluid–fluid interactions and fluid–rock interactions. The main processes arise from the viscous, gravitational and capillary forces, which are described in more detail below, but in the case of CO_2 injection also include geochemical, geomechanical and dissolution effects.

3.2.1 Impact of reservoir processes on injection pressure

Considering (Equation [3.2]), for a given CO_2 injection rate the pressure in the well will increase more if the injected CO_2 cannot be readily displaced away from the well. This could occur under various circumstances, for example:

(a) low rock conductivity;
(b) low fluid mobility;
(c) precipitation of solids (e.g. halite due to brine evaporation) or mobilisation of fines (due to dissolution of cements in the presence of acid brine) and blocking of pore throats by the solids.

Indeed, all these processes are usually coupled in the real physical system, even if they can be decoupled in our calculations. For example, low rock conductivity, as characterised by low absolute permeability, k, often results in more tortuous pathways, with more dead end pore space. The knock on effect is that when two phases are flowing, say CO_2 is displacing brine, then in low permeability rock there are fewer pathways the CO_2 can take because more of the pores are occupied with brine that cannot escape, and so the relative permeability to CO_2, k_{rCO_2}, is also reduced. Mobilisation of solids will reduce the rock conductivity, and would typically be modelled by a reduction in the absolute permeability.

For a homogeneous system, the definition of absolute permeability is usually independent of the scale at which it is being defined (say the size of the grid block); relative permeability is scale dependent. This is because relative permeability is defined as a function of fluid saturation, and saturation is scale dependent. (For example, injection of CO_2 one metre into the formation will result in a different saturation if a 10 m grid block is being used for the calculation compared to a 100 m grid block).

Also of importance to injectivity is the overall pressure response of the system. If CO_2 is injected into a relatively small volume system with closed boundary conditions, then the overall system pressure will increase more rapidly than if injection takes place in a large aquifer with no sealing faults and open boundary conditions. As the overall system pressure increases, then the injectivity of the well will decrease. Indeed in the case of injection of CO_2 produced from the Snøhvit field in Norway, the initial injection into a deep aquifer had to be stopped because of increasing downhole pressures. This was identified not to be due to problems with the injection well itself, but because the volume of rock the CO_2 was being injected into was smaller than anticipated. Subsequent injection into a shallower formation has proved more successful.

Thus injection pressure will be determined by a combination of wellbore and reservoir factors. The internal diameter (ID) and roughness of the inner surface of the well affect the frictional pressure drop along the well. In many calculations, for example Schlumberger (2012), the frictional pressure drop is calculated to be linearly proportional to length, density and a friction factor (which is a function of the Reynolds number and the roughness), is proportional to the square of the flow rate, but is inversely proportional to the wellbore diameter to the power five. Thus wellbore ID is a very sensitive factor in determining bottom hole injection pressure. Bores with larger IDs are more expensive to drill, and hence there is an economic penalty to sizing a wellbore to maximise injection capacity. Drilling deviated or horizontal wells can improve injectivity by increasing the contact between the wellbore and the formation (a part of the well called the completion), but the fact that the frictional pressure drop is proportional to length also means that there will be a maximum completion length beyond which there will be no additional benefit: the pumped CO_2 will simply not propagate as far as the 'toe' of the well if the distance between the 'heel' and the 'toe' is too great.

In addition to the density, the viscosity and the compressibility of the CO_2 in the wellbore will affect injection pressure. Since these parameters will vary with temperature and pressure down the tubing, a model of fluid flow in the wellbore will need to include the Equation of State (EOS) for CO_2, as in Galic *et al*. (2009) and Azaroual *et al*. (2012), and should also account for any impurities in the injection stream, as well as more prosaic factors such as temperature variations between summer and winter.

Thus bottom hole pressure will be affected by a complicated mix of factors, including fluid properties in the wellbore, the wellbore configuration, fluid properties in the reservoir, interactions between the various fluids in the reservoir, and between the fluids and the rock, and the overall storage complex geometry and pressure connectivity. For example, Mathias *et al.* (2013) have identified that while relative permeability functions have a strong impact on injectivity in aquifers with open boundaries, in closed aquifers it is factors that affect material balance, such as formation compressibility, that have the greater influence.

3.2.2 Impact of reservoir processes on CO_2 migration

Once in the formation, CO_2 migrates as a result of viscous, gravitational and capillary forces. Viscous forces include those that arise due to imposed pressure gradients, such as occur during injection. Gravitational forces arise due to density differences, such as when less dense CO_2 rises towards the cap rock displacing denser brine, or when brine at the top of the formation migrates downwards once it starts to dissolve CO_2, because it becomes denser than the surrounding unsaturated brine. Capillary forces tend to reduce CO_2 migration because most formations are preferentially water wet in the presence of CO_2, and hence brine displacement is favoured ahead of CO_2. Indeed, capillarity is one of the factors that can lead to CO_2 trapping, as we note next.

CO_2 may be considered to be trapped when it exists as a free phase but is immobile (does not and cannot migrate towards a leakage site), or when it exists as a component in another phase, and that phase is either immobile, or is mobile but cannot migrate towards a leakage site. There are various trapping mechanisms, a combination of which may play a role in any given CO_2 storage scenario, and which will have differing contributions to play, depending on location relative to the injection point and timing since start, or indeed end, of the injection period.

Structural trapping

Structural is the most obvious form of trapping, as buoyant free phase CO_2 migrates upwards there must be some barrier to prevent it rising any further. This may be an anticline, where the top seal cap rock prevents escape, or a fault that performs the same function, either as a fault-juxtaposed seal or as a shale gouge on a fault plane.

Stratigraphic trapping

As with a structural trap, an unconformity or a pinch out may act as a trap for CO_2. In this scenario, the lateral extent of a permeable formation is terminated by impermeable rock. Indeed, stratigraphic and structural trapping may both occur in the same formation. The key is that these trapping mechanisms operate to contain otherwise buoyant CO_2. It is not necessary that the entire formation layer be entirely surrounded by impermeable rock – indeed, this may be a disadvantage, as expulsion of brine from the pore space can significantly increase storage capacity. What is important is that the vertical rise of CO_2 is stopped, so the trapping must operate only in locations that are saturated with free phase CO_2.

Both structural and stratigraphic traps are well understood from a hydrocarbon exploration and production perspective, as these provide the primary mechanisms by which oil and gas are trapped for millennia prior to discovery of these hydrocarbon accumulations. The fact that there is a proven seal is clearly an advantage for storage in depleted oil and gas fields. However, if CO_2 migrates away from the original oil leg or gas cap, or if CO_2 injection takes place in an aquifer, there will be less certainty about the sealing capacity of the cap rock. There will also probably be a lower density of data available to characterise the aquifer, as most reservoir description effort goes into gathering data for economically valuable hydrocarbon fields, not aquifers. Furthermore, the lateral extent of aquifers is often one to two orders of magnitude greater than oil reservoirs, and while this means that there may be a large volume of pore space (pore volume) available for storage, there is inadequate data density to accurately characterise the entire system (Smith *et al.*, 2012).

Another significant issue is that in considering oil and gas production it is generally assumed that structural and stratigraphic traps act as perfect seals – they are usually modelled as no flow boundaries. However, in aquifer storage calculations thought should be given to the potential impact of albeit small but finite permeabilities in the overlying strata. Absence of hydrocarbon accumulations trapped beneath increases the likelihood of the cap rock having a finite permeability. The rock may still have such a low permeability to free phase CO_2, or a high enough capillary entry pressure, that it would still act as an effective seal to CO_2 buoyancy driven migration. Indeed, a finite permeability in the cap rock may have considerable advantages for CO_2 storage, in that it may allow for brine to be displaced out of the storage formation. Even if the permeability is very low, the effect multiplied over a very large area may be that significant volumes of brine can be displaced to make space for injected CO_2 without the same increase in pressure as if the overlying (and underlying) formations were perfect seals (Jin *et al.*, 2012).

Capillary or residual trapping

Rock wettability, fluid–fluid interfacial tension, pore geometry and interconnectedness all mean that when one fluid is displaced through pore space previously occupied by another phase, some of the originally *in situ* phase will remain trapped, and some of the displacing phase will also become trapped. This means that if one considers a representative elementary volume (or a grid block in a reservoir simulator), if a certain mass of CO_2 is injected into this volume in a given time period, less than 100% of that CO_2 would remain mobile and subsequently be displaced out of the volume at the end of that time period. How much is trapped would depend on the factors above which are specific to each storage formation, and indeed will vary within formations, but could be lower than 5% or greater than 40%.

Not only does capillary trapping retain CO_2 locally, unsaturated rock also retards the CO_2 frontal advance rate relative to saturated rock. CO_2 saturated rock that has already had one or two pore volumes of CO_2 flowing through it will not retain much more CO_2, but unsaturated rock that has only just been contacted by mobile CO_2 will trap most of the CO_2 at the leading edge of the front until it too becomes saturated.

Dissolution trapping

CO_2 has a high solubility in brine relative to other fluids encountered in subsurface systems, and as such dissolution can also prove to be a very effective trapping mechanism (Duan and Sun, 2003; Spycher *et al.*, 2003; Spycher and Pruess, 2005; Ukaegbu *et al.*, 2009). Its effectiveness is increased by the fact that brine saturated with CO_2 is denser than unsaturated brine, and so, once dissolved, buoyancy forces act to improve storage security by displacing the brine with CO_2 dissolved in it downwards, away from the surface (Ghanbari *et al.*, 2006).

CO_2 dissolution in brine also acts to retard the advancing CO_2 front, with free phase CO_2 at the leading edge of the displacement front coming into contact with unsaturated brine dissolving at the fastest rate, whereas the following CO_2 will be contacting partially or fully saturated brine. However, the fact that free phase CO_2 is less dense than the initial unsaturated brine, and CO_2 saturated brine is more dense than the initial unsaturated brine means that there is a driving force for vertical convection currents to be established which will continue to function, bringing unsaturated brine into contact with free phase CO_2 until either all the available brine is saturated, or until all the free phase CO_2 has been dissolved.

Solubility and capillary trapping are thus very effective means of containing CO_2. Free phase CO_2 trapped under an anticline, say, remains mobile – it could move if there were a pathway; it is only trapped because there is no migration pathway down the pressure gradient (i.e. vertically upwards, as the pressure gradient is induced by buoyancy). Should a pathway be created, say by reactivation of a fault in the cap rock, this CO_2 will escape. However, CO_2 that is trapped by solubility or capillary mechanisms is genuinely immobile in the presence of a different displacing phase, say water. Fault reactivation will not lead to this CO_2 escaping.

An interesting implication of this, and the fact that CO_2 is constantly being removed from the leading edge of the front as it advances into unsaturated rock, is that, perhaps somewhat counter-intuitively, a long slightly dipping open structure may provide a more secure setting for CO_2 storage than an anticline (see Plate II in the colour section between pages 214 and 215). As the CO_2 plume migrates up dip underneath the cap rock, CO_2 will continually be removed from the leading edge by capillary trapping and dissolution, until the faster travelling trailing edge of the CO_2 plume catches up with the leading edge, and there is no mobile CO_2 left. At what point this happens is obviously dependent on the length and dip angle of the structure, the volume of CO_2 injected and the residual CO_2 saturation (Jin *et al*., 2012). However, if the system volume is large enough compared to the injected volume, this may provide a trap that is more secure than if mobile CO_2 is trapped underneath an anticline.

Mineralisation trapping

The most secure form of trapping occurs when mineralisation reactions lead to CO_2 being part of a mineral compound that is precipitated as a result of the CO_2 dissolution in the brine phase, such as when $CaCO_3$ precipitates (Xu *et al*., 2005). However, for this to occur the CO_2 must first dissolve in the brine, and to all intents and purposes CO_2 dissolved in brine is considered to be trapped anyway (see above), and so mineralisation trapping should only be considered as an additional and secondary trapping mechanism – belts and braces. Furthermore, dissolution of CO_2 in brine will reduce the pH of the brine, and thus also lead to the potential of mineral dissolution. This may have positive effects around injection wells, effectively stimulating injectivity, or negative effects by releasing fines which may then block pore throats, or by removing cements and opening up leakage pathways.

3.2.3 Modelling of reservoir processes

As indicated earlier, modelling of reservoir processes may take place using analytic or numerical techniques for assessment of wellbore pressure and injectivity (Mathias *et al.*, 2013; Pickup *et al.*, 2012), but tends to be performed exclusively using numerical methods for CO_2 saturation tracking, and identification of migration fronts and extent of trapping. Numerical models tend to be either finite difference or streamline models (Jin *et al.*, 2012; Qi *et al.*, 2008). Regardless of type, the numerical models discretise time and space, and perform calculations in which properties such as pressure and saturation are evaluated for each grid element or block for each time step.

Treatment of numerical errors

Some of the most significant errors arise from the discretisation process, since for any given property only a single value can be used within any grid element or block. This applies for static geological properties, such as permeability and porosity, and so averaging techniques need to be used to assign values when initialising the model. Furthermore, properties such as depth, permeability, porosity, initial saturation and so on may be well known around wells where logging tools have allowed measurements to be made, but deep in the reservoir away from the wells these parameters may be very uncertain, introducing uncertainty in the reservoir description.

Dynamic properties, such as pressure and saturation, are also subject to what are termed 'numerical dispersion' errors, which tend to be greater for more poorly resolved large grid cell models. Again, since a single value of a property – say saturation – is calculated for each grid cell, injection of a certain volume of CO_2 into a grid cell of a given size over a single time step will change the free phase CO_2 saturation throughout that cell by a given amount. This means that the entire space in the formation that is described by that cell is treated as if it were at that saturation. If the cell were twice as long, but all other conditions were as previously, then the cell's volume would have doubled, and so the saturation in the cell would be half of what it was in our previous scenario. This means that in the same time period the CO_2 in the calculation would have travelled twice as far, but be at half the saturation. Material balance would be conserved, but the calculation of how far the CO_2 had propagated would be quite different, purely as a result of our choice of grid block size.

Finer resolution grids will, in general, produce more accurate results. However, finer resolution grids require more grid cells to model a given volume, and so computing power tends to limit the resolution of models. Some of the numerical errors can be addressed by appropriate upscaling techniques, such as manipulation of relative permeability functions in a process referred to as pseudoisation, which can be used to control the speed at which fronts propagate.

However, calculations of CO_2 injection and displacement are particularly susceptible to numerical errors for a variety of reasons:

(a) As is the case with hydrocarbon gas injection, there is a significant density difference between the injected and the *in situ* phases. This leads to CO_2 rising to the top of the system, and spreading out in a thin but laterally extensive layer or tongue under the cap rock. High vertical resolution models are required to accurately resolve this buoyancy driven displacement.

(b) Since CO_2 injection will often be limited by the pressure response of the system, it will be favourable to inject CO_2 into formations that are large and highly permeable; this will limit the pressure rise at the point of injection. Large open saline aquifers are therefore being considered for CO_2 injection, but these may be two to three orders of magnitude larger than conventional hydrocarbon reservoirs, and thus the models need to account for a much larger volume of rock. To maintain the same grid resolution, the number of grid blocks must be increased in proportion to the increase in system volume.

(c) While it is possible to scale some input parameters, such as the relative permeability functions so that they are appropriate for the degree of grid resolution being used, others are more difficult scale up. The calculation of the rate of dissolution of free phase CO_2 into the liquid phases is important when evaluating trapping mechanisms, but is very dependent on grid size, and is difficult to correct appropriately. When free phase CO_2 enters a grid block it is effectively assumed to be in contact with all the liquid in that grid block, and thus, depending on solubility, can dissolve in all the liquid in that grid block. If a grid block is 100 m long, then CO_2 entering at one end of a grid block is, according to the calculation, able to dissolve in liquid 100 m away. If the time step for the calculation is relatively small – generally the time step size is limited so that a maximum saturation change of only 10–20% is allowed – then this can introduce a significant overestimate of the amount of dissolution.

For these reasons grid resolution is a very important issue in numerical modelling of CO_2 injection. More effort needs to be concentrated on the development and use of analytic models where these can be used to address specific questions. Greater consideration should also be given to use of dynamic gridding techniques (CMG, 2012), so that grid resolution can be enhanced in zones where CO_2 free phase saturations or degrees of dissolution are varying locally, but grid resolution can be maintained coarse where only the pressure is varying.

Geochemistry

In most modelling of subsurface fluid flow, such as is undertaken for the oil and gas industry, geochemical effects are not taken into consideration. However, CO_2, when it is dissolved in brine, will significantly reduce the brine pH and this can lead to quite significant geochemical effects. As noted above, in terms of a trapping mechanism these may oftentimes be of academic interest, since CO_2 dissolution in brine is considered a trapping mechanism in its own right, and, additionally, many of the precipitation reactions have very slow kinetics, and so some of the mineralisation processes require millennia to reach equilibrium (Gundogan *et al.*, 2011). Geochemical effects may be of more significance in the near wellbore zones for the following three reasons:

(a) Acidification of brine may lead to the dissolution of naturally occurring calcite cements in sandstone formations or rock matrix in carbonate formations. Positive and negative outcomes may ensue. Oil and gas wells are often stimulated by deliberate application of acid treatments to increase productivity or injectivity, and the same may apply for CO_2 injection wells. On the other hand, release of fines which subsequently block pore throats may occur when cements are dissolved, and geomechanical rock weakening and subsidence may occur in carbonate reservoirs. In either case, effects may be relatively minor, as it is not so much the free phase CO_2, as the CO_2 dissolved in the brine that leads to these effects, and if no new brine is introduced after the mobile brine has been displaced, the calcite dissolution will quickly buffer any remaining immobile brine. One scenario where more caution will be required is when alternating slugs of CO_2 and water are injected in CO_2-EOR projects in a Water Alternating Gas (WAG) process. Here, fresh unsaturated brine will be injected at regular intervals, and when this comes into contact with CO_2 it will be acidified and the geochemical reactivity will resume again until this brine becomes pH buffered. Any single slug may not have a major impact, but the application of repeated slugs (on anything from a two week to six month cycle) could have a significant cumulative impact.
(b) As large volumes of CO_2 are pumped into the near wellbore formation, initially mobile brine will be displaced away from the wellbore zone. However, brine that is not mobile and is trapped as a residual phase in the near wellbore formation may evaporate into the flowing CO_2 stream. Depending on the salinity of this brine, salt in the form of halite (NaCl) will precipitate. This halite will occupy less of the pore space than the brine solution containing it occupied, and thus if the halite remains immobile, the evaporation process will actually increase the pore space available for CO_2 flow, and so injectivity will increase. However, if the precipitated halite can be mobilised at all, there is a risk it may be displaced and lodge in pore throats, reducing permeability. This is observed in gas production wells at very low water cuts, and although the amount of water involved may be small, the mass of precipitate and the damage caused can be significant. This may be exacerbated if injection rates vary, and due to pressure fluctuations salt saturated brine can, from time to time, reinvade the near well zone due to imbibition effects, leading to

renewed precipitation of the salts. In oil and gas systems this problem is remediated by fresh water washes, which are usually very effective since the solubility of halite is very high. The key issue then becomes the frequency with which these wash water treatments need to be carried out.

(c) If CO_2, or particularly CO_2 saturated brine, comes into contact with wells, be they the CO_2 injection wells or perhaps other old abandoned exploration or production wells in the vicinity of the injection site, then there is a risk that the leakage pathways could be created as a result of reactions between the brine and the cement, elastomers and/or metal used in the construction, completion, working over and/or abandonment of the well. Clearly the choice of materials used will be critical, but this choice may be unknown, or may have been made at a time when it was not anticipated that there would be significant amounts of CO_2 in the system. Again, the extent to which buffering of brine has occurred prior to contact with the well will have a significant impact on the extent to which there is a risk of leakage being induced at the well. The evidence from the oil and gas industry is that seepage of fluids through the geological strata from subsurface formations to surface as a result of human activity is rarely if ever observed, but that such leakage events as do occur are usually associated with wellbores. Thus, consideration should be given to ensuring that the risk of CO_2 migration towards wellbores is minimised where there is uncertainty about the impact that the CO_2 could have on the materials used in the well.

While extensive geochemical modelling of groundwater systems has been carried out, there is a lack of thermodynamic, and particularly kinetic data to inform geochemical modelling of CO_2 storage at hotter and higher pressure subsurface conditions, and as such there is not a large body of work available to date. However, a good understanding of geochemical effects is required because CO_2 injection systems are potentially much more reactive than conventional hydrocarbon recovery processes.

Geomechanics

As with geochemistry, in most subsurface fluid flow modelling, geochemical effects are often not taken into consideration. This is partially because the calculations are not easy to perform and input data may be limited. In systems undergoing voidage replacement (injection of the same volume of fluid downhole as the volume of fluid that is extracted), then there will not be significant changes in system pressure overall – although there may be significant local pressure variations. However, during CO_2 injection it is to be anticipated that system pressure will increase, and indeed the capacity of the system will often be determined by the amount that can be safely injected without there being a significant risk of cap rock failure. Thus geomechanical modelling may be very important in proving storage security and determining storage capacity (Olden *et al.*, 2012). Since the geomechanical models tend to be computationally very intensive, and since it is not just the storage formation but the overburden and potentially the underburden that also needs to be modelled, models will necessarily often be restricted to the near wellbore formation. However, caution is required, since it is not necessarily only the formation immediately around the injection well where rock failure may take place. The risk of rock failure tends to decrease with increased depth, and thus injection deep into a formation that has a significant dip angle may result in an increased risk of rock failure in shallower parts of the formation, depending on local pressure variations.

Temperature

Properties of CO_2 such as viscosity and density are very sensitive to temperature around the critical point: 304 K (31°C, 87.8°F) and 7.39 MPa (73.8 bar, 1071 psia). However, isothermal calculations are often performed. For injection at higher pressures the error introduced may be not so great, but for systems close to the critical point, or where Joule–Thomson effects may be observed (Mathias *et al.*, 2010), temperature should be included.

Impurities

The majority of calculations performed in modelling CO_2 injection assume pure CO_2 is being used. However, depending on the original source of the carbon and the capture process, there may be sufficient impurities (e.g. H_2S, SO_X, NO_X, O_2, H_2, CO, Hg, As, Se, etc.) to affect the EOS. For example, even relatively small amounts of impurities can appreciably alter the critical point (Chapoy *et al.*, 2011). Further work is required to adapt reservoir simulation calculations to account for the effect of impurities, particularly with regard to the impact on properties that affect injectivity.

3.3 Engineering options to manage CO_2 storage

There are considerable challenges associated with the development of CO_2 injection projects. Some of these challenges arise from issues identified above (and are described further in introducing challenges and emerging trends, below). However, there are also opportunities to use knowledge gained from other more mature engineering industries, such as the oil and gas industry, to improve injectivity, storage security and also project economics.

3.3.1 Injectivity

One of the principal challenges is the increase in pressure that occurs during CO_2 injection, and the resulting risk of causing the cap rock to fail. The primary method to reduce wellbore pressure while maintaining the desired injection rate, other than by fracturing the well, is to extend the interval of wellbore that is in communication with the target formation – that is, establish longer completion length. This may be achieved by drilling additional wells, or by the use of horizontal or deviated wells instead of vertical wells, since the completion in vertical wells is restricted to the height of the target formation, whereas deviated and horizontal wells can extend further into the target formation. The penalty with drilling of additional wells, and of extending the completion wellbore, is increased cost. There is also a principle of diminishing returns in drilling horizontal wells, in that wellbore friction decreases the local injectivity moving from the heel of the well towards the toe, to the point that there may not be any value in extending a well beyond a certain threshold length.

Injection of CO_2 at greater depth may entail greater costs in terms of having to drill longer wells and in terms of higher injection pressures required. However, a corollary is that at greater depths higher injection rates can be maintained before there is a risk of fracturing the rock, and hence it may be possible to use fewer wells at greater depths compared with a greater number of wells at shallower depths. Furthermore, at greater depths there will be more intervening layers for CO_2 to seep through should it escape from the target store, and hence long term security is greater.

One option for pressure management in CO_2 injection projects is brine extraction from the target formation. This would entail drilling a water production (or Enhanced Voidage, EV) well into the same formation away from the zone where CO_2 migration will take place, but which is in pressure communication with the injection well. It has been demonstrated that this method of pressure relief can increase storage capacity by a factor of four times (Jin and Mackay, 2009). This would result in considerable cost savings, since the cost of storing a given amount of CO_2 would include appraising one site, drilling two wells (one for CO_2 injection and one for brine extraction) and monitoring of this one site, which would be much lower than the cost of appraising four similarly sized sites, drilling four CO_2 injection wells and monitoring of the four sites to store the same amount of CO_2. EV wells were drilled to produce just water from the Brent formations when the decision was taken to depressurise the Brent oil field. While these wells required electrical submersible pumps (ESPs) to assist with lifting the water to surface, in the case of pressure relief in a CO_2 injection project, much of the necessary energy to lift the brine to surface would be introduced in the process of injecting CO_2, further reducing the cost penalty.

It should also be noted that according to data from the UK Department of Energy and Climate Change (DECC), from the start of oil production in the North Sea (in the Argyll Field in June 1975) through to October 2011, some 5.6×10^9 m^3 (35 billion barrels) of water have been produced, 5.1×10^9 m^3 (32 billion barrels) of which have been treated and disposed of in the sea. (This compares with a total of 4.5×10^9 m^3 (28 billion barrels) of oil that have been produced and exported during that period.) Thus water extraction and disposal is a well established procedure, and strict quality controls are already in place (e.g. limit of 30 ppm oil in water content, regulations on chemical content determined by the OSPAR convention, etc.)

3.3.2 Migration pathways

The most likely pathway by which CO_2 could escape from a storage complex is by a well. One option to reduce this risk is to inject a brine post flush after the end of the CO_2 injection period to displace CO_2 away from the well (Qi *et al.*, 2010). Any CO_2 remaining near the well bore after such a brine post flush would be trapped by capillary forces as residual CO_2, and thus would pose a minimal risk of leakage.

The risk of leakage of free phase CO_2 could be almost completely eliminated by not injecting any free phase CO_2, but injecting it dissolved in brine instead. Brine with CO_2 dissolved is denser than unsaturated brine, as noted earlier, and hence will tend to sink downwards, away from potential leak sites. As well as increasing storage capacity and security, cost of site appraisal and subsequent monitoring and verifications costs would be much lower, since the risk of CO_2 escape through the cap rock or through wells would be negligible. Methods proposed include mixing CO_2 in brine at surface (Burton and Bryant, 2009). However, over 30 kg of brine (depending on the salinity of the brine) is required to dissolve 1 kg of CO_2, and thus, as well as the considerable energy penalty, there would be a considerable increase in formation pressure – injecting 1 MT/year of CO_2 would entail injecting 30 MT/year of brine. One option to avoid this increase in formation pressure is to produce the brine used for dissolution from the same formation; the overall system pressure would then only be affected by the mass of CO_2 introduced, since the mass of brine would be neutral. The energy penalty of lifting this brine to surface could be overcome by using a multilateral arrangement, in which one lateral produces the brine from the formation, boosted by an ESP, and this brine is then mixed downhole with the CO_2 that is being injected from surface – the mixture then being injected through another lateral into the target formation (Shariatipour *et al.*, 2012).

3.4 Challenges and future trends

The CCS industry will benefit from expertise and knowledge developed from the oil and gas industry. There are many issues which have their direct parallels in the oil and gas industry (e.g. the benefits of extending completion intervals to improve injectivity, knowledge of structural trapping mechanisms, etc.). There are other issues which are inspired by comparison with the opposite scenario in the oil and gas industry (e.g. whereas water is injected to prevent pressure from decreasing during hydrocarbon extraction, water may be extracted during CO_2 injection to prevent pressure from increasing). However, there are still other issues which are significantly different from those experienced in the oil and gas industry, and while expertise and experienced gained in hydrocarbon production may be useful, radically new thinking is required in order for CCS to work.

3.4.1 CO_2 injection in aquifers

Where CO_2 injection is into aquifers, the sheer size of some of these aquifers may present challenges. The aquifers may be one to two orders of magnitude larger than hydrocarbon reservoirs, and indeed any one aquifer may underlie a number of oil and gas fields. Reservoir description tends to be much less clear-cut, because typically there is a lower density of appraisal wells, and because there will not be production data to validate the understanding of the reservoir. What wells have been drilled will have been plugged and abandoned on the assumption that the only fluid that would be found in the vicinity would be brine of intermediate pH. Larger aquifers will also be more likely to host multiple users. It may be that various storage projects could share a large aquifer, or that a storage project might involve injection into an aquifer which underlies one or more hydrocarbon fields which are being produced. Oil production is often supported by water injection, such that there is little change in the field average pressure. Thus interference between oilfields that share a common aquifer is generally not significant. However, injection of large volumes of CO_2 will likely lead to an increase in pressure in the aquifer, and this may affect other projects associated with the same aquifer. This pressure effect has been observed between oilfields 15 km apart in the Central North Sea (Heward *et al.*, 2003). Additionally, it would be undesirable for CO_2 to migrate into an oil or gas field that had not accounted for the presence of CO_2 in the field development plan, and so neither wells nor surface facilities were designed to cope with CO_2.

While the lifecycle of oil and gas fields is typically a few decades at most, CO_2 may be mobile for centuries or even millennia after an injection project is completed. Predicting fluid flow and reaction behaviour for centuries is clearly more error prone than predictions for years or decades, and planning for monitoring over large areas for long periods, potentially quite some distance from the point of injection and for quite some time after the project team has stopped working on injection will pose very significant procedural and financial challenges.

Linked to the lack of data due to poor resolution in the reservoir description, there is generally a lack of data such as relative permeability functions for potential target storage formations. To attempt a prediction of CO_2 migration with any degree of accuracy requires relative permeability functions to have been determined by experiments on core samples from that formation, since this dynamic behaviour is different in every system, and thus extrapolation from one storage site to another introduces large errors. Furthermore, fluid phase behaviour used in the flow models should take account of project specific factors, such as the salinity, pressure and temperature of the brine in the storage formation, and also the presence of impurities in the injected CO_2 stream, as identified above. Geochemical effects may also be important, and it is certainly important to ascertain what risk there is of halite precipitation, of mineral dissolution, of fines mobilisation, even of hydrate formation as potentially cold gas contacts brine at high pressures. Furthermore, while in hydrocarbon exploration often little attention is paid to an accurate characterisation of the cap rock, in CCS projects ensuring that the CO_2 will not seep through the cap rock or migrate through fractures or faults in the overburden may be as important as characterising the storage formation itself.

3.4.2 CO_2 injection for Enhanced Oil Recovery (EOR)

While it proves challenging to finance CO_2 storage in aquifers, attention is increasingly being paid to the opportunity for CO_2 injection in producing oil reservoirs to enhance recovery, and help cover expenditure in that way. The primary focus is on using CO_2 as a sweep fluid. At high enough pressure CO_2 will dissolve into the oil phase, causing the oil to expand. If the oil that is being contacted is residual oil, then the resulting swelling of the oil may help to mobilise it as the saturation increases beyond the residual saturation. Oil may also vaporise into the flowing CO_2 stream, also helping to mobilise it. Furthermore, in addition to these pore scale displacement processes, if the field has been undergoing water injection, due to gravitational effects the sweep efficiency may have been better lower down in the formation leaving behind 'attic' oil towards the top of the reservoir, and it may be that the injection of less dense CO_2 will help displace this oil. In general it is found that tertiary recovery using CO_2 injection, or alternating slugs of CO_2 and brine injection in a WAG process, can increase recovery beyond that achieved by secondary waterflooding by 5–10%.

More than one hundred such CO_2-EOR projects have been undertaken successfully onshore in the USA, accounting for some 6% of US oil production, with more than 95% of the CO_2 used coming from natural rather than anthropogenic sources. Due to the cost of producing and transporting the CO_2, minimising the amount of CO_2 that is imported generally improves project economics, and thus the projects are not designed to maximise CO_2 storage. However, should there be value placed not only on the additional volume of oil that may be produced, but also on the volume of CO_2 stored, then consideration may be given to the injection of CO_2 into the underlying aquifer, not to directly sweep the oil, but to provide pressure support, as illustrated in Plate III (see colour section between pages 214 and 215). Such CO_2 injection could be used to replace water injection in regions where water resources may be scarce, or where water injection wells located close to the oil water contact lead to a poor sweep efficiency, but where an increase in pressure in the aquifer could lead to a more effective aquifer support and sweep profile, with the advancing flood front being spread over a wider area.

The fact that the majority of CO_2-EOR projects have been onshore in North America is a consequence of the availability of natural sources of CO_2 which are cheaper than capturing CO_2 from power plants, the improved sweep efficiency that can be achieved, and the fact that water is not always an abundant resource for injection. These projects are distinguished by the fact that well spacing tends to be small. This has two consequences. Firstly, the fact that inter-well spacing is relatively short and relatively regular pattern drives are the norm means that modelling studies may be conducted based on relatively small areas of investigation. Secondly, production of injected CO_2, while reducing the efficiency of the process by which CO_2 displaces oil, does have the benefit of reducing the amount of CO_2 that needs to be transported to the field for injection.

CO_2-EOR is being considered for offshore application in basins such as the North Sea. Here, well spacing tends to be much larger, and also, one of the objectives, additional to increasing oil recovery, may be the storage of anthropogenic CO_2. Thus simulation and optimisation of CO_2-EOR in an offshore environment will likely be very different from an onshore environment. Model sizes will tend to be much larger, since even a detailed study of an injector–producer pair will involve much larger inter-well spacing. This means that grid resolution will become an even more significant issue than it is already for modelling of onshore CO_2-EOR projects. Additionally, offshore pay zones can oftentimes be much thicker than for onshore fields, and thus gravitational effects can be more pronounced. This means that gravity override and the formation of a Dietz tongue may occur. As noted already, such a system may only be accurately represented using a grid that is finely resolved in the vertical direction.

CO_2-EOR projects classed as CCS will have to be optimised based on two criteria – maximising and accelerating oil recovery, and ensuring that as much of the injected CO_2 as possible stays within the storage complex, and is neither produced, nor allowed to migrate out of the target formation.

There are various factors that have meant that CO_2 has not been widely used for EOR projects offshore. These include:

(a) Large CAPEX costs are associated with ensuring well and topside facilities are CO_2 compliant (which can involve drilling new wells, and also installation of a new jacket to process the CO_2 prior to injection), as well as the cost of sourcing and transporting the CO_2;
(b) Lack of a secure of supply of CO_2, which creates the risk that the large capital expenditure could be at risk if CO_2 is not available in sufficient quantities;
(c) The fact that while possibly yielding lower returns in terms of oil recovery, injecting seawater is also much lower risk, as there is an effectively infinite and secure supply of seawater at relatively low cost, and the operator can control the amount of seawater used on a day to day basis, and is not constrained by insecurity or fluctuations in supply or by a binding agreement to import a given amount of CO_2;
(d) Pilot studies that can be used to increase confidence in the viability of CO_2-EOR in a given field, and which may be feasible in small sections of onshore fields, are generally not practical offshore, since so much of the overall infrastructure has to be adapted to accommodate any CO_2 injection;
(e) There is additional monitoring and liability after field abandonment, including the fact that the maximum liability is unlimited because the carbon price is variable.

However, it is to be expected that if infrastructure is developed to capture and transport CO_2 to offshore regions such that there is security of supply, if oil prices remain high, and if issues around long term liability can be resolved, say by putting a cap on the liability and limiting the time that monitoring is required, then there will be incentives for the development of CO_2-EOR projects offshore in various parts of the world.

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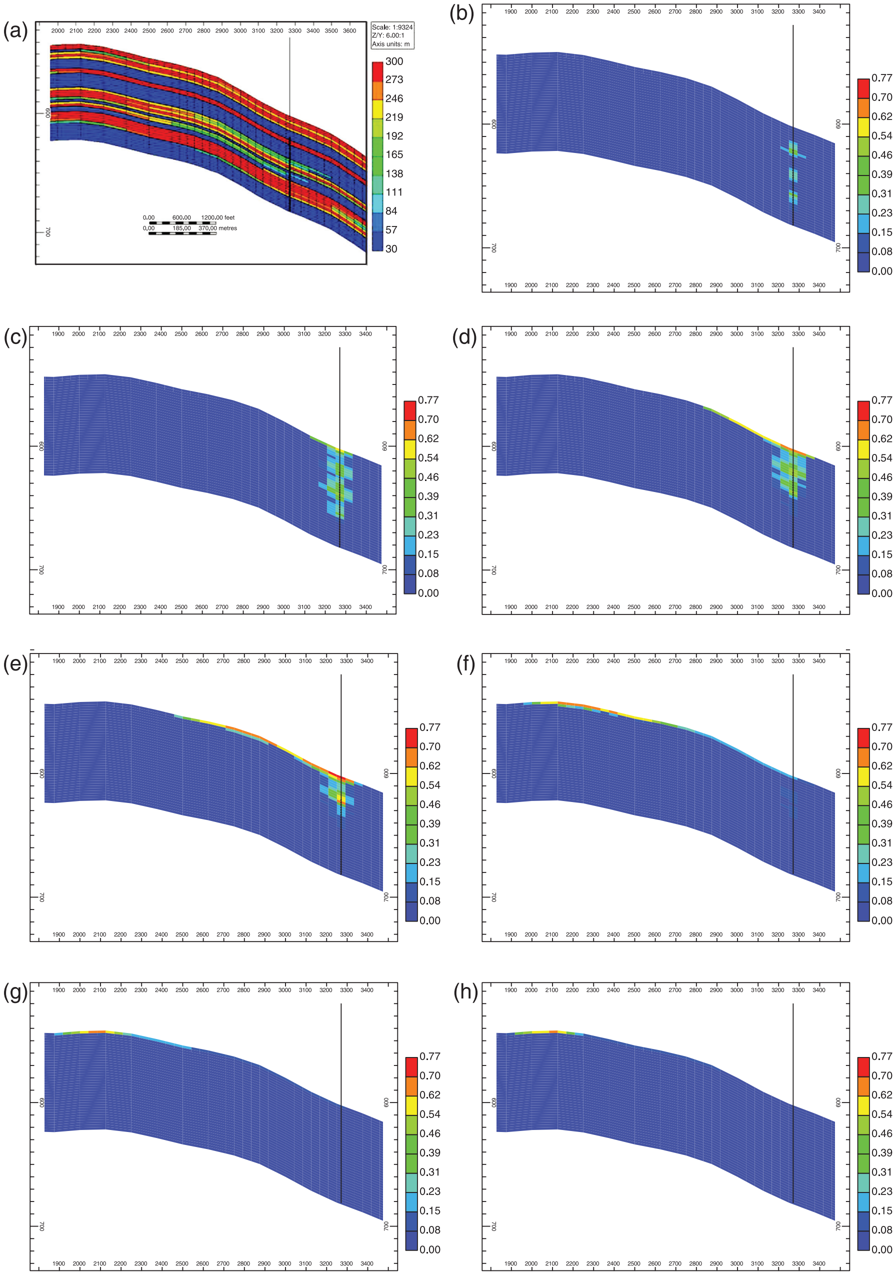

Plate I (Chapter 3) Permeability distribution at Ketzin test CO_2 injection site, and prediction of gas migration over a 50-year period. (a) Permeability distribution, (b) gas saturation after 2 months, (c) gas saturation after 6 months, (d) gas saturation after 1 year, (e) gas saturation after 2 years, (f) gas saturation after 5 years, (g) gas saturation after 20 years and (h) gas saturation after 50 years. Scale: 1:9324. Z/Y: 6.00:1. Axis units: metres.

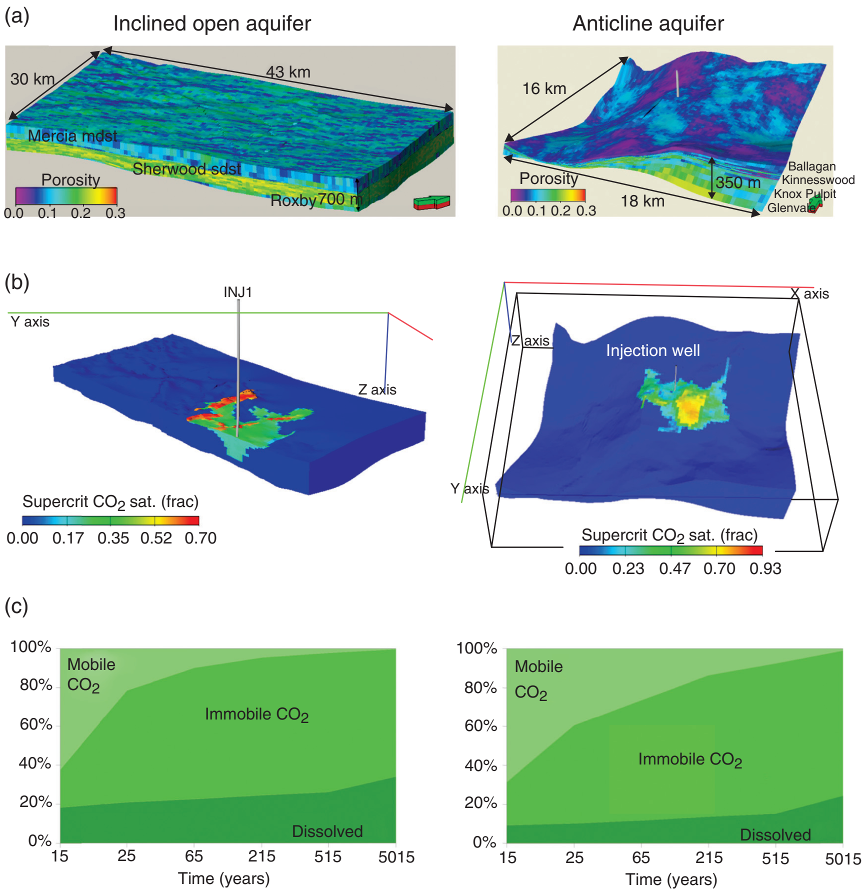

Plate II (Chapter 3) Fate of CO_2 during 5000-year period after 15-year injection in a large open inclined aquifer (left) and an anticline aquifer (right) showing a higher proportion of mobile CO_2 in the anticline aquifer at all times (from Jin *et al.*, 2012). (a) Porosity distribution (mdst, mudstone; sdst, sandstone). (b) Supercritical CO_2 saturation after 1000 years and (c) fate of CO_2 during 5000 years.

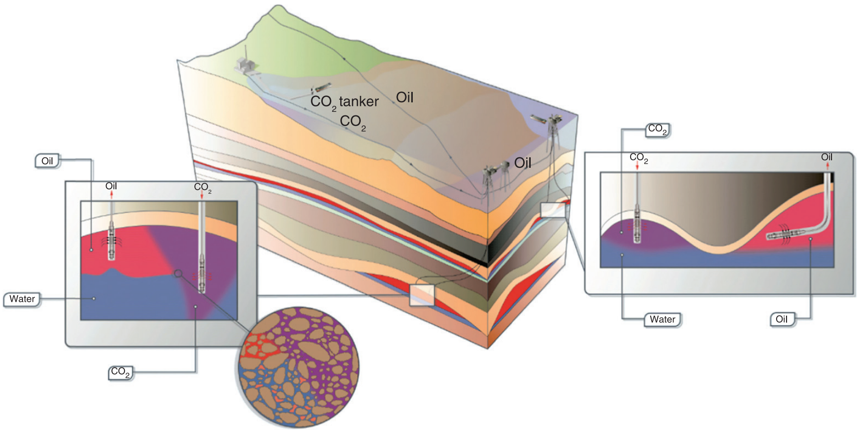

Plate III (Chapter 3) Opportunities for offshore CO_2-EOR, including improvement of microscopic sweep efficiency (left-hand insert) and pressure support through the aquifer (right-hand insert).

4
Monitoring the geological storage of CO_2

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Abstract: The ultimate purpose of monitoring is to confirm safe and permanent storage of CO_2 in the reservoir. Other more specific monitoring objectives are also identified in this chapter. A selection of the technologies able to meet these objectives are described using examples from existing CO_2 storage sites. Each site will have different characteristics, so the most suitable combination of monitoring technologies will be site specific. Therefore, possible methods to help devise suitable monitoring strategies are also suggested. Monitoring results can be used to validate site performance using temporal modelling and these can build confidence in long-term predictions of safe storage.

Key words: CO_2 storage site monitoring, monitoring technologies, monitoring programme, monitoring strategies, modelling CO_2 storage.

4.1 Introduction

The ultimate purpose of monitoring is to confirm safe and permanent storage of CO_2 in the reservoir. Many technologies are available to demonstrate appropriate storage site performance during the operational and post-closure periods, and it is expected that a subset of these will be deployed in combination at a single site. As each site will have particular characteristics, the most suitable combination of monitoring tools (the 'monitoring programme') will be site specific. It is important regulations reflect this by specifying monitoring objectives, rather than prescribing specific tools to be deployed. These objectives are identified in Section 4.2, followed by a description of the available tool types (Section 4.3). Descriptions of techniques have been broadly split into deep or shallow focused. Monitoring results from CO_2 storage sites around the world at both the commercial and pilot scale are used as illustrative examples of where techniques have worked particularly well or have revealed potential limitations. Possible methods to help devising suitable site specific monitoring programmes are outlined in Section 4.4, monitoring strategies. These revolve around the concept of a core suite of techniques to fulfil the site performance assurance objectives, with additional monitoring that could be deployed in the event of site non-conformance.

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Once the operation starts, data from monitoring programmes are used for validating and revising predictive models of site performance. This is discussed in Section 4.5, modelling temporal responses. Acceptable levels of 'matching' between observed performance and model results are discussed, together with convergence of successive models. Models, history matched to most recent data, are used for long-term predictions to build confidence in future site behavioural predictions. These are especially relevant to demonstrate the site will continue to behave as predicted to allow site closure and subsequent transfer of liability back to the state. Remaining technology gaps and suggested further reading are also included in the final sections, 4.6 and 4.7.

4.2 Storage site monitoring aims

Current CCS regulations (e.g. the EC CO_2 Storage Directive (Directive 2009/31/EC)) generally define the high level objectives of monitoring, but do not prescribe the techniques themselves. This is because it is recognised that each storage site will have different characteristics so the technologies deployed must be tailored to the site in question, and that technologies will improve in the future. CO_2 storage sites are necessarily designed not to leak, but assurance that this is not occurring is required both for site permitting and public acceptance. The main monitoring aims are outlined below:

- *Site performance*: monitoring to provide assurance that the site is not leaking, demonstrate that the site is performing as expected and provide evidence and predictions of long-term behaviour.
- *Health and safety*: monitoring to detect any possible hazardous build up of CO_2 and to provide assurance that the project is safe and does not pose serious risks to health or environment.
- *Emissions accounting*: monitoring to quantify any CO_2 emitted to the atmosphere or water column.

A key use of monitoring technologies is to provide an 'early warning system' to trigger changes in strategy to prevent leakage, as well as being able to detect any subsequent leakage should it occur.

While most commercial sites will likely deploy the minimum monitoring required to achieve these objectives, some of the examples from sites discussed in this chapter may also have research objectives and have therefore employed multiple techniques at high frequencies to test their suitability and address specific research questions. Development and testing of tools at research sites and testing them in combination is important to optimise efficiency of monitoring at a commercial scale.

4.3 Types of monitoring technologies and techniques

Monitoring covers a range of possible techniques including measuring geochemical, geophysical or biological parameters, continuously or at timely intervals over the storage site. This extends from the reservoir up to the surface and includes the atmosphere or water column above the site. Techniques work on the basis that the injected CO_2 creates a measurable change within the volume investigated by the tool, detectable above baseline readings (readings from before CO_2 was injected). There are therefore two possible desirable response types: those that detect CO_2 injection related response, expected in the reservoir region (plume monitoring); and those that do not, anticipated everywhere else; where to detect any change above background might be indicative of unexpected CO_2 migration or a CO_2 leak (assurance monitoring). For both types, a storage site that is performing correctly should have measured responses that match those predicted within a certain range of values (see Section 4.5).

Geological scenarios considered for storage of CO_2 include mature or depleted oil and gas fields and saline aquifers. The variety of possible suitable scenarios and the spatial distribution of storage properties and features, trapping mechanisms, site design and location mean that the most suitable combination of monitoring techniques varies widely from site to site. For example, some techniques appropriate to an onshore site (e.g. surface gas flux monitoring) would naturally not be appropriate at an offshore site (where some form of bubble detection monitoring could perhaps fill a similar role). This is discussed further in the storage site monitoring aims and monitoring strategies in Sections 4.2 and 4.4.

Table 4.1 lists some of the available techniques for CO_2 storage site monitoring, including some of the sites at which they have been tested. It is helpful when considering monitoring to subdivide techniques into deep focused or shallow focused (Chadwick *et al.*, 2009a). Deep focused tools primarily investigate the reservoir for plume monitoring but may also investigate the overlying rocks for assurance monitoring. The use of deep focused techniques is well established by the oil and gas industry and many of these tools also perform well for CO_2 storage site monitoring. This is because CO_2 also has significantly different and predictable geophysical properties or behaviour, relative to host formation waters. However, this can become a disadvantage for their use in depleted hydrocarbon reservoirs or at enhanced oil or gas recovery (EOR or EGR) sites if the CO_2 has a similar signature to the residual hydrocarbons. Shallow focused tools investigate the shallower subsurface, surface and atmosphere or ocean and are used for assurance monitoring purposes only. However, should a site be found to be leaking, these techniques will also be required to measure emissions and monitor the effectiveness of any corrective measures. Selected examples of both deep

Table 4.1 Monitoring types, broadly grouped into deep and shallow focused

Monitoring technique	Primary purpose	Testing sites									
		Sleipner	Snovit	K12-B	In Salah	Ketzin	Weyburn	Nagaoka	Otway	Frio	Cranfield
Deep focused											
2D/3D/4D surface seismic	Imaging the CO_2 plume. Detection of leakage in overlying rocks.	X	X		X	X	X	X	X		
Vertical seismic profiling (VSP) and other well seismic	High resolution imaging over the reservoir.					X	X		X		
Cross-hole seismics	Imaging the CO_2 plume between boreholes. Detection of leakage in overlying rocks.						X	X		X	X
Microseismics	Passive detection of CO_2 injection induced seismic events.				X	X	X		X		X
Surface gravity	Measuring gravimetric effect of CO_2 plume in the subsurface.	X									
Pressure and temperature methods	Monitoring injection and hydraulic/thermal connectivity between wells/strata.	X	X	X	X	X	X	X	X		X
Geophysical logs	Detection of CO_2 breakthrough and saturation changes around boreholes. Well bore integrity.			X	X	X	X	X	X		
Electrical resistivity tomography (ERT)	Imaging the CO_2 plume between boreholes. Detection of leakage in overlying rocks.					X					X
Electromagnetic methods (EM)	Imaging the CO_2 plume between boreholes. Detection of leakage in overlying rocks.	X				X				X	

(*Continued*)

Table 4.1 Continued

Monitoring technique	Primary purpose	Testing sites									
		Sleipner	Snovit	K12-B	In Salah	Ketzin	Weyburn	Nagaoka	Otway	Frio	Cranfield
Fluid chemistry sampling	Detecting of CO_2 plume breakthrough and saturation changes. Reservoir geochemical evolution.			X	X	X	X	X	X	X	X
Tracers	Tags the CO_2 plume with unique signature for identification of injected CO_2 leakage.			X	X	X			X	X	X
Monitoring shallow aquifers	Mainly geochemical analysis to detect CO_2 leakage into potable water.				X				X		
Tiltmeters and satellite interferometry (InSAR)	Monitors CO_2 injection related ground displacement.				X						
Shallow focused											
Multibeam echosounding, Sidescan sonar, video	Monitoring sea bed for CO_2 leakage.	X									
Bubble-stream detection, and gas sampling	Monitoring sea bed for CO_2 leakage.										
Soil gas/surface flux	Measurement of CO_2 concentration and flux.				X		X		X		X
Flux towers (eddy covariance (EC))	Detection of CO_2 leakage from the surface.						X		X		
Passive detectors/IR diode lasers	Detection of CO_2 leakage from the surface.				X		X		X		
Ecosystem monitoring	Monitoring for effects of CO_2 leakage.	X			X						
Airborne spectral imaging	Monitoring for effects of CO_2 leakage.				X	X					

and shallow focused techniques are discussed throughout the section below, illustrated with results from existing sites where they demonstrate a method particularly well within its limitations at that specific site.

4.3.1 Deep focused techniques

Deep focused tools primarily investigate the CO_2 reservoir, caprock and overburden. Many of the techniques were originally developed for petroleum, geothermal or engineering geology applications and have since been trialled or further developed for use on CO_2 storage projects. They may be invasive, requiring a borehole and direct penetration of reservoir, or non-invasive, for which measurements are made of the reservoir from the surface. Non-invasive techniques are often complemented or calibrated by invasive measurements. For example, borehole geophysics provides saturation information and allows higher resolution surveillance over the reservoir interval. Similarly, a single borehole effectively allows investigation of a cylinder of rock; a 1D line of data about the area it penetrates, which alone may not offer much information about the 3D volume of the CO_2 plume. However, when combined with surface surveys the volume of rock investigated is increased. In addition, where boreholes are sufficiently close, cross-hole techniques can be used which may allow tomographic imaging, giving higher resolution information in the area between the wells compared with purely non-invasive techniques.

Invasive techniques

A review of recently developed wellbore investigation tools is available in Freifeld *et al*. (2009a). The drilling of multiple boreholes (or reconditioning of old wells) for use as monitoring wells may be prohibitively expensive for some projects. In any case, more boreholes penetrating a site increases the chances of wellbore related leakage. Bachu and Watson (2009), in a study from 35 years of enhanced oil recovery (EOR) operations, found that wellbore leakage (mainly due to component failure) was by far the highest cause of CO_2 leakage. Conversely, all storage projects will have at least an injection well and, as a minimum, this could be instrumented with downhole pressure and temperature gauges.

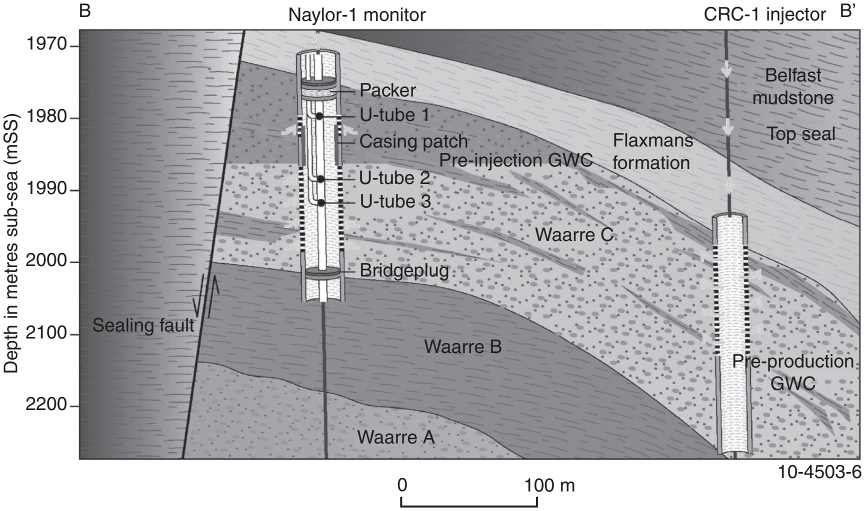
Pressure monitoring is now widely recognised as one of the key tools that will be necessary at nearly all sites (Chadwick *et al*., 2009a) and in the United Kingdom it is one of the few parameters prescribed in the EC CO_2 Storage Directive (Directive 2009/31/EC). Measurement of reservoir pressures and in particular rates of pressure change are important to ensure geomechanical integrity of the site. For example, an unexpected drop in pressure could indicate leakage from the reservoir. If pressure measurements are available from multiple surrounding wells, it may be possible to determine the extent of the pressure footprint of CO_2 or the provenance of any suspected leakage. Monitoring pressure, particularly when combined with temperature monitoring at zones above the reservoir, may also help to confirm that the zones are not hydraulically connected or help to determine the route of leaking CO_2. The efficacy of this 'out of zone' pressure and temperature monitoring technique is being evaluated at the Cranfield site in Mississippi, USA (Meckel and Horvorka, 2011). Here, continuous pressure and temperature gauges were installed in monitoring wells on tubing in the injection zone and also in a zone above it to detect migration into overlying strata. Interpretation is challenging at that site because of the past production history, current CO_2 flood activities, strong aquifer drive and high numbers of potentially leaky abandoned wellbores penetrating the trap. At the Nagaoka site in Japan, small fluctuations in downhole pressure measured with continuously monitoring gauges allowed CO_2 saturations to be estimated via a method known as 'earth tides' (Sato, 2006). The small daily deformation of pore spaces which occurs due to the earth's gravitational attraction to the moon and sun increased as CO_2 displaced the formation water, because the CO_2 has a lower bulk modulus (i.e. more compressible) than the water it displaced.

Downhole temperature sensors can be used to calibrate other tools and assess injection performance. These can be in the form of memory or continuous gauges, similar to the pressure monitoring, or continuous along-wellbore temperature sensors known as Distributed Temperature Sensing (DTS) are also available. This system has been installed at two CO_2 storage sites, Ketzin in Germany and Cranfield in the United States, by means of fibre optic cables behind the casing, along the wellbore length. These measurements are useful for monitoring injection and also for wellbore integrity, if leakage creates near-wellbore temperature changes. This equipment has also been installed in conjunction with a heater cable, which allows heat pulses to be transmitted into the formation and the temperature decay to be measured. This is known as Distributed Thermal Perturbation Sensing (DTPS) and it allows investigation of the thermal conductivity of the formation from which CO_2 saturation can be estimated because CO_2 has a much lower thermal conductivity than the formation waters (Freifeld *et al.*, 2009a).

In addition to permanently deployed downhole sensors, specific timelapse downhole surveys may also be run that also allow estimations of CO_2 saturations, for example, timelapse geophysical logs. These include the resistivity, neutron, sonic log combination measurements used at Nagaoka (Xue *et al.*, 2009) and the measurements of CO_2 capture cross section with a reservoir saturation tool at Frio, USA (Müller *et al.*, 2007). However, direct confirmation of geochemical changes may also be achieved by deploying tools that sample the formation fluids.

Geochemical methods of fluid sampling via downhole tools are also well established, for example the cased hole dynamics tester (CHDT) tool is routinely used in oil and gas operations for retrieving fluid samples from behind the casing. This tool is run downhole on wireline where it drills a small hole in the casing, inserts a sampling probe to both measure pressure and take samples and then plugs the hole before being retrieved. This technique was deployed at Nagaoka to corroborate geophysical log findings (discussed further in Section 4.5.3). More continuous downhole fluid geochemical methods that have been developed specifically for CO_2 storage sites include the gas membrane sensor (GMS), tested at Ketzin (Zimmer *et al.*, 2011), and the U tube fluid sampling system, developed at Frio (Freifeld *et al.*, 2009b), which has also since been deployed at the Cranfield and Otway sites. The GMS uses a downhole phase separating membrane, linked to a mass spectrometer at the surface via a capillary tube. Gases dissolved in the downhole fluid permeate into the tool and are pushed to surface using pressurised argon. This allows measurement of downhole dissolved CO_2 concentrations and allowed CO_2 and Krypton tracer gas breakthrough to be detected in the monitoring wells at Ketzin. The U tube is a steel, U-shaped tube running from the sampling depth to surface with a junction at the base with a ball check valve. The sample entering the tube is forced to surface at reservoir pressures using pressurised nitrogen gas where it is collected for analysis. At Otway, a depleted gas field site in Australia, three U tubes were installed in a monitoring well, 300 m from the injection well (Fig. 4.1). The highest tube sampled the residual gas cap; the other two were located just below the gas water contact. In this way, as well as being able to detect the CO_2 plume arrival and subsequent saturation changes, they were also able to give information on the filling of the structure, as successively deeper U tubes sampled the CO_2 and injected tracers over a period of 10 months (Boreham *et al.*, 2011).

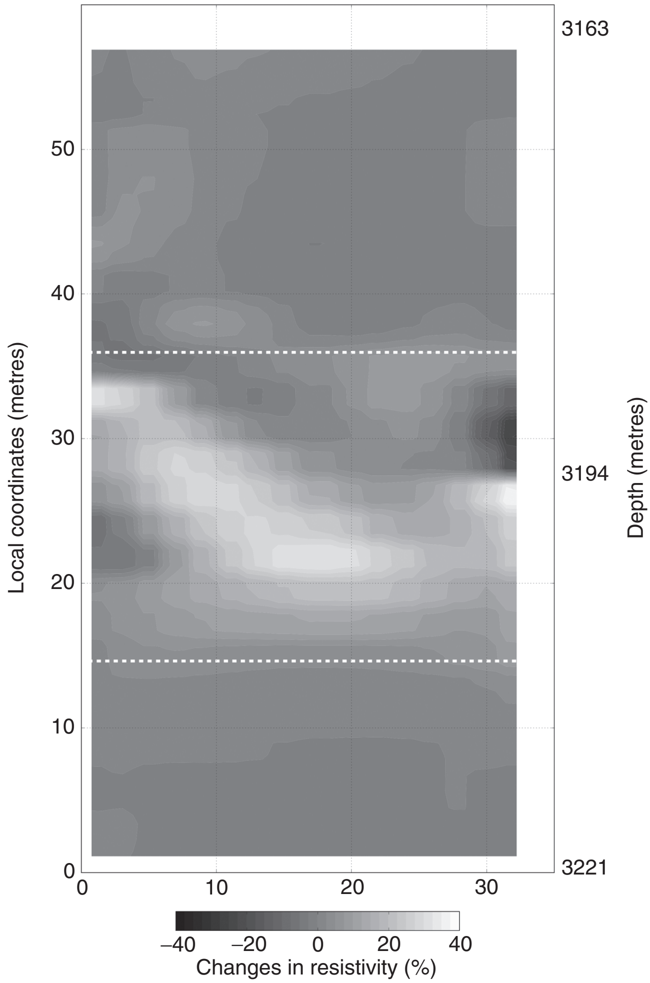
Tracer technology has been tested at a number of sites (Table 4.1) and involves 'tagging' the CO_2 plume to give it a unique 'fingerprint' by the introduction of a pulse of suitable chemical compounds into the injection stream. In addition to giving information on plume breakthrough at monitoring wells, tracers can be particularly important for surface assurance monitoring methods that could thereby conclusively prove or anticipate the detection of injected CO_2 at surface. This application is discussed further in the surface focused methods in Section 4.3.2. Compounds used as tracers include noble gases, such as krypton (Kr) and chemicals such as sulphur hexafluoride (SF_6). The particular isotopic signature of injected CO_2 can also be used if it is different to any CO_2 already existing in the formation or that found in the near surface (e.g. from respiration or decomposition processes), which is the case at Otway. At that site fully deuterated methane (CD_4) was also used as a tracer, as the injected CO_2 stream contained 20% methane and there was



4.1 U tube set up at Otway (GWC: gas–water contact). (*Source*: Courtesy of C. Boreham, reprinted from Boreham *et al.*, 2011 with permission from Elsevier.)

also methane in the residual gas cap in the reservoir. This CD_4 was injected together with Kr and SF_6. The geochemical interaction of the tracers with CO_2 and their relative arrival times at the U tube sampling devices is complex to interpret, but can lead to insights into the fluid dynamics of the reservoir and aid understanding of CO_2 plume behaviour (Stalker *et al.*, 2009).

A few sites have sufficiently closely spaced wells to allow cross-hole monitoring techniques for imaging of plume response between wellbores. These include cross-hole seismic monitoring at Nagaoka (Onishi *et al.*, 2009; Sato *et al.*, 2011b) whereby one well hosts the seismic source or transmitter, activated at different depths across the interval of interest and the other hosts a string of geophones or receivers. The three monitoring wells at Nagaoka are within 120 m of the injection well and the supercritical CO_2 between the boreholes reduces the velocity and amplitude of the transmitted acoustic pulses. By firing the source along the 160 m borehole interval, the location and saturation of the CO_2 plume can be determined along the plane between the boreholes. An extension of this technique was used at Frio, known as Continuous Active Seismic Source Monitoring (CASSM) whereby a semi-permanent source was installed on tubing in one well and a permanent array of 24 hydrophones were installed in the neighbouring well. High resolution surveys across the reservoir at 15 min intervals throughout injection showed plume growth in real time between the wells (Daley *et al.*, 2011). These two sites, Frio and Nagaoka, are both saline aquifers. Imaging using seismic methods in sites which contain hydrocarbons is likely to be more challenging as



4.2 Electrical resistivity tomography image for plume detection at Cranfield shown after 48 days of injection. Depth in metres is shown on the right side and the reservoir is shown bounded by the white dotted lines. The CO_2 injection well is collinearly located with the left of the image. (*Source*: Image provided courtesy of Xianjin Yang and Charles Carrigan, Lawrence Livermore National Laboratory.)

the acoustic impedance contrast between CO_2 injected and native hydrocarbons is less pronounced. Non-seismic cross-hole borehole techniques include cross-hole electrical resistivity tomography (ERT) which has been deployed via the instrumented wellbore completions at the Ketzin and Cranfield sites (Fig. 4.2). A series of metal rings around, but insulated from, the casing can act as electrodes or transmitters that inject current into the formation or receivers that measure voltage. These are activated in various sequences between and along boreholes to build up a picture of the electrical resistance between boreholes (Kiessling *et al*., 2010). This method is sensitive primarily to the fluids in the rock, so it requires a significant difference in the electrical conductivity of the CO_2 as compared to the formation fluids. This is more likely to be the case in saline aquifer sites, as brine is very conductive and supercritical CO_2 is very resistive. In a depleted hydrocarbon field, resistive residual hydrocarbons may make imaging challenging. The region of the Cranfield site where this technique is deployed is in the water leg beneath the hydrocarbons (Hovorka *et al*., 2011). Another non-seismic method is cross-hole electromagnetics (EM). Again transmitter and receivers are placed in adjacent wells and similarly to ERT methods, they respond to the strong conductivity differences between CO_2 and brine in the region between boreholes. Time variant source fields are used to induce secondary electrical and magnetic fields. The receivers detect the strength and phase angle of the induced fields, from which plume shape and CO_2 saturation can be deduced. This technique has been deployed at relatively fewer sites to date.

For these cross-hole techniques to be effective, monitoring boreholes need to be sufficiently closely spaced and in a useful position relative to plume migration path predictions (e.g. up dip from the injection well). However, once drilled, it is likely that the information gathered from the new well itself will correspondingly improve these plume migration pattern predictions. Some sites may be able to take advantage of existing wellbores for monitoring, although, in the case of the Cranfield site, recompleting an existing abandoned well proved to be significantly more problematic (and costly) than had been expected.

Non-invasive techniques

The techniques discussed for use in cross-hole methods can also be used in combination with non-invasive, surface deployments, to yield data over an expanded volume and enhance resolution over the wellbore interval. For example, temporary surface electrodes were also deployed at Ketzin for specific surface-to-downhole and surface-to-surface surveys to complement the cross-hole measurements (Kiessling *et al*., 2010).

The most commonly described and often the most useful non-invasive technique is 4D seismic, whereby repeat 3D seismic reflection surveys detect changes in the CO_2 related acoustic impedance contrast using reflected acoustic energy. This is the primary plume monitoring technique used at the Sleipner site in Norway and a good explanation of the latest data and plume images are available in Chadwick (2009b) and Chapter 13. This technique is well established for both onshore and offshore operations.

Monitoring of ground displacement using satellite interferometry is another non-invasive technique. It can yield useful information covering a large area over timesteps of a few days to weeks and is relatively inexpensive in comparison to other methods. This relies on the fact that as CO_2 is injected, the pressure changes create a geomechanical response in the overburden that is expressed as a measureable change in the surface as ground displacement. It therefore is only suitable for onshore sites. It works well at the sparsely vegetated In Salah storage site in the Algerian desert. Injection history can be reconstructed by observations of the ground displacements over the wells in question (Onuma *et al.*, 2011). However, drawing meaningful conclusions about plume location requires coupling with geomechanical models and combining with results from other monitoring techniques to improve interpretation of results (Rutqvist *et al.*, 2010).

4.3.2 Shallow focused techniques

Shallow focused monitoring techniques investigate the shallow subsurface or atmosphere and are generally for assurance purposes only. Testing the sensitivity of these methods is difficult at real storage sites when none are currently leaking. Therefore many of them are tested at natural analogue sites where natural accumulations of CO_2 are being emitted at surface, or at specifically designed shallow test emission sites, which include the ASGARD site at Nottingham, the ZERT site in Montana and the CO_2 Field Lab in Norway. At these sites, CO_2 is deliberately injected into the shallow subsurface and monitored using various assurance methods.

Surface monitoring techniques either rely directly on identifying the injected CO_2 gas escaping (confirming its identity either via its isotopic signature or its association with gases, including tracers, injected with the CO_2 stream), or indirectly by measuring CO_2 induced geochemical, geophysical or biological changes in shallow groundwater and subsurface (reviewed in Klusman, 2011).

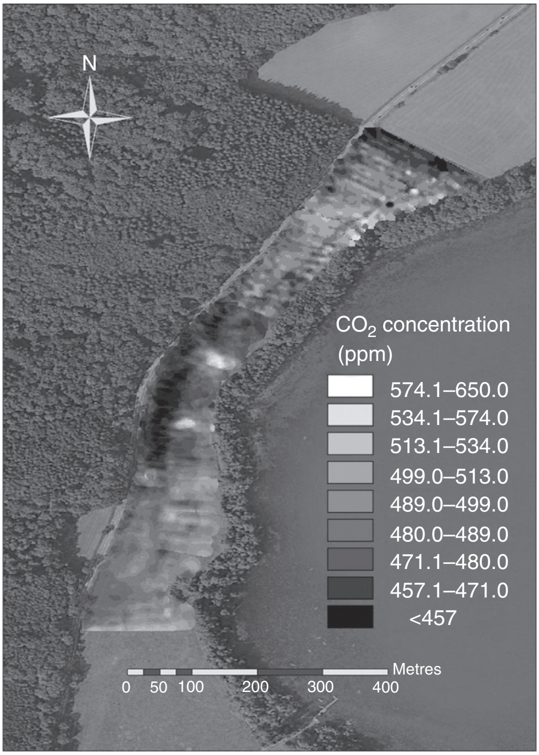
One of the most widely deployed techniques for directly measuring escape of CO_2 gas at surface (at onshore sites) is the measurement of the concentration of CO_2 and other gases in the soil and the surface gas flux. Determination of soil gas composition involves the insertion of a probe to a depth of perhaps less than a metre or so that allows entry of the soil gas into the tube which is pumped through a gas analyser to measure the concentrations. Flux measurements are made by placing an accumulation chamber of known volume over the sampling area. This is connected to a gas analyser that measures the rate of change of CO_2 concentration as it collects in the chamber from which the flux of CO_2 being transferred from soil to atmosphere can be calculated (Jones *et al.*, 2009).

Developments and extensions of these techniques include more extensive analysis of the relative amounts and isotopic ratios of gases collected to give more accurate indication of the provenance of any CO_2 detected. This may help in establishing whether any CO_2 detected is deep sourced from injection, or shallow from respiration or decomposition of organics. Equipment has also been developed to allow continuous deployment of these methods, including flux measurement at surface and just below the root zone (Bernardo and de Vries, 2011).

However, this type of discrete point survey method remains limited because detection of a leak relies on the leakage path intersecting with the measured point. Additional complementary monitoring over wide areas may therefore increase the chances of detecting a leak, although they may be less sensitive because of air mixing in the region immediately above the ground. Under unfavourable wind conditions, CO_2 or tracer gases may become too rapidly dispersed for detection. This type of technique includes laser based measurements, whereby CO_2 concentration is detected within the open path length of an infra-red laser set to the absorption frequency of CO_2. These can be static, potentially sweeping an area, or vehicle mounted such as that described in Jones *et al*. (2009). Such methods have been tested at both natural analogue and shallow test emission sites (Jones *et al*., 2009; Barr *et al*., 2011). For example, at the Laacher See natural analogue site in Germany, an area approximately 100 000 m^2 was surveyed over three days using an open path laser mounted on a quad bike (Fig. 4.3). Significant gas venting and also areas of weaker gas flux at lower concentrations were successfully identified (Jones *et al*., 2009).

The eddy covariance (EC) method has been deployed at some sites, including Otway. This method requires strategically placed monitoring towers equipped with detectors to measure wind speed and direction and CO_2 concentration continuously. From this, together with other atmospheric measurements, the vertical CO_2 flux can be calculated, in addition to the direction of leakage and potential amounts of leakage. The Otway site is well suited to the EC technique because of the relatively consistent wind direction and low topography. The method has also been tested at the ASGARD site (among others), but complex wind currents around nearby buildings rendered the measurements ineffective. At Otway a controlled release was initiated as part of the assurance monitoring programme, in order to test and prove the ability of the surface monitoring methods to detect leakage. The EC method was able to correctly identify the leak direction and rate (~20 kg/day of gas for 1.5 h containing 63% CH_4, 29% CO_2, 3.5 ppm SF_6), although this was primarily due to the methane and SF_6 signature of the gas stream, as the CO_2 content of the emission was about a tenth of the target leak rate and so was masked by background diurnal variations (Etheridge *et al*., 2011). Use of tracers in the CO_2 plume was therefore important for detection of low level leak rates. The stationing of multiple towers would allow the position of a leak to be more accurately pinpointed.

(a)



(b)

4.3 Showing onshore and offshore leak detection results at natural analogue sites. (a) Image of mobile laser data from Laacher See. (*Source*: Courtesy of D. Jones, CP12/106 British Geological Survey © NERC 2011. All rights reserved.) (b) Natural methane gas seeps in the Sea of Okhotsk (mbsl, metres below sea level). (*Source*: Courtesy of Y. K. Jin, reprinted from Jin *et al*., 2011 with permission from Elsevier.)

As CO_2 storage sites might span large areas, it may be difficult to continuously monitor the entire area using the above described on-the-ground surveys. If paying for CO_2 emissions dated back to the point at which it can be proved the sites were not emitting is a possibility, regular surveying over a large area will be useful. Remote sensing methods that interrogate ecosystem response to CO_2 over wide areas have been evaluated mainly at natural analogue sites. Vegetation and microbial changes in proximity to CO_2 release areas have been documented by numerous authors including Beaubien *et al*. (2008). Remote sensing techniques try to identify these CO_2 related changes using images from satellites or aeroplane mounted instruments. Hyperspectral remote sensing methods were tested at Latera, a natural analogue site in Italy, by Bateson *et al*. (2008). The most successful methods involved those that indirectly measured plant stress in proximity to CO_2 vents by measuring the normalised difference vegetation index (NDVI), which reflects the amount of chlorophyll in plants when used in combination with other parameters. This method showed a 47% success rate at identifying known vents which was considered to be relatively good, although there were still several false positives. At a real storage site it is likely that accurate baseline data would help to remove the false positives and thereby improve the detection rate. Such wide aerial coverage methods could be useful to focus more accurate ground-surveying for early detection of surface leaks. However, techniques which use plant stress as an indicator will not be so appropriate at sites like In Salah, where there is little vegetation, or in heavily forested areas where near surface changes might not be detectable by remote sensing methods.

In an offshore scenario, marine ecosystem surveying is possible and marine benthic chambers able to monitor biogeochemical processes have also been tested. Equivalent far-reaching techniques to detect any ecosystem or sea bed changes that may be CO_2 leakage-related can be mounted on automated or remotely operated submarine vehicles (AUVs or ROVs). These include sidescan sonar, multibeam ecosounding and high resolution shallow seismic surveys, that may be able to detect the appearance of pock marks, bubbles rising from the sea bed (Fig. 4.3) or more widespread sediment changes that could be caused by biological or geochemical responses that may be indicative of CO_2 leakage (Caramanna *et al*., 2011; Korre *et al*., 2011).

Particularly important for assurance monitoring methods at or near surface is establishing a baseline which allows natural variation of a site to be distinguished from any possible CO_2 leakage-related signature. Ideally deeper focused monitoring methods would provide an early warning of any leakage out of the reservoir and allow changes in injection strategy to mitigate the situation before CO_2 arrives at the surface. However, if leakage occurs over a short timescale (i.e. via a direct fast pathway to surface such as a wellbore or geological pathway) between deep focused survey timesteps or at diffuse levels below the detection limit of the deep tools, surface methods will be important for identifying leakage. Detection of diffuse leakage over wide areas and particularly quantifying such leakage requires further development (see Section 4.6).

4.4 Monitoring strategies

Technique suitability and selection will be based on a consideration of site conditions including the site geology, reservoir conditions and surface location. A monitoring programme will therefore need to be tailored to the specific site. However strategies for deciding on the most suitable monitoring programme can be applied to multiple sites. Methods that may aid decision making on which techniques to deploy are suggested below. Naturally the final programme selected will also need to meet objectives and abide by regulations of the applicable jurisdictions. Timing and frequency of monitoring surveys (pre-injection, injection, post-injection, post-closure) and also the concept of core plus additional monitoring are also discussed. The monitoring programme will need to be adaptive, so that frequency of monitoring and/or technologies deployed can be changed appropriately; for example, if results suggest the site is not behaving as expected or if new technologies become available.

4.4.1 First pass to identify suitable monitoring tools

There are many monitoring tools available and selection of suitable monitoring techniques for a specific site may be achieved in various ways. A good first pass would be to use an impartial decision support tool such as the online IEAGHG monitoring selection tool (www.ieaghg.org/index.php?/Monitoring-Selection-Tool.html). Here site characteristics can be defined and suggested suitable techniques are listed as output. Minimum site characteristics to input are whether the site is on- or offshore, proposed storage depths and the host reservoir type. Injection amount and duration are also required, together with an idea of monitoring objectives. The returned tool list is ranked according to suitability. Descriptions of the tools together with case studies describing their use at existing sites are also included, together with links and references to further information. This initial list can be further refined or improved by using further strategies to tailor it to the site in question and could include the methods described below.

4.4.2 Monitoring to address storage site specific risks

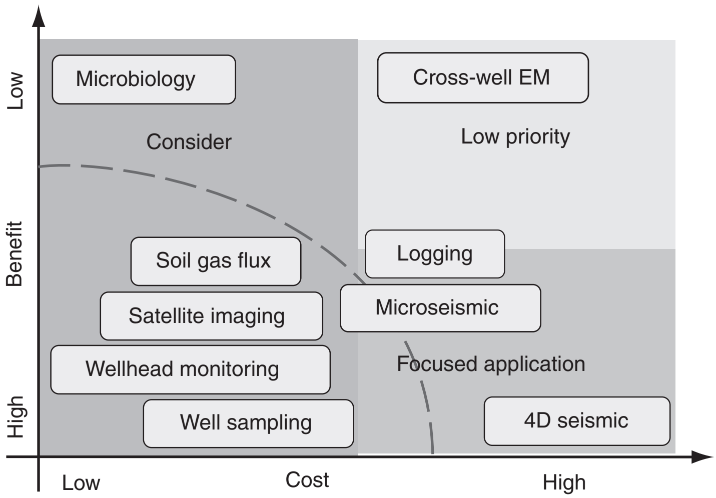
A risk assessment will be carried out throughout the course of storage site design and prior to granting a storage permit, regulators will need to be satisfied that these risks have been suitably addressed. Risk assessment will be a multistage process including modelling CO_2 migration and its long-term fate. Results will help to highlight where risks lie and allow them to be mitigated as far as possible through site design and construction. However it is likely that some 'residual' risk and uncertainty will remain, at a level considered 'acceptable' for permitting. A monitoring programme can therefore be designed to monitor these to confirm storage integrity and other site objectives.

4.4.3 Boston square cost/benefit approach

The cost of monitoring needs to be balanced against the benefits derived from the information that would be gained. Deployment of monitoring tools may be costly, but as well as being required by law, the potential cost of not monitoring sufficiently well also needs to be taken into account. Under jurisdictions which charge for CO_2 emissions and for any remedial work necessary, costs could be greatly increased if effects of the site not behaving as expected are not discovered sufficiently early. The cost of damage to the reputation and social acceptance of CO_2 storage if this should occur is beyond calculable. A tool to aid decision making includes assessing the cost/benefit of each individual technology and plotting them on a Boston square (Fig. 4.4). This method has been used at In Salah to help define the initial monitoring plan. Techniques which plot in the bottom left hand corner in this case (i.e. in the low cost, high benefit region) should therefore be used in the programme and other high benefit techniques could also be considered and budgeted for. This method is a simple but effective visual communication tool. Tools that have the highest cost/benefit are immediately obvious. As with all monitoring programmes, at In Salah, the method is periodically reviewed and updated, for example, to reflect new tools available (Mathieson *et al.*, 2010).

4.4.4 Value of information (VOI) analysis

Value of information (VOI) analysis is a commonly used decision making tool, but one which has been rarely used in the context of CO_2 storage to date (Sato, 2011a). However, it may prove useful for designing monitoring programmes as it allows a quantitative insight into the value of the information that may be gathered through monitoring. When all storage sites are different and require tailored monitoring programmes, this method may give a more objective way of designing and impartially justifying a monitoring programme. It allows quantitative analysis when the information sought is of a continuous probabilistic nature (e.g. porosity or permeability) as



4.4 Use of Boston square cost/benefit technique to help define initial MMV (monitoring, measurement and verification) programme at In Salah. (*Source*: Adapted from Mathieson *et al.*, 2010 with permission.)

well as for discrete probabilities (such as whether a fault is open or closed). Another useful feature may be to help to determine the level of accuracy required to give the same VOI. The point that not all information collected may be of value is emphasised. It also takes account of effects of uncertainty and information reliability.

4.4.5 Timing and frequency of monitoring surveys

Most surveys will span the life of a project, starting with baseline surveys prior to injection, followed by operational and post-injection monitoring. Baseline monitoring records natural background measurements of the site prior to CO_2 injection, from the reservoir level up to the surface. These surveys may include diurnal or seasonal variations and will be important to compare with later surveys to help distinguish effects related to CO_2 behaviour. Note that for some techniques, for example, soil gas, capturing the maximum expected natural range of parameters may involve prolonged acquisition over multiple seasons. By comparing results of baseline and subsequent surveys (timelapse monitoring) it is possible to demonstrate whether performance aligns with expected CO_2 behaviour. In most cases, unless monitoring is continuous and automatically recorded, survey frequency will be a balance between the need for site information and cost of obtaining it. In commercial sites this will likely be the minimum required in order to achieve monitoring objectives. At some of the pilot storage sites where the monitoring has a research objective, large quantities of information are gathered. This in turn may require a large amount of processing and analysis to interpret. However information gained at these sites help to identify the redundant information and thus allows the most efficient methods to be applied to large-scale commercial sites. Strategies such as the 'value of information' method discussed earlier (Section 4.4.4) may aid decision making on the frequency of surveys required.

4.4.6 Additional monitoring

The strategies outlined so far generally refer to what is known as 'core' monitoring (Chadwick, 2009a) and is monitoring that would be deployed assuming the site is behaving as expected. However, if results show significant deviation from predicted ranges, or cannot be explained with existing information, then this might require the deployment of additional monitoring, to investigate further (see Section 4.5). This 'additional monitoring' (Chadwick *et al.*, 2009a) is also known as 'contingency' monitoring (Sato, 2011a) and is targeted to provide results which would help understand the anomaly, its cause and likely severity. These additional monitoring results could help facilitate mitigation strategies by improving understanding of the leakage pathway, the extent of leakage and the quantities escaping.

4.5 Monitoring results: modelling temporal responses

Modelling temporal responses helps to fulfil the monitoring aims related to site performance in two ways. Firstly, in demonstrating whether the site is performing as expected, by validating predictions and history matching models to results and secondly in providing predictions of long-term behaviour. The point at which any deviation of monitoring results from those expected by the model would trigger a change in operation or remedial action is also discussed in the following section. Incorporating updated monitoring results into the model can aid understanding of site behaviour.

4.5.1 Validating predictions and history matching

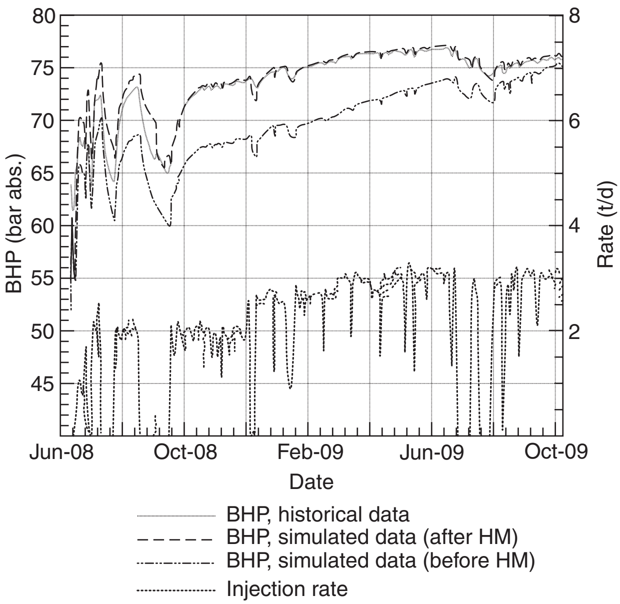
Site performance will be assessed prior to permitting to predict CO_2 migration and assess long-term safe storage. Simulations of most likely injection and storage scenarios are run using models with relevant geological and injection parameters to achieve a prediction of expected and acceptable site performance. Permitting of a site will be based on the safe storage predicted by these models. It is therefore necessary to verify them once injection begins to provide assurance that the CO_2 is behaving as expected, staying within the reservoir and not causing any adverse environmental impacts. Monitoring results are the key evidence to proving the validity of these predictions. Prior to this validation, there will also be a period during which the models themselves are refined and the simulations rerun to better match the real injection rate data and new information emerging about the site. This is called history matching.

These pre-permitting models will therefore need to predict features that should be verifiable by monitoring results. Wellbore saturation measurements at Frio (Ghomian *et al*., 2008) and pressure monitoring at Ketzin (Pamukcu *et al*., 2011) are good documented examples of history matching. At Ketzin, the pre-permitting geological model on which CO_2 injection simulations were run was updated following the collection of a range of monitoring results. Permeability in the original model had a high uncertainty as it had been based on the relationship between porosity and permeability measurements from core samples. Permeability was therefore the model property that was altered until the timing of breakthrough of CO_2 and reservoir pressure at the closest monitoring well most closely matched observations. This was an iterative process that may have multiple possible solutions. It was found that decreasing the model horizontal and vertical permeabilities by a factor of ten gave the best match with reality. The history matched model then matched well with observations of pressure (Fig. 4.5) and timing of breakthrough at the closest monitoring well. However at the more distant monitoring well, breakthrough was predicted 160 days earlier than it actually occurred.

Mechanisms that could cause this separation in simulated breakthrough time from reality are being studied using monitoring survey results. Geological heterogeneity creating permeability baffles or anisotropy is perhaps the most likely explanation although the exact cause is still being studied (Wiese *et al*., 2010; Würdemann *et al*., 2010). Analysis and integration of the results of multiple monitoring technologies will help to improve the understanding of site characteristics and CO_2 behaviour in the subsurface and ultimately build confidence in future site predictions.

4.5.2 Defining an acceptable model match

There is some discussion as to what constitutes a ‘successful match’ between modelled and measured results, but perhaps more pertinent is at what point differences become significant. Firstly, it is highly unlikely that any pre-permitting model would match monitoring results exactly, mainly because of lack of input data prior to injection and the actual injection rates used. This is perhaps best discussed using the site example described above. Often

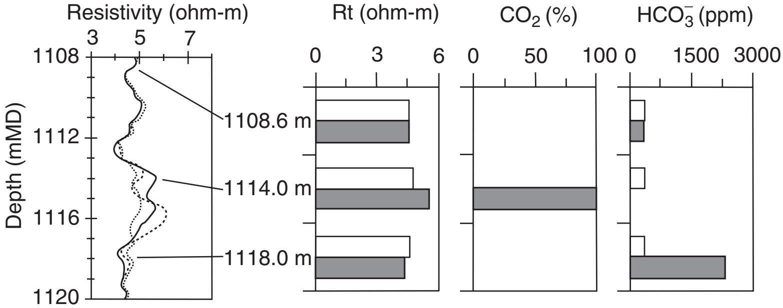


4.5 Bottom hole pressures (BHP in bar) at the Ketzin site injection well: measured values and simulated values both before and after history matching (HM). (*Source*: Courtesy of Y. Pamukcu, reprinted from Pamukcu *et al.*, 2011 with permission from Elsevier.)

the geological extrapolation between data points may be extremely hard to predict, especially for a complex geological setting, such as at Ketzin. Here model results suggest that there may be as yet unknown geological features affecting permeability at some distance from the wellbore, inhibiting CO_2 flow as predicted and causing later breakthrough in the furthest monitoring well (Würdemann *et al.*, 2010). This geological detail may be very difficult to incorporate into models to make them match exactly. As such there is no universally accepted level at which differences become 'significant' or the matches become 'acceptable'. It is important to be sure that mismatches cannot lead to serious non-conformance. Perhaps the most important thing that is required is for successive history matched models to converge, as this suggests that the level of knowledge and understanding of site behaviour is increasing and becoming more like the real situation. This lends confidence to future predictions. There should therefore be a period, once the model has been successively history matched, when it should remain without further refinement to demonstrate that its predictions match observations. It is only then that confidence in the model's ability to predict future behavioural trends could be established. This period will likely be dependent on individual site characteristics and timing of monitoring surveys scheduled, among other things.

4.5.3 Long-term predictions of site safety

The second important use of temporal modelling is to make long-term predictions of site safety and the fate of the CO_2 to enable site 'closure' and transfer of liability. This site handover will only occur when regulators are satisfied that the site is behaving as predicted and is heading towards long-term stability. At a conceptual level the stability of CO_2 storage increases with time as the proportion of dissolved CO_2 increases and the potential for subsequent mineral trapping also increases. (Refer to storage mechanisms discussed in Chapter 2, this volume.) Models simulating storage site development over thousands of years incorporate these reactions. Due to the long timescales needed for some of these stabilisation processes to occur and the relatively short time CO_2 storage sites have been operating, few sites have had the opportunity to observe them in the field. However, at the pilot site at Nagaoka, monitoring results indicate the initial stages required for mineral trapping have begun. Some of the CO_2 injected into the reservoir has begun ionic disassociation, an indication of the later stages of dissolution trapping (Sato *et al.*, 2011b). Here, around 10 000 t of CO_2 were injected into a saline aquifer over 554 days ending in 2008. Various monitoring data were collected throughout the operation and post-operation period. The simulation model was history matched to this data up to 3 years post-injection, and then run for 1000 years to make long-term predictions about the site. Results showed that the CO_2 would move slightly downdip, but remain in the storage formation for at least that period and that a significant amount of the CO_2 would be stored as ions. The initial stages of these predictions were detected by monitoring results from timelapse downhole logging of resistivity changes and further confirmed by downhole fluid sampling. The arrival of the CO_2 plume was detected by a rise in the resistivity caused by non-conductive CO_2 replacing the native, less resistive reservoir formation fluid. Post-injection surveys showed the resistivity then decreased relative to baseline data, especially in layers below the CO_2-bearing zone, which was interpreted to be due to CO_2 dissolving into component ions in the formation water (detectable at this site because of the relatively low salinity of the formation water). This was later confirmed by the downhole fluid samples (Fig. 4.6). The sample from below the reservoir (at 1118.0 m in Fig. 4.6) showed a 6.5% decrease in resistivity and 520% increase in HCO_3^- ions (from the baseline sample) (Sato *et al.*, 2011b). The amount of HCO_3^- in the samples was around five times more than the amount that would have been provided from the dissolution of calcite based on the observed calcium ion level, indicating that the additional HCO_3^- was from dissolution of the injected CO_2 (Xue *et al.*, 2009).



4.6 Evidence of CO_2 dissolution at the Nagaoka site. Far left: resistivity profiles at OB-2 monitoring well; dotted, black, and dashed lines for the baseline, the 29th run (after 921 days) and the final run (after 1611 days), respectively. Fluid sampling depths indicated. Right-hand three images: comparison of resistivity and chemical compositions of fluid samples in OB-2 before and after the CO_2 arrival; white and grey bars for pre-arrival (423 days before injection) and post-arrival (elapsed time of 880 days), respectively. (*Source*: Reprinted from Sato *et al.*, 2011b with permission from Elsevier.)

This evidence of ionic disassociation of CO_2 helps build confidence in the model predictions and implies that the storage stability is increasing as the CO_2 moves from structural to solution trapping.

As time passes it is likely that more evidence of increased storage stability will be collected. In the post-operational phase if all results show the site is evolving as predicted, the need for monitoring will be reduced and so survey frequency may decline or measurements cease, depending on site handover procedures.

4.6 Challenges and future trends

Results and interpretations from appropriately deployed monitoring allows successfully history matching of models and builds confidence in their long-term predictions. However, there are remaining issues and technology gaps as discussed below. Monitoring to adequately detect and measure potential leaks over wide areas and long timescales, remains challenging.

4.6.1 Monitoring timescales

Storage sites are designed to permanently contain CO_2. Meanwhile, the length of time before transfer of liability occurs is finite. Site closure relies heavily on convergence of model and monitoring results to show the site is reaching stabilisation and a number of years could elapse before this is the case. Further monitoring may still be required after closure to confirm this, although, as evidenced by the example of the Nagaoka site discussed in the previous section, post-site closure, the frequency and number of surveys will be greatly reduced. However for larger or more complex, less well-understood sites, the time before this point is reached could be significantly longer. Factors such as existing lifetimes of installed technologies may therefore become limiting. For example, to date downhole sensors have only been tested in a CO_2 environment for a certain number of years. As technology develops, more techniques suitable for CO_2 storage site monitoring are likely to become available. However comparisons of old versus more newly produced data may be challenging. This has been the case to a certain extent with interpreting legacy seismic data, for example, at the In Salah site. In addition, making deductions from results of new survey techniques for which baseline measurements do not exist may also be challenging.

4.6.2 Extent of monitoring coverage

CO_2 storage sites will cover large areas. This can be a particular challenge for monitoring for surface leakage. If there is a risk or evidence that the CO_2 is leaking laterally, the areas requiring surveillance may also be increased. Specific techniques are being developed that are able to monitor large areas for this purpose. For example, the remote sensing techniques discussed in Section 4.3.2. Although their current accuracy rate of vent detection is less than 50%, ideally this type of technique could be developed to more cheaply survey large areas and focus more accurate but time consuming and costly ground truthing survey efforts. As this type of technique develops hopefully more accurate and automated scans will become available such as those tested by Govindan *et al*. (2011). Surveillance for underwater leakage detection over large areas is at present more complicated and consequently expensive. Techniques for bubble detection and sea bed characterisation are available but require further development for CO_2 storage monitoring purposes (Jin *et al*., 2011).

4.6.3 Measuring leakage for emissions accounting

Once a leak has been identified, it will require quantifying. Suitable monitoring technologies capable of quantifying a leak within a certain level of uncertainty will be required for emissions accounting purposes. Isotopic and tracer analysis of gases detected should be able to identify the source of the CO_2. Previously collected monitoring results, if they have sufficient aerial coverage and frequency, can provide evidence of when the site started leaking. This will be important if paying for emissions back to the point in time at which it can be proven that the site was leaking is required. If the leak can be successfully mitigated, then monitoring should continue until the site has restabilised to allow site closure. If leakage is detected, current technology to measure them remains challenging. Despite testing at natural analogue and test sites, diffuse land and especially underwater emissions quantification is limited and requires development (Leighton and White, 2012). Combining flow models with observations may help to provide a convincing quantification.

4.7 Sources of further information and advice

More detailed descriptions of the techniques mentioned in the main text of this chapter can be found in the specific references given in each section and listed in full in the references section below. Weblinks to CO_2 monitoring related information, maps and storage sites are listed below.

General CO_2 monitoring related information

The IEAGHG webtool gives information on tool selection and brief case studies of where these techniques have been used: www.ieaghg.org/ccs-resources/monitoring-selection-tool1.

Other organisations or projects that have information on various tools and storage sites include:

- CO_2ReMoVe, Research and technology development for the monitoring and verification of geological storage: www.co2remove.eu/ CO_2GeoNet project: www.co2geonet.com/
- RISCS, Research into impacts and safety in CO_2 storage: www.riscs-co2.eu/

CO_2 storage sites

Site location and status maps are available from the following organisations:

- Scottish Carbon Capture and Storage global CCS map: www.sccs.org.uk/expertise/map.html
- Global CCS Institute projects map: www.globalccsinstitute.com/openccs/page/maps
- IEAGHG RD&D projects database: http://www.ieaghg.org/ccs-resources/rd-database

Sites mentioned in the text are listed here in alphabetical order. Many of these can also be found in the specific chapters of Part III later in the book.

- Cranfield: www.secarbon.org/files/gulf-coast-stacked-storage-project.pdf
- Frio: www.beg.utexas.edu/gccc/fieldexperiment.php

- In Salah: www.insalahco2.com/
- K12B: www.k12-b.nl/
- Ketzin: www.co2ketzin.de/nc/en/home.html
- Nagaoka: www.rite.or.jp/English/lab/geological/demonstration.html
- Otway: www.co2crc.com.au/otway/
- Sleipner: www.statoil.com/en/TechnologyInnovation/ProtectingTheEnvironment/CarbonCaptureAndStorage/Pages/CarbonDioxideInjectionSleipnerVest.aspx

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5

The role of pressure in carbon capture and storage (CCS)

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Abstract: Pressure controls the phase and the behaviour of CO_2 in the subsurface environment, and may be used to define and identify suitable containment sites, even when the usual structural trapping mechanisms appear to be absent. It is also an essential property in quantifying the capacity of storage sites and determines the injection pressures that can safely be used. This chapter describes the fundamentals of pressures and overpressures in the subsurface and their relevance for sites for the geological storage of CO_2.

Key words: CO_2, pressure, pressure compartments, seal failure, overpressure, closed system, open system.

5.1 Introduction

Fluids respond to pressure differences in their environment, and will migrate, largely driven by buoyancy contrasts, through their host medium until buoyancy pressures are too small to allow fluids to move, or the fluid is constrained by physical barriers. It follows that if we are to understand the mechanisms of underground CO_2 storage, we first must understand the prevailing subsurface pressure regime and its relationship to geological barriers and conduits for fluid flow. This chapter examines implications of pressure on potential carbon capture and storage (CCS) sites which are both confined (compartments) and open (saline aquifers). The limitations imposed by pressure in the local wellbore conditions during injection are not considered here (see Mathias *et al.*, 2009).

Subsurface pressure has an impact on CO_2 storage in several ways:

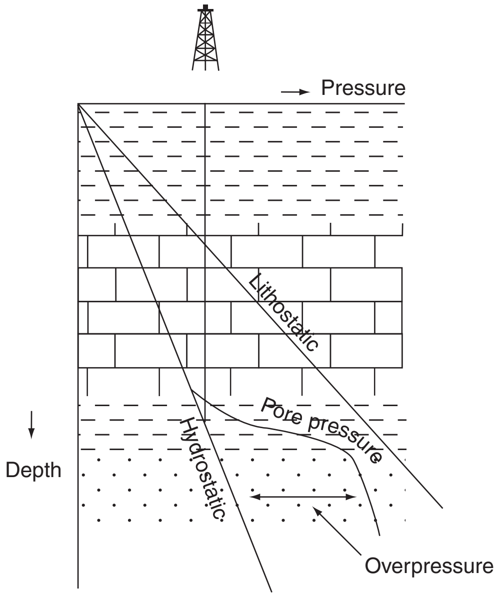
1. It controls the CO_2 phase, and determines whether it is in a liquid or gaseous form. The pressure at depths greater than 800 m is sufficient to keep CO_2 in its condensed state and therefore maximise the amount of CO_2 that can be stored.

2. The pore fluid pressure following CO_2 injection must not exceed the membrane seal capacity and/or hydraulic fracture limit or shear failure limit of any sealing or containing rock units. Failure of the host rock is most likely to occur either:
   (a) at the shallowest point of the containing structure (the top seal),
   (b) at/near the injection site, or
   (c) at the weakest point with respect to shear failure, which may, for example occur along a fault.
3. Fluid pressure is used to define 'open' or 'closed' systems and provides a convenient means of both recognising and classifying potential storage sites.
4. Fluid pressure is used to calculate the degree of overpressure, which is a key value in the identification of discrete pressure compartments and hence individual storage sites within closed systems.

5.1.1 Pressures and overpressures in the subsurface

Permeable formations which are hydraulically open and static exhibit pressures which are equivalent to that of a column of water extending to the surface. This pressure–depth profile is termed hydrostatic pressure. The pressure distribution changes, however, when impermeable layers such as shales are present. Compaction in response to burial and tectonic stress causes dewatering of the rock releasing water into the pore spaces of neighbouring permeable layers, unless the permeability is too low, in which case there is a buildup of pore pressure above hydrostatic. The excess pore pressure over the hydrostatic pressure is the overpressure at that depth, and the pattern of overpressure values across a region is a key indicator of subsurface conditions, indicating conditions of both containment (e.g. pressure compartments) and hydrodynamics within reservoirs.

The key subsurface pressures that we need to know are shown in Fig. 5.1. CO_2 injected into the rock will contribute a partial pressure which adds to the existing pore fluid pressure, initially in the vicinity of the injection site, but quickly moving into a larger volume of the aquifer. For containment controlled by membrane seal capacity (i.e. the ability of the CO_2 to move into the seal by displacement of water), the pressure limit is governed by the relationship between the buoyancy pressure of the CO_2 and the capillary entry pressure of the seal relative to the CO_2–water system. Membrane seal failure involves slow remigration of the buoyant fluid through the low-permeability seal, and is a process which is governed by geological timeframes of 100 000+ years or greater. Hence since CCS retention is generally considered over 1000s of years, it is not considered further in this review of CCS. On the other hand permeability created in re-activated faults (during shear failure) or newly-created tensile cracks (during hydraulic failure)



5.1 Subsurface pressures illustrated on a pressure–depth plot. Hydrostatic gradient represents the static formation water density starting from surface pressure (sea level offshore; water table onshore). The lithostatic gradient captures the weight of the column of rocks from sea-bed or land surface. (*Source*: Adapted from O'Connor *et al.* (2010).)

creates pathways to the surface which may take only days (e.g. hydraulic failure involving high pressure water and mud at the site of the LUSI mud volcano, East Java took only 2 days to reach the surface from 2.0 km depth; Davies *et al.*, 2008).

When considering hydraulic failure of the top seal, the limit for the CO_2 injection volume relates to the difference between the initial pore fluid pressure and either the fracture pressure or lithostatic pressure, whichever is lowest (it is possible for fracture pressure to be greater than the lithostatic pressure under certain tectonic conditions). The fracture/lithostatic pressure is therefore considered a limiting factor for the volume of CO_2 which can be stored.

To assess the initial conditions, prior to estimating injection volumes, pressures in the subsurface are plotted on pressure–depth plots to illustrate these relationships between fluid and rock pressures. Three pressures are of particular importance:

1. Pore fluid pressure, which is the pressure of the fluid filling the pores in the rock. The fluid will usually be water initially, then a mixture of water and CO_2 during injection. Injecting CO_2 will raise the pressure and create additional stress locally.

2. Fracture pressure, which is defined by the rock strength, which normally increases with depth but varies with lithology. Mudrocks/shales are normally more resistant to fracturing than sandstones. Fracture pressure (and hence rock failure during excessive injection) usually relates to the minimum horizontal stress, since most injection sites are planned in areas where the vertical or maximum horizontal stress is the maximum stress.
3. Lithostatic pressure (also known as vertical stress or overburden) also increases with depth and is defined by the combined weight of rock and contained fluids. In the majority of sedimentary basin settings where CO_2 would be injected the lithostatic pressure is greater than the fracture pressure, but not in all cases.

The difference between the pore pressure (fluid) and the fracture pressure and/or lithostatic pressure (rock) is a key parameter governing CO_2 volumes which can be injected, as discussed below.

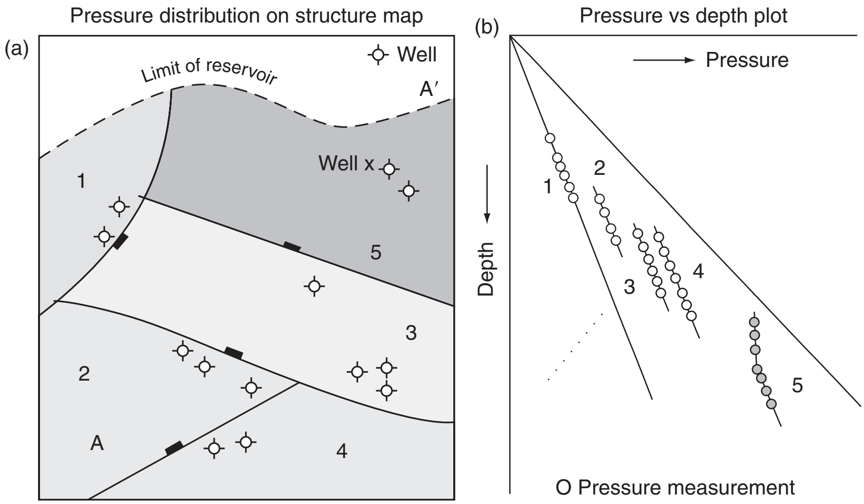
Reservoir and field scale pressure studies have long been a standard tool of hydrocarbon exploration and extraction activities. The measurement and prediction of subsurface pressures can provide information on potential oil or gas reserves, help with well planning and reduce risks in drilling and hydrocarbon extraction. Such studies often reveal patterns in the overpressure values. When the overpressure values vary from location to location there are two likely explanations: (1) presence of discrete compartments, each characterised by similar overpressure values, but different from adjacent compartments; (2) a hydrodynamic aquifer in which overpressure values change systematically from location to location, defining a hydrodynamic flow pattern. CO_2 storage is therefore possible in open reservoir systems (aquifers), which may be static (hydrostatic throughout) or hydrodynamic (where there is overpressure decreasing upwards/laterally to the discharge area of the aquifer) and in compartments. Open systems with saline aquifers tend to be more extensive in area than pressure compartments. In open systems storage volumes of CO_2 are estimated by defining daughter storage units. Daughter storage units are defined as discrete structural culminations of a reservoir beneath an effective seal (called traps in petroleum systems).

5.2 Types of CO_2 storage units

Two main categories of storage units are considered based on considerations of pressure: pressure compartments in closed reservoir systems and saline aquifers, both active (hydrodynamic) and static (hydrostatic).

5.2.1 Pressure compartments (closed systems)

Pressure compartments are identified when subsurface overpressure values vary from well to well, and do not show any significant change in value within



5.2 Pressure compartments, shown schematically but recognised by a combination of (a) the location map of wells, showing faults and reservoir limits and (b) the pressure-depth plot.

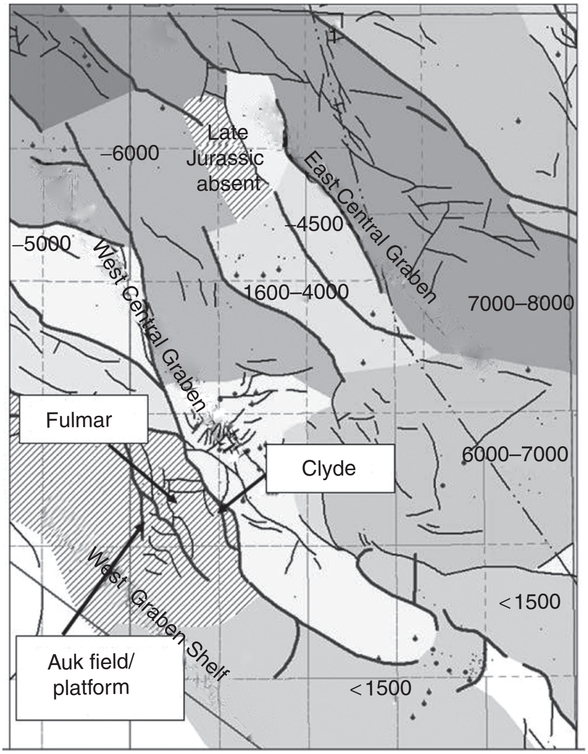
a reservoir which is considered to be geologically continuous. Figure 5.2 shows diagrammatically how pressure compartments are identified on a multi-well pressure–depth plot and outlined in a corresponding structural map. In this example, the compartment boundaries are sealed mainly by faults, but also defined by the limits of the reservoir.

Worldwide, there are many examples of pressure compartments in association with the containment of hydrocarbons (O'Connor *et al.*, 2007), and the North Sea example in Fig. 5.3 shows typical features.

Pressure compartments require top seal, bottom seal and side seals to trap fluids in reservoirs. Top and bottom seals are likely to be fine-grained and low permeability rocks such as shales and evaporites. Side seals are most likely to be created by faults or lateral change from reservoir to low permeability non-reservoir rock. The permeability of the top, bottom and side seals is likely to be on the order of micro- to nano-Darcy values, restricting significant movement of water over long periods of time. Mapping the location of all compartment boundaries remains beyond the resolution of most types of subsurface data, including seismic data at most suitable site depths, and inferences for the location of boundaries relies on interpolation between well data points where overpressures are known or can be inferred.

5.2.2 Saline aquifers (open and static systems)

At first sight, drained saline aquifers may not appear to be useful as storage units, because if water has drained from the formation and the aquifer

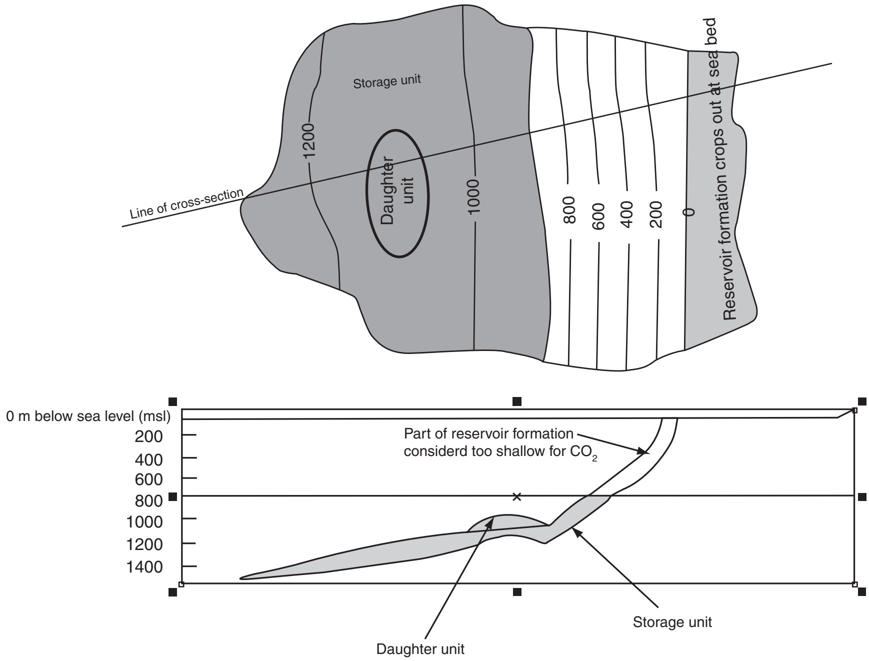


5.3 Overpressure compartments in the North Sea. The various pressure compartments are shown in shades of grey. The pressure values are in psi. (*Source*: Figure adapted from Swarbrick *et al.* (2003).)

remains open to flow to the surface, then so could liquids, including injected CO_2, reach the surface. However, folds and local faults (which are known to trap hydrocarbons) will cause CO_2 to be trapped against impermeable boundaries where it will accumulate by displacement of pore water. The sites where retention can be anticipated are where there is four-way closure provided by top seal dip and/or faults or other permeability barriers. These will be referred to as daughter storage units within the reservoir (Fig. 5.4).

5.2.3 Saline aquifers (open and hydrodynamic systems)

In the case of hydrodynamic systems (saline aquifers in which there is fluid flow directed towards the surface driven by association with overpressured shales or a hydraulic head) there remains the potential to trap CO_2 in daughter storage units. In this case, however, consideration must be made in relation to the tilting of any CO_2–water interface during and after injection.



5.4 A saline aquifer containing a daughter unit. (*Source*: Adapted from Gammer *et al*. (2011).)

Analysis of hydrocarbon–water tilt shows that the overpressure differences and the buoyancy of the fluid above the water determine the degree of tilt, and the confines of a trap relate to the hydrodynamic spill point (see Dennis *et al*., 2005). The same consideration will be relevant when considering the storage of CO_2 in hydrodynamic aquifers.

Recognition of an open system, both static and hydrodynamic, relies on examination of pressure data and mapping of aquifers. Mapping of overpressure can demonstrate the hydrodynamic nature of a reservoir when there is a systematic decline in overpressure towards the escape route of fluids from the aquifer to the surface. An example from the Central North Sea is shown in Plate IV (see colour section between pages 214 and 215) (O'Connor *et al*., 2008). Recognition of hydrodynamic reservoirs can be assisted by interpretation of pressures in the shales above the reservoir, and a pressure reversal from the shales. Hydrodynamic aquifers created by a hydraulic head can be identified when the reservoir pressure exceeds the seal pressures (water is termed artesian). In the case of hydrodynamic reservoirs created by association with overpressured seals and an escape route for fluid along laterally draining reservoirs, the seal pressures exceed the reservoir pressures. Note that the fluid drive from top seal (higher overpressure) to reservoir (lower overpressure) acts to enhance the sealing capacity of the storage unit, as the buoyancy force is counteracted by the fluid drive (Underschultz, 2007).

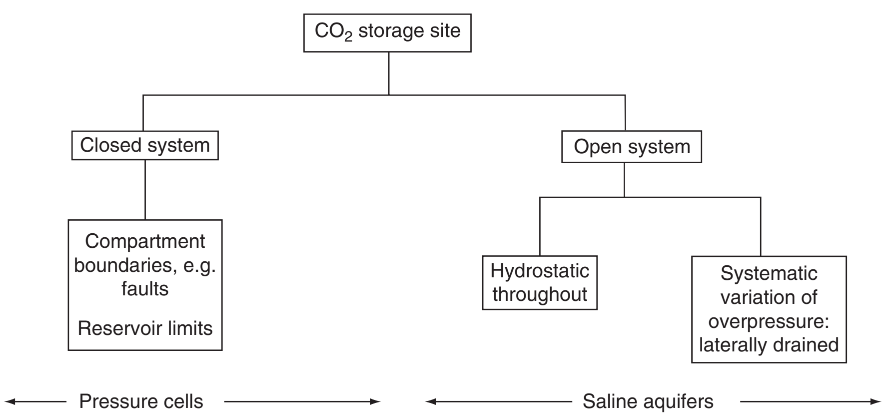
5.3 Relevance of pressure to CO_2 storage sites

CO_2 storage sites have been classified into two principal types: open and closed systems (Fig. 5.5).

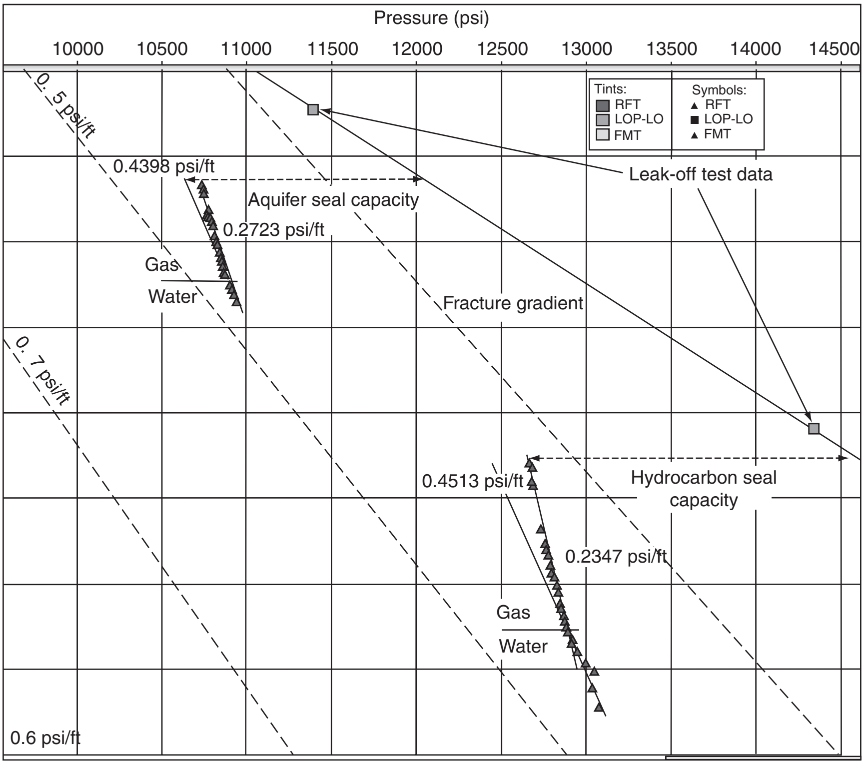
5.3.1 Closed systems

In a closed system, the maximum volume of storage is normally determined by top seal hydraulic failure or lateral seal failure. If the reservoir designated for injection is already overpressured, the amount of additional pressure from injection that it can withstand prior to failure is limited. The upper limit to injection is the point of rock failure, which is likely to be linked to the fracture pressure. Failure is either tensile (fractures opening up without displacement in the direction relating to the minimum principal stress) or in shear (linked to the differential stresses between principle stresses). Pore pressure-stress coupling in sedimentary basins (Engelder and Fisher, 1994; Hillis, 2001) leads to small differential stresses in high pressure reservoirs, such that the expected mode of failure is tensile.

The example in Fig. 5.6 shows a pressure–depth plot in which there are two high pressure compartments, each with a gas/water contact. The example illustrates pressure data collected at the time of first drilling into these high pressure compartments, in which gas was discovered. Initial high pressure leads to small potential volumes for injection. After depletion of the



5.5 A CO_2 storage site classification system.



5.6 Pressure–depth plot showing seal capacity. (Lithostatic gradient not shown.) RFT: repeat formation tester; FMT: formation multi-tester; LOP-LO: leak off pressure.

reservoirs by gas production the pressures will be reduced and large volumes of CO_2 can be injected and stored. The benefit of using depleted reservoirs is that there is likely to be a well characterised reservoir (e.g. porosity, permeability, connectivity in the reservoir), and there will be a production history from which reservoir and wellbore behaviour can be anticipated. Pre-site analysis will need to consider the pressure condition of the aquifer below and outside the area of production but still within the same compartment, however, as well as the integrity of any existing wells which would offer potential leakage pathways to the surface and/or contamination of other aquifers in the associated stratigraphic sequence of rocks.

The CO_2 storage capacity of each compartment is therefore the injection volume which will reduce the pressure difference between the initial compartment pressure and the fracture failure pressure. Failure is most likely to take place initially at the crest (where the pressure difference is smallest) and hence the volume is limited to the pressure difference estimated at the crest. Although the fracture pressure represents the absolute limit of pore pressure, a safe practical value will be less than this and a safety factor of 10% of the fracture pressure is suggested.

Failure of the integrity of a compartment during injection of CO_2 is not exclusively the top seal, however. Lateral seal failure is also possible, in which increased pressure differences across a lateral seal (such as a fault) is sufficient to cause rock failure and fluids can move effectively across the former barrier to flow. This phenomenon of lateral seal failure is known to take place during differential depletion of oil and gas fields, but the phenomena is poorly defined at the scale of pressure compartments. Lateral seal failure therefore represents a potential risk during injection, although the most likely outcome would be escape into an adjacent compartment which would limit the total possible future injection volume (if the adjacent compartment was considered unsuitable for injection) rather than cause loss of total integrity of the injection system.

One of the main controls on the rate of injection is reservoir permeability, which will ultimately control the pressure around the injection site. A high permeability will allow fluid to move away from the injection point at a fast rate and hence reduce the local pressure response.

The energy industry has extensive experience with injection of both water and gas during secondary recovery of hydrocarbon reserves, and the techniques are well understood. During the injection process, pore pressure and fracture pressure play a key role, as the rate of injection is constrained by the need to avoid creating hydraulic fractures around the injection site (see Mathias *et al.*, 2009).

5.3.2 Open systems

In open systems, fluid could ultimately escape to the surface since the aquifers are open to the surface. But, energy industry experience shows that separation of fluids by density will still permit the system to trap CO_2 if the appropriate geological structures are present. But even if this sort of trapping does not occur, other factors, identified only by pressure measurements, allow us to refine our ideas on what would be a suitable formation for CO_2 storage and which may greatly expand the number of storage resources available.

Any viable storage reservoir must contain the injected CO_2 for at least 10 000 years. This time period is much less than the period of containment of any economic hydrocarbon reserves, and means that we can consider for CO_2 storage site structures with less rigorous containment than typified by the majority of hydrocarbon reservoirs. Such reservoirs include open formations in which the rate of leakage is low enough for the time condition to apply.

A possible example of such a storage unit is the Andrew Sandstone formation (see Plate IV). A map of the overpressure values shows that the entire aquifer is active and connected hydraulically, with high overpressure at the deepest, southern part and lower overpressure in the shallow northern extent. The change from high to low values takes place over a short distance, indicating a sharp transition of permeability within the formation which acts as a barrier to fluid flow.

Measurements of the rate of flow, and the anticipated rate of flow of CO_2, would show whether the high overpressure sector of the formation is indeed a candidate for CO_2 storage.

5.4 Conclusion

Pressure plays a pivotal role in CO_2 storage in relation to recognition and definition of storage sites and ultimate storage capacity (and relates also to the rate of injection). Subsurface pressures are well known in places where many hydrocarbon boreholes have been drilled and pressures measured (e.g. North Sea, Gulf of Mexico, NW Shelf). Many of these potential sites are in closed systems, where aquifers are compartmentalised, and may be partially depleted by hydrocarbon production. Here injection volumes are limited to the increase in pressure during injection up to a limit determined by the seal failure criteria of the compartment. Both top seal and lateral seal failure conditions require estimation. Alternative potential sites are located in saline aquifers which are open systems (either static or hydrodynamic) which communicate with the surface. Some of these are well characterised by wellbore pressure measurements, but sometimes little pressure data are available to define initial conditions. Storage is not viable in the entire aquifer, and volume calculations are generally estimated based on the geometry of daughter units. Whilst top seal failure remains a limit to the pressures which can be accepted during injection, the open system has potential for pressure dissipation into the aquifer so the volumes are considered limited to the 'trap' volume in the daughter unit, similar to hydrocarbon trap volumes in the oil/gas industry. When the aquifer is hydrodynamic, however, consideration of tilting of the CO_2–water contact may reduce (or enhance) the injection volume, depending on top reservoir geometry and hydrodynamic flow direction.

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5.6 Appendix: glossary

- **Pore pressure** is the pressure acting on fluids in the pore spaces of a formation. Pore pressure can only be measured directly in permeable rocks, using wireline logging devices which sample the pore space fluid. Drill stem tests and other observations of well behaviour can also be used to provide an estimate of the pore pressure.
- **Fracture pressure** is the magnitude of pore pressure that the rock can withstand before it fails. It is related to the minimum compressive stress, and is estimated from borehole tests such as Leak-off Tests. It can also be estimated using lithostatic (vertical) stress and pore pressure-fracture pressure coupling.
- **Lithostatic pressure** is the pressure exerted by the weight of overlying sediments, including the weight of the contained fluids.

One of the main factors in recognising storage spaces for CO_2 is the magnitude of pore pressure in relation to other pressures, one of which is the **hydrostatic pressure**. Hydrostatic pressure is the (often hypothetical) pressure of an entirely open system at the depth of interest. It is a function of depth and related to water salinity, varying from fresh water (1.0 $g \cdot cm^{-3}$) to full saline (approx 1.2 $g \cdot cm^{-3}$) depending on temperature and pressure. Formations in which the pore pressure values are greater than hydrostatic values are termed overpressured.

- **Overpressure**

$$(\mathrm{O/P}) = P_{\mathrm{pore}} - P_{\mathrm{hydr}}$$

Regional overpressure variations can be interpreted as:

(a) evidence for compartmentalised reservoirs (closed pressure systems);
(b) evidence for hydrodynamic, laterally draining reservoirs (open pressure systems).

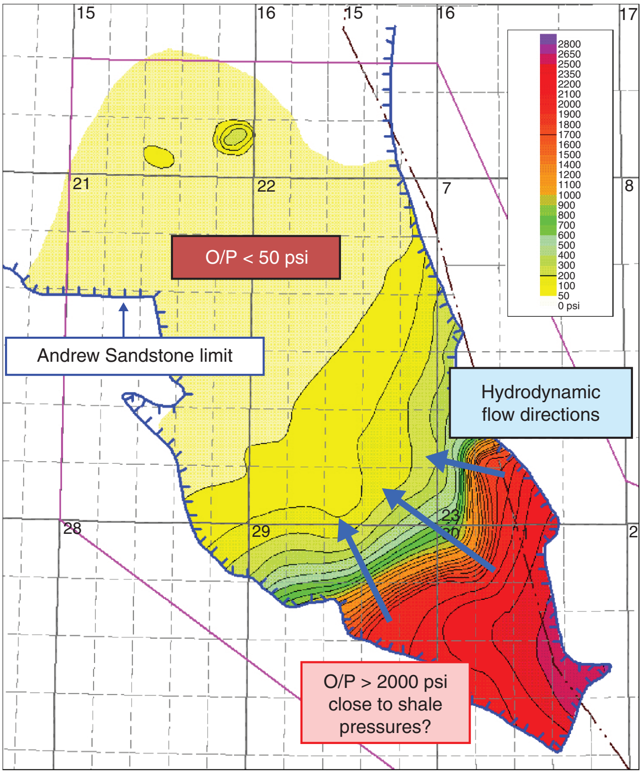

Plate IV (Chapter 5) Overpressure (O/P) map of the Palaeocene Andrew Fan System in the Central North Sea. The values of overpressure are high in the distal reaches of the fan (SE) and decrease towards the NW where the reservoir reaches the sea-bed and fluids escape. (*Source*: Figure adapted from O'Connor *et al*. (2008).)

6
Modeling long-term CO_2 storage, sequestration and cycling

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Abstract: A review of numerical and analytical models that have been applied to CO_2 sequestration is presented, as well as a description of frameworks for risk analysis. Various issues related to carbon storage and sequestration are discussed, including trapping mechanisms, density convection mixing, impurities in the CO_2 stream, changes in formation porosity and permeability, the risk of vertical leakage, and the impacts on groundwater resources if leakage does occur. A discussion of the development and application of site-specific models first addresses the estimation of model parameters and the use of natural analogues, and then surveys modeling that has been done at two commercial-scale CO_2 sequestration sites, a pilot-scale injection site and an experimental site designed to test monitoring of CO_2 leakage in the vadose zone.

Key words: modeling, multiphase flow, reactive transport, geomechanical, geochemical, Sleipner, Frio, In Salah, ZERT Release Facility, carbon dioxide, CO_2.

6.1 Introduction

Models have been applied to the simulation of geological carbon storage, sequestration and migration in order to predict the capacity of the formation to receive and store CO_2 over long periods of time. Because the injected CO_2 will be less dense than the formation water, it will have a tendency to migrate vertically due to density and pressure differences. Several processes may promote the long-term sequestration of CO_2, effectively trapping it in the subsurface. These processes include physical trapping beneath low-permeability or high-entry-pressure rock layers or local heterogeneities, dissolution of CO_2 into the formation water, precipitation of carbonate minerals, sorption onto mineral surfaces, or trapping as a residual, immobile fluid phase. Different techniques have been applied for solving the multiphase fluid flow, geochemical reactions and geomechanical changes that may occur as a result of geological carbon sequestration. A review of numerical and analytical models that have been applied to CO_2 sequestration are presented in Section 6.2, as well as a description of frameworks for risk analysis. A discussion of the application of models to various issues related to carbon sequestration are presented in Section 6.3, including trapping mechanisms, density convection mixing, impurities in the CO_2 stream, changes in formation porosity and permeability, the risk of vertical leakage, and the impacts on groundwater resources if leakage does occur. A discussion of the development and application of site-specific models in Section 6.4 first addresses the estimation of model parameters and the use of natural analogues to inform the development of CO_2 sequestration models, and then surveys modeling that has been done at two commercial-scale CO_2 sequestration sites, Sleipner and In Salah, along with a pilot-scale injection site used to study CO_2 sequestration in saline aquifers (Frio) and an experimental site designed to test monitoring of CO_2 leakage in the vadose zone (ZERT Release Facility). These sites were chosen because they afford the opportunity to compare the application of different modeling approaches by various groups at each site. Finally, a discussion of future challenges and other sources of information are presented.

6.2 Types of models

Models using numerical, analytical and semi-analytical solution methods have been used to simulate the injection of CO_2 into subsurface formations. Code benchmark studies have compared various mathematical and numerical models applied to problems of CO_2 sequestration (Class *et al.*, 2009; Pruess *et al.*, 2004). Reviews of CO_2 sequestration codes have been done previously (Schnaar and Digiulio, 2009); in this section a selection of codes that have been applied to CO_2 sequestration are described.

6.2.1 Numerical models

Multiphase flow and heat transport

To simulate the sequestration of supercritical CO_2 in subsurface formations, a multiphase flow and heat transport simulator is required. The injected CO_2 may be at a different temperature than the formation. CO_2 will be in a supercritical fluid state at depths greater than 800 m, and in either a liquid or gas state at lesser depths. CO_2 will be less dense than the formation water and will migrate in response to density and pressure gradients.

The CO_2 Reservoir Environmental Simulator (COORES) is a research code designed by the IFP School in France. COORES simulates multi-component, three-phase and 3D fluid flow in heterogeneous porous media using structured or unstructured grids. COORES has been applied to CO_2 storage at the Snøhvit site (Estublier and Lackner, 2009) and to an assessment of cosequestration of CO_2 and H_2S (Jacquemet *et al.*, 2009).

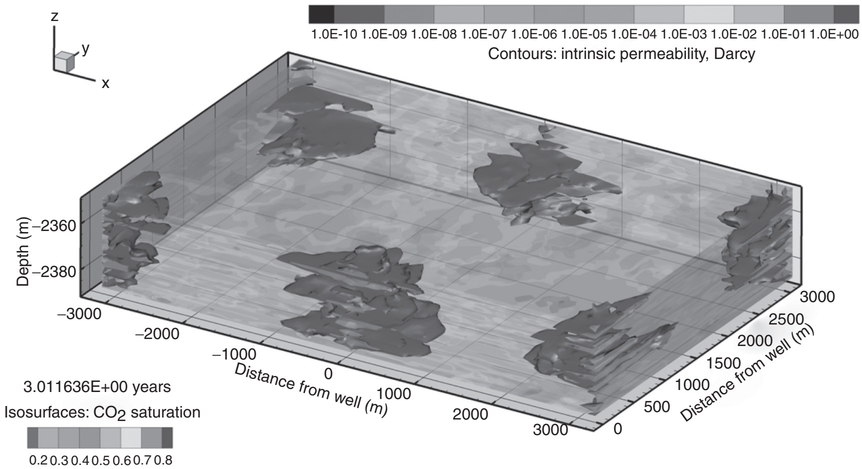
ECLIPSE is a commercial code, developed by Schlumberger, used in the oil and gas industry. It consists of two software packages: ECLIPSE BlackOil simulator, which is a fully implicit, three-phase, 3D, general-purpose black oil simulator, and ECLIPSE Compositional simulator with a cubic equation of state, pressure-dependent permeability values and black oil fluid treatment. ECLIPSE has been applied to studies of CO_2 sequestration in gas fields, saline aquifers, and enhanced oil recovery (Huang *et al.*, 2008; Maldal and Tappel, 2004; Trivedi *et al.*, 2007; Zhao *et al.*, 2010).

The Finite Element Heat and Mass Transfer Simulator (FEHM) is a porous media fluid flow simulator developed at Los Alamos National Laboratory. FEHM solves fully coupled heat, mass and stress balance equations for 3D, non-isothermal, multiphase fluid flow. FEHM uses a control volume finite element discretization approach with unstructured grids and iterative solution schemes. FEHM has been applied to geothermal reservoir simulations, groundwater flow simulations, contaminant transport simulations and methane hydrate reservoir simulations (Robinson *et al.*, 2000; Tenma *et al.*, 2008).

The Computer Modeling Group's Generalized Equation-of-state Model compositional reservoir simulator (CMG-GEM) is a commercial simulator which is used in the petroleum industry. It is an equation-of-state (EOS) based compositional reservoir simulator for modeling the flow of three-phase, multi-component fluids. CMG-GEM supports Cartesian, Radial, and Corner-Point fundamental grids, together with multi-level Local Grid Refinements. CMG-GEM's adaptive implicit formulation automatically decides, from time-step to time-step, which grid blocks must be solved in fully implicit mode or explicit mode. This code has been used to evaluate CO_2 storage and leakage scenarios (Alexander and Bryant, 2009) and to compare carbon sequestration in an oil reservoir to sequestration in a brine formation (Hovorka *et al.*, 2009).

The MUFTE simulator is developed and applied by the group of the Department of Hydromechanics and Modeling of Hydrosystems at the University of Stuttgart. MUFTE is capable of solving isothermal and non-isothermal multiphase flow problems, including compositional effects. Based on the assumption of local thermal and chemical equilibrium, it solves a fully coupled system of mass balance equations in 3D embedded into a Newton–Raphson linearization. MUFTE has been applied to numerical simulation of CO_2 storage in geological formations (Class *et al.*, 2006).

OpenGeoSys (OGS) is a scientific open source project for the development of numerical methods for the simulation of thermo-hydro-mechanical-chemical (THMC) processes in porous and fractured media. OGS is implemented in C++, and is object-oriented with a focus on the numerical solution of coupled multi-field problems (multi-physics). Parallel versions of OGS are available relying on both MPI and OpenMP concepts. OGS is based on RockFlow (University of Hannover; University of Tübingen).



6.1 Simulated supercritical CO_2 saturation after 3 years of multiple well injection into the Rose Run Formation (Bacon *et al.*, 2009).

Application areas of OGS are currently CO_2 sequestration, geothermal energy, water resources management, hydrology, and waste deposition (Goerke *et al.*, 2011; Nowak *et al.*, 2011; Shao *et al.*, 2009; Singh *et al.*, 2011; Sun *et al.*, 2009; Xie *et al.*, 2011).

The STOMP simulator (White and Oostrom, 2006) solves the partial-differential equations that describe the conservation of mass or energy quantities by employing integrated-volume finite-difference discretization to the physical domain and backward Euler discretization to the time domain. The resulting equations are nonlinear coupled algebraic equations, which are solved using Newton–Raphson iteration. The simulator has been written with a variable source code that allows the user to choose the solved governing equations. The currently available operational modes of STOMP are: water, water-air-energy, water-oil, water-oil-air, water-salt, water-CO_2-salt, and water-CO_2-CH_4-salt-energy (hydrates). STOMP has been used to help design and simulate results of CO_2 sequestration field pilots (Bacon *et al.*, 2009b; Bacon *et al.*, 2009c) (Fig. 6.1).

TOUGH is a suite of simulators for non-isothermal multiphase flow and transport in fractured porous media. TOUGH2 is the basic simulator, with equation of state modules for different applications. An EOS property module for mixtures of water, NaCl, and CO_2 (ECO2N) has been developed (Pruess, 2005) and is widely used for the analysis of geologic carbon sequestration processes (Doughty, 2010; Liu *et al.*, 2011; Zhou *et al.*, 2009). A newer EOS module, ECO2M, that includes sub-critical conditions and phase change between liquid and gaseous CO_2 has recently been developed (Pruess, 2011).

Coupled reactive transport

A simulator with coupled reactive transport is required to simulate the effect of mineral trapping of CO_2, or dissolution of formation minerals due to increased acidity. An overview of geochemical and solute transport modeling for CO_2 storage purposes has been done, with data requirements and gaps highlighted, and recent progress discussed (Gaus *et al*., 2008).

CRUNCH is a computer program for simulating multicomponent multidimensional reactive transport in porous media. Using an automatic read of a thermodynamic and kinetic database, the code can be used for reactive transport problems of arbitrary complexity and size (i.e., there is no *a priori* restriction on the number of species or reactions considered). The main features of the code include the ability to simulate advective, dispersive, and diffusive aqueous phase and gas transport in three dimensions under non-isothermal conditions. Multicomponent reactions may be either coupled directly to transport (a global implicit approach), or transport and reaction may be solved sequentially. CRUNCH has been used to evaluate the impact of CO_2, H_2S and SO_2 storage and sequestration in the Frio formation, Texas (Knauss *et al*., 2005).

Coupling between multiphase flow and thermodynamic equilibrium calculations were implemented on the basis of the commercially available thermodynamic simulator ChemApp and the object-oriented programming finite-element method simulator OpenGeoSys (Xie *et al*., 2011). ChemApp uses the Gibbs energy minimization approach for the geochemical reaction simulation. Activity coefficients in high-saline solutions were calculated using the Pitzer formalism. This model simulates 3D multiphase thermo-hydrochemical coupled processes even with highly saline solutions under complex conditions.

ECKEChem (Equilibrium-Conservation-Kinetic Equation Chemistry) is a reactive transport package for the STOMP simulator (White and McGrail, 2005). The ECKEChem batch chemistry module was developed in a fashion that would allow its implementation into all operational modes of the STOMP simulator. ECKEChem uses an operator split, non-iterative solution scheme to minimize the Jacobian matrix size and computation time. STOMP-ECKEChem has been applied to the co-injection of CO_2 and SO_2 into carbonate, basalt and sandstone deep saline formations (Bacon *et al*., 2009a; Bacon and Murphy, 2011).

PFLOTRAN is a massively parallel subsurface reactive flow and transport computer code that runs on laptops to high-end supercomputers (Hammond *et al*., 2011). PFLOTRAN solves a system of nonlinear partial-differential equations describing multiphase, multicomponent, reactive flow and transport processes in porous media. Chemical reactions currently include aqueous complexing, mineral precipitation/dissolution and sorption.

Sorption reactions include ion exchange and surface complexation with both equilibrium and kinetic formulations and colloid-facilitated transport. PFLOTRAN has been applied to a high-resolution numerical investigation on the effect of convective instability on long-term CO_2 storage in saline aquifers (Lu and Lichtner, 2007).

TOUGHREACT is a numerical simulation program for chemically reactive non-isothermal flows of multiphase fluids in porous and fractured media, developed by introducing reactive chemistry into the multiphase flow code TOUGH2. Interactions between mineral assemblages and fluids can occur under local equilibrium or kinetic rates. The gas phase can be chemically active. Precipitation and dissolution reactions can change formation porosity and permeability, and can also modify the unsaturated flow properties of the rock. TOUGHREACT has been applied to a two-dimensional (2D) reactive transport model of CO_2 injection into a saline aquifer at the Sleipner site (Audigane *et al.*, 2007).

Coupled geomechanics

The large amounts of supercritical CO_2 to be injected into deep saline aquifers may cause large fluid pressure increases. The resulting overpressure may promote reactivation of sealed fractures or the creation of new fractures in the caprock. Simulating these processes requires a multiphase fluid flow code coupled with a code that solves geomechanical stress–strain equations in order to predict changes in formation porosity and permeability with a change in stress. Rutqvist (2011) provides an overview of coupled thermal-hydraulic-mechanical (THM) codes.

The TOUGH-FLAC simulator (Rutqvist, 2011) is based on a coupling of the two existing computer codes TOUGH2 and FLAC3D (Itasca Consulting Group 1997). TOUGH2, described previously, is a code for multiphase, multicomponent fluid flow and heat transport, while FLAC3D is a widely used commercial code that is designed for rock and soil mechanics. For analysis of coupled THM problems, the TOUGH2 and FLAC3D are executed on compatible numerical grids and linked through external coupling modules, which serve to pass pressure, saturation and temperature between the field equations that are solved in each code. TOUGH-FLAC has been applied to both generic and site specific studies involving supercritical CO_2 injection, geomechanics, and ground surface deformations (Cappa *et al.*, 2009; Rutqvist *et al.*, 2007, 2008; Rutqvist and Tsang, 2002; Todesco *et al.*, 2004).

The numerical simulation of two-phase flow and geomechanical processes during CO_2 injection into deep saline aquifers has been conducted using OpenGeoSys (Goerke *et al.*, 2011). The work focused on isothermal short-term processes in the vicinity of the injection well. Governing differential equations are based on balance laws for mass and momentum, and completed by constitutive relations for the fluid and solid phases as well as their mutual interactions. The effective stress principle was used in the geomechanical analysis.

The injection of CO_2 into a homogeneous saline aquifer has been simulated using the finite element numerical code CODE_BRIGHT (Olivella *et al.*, 1994; 1996) modified for CO_2 injection; quadrilateral elements were used to enable the calculation of the mechanical problem. They (Vilarrasa *et al.*, 2010) modeled an axisymmetric horizontal aquifer–caprock system, including hydromechanical coupling, and looked at the failure mechanisms using a viscoplastic approach. Simulations illustrate that the most likely time for failure occurs initially, when fluid pressure rises sharply because of a reduction in permeability due to desaturation. However, in the case of closed boundaries, pressure may continue to rise.

6.2.2 Analytical and semi-analytical codes

Analytical and semi-analytical codes have been developed that, while employing various simplifying assumptions relative to numerical simulators, display significantly faster execution times. For this reason, these codes may be valuable components in risk estimation frameworks, discussed in the following section, which require multiple runs of a model with variations in its input parameters. Also, they are valuable for problems, such as leakage through abandoned wells, where the grid refinement necessary to resolve multiple wells in a numerical model would be computationally expensive. Further, analytical solutions are valuable for verifying the accuracy of numerical simulators.

Estimating Leakage Semi-Analytically (ELSA)

The code Estimating Leakage Semi-Analytically (ELSA) was developed at Princeton University and the University of Bergen (Nordbotten *et al.*, 2009). The code provides quantitative estimates of fluid distribution and leakage rates in systems involving a sedimentary succession of multiple aquifers and aquitards, penetrated by an arbitrary number of abandoned wells. The computational model used in this work is based on a set of analytical and semi-analytical solutions for CO_2 injection, leakage along segments of wells and up-coning in the vicinity of leaky wells. These individual components are integrated into an overall solution algorithm that can accommodate an arbitrary number of layers and an arbitrary number of potentially leaky wells.

Vertical equilibrium with sub-scale analytical method (VESA)

The vertical equilibrium with sub-scale analytical method (VESA) combines the flexibility of a numerical method, allowing for heterogeneous and geologically complex systems, with the efficiency and accuracy of an analytical method, thereby eliminating expensive grid refinement for sub-scale features (Gasda *et al.*, 2009). VESA combines both numerical and analytical models with a specific set of simplifying assumptions to produce an efficient numerical-analytical hybrid model. The model solves a set of governing equations derived by vertical averaging with assumptions of a macroscopic sharp interface and vertical equilibrium. These equations are solved numerically on a relatively coarse grid, with an analytical model embedded to solve for wellbore flow occurring at the sub-gridblock scale.

Multiphase flow and solute transport

Recently, a set of semi-analytical solutions for the movement of solutes in immiscible two-phase flow have been derived (Schmid *et al.*, 2011). These solutions account for the effects of capillary and viscous forces on the transport for arbitrary capillary-hydraulic properties, and for hydrodynamic dispersion for the variable two-phase flow field. The solutions build on the solutions derived previously (McWhorter and Sunada, 1990) to obtain analytical expressions for transport of solutes in two-phase flow.

Sharp interface models for CO_2 injection

A closed-form analytical solution describing the dynamics of interfaces in 3D porous media has been developed and applied to the problem of CO_2 injection in a deep aquifer (Dentz and Tartakovsky, 2009). A typical interface separates two fluids with different physical properties, that is, density and viscosity. For the solutions to remain valid, flow has to reach a quasi-steady regime after the initial injection phase, and the Dupuit approximation has to be valid (Dupuit, 1863), which holds that groundwater moves horizontally in an unconfined aquifer, and that the groundwater discharge is proportional to the saturated aquifer thickness. The authors conclude that 3D flow regimes are characterized by a logarithmic interface, whose curvature is controlled by a single dimensionless parameter that compares the relative strength of viscous and buoyancy forces.

An analytical solution for estimating storage efficiency of an aquifer for geologic sequestration of CO_2 has been developed (Okwen *et al.*, 2010) based on the sharp interface model used in ELSA (Nordbotten *et al.*, 2009). The limiting assumptions of the model are fairly numerous. The porous medium must be incompressible, and the temperature, fluid densities and viscosities must be assumed constant. The injection well must be perforated across the entire thickness of the aquifer, and there is negligible dip or incline in the top or bottom of the confining units. Nevertheless, because deep saline aquifers are often not well characterized, these are reasonable assumptions for a preliminary screening calculation.

Pressure build-up during CO_2 injection in brine aquifers

A recent analytical solution for pressure build-up during CO_2 injection in brine aquifers (Mathias *et al.*, 2009a) accounts for two-phase Forchheimer flow of supercritical CO_2 and brine in a compressible porous medium. This solution improves on previous work by not requiring the specification of a radius of influence, and allowing for compressibility in both the fluids and formation. This model has been applied to the screening of sites for CO_2 sequestration by estimating pressure build-up during CO_2 injection, and the limiting pressure at which the formation begins to fracture (Mathias *et al.*, 2009b).

6.2.3 Risk estimation

Codes that quantify the risks associated with carbon sequestration are used to screen and rank potential sites, or to determine if it is safe to inject CO_2 at a particular site. The flow and transport models used in these systems may be simplified relative to the numerical models described previously, either to reduce computational requirements for the end user, or to enable the execution of multiple simulations to quantify the overall risk resulting from many uncertain input parameters.

CO_2-PENS

CO_2-PENS is a system-level computational model for performance assessment of geologic sequestration of CO_2 (Stauffer *et al.*, 2009). CO_2-PENS is designed to perform probabilistic simulations of CO_2 capture, transport and injection in different geologic reservoirs. The long-term fate of CO_2 injected in geologic formations, including possible migration out of the target reservoir, is simulated. The simulations sample from probability distributions for each uncertain parameter, leading to estimates of global uncertainty that accumulate through coupling of processes as the simulation time advances. CO_2-PENS links together modules that describe the CO_2 sequestration pathway, from capture at a power plant, through pipeline transport to the injection site and into the storage reservoir, and migration through the reservoir. The system-level model used is GoldSim (Zhang *et al.*, 2007), which passes variables in and out of the process modules. Process modules include a wellbore leakage module based on ELSA (Nordbotten *et al.*, 2009), and FEHM (Zyvoloski *et al.*, 1997), a multiphase flow and transport simulator. An economic model has been coupled to the injection model in order to compare costs for different injection cases, based on the number of wells and drilling completion and maintenance costs. CO_2-PENS has been applied to carbon management for potential oil shale development in the Piceance-Uinta Basin in Colorado and Utah (Keating *et al.*, 2011).

Certification Framework (CF)

The Certification Framework (CF), developed by Lawrence Berkeley National Laboratory and the University of Texas, is a code that certifies that the risks of geologic carbon sequestration sites are below agreed-upon thresholds. The CF is based on effective trapping of CO_2, the proposed concept that takes into account both the probability and impact of CO_2 leakage (Oldenburg *et al.*, 2009a). The CF uses probability estimates of the intersection of conductive faults and wells with the CO_2 plume along with modeled fluxes or concentrations of CO_2 as proxies for impacts to compartments (such as potable groundwater) to calculate CO_2 leakage risk. To simplify the determination of the extent of the injected CO_2 plume, a catalog of 3D reservoir simulations of CO_2 injection and migration were developed using CMG-GEM and the Peng–Robinson equation of state for the CO_2-brine system. A large number of cases were simulated with a range of combinations of key reservoir properties such as thickness, dip, porosity, permeability, permeability anisotropy, injection interval and injection rate (Nicot *et al.*, 2009). The CF has been applied to a hypothetical large-scale GCS project in the Texas Gulf Coast, and WESTCARB's Phase III GCS pilot in the southern San Joaquin Valley, California (Oldenburg *et al.*, 2009b).

6.3 Long-term behavior and modeling issues

Once CO_2 is injected into a subsurface formation, the goal is for it to stay in place through various trapping mechanisms, and to avoid leakage of CO_2 or brine through caprock fractures or abandoned wellbores into drinking water aquifers.

6.3.1 Trapping mechanisms

The main trapping mechanisms of interest include the following:

- *stratigraphic trapping*: confinement of mobile (supercritical, liquid or gas) CO_2 under low-permeability layers, faults or anticlinal structures;
- *mineral trapping*: conversion of CO_2 to mineral precipitates;
- *solubility trapping*: dissolution of mobile CO_2 into the formation fluids (aqueous or oil);
- *residual trapping* (also known as capillary trapping, mobility trapping, or phase trapping): as injected CO_2 rises buoyantly, isolated pockets of free-phase CO_2 are left to dissolve slowly into surrounding fluids;
- *heterogeneity trapping*: local capillary trapping due to variations in multiphase hydraulic properties.

Stratigraphic trapping

A large-scale facies model of the Vedder Formation was used as the basis for a simulation of CO_2 injection beneath the Kimberlina power plant in the southern San Joaquin Valley, California (Doughty, 2010). The facies model used 180 layers, of equal thickness, to represent the Vedder Formation. A facies (either sand or shale) was assigned to each cell, by interpolating sand/shale picks obtained from eight well logs, and homogeneous properties given to each facies. CO_2 was injected into the sand facies, with stratigraphic trapping occurring beneath the shale layers over the 10 000-year simulation period.

Mineral trapping

Han *et al.* (2010) is one of the few papers to provide an evaluation of the first four trapping mechanisms at a particular site. Their modeling of supercritical CO_2 injection into the SACROC Unit in the Permian basin of western Texas shows that after 200 years, CO_2 is somewhat evenly distributed between the mobile, residual, and aqueous CO_2, with considerably less trapped in mineral form. This is not surprising as the SACROC Unit is predominantly limestone, and other simulations of CO_2 injection into dolomite have shown that carbonates buffer the pH changes associated with CO_2 sequestration by dissolving slightly in response to added CO_2 (Bacon *et al.*, 2009a).

Mineral trapping may occur in sandstone formations, but the rates of primary mineral dissolution and resulting carbonate precipitation have been predicted to be quite slow, occurring over 1000 to 10 000 years (White *et al.*, 2005; Xu *et al.*, 2003; 2005).

In contrast, a modeling analysis of experiments with Columbia River basalt in supercritical CO_2 (McGrail *et al.*, 2006) indicated rapid mineralization rates relative to typical sedimentary rocks. Geochemical modeling conducted using the EQ6 (Wolery and Daveler, 1992) geochemical reaction path model (Wolery and Jarek, 2003) of a Columbia River basalt sample consisting of plagioclase, clinopyroxene, mesostasis glass and a trace amount of magnetite predicted that calcite and dolomite would begin to precipitate in less than one day. Similar modeling exercises (Marini, 2007) excluding the basalt glass component predict the precipitation of calcite and dolomite [$CaMg(CO_3)_2$] as well as siderite and dawsonite [$NaAl(CO_3)(OH)_2$] after 1 year. This indicates that the glass component is a major factor in accelerating CO_2 mineralization in basalt.

Trapping by sorption onto mineral surfaces is another way in which CO_2 may be trapped. Coals will sorb CO_2 in preference to methane, which provides an economical way to sequester CO_2 and recover CH_4 as an energy source. Bromhal *et al.* (2005) used the PSUCOALCOMP compositional coal bed methane reservoir simulator and measured sorption isotherms to predict the maximum amount of CO_2 that could be sequestered in a coal seam and show how coal seam characteristics and injection practices will reduce the actual amount sequestered. Liu and Smirnov (2009) modeled structural deformation during carbon sequestration in coal beds using a coupled multiphase flow, CO_2 adsorption, and geomechanics simulator, showing that the deformation allows less CO_2 to be stored because the fluids will be less dense and the relative permeability–capillary pressure–saturation relationships will be less favorable.

Dissolution trapping

In order to accurately model the amount of dissolution trapping of CO_2 in formation brine, the multiphase flow model must accurately predict the solubility of CO_2 in water as a function of pressure, temperature and salinity. Although several models of CO_2 solubility in water/brine have been proposed, few can predict solubility in a very wide range of conditions with accuracy close to experimental observations (Lu *et al.*, 2009). The STOMP simulator uses a non-iterative model for H_2O–CO_2 mutual solubility in chloride brines (Spycher *et al.*, 2003) which is applicable over the range from 285.15°C to 373.15°C and from 0 to 60 MPa. The solubility model in ECO_2N fluid property model for TOUGH was recently extended to temperatures above 100°C and various salts (Spycher and Pruess, 2010). A more accurate solubility model for the dissolution of CO_2 in a water/brine solution (Duan and Sun, 2003) is applicable in a much wider range of conditions, from 273 to 533 K and from 0 to 200 MPa, and ionic strength from 0 to 4.3 mol/kg H_2O, and is used in PFLOTRAN (Lu and Lichtner, 2007).

Residual trapping

During transient multiphase flow of CO_2 and brine, if gas saturation increases because more CO_2 enters a grid block than leaves it, the process is known as drainage. Alternatively, when liquid saturation increases because more brine enters a grid block than leaves it, the process is known as imbibition. After injection ends, CO_2 moves buoyantly upward through brine-saturated rock. Some CO_2 remains trapped in the displacement path as a residual phase because brine imbibes into the volume previously occupied by the mobile CO_2. Over time, the entrapped CO_2 may dissolve slowly into the brine.

Numerical models of geologic storage of CO_2 in brine-bearing formations use characteristic curves (Brooks and Corey, 1966; Burdine, 1954; Mualem, 1976; van Genuchten, 1980) to represent the interactions of non-wetting-phase CO_2 and wetting-phase brine. When a problem includes both injection of CO_2 (a drainage process) and its subsequent post-injection evolution (a combination of drainage and wetting), hysteretic characteristic curves are required to the effect of residual trapping (Doughty, 2007). A theoretical model for hysteretic saturation functions for aqueous-gas systems was developed by Parker and Lenhard (1987). A simplified version of this model, analogous to Kaluarachchi and Parker (1992), has been implemented in the STOMP simulator (White and Oostrom, 2000). The amount of entrapped gas varies linearly between zero and the gas-effective residual saturation with the apparent saturation, which varies between the reversal point from the main drainage to one. Gas-effective residual saturations are computed using an empirical relationship (Land, 1968) for aqueous–nonaqueous phase liquid (NAPL) systems. Experimental studies of CO_2/brine displacement in sandstone, carbonate and shale provide parameters for these characteristic curves (Bachu and Bennion, 2008).

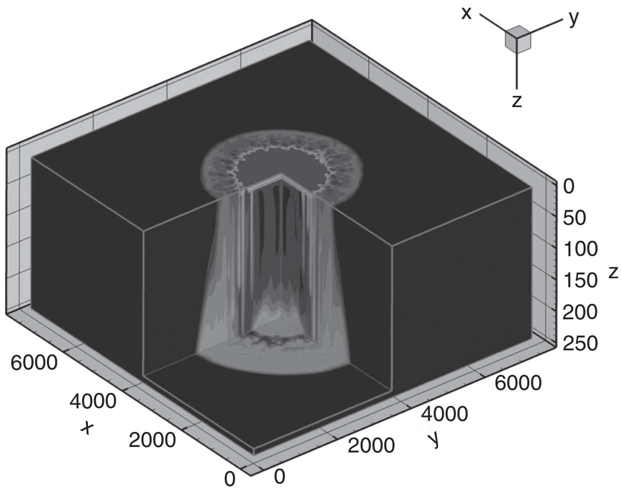
Heterogeneity trapping

Local capillary trapping occurs during buoyancy-driven migration of bulk phase CO_2 within a saline aquifer. When the rising CO_2 plume encounters a region where capillary entry pressure is locally larger than average, CO_2 accumulates beneath the region (Saadatpoor *et al.*, 2010). Local capillary trapping differs from residual trapping in that the accumulated saturation can be much larger than the residual saturation for the rock.

6.3.2 Density convection

Density-driven convection may result from the dissolution of CO_2 in formation brines. When free-phase CO_2 gas accumulates beneath a low-permeability caprock, CO_2 dissolution into the formation water increases the aqueous phase density, which can result in a gravitational instability. The aqueous phase saturated with CO_2 will then move downward due to gravity accompanied by the upward movement of brine, giving rise to convective mixing. This process can contribute to faster dissolution of CO_2 because it causes mixing between under-saturated formation water and the CO_2 plume. It also contributes to a longer residence time of the dissolved CO_2 in the subsurface because it flows toward the bottom of the target formation.

Several studies have applied both linear stability analysis and nonlinear global stability analysis to investigate the onset of convective mixing during CO_2 sequestration in isotropic and anisotropic porous media (Ennis-King *et al.*, 2005; Rapaka *et al.*, 2008; Xu *et al.*, 2006). While stability analysis can provide rough guidance for determining the conditions of instability and an estimate of the grid size needed to resolve fingering, there are disparities between the prediction of the onset of instability and stability as determined by linear and nonlinear analysis. Also, the analyses apply only to



6.2 Fine grid simulation of convective density mixing (Lu and Lichtner, 2007).

homogeneous or anisotropic media and not to heterogeneous media which is essential for representing natural geologic systems.

PFLOTRAN was used to compare results obtained from high-resolution simulations carried out on massively parallel computers with the predictions of stability analysis (Lu and Lichtner, 2007). The global dissolution rate of CO_2 into the formation brine of a saline aquifer in which supercritical CO_2 is injected was found to be highly dependent on grid resolution because of density-driven instabilities resulting in fingering of the dissolved CO_2 (Fig. 6.2). According to stability analysis, finger width can range over many orders of magnitude and for highly permeable regions may be too small to resolve even with massively parallel computing architectures.

More recently, a 2D reactive transport model was used to investigate the interplay of geochemical reactions with dissolution, diffusion and convection of CO_2 in brine (Zhang *et al.*, 2011a). Sensitivity modeling indicated brine salinity, initial CO_2 gas saturation accumulated beneath the caprock, geochemical reactions, mineralogical compositions, permeability perturbations and anisotropy ratio have an influence on the onset and/or evolution of the convection process.

6.3.3 Impurities in the CO_2 stream

The economic and energy costs of separation and compression of CO_2 from coal-fired power plants can account for a significant portion of the total cost of a geologic sequestration process. Sequestering a less-pure CO_2 stream is one option to reduce costs. A number of modeling studies have been conducted to consider the effect of co-injecting H_2S and SO_2 along with CO_2.

Simulations conducted to investigate the long-term impact of dissolved CO_2, H_2S and SO_2 on carbon sequestration in the Frio sandstone (Knauss *et al*., 2005) and in a typical Gulf Coast sandstone (Xu *et al*., 2007) yielded generally consistent results. A simple 1D, radially symmetric model was used for injection. Transport of co-contaminants in the gas phase was not considered; equilibrium with fixed partial pressures of SO_2 and H_2S was assumed, and it was assumed that all SO_2 oxidized to sulfate. After 100 years the CO_2 and $CO_2 + H_2S$ cases have identical sequestration. The $CO_2 + SO_2$ case results in lower pH, so more carbon remains in fluid and less has been trapped in the mineral phase. Batch geochemical modeling shows that during co-injection of CO_2 and SO_2 into redbeds, iron is transformed almost entirely to siderite or ankerite and sulfur is converted predominantly to dissolved sulfate (Palandri and Kharaka, 2005).

Although carbonate aquifers have not been shown to be good mineral traps for CO_2 (Bacon *et al*., 2009a; Gunter *et al*., 2000; Han *et al*., 2010; Zhang *et al*., 2011b), by dissolving in response to lowered pH they can release calcium, causing SO_2 and H_2S to precipitate as sulfate/sulfide minerals.

Recent simulations of CO_2 cosequestration assert that acidification due to CO_2 and SO_2 will be confined to a fairly sharp interface between the injected CO_2 and SO_2 (Crandell *et al*., 2010; Ellis *et al*., 2010); however, their flow model simulates the injected gas phase as a cone-shaped plume, with no residual brine within the area of influence of the plume. Dissolution between the injected CO_2 and SO_2 into the brine phase can only occur at the sharp interface between the plume and brine.

The most realistic approach to modeling the sequestration of an impure CO_2 stream requires that the multiphase flow simulator include the gas-phase flow of multicomponent mixtures, accounting for binary diffusion of CO_2, H_2S and SO_2 in the gas phase as well as the aqueous phase. An equation of state for TOUGH has been developed recently which calculates the properties of supercritical mixtures of inorganic gases such as CO_2, H_2S and N_2, as well as hydrocarbons and their dissolution in brine (Battistelli and Marcolini, 2009). The code was applied to the injection of a dry gas mixture into a sour oil reservoir, and shows the thermal front and evaporation/precipitation front lagging behind the impure CO_2 plume front.

6.3.4 Changes in porosity and permeability

CO_2 injection can result in a significant increase in pressure in the target formation, resulting in porosity and permeability changes due to changes in rock stress/strain. A poro-elastic model that considers macroscopic stress/

strain changes and grain deformability (Settari and Mourits, 1998) has been implemented in TOUGH-FLAC (Rutqvist, 2011). An empirical model has been proposed that describes a nonlinear change in porosity as a function of the effective mean stress (Rutqvist and Tsang, 2002). For geomechanical simulations, the nonlinear stress-dependent effects on porosity and permeability over the range of stress expected during CO_2 injection may be derived from laboratory data and fitted to theoretical or empirical functions (Liu *et al*., 2009). These parameters may also be determined by calibration to field experiments (Rutqvist *et al*., 2008a; 2008b).

Reaction of dissolved CO_2 with minerals in the receiving formation can cause changes to mineralogy and the physical properties of the aquifer due to the precipitation or dissolution of minerals (Bachu *et al*., 1994). In reactive transport codes that are coupled to multiphase flow and transport (e.g. TOUGHREACT, STOMP-ECKEChem), porosity changes are related to mineral volume changes, based on specified mineral densities, as a result of mineral precipitation and dissolution. These codes are also able to simulate the precipitation of salt near the injection well, as dry CO_2 is injected and extracts water from the brine (Pruess and Spycher, 2007).

Joule–Thompson cooling occurs when CO_2 expands from high pressure to low pressure at constant enthalpy. Injection of CO_2 into under-pressured depleted oil and gas reservoirs may therefore result in the formation of CO_2 or CH_4 hydrates, causing loss of injectivity. TOUGH2 with the EOS7C module (Oldenburg *et al*., 2004) for CO_2–CH_4–H_2O mixtures was used to simulate CO_2 injection into natural gas reservoirs in the Sacramento Valley, California (Oldenburg, 2007), with the conclusion that for constant-rate injections into high-permeability reservoirs, this effect is not expected to be problematic. A mathematical model for Joule–Thompson cooling during CO_2 sequestration (Mathias *et al*., 2010) considers the constant-rate injection of fluid from a fully penetrating injection well into an infinite, homogeneous and isotropic, insulated and confined formation. It is assumed that the Joule–Thompson coefficient remains constant at the low pressures of interest, and that the flow-field is single-phase and steady state. These assumptions lead to an overestimation of the temperature decline related to Joule–Thompson cooling, making the analytical solution suitable for conservative bounding analysis. The analytical solution can evaluate the minimum temperature for Joule–Thompson cooling using a single calculation, in contrast to TOUGH2, which requires multiple simulations to determine this minimum temperature.

Empirical equations that predict permeability from porosity are commonly used (Ghabezloo *et al*., 2009; Nadeau, 2000), and have been fitted for various rock types (Pittman, 1992; Saar and Manga, 1999; Yang and Aplin, 2010). For fractured rock an exponential empirical model has been applied to correct permeability for changes in the 3D stress field (Rutqvist *et al*., 2002).

A numerical model of colloidal transport in multiphase flow simulates permeability reduction near the CO_2 injection well due to blocking of pores with particulates (Sbai and Azaroual, 2011). Model results indicate that lower CO_2 residual saturation and formation porosity enhance clogging, and that permeability reduction processes depend on the permeability distribution and connectivity around wells.

6.3.5 Risk of vertical leakage

Upward CO_2 leakage out of the injection formation can occur as a result of the caprock failing to contain CO_2, the presence of faults or fractures, or through poorly cemented or abandoned boreholes (Intergovernmental Panel on Climate Change, 2005). The caprock itself can fail to contain CO_2 because of insufficiently low permeability or the propensity for capillary breakthrough.

Simulation of leakage through abandoned boreholes requires special computational techniques because of the unique challenges associated with simulation of injection and leakage in systems that include hundreds or thousands of existing wells over domains characterized by layered structures in the vertical direction and very large horizontal extent. At a field site in Alberta, Canada, the ELSA model (Nordbotten *et al*., 2009) was applied to a location where four large coal-fired power plants currently operate, emitting 30 Mt of CO_2 per year (Celia *et al*., 2009). Actual locations and depths of 1344 wells over a study area of 2500 km^2 were used to examine the impact of location and depth of CO_2 injection. The intermediate-depth Nisku formation has the highest injectivity, while having a moderate number of penetrating wells, resulting in a moderate risk of leakage as compared to formations above and below.

Numerical simulations of reactive transport have been used to demonstrate that the occurrence of gas leakage from a depleted gas reservoir influences the geochemical evolution of the caprock (Gherardi *et al*., 2007). When a free CO_2-dominated phase migrated into the caprock through pre-existing fractures, or through zones with high initial porosity acting as preferential flow paths for reservoir fluids, low pH values were predicted, accompanied by significant calcite dissolution and porosity enhancement. In contrast, when fluid–rock interactions occurred under fully liquid-saturated conditions and a diffusion-controlled regime, pH was buffered at higher values and some calcite precipitation was predicted which leads to further sealing of the storage reservoir.

The probability of CO_2 leakage along conduits such as faults and fractures is controlled by the probability that the CO_2 plume encounters a conductive fault, and the probability that the conductive fault(s) provide a connected flow path through a sealing layer to a freshwater aquifer. Zhang *et al.* (2010) describe a method for determining this probability. Assuming that a random network of conduits follows a power-law distribution, a critical conduit density may be calculated based on percolation theory. For systems above the critical density, Monte Carlo simulations are used to calculate the leakage probability. The results of these simulations are used to construct fuzzy rules to relate the leakage probability of system characteristics such as system size, plume size and parameters describing the fault network. Then, the CO_2 leakage probability and uncertainty range for a particular system may be calculated using these fuzzy rules.

Natural helium is a screening tool for identifying the presence or absence of caprock imperfections. Heath *et al.* (2009) present theory and simulations to show how various types of imperfections affect the spatial distribution of natural helium above, within, and below caprock in a single-phase, brine-saturated system. Specifically, the distribution of natural helium can reveal the presence of preferential flowpaths through formations with low matrix permeability, and shed insight on the size, shape, location and connectedness of imperfections in caprock.

6.3.6 Groundwater impacts

Potential impacts to groundwater include acidification, carbonation, mobilization of inorganic and organic contaminants, and intrusion of saline groundwater. Minor components in the CO_2 stream such as H_2S could also impact groundwater quality and affect metal and metalloid behavior (Schnaar and Digiulio, 2009).

Reaction path and kinetic models indicate that geochemical shifts caused by CO_2 leakage are closely linked to mineralogical properties of the receiving aquifer (Wilkin and Digiulio, 2010). In a sandstone aquifer, calcite acts as an important buffer of the pH changes caused by leakage of CO_2. To a lesser extent, albite may also act as a buffer, first by incongruent dissolution to kaolinite, which then dissolves, albeit at a slower rate than calcite.

In a natural analogue study of risks associated with carbon sequestration, impacts of CO_2 on shallow groundwater quality have been measured in a sandstone aquifer in New Mexico, USA (Keating *et al.*, 2010). Despite relatively high levels of dissolved CO_2, originating from depth and producing geysering at one well, due to the buffering capacity of the aquifer, pH depression and consequent trace element mobility are relatively minor effects. Geochemical modeling of major ion concentrations using PHREEQC (Parkhurst and Appelo, 1999) suggests that high alkalinity and carbonate mineral dissolution buffers pH changes due to CO_2 influx. Analysis of trends in dissolved trace elements, chloride, and CO_2 reveal no evidence of in situ trace element mobilization. However, local contamination due to influx of brackish waters in a subset of wells is significant, and there is evidence that As, U and Pb are locally co-transported into the aquifer with CO_2-rich brackish water.

6.4 Development and application of site-specific models

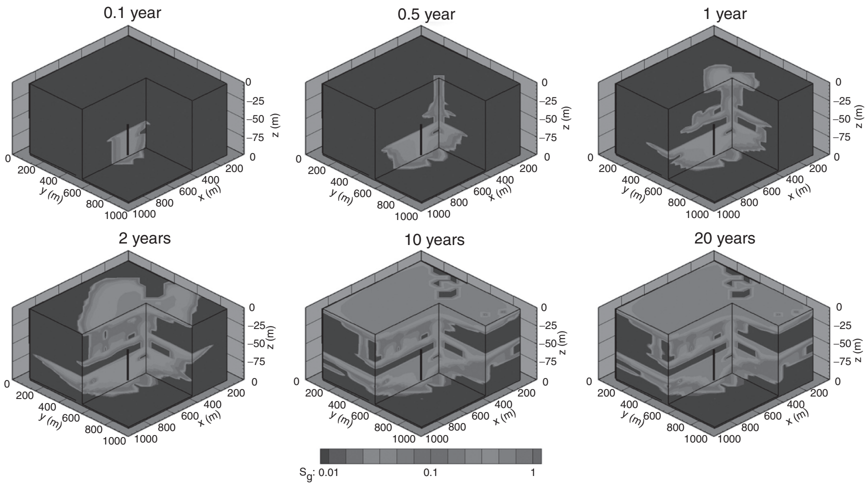
The main challenge in the development of site-specific models is the estimation of model parameters, such as hydraulic and geochemical properties, where there may be little data available from pre-existing wells. A survey of models developed at natural analogue, pilot-scale and commercial-scale sites provide examples.

6.4.1 Estimation of model parameters

Multiphase flow models require values for hydraulic properties, such as porosity and permeability, throughout the model domain. Values for these parameters may be obtained from well logs or from testing of rock cores collected during well drilling. Geophysical well logs can help correlate the occurrence of geologic units between wells. At a CO_2-enhanced oil recovery and sequestration demonstration site in the Citronelle Field, Alabama, USA, there were enough wells in a regular pattern to simply correlate observed geologic units between wells (Esposito *et al.*, 2010).

In deep saline formations, there may be few characterization wells available. Application of geostatistical and stochastic methods for modeling of geologic heterogeneity has become common practice due to the complexity of the subsurface and the relative scarcity of data on media properties. The sequential Gaussian simulation (SGS) package available in GSLIB (Deutsch and Journel, 1998) is a Gaussian random field model that produces a continuous distribution of permeability (or porosity). Correlations between values of permeability are represented with a variogram model. The transition probability indicator simulation (TPROGS) code (Carle and Fogg, 1996; 1997; Fogg *et al.*, 2000) is an indicator conditional simulation method that has special capabilities for generating 3D representations of sedimentary architecture. In this approach, discrete geologic units, or facies are identified based on well logs, and the distribution of these facies are simulated based on the characteristics of different depositional environments.

Lee *et al.* (2007) used these two geostatistical simulation methods, SGS and TPROGS, to create realizations of alluvial fan aquifer systems near Livermore, California. The simulated K field generated by TPROGS created an aquifer channel network having greater lateral connectivity, whereas



6.3 Spatial distributions of gas saturation in fine grid Umbrella Point model during a 20-year injection period. (Doughty and Pruess, 2004, *Source*: Soil Science Society of America.) (Sg: gas saturation)

SGS neglected important geologic structures associated with channel and overbank (levee) facies. The observed drawdown response in monitoring wells during a pumping test was simulated more closely with permeability realizations generated by TPROGS, indicating the importance of representing high-permeability channels.

Doughty and Pruess (2004) used TPROGS to generate facies distributions for three different depositional settings in the fluvial/deltaic Frio formation in Texas. They constructed 3D models using idealized representations of fluvial depositional settings found in the Frio: barrier bars (continuous very high-permeability sands), distributary channels (intermingled sands and shales, with a large high-permeability sand component), and interdistributary bayfill (predominantly low-permeability discontinuous shale lenses, interspersed with moderate permeability sand). They compared results from coarse, medium and fine model grids during a 20-year injection period (Fig. 6.3), and found greater variability in results due to grid resolution than between alternative stochastic realizations, pointing out that a homogeneous model would not show such great sensitivity to grid resolution.

6.4.2 Natural analogues

Instances of gas leakage from naturally occurring CO_2 reservoirs serve as analogues for potential releases from geologic storage sites (Lewicki *et al*., 2007). A review of these sites indicate CO_2 can accumulate and be released from storage sites located at a wide range of depths, and that many natural CO_2 releases can be correlated with specific triggering events, such as magmatic or seismic activity. Also, unsealed faults, fractures, and abandoned wells may act as conduits for upward leakage of CO_2. In most cases the hazard to human health was small, although human and animal deaths were documented in some instances. Measureable geochemical changes in groundwater could be attributed to leakage, but waters often remained potable. The features, events and processes identified by the review of these natural analogue sites could be used to inform risk analyses of geological carbon sequestration projects.

The Alhama–Jaraba thermal complex in Spain is a natural analogue of CO_2 storage in carbonate rocks. Mass-balance calculation results have indicated that the observed hydrogeochemical evolution between springs is mainly due to halite dissolution and dedolomitization triggered by gypsum or anhydrite dissolution (Auque *et al.*, 2009). CO_2(g) mass transfer has been estimated to be negligible, which suggests that the main processes responsible for the variation in the total inorganic carbon and the CO_2(g) pressure during deep circulation are dissolution and precipitation reactions for carbonate minerals.

The Montmiral CO_2 field in south-eastern France is one of the European sites investigated in the framework of the EU research project 'Natural Analogues for the Storage of CO_2 in the Geological Environment' (NASCENT) (Pearce *et al.*, 2003). The availability of fluid samples from the CO_2-rich reservoir provides an opportunity to test fluid monitoring as a tool for the assessment of CO_2–water–rock interaction. Pauwels *et al.* (2007) use PHREEQC with the Davies ion activity model and the SCALE 2000 model with a Pitzer ion activity model to calculate mineral saturation indices in equilibrium with these fluid samples. Compositions of these deep saline waters are consistent with evaporation of seawater and reaction with CO_2. They conclude that potassium enrichment and calcium impoverishment of water appear to be significant indicators of interactions with CO_2, due to dissolution of K-feldspar and precipitation of carbonate minerals.

6.4.3 The Sleipner field

In the Norwegian North Sea, the Sleipner field produces gas with a high CO_2 content. For environmental reasons, since 1996, more than 11 Mt of this CO_2 have been injected in the Utsira Sand saline aquifer located above the hydrocarbon reservoir (Delepine *et al.*, 2011). The Utsira Sand is an approximately 200 m thick saline aquifer located at a depth of 1012 m below sea level. CO_2 is injected at the bottom of the aquifer and migrates under the combined action of injection and gravity. At the aquifer conditions, CO_2 is less dense than the aquifer brine and therefore rises buoyantly. By 1999, the CO_2 appeared to have reached the top of the reservoir (Hayek *et al.*, 2009). Well and seismic data obtained prior to the injection showed that the aquifer sandstone is divided by nearly horizontal discontinuous thin mudstone layers (Lindeberg *et al.*, 2001). Time-lapse seismic profiles measured showed large increase in reflectivity indicating individual CO_2 accumulations under mudstone layers (Arts *et al.*, 2004). Multiphase flow and reactive transport models of increasing complexity have been developed over the last decade.

Lindeberg *et al.* (2001) constructed a 3D numerical model of upward leakage and accumulation of CO_2 under the mudstone layers, based on a seismic image 3 years after the start of CO_2 injection. From the modeling results it was inferred that the CO_2 is transported in distinct columns between the mudstone layers rather than as dispersed bubbles over a large area, and that lateral aquifer flow could be estimated by fitting CO_2 accumulation locations to the seismic data.

Bickle *et al.* (2007) modeled flow of CO_2 at the site by using modifications of analytical solutions for gravity flows in a permeable medium with axisymmetric symmetry. The model comprises a permeable medium filled with a fluid into which a less dense and more viscous fluid is introduced along a vertical line source under a flat impermeable cap (Neufeld and Huppert, 2009). They applied this analytical solution to model the growth of CO_2 accumulation under several mudstone layers, and then quantified CO_2 volumes and permeabilities from the CO_2 radii estimates. Calibrated formation permeabilities agreed with measured values for one layer, but under-predicted values for other layers. They consider that the most likely cause of the discrepancy in the modeling of the Sleipner CO_2 layers arises from the reduction in relative permeability from two-phase flow.

Gaus *et al.* (2005) have developed a 1D reactive transport model of CO_2 diffusion through the caprock at Sleipner using PHREEQC. Diffusion of CO_2 through the rock is modeled by Henry's law with a constant fugacity coefficient. The Norland shale caprock is modeled as consisting largely of quartz, mica/illite, kaolinite and plagioclase, with lesser amounts of smectite, chlorite, K-feldspar, pyrite, siderite and calcite. Secondary minerals are dawsonite, dolomite and magnesite. Kinetic rate data for the primary and secondary minerals are taken from the literature. To simulate mineral dissolution in the acid region, a uniform H^+ power law coefficient of 0.5 is applied uniformly. Simulation results show that although initially some carbonate dissolution occurs, feldspar alteration is the dominant long-term reaction. The proportion of albite/anorthite in the plagioclase is a controlling factor, as anorthite is predicted to be more reactive than albite, driving the precipitation of calcite. Overall, the reaction of CO_2 with the caprock is slow, and the porosity change predicted was less than 3% in all cases.

Audigane *et al*. (2007) developed a 2D radial numerical multiphase flow and reactive transport model of the Sleipner site that demonstrates the combined effects of buoyant upward CO_2 flow, CO_2 trapping under mudstone layers, mineralogical reactions, and convective density flow. Their simulations indicate that the geochemical reactivity of the Utsira formation is rather low, so that mineral trapping makes only minor contributions to CO_2 storage. Solubility trapping is predicted to be the dominant long-term storage mechanism and should be essentially complete after 5000 years.

6.4.4 Frio-I Brine Pilot

The Frio-I Brine Pilot was conducted to demonstrate the potential for geologic storage of CO_2 in saline aquifers (Hovorka *et al*., 2006). Approximately 1600 metric tons of CO_2 were injected during October 2004 through a single injection well into a sandstone, the 'C' zone, of the Oligocene Frio Formation – a regional petroleum and brine reservoir in the US Gulf Coast. An old oil-producing well penetrating the 'C' zone located about 30 m updip from the injection well was recompleted and perforated as an observation well. The results of the pilot test have been analyzed with several different models.

A detailed reservoir model for the aquifer was developed (Ghomian *et al*., 2008) using a geocellular model specifically constructed for the Frio aquifer by the Bureau of Economic Geology (BEG) at the University of Texas at Austin, as well as accurate PVT (Pressure, Volume, Temperature) information to account for precise density calculations and CO_2 solubility in brine. Results of the CMG-GEM model were verified against CO_2 saturation profiles at the monitoring well (inferred from reservoir saturation tool logs). Local grid refinement around both injection and monitoring wells helped to obtain accurate results.

A 3D multiphase flow model was also developed using TOUGH2 (Doughty *et al*., 2008). Parameters for the model were determined from wireline logs, core analyses, tracer tests, interference well tests, fluid sampling and downhole sensors. The results of the flow model were verified against CO_2 breakthrough at the monitoring well measured by U-tube sampling (Freifeld *et al*., 2005), and also with estimations of CO_2 saturations from a vertical seismic profile survey (Daley *et al*., 2008).

Geochemical sampling and modeling was used to distinguish between leakage through the caprock and leakage through wellbore cement (Kharaka *et al*., 2009). Long-term reactive transport modeling was used to predict that the free-phase CO_2 injected will be sequestered by dissolution and mineral trapping in 500 years (Xu *et al*., 2010).

6.4.5 In Salah Gas Project

The In Salah Gas Project in Algeria has been injecting 0.75 MMT (million metric tons) of CO_2 per year using several horizontal wells into a relatively low-permeability, 20 m thick sandstone at a depth of 1800–1900 m in the Krechba field (Iding and Ringrose, 2009). Surface deformation associated with the injection has been observed using interferometric synthetic-aperture radar (InSAR). Rutqvist *et al.* (2010) developed a sequentially coupled hydromechanical simulation using TOUGH-FLAC to model injection into the reservoir. Using a model consisting of homogeneous layers of rock, with and without a vertically dipping fault zone, they were able to match the magnitudes of the surface displacements observed above the KB-501 CO_2 injector. Morris *et al.* (2011) performed simulations of the hydromechanical response in the vicinity of the KB-502 injector using NUFT (Nitao, 1998). Matching the observed surface displacements, as well as the shape of the displacement pattern, required the inclusion of discrete conducting and bounding faults, as well as flow into a hypothetical vertical extension of observed faults.

6.4.6 Zero Emissions Research and Technology (ZERT) Release Facility

The difficulty in near-surface detection of CO_2 leakage from geological carbon sequestration sites is to detect a leakage signal from within natural background CO_2 variability, especially when the signal is of very small magnitude and/or spatial extent. Approximately 300 kg/day of food-grade CO_2 was injected through a perforated pipe placed horizontally 2.0–2.3 m deep during 9 July–7 August 2008 at the Zero Emissions Research and Technology (ZERT) Release Facility, Bozeman, Montana, to evaluate atmospheric and near-surface monitoring and detection techniques applicable to the subsurface storage and potential leakage of CO_2 (Spangler *et al.*, 2009). Multiphase flow results using the TOUGH2/EOS7CA simulator indicate that shallow soils and sediments are very permeable due to the presence of subsurface cracks and root casts, and that CO_2 will spread out laterally via diffusion once it reaches the vadose zone (Oldenburg *et al.*, 2010a). Modeling results (Oldenburg *et al.*, 2010b) were also used to explain the pattern of CO_2 emissions from the experiment. Geochemical modeling using SOLMINEQ (Kharaka *et al.*, 1994) was used to understand rapid changes in pH, alkalinity and major ion concentrations following CO_2 injection (Kharaka *et al.*, 2010). Dissolution of observed carbonate minerals and desorption ion exchange resulting from lowered pH values following CO_2 injection are likely responsible for the observed increases in the concentrations of solutes, which could provide early detection of CO_2 leakage into shallow groundwater from geological carbon sequestration.

6.5 Challenges and future trends

In their review of models for geologic sequestration of CO_2, Schnaar and Digiulio (2009) identify several challenges for future work. They suggest that because model results are sensitive to assumptions about formation heterogeneity, residual saturation–permeability relationships and geochemical precipitation and dissolution kinetics, future experimental research is needed to reduce the uncertainty related to these parameters. Also they highlight the need for model predictions to be validated against field monitoring during pilot projects, such as those being conducted by the US Department of Energy's Regional Carbon Sequestration Partnership Program (Litynski *et al*., 2009).

In her overview of the role and impact of CO_2–rock interactions during CO_2 storage in sedimentary rocks, Gaus (2010) identifies several challenges. One of the major gaps remaining is the lack of basic thermodynamic and kinetic data at temperature and pressure conditions relevant to carbon sequestration. The pressure and temperature conditions for geological carbon sequestration are intermediate between those relevant to groundwater hydrogeochemists and rock geochemists, so more experiments of CO_2–brine–rock interaction under relevant reservoir conditions are needed. She identifies coupled reactive transport and geomechanical modeling as an area of need in the area of geological carbon sequestration. These types of models have been applied in other fields, such as nuclear waste disposal (Tsang, 2009) and enhanced geothermal systems (Taron and Elsworth, 2009). Pore scale modeling of geochemical reactions is also identified as an area of future research for geological carbon sequestration, which is an area of active research and application in other fields such as materials engineering (Ryan *et al*., 2011) and advanced computing (Scheibe *et al*., 2008).

Also, although a significant amount of modeling has been done in relation to cosequestration of H_2S and SO_2 along with CO_2, little attention has been paid to modeling the impact of other impurities in the CO_2 stream. Other significant impurities include NO_x, mercury and oxygen. NO_3^- is a strong acid and could affect the pH of formation water, whereas oxygen could affect the redox conditions in the formation, causing dissolution or precipitation of minerals.

Participants in a recent meeting of the International Energy Agency Greenhouse Gas (IEAGHG) International Research Network on CO_2 Geological Storage Modelling (IEAGHG, 2010) identified several topics in need of further modeling research:

- Storage engineering options, for example, brine extraction.
- Wettability and relative permeability.

- Rates of CO_2 dissolution into formation brines.
- Efficiency of capillary trapping.
- Coupling of processes, and the merits of modeling processes separately to aid upscaling.
- Realistic boundary conditions for flow modeling.

6.6 Sources of further information and advice

There are several review papers that provide more information on models available for carbon sequestration. Schnaar and Digiulio (2009) review models for geologic carbon sequestration. Gaus *et al*. (2008) review geochemical reactive transport codes for simulating CO_2–rock interactions. Wei *et al*. (2007) provides a review of models for simulation of coalbed methane recovery using CO_2. Code comparison studies also provide information on a number of different models and show their performance on practical problems related to geologic carbon sequestration (Class *et al*., 2009; Pruess *et al*., 2004).

Other fields with literature relevant to geological carbon sequestration include petroleum reservoir engineering, enhanced geothermal systems, rock mechanics, vadose zone hydrology and subsurface radioactive waste disposal.

Information on various numerical models for simulating geological carbon sequestration can be found on their respective websites:

- CMG-GEM: http://cmgroup.com/software/gem.htm
- CRUNCH: http://esd.lbl.gov/ESD_staff//steefel/WebCrunch.htm
- Eclipse BlackOil: http://www.slb.com/services/software/reseng/blackoil.aspx
- Eclipse Compositional simulator: http://www.slb.com/services/software/reseng/compositional.aspx
- OpenGeoSys: http://www.ufz.de/index.php?en=18345
- STOMP: http://stomp.pnnl.gov/
- TOUGH2: http://esd.lbl.gov/research/projects/tough/
- TOUGHREACT: http://esd.lbl.gov/TOUGHREACT/index.html

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7

CO_2 leakage from geological storage facilities: environmental, societal and economic impacts, monitoring and research strategies

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Abstract: Carbon capture and storage (CCS) has the potential to significantly limit CO_2 emissions to the atmosphere; however a leakage of CO_2 from transport or storage could have environmental and safety implications. Monitoring of CCS storage is a further challenge, both to assure the public and, should leakage occur, to enable mitigation and verification. This chapter reviews the current state of knowledge regarding environmental sensitivities and monitoring and outlines the challenges for research over the next few years. The current hypothesis is that significantly large leaks would be required to cause noticeable damage in the ecosystem.

Key words: carbon capture and storage (CCS), environment, impacts, monitoring.

7.1 Introduction

Carbon capture and storage (CCS) has the potential to remove a significant proportion of anthropogenically generated CO_2 and mitigate against the ensuing environmental and economic cost of climate change. At the same time concern about environmental and health impacts of leakage from CCS have, at least in part, curtailed several ambitions to develop CCS demonstration facilities, mainly in terrestrial settings. There is accordingly a need to understand and communicate the risks associated with long-term geological storage and the potential impacts on the environment, economy and health and safety. This dialogue would also benefit from a contextual understanding, for example what are the probable consequences of not mitigating CO_2 emissions, how do potential CCS impacts compare with everyday anthropogenic impacts and what are the options for fulfilling energy requirements over the next several decades? Another essential requirement for the successful deployment of CCS is effective and trusted methods and strategies by which to monitor containment or leakage. This is likely to require not only development of specialised tools but also an understanding of natural variability in CO_2 and related substances.

Understanding risk and consequence is a multi-faceted challenge. The risk can be defined partly as a geologic issue but must also factor in transport integrity and accident potential. Consequence analysis requires an understanding of geological migration and dispersal in soils, sediments, water and the atmosphere as well as comprehending the impacts on natural systems. Similarly monitoring techniques can be geophysical or based on shallow or surface physical, chemical and biological signals.

Several research projects are currently addressing many aspects of these challenges, but are hampered by a lack of direct observations. In this chapter, as well as reviewing the state of knowledge about impacts in both terrestrial and marine environments, and monitoring technologies, we review the utility of natural seep systems to elucidate what could happen if a leakage occurred and describe what future initiatives would facilitate further understanding in this area.

7.2 A generic approach to risks and impacts

When considering risk and potential impacts it is helpful to consider the Features, Events and Processes (FEPs) that could be significant. Analysing the system in this way helps to ensure that modelling studies represent everything that could be important, and ensure that field studies are designed to yield information where it is most needed. There are many slightly different formal definitions of these terms but fundamentally:

- A 'Feature' is a physical component of a system (a 'fault' could be a feature of the terrestrial system).
- An 'Event' is a process that influences the evolution of the system over a time period that is short compared to the time frame being considered (an earthquake might be considered to be a relevant 'event').
- A 'Process' is a dynamic interaction between 'Features', which may operate over any particular time interval of interest (dissolution of CO_2 in a near-surface might be considered be a relevant 'process').

An online generic FEP database (Maul *et al.*, 2005; Walke *et al.*, 2011) is freely accessible from the International Energy Agency (IEA) website (www.ieaghg.org). The database is generic, in that it is not specific to any particular storage concept or location. The FEPs included have been chosen for their relevance to the long-term safety and performance of the storage system after CO_2 injection has ceased, and the injection bore-holes have been sealed.

7.3 Impacts and risks relating to the marine system

In aqueous media, CO_2 dissolves rapidly and dissociates into bicarbonate and hydrogen ions, the latter decreasing pH and combining with carbonate ions to form more bicarbonate. Hence any biological process that is dependent on bicarbonate or carbonate ions, or impacted by pH, is vulnerable to changes in CO_2 concentration. In brief, excess CO_2 in marine systems can enhance photosynthesis, inhibit the maintenance of carbonate based structures (e.g. shells and corals) and undermine many physiological processes that are sensitive to pH.

Dispersion of CO_2 plumes in seawater is a complex process. Initially highly buoyant gaseous CO_2 dissolves rapidly, forming potentially dense plumes of high CO_2 water that will tend to sink in the water column. Dispersal of plumes, especially in regions like the North Sea, will be strongly influenced by tidal mixing as well as residual currents. Model based studies (Blackford *et al.*, 2008; Chen *et al.*, 2005) indicate that dispersion can be relatively rapid so that only the epicentre of a leak event would be strongly impacted. However, tides and currents will combine to impart a complex dynamic in plume behaviour such that the CO_2 concentration and pH is prone to oscillate at any given point in space. Clearly any leak event will be unique, depending on flux rates, tidal state, currents and season.

Thus current evidence would suggest that if leaks were to occur they would tend to be localised and therefore more likely to impact upon those organisms that are unable to move away from the source of CO_2. In this respect, organisms that are restricted to a specific habitat or that have limited horizontal mobility are likely to receive the highest exposure. For the most part this would mean that sessile, benthic organisms are more likely to be affected by CO_2 leakage than mobile pelagic ones. In addition, it is predicted that rather than a rapid stream of CO_2 passing through the seafloor, leaks could take the form of a slow dispersive transport through the sediment. This would lead to an acidification of the sediment pore waters and a strong impact on sediment dwelling (infaunal) organisms. The formation of higher density plumes of CO_2 enriched seawater suggest that, in most types of potential leak, benthic organisms will be most heavily exposed to elevated levels of CO_2.

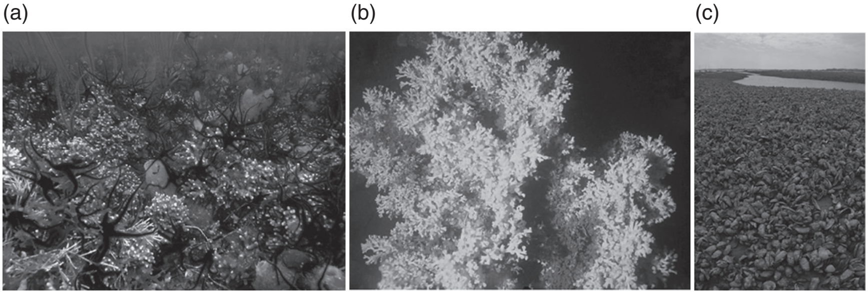
Unlike many other pollutants, CO_2 also occurs naturally, throughout the marine (and terrestrial) environment. In sediment systems in particular, large gradients in CO_2 can occur over very small spatial scales with marine organisms being exposed to changes in pH of over 1 unit (see Widdicombe *et al.*, 2011, for a review). Consequently, controlling internal levels of pH and CO_2 is an integral part of marine organism physiology (see Pörtner, 2008; Pörtner *et al.*, 2011) and many infaunal organisms have developed physiological and/or behavioural mechanisms designed to cope with short-term variability in seawater carbonate chemistry (e.g. acid-base buffering, metabolic depression or changes in respiratory behaviour). However, these mechanisms are only effective within specific ranges of pH and CO_2 and the largest changes in seawater chemistry predicted to occur in association with leakage events could swamp these mechanisms, resulting in significant impacts on organism health, activity and ultimately survival. In addition, the mechanisms used by many organisms to cope with elevated CO_2 levels often come at a metabolic cost and need to be supported by either increased feeding or by diverting energy away from other physiological processes (e.g. growth or reproduction). This would mean that in situations where resources are limited, even small changes in seawater chemistry, if maintained for long enough, could result in negative effects on key ecological processes and a subsequent loss of either organism or population fitness (Blackford *et al.*, 2010).

The effectiveness of physiological and behavioural mechanisms and the ability to assimilate and redistribute energy will vary between different taxa. This will naturally lead to a range of different tolerance levels between the species that make up the resident community (see Wicks and Roberts, 2012). For example, organisms that are dependent on heavily calcified structures may need to spend more energy on maintaining these structures than non-calcified species. Consequently, exposure to elevated CO_2 is likely to cause a shift from calcified to non-calcified organisms and, given the predominance of calcified groups in marine communities, this is likely to cause a decrease in species as well as functional diversity. This community level response has been seen in mesocosm experiments (Widdicombe *et al.*, 2009; Hale *et al.*, 2011) as well as studies conducted around natural CO_2 seeps (Hall-Spencer *et al.*, 2008). These studies also demonstrate that changes to community structure and diversity following a leak cannot be predicted by assessing the tolerance of individual species in isolation and assuming these will hold true in a natural setting. For example, recent exposure experiments on natural communities have shown that, despite previously being shown to be negatively affected by exposure to elevated CO_2 (e.g. Thistle *et al.*, 2007), the abundance of nematode worms increased under high CO_2 conditions (Widdicombe *et al.*, 2009; Hale *et al.*, 2011). The authors concluded that this increase in abundance was due to the nematodes being released from ecological pressures, such as competition or predation, due to the reduced abundance of other infaunal species in these high CO_2 treatments.

When considering the potential biological impacts of leakage it is also important to consider whether organisms are likely to be exposed to any other environmental stressors or pollutants, in addition to the elevated levels of CO_2 and changes in seawater chemistry. For example, as the CO_2 passes through the sediment it may act to liberate and transport other harmful substances such as methane, heavy metals and hydrogen sulphide. For CO_2 storage situated in or near oil or gas reservoirs, leaking CO_2 may also bring with it hydrocarbons and other drilling related pollutants. Currently there are few data published which quantify the potential interactions between CO_2 and these other pollutants. However, using evidence from the few studies that have been conducted, simultaneous exposure to both CO_2 and pollutants can be expected to exacerbate the biological impact of leakage. Much more evidence exists with respect to the interactive effects of CO_2 and other environmental stressors, such a temperature, hypoxia and salinity. In many of the studies conducted to date, an organism's vulnerability to CO_2 is increased when exposure is combined with these other environmental stressors. In particular, an organism's window of thermal tolerance and its general level of aerobic performance can be drastically reduced by exposure to elevated levels of CO_2 (Pörtner and Farrell, 2008; Pörtner, 2010).

It is not just multi-cellular organisms that could be impacted by leakage; elevated levels of CO_2 have also been shown to have significant effects on the structure and function of sediment dwelling microbes, both bacteria and archea (Tait *et al.*, in press). This, in turn, will impact upon the key biogeochemical processes these microbes support, such as elemental cycling, primary production and waste degradation. In a recent study, Tait *et al.* (in press) showed that rates of ammonium oxidation can be significantly altered by high levels of CO_2, primarily through the differential effects of CO_2 on bacteria and archea. This study also demonstrated that the potential impact of leakage on nutrient cycling is likely to be governed by the nature of the microbial community already present at the leakage site. The direct impacts of CO_2 on microbes could be further exacerbated by changes in sediment mixing (bioturbation) performed by burrowing macrofauna. Bioturbation is a key process in structuring microbial communities (Laverock *et al.*, 2011) and the nature and intensity is dependent on the types of bioturbators present and the levels at which each of these types are performing; both of which can be altered by elevated levels of CO_2. However, it should also be noted that not all microbes will be negatively impacted by leakage. Those organisms that consume CO_2 (e.g. cyanobacteria) or those that consume other substances that could be liberated by any leakage (e.g. methane or sulphide) may increase in function and activity.

In addition to sediment systems, there are other important benthic ecosystems that could be affected by leakage. In particular, those habitats which rely heavily on calcification for the provision of structural integrity could be badly impacted. These biogenic habitats (Fig. 7.1) include coral reefs (warm water and cold water varieties), calcifying algae (such as the mearl beds) and large aggregations of molluscs (e.g. mussel beds). All of these habitats support high levels of associated biodiversity and could be vulnerable to exposure to high levels of CO_2. Conversely, there are non-calcifying species that



7.1 Examples of biogenic habitats that are created by calcifying organisms: (a) mearl, (b) cold water coral *Lophelia*, (c) mussels. (Photograph credits: (a) N. Kamenos, (b) J. M. Roberts, (c) R. Ellis.)

provide biogenic habitats (e.g. seagrasses) which have been shown to flourish under high CO_2 conditions. However the associated cryptic fauna is still negatively impacted and biodiversity is lost (e.g. Hall-Spencer *et al.*, 2008).

7.4 Impacts and risks relating to terrestrial systems

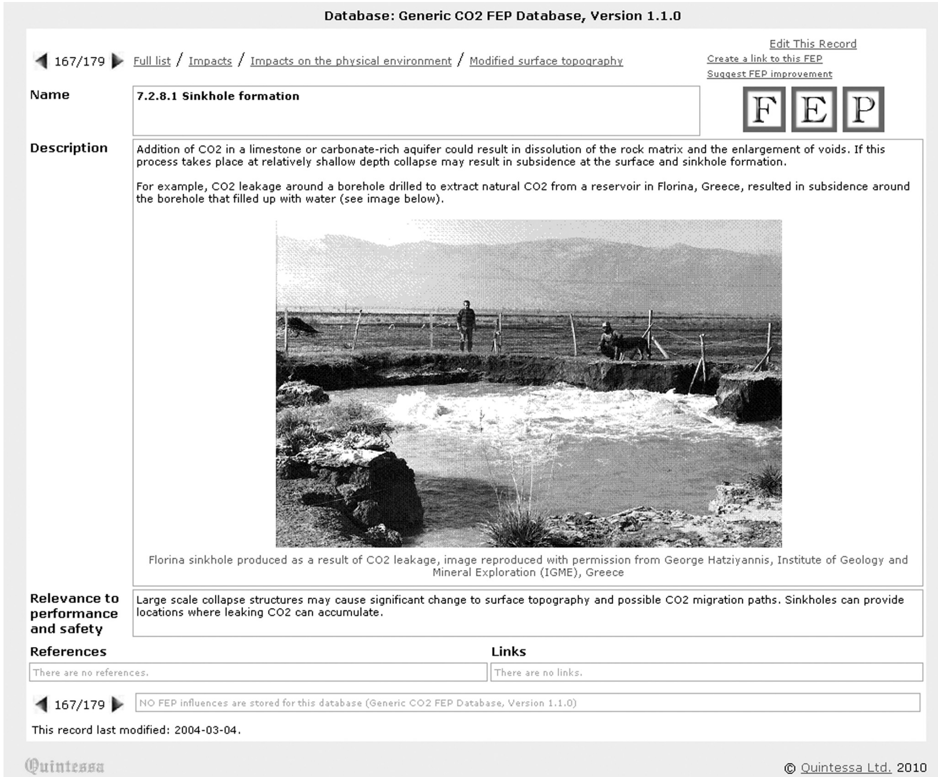
In its gaseous phase, CO_2 is relatively unreactive, the main potential effects stem from impacts on photosynthesis – which may be positive at moderate levels, and its action as an asphyxiant, at high concentrations, preventing respiration. In this section consideration is given to the risks and potential impacts if CO_2 from a geological storage system were to return to the surface in a terrestrial environment.

Of the eight categories of FEPs detailed in Section 7.2, two directly relevant to the scope of this section:

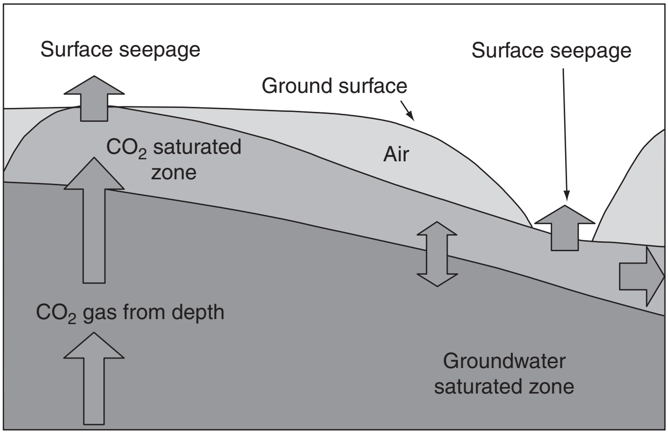
- The 'Near-Surface Environment' category of FEPs is concerned with factors that can be important if sequestered CO_2 returns to the environment that is accessible by humans. This includes a sub-category for the terrestrial environment and human behaviour.
- The 'Impacts' category of FEPs is concerned with endpoints that could be of interest in an assessment of performance and safety. An example of a FEP entry in this category is shown in Fig. 7.2.

7.4.1 CO_2 transport in the near-surface environment

When CO_2 enters the near-surface environment from the geosphere below, as it is denser than air it may 'pond' on top of the water table and migrate laterally, as illustrated in Fig. 7.3. CO_2 will only break through at the surface when surface topography and the top of the CO_2 layer intersect, as is



7.2 Example of an 'impacts' category FEP.



7.3 CO_2 transport in the near-surface environment.

typically observed in local depressions and near rivers and springs, or where there are high localised fluxes of CO_2 from depth. There is the potential for the CO_2 to decrease the pH of potable waters and potentially mobilise certain contaminants, such as heavy metals, from solid phases in the rocks or sediments (e.g. Lu *et al*., 2010).

7.4.2 Potential environmental impacts

As discussed by West *et al.* (2005), although extensive physiological research is available, the environmental impacts of elevated CO_2 (whether through slow or catastrophic release) on terrestrial ecosystems are poorly understood. Essentially, respiratory physiology and pH control are the primary physiological mechanisms controlling responses in organisms to elevated CO_2 exposures. Information is available from a diverse research base including physiology, food preservation and botany; these data, however, are mostly from studies on organisms exposed to either slightly elevated concentrations of CO_2 or the high concentrations that give a lethal response.

Current research (e.g. the European Union project RISCS: Research into Impacts and Safety in CO_2 Storage; http://www.riscs-co2.eu/) aims to develop the knowledge base necessary to assess the potential impacts of leaks on near-surface ecosystems. As part of this project, potential receptor classes have been defined for European terrestrial environments, and these are summarised, together with potential impact mechanisms, in Table 7.1.

In a related study, Roberts *et al.* (2011) quantified the risk of human fatality at natural seeps onshore in Italy. This work demonstrated the relatively low

Table 7.1 Receptor classes for European terrestrial systems

Receptor class	Potential impact mechanisms
Plants associated with agricultural ecosystems Crops and grasses **Plants associated with natural systems** Plants associated with forest, moorland, heath, wetland and alpine ecosystems	Stress/death as a result of the effects of CO_2 concentrations on roots. Stress/death as a result of CO_2 ponding and impacts on the canopy. Stress/death as a result of degradation of soil quality (acidification, toxicity, etc).
Animals that inhabit agricultural or natural ecosystems Invertebrates (e.g. insects) Vertebrates (including mammals, amphibians, birds) Microbiota	Death (of animals unable to move away from a localised surface ponding event). Potential for chronic low-concentration exposure effects, e.g. on skeletal structure, or other effects (some burrowing animals may have reduced sensitivity). Impacts due to a reduction in feed quality and availability. Habitat damage/loss (see impacts on plant receptor classes).
Terrestrial freshwater bodies/resources (lakes, rivers, springs) Surface water resources as receptors in their own right Aquatic plants (e.g. algae) Vertebrates (e.g. fish) Invertebrates (e.g. mosquito larvae)	Surface water body acidification/toxicity. Stress/death of aquatic plants as a result of CO_2 concentrations. Impacts on animals due to a reduction in feed quality and availability. Habitat damage/loss (see impacts on plant receptor classes above). It is necessary to distinguish between stratified and more homogeneous lakes.
Aquifers that may be exploited as drinking or irrigation water resources Aquifer water resources as receptors in their own right Microbes that might inhabit the aquifer	Degradation of water quality as a result of biogeochemical processes leading to acidification/toxicity etc. (it is not possible to be more specific without site-specific geochemical information). Microbial populations could be regarded as receptors in their own right, in addition to contributing to biogeochemical processes.
Humans Non-operators who might be exposed to impacts as a result of CO_2 leak/migration to and through the environment	Death as a result of sudden releases to and accumulation within basements/subsurface features. Impact on urban environment (gardens, other structures and resources). It is extremely unlikely that a storage system would be built sufficiently close to a large urban population, that releases could then occur to a basement, and that the release would be acute enough to lead to death. Similarly it is unlikely that any leak would happen to interact with basements associated with a less laterally extensive settlement. Related scenarios must therefore be, by definition, high impact (in that death could occur) but very low likelihood.

risk of mortality even at largest seeps. However, these risks really describe the risk of mortality at a site where a seep has already been identified – not a newly emerging seep. Natural seeps in West Africa further confirm this (Smets *et al*., 2010) where most fatalities occur to travellers through a region who are unaware of the threat. This suggests that we can manage the risks of mortality at onshore storage sites by surface monitoring to identify any new seeps.

7.5 An ecosystem services description of economic impacts

The economic impacts of leakages, and the impacts of these leaks on society, are likely to be important determinants of whether CCS will be developed and make a contribution to climate change abatement strategies (van der Zwaan and Gerlagh, 2009). Understanding the economic and societal impacts of leaks can potentially be achieved through the assessment and valuation of ecosystem services. Ecosystem services are 'the aspects of ecosystems utilised (actively or passively) to produce human well-being' (Fisher *et al*., 2009, p. 645). According to the Millennium Ecosystem Assessment (2003), they can be categorised into four broad functional groups (Table 7.2): provisioning services, which are the products we obtain from the environment, such as food, fuel wood and other natural resources; regulating services, which are the outputs of processes that regulate ecosystems, such as a regulated climate, clean water and air; cultural services which generate largely non-material benefits such as cultural diversity, knowledge systems and opportunities for leisure and recreation; and supporting services which are the processes and functions that underpin all the other ecosystem services, including nutrient cycling, primary productivity and the provision of habitat for other species. Due to concerns over double counting (e.g. Boyd and Banzhaf, 2007), ecosystem service valuation only focuses on provisioning, regulating and cultural services (because the value of supporting services are implicit in the value of all other services); however, understanding how leakages of stored CO_2 may affect supporting services is critical. Any change in supporting services will have implications for provisioning, regulating and cultural services. For example, many marine benthic organisms, soil organisms and organisms living in freshwater sediments are effective bioturbators, burying and transforming waste products within sediments, contributing to the levels of oxygenation in the sediments, the rate of decomposition of organic materials and the regeneration of nutrients. They may also form a food supply for other species. All of these processes are at the core of many ecosystem services that are valued by society for the contribution they make to human well-being.

Table 7.2 The Millennium Ecosystem Assessment's typology of ecosystem services

Service type	Specific ecosystem services
Provisioning	Food; fibre; timber and fuel; genetic resources; biochemicals, natural medicines and pharmaceuticals; ornamental resources and freshwater
Regulating services	Air quality maintenance; climate regulation; water regulation; erosion control; water purification and waste treatment; regulation of human diseases; storm protection
Cultural services	Cultural diversity; spiritual and religious values; knowledge systems; educational values; inspiration; aesthetic values; social relations; sense of place; cultural heritage values; recreation and tourism
Supporting services	Production of oxygen; primary production; nutrient cycling; water cycling; provision of habitat

The relationships between these underlying processes and functions and ecosystem services though, are often poorly understood.

7.5.1 Provisioning services

The area impacted by an individual CO_2 leak in the marine environment is likely to be relatively small (Blackford *et al*., 2008). This suggests that the implications for marine food provision are likely to be minimal. Mobile marine organisms, such as commercially important fish species, will simply be able to avoid areas in which seawater acidity is likely to cause them some level of stress. Problems may only occur for mobile species if CO_2 leaks occur in important breeding or nursery grounds, as juvenile forms of some fish species have been shown to be sensitive to higher levels of seawater acidity (Munday *et al*., 2009; 2010). The implications for sessile organisms, such as shellfish, with close proximity to the leak may be more severe as seawater acidification is known to affect calcification, fertilisation success and development in some species (Gazeau *et al*., 2007; Fabry *et al*., 2008).

On land, the loss of CO_2 through soils from natural vents has been shown to lead to the death of trees (Farrar *et al*., 1995); early senescence and reduced photosynthetic capacity (Cook *et al*., 1998); and in an experimental situation, to reduced biomass production in pasture grass and poor germination in winter beans (Patil *et al*., 2010). If these findings can be extrapolated to other plants, and in particular food crops, then there may be implications for agriculture and food production; however, as with the marine environment, the area affected by a leak is likely to be relatively small.

In addition to the production of food, CCS may also have implications for the provision of freshwater. Although the CO_2 being stored may be relatively uncontaminated, it may interact with minerals and potential pollutants within the storage site that may enter freshwater supplies (Pires *et al.*, 2011). CO_2 can cause the acidification of groundwater supplies, affecting the quality of drinking water obtained from them (van der Zwaan and Smekens, 2009).

7.5.2 Regulating services

Depending on the scale of the leak, the degassing of CO_2 from underground storage sites could potentially influence a number of regulating services. Section 7.2 discusses how acidification of seawater and seabed sediment can affect marine organisms responsible for bioturbation. Any loss of bioturbators may result in a reduction in the level of burial and storage of waste products in marine sediments, including organic matter (Solan *et al.*, 2004). This may have implications for the control of waste and the regulation of climate, as less CO_2 and other pollutants are locked away and prevented from interacting with the environment. On land, any reduction in vegetation as a result of CO_2 leakages may also reduce the amount of CO_2 that is sequestered from the atmosphere and could potentially lead to a change in the hydrology of an area. Loss of vegetation cover is known to increase runoff, which can contribute to soil erosion (e.g. Bosch and Hewlett, 1982). However, the impacts of CO_2 leaks in both the marine and terrestrial environments are likely to be contained within relatively small areas; consequently the effects of leaks on these regulating processes which function at a global scale are likely to be minimal.

7.5.3 Cultural services

The benefits generated from cultural services are often non-material in nature and are related to individuals' beliefs and values. Any impacts of CO_2 leaks on these non-material benefits is likely to be closely related to the perceptions the public holds for CCS and hence their support for CCS projects. Most studies of public perceptions for CCS have indicated that the public have little knowledge of it (Huijts *et al.*, 2007; Shackley *et al.*, 2009). Consequently it is difficult to assess how a CO_2 leak might influence their values and beliefs; although it can be supposed to have a similar impact as other pollution incidents.

Another important cultural service is the opportunity the environment provides for leisure and recreation. CO_2 leaks are unlikely to have any effect on leisure and recreation, especially in the marine environment, due to the depth at which storage occurs and its distance from shore. The same is true for land-based activities, unless a leak occurs in a popular recreational site. Degassing of CO_2 from naturally occurring sources has been responsible for symptoms of asphyxia (Farrar *et al*., 1995) and death in people and animals (Roberts *et al*., 2011). This risk, however, is minimal and is much higher during other stages of the CCS process (Ha-Duong and Loisel, 2010) and from other activities, such as car accidents (Roberts *et al*., 2011).

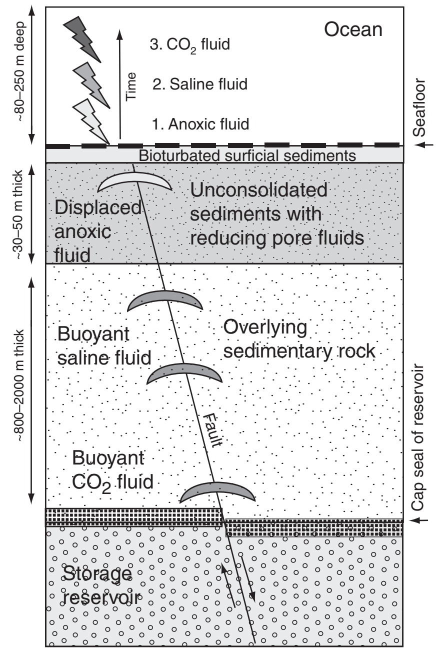
The above discussion suggests that CCS site selection needs to be considered with reference to fish nursery habitats or shellfish beds, important agricultural ground and essential freshwater aquifers. Leaks, however, may not occur at the site of injection of CO_2 into the storage site, which implies a need for monitoring of storage sites to ensure any leaks are quickly identified and appropriately managed (e.g. to restrict access to areas affected by leak). The potential impacts of CO_2 leaks also need to be placed in context. Within the marine environment, fishing activities, in particular demersal trawling, may significantly alter marine benthic communities (Jennings and Kaiser, 1998), yet some areas of seabed (e.g. within the North Sea) are trawled more than once a year (Mills *et al*., 2007) and this has been the case for decades. The impacts of CO_2 leaks will be on a substantially smaller scale.

7.6 Monitoring and mitigation of storage sites

Strategies and technology for monitoring, measurement and verification (MMV) of offshore CCS sites will be largely determined by: (1) the nature and scale of the storage site, and (2) the status and need of the monitoring whether it may be baseline surveys, verification of reservoir containment, or quantification of CO_2 leakage. Potential storage sites, comprising either depleted hydrocarbon reservoirs or saline aquifers, impart important limits on MMV strategies and technology. Here, given storage sites in the UK are predominantly offshore, we restrict discussion to marine environments, although the general principles outlined will apply to terrestrial environments as well. In the context of the North Sea, depleted reservoirs will typically have an aerial extent of 250–400 km^2, overlain with an ocean volume of the order of 25–40 km^3, have an array of cap seal penetrations (in the form of abandoned wells), and a cumulative storage capacity of >28 Gt of CO_2 sequestered by 2050. Saline aquifers will typically have an aerial extent of >22 000 km^2, overlain by an ocean volume of >2000 km^3, and a theoretical storage capacity exceeding 50 Gt of CO_2 (Senior, 2010). Such storage options lead to potential leakage scenarios ranging from high discharge (e.g. >200 tonnes d^{-1}) point source leakage (due to acute well-casing leakage or hydro-fracturing of a seal cap) in a relatively small depleted reservoir site, through to low discharge (e.g. <20 tonnes d^{-1}), dispersed source discharges from an extensive saline aquifer system. Such a continuum of leakage scenarios necessitates diverse, and responsively staged monitoring.

Current and proposed regulatory monitoring practice (EU Carbon Capture Storage Directive 2009) places significant emphasis on 'deep' geophysical monitoring of the reservoir containment formation, integrity of the capping seal, and migration of CO_2 within the reservoir, typically at sub-seafloor depths of 800–2000 m. As demonstrated at the Sleipner storage site, repeat seismic reflection surveys (termed '4D' seismic) have proven to be an excellent method of intermittently imaging progressive dispersion of CO_2 within the reservoir (Chadwick *et al.*, 2009), where differences in reflector amplitude and velocity 'pushdown' (e.g. Shi *et al.*, 2007) are interpreted as CO_2 fluid within intra-reservoir beds. Other geophysical techniques including passive micro-seismicity recording, seafloor gravimetry, controlled source electromagnetics, and even bore-hole or arrayed bore-hole electrical resistivity tomography and electromagnetic monitoring have been proposed with varying assessments of cost and applicability. All these methods rely on changes of a geophysical parameter due to varying saturation with supercritical CO_2, whether it be acoustic impedance, electrical resistivity, or rock density, being used either qualitatively to image CO_2 migration, or quantitatively inverted into predicted CO_2 volumes. The latter is predicated on knowing the quantitative relationship between CO_2 saturation and change in the geophysical parameter. Whether such geophysical inversions will be sufficiently sensitive to determine volumes of potential CO_2 loss from the containment formation for the purposes of regulation and carbon emission trading is an open question.

If CO_2 leakage occurs from the containment formation (Fig. 7.4), monitoring at the seafloor and shallowest subsurface provides two additional significant opportunities for monitoring of offshore carbon capture storage sites. The first is that in many circumstances it is probable that initially pre-cursory fluids will be emitted at the seafloor before CO_2 due to the buoyancy pressure of CO_2 displacing stratigraphically higher fluids. Such pre-cursory fluids would include displaced formation brines and reduced pore fluids within unconsolidated, shallow sub-seafloor sediments. Both brines and reduced pore fluids have characteristic chemical signatures, with the former having elevated temperature and salinity, and the latter having higher Mn, ferrous Fe, acidity, H_2S, and lower dissolved oxygen. The second significant monitoring opportunity lies in the fact that the seafloor, and to a lesser extent the overlying ocean, provide a site for more direct and quantitatively explicit measurement of CO_2 flux (both as free gas and dissolved phases) that is potentially more sensitive for measurement and verification of CO_2 leakage. Physical and chemical signatures of CO_2 loss from the seafloor, either as direct CO_2 measurement, a decrease in pH, or emission of gas bubbles, are arguably more tractable both in the sense of making the observation and understanding its relationship to CO_2 volume loss.

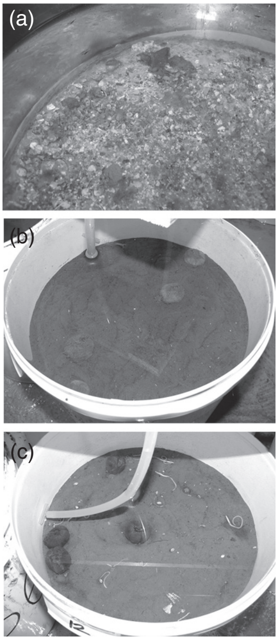


7.4 Schematic diagram of potential CO_2 leakage from an offshore sub-seafloor reservoir along a fault with buoyant CO_2 plume (dark-tinted crescent) driving buoyant expulsion of formation brines (medium-tinted crescent) that in turn drives the expulsion of reducing pore fluids (pale-tinted crescent) at the seafloor. The base of the reservoir capping seal, and seafloor are the two most important boundaries at which to undertake monitoring.

Such monitoring opportunities of the seafloor and overlying ocean are stimulating considerable research of potential physical and chemical processes that would signify CO_2 leakage. Physical techniques are principally developing around passive and active acoustic bubble detection that would resolve the free gas leakage. Passive detection uses hydrophones to acoustically detect bubble oscillation and expansion during ascent from the seafloor, while active sonar records the acoustic back-scatter response of ascending gas bubbles. Theoretical considerations demonstrate that both passive and active multi-frequency acoustic data can be inverted to determine bubble size populations (Leighton and White, 2011), which if combined with bubble ascent velocity could yield a gas flux, though it is known that at least for methane bubbles, both gas and any surface skin hydrate compositions can change during ascent (e.g. Greinert *et al*., 2006). Similarly, high-frequency, broad band 400 Hz–24 kHz seismic profiling may provide a method to image shallow, CO_2-charged sediments. Chemical techniques principally determine changes in marine carbonate chemistry (e.g. CO_2 directly or pH) or pre-cursory saline or reduced pore-fluid signatures described above.

These chemical and physical techniques require the development of both new instruments and sensors, and 'underwater platforms' capable of low-cost, long-term, and sustained observing with delayed or real-time data telemetry. For chemical sensors, newly developed techniques in solid state optical-transistor (e.g. Garcia and Masson, 2004) and microfluidic-reagent reaction sensors (e.g. Floquet *et al*., 2011) provide the opportunity to observe a number of important chemical parameters. Improvements in limits of detection, and correction for pressure and temperature changes, now herald an emerging capability to undertake sustained *in situ* monitoring. Typically limits of detection for dissolved Fe and Mn are nM, methane 0.2 nM, salinity 0.00001 psu, temperature 0.005°C, and for pH the limit is currently 0.005–0.003 pH units, but could be improved to 0.0005 pH units in the near future. Similarly, a CO_2 sensor with a detection limit of ~3 ppm is possible using microfluidic techniques. In parallel, the development of 'underwater platforms' both as seafloor observatories (e.g. Bagley *et al*., 2007) or mobile autonomous underwater vehicles (AUVs) (e.g. McPhail, 2009) and gliders are developing the necessary capability from which to deploy sensors for long-term deployment. New AUV developments include vehicles that are capable of being deployed for up to 6 months that provide the prospect of surveying large seafloor areas and ocean volumes at storage sites with minimal ship support. These combined sensors and vehicle developments are also stimulating interest in using natural analogue CO_2 seep sites (e.g. Caramanna *et al*., 2011) or existing North Sea storage sites as 'test beds' for trial deployment of these emerging monitoring technologies. Effective chemical monitoring will also depend on understanding spatial and temporal scales and causality of natural variability and it is probable that multi-variate monitoring would be more effective in identifying irregularities than high precision univariate techniques.

Identifying effective biological tools for monitoring the marine environment above any geological CCS facility, in order to identify sites of CO_2 leakage, is not straightforward. The horizontal extent of many potential geological reservoirs means that CCS monitoring programmes will need to cover far larger areas than existing programmes, such as those used to assess the impact of oil and gas extraction. So, while many marine organisms and processes are impacted by exposure to elevated levels of CO_2, their use in monitoring may be restricted by the speed at which appropriate biological data can be gathered and the limited spatial extent to which specific biological observations apply. With this in mind, wide-scale observations of the seafloor using AUV mounted cameras may provide the most potential for identifying effective biological monitoring with



7.5 Visual biological responses to elevated levels of CO_2. (a) A cyanobacteria bloom which appeared on the sediment surface after exposure to CO_2 acidified seawater (pH 7.5) for 2 weeks. (b) The appearance of burrowing heart urchins (*Echinocardium cordatum*) at the sediment surface after exposure to CO_2 acidified seawater (pH 6.5) for 2 weeks. (c) Observed mortality of infaunal animals (including *E. cordatum*) after exposure to CO_2 acidified seawater (pH 5.6) for 2 weeks.

recent experiments showing two main biological responses visible at the sediment surface (Fig. 7.5). Firstly, elevated levels of CO_2 may promote the growth of microbial mats by fertilising CO_2 limited bacteria (e.g. cyanobacteria, Fig. 7.5a) or by liberating other substances (e.g. methane or sulphide) that could stimulate the growth of specific microbial groups. Secondly, reduced pore-water pH levels could drive infaunal organisms onto the sediment surface (Fig. 7.5b) and in extreme cases result in large-scale mortality (Fig. 7.5c). While the application of biological monitoring tools in identifying CO_2 leakage appears limited, the use of biological observations in monitoring environmental recovery after a leak provides far more opportunity. In this activity a number of traditional tools could be applied including the assessment of macrofaunal community structure and diversity and the use of bioassays that quantify organism immune function and general health status.

7.7 The role of natural analogue sites and artificial experiments

Natural analogues for CO_2 storage can provide useful information on the processes that are important for the migration and storage of CO_2 as well as for testing monitoring strategies (Pearce *et al*., 2004; Holloway *et al*., 2005). The IPCC Special Report on Carbon Dioxide Capture and Storage (IPCC, 2005) includes a review of natural CO_2 accumulations, supplying information on migration mechanisms and potential impacts of leakage. Concentrations and fluxes of CO_2 in natural 'baseline' environments and in sites where CO_2 leakages occur naturally vary over a wide range (see, e.g., West *et al*., 2005). Onshore concentrations can vary from <0.1% to ~95% of the total gas in soils.

The European Commission (2011) considers that CO_2 stored by man at depth in geological reservoirs could potentially find its way into three different spatial regimes

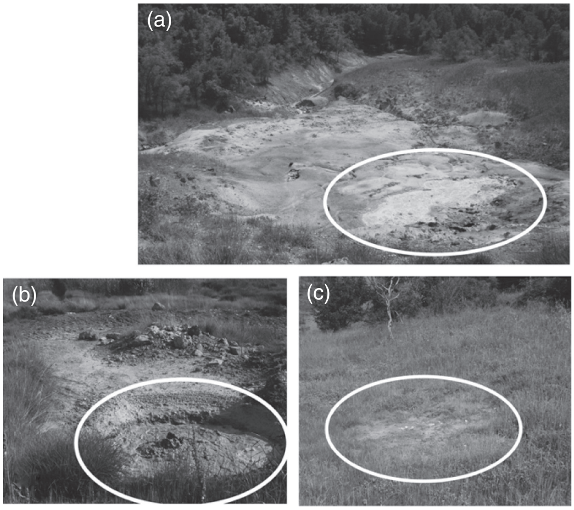
(i) *Primary storage site* and seal at ~1 km depth within which CO_2 is expected to be securely stored.
(ii) *Secondary containment formations* which are defined by secondary seals and reservoirs that may contain the CO_2. If present these overlying formations may provide a natural self-remediation in case the plume migrates beyond the primary seal.
(iii) *The surrounding environment*. Migration of CO_2 above the secondary containment formations into the shallow subsurface would be termed leakage and incur a financial penalty. Should CO_2 leak into the surface environment the operation would come under scrutiny from further environmental legislation. It is the responsibility of the store operators to ensure that their store, injection strategy and monitoring strategy is designed such that there is minimal risk of CO_2 escaping the secondary confinement into the shallow subsurface and surface environment.

Natural CO_2 seeps occur both onshore and offshore. The CO_2 emerging from the onshore seeps has typically been identified as derived from volcanism, metamorphism (such as may be occurring at depth beneath active mountain belts) and degassing from the mantle, while offshore seeps are predominantly associated with volcanism. As well as natural CO_2 seeps, a large number of natural CO_2 fields have been discovered which have been exploited to, for example, produce CO_2 for carbonated water or enhanced oil recovery (EOR). Typically, these were discovered in the search for hydrocarbon resources (Bonini, 2009; Chiodini *et al*., 2010). Studying natural CO_2 stores (natural CO_2 fields) and seeps allows us to explore factors important to storage security and may help in understanding the size and nature of potential migration paths through the deep and shallow subsurface. Thus study of natural analogues for both geological storage and migration of CO_2 to the ground surface or seabed can make a significant contribution to reducing the risks of leakage from anthropogenic stores. As an example of the former, there is geological evidence that some 215 Mt of natural CO_2 has been stored in the Pisgah Anticline, Mississippi since late Cretaceous times, some 65 million years ago (Studlick *et al*. 1990). Study of the structure of the natural geological trap in which this CO_2 is found, and the cap rocks above the reservoir, could yield important information about long-term sealing capacity. Natural analogues can also tell us about CO_2 leakage pathways and the effects of CO_2 emerging from the ground surface or seabed on the environment. Fault related CO_2 seeps near Green River, Utah, provide a good example of pathway evolution and variable flow through time. At this location U-Th dating of numerous fossilised travertine deposits show that CO_2 leakage location has repeatedly switched km distances over 100 000 year time scales and that the volume of emitted CO_2 has varied throughout time (Burnside *et al*., 2012). Natural offshore seeps at Panarea, Italy allow monitoring of the effects of dissolving bubbles of CO_2 on the pH of seawater in their immediate vicinity, and the resulting effects on biota.

Onshore seeps include, for example, springs and streams of carbonated water, bubbling pools of water or mud (e.g. Figs 7.6a and 7.6b), and diffuse seeps through soil (e.g. Fig. 7.6c). Flux rates at natural CO_2 seeps vary over orders of magnitudes. For example, at the Pululahua Caldera in Ecuador the mean flux is 3.1×10^{-2} T m^{-2} yr^{-1} (Padrón *et al*., 2008; Fig. 7.7a), while at the Mefite d'Ansanto site (Fig. 7.6a), the CO_2 flux rate is ~100 t T m^{-2} yr^{-1} (Chiodini *et al*., 2010; Fig. 7.7a). Since the emerging CO_2 is denser than air, at this location it travels downslope into the river channel; it has killed off vegetation in the area immediately around the seep and an impact on the vegetation can be seen for some distance downstream.

Although seep rates at natural analogue sites are measureable, it is important to bear in mind that because of the highly variable geology and, in many cases the active volcanic processes that generate the CO_2, these measured fluxes may be highly site-specific and may vary through time. This makes it difficult to make inferences about seep rates at potential anthropogenic storage sites.

The potential effects of such seeps on human health and the environment are clearly potentially important analogies. It is worth noting that the area around the Mefite seep is well populated and people are currently living within 100 m. It is the build-up of relatively high concentrations of CO_2 in air that poses a threat to human or animal life rather than the flux through the ground. In this context, if a dry seep such as that in Fig. 7.6c emerged within the basement of a building, there could be a risk of asphyxiation that could



7.6 Photos of Italian CO_2 seeps inland from Naples: (a) Mefite D'Ansanto, (b) Mefitiniella Polla and (c) a diffuse seep at Casale.

otherwise be difficult to detect without proactive monitoring, even if the flux from the seep was relatively low, because of the confined environment. Conversely, as long as seeping CO_2 is dispersed and mixes with the ambient air instead of being allowed to build-up, the risks should be minimal.

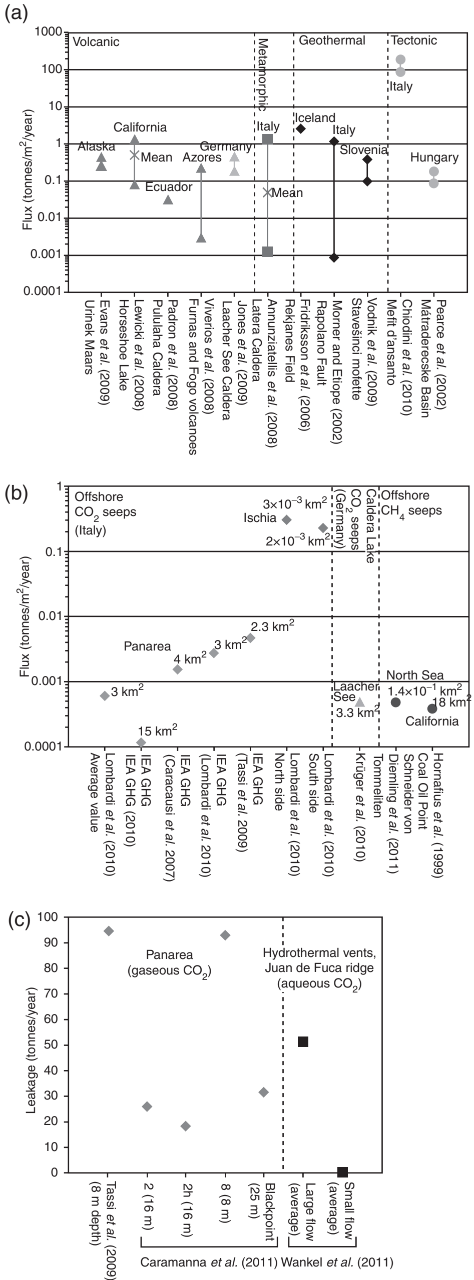
Another onshore example of benefit derived from studying a natural analogue site is given by the Latera site in Italy (Annunziatellis *et al.*, 2008). In this volcanic area CO_2 migration pathways are restricted at depth to relatively narrow vertical zones associated with faults and/or intersections of faults. 'Channelling' occurs along the pathway of highest permeability, so that the 'pipes' will not necessarily be straight, but weave in two or three dimensions within the fault. Above these faults, transport in the near-surface terrestrial environment is determined by the properties of heterogeneous layers of alluvium and various volcanic products. This heterogeneity results in the near-surface vents that range in diameter from about 10 to 80 m. CO_2 fluxes across vents that cause substantial plant loss are typically in the range 0.2–1.8 kg CO_2 m^{-2} d^{-1} (Beaubien *et al.*, 2008). The key features of a detailed study of a single vent at the site were reproduced by mathematical models, as described by Maul *et al.* (2009).

Active offshore seeps have generally been identified by the observation of bubbles of CO_2 rising within the water column; some palaeo-seeps may be identified by pock marks on the seabed and/or gas chimneys imaged rising to the seabed. Typically, measured flux rates are comparable to those of onshore seeps, however none have been documented with a flux rate as high as Mefite. Leakage rates measured on individual point seeps at Panarea (offshore from the Aeolian Islands, Italy) are typically between 10 and 100 T yr^{-1}. What is less clear is whether there is an offshore analogy for the more diffuse onshore seeps. For example, in an offshore setting it seems likely that low fluxes of migrating CO_2 might dissolve within any shallow sediment layer that might be present and CO_2 rich water might be displaced into the seawater column. Such a seep might not be detectable by monitoring for bubbles – and hence there is a potential for an absence of evidence for low rate seeps offshore. One example of this is the Juist Salt Dome in the Southern German North Sea where there are no visible signs of seepage even though CO_2 levels are locally 10–20 and in one case 53 times greater than background (McGinnis *et al*., 2011).

Few natural offshore CO_2 seeps have been studied in detail. Consequently there is a need for field scale experiments which can characterise the impacts, both chemically and biologically, of new seeps. Kirk (2011) listed some of the questions about offshore seeps that could be potentially valuable in terms of understanding the physical, chemical and biological interaction between CO_2 leakage and the seafloor/seawater environment including:

- How much of the CO_2 being released is dissolving in the seabed sediment layer immediately below the seabed itself?
- What pH changes result?
- What is the impact of a new seep on benthic marine organisms?
- How much geochemical interaction is there between naturally seeping CO_2 and sediments?
- What level of accuracy of seepage quantification can be achieved offshore, especially below easily diveable depths? For example will it be possible to account for all of the CO_2 potentially leaking from an offshore CO_2 storage site by direct measurements (bubbles, dissolution etc.)?
- What would a comprehensive offshore seabed leakage detection and measurement system look like and cost?
- Is there any realistic prospect of remediating or mitigating a leak at the seabed from an offshore CO_2 storage site?
- Would an offshore leak naturally decay and if so over what kind of time period?

It is informative to compare shallow-water CO_2 seep analogues with water and gas emissions at mid-ocean ridges, particularly associated with black smokers and hydrothermal vents (Wankel *et al*., 2011). By mass, the emissions from the latter are typically composed of 94.1% $CO_{2(aq)}$, 5.8% CH_4 and 0.1% H_2. The large and small focused seeps recorded annual $CO_{2(aq)}$ emission rates very similar to those from the shallow-water free CO_2 seeps



7.7 Published leakage rates from (a) terrestrial flux measurements, (b) marine flux measurements and (c) marine point source leakage rates. Where the seep is smaller than the measuring equipment a leakage rate can be measured; where the seep is spatially extensive, a flux rate must be determined and a representative area estimated in order to estimate the leakage rate. In (a) flux values are grouped by the source of the CO_2 described by the authors of the publication. In (c), the value from Tassi *et al*. (2009) is for the same seep as vent 8 from Caramanna *et al*. (2011) (IEAGHG: International Energy Agency GreenHouse Gas programme).

at Panarea (Fig. 7.7c). These sites also provide evidence that CO_2 can leak from the seafloor in an aqueous phase – although the hydrothermal regime at an engineered CO_2 storage site would be considerably different to the mid-ocean ridge setting.

Natural analogues may provide an idea of the long-term effects that could be expected in the event of leakage from a geological storage site. By their nature, natural analogues are mature systems in which CO_2 has either remained trapped in the subsurface at depth (~km to hundreds of metres) or it is leaking through an established seep. We can therefore consider their spatial extent of CO_2 in the subsurface to be relatively constant. There is rarely monitoring of systematic changes in seep rate through time except where human intervention has impinged on the integrity of natural stores. One natural analogue that has showed variation in flow rate is Panarea which has been known to increase CO_2 activity in response to increased geothermal activity (Caramana *et al.*, 2011). The last known event occurred in November 2002 when 'a series of underwater gas explosions' led to an abrupt increase in the volume of emitted fluids. It has been estimated that one of the most active vents emitted 54 t/day of CO_2 for nearly 2 months.

Natural analogues can be used to test different monitoring techniques both at storage depths (3 km–500 m), shallow depths (~500 m to surface) and fluxes out of the surface – but these are images of a long-lived store and/or seep. However, the monitoring of a newly forming seepage pathway requires modern analogues that experience breakthrough of CO_2 for the first time. We have not identified analogues of such evolving systems that are required to assess the performance of monitoring techniques by tracking the unintended migration of CO_2. The physical limitations of different monitoring techniques make them appropriate for monitoring different parts of the systems so an effective monitoring strategy will need a range of tools capable of monitoring across the whole depth range. Triggers typically form an integral part of any monitoring strategy: for example, when a measured parameter departs from an acceptable range this may trigger new monitoring activities aimed at obtaining further information as to the reason for the observed anomaly.

Research is under way at several experimental locations to investigate the shorter term effects of CO_2 on terrestrial ecosystems and marine test sites are under development. An example is the ASGARD (Artificial Soil Gassing and Response Detection) field site at the University of Nottingham. The impacts of a controlled injection of CO_2 on soil microbiology, soil geochemistry and the range and health of plants growing at the surface are being studied; some early results from this work are described by West *et al.*, (2009). In these types of experiments it is as yet difficult to determine which biogeochemical processes contribute to the observed impacts.

7.8 Challenges and future trends

The EU Directive on Geological Storage of CO_2 states that

> The operator … must monitor continuously all aspects of the CO_2 flow and the surrounding storage complex, … and respond with corrective measures to any leakages or 'irregularities' that occur.

In addition, guidelines ask:

> Have all vulnerable domains surrounding the targeted storage sites … been identified? Has relevant environmental data required for screening been acquired and reviewed?

The ensuing research challenges are clear. Firstly methods of monitoring that are efficient and effective need to be developed. While primary monitoring will logically be focused around the geological storage zone and within transport mechanisms, for geological leaks, quantifying leakage (and subsequent penalties) will be far more tractable using surface-based methods. This will be complicated by the potential for horizontal movement within geological structures and strong mixing and dispersion potential in the atmospheric and marine systems. In this latter respect hydrodynamic models are vital predictors of dispersion and thus vital for the design of appropriate monitoring strategies.

A second challenge is to define 'irregularities'. Natural systems are dynamic and vary on multiple spatial and temporal scales. Understanding this dynamic baseline is vital not just for monitoring but also to ensure that irregularities are correctly attributed to their cause.

A third challenge is to assess if any vulnerable domains exist and in general be aware of the economic value of the environment so that risk assessment can be carried out in as quantitative a way as possible. Understanding the potential damage that a leak from CCS storage might cause and how this relates to the ecological value of the wider region and impacts from other anthropogenic activities, especially climate change, will promote a coherent and informed assessment of risks and management. In turn this is again dependent on understanding dispersion and the spatial extent of potential impact. If CCS is to be an effective and accepted climate change abatement strategy, the implications of CCS and CO_2 leaks need to be better communicated to the public.

This chapter has outlined the current status of research with respect to impacts, valuation, monitoring and the utility of natural analogue sites. In particular the concept of ecosystem services can be useful in exploring the potential impacts of CO_2 leaks on society, but if meaningful assessments are to be made then better understanding is needed of the links between biodiversity, ecosystem process and function, and ecosystem services in a context that encompasses the multiple uses and stressors of the natural environment.

Finally while the research effort is currently buoyant, a remaining challenge is to ensure that the scientific knowledge gained is transferred to the emerging regulatory mechanisms coherently and comprehensively so that the widest range of stakeholders can have confidence in the operation of CCS demonstration programmes over the next decade.

7.9 Sources of further information and advice

A number of projects are currently undertaking research into environmental impacts of CCS; a by no means exhaustive list is:

- RISCS (Research into Impacts and Safety in CO_2 Storage), http://www.riscs-co2.eu/
- ECO_2 (Carbon storage and the marine environment), http://www.eco2-project.eu/home.html
- QICS (Quantifying Ecosystem Impacts of Carbon Storage), http://www.bgs.ac.uk/qics/home.html

A number of reports have detailed the issues and challenges for CCS, these include: The Intergovernmental Panel on Climate Change released a report on CCS, 'CCS, IPCC Special Report, Working Group III, September 2005', which is available from Cambridge University Press (http://www.cambridge.org/ipcc), The Edinburgh Building, Shaftesbury Road, Cambridge, CB2 8RU, UK.

A readable description of the chemistry and ecological implications of adding CO_2 to marine systems, in the context of ocean acidification can be found in the Royal Society report of 2005 by Prof John Raven *et al*.: 'Ocean acidification due to increasing atmospheric carbon dioxide' (Royal Society, 2005). This can be downloaded from: http://royalsociety.org/document.asp?id=3249.

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7.11 References

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8

Risk assessment of CO_2 storage complexes and public engagement in projects*

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Abstract: Carbon capture and storage is a 'show-me' business – the highest standards must not only be achieved but also demonstrated. The quality of a performance risk assessment and the confidence in taking a quality decision is a function of technical maturity. Increasing maturity of assessment allows definition of activities to systematically accept or exclude identified storage complex options. The intent is to identify at an early stage which options offer a low life-cycle seepage risk while excluding others with a high life-cycle seepage risk.

Key words: storage complex, risk assessment, containment, safe storage, public engagement.

8.1 Introduction

'Risk management is considered essential to ensuring the safety of carbon storage. This will require periodic and ongoing assessment of the risks relating to containment and leakage, as well as uncertainties in the geological framework, models and performance assessments. It is intended that risk management techniques will be used to identify, mitigate and manage identified risks and uncertainties in order to ensure the safety of any storage.'

EU Guidance Document 1 – CO_2 Storage Life-Cycle Risk Management Framework

* This chapter is consistent with current and emerging regulatory frameworks and key reference texts for carbon storage.[1–18] The framework described forms the basis for a proposed new methodology for carbon capture and storage (CCS) in the Clean Development Mechanism which was circulated in draft at COP 14 in Poznan (December 2008) through the IEA Regulatory Network. It has also been shared by Shell within the CO_2 Qualstore Joint Industry Project and largely incorporated within the CO_2 Qualstore Guideline for Selection and Qualification of Sites and Projects for the Geological Storage of CO_2.[19, 20]

CCS (carbon capture and storage) is a 'show-me' business – the highest standards must not only be achieved but also demonstrated. The public and regulators require, *a priori*:

1. Demonstration that CO_2 will most likely be contained safely in the long term and that control, monitoring and verification measures (possibly by a designated third party) will be in place and trustworthy. Leakage risks will be as low as reasonably practicable (ALARP).
2. That large-scale surface operations will be managed safely and with appropriate corporate and detailed regulatory oversight.

Consequently, the characterisation and risk assessment of a storage complex should be precautionary and existing equity interests, mineral and groundwater resources need to be fully protected. As there is no significant statistical base for long-term containment, known high-risk seepage features should in the first instance be avoided, then the residual risk minimised by distance. In particular, this means avoiding, as much as possible, known seepage risk features such as legacy wells with poor containment integrity.[21] Storage complex selection needs to be backed up by demonstrative models that identify potential seepage paths. The seepage scenarios need to be verified through base level surveys and a robust monitoring and verification framework.[3,8,9,22]

The risk assessment of a storage complex should be carried out in four steps that correspond to the criteria defined in Annex I of the European Union Directive on the Geological Storage of Carbon Dioxide:[10,17]

1. Data collection.
2. Computerised simulation of the storage complex.
3. Security, sensitivity and hazard characterisation.
4. Performance risk assessment.

Derogations from one or more of these criteria are permitted so long as characterisation and performance assessment indicates that under the proposed mode of operation there is no significant risk of seepage and that no significant negative environmental or health impacts are likely to occur.

8.2 Risk assessment of a storage complex

8.2.1 Data collection

Sufficient data shall be accumulated to allow basin wide screening to be undertaken to identify the presence of the components that support CO_2 storage (reservoir, seal, structure) and to inventorise available data and identify knowledge gaps. Each potential storage complex will be screened for capacity, injectivity and life-cycle containment criteria and will demonstrate the acceptability of the proposed CO_2 source composition. The potential storage complexes will be evaluated in the context of other economic interests – hydrocarbons, minerals, potable water, biosphere/marine biosphere and atmosphere (including environmental, health safety and environment (HSE), population).

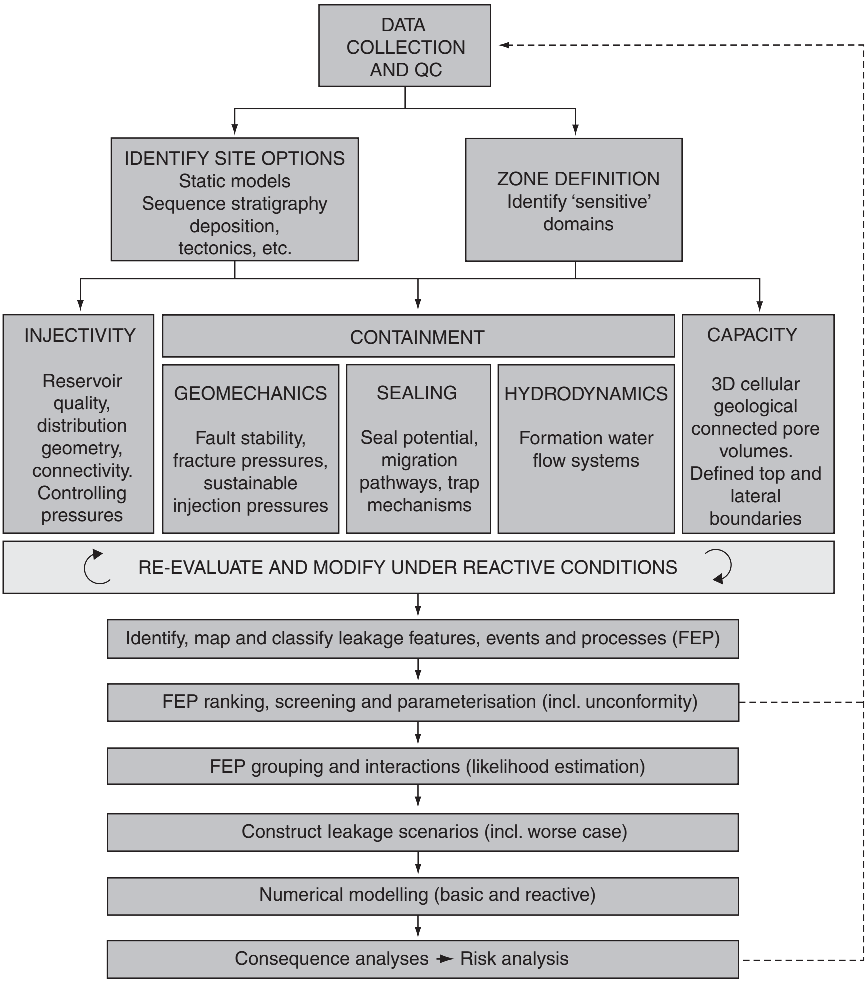
Locating, characterising, screening and risk assessing a preferred storage complex in a time effective and technically robust manner is key to appropriate storage complex characterisation and selection. This requires projects to search widely for subsurface container formation options, utilising a well-defined framework for such investigations (Fig. 8.1).

The data shall cover at least the following intrinsic storage complex characteristics:

1. Reservoir geology and geophysics.
2. Hydrogeology (in particular existence of potable ground water).
3. Reservoir engineering (including volumetric calculations of pore volume for CO_2 injection and ultimate storage capacity, pressure and temperature conditions, pressure volume behaviour as a function of formation injectivity, cumulative injection rate and time).
4. Geochemistry (dissolution rates, mineralisation rates).
5. Geomechanics (permeability, fracture pressure).
6. Seismicity (assessment of potential for induced earthquakes).
7. Presence and condition of natural and man-made pathways which could provide seepage pathways (e.g. boreholes).

To allow a comprehensive risk assessment, the following characteristics of the potential storage complexes shall be documented:

1. Domains surrounding the storage complex that may be affected by the storage of CO_2 in the storage complex.
2. Population distribution in the region overlying the storage complex.
3. Proximity to valuable natural resources (including but not limited to potable groundwater and hydrocarbons).
4. Possible interactions with other activities (e.g. exploration, production and storage of hydrocarbons, geothermal use of aquifers).
5. Proximity to the potential CO_2 source(s) (including estimates of the total potential mass of CO_2 economically available for storage).
6. The near surface environment shall be described with regard to:
   - terrestrial environment (e.g. topography, soils and sediments, surface water bodies, etc.);
   - human behaviour (e.g. land and water use, community characteristics, buildings, etc.).



8.1 Framework for storage complex investigations.

8.2.2 Computerised simulation of the storage complex

When screening has been completed, sufficient data should be available for a preferred storage complex, to construct volumetric and dynamic three-dimensional (3-D) earth models that include the caprock, and the surrounding hydraulically connected areas. The models should address the following elements, which are essential aspects of a robust assessment of a storage complex and are described in the joint Shell–ERM report for the International Energy Agency Greenhouse Gas Research and Demonstration Programme (IEA GHG R&D Programme) '*Carbon Dioxide Capture and Storage in the*

Clean Development Mechanism – Possible Approaches to Clean Development Mechanism (CDM) Methodology Issues', 2007:[5]

(a) A capacity estimation of the 'storage complex'. Capacity estimation relies on a thorough understanding of trapping mechanisms that vary over time and the maximum allowable injection induced pressure increase within the formation.[23] The effective capacity will be ultimately controlled by injection efficiency, acceptable well count, coupled with actual pressure conductivity. Initially, structure and stratigraphy constrain upward migration through buoyancy, seal entry pressures and seal geometry. As the injected CO_2 migrates, residual gas is left behind as the plume travels through pore-space, with some components of the gas dissolved in formation waters. This further attenuates mobile volumes with potential mineral precipitation fixing a further proportion of the injected gas.
(b) A thorough definition of primary and any additional subsurface containment formations (or 'storage complex'). This introduces a significant safe storage concept with increased operating safety margins that is analogous to an engineered storage system such as a tank farm. In a tank farm, there is a primary vessel and primary seal (the tank and tank walls); there is also a secondary containment system comprising a concrete apron and bund-wall, and there may be subsequent barriers and controlling drainage systems. In subsurface terms this may mean a primary reservoir with primary seal, with additional containment potential provided by subsequent (non-sensitive) reservoir/seals or through extensive connected pore-space that allows attenuation. These additional containment formations are safety features designed in such a way that migration across the boundaries of the primary containment formation does not lead to seepage emissions to the atmosphere/hydrosphere.
(c) A thorough understanding of the storage complex seepage features and processes. In order of perceived significance these seepage features are:

   (i) legacy and future wells (at all reservoir levels);
   (ii) faults and fractures;
   (iii) caprock/seal properties;
   (iv) lateral boundaries, that is, controlling factors on lateral 'plume' migration.

In the context of a storage project, 'legacy' wells mean pre-existing wells that have been either abandoned or suspended or remain in operation. Wells are considered to be the highest risk of seepage for the following reasons:

- Annular pressures are common phenomena in oil field operations throughout the world. The likelihood of communication and flow, even through long sections of well bores may be significant, but can be adequately managed given good oilfield practices.
- There is little industry experience with abandonment of wells for extended containment periods or with follow-up, long-term monitoring to assure sustained integrity.

(d) A detailed understanding of the interactions and consequences of location choice for above-ground installations and pipelines. There is a consensus that the risk of fugitive emissions from capture facilities, pipelines and surface equipment can be quantified. Consequently, standard operating, maintenance and monitoring practices can be designed to minimise such emissions. These practices have been proven over 25 years of acid gas injection (AGI) operations in Western Canada. However, given the step-out in scale of the next generation of CCS projects these 'standard' practices need to be thoroughly challenged and reviewed during the design phase of a project. Aligned operating and maintenance philosophies (including simultaneous operations (SIMOPS) planning) between different project proponents are a prerequisite for safe operations. Advanced capabilities in plume dispersion modelling that incorporate the local (seasonal and diurnal) variations in air movement are equally fundamental to safe operations.

(e) Clear definition and assessment of sensitive zones which surround or overlie the subsurface storage complex. This includes an assessment of the consequences of possible migration or seepage into sensitive zones/domains. It is critical that both spatial and temporal 'separation' exists between the injection and robustly assessed seepage features/processes such that the risk of significant migration or seepage into sensitive areas in the future is minimised. Therefore, the areal extent of the CO_2 plume, the 'plume separation margin' and degree of confidence in containment between storage complex and potentially sensitive domains must take into account other uses and users. Sensitive domains are categorised as follows:

   (i) Geosphere sensitivities. Proximity to current and future hydrocarbon developments of either own or other operators.
   (ii) Hydrosphere sensitivities. Possible communication and contamination affecting water extraction, for example for potable, agricultural or industrial uses.
   (iii) Biosphere sensitivities. The biosphere and atmosphere are differentiated to separately quantify the impact of greenhouse gas emissions.
   (iv) Atmospheric sensitivities such as releases of toxic material.

(f) An assessment of the potential for sustained injectivity into the storage complex. Establishing confidence in the sustained injectivity of the required volume of CO_2 is essential. Ultimate geological constraints on this are fracture propagation pressures, fault reactivation pressures and capillary entry pressures under reactive flow conditions. These require specific additional data acquisition programmes and modelling capabilities that extend beyond standard oilfield practices. Reservoir homogeneity, compartmentalisation, water displacement and reactive effects also impact long-term injection sustainability. Significant near-well bore impairment issues may also exist for injecting CO_2 under certain reservoir conditions and must be modelled.

> The uncertainty associated with each of the parameters used to build the models shall be assessed by developing a range of scenarios for each parameter and calculating the appropriate confidence limits. Any uncertainty associated with the model itself shall also be assessed.

The model or set of models shall be approved by a competent authority appointed by the host country.

8.2.3 Security, sensitivity and hazard characterisation

Security characterisation

Security characterisation shall be based on dynamic modelling, comprising a variety of time-step simulations of CO_2 injection into the storage complex. The time-steps and temporal range of the models are to be agreed (and documented) with a competent authority. The following factors shall be considered:

1. CO_2 properties, including trace components;
2. operating envelopes for injection rates, volumes and pressures;
3. coupled process modelling (i.e. the way various single effects in the simulator(s) interact);
4. reactive processes (i.e. the way reactions of the injected CO_2 and other compositions with in situ fluids and minerals feedback in the model);
5. the reservoir simulator used (multiple simulators may be required in order to validate certain findings);
6. different scales of interest (near well bore *vs* full reservoir);
7. short- and long-term simulations (to establish CO_2 fate and behaviour over decades and millennia including the solution velocity of CO_2 in water);
8. migration of the CO_2 plume beyond the primary seal and beyond the storage complex to determine migration and potential seepage pathways (e.g. model a breached primary seal).

The dynamic modelling shall provide insight to:

1. pressure volume behaviour *vs* time within the storage complex;
2. areal and vertical extent of CO_2 *vs* time;
3. the nature of CO_2 flow in the reservoir including phase behaviour;
4. CO_2 trapping mechanisms and rates (including spill points and lateral and vertical seals);
5. secondary/tertiary containment systems in the overall storage complexes;

6. storage capacity and pressure gradients in the storage complex;
7. the risk of fracturing caprock (note that reservoir stimulation through controlled fraccing prior to injection should not be prohibited, provided that the caprock is unaffected);
8. the risk of CO_2 entry into the caprock (e.g. due to exceeding the capillary entry pressure of the caprock or due to caprock degradation);
9. the risk of seepage through abandoned or inadequately sealed wells;
10. the rate of migration (in open-ended reservoirs);
11. fracture sealing rates;
12. changes in formation(s) fluid chemistry and subsequent reactions (e.g. pH change, mineral formation) and inclusion of reactive modelling to assess affects;
13. displacement of formation fluids and minerals.

Sensitivity characterisation

Multiple simulations shall be undertaken to identify the sensitivity of the assessment to assumptions made about particular parameters. The simulations shall be based on identifying and applying sensitivities to key parameters in the static geological earth model(s), and varying rate-dependent functions and assumptions in the dynamic modelling exercise. Any significant sensitivity shall be taken into account and incorporated in the performance risk and uncertainty assessment.

Hazard characterisation

Hazard characterisation shall be undertaken by assessing the potential for migration out of the storage complex and risk of seepage, as established through dynamic modelling and security characterisation described above. This shall include consideration of inter alia:

1. potential seepage pathways;
2. potential magnitude of seepage events for each identified seepage pathway (flux rates);
3. critical parameters affecting potential seepage (e.g. maximum reservoir pressure, maximum injection rate, sensitivity to various assumptions in the static geological earth model(s), etc.);
4. secondary effects of storage of CO_2 including displaced formation fluids and minerals and new substances created by the storing of CO_2;
5. any other factors which could pose a hazard to human health or the environment (e.g. physical structures associated with the project).

The hazard characterisation shall cover a range of potential scenarios including simulated migration of the CO_2 plume beyond the primary seal (but within the storage complex) and lateral and vertical migration of CO_2 across the boundaries of the storage complex into potentially sensitive domains or seepage to the atmosphere/hydrosphere. The purpose is to further understand CO_2 plume migration within the storage complex and accurately define seepage pathways, supporting the accurate definition of monitoring and verification activities.

8.2.4 Performance risk assessment

The quality of a performance risk assessment and the confidence in taking a quality decision is a function of technical maturity.[24,25] Increasing maturity of assessment allows definition of activities to systematically accept or exclude identified storage complex options. The intent is to identify at an early stage which options offer a low life-cycle seepage risk while excluding others with a high life-cycle seepage risk.

Both storage complex and containment mechanisms must be well described. Each possible storage complex system requires:

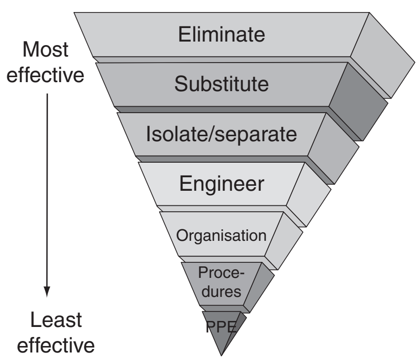
1. a risk mitigation strategy for the main seepage risk factors (e.g. current and future well bores); and
2. an evaluation of the main geological constraints that govern seepage processes and features.

The performance risk assessment shall cover the range of scenarios developed under the hazard characterisation of Section 8.2.3 and shall comprise the following as part of an environmental impact assessment:

1. Exposure assessment – based on the characteristics of the environment and distribution of flora and fauna and of human population above the storage complex, and the potential behaviour and fate of seeping CO_2 from potential pathways identified under Step 3.
2. Effects assessment – based on the sensitivity of particular species, communities or habitats linked to potential seepage events identified under Step 3. Where relevant it shall include effects of exposure to elevated CO_2 concentrations in the biosphere (including soils, marine sediments and benthic waters (asphyxiation; hypercapnia) and reduced pH in those environments as a consequence of seeping CO_2). It shall also include an assessment of the effects of other substances that may be present in seeping CO_2 streams (either impurities present in the injection stream

or new substances formed through storage of CO_2). These effects shall be considered at a range of temporal and spatial scales, and linked to a range of different magnitudes of seepage events.
3. Risk characterisation – this shall comprise an assessment of the safety and integrity of the storage complex in the short and long term, including an assessment of the risk of seepage under the proposed mode of operation, and of the worst-case environment and health impacts. The risk characterisation shall be conducted based on the hazard, exposure and effects assessment. It shall include an assessment of the sources of uncertainty.

In summary, containment risk management is first weighted towards mitigation by avoidance, by minimising potential exposure to other wells and by reduction in the number of puncture points. It is followed up rigorously by best-in-class well design, construction and operational excellence. An assessment should be made of the risk reduction effect of alternative safeguards; measures that eliminate risk are preferable to those which reduce risk (Fig. 8.2). Fundamentally, the timeframe required to confidently deliver a CO_2 injection and containment solution, depends on the early availability of quality information and the ability to consider both depleted field and saline aquifer solutions. Risk factors must assess the time-dependent issues of CO_2 plume migration within the storage complex and potential seepage across the storage complex boundaries, theoretical capacity and trapping mechanisms. Descriptions must also include the proximity to economically and environmentally sensitive domains. Where possible, the effective distance to these domains must be maximised to mitigate future economic liabilities. Performance risk assessment shall also identify and assess the



8.2 Hierarchy of control for risk reduction (Shell HSSE Control Framework). PPE, personal protective equipment.

possible sources for human error during the operation of the injection facilities and the storage complex.

8.3 TESLA: an advanced evidence-based logic approach to risk assessment

Shell believes that the main issues for secure CCS development are the long-term containment of the injected CO_2 in the subsurface and the safety of large-scale operations. A detailed and technically mature assessment of risk governs whether and how a developer can commit responsibly to a safe storage operation. An increasing maturity of assessment allows definition of activities to systematically accept or exclude identified storage complex options and to define an appropriate monitoring and mitigation strategy. The intention of a project developer should be to identify at an early stage which options offer a low life-cycle leakage risk while excluding others with a high life-cycle leakage risk.

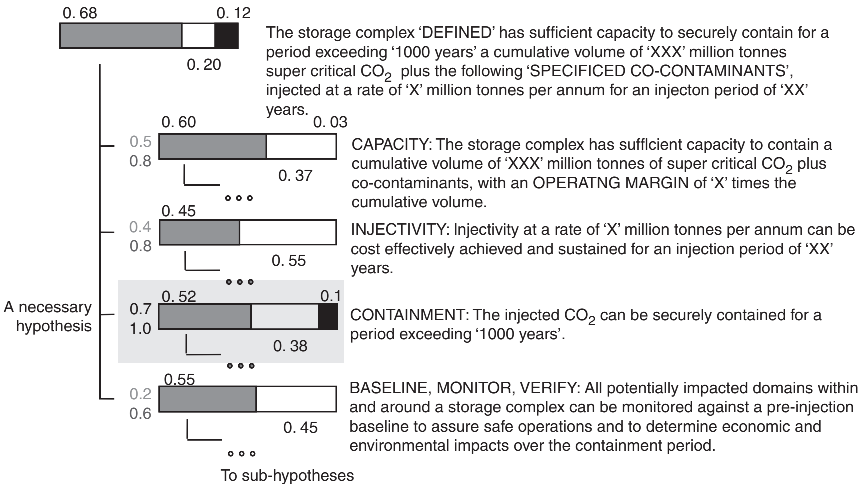
In order to responsibly manage the risk factors involved, this process should include the evaluation and risk assessment of more than one storage option (e.g. alternative reservoirs and structures). To make quality decisions, the risk assessment process should be consistent and auditable across a portfolio of projects that are at different degrees of technical maturity and managed by different teams.

8.3.1 Evidence-support logic

To improve project efficiency, the assessment of a potential storage site's suitability should be identified or rejected as quickly as possible. To achieve this, Shell has developed together with Quintessa Ltd,[26] a technical risk assessment framework to support development decision-making. The framework has been implemented using TESLA, an evidence-support logic tool (ESL; Reference 15), through which a common set of hypotheses can be tested against site-specific conditions. A generic root hypothesis is described as:

> The defined storage complex has sufficient capacity to securely contain for a period exceeding '1000 years' a cumulative volume of 'XXX' million tonnes of super critical CO_2 plus specified co-contaminants, injected at a rate of 'X' million tonnes per annum for an injection period of 'XX' years.

A risk-tree structure (Fig. 8.3) is used to link the root hypothesis to data or information, *via* intermediate steps or sub-hypotheses that specifically



8.3 TESLA risk structure: root and first level hypotheses. Shading indicates the following: dark tint – evidence in favour, black – evidence against, white – lack of evidence (uncertainty). The evidence ratings shown here are illustrative of a project of medium maturity requiring further studies and appraisal work to finalise container characterisation.

address capacity, injectivity, containment and monitoring and verification. Progressively breaking down the main containment hypothesis into more detailed sub-hypotheses, allows a judgment to be made about the amount of evidence available against some ideal optimum.

At any point in the maturation of the containment risk, the sub-hypotheses can then be rolled up to give an overall definition of confidence in containment by illustrating:

1. the degree of evidence in support of secure containment;
2. the degree of evidence against secure containment;
3. the remaining uncertainty (or 'white space').

The white space is a measure of technical maturity and it is this measure, together with a detailed understanding of the source of the uncertainty that drives a robust appraisal, studies and a technical work programme to further de-risk a containment complex.

The TESLA technique allows site characterisation where one or more of the following conditions exist:

- incomplete knowledge; not all involved processes are understood;

1) INJECTIVITY: Injectivity at a rate of ‘X’ million tonnes per annum can be cost effectively achieved and sustained for an injection period of ‘XX’ years.

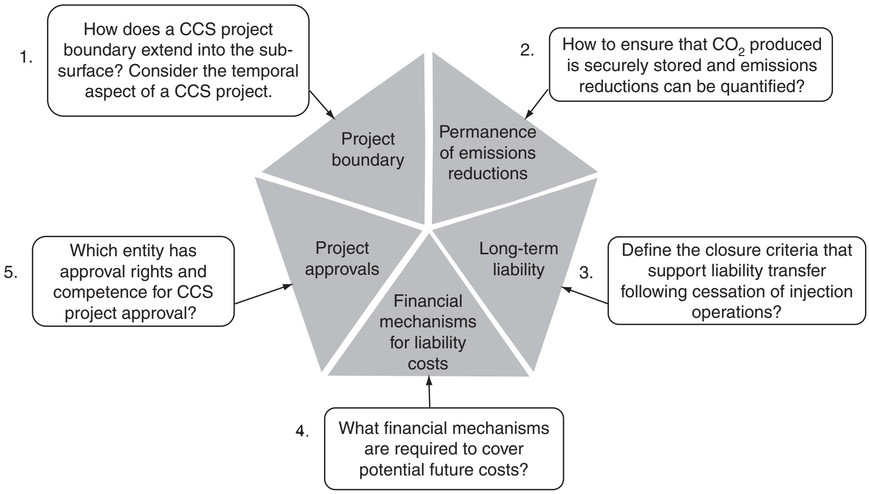
- 1.1) Reservoir-natural factors controlling super critical CO_2 injection are understood and supportive of sustained injection
  - 1.1.1) Reservoir heterogeneity-geometry and flow barriers can be sufficiently characterised to optimise well placement and manage injectivity
  - 1.1.2) Matrix and fracture permeability systems can be sufficiently characterised to optimise well placement and injectivity
  - 1.1.3) Critical pressures (CEP, FRP, FPP, FVP) and pore pressure distribution are sufficiently understood to set an upper limit on BHP
  - 1.1.4) Near well bore impairment by mineral precipitation, particulates or bio-films is sufficiently understood to demonstrate sustained injectivity
- 1.2) Field development concept - A cost effective, technically feasible injection concept can be designed to achieve and sustain injection
  - 1.2.1) Reservoir pressure under injection conditions can be sufficiently quantified and can be managed within agreed operating envelopes
  - 1.2.2) Pumping and compression - the PT operating envelope is sufficiently quantified and full-field injection operations can be maintained for the required injection period
  - 1.2.3) Wells can be designed, sited, drilled, completed and stimulated to achieve and maintain injectivity without comprising primary seal integrity

8.4 An example of how a first level sub-hypothesis on injectivity is broken down (partial example) into a logical model. The lower-level hypotheses expose essential judgments that relate to evidence (not shown) and ensure there is a comprehensive assessment of relevant factors and uncertainties, providing an audit trail for the assessments that need to be made.

- incomplete system characterisation; not all data is available;
- uncertain quality; data is available but of uncertain reliability as evidence;
- uncertain meaning; data is available but interpretation is uncertain;
- conflict; relevant data from different sources do not agree;
- variability; relevant data do not give a unique answer.

Significantly, the weighting of the tree, that is, the way that evidence for sub-hypotheses is rolled up, is conservative. Handling of supportive and non-supportive evidence has been made asymmetric. Individual pieces of evidence against containment, injectivity, capacity or monitor-ability can effectively ‘kill’ a project whereas a positive polarisation requires many different subcomponents to be positive and add up, to make a project ‘fly’. This focuses study work on managing the principle risks and providing mitigation options.

The lower-level, discipline-specific sub-hypotheses (e.g. evidence for fault-fracture leakage) require input and completion by technical experts in a specific discipline (Fig. 8.4). Evidence scores are collected and rolled up through conversation with teams by a portfolio risk manager who oversees



8.5 Issues underpinning regulatory acceptance of CCS.

the process for all projects. Portfolio and program managers then discuss work programme, resourcing and prioritisation.

8.4 Addressing technical, governance and fiscal challenges to carbon capture and storage (CCS) with risk assessment

In recent years there have been extensive advocacy efforts to support the development of CCS in international emissions trading frameworks and through emerging regulatory frameworks. These efforts have highlighted particular technical, governance and fiscal challenges that require further resolution (all intrinsically requiring a risk-based assessment of performance) (Fig. 8.5).

8.4.1 Project boundaries

For a CCS project two different types of boundaries should be considered:

1. spatial boundary
2. temporal boundary.

This distinction seems reasonable since CCS involves not only a spatial boundary in analogy to other projects from the industry sector but also a temporal boundary to address the issue of potential non-permanence of emissions reductions beyond the crediting period.

The spatial boundary is set such that all emissions that are significant and reasonably attributable to the project activity are included in the project boundary. Sources due to capture, treatment, compression, transportation, reception, injection and storage of CO_2 and all anthropogenic GHG emissions that are significant and reasonably attributable to the project activity are included in the project boundary. The project boundary significantly goes beyond the point of injection to account for subsurface migration of the injected CO_2 and could be established as the pre-defined storage complex and overburden boundaries. This may become significant in terms of land-take requirements and liability transfers in some jurisdictions (Plate V in the colour section between pages 214 and 215).

The boundaries of the storage complex and associated overburden are therefore defined by the storage complex characterisation procedures and can be summarised as:

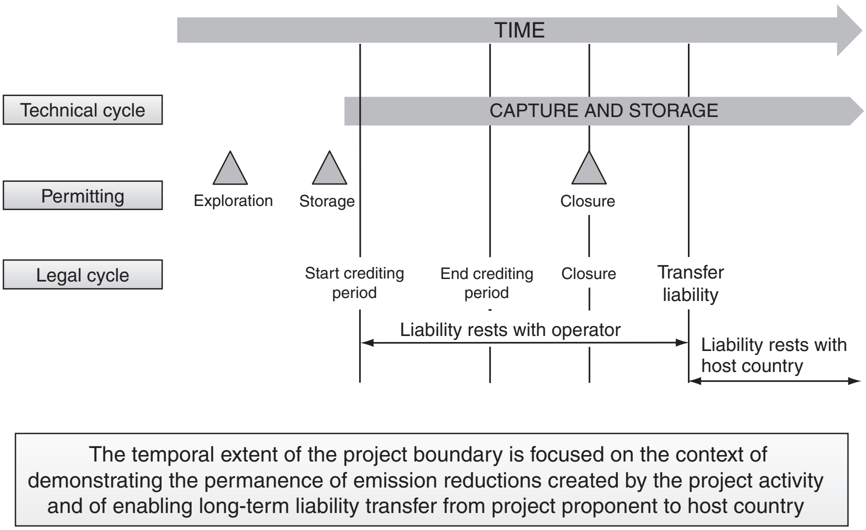
- Vertical boundary (which is the surface area of the geosphere directly above the storage complex and overburden).
- Lateral boundaries (based on the lateral limits of the storage complex, which is an estimation based upon a characterisation of the storage complex and predictive forward models of the CO_2 plume migration, potential seepage pathways and ultimate distribution of CO_2-rich acid gas in the targeted storage complex).

Minimum depth of the storage complex

A reasonable guideline may state a requirement to inject fluid in a dense phase to improve the use of pore-space and reduce buoyancy pressures significantly. Consequently a 'guideline depth' is dependent on the depth at which dense phase is achieved. In a high permeability setting, with no boundaries or baffles, injection at just over hydrostatic (740 m plus) should be sufficient to achieve desired rates. A conservative approach would be to ensure that 750 m below ground level is utilised as a cut-off, so that even after pressure relaxation, the CO_2 would remain in dense phase. However, in some settings (e.g. tight, heterogeneous, compartmentalised reservoirs), pressures would not relax, and regulatory approval would be required to access useful storage capacity in shallow, tight formations.

Minimum depth separation between injection and potable aquifer

Given an effective caprock, there is no technical justification to prescribe a depth separation guideline. If a separation measure is required by regulation



8.6 Temporal boundaries for CCS projects.

it would have to incorporate the risk management principals of either (i) confidence in sealing pressures and/or (ii) allowable (harmless) levels of contamination in the potable zones. Sound risk management principals would allow a discussion on the significance of leakage to a potable aquifer.

8.4.2 Temporal extent of the project boundary

The temporal extent of the project boundary is focused on the context of the permanence of emission reductions created by the project activity (Fig. 8.6). There are five distinct phases/events of the temporal extent:

1. Capture and storage of CO_2 (including the crediting period)
2. Closure
3. Aftercare
4. Liability transfer
5. Host country liability

Permanence

All potential emission sources can be effectively managed through good site selection and operations management, including effective monitoring (which serves to support zero-seepage assumptions), and the use of corrective measures to control any significant irregularities in the subsurface behaviour of the CO_2. Risk-based site selection, coupled with effective regulatory and liability frameworks, together provide a basis for zero-leakage assumptions and is the most effective process by which to handle permanence. Agreed site selection criteria and consistent methodological steps can be developed within trading frameworks and included within emerging regulation to ensure that only geological storage sites with evidence of effective, long-term (permanent) CO_2 trapping mechanisms are chosen.

CCS differs from other technologies in that the formation of CO_2 is not avoided but rather its release into the atmosphere is avoided. Consequently, monitoring cannot simply stop at the end of the crediting period as for other projects in the energy sector but must rather be continued until all available evidence indicates that the stored CO_2 will be completely contained for the indefinite future. A well-defined and executed monitoring plan is of crucial importance to defining and managing effective mitigation options and for the acceptance thereof by regulatory authorities and the public. Effective monitoring plans must be determined on a site-specific basis, according to the geological conditions of the planned storage complex. All phases of a project (i.e. pre-injection, injection, closure, aftercare and post-liability transfer) need to be monitored, as well as all the environmentally sensitive domains identified in proximity to the storage complex (geosphere, hydrosphere, biosphere, oceansphere and atmosphere). This can only be achieved against agreed base levels, which allow accurate accounting of CO_2 entering and leaving the storage complex. A scientifically sound and commercially viable monitoring plan, can only be achieved when the risk assessment is intrinsically linked to the development of the storage complex-specific monitoring plan.

Liability transfer

'Liability' means the responsibility to appropriately manage the storage complex, to execute appropriate remediation and corrective measures in the event of any seepage, and to undertake compensation for seepage, in the event that it is required. With respect to the long-term permanence of CO_2 storage, effective stewardship of the storage complex requires the project proponent to demonstrate that appropriate arrangements are in place for the liability transfer for monitoring from the project proponent to the host country. Given that the required containment periods exceed the longevity of most corporate entities, states must at some point take on long-term liability, and thus the responsibility for post-closure monitoring.

The terms of liability transfer shall be agreed with the host country prior to registration of the project. The terms of liability transfer should be performance-based (i.e. based on the performance of the CO_2 storage complex), and should follow broadly the conditions proposed in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 2, Chapter 5, Section 5.7.1, para. 4(v). This requires that once the CO_2 approaches its predicted long-term distribution within the reservoir, and there is agreement between the models of CO_2 distribution and measurements made in accordance with the monitoring plan, it may be appropriate to decrease the frequency of (or discontinue) monitoring. On this basis, the convergence of observed and predicted behaviour, and the reduction or cessation of monitoring should provide a basis for liability transfer. Consequently, satisfactory history matching is a prerequisite for a liability transfer.

Financial mechanisms

The arrangements for liability transfer must be supported by a financial mechanism by which to provide funds to the host country to cover these requirements. This must be demonstrated prior to project registration. The financial mechanism may consist of either/or a combination of the following provisions, set at a suitable level to cover the costs associated with responsibilities described above:

1. The payment of tax revenues or royalties from the project proponent to the host country (e.g. linked to revenues from CER sales).
2. Credit reserve or fund in escrow established by the project proponent, and accessible by the host country.
3. A suitable insurance policy underwriting the potential financial requirements, transferable to the host country upon liability transfer.

Approvals

The storage complex characterisation and selection procedure, risk assessment report, subsurface monitoring plan (and systematic reviews) and plans for corrective measures shall be approved by the host country and/or by competent national/international authorities. The definition of competent authorities needs to be fully articulated within trading frameworks and included within emerging regulation. Independent verification may be desirable as it can transparently demonstrate compliance with regulation and demonstrate appropriate management and mitigation of risks and uncertainties. This in turn provides assurance to stakeholders and supports a transparent, consistent and cost-effective process.

8.5 Public engagement in CCS projects

8.5.1 Informing CCS communications: where we stand today and why

CCS faces a broad set of significant challenges if it is to be successfully scaled-up and validated through demonstration programmes before subsequent rapid and widespread deployment. While important progress has been made over a short period to create suitable conditions to launch a demonstration programme, this has not been paralleled by the necessary increases in awareness and understanding of CCS among the varied audiences that make up the general public.

Today, low to non-existent levels of awareness of CCS remain the rule, not the exception.[27] This has led to a disconnect between the actions of supportive governments which are engaged in demonstration projects and programmes (EU; USA; Canada; Australia; China; South Africa) and a public that remains effectively uninformed about the need for CCS technology and its workings. Addressing this information vacuum requires a series of stakeholders to deliver an effective CCS communications strategy.

In general, local acceptance of a CCS project may take place when the following factors are in place:[28]

1. low population density (rural);
2. offshore storage;
3. familiarity with oil/gas industry;
4. economic benefits;
5. trust in industrial players;
6. sufficient public engagement;
7. regional/national government support;
8. non-governmental organization (NGO) and credible third-party support.

In contrast, rejection of a CCS project (usually CO_2 storage related) may occur when the following factors are in place:

1. onshore storage;
2. distrust in industrial actors;
3. insufficient regional/national government support;
4. lack of economic benefits;
5. insufficient public engagement;
6. high population density (urban);
7. lack of NGO and credible third-party support.

8.5.2 Communication gaps and opportunities

The gaps that currently exist with respect to effective CCS communications can be outlined as follows:

1. a widespread lack of understanding exists with respect to the fundamentals and science behind climate change;
2. climate fatigue and climate change scepticism are a reality;

3. awareness of CCS remains low to non-existent in sharp contrast to other energy technologies (i.e. renewables);
4. CCS is perceived as complicated, expensive, entirely at the expense of renewables, linked solely to fossil fuels and thus part of the past, not the future;
5. no understanding of, or belief in, CO_2 storage remains a key barrier to overcome;
6. the benefits of CCS have not been sufficiently articulated and adapted to suit respective audiences (local, national, etc.);
7. industry and governments are not considered credible or trustworthy.

There are a myriad of opportunities to bridge these gaps in a manner that recognises the legitimate concerns of the public and seeks to provide clear, factual information to ensure informed decisions can be reached, including:

1. CCS must be placed within the context of climate change and the challenge posed by the continued use of fossil fuels for decades to come;
2. a portfolio approach will be required, with renewables, energy efficiency and CCS all required;
3. clearly outlining the benefits of CCS and directly addressing valid and relevant concerns over the safety of CO_2 storage;
4. leveraging the diverse CCS stakeholder community (industry; NGOs, academics/scientists; governments) to provide appropriate and legitimate input;
5. making CCS a reality to those most directly impacted by CCS projects, through opportunities to 'touch, feel and see' it in operation;
6. engaging in a debate with stakeholders that recognises the rational and emotional components related to CCS and addresses them equitably and factually.

8.5.3 The importance of public dialogue

Dialogue between CCS stakeholder and the wider public is not only vital to ensure the latter can make informed decisions, it also reflects the larger issues mentioned previously regarding climate fatigue/scepticism and the reality of increased resistance to what are perceived as invasive and visible energy technologies.

The reality is that a certain level of sacrifice will be required by all stakeholders in the climate change debate in order to unlock the vast potential that a shift towards a low-carbon model contains, including jobs, energy security and a healthy environment. Public funds and support will be essential to kick-start a large number of what are currently non-economically viable energy technologies. The debate over which technology is deserving of support ignores the realities and time constraints imposed by climate change which, increasingly urgently, require a portfolio of technologies to address. There is no silver bullet.

CCS will require significant investments ($2.5–$3 trillion over the next 40 years – IEA) and major infrastructure developments (pipelines, etc.), both of which will require public involvement, understanding and eventually support. The next decade will be critical in launching CCS on the path towards its necessary widespread deployment and this cannot be done without the explicit and implicit support of the public. The public's legitimate concerns over the largely unknown activity of storing CO_2 in the subsurface and the economic benefits of CCS must be given the highest priority.

The objectives of any public-facing CCS communications strategy should therefore be to:[28]

1. Clearly outline what is known, the experience to date and what remains to be validated when it comes to the entire CCS value chain, addressing the key legitimate concerns over the benefits and safety of CCS.
2. Engage in an open dialogue that includes all of the CCS stakeholders involved (industry; government; NGOs, science and academia).
3. Provide the widest possible context and overview of climate change and energy technologies.
4. Achieve the highest possible levels of transparency, factuality and responsiveness.

8.5.4 Communicating the role of CCS in tackling climate change

Increasing awareness of CCS and its crucial role in combating climate change can only be achieved if the technology is placed in the proper context and placed within a portfolio of solutions which also include renewables and energy efficiency.

CCS is the single biggest lever to combat climate change and has the potential to address almost half of the world's current CO_2 emissions. Why? Because we will be continuing to burn coal, oil and gas for many decades to come and we cannot afford to ignore this reality merely because it does not fit into what many would prefer to believe: that the sustainable energy system of tomorrow is here today. It isn't, and will take decades and colossal investments to establish. What we do in the meantime is just as important as the end solution, and CCS proponents have the responsibility and obligation to convey this fact, however irksome.

CCS stakeholders are often struck by the sharp contrast between the realities of very low levels of public awareness and, say, the IEA's projection that CCS will deliver 20% of the necessary CO_2 emissions reductions by 2050. However, this gap was created by the technology's relatively recent emergence as a full value chain – given its individual parts have been in use for up to 40 years – abetted by far too modest communications resources given its current lack of commercial viability and a trend to focus too narrowly on CCS as a mere technology, rather than as a part of the larger climate change debate.

CCS remains only part of an overall solution for combating climate change. CCS advocates understand this and should clearly communicate their recognition of this reality, thereby outlining a new take on the climate change debate: an inclusive perspective that recognises the need for all technologies rather than just one. There is currently no single solution to climate change.

8.5.5 Building and leveraging the CCS community

The untapped strength of the CCS community is its incredible diversity and expertise, and the authority and credibility this can carry when applied to public engagement.[29] In recognition of this reality, it is important to map the existing CCS universe and the key players therein, in order to not only leverage and share messaging, content and tools, but also to link the right entities with the right issues and audiences.

An overview of the current CCS universe shows how CCS bodies might relate to one another in a more coordinated and consistent manner

International bodies (IEA, IPCC, CSLF, GCCSI, Industry, NGOs) vary from intergovernmental initiatives like the CSLF, all the way to NGOs such as the WWF. While their individual roles clearly differ, they can provide vital global perspectives, analysis, direction and support.

Pan-regional bodies (European Commission/EU; Zero Emissions Platform; CCS EII; CCS Project Network; Berlin Forum; CO_2 GeoNet; Universities; Research Institutes) have the particularity of leveraging a broader view on developments within the field of CCS. Furthermore, expert and EU bodies can maximise knowledge sharing.

At a national level, the diverse CCS stakeholder model (industry; NGOs, government; science/academia) exists within each EU Member State with collaborative models already well developed in certain countries through CCS organisations (CCSA, IZ Klima, PTECO$_2$, CO_2 Club, etc.).

At the closest point of contact to the CCS projects themselves lie local bodies that directly represent the inhabitants concerned, and the inhabitants themselves. They play a direct and primary role and deserve open and transparent lines of dialogue in order to understand and address local concerns and issues.

8.5.6 Key communications activities

Resources for communicating around CCS have been limited to date. Not only does the current low level of awareness of CCS demand appropriate and significant up-scaling of resources to address, but CCS is merely one component within the highly competitive, costly and sophisticated area of 'green' communications. Many billions of dollars are spent annually to demarcate one entity and product from the next in terms of environmental performance and importance to the public. Once again, CCS is not alone in this space and any communications strategy must reflect this reality.

As such, a variety of communications activities should be part of any structured CCS communications plan. These include, but are not limited to:

Media relations: While a certain level of interest exists among the media, far more needs to be done to provide the facts and realities around CCS, its workings and move towards deployment. Organisations should leverage the expertise and perspectives of their members to engage one of the most important stakeholders in any communications plan.

Events: CCS organisations and their members must break out of their comfort zone and spend more time sharing their expertise within the larger climate change and energy technology debate, effectively serving as CCS ambassadors. Their activities include: providing speakers, panellists, sponsorship, stands and collateral.

Online presence: Perhaps the most direct means of interacting with the public – and ensuring genuine responsiveness – CCS websites must be designed and built from the outset to provide clear and compelling information, *via* the right tools, to the right audience. Particular attention should be paid to already existing collateral which is often freely available from CCS proponents. Products and activities include: animations; films; FAQs; participation in appropriate and relevant forums; regularly updated content; online community creation.

Printed collateral and information campaigns: Alongside traditional brochures, reports and leaflets, information campaigns are a vital means of communicating CCS to a much wider audience. Inspiring and involving design, content and messaging are absolutely necessary to avoid the technical wrapping that has too often enveloped CCS.

It can be seen from the above that a broad and diverse universe of CCS bodies exists. The challenge remains to appropriately tie into and leverage this wealth of expertise and diversity of viewpoints, including supportive academia, NGOs and local bodies representative of communities.

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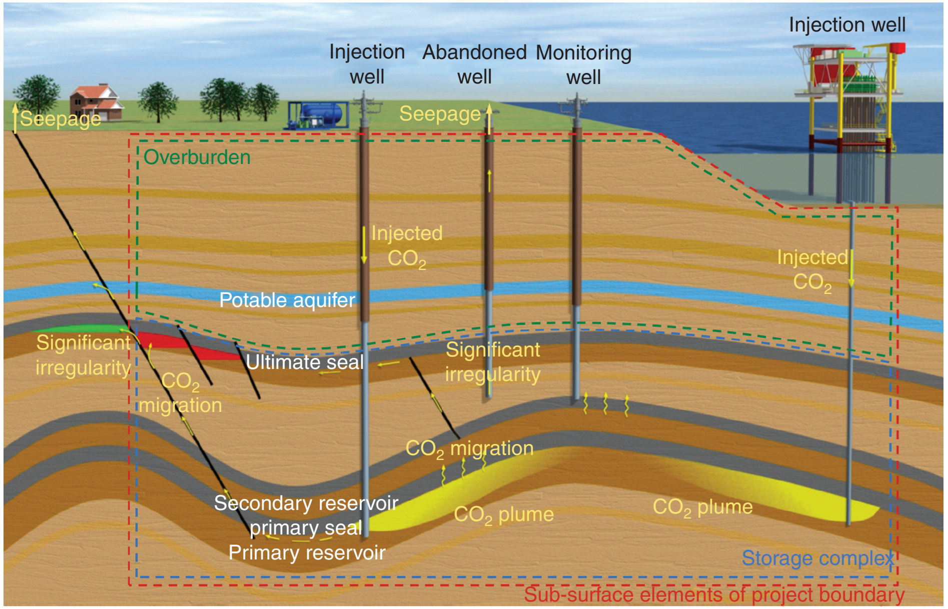

Plate V (Chapter 8) Schematic of primary migration and seepage pathways (not to scale).

9
The legal framework for carbon capture and storage (CCS)

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Abstract: This chapter seeks to place carbon capture and storage (CCS) in a legal framework. The chapter commences with an overview of relevant international law. The coverage of institutional frameworks continues with a discussion and analysis of the key provisions of European Directive 2009/31/EC on the geological storage of CO_2. The chapter then explores some key issues relating to potential liabilities for CCS related activities, in particular examining the difficult question of allocating long-term, post-closure liabilities. The chapter concludes with an analysis of some of the key future challenges for regulatory systems and for CCS more generally.

Key words: carbon capture and storage, law, international treaties, European Union law, CCS Directive, licensing procedures, legal liabilities, future challenges.

9.1 Introduction

This chapter seeks to place carbon capture and storage (CCS) in a legal framework. The clarity and robustness of that legal framework is a natural precondition for the successful development of what is increasingly seen to be a key component of the international response to the threat of climate change. The use of the term 'precondition' connotes an idealised set of mandatory characteristics for any laws designed to regulate CCS activities. They should be clear and certain, while also being stable and readily adaptable to changing circumstances providing a framework which:

- minimises risks to human health and the environment,
- incentivises operators to invest in the technology required for operating and managing CCS,
- provides a fair and efficient system for permitting and controlling operational activities and post-operational storage,
- allocates the external costs of CCS equitably among those responsible for creating CO_2 emissions,

- creates clear and fair systems of allocating and apportioning liability for any losses/damage caused by operational activities and post-operational storage.

In an ideal world perhaps we would have such a framework. In reality, however, this framework reflects many of the complexities, uncertainties and rapid change of the scientific and technological aspects of CCS with some additional nagging doubts as to the practical implementation and challenges in the medium and long term. This complexity and lack of certainty has various elements. First, we have institutional complexity with a mosaic of laws and regulatory bodies at international, European and national levels. While there has been a degree of consistency in terms of the acknowledgement of the need for a truly global response to CCS, there has been the development of national frameworks, reflecting similar but different regulatory approaches and tools which raise issues relating to the harmonisation of standards and solutions. Secondly we have interconnected aspects of CCS which raise very distinct legal questions. For example, what controls apply when CCS takes place offshore or onshore? How should the risks of transporting CO_2 be addressed? To what extent are there regulatory overlaps with the Emissions Trading (Directive 2003/87/EC), Pollution Prevention and Control (Directive 2008/1/EC) and Waste Management (Directive 2008/98/EC) regimes? And how do we allocate and apportion potential liabilities for damage from CCS activities, including the role of insurance schemes? Finally there are spatial and temporal complexities including different types of sub-surface ownership rights and the prospect of liabilities potentially lasting for millennia in uncertain and changing environments.

This makes the task of ordering an outline of the relevant legal framework for CCS in an introductory chapter somewhat of a challenge. Should the coverage be primarily operational/functional, focusing upon the ways in which the law addresses various components of the CCS process – capture, transport and storage (both onshore and offshore)? Should it be primarily 'legal', focusing on private law issues such as ownership and insurance and public law regulatory systems for licensing CCS activities and statutory mechanisms for allocating liabilities? Or should it be institutional, focusing on comparisons of regimes at international, European and domestic levels? Of course there is no correct answer – each lens provides a different perspective. All that can be done is to select the essential elements to construct as coherent a picture as possible. Thus this chapter commences with an overview of relevant international law which provides a common set of principles for action in promoting, developing and implementing CCS within the Clean Development Mechanism of the Kyoto Protocol. The coverage of institutional frameworks continues with a discussion and analysis of the key provisions of the overarching framework found in the European Union

(EU), which, to date, is the most developed CCS framework as found in Directive 2009/31/EC on the geological storage of CO_2. We will then explore some key issues relating to potential liabilities for CCS related activities. The chapter will conclude with an analysis of some of the key future challenges for regulatory systems and for CCS more generally.

9.2 The role of international law: the Kyoto Protocol

The driving force for CCS in international law can be found in the Kyoto Protocol to the *UN Framework Convention on Climate Change*. The protocol seeks to establish binding obligations upon 37 industrialised countries and the 15 Member States of the European Union at the time of signing (collectively known as Annex I parties) including mandatory reduction targets for greenhouse gas emissions and the creation of a system of flexible mechanisms designed to set down 'common but differentiated' national targets in relation to the production of those greenhouse gases. Key provisions deal with:

- aggregated emissions targets:

  Article 4 permits groups of Annex I parties to pool overall emissions in an aggregated total and not be restricted to individual quotas. An example can be found with EU Member States who have an overall target with some discretion as to allocation to meet the overall target.

- joint implementation mechanisms:

  Article 6 permits Annex I parties to receive credit for helping other parties reduce emissions through, for example technology transfer.

- emissions trading systems:

  Articles 4 and 17 permit the banking or trading of 'surplus' credits where parties exceed reduction targets – thereby offsetting future targets or assisting other parties who are not meeting current targets.

These provisions set the foundations for the development of CCS as a response to the challenge of meeting the agreed reduction targets. The foundations of CCS are found in the provisions on the clean development mechanism (CDM – see Art. 12) in which Annex I parties gain credit for assisting developing countries in the creation of specified clean development projects for the reduction of emissions, notwithstanding the fact that those countries have no reduction targets themselves. The credit gained for such projects is offset against the Annex I countries' own targets (subject to the reduction being in excess of what would have happened without the project itself).

After some years of discussion documents and COP Decisions (COP Decisions 2 and 7), in 2011, CCS was finally included within the list of activities which can be considered to be eligible under the CDM. Decision 10 CMP.7 makes provision for rules and procedures which must be complied with before any credit for an associated CCS project can be used to account against Annex I mitigation targets under the Kyoto Protocol (FCCC/KP/CMP/2011/10/Add.2). Thus before CCS projects can be eligible for credit under CDM mechanism there must be national legislation in the nation hosting the project in force which governs:

- Operational matters including access to sites and the selection, characterisation and development of sites and long-term controls over storage.
- Liability systems dealing with any damage caused by the site including losses from seepage and the costs of remedial measures to restore site integrity.

Other provisions address:

- Project validation. In order to qualify for credit the responsible authority in the host nation has to certify that the project is properly authorised under the national legislation; that there has been adequate participation from the host nation including the site characterisation and an assessment of the risks and environmental impacts of the project; that there is adequate financial provision in place to enable safe operation, meet liabilities, address potential insolvency and provide remedies for seepage and other associated losses; and that the host nation accepts any liabilities associated with long-term storage.
- A register for the banking of credits from the CDM with an allowance for 5% on any credit being allocated to take into account losses caused by seepage. Who takes responsibility for such seepage is subject to the agreement of the host nation to accept such losses as part of the approval. The host nation does have a discretion to accept such obligations or to make specific provision to transfer to the Annex I party responsible for the project.

Although these technical rules provide some certainty for CCS projects, the most significant aspect of the scheme is the promotion of CCS as a credible technology to address climate change mitigation. A common system of registration, validation and certification for both the approval of CCS projects and the treatment of credits from such projects go a long way to legitimising the technology and ensuring that there is a transparent and clear regulatory system of controls across different host nations. As is often the case with such measures there are still areas of uncertainty – primarily in relation to the use of credits from CCS in the EU Emissions Trading Scheme (ETS) (see Directive 2003/87/EC (as amended) – the Directive only allows credits from projects in what are known as the 'Least Developed Countries' unless there is a specific agreement in place) and the extent of the discretion given to host countries to determine its own way of addressing liability schemes as between itself and the Annex I parties. The process of review for these 'modalities and procedures', which is scheduled to take place in 2016, should address these potential inconsistencies which may operate to distort the equal distribution of such projects where host nations adopt more favourable standards.

9.3 The role of European law: Directive 2009/31/EC on the geological storage of carbon dioxide

The EU Directive on the geological storage of carbon dioxide (CCS Directive) represents probably the most complete and detailed regulatory framework for CCS in the world. It provides a common framework for Member States and is a key element of the EU's Climate Change 'Package'. This package includes other initiatives on renewable energy (Directive 2009/28/EC); Emissions Trading (Directive 2009/29/EC) and a decision on sharing emissions reduction targets (Decision No. 406/2009/EC). The Directive 'establishes a legal framework for the environmentally safe geological storage of CO2 to contribute to the fight against climate change'(Art. 1(1)). The main provisions of the Directive deal primarily with storage with incidental provisions dealing with capture and transport. More specifically this includes where storage facilities may be erected; who may operate them; how the facilities are to be managed; the need to monitor for leaks; and procedures to be taken in case of leaks or other irregularities in management. Under the Directive, CCS is not a mandatory requirement for Member States; instead the Directive provides a consistent framework for the implementation of CCS throughout the EU. The incentives for Member States to invest in CCS can be found in the ETS. For example, under Phase III of the ETS, from 2013 to 2015, CCS commercial demonstration projects are given allowances in the scheme (Directive 2003/87/EC Art. 10a(8)). For the purposes of emissions targets, these allowances render neutral any CO_2 emissions which are captured and stored.

9.3.1 Aims, scope and overlapping provisions

The Directive covers the geological storage of CO_2 within Member States. The general aim of the Directive is to store CO_2 in an 'environmentally safe' manner, that is, in such a way as to prevent and, where this is not possible, eliminate as far as possible negative effects and any risk to the environment and human health (Art. 1(2)). Onshore and offshore storage may take place in the territory of the Member States, in their 'exclusive economic zones' or on their continental shelves (Art. 2). Insofar as they pertain to underwater storage, the locations are defined by the *United Nations Convention on the Law of the Sea* (Art. 32).

The Directive makes amendments to existing regimes to take account of CCS projects. The pre-existing prohibition on the injection of CO_2 into groundwater is lifted so long as injection takes place within the terms of the CCS Directive (Art. 32). The Directive (Arts 35–36) also excludes CO_2 'captured and transported for the purposes of geological storage and geologically stored in accordance with' the CCS Directive from the definition of 'waste' under both the Waste Framework Directive (Directive 2006/12/EC) and the Transfrontier Shipment of Waste Regulations (Regulation No. 1013/2006). The cumulative effect of these provisions is to make the CCS Directive the primary framework for all CCS operations rather than other framework legislation relating to water quality and waste.

The CCS Directive amends three other Directives to address different aspects of activities relating to the *capture* of CO_2. First, new CCS capture projects are made subject to the requirement to assess likely environmental impacts from these activities under the Environmental Impact Assessment Directive (Art. 31 amends Directive 85/337/EEC).

Second, the Integrated Pollution Prevention and Control (IPPC) Directive (Directive 2008/1/EC) is amended to include the regulation of activities connected to the capture of CO_2 (Art. 37). Thus installations involved in CO_2 capture activities will be subject to a permit requiring the use of the Best Available Techniques (BAT) for capture and to prevent or render harmless all releases to the environment. Finally, the CCS Directive amends the Large Combustion Plant Directive (Art. 33 inserting Art. 9a in Directive 2001/80/EC), by imposing a requirement that new combustion plants of over 300MW output should be designed so as to permit the retrofitting of capture technology subject to the availability of suitable transport capability and storage sites and that the capture is technically and economically feasible. It is assumed that any requirement to carry out the retrofitting would be enforced through the BAT requirements under the IPPC Directive.

As an alternative to this technological retrofitting, the CCS Directive (Art. 38) provides for a review of the fitting of capture technology at large combustion plants and the results from the demonstration projects with a view to considering the imposition of CO_2 emission performance standards with quantitative limits on emissions (Art. 38(3)).

9.3.2 Transport

It is envisaged that existing pipeline networks will be used for the transport of CO_2 to the final storage sites. For example in the UK this includes a combination of the Planning Act 2008, the Pipeline Act 1962 (for long distance onshore pipelines) and the Petroleum Act 1998 (for offshore pipelines). Accordingly, the Directive contains few specific provisions dealing with transport networks but instead relies upon existing alternative legislation on pipelines dealing with planning, property rights for routing and operational controls. The Directive makes provision for 'fair and open' arrangements for third party access to the transport network and storage sites (Art. 21). The arrangements must ensure that where an operator refuses access on the grounds of any lack of capacity or no connection to the network, the operator must address these deficiencies where it is 'economically viable' or where the customer is willing to pay providing doing so does not have a detrimental impact on the integrity of the pipeline or storage site (Art. 21(4)). The CCS Directive also allows access to be refused where there is incompatibility in technical specifications which cannot reasonably be overcome, or where there is insufficient current or likely future capacity (Art. 21 2(c)).

9.3.3 Storage

Site selection

With relatively little detail on capture or transport, the vast majority of the CCS Directive provides a framework for the selection and management of storage sites. The Directive gives Member States a discretion to determine the areas from which to select storage sites (Art. 4(1)). The suitability of a potential storage site is to be determined following a site 'characterisation and assessment' subject to a set of criteria set out in Annex I to the Directive (Art. 4 (3)). This process takes into account the 'storage site' itself and the wider 'storage complex', namely the defined volume area within a geological formation (Art. 3(3)). The whole site complex is subject to characterisation – providing for a predictive model dealing with the long-term integrity of the site. More specifically, a storage site should only be selected if there is no 'significant risk of leakage' and 'significant environmental or health risk' (Art. 4(4)). To facilitate the site characterisation and assessment process, there is a procedure for granting 'exploration permits' which grant sole rights to explore potential storage sites on the basis of 'objective, published and non-discriminatory criteria' (Art. 5).

Permitting process

Where an appropriate exploration permit has been granted and the subsequent site characterisation and assessment has demonstrated the suitability of a storage site, a potential operator may apply for a 'storage permit' (Arts 6–11). No storage site may be operated in the absence of such a permit (Art. 6(1)). The Directive makes provision for the data to be included in an application for a permit; this information covers technical competence, the site characterisation and assessment, total quantity of CO_2 to be stored, plans for monitoring, corrective measures and provisional post-closure plans (Art. 7); the pre-conditions which must exist before a permit can be granted, these include that the requirements of the CCS Directive and other relevant EU legislation are met and that the operator is financially sound and has the requisite technical competence (Art. 8); and the content of granted permits, these include, the location and extent of the storage site and storage complex; the requirements for storage; the quantity of CO_2 stored; the composition of the CO_2 stored; and the details of the associated risk management plans (Art. 9). The CO_2 stream accepted and stored at the site is required to consist 'overwhelmingly' of CO_2 and no other waste or other matter is permitted. This prohibition is relaxed in relation to incidental substances from the process of capture, or injection process as long as such substances are below levels which would adversely affect the integrity of the site, or pose a significant risk to the environment or human health (Art. 12(1)).

The European Commission has a role in reviewing all draft permits which are submitted for peer review by the Commission with assistance from a Technical Scientific Panel. The national licensing authority must make all applications available to the Commission within one month of receipt (Art. 10(1)). The Commission may then issue a 'non-binding opinion' on the application, and must do so within four months (Art. 10(1)). The national licensing authority must thereafter notify the Commission of its final decision. If the authority departs from the Commission's opinion, they must give reasons for doing so (Art. 10(2)). In the initial period of the implementation of the Directive, the aim of this process is to promote consistency of application and recognition of best practice from across all Member States. The first Opinion on a draft permit was issued by the Commission in February 2012 in relation to the permanent storage of CO_2 in the Dutch continental shelf (see *ec.europa.eu/clima/news/articles/news_2012022901_en.htm*).

Operations: monitoring, reporting and inspection

The operational phase of storage is subject to a regular process of monitoring compliance with conditions; reporting by the operator on operational matters; and inspection by the relevant authorities of the Member State. The key operational element of the permit is a series of plans which address any associated risks of operating the site, including post-closure storage. The plans must outline monitoring measures to assess site integrity and possible environmental impacts (in accordance with details set out in Annex II to the Directive); any remedial measures to be taken in response to CO_2 seepage; risk of seepage or any risks to health or the environment; and any measures to be adopted post-closure.

The Directive makes provision for Member States to ensure that the operator monitors the storage and injection facilities and, 'where appropriate', also the adjacent environment (Art. 13). This is to check on the safety of the facilities, and for detecting CO_2 leakage and any damage to the adjacent environment (Art. 13(1)). Annex II of the Directive lays down criteria on which a 'monitoring plan' must be based (Art. 13(2)). The operator must submit a report on the results of monitoring at least once per year to the authority, but national law may ask for more frequent reporting (Art. 14).

In case of 'leakage or significant irregularities' the operator must inform the authority and undertake 'corrective measures' (Art. 16). The corrective measures are agreed with the authority as part of the licensing procedure (Art. 7(7)). If the operator fails to undertake these measures, the national authority must step in and ensure that they are taken (Art. 16(4)). The authority may also ask the operator to undertake any corrective measures deemed necessary, including any not mentioned in the plan (Art. 16(3)).

The Directive obliges the Member State authority to undertake inspections of the storage facilities (Art. 15(1)). These should be routine, at least once per year, and non-routine in case of reported irregularities. Triggers would include a notification of seepage or risks of environmental harm (Art. 15(3)). The authority must prepare its own report after each inspection and publish the report within two months of the inspection (Art. 15(5)).

Closure and post-closure obligations

When active injection operations have ceased, an operator is under an obligation to remove any associated injection facilities, seal the site and review the post-closure plan which forms part of the permit with a view to taking into account changes in conditions and resubmitting a definitive plan for the site post-closure. Following this closure, an operator continues to take responsibility for monitoring, reporting and any corrective measures required under the permit conditions until such time as there is a formal transfer of responsibility to the licensing authority (Arts 13–17). Thus the site operator does not take responsibility for the site post-closure in perpetuity. The Directive makes provision for the transfer of long-term responsibility for the storage site following completion of the post-closure plan (relevant changes include technological improvements and any assessment of risks, see Art. 17(3)). Following this transfer, the operator is released from any further monitoring or other measures required under the Directive (Art. 18). Release from these types of operational obligations is not the same as the transfer of *legal* liabilities associated with post-closure conditions. The Directive makes explicit provision for the recovery of costs in cases where there has been fault on the part of the operator, even beyond the closure of the site and transfer of responsibility. 'Fault' in this context includes deficient data, negligence, deceit, or a failure to exercise due diligence (Art. 18(7)).

Liabilities for harm to humans and the environment

In addition to the general monitoring provisions and obligations to undertake corrective measures in accordance with the relevant plan in the event of leakages or 'significant irregularities', the Directive amends the Environmental Liability Directive (Directive 2004/35/EC) to include the operation of storage sites as an Annex III operation covered under that Directive (Art. 34). This imposes a duty on operators and in default the competent national authority to take preventative or remedial action in connection with imminent or actual environmental damage. This includes damage to protected species and habitats under nature conservation legislation, water quality and land contamination which is harmful to human health (Directive 2004/35/EC, Arts 2, 5 and 6).

Financial security

A key part of the licensing system is found in Arts 19 and 20 of the CCS Directive. These provide for financial security to be made available as part of the licensing procedure; and for a financial contribution to be made available to the authority at the transfer of responsibility for the storage site. The purpose of the financial requirements is clear: a licence should not be granted to an operator that does not have the financial means of safely running the storage facility, or does not have the finances to cover any clean-up in the case of leakage. The CCS Directive does not provide a definition of what amounts to a sufficient financial security; hence this is left to Member States. In the UK, financial security is defined as a charge over a bank account or property, a deposit of money, a performance bond of guarantee, an insurance policy or a letter of credit (The Storage of Carbon Dioxide (Licensing etc.) Regulations 2010/2221, reg. 1(c)).

The financial security must be effective for the duration of operation (Art. 19). The financial security requirement is ended when transfer of responsibility takes place (Art. 18). The financial security must cover costs if the authority undertakes duties under the licence criteria when and if the operator does not do so, and such duties if the licence is revoked (Art. 19(3)). Among other things, the financial security must cover the cost of monitoring and undertaking corrective measures, as identified in the licence criteria. An operator must make a financial contribution to the authority before transfer of full responsibility for a storage site takes place (Art. 20). The contribution must at least cover the 'anticipated cost' of monitoring for 30 years. UK law makes it explicit that transfer of responsibility cannot take place before the financial contribution is made (The Storage of Carbon Dioxide (Termination of Licences) Regulations 2011/1483, reg. 8(c)).

9.3.4 The impact of the Directive

The CCS Directive framework for site selection and granting permits to operate a storage site is comprehensive and clear. It strives to do two things: make CCS schemes sufficiently attractive for operators, while ensuring that CCS operators can make significant strategic investment decisions with confidence. The success or failure of the CCS Directive remains to be seen, as CCS schemes are now beginning to get under way. The final date for transposition of the Directive into national law was 25 June 2011. As with many European Directives a failure to transpose by the deadline does not necessarily give rise to immediate enforcement action.

Evidence suggests that the formal implementation across the 27 Member States is patchy at best with the UK relatively well advanced in comparison to a significant number of Member States without any measures at all. In April 2012, it was suggested that the UK had 'done more than any other country to establish a comprehensive legal framework for CCS' (DECC, *CCS Roadmap – The Regulatory Framework* para. 2.1). For a more general picture on transposition, see www.ucl.ac.uk/cclp/ccseutransposition.php.

In an effort to achieve consistent implementation, the Commission has issued four guidance documents dealing with key provisions of the Directive. These cover a risk management framework; site characterisation of the storage complex; CO_2 stream composition, monitoring and corrective measures; and financial security (www.ec.europa.eu/clima/policies/lowcarbon/ccs/implementation/documentation_en.htm).

These documents were produced by the Commission in conjunction with a working party of technical experts, known as the Information Exchange Group to monitor the status of implementation.

9.4 Legal liabilities

One of the major disincentives to the development and implementation of CCS technology on a commercial scale is the lack of certainty over the nature and extent of potential liabilities for long-term CO_2 storage. Certainly there is a degree of counter-intuitiveness about this concern. CO_2 is not particularly hazardous as a substance. It poses no greater risks than many other substances which are created, transported and disposed of within a normal regulatory context. But a lack of clarity about who is liable for any losses arising from the long-term storage of CO_2 is proving to be the most controversial aspect of commercialisation. Partly this is because of the nature of the issues involved. Temporal, spatial, geological, technological and legal uncertainties combine to raise seemingly complex problems without an answer. In this section we examine some of the background to that issue of liability for CCS and analyse whether it is such a major issue.

9.4.1 Relevant factors

In a very general sense the debate about CCS liabilities is a substitute for every environmental debate which has competing values at its core. If in the broader context of climate change we are asking a question of what is an adequate response to the immense challenge posed by climate change, in the specific context of CCS we are asking whether the risks involved are worth it and if they are, who should underwrite those risks? In other words there are tricky questions of how to allocate the potential externalities of the long-term storage of CO_2. Operators argue that the incentives to invest in complicated and untested storage facilities will be reduced where unknown, long-term liabilities are allocated to the very parties who are investing where others are unwilling or unable to do so. Governments have to balance the tension between wanting to promote the potential of CCS (through making it as attractive as possible to operators) and accepting long-term, open-ended liabilities in situations of great uncertainty. In addition they want to avoid the 'deepest pockets' syndrome whereby the liabilities are transferred to those with the ability (and longevity) to pay – while those who have seen the commercial benefits are able to avoid liability – just at the time when it is more likely to be an issue.

In trying to identify the risks in terms of nature and magnitude there may be disagreement; there should, however be an ability to fall back on the certainty; of legal principles to allocate liabilities for when those risks occur. But the concept of legal liability is a contested area, and is fraught with misconception. It is easy to equate liability with 'fault', but such a view would be too simplistic and, at times, misleading and incomplete. If there is a leakage from a storage site, who would pay for any damage to the environment? The simple answer would be to say the party to blame for the leak occurring. In truth, however, it is far from a straightforward question. How far does blame stretch in this context? Should it be the operator responsible for running the storage site? Should it be the company that built the storage facility? Should it be the company that provided the equipment? Should it be the national authority that authorised the initial site for safe CO_2 storage? Should it be the land owner(s)? Should it be the government? In most situations it is unlikely to be any one single cause and this additional complexity of chains of causation make the challenge of allocation and apportion of liability even more uncertain.

In many ways these sorts of questions are familiar in other areas of liability. For example in the context of land contamination where different parties have contributed over time to an environmental state which is more or less harmful depending upon the context of the target of the damage. In such circumstances, legislative measures have proved to be highly complex and controversial (e.g. Environmental Protection Act 1990 Part IIA). There are, however, a number of distinctive features which raise the stakes in terms of allocating liability for CCS activities:

- *Political factors*
  Namely the contentious nature of the responses to climate change and the role of CCS in such a response. In a contested area such as climate change, the use of CCS as a response is attacked from both sides of the debate. From those who suggest that the creation of such long-term risks are a disproportionate response to the problem through to those who suggest that it is a wrong and inadequate response to the problem.

- *Spatial factors*
  Namely the sheer size and remote location of many of the favoured locations for storage sites (e.g. offshore) make it difficult to monitor and respond to any issues which might arise. The difficulties of monitoring and assessing the risk of liability, heighten the perception of the risk and therefore distort the nature of the liability.

- *Temporal factors*
  There are two aspects. First, the geological aspects of indefinite storage. In particular, any uncertainties about the technology of storage are only magnified when considered over a 50 year period or more. It is clear that we should expect *some* changes to the surrounding storage area but what those changes are; when they occur; and the nature of the consequences are unpredictable – even with the current state of modelling. Secondly, there are likely impacts of changing attitudes to CCS, corresponding changes to regulatory frameworks and the technological response to those frameworks. Put simply, it is almost a certainty that the legal framework we have today will be a lot less onerous as compared to 50 or 100 years' time. In designing safe storage facilities in the twenty-first century we have no clear picture of what 'safe' might mean in the twenty-second century. Those who are responsible for dealing with storage sites at the end of their operational lives may be facing a bill which was completely unpredictable at the beginning.

- *Commercial and economic factors*
  Namely that the speed at which the technology is being introduced and the imperative nature of the response is putting more emphasis on operators to invest early while being allocated potential CO_2 liabilities caused by other parties' production of CO_2. In addition there is what might be termed the consequences of a changing 'carbon economy'. In other words there is the challenge of dealing with any increase in the scale of the liability because the impact of CO_2 leakages may increase over time in a global economy where the carbon 'price' is rising as a result of emissions reduction targets. Thus in a system of emissions trading where caps are incrementally lowered, the 'cost' of a unit of CO_2 will inevitably rise – thereby increasing liabilities from leakages over time and having a disproportionate effect the further away in time from the initial storage.

- *Scientific factors*
  This links to the spatial factors mentioned above. With difficulties in monitoring and detecting leaks at large, inaccessible sites, there is the additional challenge of developing sufficiently accurate scientific methods of detecting 'trigger levels' of 'harmful events' where action may be required to respond. The Directive anticipates these being discovered through normal monitoring by the operator; through agency inspections or by third parties triggering a non-routine inspection. All of these are predicated on the abilities to detect, with sufficient accuracy, a problem emerging at a time when reasonable steps can be taken to deal with the problem.

The aggregated effect of these factors is to place a disproportionate emphasis on the nature and scale of liability and to magnify the uncertainties of the current regimes.

9.4.2 Overlapping liabilities

Although the CCS Directive and implementing legislation set out a framework for identifying liabilities associated with 'harmful events' and the costs of responding to those events, these are only part of the mosaic of liabilities for harm from CCS activities. It would be wrong therefore to focus entirely on the regime itself as defining the scope of liability for such activities. Existing environmental frameworks governing such things as water quality, contamination, waste and the protection of habitats and species will all be relevant unless the CCS regime specifically excludes such liability. In addition, private law systems such as contract and tort, along with associated mechanisms such as insurance regimes may trigger liabilities for physical harm and economic losses. Thus, for liability to arise there must be 'actionable conduct'. This is easiest described as conduct which breaches a legal provision, be it an EU Directive, a national regulation, or an obligation as between private parties (e.g. a contract). If there has been 'actionable conduct', there will necessarily be a 'wronged' party. That party will then seek to establish liability in court and obtain a legal 'remedy'. The availability of these alternative liabilities is therefore linked to the party seeking the remedy. For example, if there is migration from a storage site to land owned by someone other than the operator or company, and caused damage to property owned by a third party, any affected landowner could bring an action for nuisance. The company could be liable for compensatory or restorative damages. This would be a financial payment to compensate for the damage to the land and/or to restore the land to its previous state. These damages would be above and beyond any financial payments required under legislative provisions, which would be paid to the licensing authority as payment for the works undertaken on their behalf. The damages for nuisance would be paid directly to the affected landowner. The CCS Directive's focus is largely on the prevention and remediation of environmental harm associated with 'harmful events'. It is less obvious that it is associated with compensation to individuals who have suffered private losses as a result of such events.

Allocation of liability

As a result of the temporal factors outlined above, the issue of who takes responsibility for long-term liabilities following the cessation of active CCS operations is considered to be one of the more controversial aspects of the regulatory framework. The obvious solution of allocating such liabilities to the operator at the time of site closure runs up against a number of conceptual hurdles. The first is that the length of time over which such liabilities may be incurred does not sit easily with the typical life spans of corporate entities. Longevity is not a typical feature of modern corporate entities. Typical estimates suggest that even the most successful companies do not have an average life span beyond 50 years – with new identities and reorganisations reducing the life cycle in recent times.

The same is not true for the Governments of Nation States which have the attraction of stability, longevity and an ability to raise finance. The second hurdle is that the contingent nature of liability suggests reserving funds to meet liabilities which may never arise over centuries. While the use of such funds is not unknown in environmental liability schemes (e.g. in relation to long-term liabilities from landfill sites),the time over which funds must be held is usually finite. The third hurdle is linked to situations where liabilities are likely to increase over time and there is a corresponding incentive to reduce the ability to meet those liabilities as time progresses. This can be seen at its clearest in the creation of a 'shell' subsidiary without assets by a 'mother' corporation. A company can only be forced to pay damages if the company has sufficient assets to meet the liability. Creating a limited liability company without any assets is therefore a way of creating a 'liability shield' between the mother company and the subsidiary. Hence it would not have to pay. This last conceptual hurdle has been addressed during the period of operation and post-closure through the requirements to have one operator; for that operator to be 'financially sound' along with a requirement to hold financial security and a contribution.

Residual and post-closure liabilities

In addressing the first two hurdles, there is a recognition that any residual liability for CCS storage activities following cessation of CCS activities will at some stage transfer from an operator of CCS storage sites to the state once the site has been closed and operational activities cease. The critical question is when this transfer should take place, that is, what is the correct balance between allocating liabilities to an operator and when should an operator be allowed to transfer the burden of this risk to the state? The allocation of the cost of post-closure monitoring and supervision (which could be considerable) may be more or less onerous depending upon the length of the time post-closure activities take place prior to the permanent transfer of liability from operator to the state. The CCS Directive sets a default minimum of not less than 20 years, with a shorter period only if there is sufficient evidence that a permanent containment condition has already been achieved. But setting a time period is just one of the parameters to be considered. For example, as mentioned above under the CCS Directive there can never be a wholesale transfer where the liability is triggered by a condition, which is attributable to the fault of an operator (Art. 18(7)). In addition, liabilities under other mechanisms such as under civil and common law do not explicitly form part of the transfer of responsibility. Thus there are still areas where the issues outlined above will still be relevant.

9.5 Challenges and future trends

The use of CCS is not a panacea to address all of the challenges of climate change. It represents a complex, uncertain response which is still very much in its infancy. A regulatory framework within which to develop the demonstration projects will address some of the uncertainties and may be a necessary precondition for the full-scale development of CCS but it is not the end point. Although there is a growing consensus on the ability for existing technology to facilitate the capture, transfer and storage of CO_2 there is a large portion of associated risks which are unquantified and unknowable until the process is tested operationally on large-scale projects. On the other hand the acceptance of CCS as a significant element of the process of greenhouse gas reduction within the international community means that the rapid pace of change and implementation is set to continue.

Before examining continuing uncertainties, are there fundamental principles that are largely agreed upon – or appear to be largely agreed upon – as the foundations upon which to develop CCS further? First, the known pluses outweigh the unpredictable minuses. In other words the benefits of utilising CCS as a method of achieving emissions reduction targets must outweigh the potential liabilities from doing so. Secondly, in order for CCS to be successful it will have to be on a very large scale and for a very long period of time. Thirdly, there are suitable sites but they are not evenly distributed across all States. Identifying those sites is important and may require co-operation between States. Fourthly, there must be a commercial incentive to storing CO_2 and that incentive must be based around a system of credits or allowances which form part of a 'carbon economy'. Those incentives must be sufficient to reward and not penalise early adopters. Finally notwithstanding the variables of time and trigger conditions, there is a need for a clear and accountable system of transferring liability from private operators to the state to address long-term responsibilities.

So far so good – these principles form the basis of a number of existing frameworks across the world. We are not, however, at the stage where large-scale commercial deployment is a reality and uncertainties in the regulatory framework are part of the reason for this. Perhaps it is too much to expect at a relatively early stage of the regulatory cycle but stability and certainty are needed for a range of key stakeholders including operators, funders, insurers and national regulatory authorities.

There appear to be three main areas where further uncertainties will continue. First the notion of providing sufficient incentives to move from demonstration projects to full-scale implementation. Within the EU, the Emissions Trading System gives carbon capture a 'value' which can fund deployment of the technology and provides some additional funding in the form of the NER 300 process. Under Art. 10a(8) of the amended Emissions Trading Directive 300 million allowances for new entrants to the ETS were reserved to support commercial CCS demonstration projects. Seven UK projects submitted a bid, which was more than the rest of Europe combined. None were successful in the first round of bidding.

The success of this system is largely dependent upon the price of 'carbon' within the scheme and current experience suggests that the price levels are simply too low to incentivise operators to invest in carbon capture technology at power stations. In addition funding streams from government have proved to be patchy at best. It was reported that cost was the major reason for cancelling the only demonstration project at Longannet Power Station in Scotland. The UK government had pledged £1billion for the project but it was estimated that the costs would eventually reach £1.5bn (www.bbc.co.uk/news/uk-scotland-scotland-business-15511590).

Secondly, the thorny issue of the allocation of long-term responsibilities and potential liabilities for CO_2 storage. Although the regulatory framework deals with the general shape of transfer there are still many questions about long-term liabilities under civil and common law and other overlapping regimes in particular related to liabilities for trespass and nuisance. There is a need to develop clearer criteria for determining when a site is in a 'post-closure' state and can be transferred from the operator to the state. Performance based criteria will always be more suitable than static time periods but those criteria need to be clearer and more consistently applied for there to be a greater understanding of the true nature of longer term liabilities. There is also little clarity on the exact types of funding mechanisms which would be suitable for covering long-term liabilities. In drawing analogies with existing mechanisms it is envisaged that insurance or escrow type accounts would be ideal for the long term – potentially financed by a levy on charges for injected CO_2 during the operation phase. These charges could then be allocated to the general fund/bond insurance policy which could be transferred for the benefit of the state as part of the overall transfer of responsibility.

Finally, and above all, there is a general uncertainty about a consistent international programme of CCS projects. There are often gaps between the rhetoric of Governmental support for the adoption of this new technology and the incentives in place to attract commercial-scale investment. The rapid pace of change has masked some of the nagging doubts about a system which is critical to achieving emissions reductions. There has been much focus on the desire to prove that the technology can be successful and the legal framework has been robust enough to underpin this initial work but certainly in the very recent past there has been a stalling of progress after an initial burst of activity. This slowing down has a number of causes and is certainly not entirely due to uncertainties about the legal framework.

In any event uncertainty is often a component of many environmental regulatory systems. For example when we look at ecosystems management we are faced with many of the characteristics of uncertainty and complexity. The regulation of a complex system with a host of connected variables is characterised in much of the experience of adaptive management in the context of ecosystem management. This notion of adaptive management involves the design of a project, complete with monitoring and active management as a method of testing assumptions and predicted behaviours. This puts law and regulation at the heart of a learning system which can adapt and change to different circumstances, evolving and responding to the information received. In particular it is a participatory system involving key stakeholders in making decisions about the most effective and efficient responses to the changing circumstances. The process of adaptation acknowledges that in seeking to achieve a desired outcome law has to be flexible enough to experiment with different approaches. Changing those approaches to cope with new information and explicitly documenting what works and what does not enables others to design and manage future projects more effectively. But the key to this approach is an acceptance from all parties involved that the nature of adaptive management is as much about understanding what is a 'failure' as much as taking too precautionary an approach. The underlying tension in developing a clear, stable and certain regulatory system for long-term CCS projects is that we have to also acknowledge the opaque, unstable and uncertain nature of the problems we are seeking to address. In doing so we will have a better chance of understanding the best 'path' to obtaining real benefits from CCS while realistically minimising the risks.

9.6 Sources of further information and advice

9.6.1 Publications

Bode S. and Dietrich L. (2008), 'Regulating carbon capture and storage in the European Union: an economic and legal analysis' *Carbon and Climate Law Review*, **2**, 71.

European Commission, Implementation of Directive 2009/31/EC on the geological storage of carbon dioxide Guidance Document 1: CO_2 Storage Life Cycle Risk Management Framework.

European Commission, Implementation of Directive 2009/31/EC on the geological storage of carbon dioxide Guidance Document 2: Characterisation of the Storage Complex, CO_2 Stream Composition, Monitoring and Corrective Measures.

European Commission, Implementation of Directive 2009/31/EC on the geological storage of carbon dioxide Guidance Document 3: Criteria for Transfer of Responsibility to the Competent Authority.

European Commission, Implementation of Directive 2009/31/EC on the geological storage of carbon dioxide Guidance Document 4: Financial Security (Art. 19) and Financial Mechanism (Art. 20).

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9.6.2 Web pages

European Commission: ec.europa.eu/clima/policies/lowcarbon/ccs/index_en.htm.
Department of Energy and Climate Change: www.decc.gov.uk/en/content/cms/emissions/ccs/ccs.aspx.
International Energy Agency: www.iea.org/topics/ccs/ccslegalandregulatoryissues/.
UCL's Carbon Capture Legal programme: www.ucl.ac.uk/cclp/index.php.

9.7 References

COP Decision 2/CMP.4 *Further Guidance on the clean development mechanism.*
COP Decision 2 CMP.5 *Further Guidance relating to the clean development mechanism.*
COP Decision 7 CMP.6 *Carbon dioxide capture and storage in geological formations as clean development mechanism project activities*, available at cdm.unfccc.int/about/ccs/index.html.
DECC, *CCS Roadmap – The Regulatory Framework*2012, available at www.decc.gov.uk/en/content/cms/emissions/ccs/ccs.aspx.
FCCC/KP/CMP/2011/10/Add.2, *Modalities and Procedures for the carbon dioxide capture and storage in geological formations as clean development mechanism project activities*, available at unfccc.int/resource/docs/2011/cmp7/eng/10a02.pdf.

10

Offshore CO_2 storage: Sleipner natural gas field beneath the North Sea

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Abstract: Sleipner is the world's longest-running industrial-scale storage project and the first example of underground CO_2 storage arising as a direct response to environmental legislation. It began in 1996, injecting around one million tonnes (1 Mt) of CO_2 per year into the Utsira Sand, a relatively shallow saline aquifer. By late 2011 over 13 Mt of CO_2 had been securely stored. A comprehensive research-focused monitoring programme was carried out with multiple time-lapse surveys; predominantly 3D seismic but also 2D seismic, gravimetry and controlled-source electromagnetics (CSEM). The time-lapse seismic data image the CO_2 plume clearly in the reservoir with very high detection capability and show no evidence of CO_2 migration from the storage reservoir. Although not specifically designed for this purpose, the monitoring programme fulfils most of the requirements of the recently developed European regulatory framework for CO_2 underground storage.

Key words: Sleipner, Utsira, carbon capture and storage, CCS, CO_2 storage, storage monitoring, CCS regulation, North Sea.

10.1 Introduction

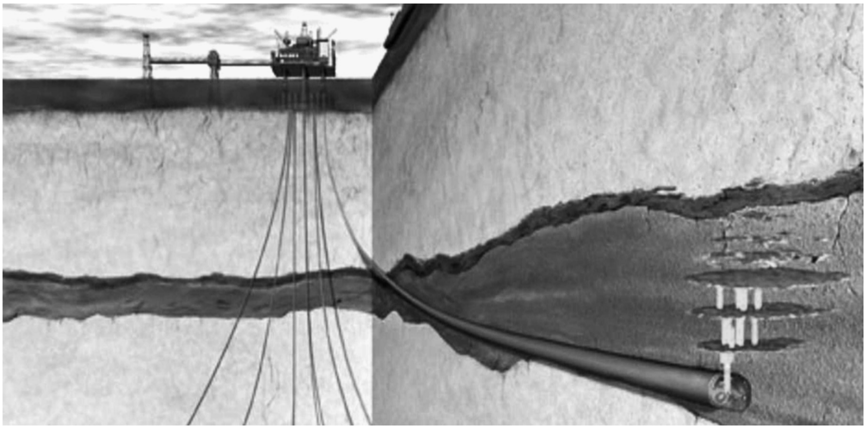
Sleipner, situated in the Norwegian sector of the North Sea, is the world's longest-running industrial-scale storage project (Baklid *et al.*, 1996). This chapter firstly sets out the background and rationale for the CO_2 storage operation. It then outlines the geological setting including key reservoir and overburden properties. The aims of the monitoring programme are explained and key monitoring results described. Finally the monitoring is placed in the context of recently developed European storage legislation, with emphasis on key regulatory requirements such as predictive modelling and verification and leakage detection.

10.1.1 Background to Sleipner

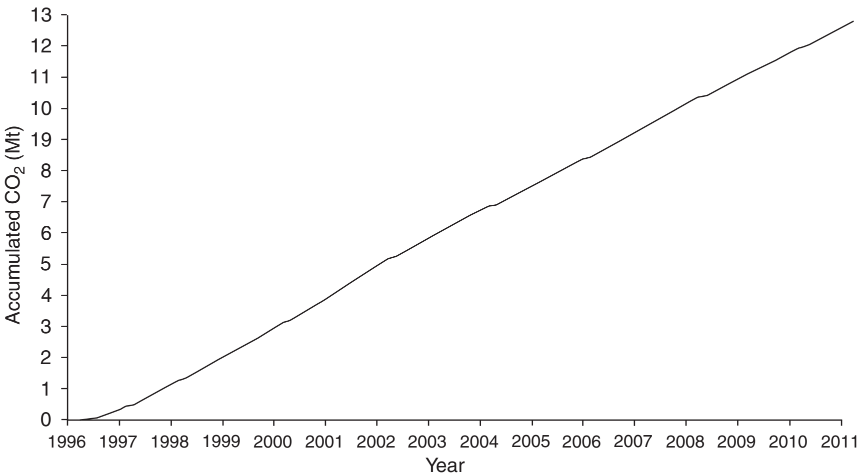
CO_2 injection at Sleipner commenced in 1996. Natural gas produced from a depth of around 3400 to 3600 m in the Sleipner Vest gas field contains about 9% CO_2. This has to be reduced to less than 2.5% for the gas to meet saleable specification, so the CO_2 is separated at the Sleipner T platform via amine scrubbers. Prior to implementation of the Norwegian offshore carbon tax, the separated CO_2 would have been vented to the atmosphere, but in response to this legislation, the field operator Statoil and partners ExxonMobil and Total elected to develop the field with re-injection of the CO_2 into a large subsurface formation, the Utsira Sand. The whole injection and storage operation is cost-effective, with total tax avoided comfortably exceeding storage costs.

The separated CO_2 contains 1–2% methane and is injected into the Utsira Sand, a regional-scale saline aquifer. Injection is via a single deviated well, sub-horizontal at the injection point which is located 1012 m below sea-level, some 200 m below the reservoir top (Fig. 10.1). Since 1996 CO_2 has been injected at a relatively uniform rate of around one million tonnes (Mt) per year, with about ten more years of gas production anticipated (Fig. 10.2). By late 2011 over 13 Mt of CO_2 had been securely stored.

With this injection configuration, the wellbore lies beneath the buoyant CO_2 plume. This is important for two reasons. First, the wellbore is not impacted by the plume of free CO_2 so does not constitute a containment risk. Second, no invasive monitoring or direct invasive measurement of the plume is possible (see below).



10.1 Schematic diagram of the Sleipner injection infrastructure and the CO_2 plume.



10.2 Sleipner CO_2 injection history 1996 to 2011.

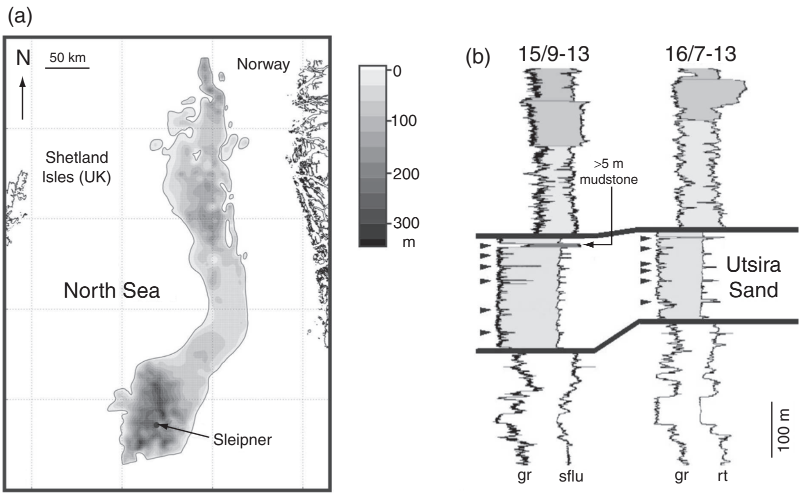
10.2 Geological setting

The geological setting of Sleipner is relatively simple (e.g. Zweigel *et al*., 2004; Chadwick *et al*., 2004a) and a brief summary is given here.

10.2.1 Utsira reservoir

The Sleipner storage reservoir is the Utsira Sand, a saline aquifer of regional extent. It forms part of the late Cenozoic post-rift succession of the North Sea Basin and stretches for more than 400 km north to south and between 50 and 100 km east to west (Fig. 10.3a). Its eastern and western limits are defined by stratigraphical lap-out, to the southwest it passes laterally into finer-grained sediments, and to the north it occupies a narrow, deepening channel. Locally, particularly in the north, depositional patterns are quite complex with some isolated depocentres, and lesser areas of non-deposition within the main depocentre. The top Utsira Sand surface generally varies quite smoothly in the depth range 550–1500 m, and is around 800–900 m deep near Sleipner. Isopachs of the reservoir sand define two main depocentres (Fig. 10.3a), one in the south, around Sleipner, where thicknesses locally exceed 300 m, and another some 200 km to the north with thicknesses approaching 200 m.

In the vicinity of Sleipner detailed reservoir structure has been mapped using 3D seismic data. The top of the Utsira Sand deepens generally to the south, but in detail it is gently undulatary with small domes and valleys. The CO_2 injection point is located beneath a small domal feature that rises about



10.3 (a) Thickness map of the Utsira Sand showing the location of Sleipner. (b) Sample wireline logs through the Utsira Sand from two wells in the Sleipner area. Note the low γ-ray signature of the Utsira Sand, with peaks denoting the intra-reservoir mudstones (gr: γ-ray log; sflu/rt: resistivity logs).

12 m above the surrounding topseal topography. The base of the Utsira Sand is structurally more complex, and is characterised by the presence of numerous mounds, interpreted as mud diapirs. These are commonly about 100 m high and are mapped as isolated, circular domes typically 1–2 km in diameter, or irregular, elongated bodies with varying orientations, up to 10 km long. The mud diapirism is associated with local faulting that cuts the base of the Utsira Sand, but does not appear to affect the upper parts of the reservoir or its caprock (Zweigel *et al.*, 2004). Significant faulting with a tectonic origin is absent.

Internally the Utsira Sand comprises stacked overlapping 'mounds' of very low relief, interpreted as individual fan-lobes and commonly separated by thin intra-reservoir mudstone beds. The depositional environment is uncertain; many believe that this is a turbiditic sand, deposited in moderately deep water (Gregersen *et al.*, 1997) but a shallow shelf setting has also been proposed.

On wireline logs the Utsira Sand characteristically shows a sharp top and base (Fig. 10.3b), with the proportion of clean sand in the reservoir unit typically above 70%. The non-sand fraction corresponds mostly to the thin mudstones (typically about 1 m thick), which show as peaks on the gamma-ray and resistivity logs. In the Sleipner area, a thicker, laterally persistent bed, the 'five-metre mudstone', separates the uppermost sand unit from the main reservoir beneath (Fig. 10.3b). The mudstone layers constitute important permeability barriers within the reservoir sand, and have proved to have a significant effect on CO_2 migration through the reservoir (Arts *et al*., 2004).

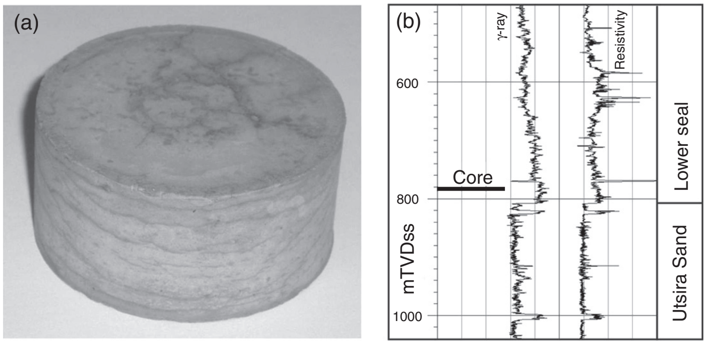
Core samples and drill cuttings show the Utsira Sand to be mostly fine-grained and largely uncemented. Porosity estimates from core, based on microscopy and laboratory experiments, are in the range 27–42% and regional porosity estimates from wireline logs are in the range 35–40%. Permeabilities are correspondingly high with measured values (from both cores and water-production testing) ranging from around 1 to 8 Darcy.

There are no downhole temperature measurements at Sleipner, but large-scale water production from the Utsira Sand at the nearby Volve field (~8 km distant) yields reliable reservoir temperatures. Here, 3–4 Mt of water per year are produced for pressure support in the Volve field (Utsira water has much lower sulphate content than seawater and so is used to reduce the risks of scaling in the production wells after water breakthrough). Before water production started, the Volve well was shut-in for 50 days, and a temperature reading of 27.4–27.7°C at 768 m below sea-level was made. A consistent Utsira water temperature of 32.2°C was obtained during flow, with a perforation interval of 822–1009 m but unknown inflow profile from the reservoir. Projecting these values on a vertical profile gives a linearised relationship $T(z) = 31.7z + 3.4$ (±0.5°C) (Alnes *et al*., 2011). Applying this to the Sleipner injection area gives initial temperatures of about 29°C at the reservoir top and 35.5°C at the depth of injection (1012 m).

10.2.2 Overburden

The overburden of the Utsira reservoir around Sleipner is about seven hundred metres thick. The primary reservoir caprock comprises a basin-restricted mudstone some 50–100 m thick, extending more than 50 km west and 40 km east of the area currently occupied by the CO_2 injected at Sleipner and well beyond the predicted final migration footprint of the plume (Zweigel *et al*., 2001). Above this, prograding sediment wedges of late Pliocene age are dominantly muddy in the basin centre, but coarsen into a sandier facies both upwards and towards the basin margins. The shallower overburden is of Quaternary age, mostly glacio-marine clays and glacial tills.

Seismic, wireline log and cuttings data enable many overburden properties to be characterised and mapped on a broad scale. Cuttings samples from wells in the vicinity of Sleipner comprise dominantly grey clay silts or silty clays, classified as non-organic mudshales and mudstones (Krushin, 1997). XRD-determined quartz contents suggest displacement pore throat diameters in the range 14–40 nm, consistent with capillary entry pressures of between about 2 and 5.5 MPa (Krushin, 1997). In addition, the predominant



10.4 (a) Caprock core from Sleipner. (b) Wireline logs from the cored well showing core position (mTVDss: total vertical depth, metres below sea-level).

clay fabric with limited grain support indicates an effective seal of the type capable of supporting a column of 35° API oil greater than 150 m in height (Sneider *et al.*, 1997).

A core sample was obtained from the caprock in 2002 (Fig. 10.4). The core material is typically a grey to dark grey silty mudstone, uncemented and quite plastic, and generally homogeneous with only weak indications of bedding. It contains occasional mica flakes, individual rock grains up to 3 mm in diameter and a few shell fragments. XRD-determined quartz contents suggest displacement pore throat diameters in the range 2.2–21 nm (Kemp *et al.*, 2002), similar values to those of the cuttings samples from other wells, and suggesting capillary entry pressures to dense phase CO_2 ranging from 3.4 to 37 MPa.

The core has been subjected to a number of laboratory procedures including geomechanical and flow transport testing. Long-term hydraulic and nitrogen gas transport testing (Harrington *et al.*, 2010) on the caprock core at reservoir P, T conditions, indicates porosities in the range 32–38%, intrinsic permeabilities ranging from 4×10^{-19} m^2 (~4×10^{-7} Darcy) vertical to 1×10^{-18} m^2 (~10^{-6} Darcy) horizontal, and a capillary entry pressure to nitrogen of around 3 MPa. A parallel study (Springer *et al.*, 2005) showed *in situ* porosity of ~35% and vertical intrinsic permeability in the range $7.5-15 \times 10^{-19}$ m^2 ($7.5 - 15 \times 10^{-7}$ Darcy), slightly higher than found by Harrington *et al.* (2010), but consistent with a lower clay content in the samples used in the second study. Capillary entry pressure was 3–3.5 MPa to both nitrogen and gaseous CO_2, and ~1.7 MPa to supercritical CO_2.

Induced adverse geomechanical effects on topseal integrity are unlikely. Injection overpressures seem to be very small (Chadwick *et al.*, 2012) and insufficient to induce either dilation of incipient fractures or microseismicity (Zweigel and Heill, 2003).

10.2.3 Thermal structure of the CO_2 plume

The CO_2 at Sleipner is injected in a dense phase. At the wellhead, temperature is thermostatically controlled to 25°C and pressures have been measured at between 6.2 and 6.6 MPa. No downhole measurements are taken, but bottomhole conditions can be estimated by solving the flow equations along the well. By assuming hydrostatic pressure (10.5 MPa) at the injection point, the corresponding temperature of the CO_2 stream is estimated at 48°C at the bottom of the hole. If reservoir pressure were to build up during injection the gas/fluid ratio in the wellbore would decrease, density would increase and this would tend to buffer any pressure increase at the wellhead. Induced temperature change in the reservoir would be minor.

In the reservoir, most of the injected CO_2 will be cooled down to the ambient reservoir temperature. However, with time a temperature perturbation will have developed, with the core part of the CO_2 plume gradually warming. Adiabatic expansion of CO_2 from the injection point up to top reservoir would give a CO_2 temperature of 36.6°C at the topseal. Such warm CO_2 would have a density of about 485 kgm^{-3} at the injection point, and about 425 kgm^{-3} at the reservoir top.

A rough estimate of the temperature distribution within the CO_2 plume can be obtained by assuming the temperature front is sharp (i.e. that the CO_2 and the rock matrix is either at initial reservoir temperature or at the higher temperature set by the injected CO_2). With a simple assumption of a cylindrical high-temperature region spanning the entire height of the CO_2 plume, a constant fraction of 7% of the CO_2 will be in the high-temperature state (Alnes *et al*., 2011). Densities of 'cold' CO_2 will be about 710 kg/m^3 at top reservoir and fairly similar at larger depths, and the warmer 'core' will then have considerably lower density and correspondingly higher buoyancy.

10.3 Monitoring: introduction and time-lapse 3D seismics

A varied time-lapse monitoring programme has been carried out at Sleipner. Its aims are twofold: first and foremost to track storage performance and assure continued storage integrity; second, via a number of scientific research projects, to test and refine monitoring tools and to improve understanding of CO_2 migration and trapping mechanisms in the storage reservoir.

10.3.1 Introduction

The monitoring is all non-invasive with a strong emphasis on deep-focused methods (Table 10.1). The very high time-lapse monitoring frequency for

Table 10.1 Monitoring at Sleipner

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

Note: (s): seismic survey, (g): gravity survey, (em): electromagnetic survey, Mt: million tonnes, TL: time-lapse.

some of the tools (notably 3D surface seismic) reflects this large research element. Basic operational monitoring requirements for CO_2 storage at Sleipner would be much more limited.

A number of key risks were identified prior to injection and the monitoring programme was designed to address these:

Migration through the caprock seal into the overburden: Migration through intact rocks is considered to be very unlikely given the high capillary entry pressures of water-saturated caprock strata (see above) and the lack of significant faulting. Monitoring strategy is to use the 4D seismic to track CO_2 migration in the reservoir and monitor for any changes in the overburden.

Migration into wellbores resulting in potential leak pathways to the seabed: This is considered unlikely in the short term due to the topography of the topseal which tends to keep the buoyantly trapped CO_2 away from the closer wells. The risk management strategy is to make predictive models of lateral spread of CO_2 with time and use 4D seismic to track CO_2 migration in the reservoir to identify developing situations with respect to the wells.

Migration of CO_2 outside of the Sleipner licence area: In the longer term this could impact on third-party wellbores and may also compromise future external activities (such as by making drilling through the Utsira reservoir more costly, or by blanking seismic signals beneath the plume). The risk management strategy is similar to the above, using predictive modelling and 4D seismic to track CO_2 migration in the reservoir to identify developing situations with respect to the licence boundary.

Generic public relations issues: Imperfect understanding of storage could result in inaccurate or poorly informed criticism of the project from external parties. The role of monitoring is to track site performance to demonstrate with a high degree of confidence what is happening in the subsurface and how storage processes are understood.

The monitoring programme at Sleipner is generally perceived to be a great success and is commonly cited as a good example of how to monitor an industrial-scale storage site. The key monitoring tool is 4D (time-lapse 3D) seismic which has proved spectacularly effective in tracking the plume, but other techniques have also been tested with varying degrees of success.

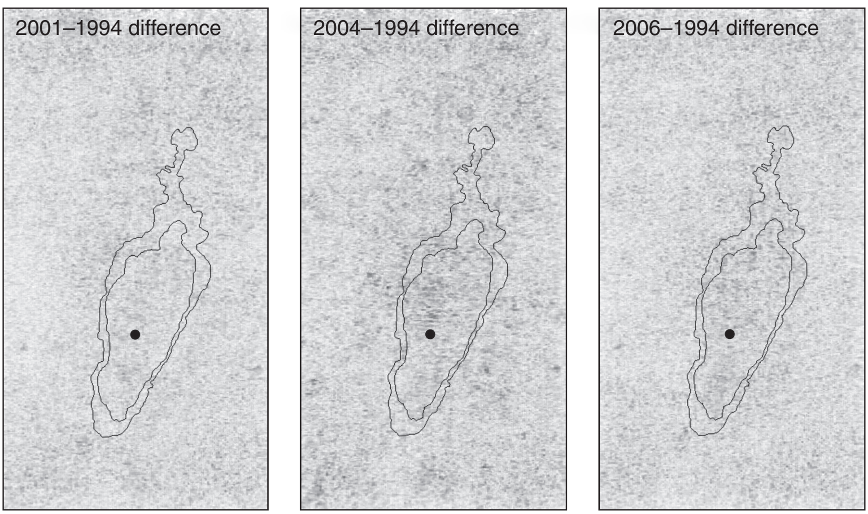
10.3.2 Time-lapse 3D seismic surveys

Imaging in the reservoir

Time-lapse surface 3D seismic surveys have been acquired in 1994 (baseline), 1999, 2001, 2002, 2004, 2006, 2008 and 2010. Details of the CO_2 distribution in the reservoir are clearly evident (see Plate VI in colour section between pages 214 and 215). In cross-section the CO_2 plume is seen to be roughly 200 m high and imaged as a number of bright sub-horizontal reflections within the reservoir, growing with time. These are interpreted as tuned wavelets arising from thin (mostly <8 m thick) layers of CO_2 trapped beneath the intra-reservoir mudstones and the reservoir caprock. The plume is elliptical in plan, with a major axis increasing to about 4500 m by 2010, accompanied by development of a prominent northerly extension since 2001. A strong velocity 'pushdown' is evident on reflectors beneath the plume and a vertical column of markedly reduced reflectivity, up to 80 m in diameter, forms a 'seismic chimney' roughly above the injection point (Chadwick *et al.*, 2004b).

Out-of-reservoir migration

In addition to imaging the CO_2 plume within the reservoir, a key objective of the time-lapse seismic is to indicate whether any migration of CO_2 into the caprock/overburden has been detected (in other words, whether CO_2 is being contained within the primary reservoir). The most straightforward way of assessing this is to use difference datasets, obtained by subtracting the baseline dataset from a repeat dataset, to reveal whether any systematic changes have occurred that may be indicative of CO_2 migration. Examples



10.5 Time-slice maps through successive difference cubes, located in the overburden immediately above the Utsira reservoir. The mottled signal is composed of repeatability noise which shows no systematic correlation with the spatial footprint of the CO_2 plume (black polygon shows the expanding outline of the plume from 2001 to 2006). The 2004 survey was acquired with ship lines perpendicular to the other surveys, acquisition geometries are completely different and the intrinsic mismatch is higher with more repeatability noise. Spot denotes position of injection point.

of difference time-slices in the overburden succession (Fig. 10.5) typically show a rather random difference signal with a characteristic mottled appearance. This difference signal, termed repeatability noise, is due to unavoidable mismatches between the baseline and the repeat survey.

Detection of CO_2 depends on being able to discriminate between the repeatability noise and real time-lapse changes due to CO_2. Detailed statistical analysis of this is ongoing, but it has been estimated that the Sleipner datasets can detect accumulations of CO_2 as small as 4000 m^3 (Chadwick, 2010). This corresponds to about 2800 t at the top of the reservoir but progressively less at shallower depths as CO_2 density decreases. The key strength of 3D seismic is the continuous and uniform coverage of the storage footprint, so the detection limit is robustly maintained across the survey area.

Predictive model calibration and verification

Early Sleipner work concentrated on history-matching flow simulations of whole plume development with the observed datasets (e.g. Van der Meer *et al.*, 2001; Lindeberg and Bergmo, 2003). A general match of plume development and flow simulations is readily obtainable, but a key uncertainty remains; that of how the CO_2 is transported through the intra-reservoir mudstones. One group of models assumes that the mudstones are semi-permeable, another group of models assumes that they are impermeable but with holes. Both groups of models are capable of reproducing the general morphology and rate of development of the plume.

For longer-term performance prediction the development of the upper plume is most relevant, in particular the topmost layer of CO_2 trapped directly beneath the caprock (Chadwick and Noy, 2010). The lateral spread of this topmost layer (see Plate VII in colour section between pages 214 and 215) is very clearly imaged on the 4D seismic and shows clear evidence of the buoyant infilling of top reservoir topography by the CO_2. Particularly prominent is a north-trending linear ridge in the topseal surface, along which the CO_2 front has advanced at a rate of about 1 m per day (see Plate VII).

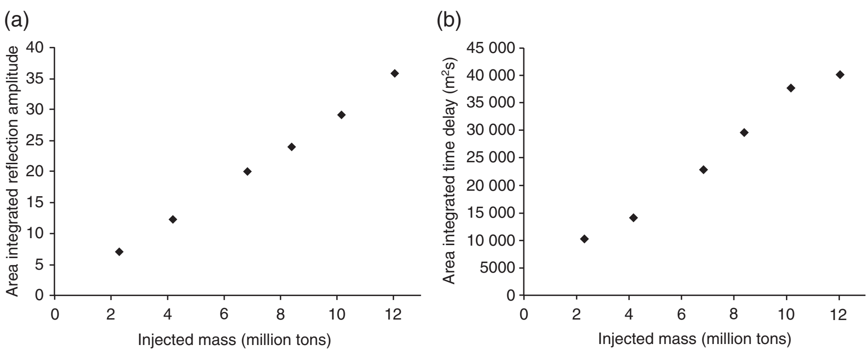
Detailed quantitative analysis of the layer has been used to develop numerical flow simulations to history-match with the observed seismic (see Plate VIII). There are significant issues with the history-matching, most notably the difficulty in modelling the very rapid northward migration of the plume between 2001 and 2006. The models shown here use lower densities and viscosities for the CO_2 than would be expected for pure CO_2 at ambient reservoir temperature. This might be explained by the central core of warmer CO_2 discussed above, perhaps 'fast-tracking' to the reservoir top, or by preferential accumulation of the minor, less dense, methane component at the reservoir top. Both would have the effect of significantly increasing the mobility of the plume fluid. Setting aside the uncertainties in CO_2 properties, the spatial mismatches are mostly quite small and are most likely caused by small errors in the depth imaging of the reservoir top topography (Chadwick and Noy, 2010).

Quantification

A significant amount of work has focused on quantitative analysis of the Sleipner datasets. Early papers concentrated on quantification of the plume reflectivity and velocity pushdown with the aim of independently verifying the measured injected amount of CO_2 (Arts *et al.*, 2004; Chadwick *et al.*, 2004b, 2005). A satisfactory match was obtained for the 1999 dataset, using a saturation model containing around 85% of the known injected CO_2 while maintaining a satisfactory match with the seismic data. On the other hand, significant volumes of low saturation CO_2 were required in the model which is difficult to reconcile with our understanding of multi-phase flow in the reservoir where low saturation CO_2 is expected to be virtually immobile.

Due to the uncertainties, a unique verification is very challenging, and it appears that the more recent Sleipner datasets are becoming more difficult to quantify. With time, reflectivity in the deeper plume is fading and velocity pushdown is becoming more difficult to map (see Plate VI in colour section between pages 214 and 215). These are partly seismic imaging effects arising from generally increasing CO_2 saturations within the plume envelope, but may also signify real and significant changes in CO_2 distribution in the deeper part of the plume.

Nevertheless some simple quantitative parameters can be measured and correlated with the injection history. Velocity pushdown time delays can be integrated over the whole spatial footprint of the plume, and reflection amplitudes



10.6 Reflection amplitudes for all layers (a), and area integrated pushdown (b), plotted against injected mass. Both measures show rather stable linearity with injection history.

can be summed for all layers. These are straightforward quantitative measures which can be plotted against the known injected mass (Fig. 10.6). Both show a remarkably linear relationship. This is surprising given the probable non-linear link between velocity and saturation from rock physics, the non-linear thickness-amplitude relationship arising from thin-layer tuning and attenuation shadowing of deeper layers. Some of these effects may counteract each other, but there certainly does appear to be a robust empirical relationship between the gross seismic response of the plume and the injection history.

In summary, it is clear that the 4D seismic provides a powerful time-lapse monitoring tool capable of imaging the CO_2 plume to a high level of detail, monitoring for evidence of out-of-reservoir migration and constraining and verifying predictive models. The complete areal coverage is also a key element, meaning that full and uniform spatial sampling of the reservoir and overburden is achieved.

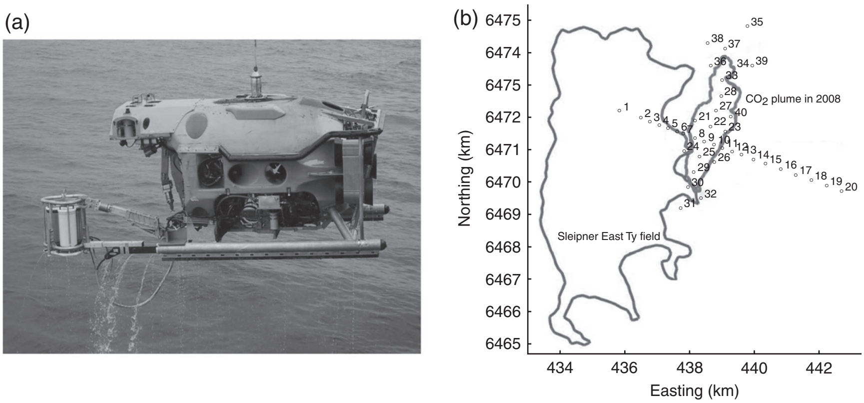
10.4 Other monitoring methods

In addition to the time-lapse 3D seismics, a number of other monitoring methods have proved to be of use in understanding storage processes and verifying performance.

10.4.1 Seabed gravimetry

An initial seabed gravity survey was acquired at Sleipner in 2002 with 5.19 Mt of CO_2 injected. Repeat surveys were then acquired in 2005 and 2009 with 7.74 Mt and 11.05 Mt of CO_2 injected respectively. The surveys used pre-positioned concrete benchmarks on the seafloor (see below) that served as reference locations for the (repeated) gravity measurements. Relative gravity and water pressure readings were taken at each benchmark by a customised gravimetry and pressure measurement module mounted on a remotely operated vehicle (ROV) (Fig. 10.7a). Benchmarks were deployed in two perpendicular lines overlapping the subsurface footprint of the CO_2 plume (Fig. 10.7b), additional stations being added in 2009 to allow for the increased plume area. Each benchmark was visited at least three times to better constrain instrument drift and other errors, resulting in a single station repeatability of about 2–4 μGal. For time-lapse measurements an additional uncertainty is associated with the relative measurements (arbitrary reference null level). Depending on which parameter to invert for, the final detection threshold for Sleipner ranges from less than 1 μGal (single parameter inversion) to 5 μGal (single station detection).

The gravimetric response of the additional CO_2 was obtained by calculating the time-lapse response from the Sleipner East field (the deeper



10.7 (a) Remotely operated vehicle (ROV) and seabed gravimeter deployed at Sleipner. (b) Location of the seabed benchmarks with respect to the 2008 CO_2 plume footprint.

gas reservoir currently in production) and removing this from the measured gravity changes since 2002. The first gravity analysis focused on constraining the *in situ* density of CO_2. Initial modelling of the 2005 dataset (Nooner *et al.*, 2007) concluded that the average CO_2 density in the plume was about 530 kgm^{-3}. One accuracy issue concerns the benchmarks which have experienced vertical movements of up to 15 cm relative to each other between the surveys. These could be caused by enhanced seafloor erosion or fish digging and sheltering beneath the benchmarks (as has been observed during measurement campaigns). More recent modelling, based on optimising several parameters simultaneously and with improved application of the various data corrections, including the changing benchmark elevations (Alnes *et al.*, 2008), gave a CO_2 density of about 760 kgm^{-3}.

The 2009 dataset, corresponding to a greater incremental mass of CO_2, should be more reliable and Alnes *et al.* (2011) obtained a best-fit CO_2 density of 720 ± 80 kgm^{-3}. These figures can be compared with the average CO_2 density of about 710 kgm^{-3} in the plume as calculated from temperature considerations (see above). With a warm core of the plume constituting 7% of the mass (as described above), calculated average density may reduce to about 675 ± 20 kgm^{-3} (Alnes *et al.*, 2011). This can be compared with the gravity-based estimates of density, and any discrepancy may be attributed to the amount of CO_2 dissolved. When CO_2 dissolves into the formation brine it loses most of its gravitational effect, so models which assume that all CO_2 is still in the free phase will tend to overestimate the true density. Neglecting small changes in brine density that occur when CO_2 dissolves, the dissolution effect is given by:

$$\rho_{\text{grav}} = \rho_{\text{actual}} \left(\frac{1}{1-\alpha} \right)$$

where ρ is the density and α is the mass fraction of CO_2 dissolved.

Alnes *et al*. (2011) looked at the full range of uncertainty in terms of the gravity modelling and also in the thermal calculation of plume density, and concluded that the upper bound on total dissolution is 0.18 (18%), with a most likely figure significantly less than this. Flow simulations of the plume development suggest that dissolution values up to around 10% are quite likely, so the gravimetry data seems to be in fair accordance with this. It is clear that provided tight spatial constraints on plume location and shape are available from the seismic data, the gravity changes at Sleipner between 2002 and 2009 can provide quite robust information on apparent CO_2 densities within the plume and from this, estimates of dissolved CO_2.

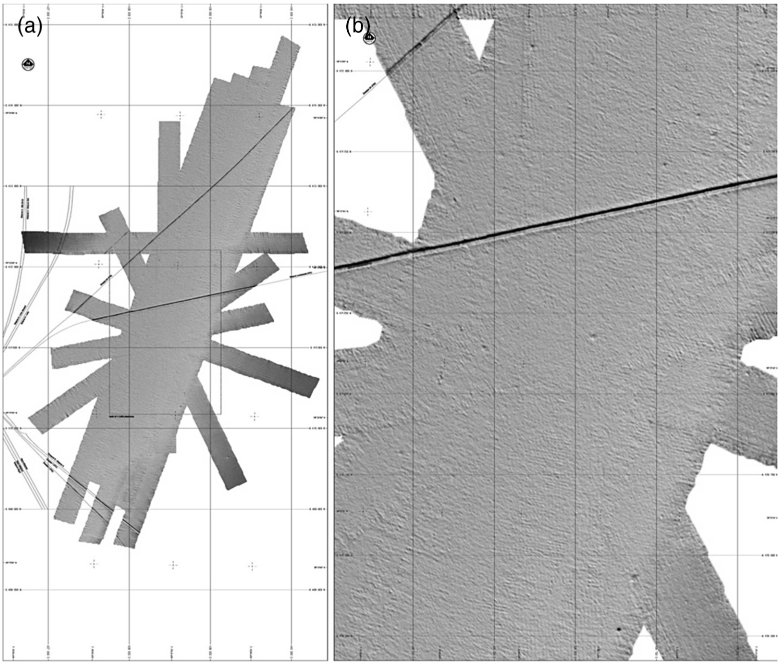
10.4.2 Seabed imaging

Seabed imaging surveys (sidescan sonar, single beam and multibeam echosounding and pinger seabottom profiler) were acquired at Sleipner in 2006. A digital seabed bathymetry terrain model with 2 m × 2 m sampling was made from the multibeam echosounding (Fig. 10.8) showing the seafloor dipping gently from 80.8 m depth in the east to 83.0 m in the west. A mosaic was also composed from the sidescan sonar data (Fig. 10.9), which has higher resolution of seafloor features. Both mapping techniques were able to detect the six pipelines passing through the area, while the sidescan data also picked up the gravimetry benchmarks (about 1.5 m in diameter and 0.3 m in height). A number of linear features observed in the sidescan data are interpreted as anchor scars. No environmentally sensitive habitats have been identified, and no evidence of gas seepage was detected.

10.4.3 Seabed remotely operated vehicle (ROV) video

Comprehensive video footage has been taken from the remotely operated vehicle (ROV) used to deploy the gravity meter. In each of the 2002, 2005 and 2009 surveys the ROV transmitted from the seafloor continuously for a period of 3–4 days.

During the ROV survey, pilots maintained careful observation through the video cameras, and no seafloor bubble-streams were observed. Normal seabed conditions were encountered, with typical flora and fauna (Fig. 10.10). The data have not been analysed in systematic detail, but video records from 2009 have been stored for future availability.



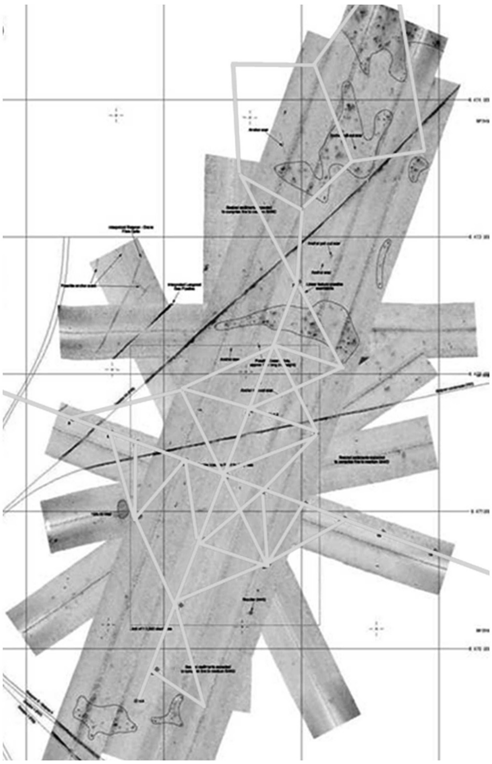
10.8 Multibeam echosounding image of the seafloor above Sleipner: (a) whole survey; (b) zooming in on the area above the injection point, showing small seabed features (note prominent linear pipelines).

10.4.4 Other surveys

In addition to the 3D seismic surveys discussed above, a high resolution 2D survey was acquired in 2006. This used a low-cost site survey vessel and results were very good. Improved resolution was obtained in the upper plume, at the expense of reduced signal penetration in the lower plume. Interpretation and analysis of the high resolution data is continuing.

Feasibility studies for Controlled Source Electromagnetic Sounding (CSEM) indicated that a resistivity anomaly should be detected from the Sleipner plume (Norman *et al.*, 2008), so a trial CSEM line was acquired in September 2008. The profile aligns with the long axis of the CO_2 plume as mapped on seismic data (Fig. 10.11). The receiver line was 9.5 km long, with twenty receivers deployed at 20 different locations. Station spacing was 500 m, and in addition seven locations had an extra receiver deployed 50 m away from the other. The source line was an extra 10 km to each side, and was towed two times with varying frequency spectra.

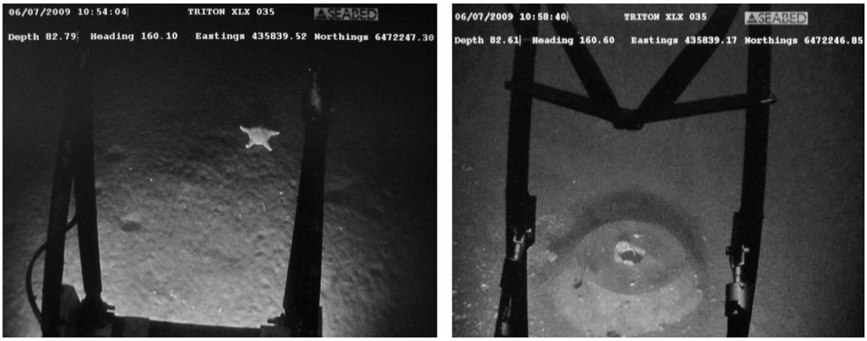
Analysis of the data has proved to be challenging. The shallow water depth gives strong air waves, and the nine pipelines crossing the survey



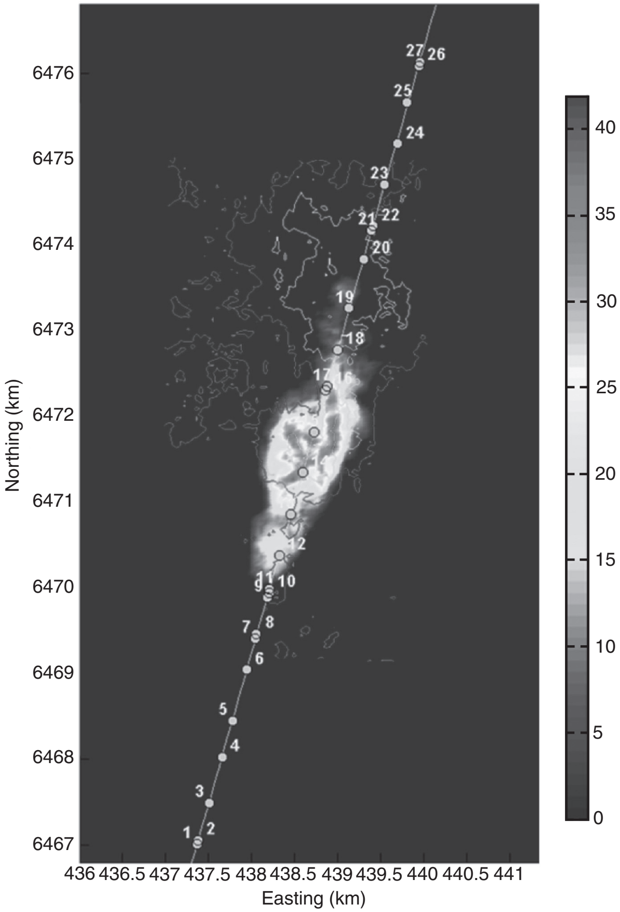
10.9 Sidescan sonar data with ROV (video) tracks in 2009 superimposed (light grey).

profile further contaminate the data. It has been difficult to see clear anomalies from the plume area, however the latest results from a number of workers indicate there may be a detectable resistivity increase corresponding to the volume occupied by the plume. Analysis of these datasets is continuing.

A rather novel biomarkers study is also in progress. The object is to study the effects of higher than normal levels of CO_2 on marine invertebrates and the adaptations and mechanisms these animals possess to withstand the acidifying effects of CO_2 in water. The research in this project involves exposing typical Sleipner crustaceans to elevated seawater/CO_2 levels and measuring changes in their ion regulating tissues by means of histochemistry, Western Blotting, PCR and enzyme activity analysis. The study has possible value for monitoring, in that changes in the seabed fauna may provide very early evidence of CO_2 leakage at seabed.



10.10 Images extracted from the ROV video, showing a starfish and one of the concrete gravimetry benchmarks on the seabed.



10.11 Map showing position of CSEM line and cumulative CO_2 plume layer thickness (m) estimated from seismic data. Contours show top Utsira Sand at 792 and 800 m below sea level.

10.5 Monitoring in the context of the EU regulatory regime

Because Sleipner injection commenced in 1996 it is not covered by the recently developed European CCS regulations. It is nevertheless instructive to assess the extent to which the current monitoring programme meets the regulatory requirements.

There are three main elements to current storage regulation in Europe: the European Directive on storage, for offshore storage the OSPAR Convention, and the European Emissions Trading System (ETS). Sleipner can reasonably be placed in the context of all three.

10.5.1 OSPAR and the European Directive on storage

The OSPAR Convention is concerned with protecting the marine environment in the NE Atlantic. A CCS amendment to OSPAR was published in June 2007 and is still in the process of ratification by partner nations. CCS requirements under OSPAR are focused around robust site selection and characterisation, risk assessment and management, environmental exposure and impacts. Monitoring is a key OSPAR requirement. It should be carried out throughout a project, must be linked to the risk assessment and focus on specific issues including performance verification, leakage monitoring, monitoring local environmental impacts and demonstration of emissions reduction efficacy.

The European Directive on storage was published in April 2009 and builds upon many of the OSPAR principles. Monitoring is a key requirement and is framed around enabling the operator to understand and to demonstrate understanding of current site processes, to identify any leakages and to predict future site behaviour. Further requirements of the monitoring include early identification of deviations from predicted site behaviour, provision of information needed to carry out remediation actions and the ability to progressively reduce uncertainty. In other words monitoring should effectively underpin the project risk management plan.

The current monitoring plan at Sleipner meets many of these objectives. In terms of understanding current site processes, explaining plume development is beset by some uncertainties, notably transport of CO_2 through the thin intra-reservoir mudstones, but in general terms the physics seems to be satisfactorily understood. Migration of the topmost CO_2 layers is crucial to predicting plume development in the medium term, in particular lateral migration of the plume in the upper reservoir. As discussed above, mismatches between observed and simulated behaviour are most likely down to small uncertainties in the geological model rather than to misinterpretation of the controlling processes (see Plate VIII in colour section between pages 214 and 215). This supports the contention that current site behaviour is, to all intents and purposes, well understood. This level of understanding further supports the reliability of longer-term predictive modelling. No systematic leakage monitoring is currently deployed at Sleipner. The current 3D seismic provides full and uniform volumetric coverage of the overburden, but the lack of observed changes, and the robust geological characterisation of the caprock, taken together provide a strong case for no leakage. The seabed imaging surveys and underwater video further support this.

Perhaps the most challenging elements of the current regulations are the arrangements for site closure, that is, transfer of liability from the operator to the state.

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

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

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

For Sleipner the key stabilisation process is dissolution of free CO_2 into the reservoir pore-waters (summarised in Chadwick *et al.*, 2008). The current non-invasive monitoring programme is unable to verify this process directly, as dissolved CO_2 is invisible on seismic. However the time-lapse gravimetry, as discussed above, might be able to provide some constraints.

10.5.2 Emissions accounting under the EU ETS

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

10.6 Future trends

Sleipner provides a superb field-scale laboratory for the study of CO_2 storage in saline aquifers. So far we have witnessed sixteen years of uniform injection and have obtained detailed time-lapse images of the growing CO_2 plume. The research described here concentrates on an interpretative approach whereby detailed mapping of reflectivity and time-shifts in the CO_2 plume have been used to build detailed assessments of layer growth. These results have been history-matched against flow simulations at a range of scales to understand more about flow and storage processes in the reservoir. More sophisticated seismic geophysics has also been deployed to determine elastic reservoir properties from the seismic signatures. In particular the pre-stack data have been analysed to see if additional information can be derived from the seismic raypaths at higher incidence angles. A number of approaches have been tried, mainly within the CO2ReMoVe project (www.co2remove.eu). These include model-based pre- and post-stack inversion (Clochard *et al.*, 2010), constrained AVO, common-focus-point imaging, spectral decomposition and velocity-attenuation tomography, and are summarised in Chadwick *et al.* (2010) and references therein. It is perhaps fair to say that the efficacy of many of these purely seismic techniques is limited by the strong thin-layer tuning effects which tend to swamp the more subtle reflectivity changes on both pre- and post-stack data. Recent work on attenuation and velocity dispersion (Rubino *et al.*, 2011) has the potential to reveal some details on CO_2 distribution, and at what scales it mixes with the reservoir brine, providing the promise of improved quantitative analysis. Spectral decomposition and spectral inversion also show promise, whereby frequency tuning can provide additional constraints on CO_2 layer thicknesses. Work is ongoing in many of these areas.

The shallow monitoring programme at Sleipner has until fairly recently been rudimentary. Much more comprehensive shallow monitoring is likely to be a requirement for future storage sites, with a strong focus on acquiring robust baseline datasets. Main advances are likely to be in the field of emissions detection and measurement, both at the seabed and in the water column. Remotely operated and autonomous underwater vehicles (ROVs and AUVs) are likely to play a key role in obtaining detailed shallow-focused data and this type of work is now being carried out at Sleipner by current European research projects.

Looking further ahead, when injection at Sleipner finally ceases, there will be an opportunity for post-injection monitoring of an industrial-scale site. Such an invaluable opportunity should not be missed as it is likely that fundamental insights into post-injection plume development (e.g. spatial stabilisation) will be gained. In the event that some form of monitoring (e.g. geophones, downhole gravimetry, fluid sampling) could be placed down the injection well (beneath the plume) it might also be possible to quantify key stabilisation processes such as dissolution.

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

10.7 Acknowledgement

This contribution is published with permission of the Executive Director, British Geological Survey (NERC).

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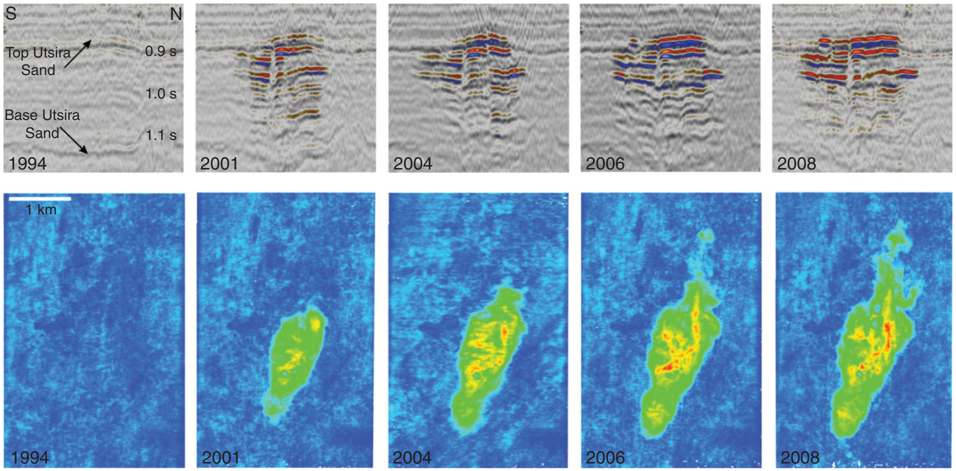

Plate VI (Chapter 10) Time-lapse images of the CO_2 plume at Sleipner. (a) N–S inline through the plume. (b) Map of total plume reflectivity. Note the strong velocity pushdown of reflectors beneath the plume and a vertical 'chimney' of reduced reflectivity prominent on the inline.

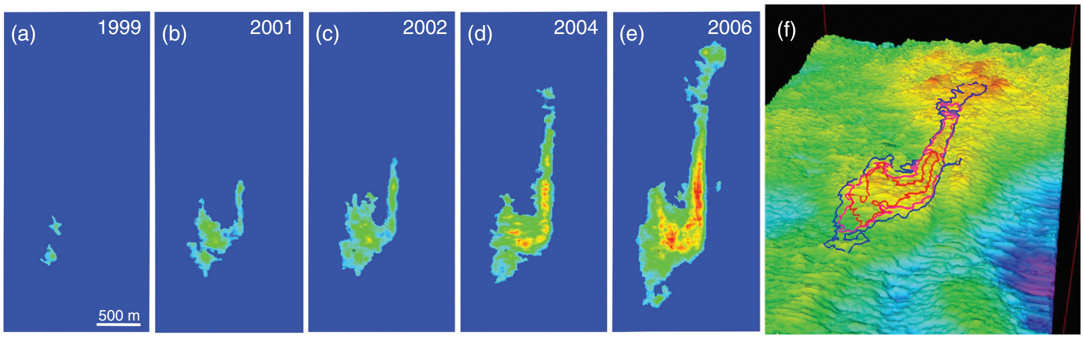

Plate VII (Chapter 10) Growth of the topmost CO_2 layer at Sleipner. (a)–(e) Plan views of the layer spreading from 1999 to 2006. (f) Perspective view of the topography of the top reservoir, showing the CO_2–water contacts in 2001 (red), 2004 (purple) and 2006 (blue). Note the north-trending tongue of CO_2 corresponding to spilling along a linear topographic ridge.

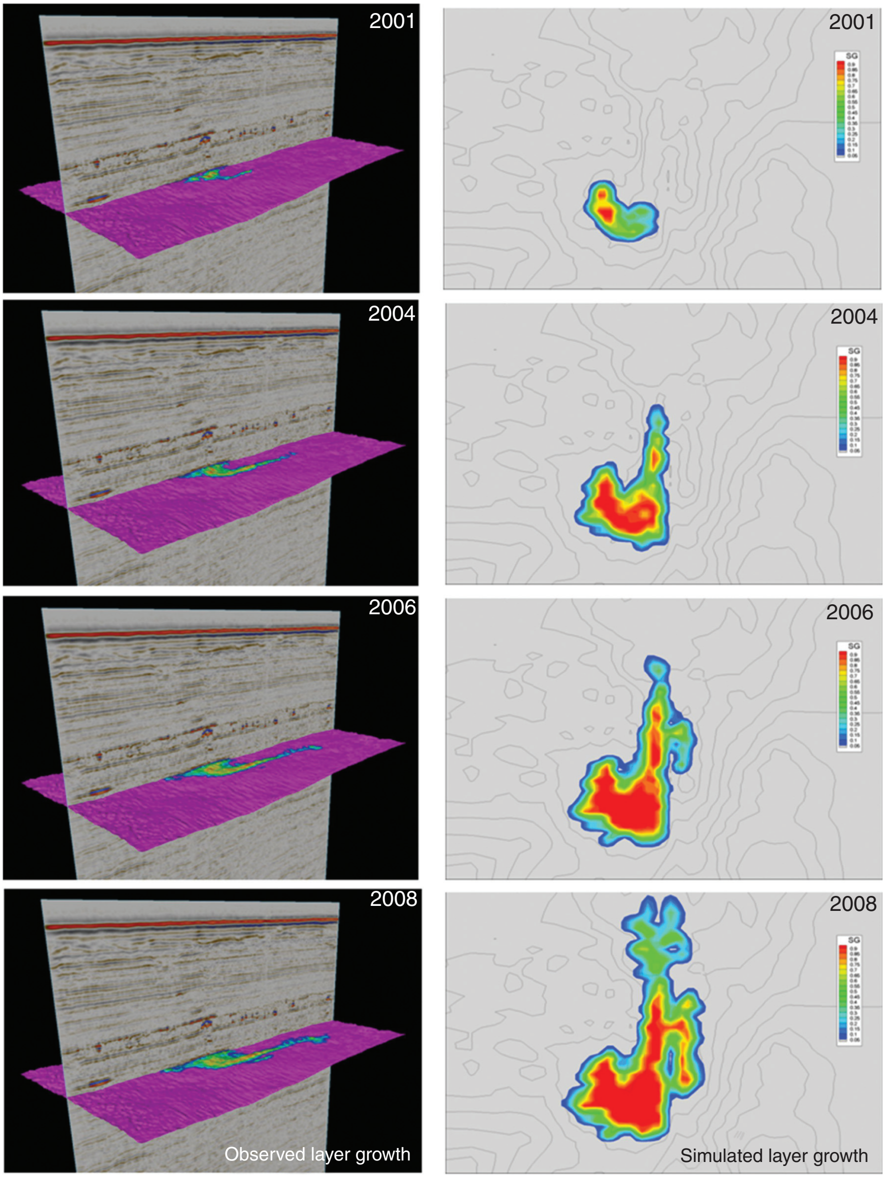

Plate VIII (Chapter 10) Topmost CO_2 layer growth showing observed images in perspective view (left) and flow simulations assuming very mobile CO_2 in plain view (right).

11
The CO2CRC Otway Project in Australia

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Abstract: The CO2CRC Otway Project, is Australia's first demonstration of geological storage of CO_2. During 2008–2009 approximately 65 000 t of 80/20 CO_2 and methane were injected into a depleted gas field at a depth of approximately 2000 m. An extensive programme of monitoring was put in place of the Waarre Sandstone reservoir and the overlying intervals such as aquifers, soils and the atmosphere. It proved difficult to use 3D seismic to monitor CO_2 behaviour in the depleted gas field because of the presence of residual methane, but U-tube sampling provided important insights into the speed of migration of CO_2 within the reservoir and associated geochemical changes. Extrapolation of Otway results to depleted gas fields suggests they could be a major storage opportunity. A new programme of carbon capture and storage research at the site is being done, with a range of innovative experiments, further advancing knowledge of CO_2 storage.

Key words: Otway, Waarre, monitoring and verification, seismic, depleted gas field.

11.1 Introduction

Marchetti (1976) first suggested engineered ocean sequestration of carbon dioxide, but the concept of geologically storing carbon dioxide, or carbon capture and storage (CCS) as it is now known, was first mooted as a possible technique for decreasing anthropogenic emissions from major stationary emission sources around 1990. In the ensuing 20 years, the idea has gained traction as concerns have increased regarding human induced climate change (IPCC, 2005; Benson *et al*., 2012). Yet at the same time, its deployment has not proceeded at anything like the speed required to counter the environmental impact of ever-increasing use of fossil fuels, particularly for electricity production and industrial processing. The developing world in particular has massively increased its use of coal, with every indication that this trend is likely for some years to come. In developed countries there is likely to be increasing use of natural gas, which will slow the increase in emissions somewhat, but it will not remove the need for CCS. In addition there are a number of industrial processes, such as iron- and steel-making, that are highly dependent on coal as a reducing agent as well as an energy source. Indeed, for as long as we continue to use fossil fuels, the only technology we have for diminishing the consequences of that use, is CCS (Cook, 2012).

Why then has the uptake of CCS been so slow? There are several reasons: First and perhaps foremost, because there is little (and in many countries no) economic incentive to produce cleaner (but inevitably more expensive) electricity using CCS. Second and closely related is the fact that CCS is regarded as expensive, though the question has to be asked 'compared with what?' The reality is that all technologies for producing low (or no) emission electricity are more expensive than conventional production of electricity using fossil fuels. Clearly there is a need for more research, development and large-scale deployment to bring down the cost of CCS. However, there is a third inhibitor to CCS uptake and that relates to the question of acceptability of CCS by the community, which almost invariably focuses on the question of geological storage of CO_2.

There are a number of storage projects under way at the present time. Because of cost and the lack of policy or economic drivers, for the moment, the only large-scale storage activities under way relate to oil or gas activities rather than to power generation. Of the order of 50 Mt of CO_2 is currently injected as part of enhanced oil recovery (EOR) operations, with more than 100 CO_2-EOR projects currently active, among the largest of which is the Weyburn Project in Saskatchewan. In addition, CO_2 is injected as part of acid gas disposal operations, particularly in western Canada. While there are some notable exceptions such as Weyburn and Cranfield, most of these EOR projects do not monitor the behaviour of CO_2 or how much of the injected CO_2 is stored.

There are currently only a limited number of projects which are injecting CO_2 solely for storage: the Sleipner and Snøhvit Projects in Norway and the In Salah Project in Algeria, which together inject about 4 Mt of CO_2 per annum (Michael *et al.*, 2009). In 2015, this will almost double when the Gorgon Project commences storage of 3–4 Mt of CO_2 under Barrow Island, Western Australia. However, this does not necessarily translate into community acceptance of any CCS operation, not least because most of the existing operations are under way in remote areas, far from major centres of population. Many are conducted under conditions of commercial confidentiality, and very few of them have the rigorous monitoring regime that will be essential if the public at large is to be convinced that geological storage is safe and secure, and effective for thousands of years and longer.

While a number of large, successful, comprehensively monitored CCS projects would provide the basis for widespread community acceptance of CCS, projects may not happen if there is strong local or national opposition to the technology in the first instance. Indeed if there is no acceptance at the start, then projects are unlikely to get under way. In other words, CCS could end up in a 'chicken–egg' situation if we are not careful! It is partly for this reason that a number of small- to medium-scale pilot and demonstration storage projects have been developed or proposed in the USA, Canada, Western Europe, South Africa, China, Japan and Australia, although few of these have as yet been completed. A number of benefits can accrue from such projects, most notably the opportunity to inform the local community (Ashworth *et al.*, 2010), and the community at large about CCS and especially storage, through a real-world storage example at a relatively modest cost (say $20–100 million) compared with a full-scale project (say $2 billion plus). The other benefits can include:

- A low-cost, on-the-job learning opportunity for technicians, engineers, scientists and managers.
- Able to decrease technical uncertainty and risk prior to embarking on a large-scale project.
- Able to test equipment (and boundaries) at a modest scale, in a way that could not be contemplated for a large-scale project.
- Encounter (and overcome) real-world problems such as maintaining CO_2 injectivity, ensuring there is no formation of CO_2 hydrates, handling contaminants, testing for brittleness in pipes and running compressors under multiphase conditions.
- Able to test monitoring options under operational conditions and assess the practicality of the various techniques as well as develop new techniques.
- If being pursued through an industry partnership, it provides a real-world working relationship for the partners.
- Tests legal and other agreements in a relatively benign atmosphere where there is not a lot of money at stake.
- Provides impetus to regulators to confront some of the regulatory issues when there is a real project (even if small to medium sized).
- Exposed to working with a real community and understanding how to communicate with and listen to the community.
- Provides something for politicians, bureaucrats and community leaders to visit and understand.
- Provides tangible evidence that CCS is moving ahead, despite the slow pace of progress on large-scale projects.

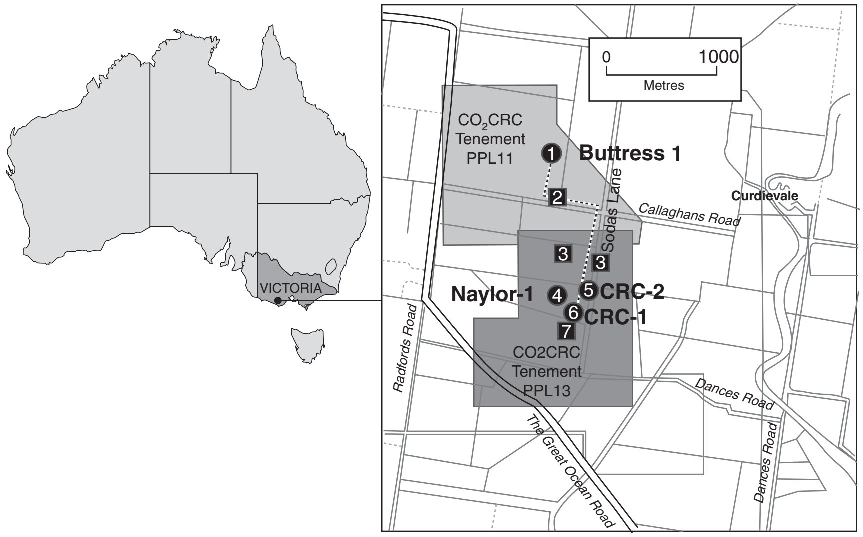
With these benefits in mind, CO2CRC decided it was important to undertake a pilot or demonstration storage project in Australia.

11.2 Developing Australia's first storage project

In Australia, research into CCS got under way in the late 1990s (Cook, 1999, 2009), initially through the Australian Petroleum Cooperative Research Centre and the Program for the GEOlogical DISposal of CO_2 (GEODISC; Cook *et al.*, 2000).The GEODISC programme was highly successful over the ensuing 4 years; it developed a body of CCS expertise in Australia and showed that geological storage was indeed a potentially very important mitigation option for Australia. It also provided the platform for the establishment of the Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC) in 2003, one of the world's largest and most comprehensive programmes of collaborative CCS research. A key element in the establishment of CO2CRC was to undertake a pilot storage project with a strong preference for storage of the order of 50–100 000 t of CO_2, which was deemed to be commercially significant. By this stage (2003), the CO2CRC was able to benefit in its planning, from the experience derived from the small-scale Frio Brine Project in the United States (Hovorka *et al.*, 2006) and Nagaoka Project in Japan (Saito *et al.*, 2006), as well as the large-scale Sleipner and Weyburn Projects (Wilson and Monea, 2004). While it was self evident that any storage project had to have the right sort of geology, it was apparent that this was likely to be easier to locate than a low-cost source of CO_2. Therefore, the starting point for the planning was not 'where is the best geology', but 'where is the best source of CO_2'. It was very soon obvious that capturing the CO_2, from a conventional power station as the source, at the scale required, was unlikely to be feasible for at least a decade. The only realistic source for a pilot or demonstration project in Australia that could be under way in 5 years or less was an industrial process such as a gas separation plant or a fertiliser plant, or a geological source. Food grade CO_2 using a geological source (resulting from a period of volcanism approximately 50 000 years ago), was commercially available in the southern part of the continent in the Otway Basin, but at a cost of several hundred dollars a tonne, which would make the cost of a relatively large-scale injection at the scale contemplated, too high.

However, in 2003–2004 a petroleum company commenced selling off its Otway Basin assets, including a number of depleted gas fields and an unproduced gas field high in CO_2. The CO_2 field, known as Buttress, was located in a dairy farming area in the western part of the Otway Basin in Western Victoria, near the small settlement of Nirranda and approximately 20 km from the Port Campbell National Park (Fig. 11.1).

Buttress was believed at that stage to have a gas composition of the order of 90% CO_2 by weight (subsequently found to be 75–80%) and of the order of 100 000 t of CO_2-rich gas (subsequently found to be of the order of 250 000 t at the P50 level). It was also close to a number of small depleted gas fields, which were geologically well described, with 3D seismic already



11.1 Location of the CO2CRC Otway Project in south west Victoria. The petroleum tenement boundaries are also shown. Numbered facilities are as follows. (1) Buttress well and site of CO_2 production and compression. (2) CO_2 transport via pipeline. (3) Atmospheric, near surface and soil monitoring. (4) Naylor well used for downhole monitoring. (5) CRC-2 well used for CO_2 injection in Stage 2. (6) Visitor's Centre and control centre. (7) CRC-1 well for CO_2 injection in Stage 1.

in existence and which were demonstrably likely to be suitable for storage, having previously held natural gas. The area also had a number of other advantages: it was in an accessible area (a 3 hour drive from Melbourne); there was an active oil and gas industry in the area (therefore support services were available); and the area was populated (meaning that there was both the opportunity and the need to develop a real programme of community engagement). In other words the area had some significant positive features, including of course an existing source of CO_2 and several known storage opportunities – and it was potentially available. Negotiations to purchase the petroleum licences that covered the Buttress CO_2 field (PPL 11) and the Naylor depleted gas field (PPL 13) were successfully concluded in 2005. However, planning had continued prior to that, on the assumption that negotiations would be successfully concluded. In particular, an early start was made with community consultation as it was recognised that if we did not get the local community onside very early in the planning phase, it would be very difficult to proceed.

The other area where extensive preliminary work was necessary was in developing the appropriate corporate structure to take the project forward. At that time, CO2CRC was an unincorporated joint venture of resource and power companies, state instrumentalities, research bodies and universities, with totally different approaches and tolerances to risk. There existed an incorporated entity CO2CRC Management Pty Ltd, which was used as the vehicle to employ staff and receive and disburse research funds, but was not suitable for management of a major storage project. Nor was the commercialisation entity CO2CRC Technologies appropriate, although both these companies were ultimately drawn into aspects of the Project structure. However, the key element was the decision to set up a limited liability company, CO2CRC Pilot Project Ltd, composed of ten companies, members of CO2CRC, who each agreed to hold 10% of any residual liability that might arise from the project. This structure worked throughout Stage 1 of the Project, but was modified (and simplified) to meet the needs of Stage 2 and of CO2CRC research more broadly.

A further area of early uncertainty arose from the lack of a regulatory regime for CO_2 storage in the state of Victoria, or indeed any state in the Commonwealth of Australia at that time. The initial Otway tenements were held under the petroleum regulations and allowed for the production of CO_2, but carried no rights to inject CO_2. In addition, a number of other regulations impacted on the feasibility of the project to varying degrees (Sharma *et al.*, 2007). As a consequence it was necessary and appropriate to work closely with the various regulatory bodies to enable the project to proceed. The key element in making it possible for storage to go ahead was the agreement by the regulators to extend existing R&D regulations of the Environmental Protection Authority, to cover the injection and storage of CO_2.

There was one other element of uncertainty remaining, namely the funding. CO2CRC had funding for 'normal research' in its original budget, but did not at that stage have the level of funding (estimated to be around \$20 million initially, but ultimately around \$40 million) for a major field operation which included deep drilling, logging, etc. In other words it was necessary to run a commercial-scale operation at the scale of a small oil company in order to undertake the research. Without going into the details, some funding was assembled from industry and government by CO2CRC to take the first steps forward, recognising that it would require additional funding as the project proceeded, without any certainty of that source. It was then possible to obtain further funding through 'gearing'. In other words an element of financial risk was involved in that it might not be possible to raise those additional funds, though in the event, the additional funding was raised in Australia from the Federal and State Governments, from industry and from international collaborators.

With a workable corporate structure for managing risk and indemnity, a practical way forward for licensing an injection and storage operation, with all the necessary assets owned by CO2CRC, and with sufficient funds to start construction, backed by confidence that we would be able to obtain the necessary additional funds, the decision was made to proceed with the CO2CRC Otway Project.

11.3 Constructing the CO2CRC Otway Project

11.3.1 The source of CO_2

The Buttress structure was known to contain high CO_2 natural gas, sourced in the Waarre Formation at a depth of about 1600 m, but the gas had never been produced, the gas reserves were uncertain and the gas composition was not known with any accuracy. Therefore as a first step it was necessary to address all these gaps in our knowledge by running a production test using the existing Buttress No. 1 well and sampling the produced gas. Compositionally the CO_2 content by molar weight was found to be somewhat lower than anticipated (75% CO_2, 21% CH_4 and 4% other components – mostly heavy hydrocarbons), but adequate as a source of CO_2, and as expected, the isotopic composition of the CO_2 showed that it was of volcanic origin (Boreham *et al.*, 2011). The production test showed that there was at least 95 000 t of CO_2-rich gas, which was seen as sufficient to carry out the project at the required scale of up to 100 000 t. The Buttress gas was supercritical when produced, which meant that compression costs could be minimised, at least initially.

The option of separating out the CO_2 from the methane was investigated in some detail for the Project by the Process Group. While technically feasible, it finally concluded that it would be too expensive to proceed with this option. In addition it was also concluded that co-injection of the CO_2 with the CH_4 was not going to materially affect the results, compared with injecting pure CO_2 as the reservoir conditions were likely to be in the supercritical field for both gases and there was known to be residual methane in the depleted gas field. Therefore the decision was made to proceed with a relatively simple process (Fig. 11.2) to remove free liquids from the gas, using a system involving the knock out and direct compression of the vapour leaving the inlet slug catcher (Dugan, per comm). Because the system did not remove all of the water in the gas, it was necessary to have some components made of stainless steel, to carefully monitor the pressure and temperature conditions to ensure that CO_2 hydrates did not form, and to use a multistage reciprocating compressor.

In the event, after some early teething problems, this system worked well (Fig. 11.2). The main complication was that heavy waxes in the gas clogged up some of the pipes initially, but this problem was soon recognised and a regime put in place for routinely removing the waxes.

11.2 Buttress facilities for production, processing and compression of CO_2. (Photograph courtesy of Process Group.)

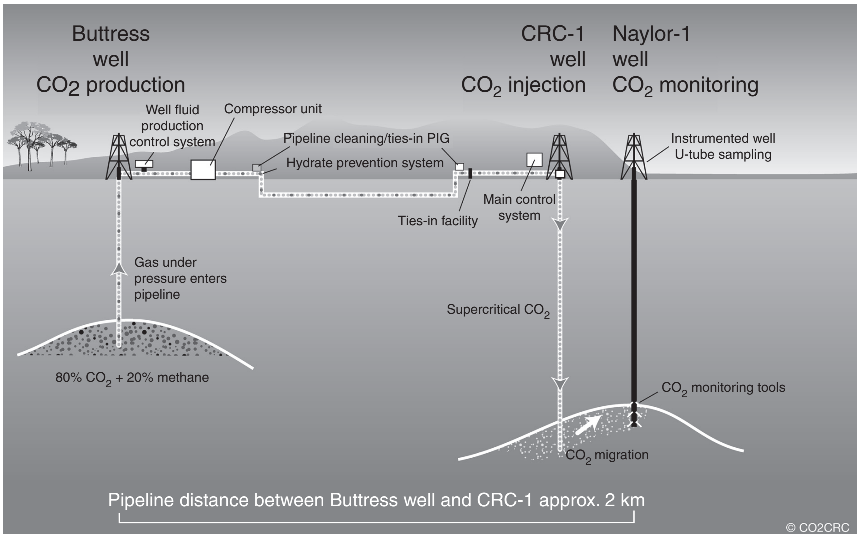
11.3.2 Transporting the CO_2

From the start of planning for the project, it was anticipated that the CO_2 would be transported by pipeline. The Buttress well (source of the CO_2) was located a kilometre north of the proposed injection site (Fig. 11.1), but as a result of the need to follow easements, paddock boundaries and tracks, the total length of the pipeline was approximately 1.4 km. Because of the potential presence of water in the gas, in order to minimise any corrosion it was decided to use a stainless steel pipeline. This added to the cost but greatly decreased the risk of corrosion. In addition, for security purposes and to assist with temperature control during transport, in order to avoid the formation of hydrates within the pipe, the pipeline was buried to a depth of approximately one metre. In one area where it was necessary to cross a water course, the depth was greater to ensure that the pipeline was well below the creek bed. The other precaution that was taken to avoid hydrate formation was to ensure that the gas was maintained at a temperature above that at which hydrates would form. It was anticipated that this would require that the gas was preheated, but in fact it was found that the heating of the gas due to the compression process was sufficient to maintain the temperature above the critical point.

In all, the system for delivery of the CO_2-rich gas to the injection site (Fig. 11.3) worked well throughout the Project and no major problems were encountered.

11.3.3 The injection site

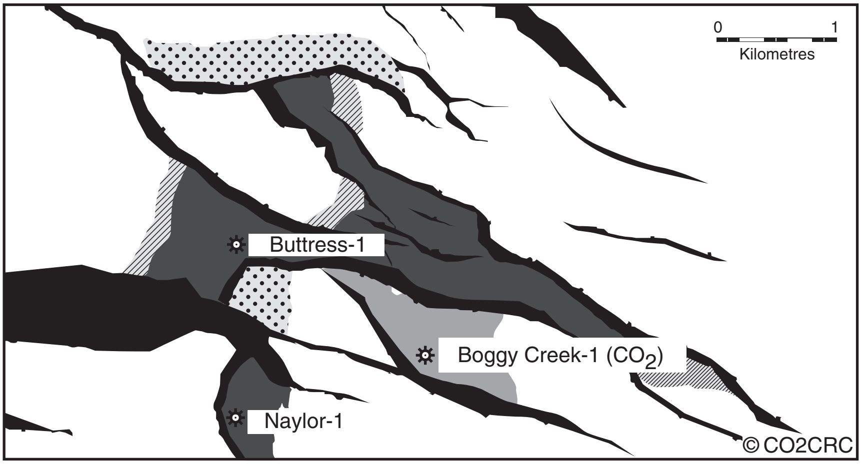
There were two related factors influencing the choice of the injection/storage site. The first was of course the location and subsurface extent of the depleted gas field and the second was the location of the existing Naylor-1



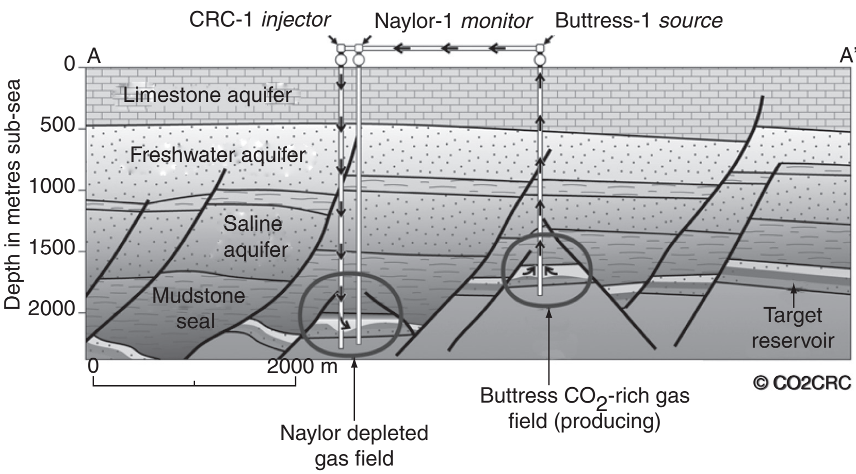
11.3 Schematic diagram to show the general layout of the CO2CRC Otway Project and its production, compression, transport and storage facilities. PIG, pipeline inspection gauge.

well (previously a gas production well) which was to be used as a monitoring well. It was very important to position the proposed injection well (CRC-1) so that the plume of CO_2 could be monitored at Naylor, and that the plume did not extend beyond the lease area held by CO2CRC (Fig. 11.1). It was also important to ensure that the Naylor structure was not overfilled and that injected CO_2 did not reach a small fault on the margins of the depleted gas field. The area around the project has numerous sealing faults (Figs 11.4 and 11.5), but they were unlikely to be active or transmissive. Nonetheless it was important to minimise the likelihood of the CO_2 reaching the fault plane.

The availability of gas production data was valuable in forecasting the likely behaviour of CO_2 in the reservoir (Fig. 11.6). However, it was recognised that even a single previously unrecognised heterogeneity could have a major unanticipated impact on CO_2 behaviour (Ennis-King *et al*., 2011). Therefore an early priority was to drill a well, CRC-1, to obtain core from the preferred reservoir, the Waarre C Formation. This was coarse sandstone from which natural gas was previously produced in the Port Campbell Embayment (Buffin, 1989). A number of preliminary depositional models were developed in order to position CRC-1 so that it would not only provide crucial information for geological characterisation of the site, but also be suitable as an injection well (Spencer and La Pedalina, 2006).The well was drilled to a depth of 2249 m in February–March 2007 and provided

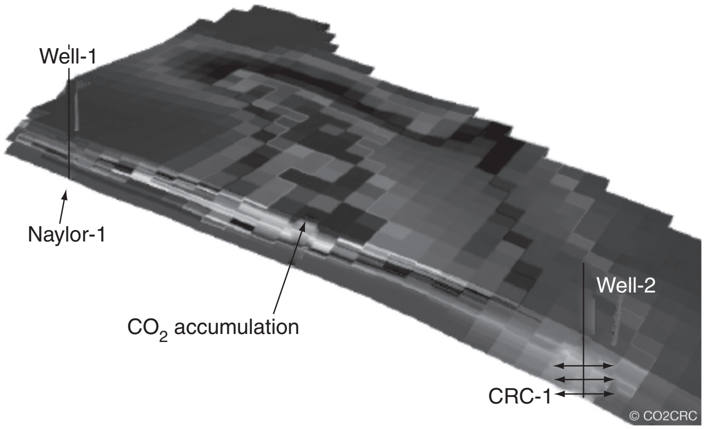


11.4 The area around the Otway site has many sealing faults, shown here on this structural map, which divide the basin into a number of compartments represented by various grey shades, with little or no hydrodynamic conductivity.



11.5 Cross section showing the compartmentised nature of the Otway Basin. The CO_2 production well and gas field is in a quite separate fault block to the depleted gas field used for the storage project.

high quality geological information on the stratigraphy of the site (Fig. 11.7) including core which could then be used for a range of tests (Daniel, 2007; Berard *et al.*, 2008; Perrin and Benson, 2010). This and other information was used by Dance *et al.* (2009), to develop the comprehensive static model for

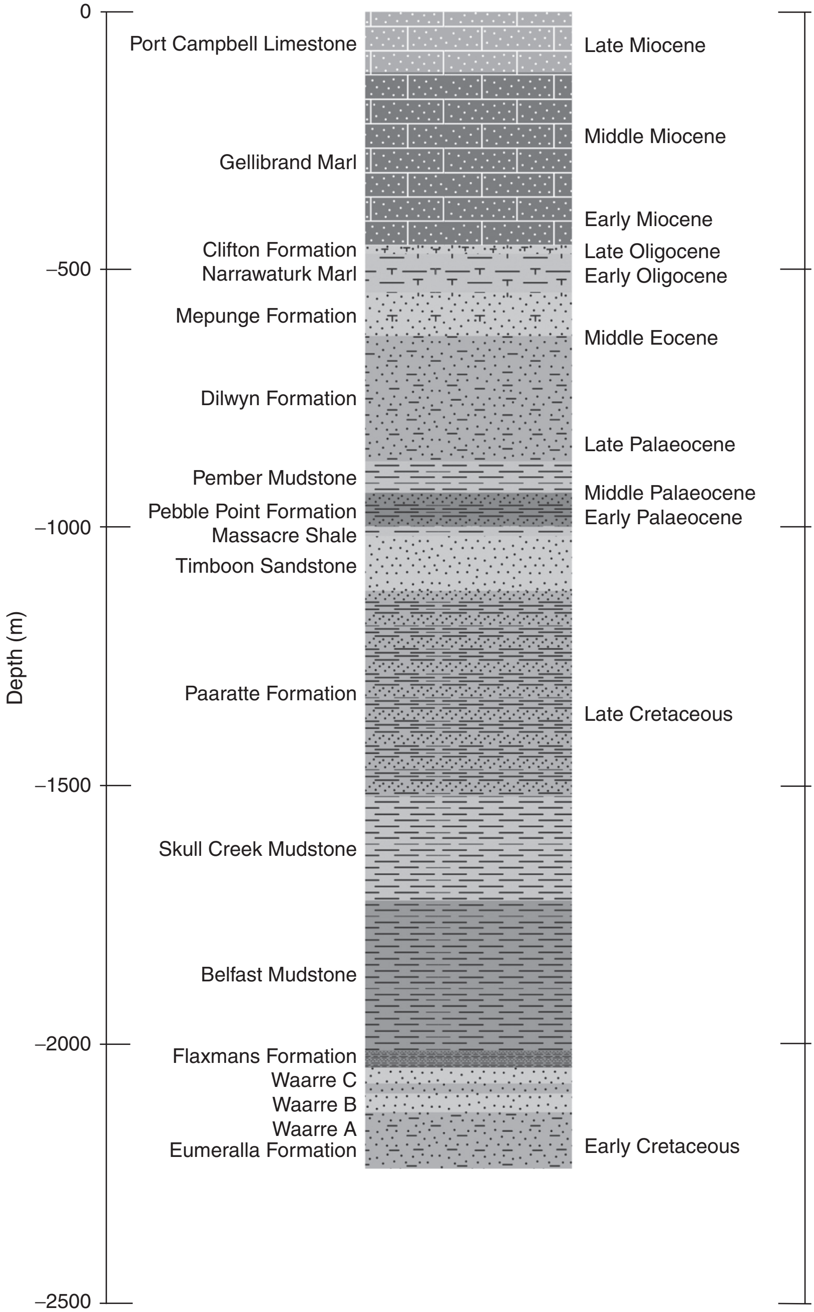


11.6 Dynamic model developed by Xu (2007) for CO2CRC, showing the anticipated migration of CO_2 within the Waarre Formation, updip from the injection well (CRC-1) towards the monitoring well (Naylor-1).

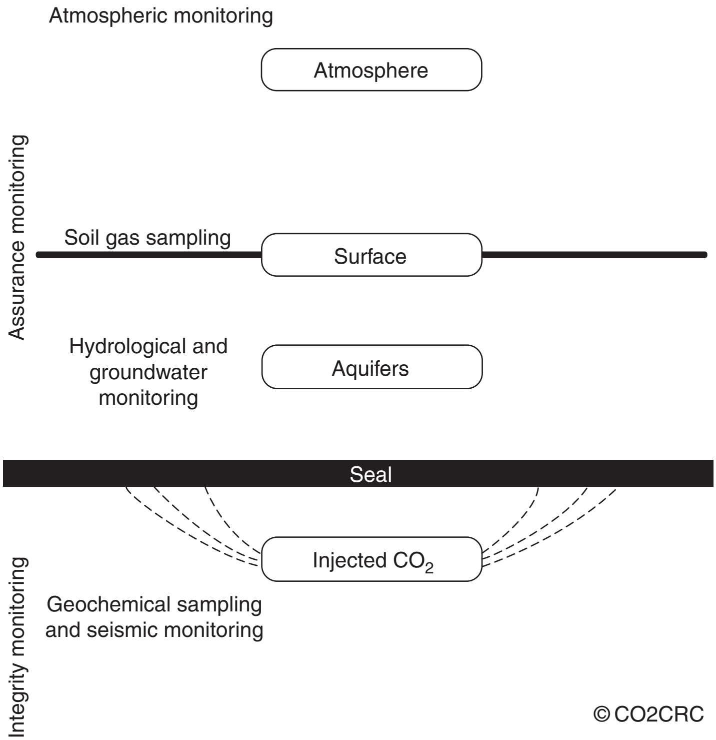
the Otway Project, which in turn provided the framework for the dynamic model. Together this provided the Project and the Board with a high degree of confidence that the proposed injection could be safely undertaken and that CRC-1 would be suitable as an injection well. One further exercise was necessary to confirm the suitability of the site and that was to carry out a risk assessment. This was undertaken initially by Watson (2007) using the methodology developed by Bowden and Rigg (2004) and this confirmed that the risk of an unanticipated event was low. Subsequently a number of other risk assessments were carried out on an ongoing basis as new information came to hand and this provided additional confidence in the project definition and methodology.

11.4 Monitoring the site

Obviously a critical element in any storage project is to be able to provide confidence to the local community and the community at large, that CO_2 will not escape to the atmosphere or into aquifers or soils, where they could adversely impact on humans and the biota more generally. From a carbon accounting point of view, it is also important to be able to verify that the amount of CO_2 injected is the quantity stored for the long term, or conversely if it is not, then perhaps a discount will need to be applied to take any leakage into account, in which case it would be necessary to know the rate of leakage. In an extreme situation, if leakage were to occur, it may be necessary to take remedial action. All of these issues require that a well-defined monitoring regime be established (Dodds *et al.*, 2009).



11.7 Stratigraphy of the sedimentary sequence intersected in the CRC-1 well. Injection for Otway stage 1 was into the Waarre C Formation at a depth of approximately 2000 m. Injection for stage 2 was into the Paaratte Formation at a depth of approximately 1500 m. For more detailed discussion on the stratigraphy of the site see Dance *et al.* (2009).



11.8 Monitoring was an essential element of the Otway Project with both assurance and integrity monitoring being undertaken, using a range of technologies. For more detailed discussion on monitoring see Jenkins *et al.* (2012).

It was important to use the CO2CRC Otway Project as an opportunity to test existing monitoring techniques and where appropriate to develop and test new techniques. Consequently it was decided to deploy a wide range of techniques in order to test their effectiveness, including, if possible, their cost effectiveness and their practicality. It was not the intention to set up the 'gold standard' for monitoring commercial projects, as it was recognised that monitoring requirements will vary enormously depending on the nature and scale of the project. However all projects are concerned to know, to the extent possible, if there is any migration of CO_2 out of the primary storage reservoir. In other words, is the containment system working? Integrity monitoring is undertaken to establish this (Fig. 11.8). Additionally, it is essential to know if there is any leakage into unconfined units (i.e. leakage beyond the primary or secondary seal), from where the CO_2 can leak into groundwater, soils or the atmosphere. Assurance monitoring is undertaken to determine whether or not CO_2 is leaking (Fig. 11.8).

The issue faced in establishing any monitoring programme is that the project is planned in the first instance, with a high expectation that the stored CO_2 will be confined to the reservoir interval and that there will be no leakage. In other words there is a high probability that a monitoring programme will not measure any significant deviation in CO_2 concentration from the norm. Nonetheless from an assurance point of view it is essential that the monitoring programme be undertaken to the highest appropriate standards. Critical to this is to have a clear picture of the natural variability of systems in terms of CO_2 concentration and any related parameters. Therefore before any CO_2 is injected at the storage site, it is essential that a comprehensive baseline study is carried out. In the case of the Otway Project this was undertaken over and around the site for at least a year before injection commenced (Jenkins *et al.*, 2012).

11.4.1 Integrity monitoring

Two monitoring systems were used to develop a picture of how CO_2 was behaving within the Waarre Formation, and particularly how and at what speed the CO_2 was migrating within the formation. The modelling undertaken provided a high degree of confidence that the CO_2 would remain within the formation and within the confines of the lease area and that the CO_2 would migrate laterally towards the Naylor well. There were two ways in which this behaviour could potentially be monitored: seismic monitoring and downhole monitoring.

Seismic monitoring

Largely as a result of the excellent 3D seismic results obtained for the Sleipner Project (Arts *et al.*, 2005), it is commonly assumed that time lapse 3D seismic surveys offer the best way of monitoring the CO_2. However, onshore 3D seismic is expensive, it is often difficult to obtain good reproducible results onshore and in the case of the Otway Project there was the added complication that because of the presence of residual methane in the Waarre C Formation, it was unlikely that any injected CO_2 would actually be 'seen' acoustically. A further complication was the presence of a very irregular karstic weathering profile at the top of the Port Campbell Limestone which had an adverse impact on the quality of the seismic record that could be obtained. Nonetheless it was seen as important to deploy seismic techniques at Otway. Therefore a series of test surveys were carried out in the 2 years prior to the commencement of injection using a range of seismic sources including a weight drop plate, vibroseis and also dynamite (Pevsner *et al.*, 2010; Urosevic *et al.*, 2010, 2011; Jenkins *et al.*, 2012). Overall, the results showed a high degree of reproducibility, although using dynamite for the sound source produced the best signal to noise ratio.

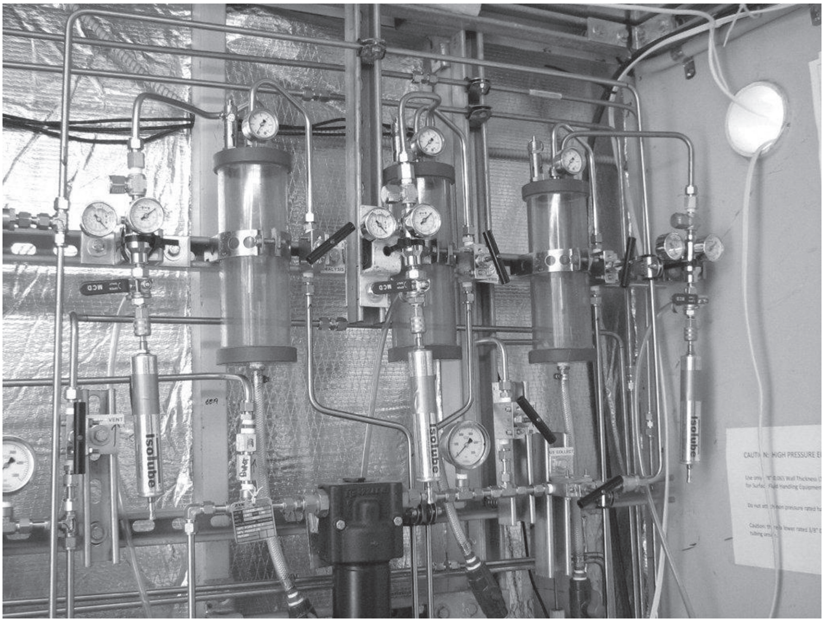
While it was not anticipated that it would be possible to see the CO_2 within the Waarre Formation, forward modelling of the seismic response (Li *et al.*, 2006) showed that leakage from the Waarre Formation into the overlying Parattee Formation (which does not contain any residual methane) would be detectable, with a limit of detection of 5000 t of CO_2. Therefore despite some of the practical limitations, it was concluded that 3D seismic should continue to be run at the Otway site.

Downhole monitoring

Downhole monitoring had previously proved to be an extremely valuable monitoring tool for the Frio Brine Project, Texas and the Weyburn Project, Saskatchewan. At Otway, the existence of the pre-existing production well, Naylor-1 located near the crest of the Naylor structure which penetrated down to the Waarre Formation, provided the opportunity to cost-effectively establish a monitoring well. There was some trade-off in this decision, such as the fact that it was a slim hole which limited the extent of instrumentation in the well. In addition, the well was several years old and there was a small leak in a casing patch. It was decided to deploy a modified version of the downhole sampling equipment developed by Freifeld *et al.* (2005), with associated pressure-temperature gauges and surface facilities (Fig. 11.9). Also, above the packer, three-component and single-component geophones were deployed, while below the packer, geophones and hydrophones were deployed to determine high resolution travel times (Underschultz *et al.*, 2011). Geochemical sampling was possible at three levels within the Waarre C interval, using a U-tube assembly, with nitrogen as the gas drive (to drive the fluid samples to the surface) in order to minimise geochemical changes during the sampling process (Fig. 11.10). The system was first deployed at the site in late 2007. The temperature-pressure gauges failed almost immediately, probably because of shorting out of the electrical connections and it was therefore only possible to use the U-tubes to extrapolate the formation pressure. Despite these difficulties, the system proved to be a particularly important part of the monitoring system for the Otway Project (Jenkins *et al.*, 2012).

11.4.2 Assurance monitoring

While integrity monitoring was very important to the scientific success of the project, in terms of the community, it could be argued that assurance monitoring was even more important. Because a number of distinct

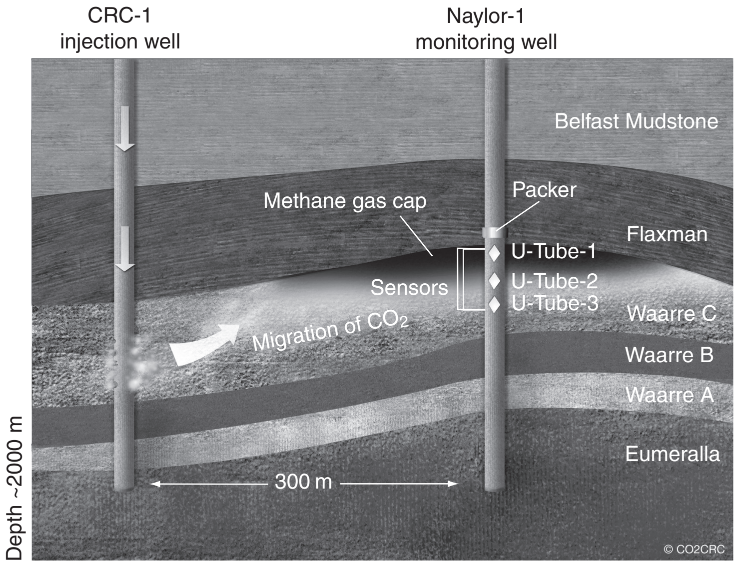


11.9 The U-tube sampling system developed by Freifeld *et al.* (2005) was successfully used to sample formation fluids at depth in the Naylor-1 monitoring well. Once at the surface, the samples were collected using the low pressure head space gas sampling configuration shown in this photograph. Boreham *et al.* (2011) provide a more detailed discussion on the instrumentation.

environments were being considered it was necessary to have a suite of technologies.

Monitoring the ground waters

In any discussion regarding the project with land owners, most of them dairy farmers who use ground water, the first question almost invariably was 'Is it going to affect the ground water?'. Therefore monitoring of ground waters was a priority for the project in order to provide the necessary reassurance to the community, with monitoring commencing some 2 years before the commencement of CO_2 injection. Sampling of bore holes was undertaken twice a year (there is a significant variation in the shallow ground waters during the year as the area has a Mediterranean-type climate of hot dry summers and cool wet winters. A total of 21 shallow bores were routinely sampled in the Port Campbell Limestone at depths of less than 100 m. Also, three deep bores in the Dilwyn Formation were sampled at depths greater than 800 m (de Caritat *et al.*, 2009; Jenkins *et al.*, 2012). The samples were subsequently analysed for conductivity, pH, cations, anions, isotopes and tracers. Because



11.10 Schematic diagram showing the injection of CO_2 into the water leg of the Naylor structure, updip migration within the Waarre Formation, and detection and sampling using the U-tube system.

the area does have a number of potential sources of natural CO_2 it was necessary to characterise these to the extent possible in order to identify any isotopic fingerprints. However, this was not always possible and therefore some tracers such as sulphur hexafluoride (SF_6), deuterated methane (CD_4) and krypton (Kr),were added to the CO_2 at the injector well to minimise the possibility of ambiguity regarding the source of the CO_2, were anomalous values to be detected in any of the bore holes (Stalker *et al.*, 2009).

Monitoring soil gases

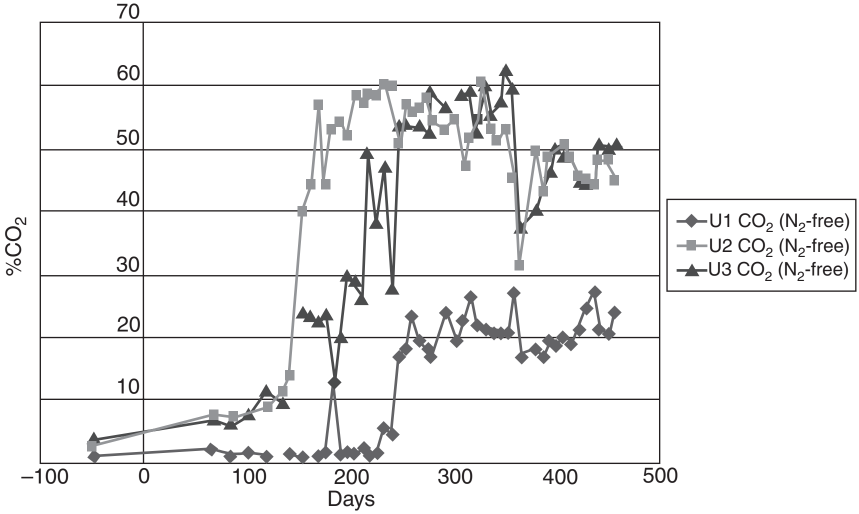
Soil gas surveys were carried out prior to commencement of CO_2 injection to determine the natural variability of the soil CO_2 content and composition, with analysis for CO_2, H_2, He, CH_4 and C isotopes (Schacht *et al.*, 2010). It also delineated an area to the north and west of the injection site where there were abnormal concentrations of CO_2, possibly due to a small natural seep. Soil gas sampling continued during and after injection, with approximately 150 samples taken each survey within an area of approximately 1 km^2. A direct push soil gas sampling methodology was used for much of the survey, involving pushing a rod into the soil to a depth of 1 m and directly recovering the gas. In addition, three automated soil flux-measuring instruments were installed at the Otway site at a depth of approximately 1.3 m (Bernardo and de Vries, 2010). Because of the annual variability in the depth of the water table, there was a large annual range in the soil CO_2 flux which had to be taken into consideration in the interpretation of results and the likelihood of detecting any significant anomalies.

Monitoring the atmosphere

Continuous atmospheric monitoring of the Otway site was a significant new initiative for CCS projects, which has been extensively reported (Leuning *et al*., 2008; Jenkins *et al*., 2011, 2012). In summary, atmospheric monitoring was undertaken using a single flux tower approximately 10 m high, located 700 m northeast (and downwind) of the injection site. A long-term baseline record of atmospheric composition was available from the Cape Grim station in northeast Tasmania approximately 400 km to the southeast of the Otway site for comparison, but atmospheric readings were taken at the Otway site for more than a year before the commencement of injection and therefore a reasonable local baseline was available. This showed a high degree of variability in the CO_2 content, reflecting the diurnal and annual variability in photosynthesis as well as changes in the wind direction although the area, which is located only 5 km from the coast, is dominated by south-westerly winds. Despite the complexities of the atmospheric conditions, it was possible in 2008 to field test the system to detect CO_2 emissions (equivalent at the flux tower to a measurable anomaly of just a few parts per million) arising from the operation of a drilling rig at the site. This provided confidence that were a leak to happen in the vicinity of CRC-1, it would be detected by the atmospheric monitoring system in place.

11.5 Successfully undertaking the Otway Project

Injection of CO_2 commenced at the Otway site in late March 2008, with the official opening of the CO2CRC Otway Project by the Federal Minister for Resources and Energy on 2 April 2008. Injection at CRC-1 (Fig. 11.11) concluded on 29 September 2009, by which stage 65 445 t of supercritical carbon dioxide (strictly, CO_2-rich gas), had been injected into the Waarre C Formation at a depth of 2053 m. The entire operation went very smoothly and there were no major mechanical failures and no health or safety incidents during this period, a reflection of the high degree of professionalism of the Project Manager (Sandeep Sharma) and the operating company (AGR). However, a key component was also the careful overview of the Board and the Operating Committee, together with the input of member companies. Inevitably a number of operational issues needed to be resolved during this extended operational period, such as the previously mentioned waxing issue (a feature of the source of the CO_2 and not likely to be a feature of most CCS operations), the non-performance of some of the downhole equipment and



11.11 The samples obtained from the U-tube system clearly show the arrival of the CO_2 at the monitoring well, with the first arrival of CO_2 evident in U-tube 2 (U2) approximately 120 days after the commencement of injection. Underschultz *et al*. (2011) and Jenkins *et al*. (2012) discuss the U-tube results in some detail.

initially some minor problems with low injectivity, probably due to minor formation damage in the immediate vicinity of the well during the drilling operations. Land access was obviously important to the success of the operations and for the most part this was not a problem. However, it was necessary to modify sampling or surveying schedules to avoid disruptions to farming operations. The most disruptive activity was undoubtedly the undertaking of 3D seismic surveys. Because these had such a significant impact, they could not be undertaken during critical times of growth or when harvesting was under way. In addition they could not be undertaken when the ground was waterlogged. As a consequence, seismic surveys were restricted to a narrow window during summer. Winter field and drilling operations were at times disrupted by heavy rain with localised flooding occasionally limiting access. However for the most part, operations were able to proceed on a continuous basis throughout the 20 months of operations. A key aspect of the operations was to provide access to the site to the community, officials and other key stakeholders throughout this time. Obviously this had to be regulated to liaise with the contractors and to ensure that health and safety issues did not arise. But at the same time it was important to be open about what we were doing. A key aspect of ensuring that this happened was the employment of a local community liaison officer, who could immediately address any communication or access concerns before they became a major issue. For some future CCS projects, an important element will be the successful abandonment and closure of the site. In the case of the CO2CRC Otway Project this was not an issue as it had been decided by 2010 that there would be new phase of the project. Therefore the CRC-1 well and activities at other project facilities were 'suspended' and placed on a care and maintenance basis in anticipation of a new phase of research getting under way in a year's time. However monitoring continued at the site, and is still under way.

11.6 Outcomes of the Otway Project

The main scientific outcomes of the Project have been reported in some detail by Boreham *et al*. (2010), Underschultz *et al*. (2011) and Jenkins *et al*. (2012) and a major volume is in progress that will serve to comprehensively cover all the methodologies and results (Cook, 2013). The overarching findings are perhaps best covered by quoting Jenkins *et al*. (2012, p. E40).

> *The CO2CRC Otway project has demonstrated that the storage of CO_2 in a depleted gas field can be designed and safely achieved. Monitoring showed that there has been no measurable effect of stored CO_2 on soil, groundwater, or atmosphere... . Seismic imagery and fluid sampling confirmed dynamic and geochemical models. Sensitivity of monitoring techniques to surface leakage rates at the few kilotons yr^{-1}, was demonstrated. Achieving this sensitivity shows that commercial-scale storage programs could be effectively monitored to ensure climate abatement was being achieved*

Because of the integrated nature of the project it is difficult to pick any particular result or methodology as being especially important. It was the comprehensiveness and quality of the data acquisition programme coupled with the integration of the data sets that together ensured the success of the Project. However there are some outcomes that are of broad significance. For example, the deployment of the downhole U-tube sampling system was vital in determining the speed of migration of the CO_2 within the heterogeneous reservoir. Because the sensitivity of 3D seismic was inadequate to 'see' the injected CO_2 within the reservoir, the U-tube system was important for validating the dynamic model with a well-defined increase in CO_2 content being evident at the monitoring well. Interestingly, the time for 'breakthrough' (the length of time taken by the CO_2 to travel from the injection well to the monitoring well), while at the lower end of the predictions, was within the predicted time and was closer than most other projects have been able to achieve. There are perhaps several reasons for this: the storage was a depleted gas field and therefore the amount of data available (including production data) was more than that for many other projects. Also a large effort by the project team was put into the development of high quality static and dynamic models. Finally the CO2CRC Otway Project was, up to the that time, the largest research project in terms of the amount of CO_2 injected and it may be that this scale of activity served to average out the effects of heterogeneities that might otherwise dominate a small-scale injection. The significance of this result is that it provides confidence that the subsurface migration behaviour of CO_2 can be predicted with confidence.

The downhole sampling system was also important in providing information on the geochemical changes occurring within the storage formation. U-tube sampling was carried out every 1–2 weeks, with a marked decrease in pH accompanied with minor changes in the composition of the formation water with the arrival of the $CO_{2.}$ A further benefit of the U-tube system was that it provides a method for obtaining a value for the reservoir storage efficiency. The storage efficiency has been much debated in the geological literature because of uncertainties regarding how much pore space can be occupied by CO_2 in a storage operation, with estimates varying markedly (Bachu *et al.*, 2007). In the case of the Otway Project and depleted gas fields more generally, the issue was the extent to which pore space previously occupied by natural gas can be occupied by injected CO_2 during a storage operation. With the sampling system used at Otway, the dynamic storage capacity of the reservoir could be measured as it re-filled with injected CO_2. Using the U-tube sampling system to determine the timing of the passage of the gas-water contact within the sampled interval, the amount of injected CO_2 can be compared with the available pore space, which is estimated both from the geological model and from the production data of natural gas. Together, these indicate that 56–84% of the space originally occupied by recoverable CH_4 is re-occupied by CO_2 (Jenkins *et al.*, 2012). This is an important value in that it provides an indicator of how much CO_2 can be stored in a depleted gas field.

Obviously the capacity of the Otway (Naylor) storage structure is quite small and will never have commercial significance as a storage site. Nonetheless it clearly demonstrates that storage in depleted gas fields is technically viable. Are then depleted gas fields likely to be an important future storage option that will materially decrease global emissions? To evaluate this requires consideration of the total volume of conventional gas reserves. Globally proven conventional gas reserves are 185 trillion m^3 with at least 75 trillion m^3 produced since 1970, according to the BP Statistical Review for 2010. We have no knowledge of how typical (or atypical) the Naylor field is of depleted gas fields in general, but if the storage values for Naylor (rounded off here to 50–75% of the original natural gas extracted from gas fields) is extrapolated to all other fields (noting the uncertainly inherent in this assumption), then this suggests that globally, gas fields might ultimately have a total potential storage capacity of the order of 700–1000 Gt $CO_{2.}$ Much of this may not be accessible for storage for technical or economic reasons, but given that global annual emissions from stationary sources are of the order of 11 Gt CO_2 per annum, depleted gas fields clearly are likely to be globally significant as a mitigation option for stationary emissions located in the vicinity of depleted gas fields.

The results of the monitoring programme indicate with a high degree of confidence, that there was no leakage of injected CO_2 into the ground waters, or the soils or the atmosphere. In addition, as pointed out earlier, while it was not possible to detect CO_2 in the reservoir using seismic methods, it can be confidently stated that a significant leak of CO_2 into the overlying formations (which contain no residual methane) would have been readily detected. There was no indication of any leakage of CO_2 through the overlying seal. It follows from this that it was possible to give the regulators and the community assurance that the CO_2 was safely and securely stored. However, the reaction of members of the local farming community to the impact of 3D seismic strongly suggests that alternative low-impact onshore seismic methods may be needed for large-scale storage projects in the future. The other observation that can usefully be made is on the use of tracers to determine whether an anomalous CO_2 reading is likely to be natural or the result of leakage of stored CO_2. On this basis it is at times suggested that tracers should be used in commercial storage projects. While this might be useful in the testing phase of a project, it is unlikely to be useful, or practical to routinely introduce tracers into CO_2 prior to large-scale storage. The experience at Otway suggests that tracer results are at times difficult to interpret and even more significant perhaps, even when taking great care, it not easy to avoid contamination, which in turn can result in false tracer anomalies. Additionally there are not many suitable tracers and some that may be suitable are very potent greenhouse gases in their own right. Therefore other than in the initial small-scale testing stage, the use of tracers for large-scale storage projects is unlikely to be a viable option. A much more useful way forward, where possible, may be the chemical characterisation of injected CO_2 using trace elements or isotopes that naturally occur within the emissions.

Finally, the outcome from the process of community consultation is instructive. While there will always be some people who will not want a project of any sort to go ahead, whether it is a CCS or a wind turbine or a geothermal project, or any number of other energy related projects, it is possible to win over the great majority of the local community. Openness and transparency is critical to this, including a willingness to show individuals and groups over the site, provide as much information as possible and be sensitive to the feelings of the community. In addition and critical to success, is to involve people from the local community in the communication and liaison with local stakeholders. The project had assumed at the start of the process, because there had been extensive oil and gas operations in the area, that the community would be attuned and perhaps sympathetic to the sort of operations that we wanted to undertake. To some degree this proved to be the case, but it was very dependent on whether the experience with the oil explorers was good or bad. What can be said is that it is never too soon to commence community consultations.

11.7 Future trends

The CO2CRC Otway Project was extraordinarily successful scientifically and technically, and as a real-world communications exercise. Things that made this possible include the level of financial and other support received from industry and government, the arrangements made within the CO2CRC corporate structure for handling liability, the dedication of researchers, the focus of management on making the project happen in an effective, timely and safe manner, and the fact that the project was 'owned' by CO2CRC. This last feature gave the project a significant potential advantage over a number of other projects which have to work on land and use facilities that are owned by a company whose primary operational motivation is, understandably, to get an adequate financial return rather than to store CO_2. There can of course also be significant advantages from working closely with a company but it can limit flexibility. The Otway Project did not have to deal with that situation and was essentially in charge of its own future – subject of course to the usual caveat of being able to obtain adequate research funding! Nonetheless CO2CRC decided to optimise the use of its existing assets including an abundance of CO_2, ongoing access to the site, ongoing approval to inject CO_2 at the site under the EPA R&D regulations, a supportive local community and major physical assets including boreholes, a pipeline, monitoring equipment and a range of other facilities

It was therefore decided to plan for CO2CRC Otway Project Stage 2, the purpose of which was twofold: First to inject CO_2 into a heterogeneous saline aquifer, the Parattee Formation, with a view to determining residual trapping and establishing storage efficiency. Second to determine the lower limit of seismic detection of CO_2 in a formation in which there was no residual methane. The third was to demonstrate effective storage in a saline aquifer. This involved, in 2009, the injection of a new injection well, CRC-2 to allow injection into the Parattee Formation at a depth of about 1500 m, about 500 m above the first injection. A large amount of core was obtained to geologically characterise the formation in some detail (Otway Project 2A). In mid-2010 a major field exercise was undertaken involving a complex huff and puff operation to determine residual trapping (Otway Project 2B). The field phase of this operation was very successful and interpretation of the results is under way. The next phase, to be undertaken in 2015–2016, is to carry out 3D seismic to determine seismic detection limits (Otway Project 2C). This is also hopefully going to be linked to the deployment of a new fixed array seismic system to overcome the logistic difficulties in running extensive 3D seismic surveys.

Beyond that, the site still has an enormous potential for further CCS science. Consideration is being given to using the site for testing CO_2 capture from natural gas; there are a range of lithologies and structural features that offer outstanding opportunities for learning more about the behaviour of CO_2 and the influence of rock properties on that behaviour. More speculatively, the area is one of interest for geothermal power and may provide the opportunity to jointly develop CCS and geothermal? Of the order of \$50–60 million has been invested to date in the Otway site and in the related science. This has been money well spent and it provides a very sound base for yet more outstanding collaborative CCS science.

11.8 Acknowledgements

Complex science undertaken on the scale of the CO2CRC Otway Project requires the combined efforts of a large number of people and organisations, too many to mention individually here. CO2CRC member companies and governmental organisations (see www.co2crc.com.au) under the CO2CRC Chairman Tim Besley and subsequently David Borthwick, provided funding, advice and review to the Project and assistance to me as Chief Executive. Thanks also to Richard Aldous, my successor as CO2CRC Chief Executive. Additional funding was provided by the Australian Government CRC Program, Ausindustry and the Victorian Government as well as the US Department of Energy and the National Energy Technology Laboratory, through the Lawrence Berkeley National Laboratory (LBNL). The setting up of CO2CRC Pilot Project Ltd under the chairmanship of Mal Lees was an essential component of success. The cooperation of a number of Victorian regulatory bodies was also critical in enabling the project to go ahead.

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12

On-shore CO_2 storage at the Ketzin pilot site in Germany

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Abstract: This chapter provides a comprehensive description of research and development work performed, and experiences gained, at the Ketzin CO_2 storage pilot site in Germany. The Ketzin pilot site was the first European on-shore CO_2 storage project and is still the only German CO_2 storage project. Since summer 2008 more than 67 kt of CO_2 have been successfully injected into Upper Triassic sandstones. A world-class integrated monitoring approach images the behaviour of injected CO_2 in the subsurface and proves safe implementation of CO_2 storage at Ketzin. The pilot site provides a well-suited case study for any future German or worldwide CO_2 storage projects.

Key words: on-shore CO_2 storage, geophysical monitoring, Ketzin, pilot site.

12.1 Introduction

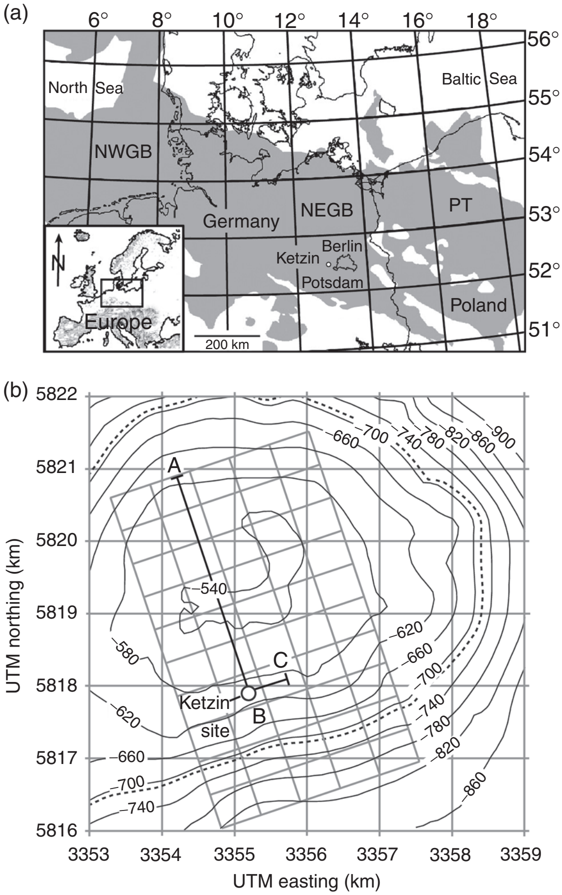
Pilot sites form an important and integral part of any roadmap for the implementation of industrial scale geological storage of CO_2. They allow us to derive scientific insights into fundamental processes that occur during geological storage of CO_2, gain experiences on the technical and operational aspects of CO_2 storage, and perform field experiments on specific aspects of CO_2 storage that may not be realisable at demonstration or industrial scale projects. Ideally, such pilot sites are continuously developed into demonstration and finally large scale storage projects such that experiences gained during the pilot phase run directly into the scaled-up operations. In the case of on-shore CO_2 storage, which is often faced with severe public concerns due to storage in populated or agriculturally used areas, pilot sites are especially important as they may help to provide public confidence in secure and sustainable implementation of geological CO_2 storage. In Germany, a large part of the estimated overall CO_2 storage capacity is located on-shore and providing public confidence in on-shore CO_2 storage is therefore essential for any successful implementation of larger scale CO_2 storage.

Cumulative CO_2 emissions of Germany amount to about 880 Mt CO_2/year; of these about 62% or 550 Mt CO_2/year are due to industry and energy production with about 375 Mt CO_2/year come from large stationary point sources which emit more than 1 Mt CO_2/year each (Stroink, 2009; Knopf *et al.*, 2010). These emissions are counterbalanced by an estimated cumulative storage capacity for Germany of 12 ± 3 Gt CO_2, which splits into 9.3 ± 3 Gt CO_2 for deep saline formations and about 2.7 Gt CO_2 for depleted gas and oil fields (Knopf *et al.*, 2010). Despite the still large errors in capacity estimates and depending on actual CO_2 reduction targets, the data show that the storage capacity in Germany potentially lasts for more than 40 years or more than one power plant generation, respectively. The data also clearly show that deep saline formations provide the most important storage options. Most promising storage sites are located in northern Germany within the North German Basin, which consists of post-Variscan Permo-Mesozoic to Cenozoic sedimentary sequences. Here, thick Permian evaporites (Zechstein) resulted in widespread salt tectonics during the Mesozoic and the formation of different scaled syncline and anticline structures in the overlying sediments (Reinholf *et al.*, 2008; Knopf *et al.*, 2010). In central and southern Germany potential storage sites in sedimentary basins are rare, either due to the lack of sedimentary basins or to the insufficient depth of the sedimentary sequences for CO_2 storage. Examples of potentially prospective sedimentary basins in central and southern Germany include the Molasse Basin, the Upper Rhine Valley, the Saar-Nahe Basin and the Thuringian Basin (Knopf *et al.*, 2010).

This chapter provides a comprehensive description of experiences gained at the Ketzin pilot site located in the Federal State of Brandenburg, Germany. The Ketzin pilot site was the first European on-shore CO_2 storage project and is still the only storage project in Germany. It is a pure research and development project and limited by legal regulations to a maximum amount of stored CO_2 of 100 000 t. Due to the lack of a national CCS law at the time of permission, the Ketzin pilot site was permitted under the German Mining Law by the mining authority of the Federal State of Brandenburg. The reservoir target horizon is a deep saline formation of Upper Triassic age in an anticline structure above a salt pillow within the Northeast German Basin. This means that the Ketzin pilot site shares fundamental geologic characteristics to be expected for most CO_2 storage sites in Germany and is a well-suited case study for any future German storage project.

12.2 Geographic and geologic setting

The Ketzin pilot site is located about 2.5 km east of Ketzin, a small village about 25 km west of Berlin and Potsdam (Fig. 12.1a). Geologically, the pilot site lies in the Northeast German Basin which forms part of the Central

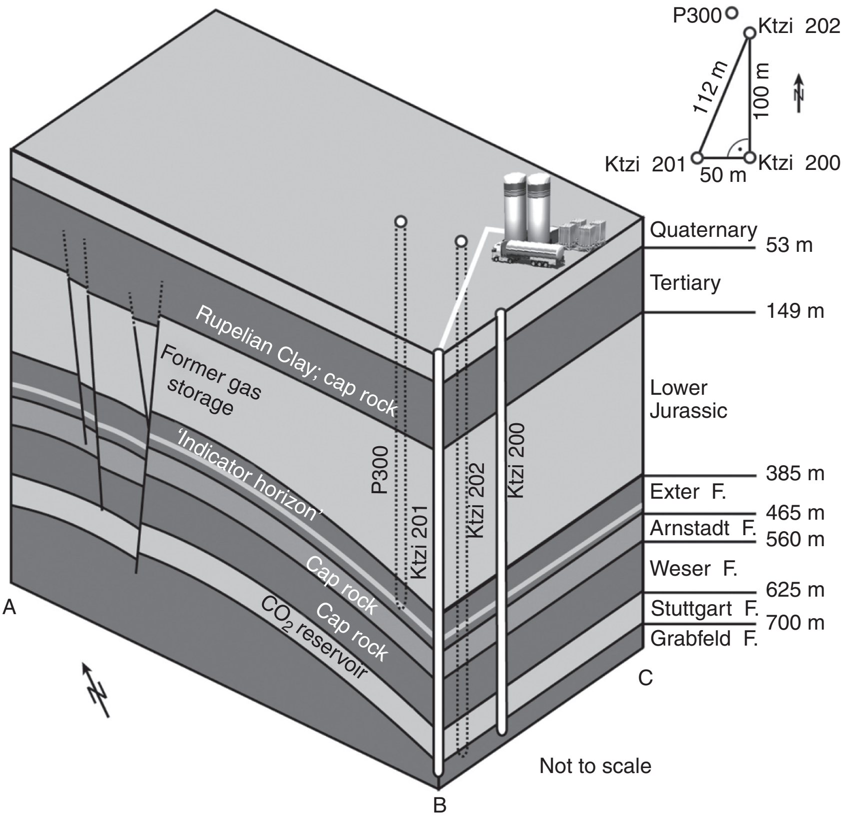


12.1 Geographic, regional and local geologic setting of the Ketzin pilot site. (a) Ketzin lies about 25 km west of Berlin and Potsdam, Germany, in the Northeast German Basin (NEGB), which forms part of the larger Permian Basin that extends from Poland over northern Germany into the North Sea (grey; NWGB = Northwest German Basin: P-T = Polish Trough). Here, Mesozoic to Cenozoic sedimentary successions are underlain by Permian salt deposits that gave rise to widespread salt tectonics. (b) The Ketzin pilot site is located about 1.5 km south of the top of the Roskow–Ketzin double anticline, which was formed by an underlying salt dome (UTM, Universal Transverse Mercator). Isobaths show the depth (m) of the top of the Triassic Stuttgart Formation. The thick dashed line refers to the 710 m isobath, which is the deepest closed top-Stuttgart isobath of the Ketzin structure and defines the maximum lateral extension of the reservoir. The thick line ABC indicates the profile line along which the schematic block diagram in Fig. 12.2 has been constructed. (*Source*: compiled and re-drawn with additions after Juhlin *et al.*, 2007 and Förster *et al.*, 2010.)

European Basin System that extends from the Polish Trough in the East to present day off-shore areas of the North Sea (Fig. 12.1a).

The Central European Basin System developed after termination of the Variscan orogeny and comprises sedimentary successions of Permian to Quaternary age. During Permian time thick Zechstein evaporites accumulated that gave rise to widespread salt tectonics within the Northeast and Northwest German Basins. Salt tectonics with accompanying basin differentiation are evident since the Middle Triassic (Scheck-Wenderoth *et al.*, 2008) and resulted in deformation of overlying strata and formation of synclines and anticlines, the latter forming potential structural sites for geological storage of CO_2. At Ketzin, salt tectonics formed the gently dipping, roughly east-northeast to west-southwest striking Roskow–Ketzin double anticline (Fig. 12.1b). Here, uplift due to the underlying salt pillow at depths of 1500 to 2000 m occurred in two major events at ~140 and 100 Ma and caused erosion of previously deposited Jurassic (Toarcian) and Lower Cretaceous, respectively (Förster *et al.*, 2010). The Lower Jurassic is discordantly overlain by Tertiary and unconsolidated Quaternary sediments (Fig. 12.2). The transgressional Oligocene Rupelian Clay forms the base of the Tertiary sediments and seals the Tertiary and Quaternary freshwater horizons from deep saline formation waters as in most other parts of northern Germany. At the Ketzin pilot site, the Rupelian Clay is the final seal of the multi-barrier system.

The Ketzin pilot site sits on the southern flank of the Ketzin part of the Roskow–Ketzin double anticline at a distance of about 1.5 km to the top of the structure (Figs 12.1b, 12.2). According to results from well logging and core interpretation performed during drilling of the wells for the pilot site, the base of the Tertiary is at ~149 m and underlain by about 236 m of Lower Jurassic down to ~385 m. The Upper Triassic Keuper at the pilot site consists of the Exter (down to ~465 m), the Arnstadt (down to ~560 m), the Weser (down to ~625 m), the Stuttgart (down to ~700 m) and finally the Grabfeld Formation (Fig. 12.2). Sandstone intervals of the Stuttgart Formation form the target reservoir horizons for CO_2 injection whereas mudstone, carbonate and anhydrite of the overlying Weser and Arnstadt Formations represent the first cap rock with a cumulative thickness of about 165 m (Norden *et al.*, 2010). The lateral extension of the storage complex is given by the 710 m top-Stuttgart isobath, which is the deepest closed top-Stuttgart isobath of the Ketzin structure (Fig. 12.1b). The lithologically heterogeneous Stuttgart Formation was deposited in a fluvial environment and consists of sand- and siltstones interlayered with mudstones. In the lower and middle part of the Stuttgart Formation sandstone layers are typically thin with thicknesses in the dm- to m-range and are interpreted as overbank or flood plain facies deposits (Förster *et al.*, 2010). The main sandstone layers in the uppermost part of the Stuttgart Formation are notably thicker with 9 to 20 m and are



12.2 Schematic block diagram of the Ketzin part of the Roskow–Ketzin double anticline with principal structural and stratigraphic features constructed along the line ABC of Fig. 12.1. Target reservoir horizon for CO_2 injection is the Upper Triassic Stuttgart Formation at a depth of about 625–700 m. The Stuttgart Formation is overlain by uppermost Triassic Weser, Arnstadt (i.e. combined first cap rock) and Exter Formations and Lower Jurassic strata, which are discordantly overlain by Tertiary deposits. The Rupelian Clay at the base of the Tertiary forms the final cap rock and seals the freshwater horizons from the deep saline waters at Ketzin as in most parts of northern Germany. Lower Jurassic strata have been used for natural gas storage until 2004. The position of the four wells is only schematically shown; exact orientation and distances of the wells are given in upper right inset.

interpreted as typical channel facies deposits (Förster *et al.*, 2010). These channel facies sandstones form the primary reservoir rocks at the pilot site. Their top and therefore the uppermost injection and CO_2 level is at about 630–627 m depth. The channel sandstones are immature and well to moderately-well sorted and dominantly fine-grained. Their typical mineralogy consists of quartz (22–43 wt%), plagioclase (19–32 wt%) and K-feldspar

(4–13 wt%) with subordinate mica, illite, mixed-layer silicates and meta-sedimentary and volcanic rock fragments and classifies the sandstones as feldspathic litharenites and lithic arkoses; cement phases analcime and anhydrite with minor dolomite, barite, and celestine make up 5–32 vol% (Förster *et al.*, 2010). Total porosity is variable due to the heterogeneous nature of the sandstones and ranges from 13 to 26 vol% with intergranular porosity variations between 12% and 21% (Förster *et al.*, 2010). Data by Norden *et al.* (2010) show even higher porosity variability with 5 to > 35%. Due to the variability in porosity, grain size and cementation the overall permeability is likewise highly variable and ranges between 0.02 and >5000 mD with average values for channel facies sandstones of 500 and 1300 mD, respectively (Norden *et al.*, 2010). Based on NMR measurements, Zemke *et al.* (2010) calculated a slightly lower and more restricted permeability for the channel sandstones of 10–100 mD comparable to results from hydraulic tests, which yielded permeabilities for the channel sandstone horizons between 50 and 100 mD (Zettlitzer *et al.*, 2010), and experimental determinations, which yielded 40–90 mD (Kummerow and Spangenberg, 2011). The immature nature of the Ketzin reservoir rocks makes the feldspathic litharenites and lithic arkoses potentially susceptible for mineral alteration during fluid–fluid–rock interactions triggered by injected CO_2 with eventual concomitant changes in petrophysical rock properties. Long-term experiments performed on reservoir samples from the Ketzin pilot site indeed show measurable changes in mineralogy with predominant alteration of plagioclase, K-feldspar and anhydrite and stabilization of albite (Fischer *et al.*, 2010). In line with these observed mineral alterations a slight increase in porosity has been observed during the experiments (Zemke *et al.*, 2010). However, the experiments also clearly show that the observed changes in mineralogy and petrophysical rock properties are too minor to affect the integrity of the reservoir rock.

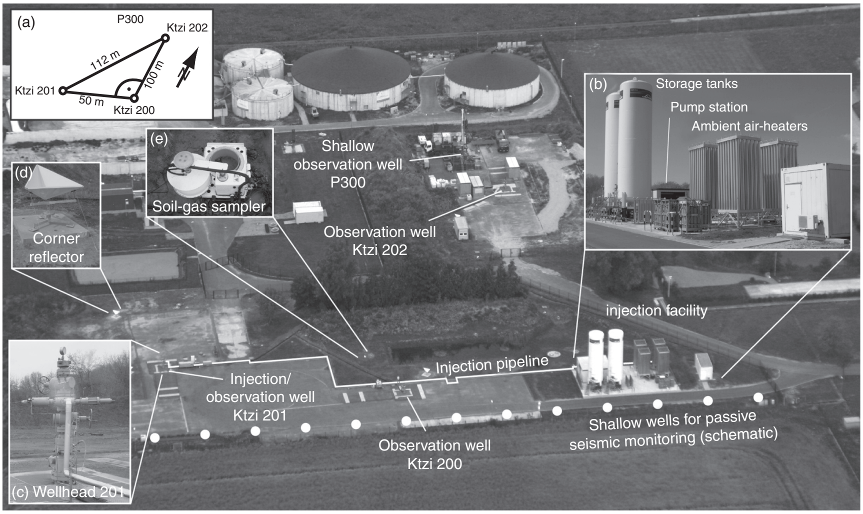
Initial reservoir conditions of the target horizon at the Ketzin pilot site were 33.5°C and 6.1 MPa at 630 m depth as determined by wire-line logging prior to start of the CO_2 injection (Henninges *et al.*, 2011). These values transform into a calculated initial density of the injected CO_2 of about only 170 kg/m^3 (Span and Wagner, 1996), which is notably less than the > 600 kg/m^3 generally postulated for CO_2 storage sites. In this regard, the Ketzin pilot site has a rather uncommon characteristic, which may make transferring gained results to other storage sites difficult. However, this characteristic makes Ketzin a perfect analogue to a first aquifer or indicator horizon above a deeper located, more typical CO_2 storage site that accumulates upward migrated or leaked CO_2. Results from the Ketzin pilot site on qualitative and quantitative CO_2 monitoring and detection therefore directly transfer into information on possibility and precision of leakage detection.

12.3 Site infrastructure and injection process

The complete infrastructure of the Ketzin pilot site has been built up and designed for its specific purposes and scientific needs. As the Ketzin pilot site is a purely research driven project the site infrastructure as well as the injection process cover some specific characteristics that may not apply to industrial scale projects. Nevertheless, besides the scientific results, important operational learning has also been gained from the Ketzin pilot site (Liebscher *et al.*, 2013).

12.3.1 Site infrastructure

Predominantly within the frame of the CO2SINK project, supported under the 6th Framework Program by the EU commission, and its nationally funded follow-up project CO2MAN, the Ketzin pilot site has been developed and the site's infrastructure built. The site infrastructure consists of three deep wells and one shallow well, the injection facility with injection pipeline as well as permanently installed monitoring devices (Figs 12.2 and 12.3). The deep wells split into one combined injection-observation well (labelled CO2 Ktzi 201/2007) and two observation-only wells (labelled CO2 Ktzi 200/2007 and CO2 Ktzi 202/2007) that have been drilled to depths of 750–800 m and are abbreviated here for simplicity as Ktzi 200, 201 and 202. The two observation wells are at 50 m (Ktzi 200) and 112 m (Ktzi 202) distance to the injection well and all three wells form the corners of a right-angled triangle (Figs 12.2 and 12.3). All three wells are designed with identical casing layout and consist of 24″ stand pipe, 18 5/8″ conductor casing, 13 3/8″ and 9 5/8″ reserve and intermediate casings, and 5 1/2″ production casing (Fig. 12.4; Prevedel *et al.*, 2008, 2009). In well Ktzi 201 a 3 1/2″ injection string is additionally installed to a depth of 560 m. At reservoir depth all three wells are connected to the reservoir with slotted liners and filter screens. For safety reasons Ktzi 201 has surface and subsurface safety valves triggered by high–low pressure pilots at the wellhead. To allow for permanent monitoring, all wells are equipped with a smart-casing concept that consists of fibre-optic-sensor cable loops for distributed temperature sensing (DTS) outside the 5 1/2″ production casing with additional electrical heater cables in Ktzi 201 and Ktzi 202, vertical electrical resistivity arrays (VERA) at depths between about 590 and 730 m, each consisting of 15 toroidal steel electrodes with a spacing of about 10 m, and an additional DTS system with a P-T gauge at 550 m depth outside the injection string of Ktzi 201 (Prevedel *et al.*, 2008, 2009; Schmidt-Hattenberger *et al.*, 2011). To allow for monitoring of the first aquifer or indicator horizon above the combined cap rocks of the Weser and Arnstadt Formations, a shallow well Hy Ktzi P300/2011 (for simplicity abbreviated as P300) has been drilled in Summer 2011 about 25 m northwest of observation well Ktzi 202 to a depth of about

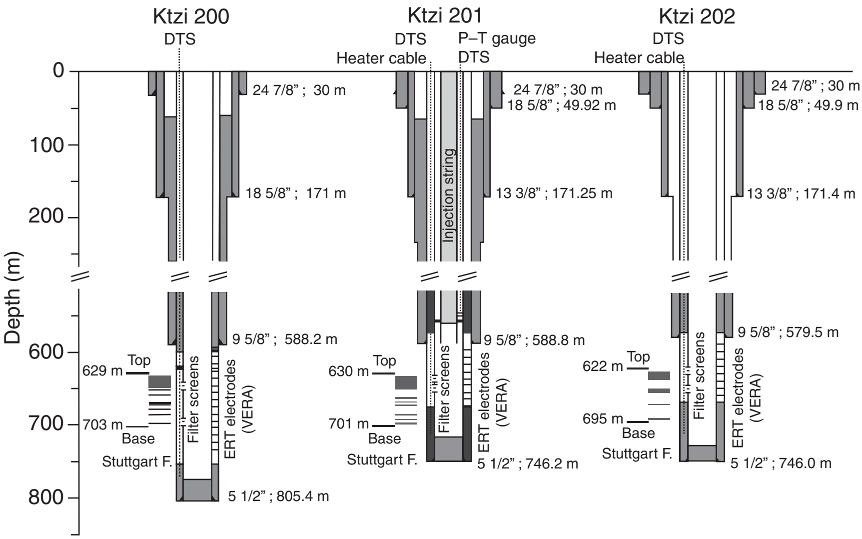


12.3 Aerial view of the Ketzin pilot site. The site consists of the injection facility with injection pipeline, one deep combined injection and observation well (Ktzi 201), two deep observation-only wells (Ktzi 200 and Ktzi 202), and one shallow observation-only well (P300). The deep wells form the corners of a right-angled triangle with distances of 50, 100, and 112 m to each other (a). Main constituents of the injection facility are two CO_2 storage tanks with 50 t capacity each, the pump station with five plunger pumps and electrical heater, and four large ambient air-heaters (b). The injection well is equipped with surface and subsurface safety valves triggered by high–low pressure pilots for safety reasons (c). Four corner reflectors are installed for InSAR monitoring (d) and CO_2 soil gas concentration is measured and monitored by automated soil-gas samplers (e).

450 m into the lowermost sandstone layer of the Exter Formation. P300 is equipped with permanent pressure gauges at depths of ~21 and ~420 m to allow for permanent detailed pressure monitoring and a U-tube type system for periodic sampling of formation fluids.

The injection facility consists of two storage tanks with capacities of 50 t CO_2 each, five plunger pumps for liquid CO_2, an electrical heater, four large ambient air-heaters, and a 100 m long injection pipeline with about 1″ diameter that connects the pump station with the injection well Ktzi 201 (Fig. 12.3). The plunger pumps allow for injection rates between a few hundred and up to 3250 kg CO_2/h.

Apart from the installations that are directly linked to the injection process, several monitoring devices have been installed at the Ketzin pilot site (Fig. 12.3). These include four corner reflectors for InSAR monitoring as well as several soil gas samplers. These samplers automatically sample and analyse the soil gas every hour. At the southern boundary of the site, 13

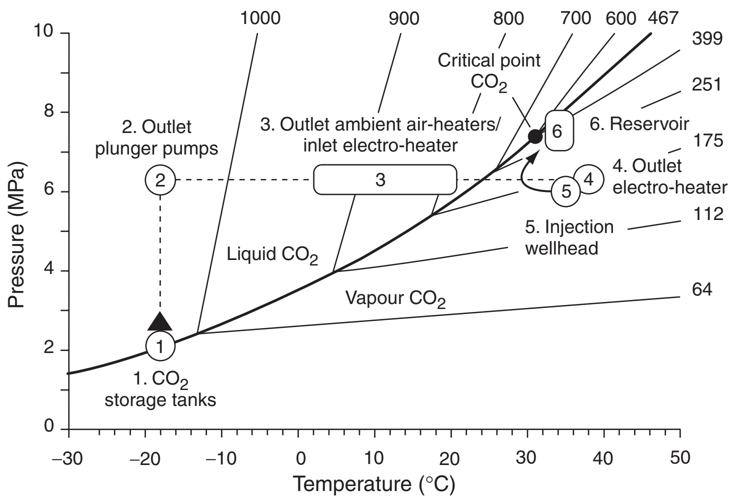


12.4 Schematic diagram showing design, casing layout and installations of the three deep wells at Ketzin. All three wells are designed with identical casing layout. Casing quality is 4140 for 24″ stand pipe, X56 for 18 5/8″ conductor casing, K-55 for 13 3/8″ and 9 5/8″ reserve and intermediate casings, and 13Cr80 for the 5 1/2″ production casing. In Ktzi 201 a 3 1/2″ injection string of C-95 with inside coating is installed. Wells are connected to the reservoir with slotted liners and sand filters in the reservoir section. All wells are equipped with a fibre-optic-sensor cable loop for distributed temperature sensing (DTS) outside the 5 1/2″ production casing. Ktzi 201 and Ktzi 202 additionally contain electrical heater cables. Vertical electrical resistivity arrays (VERA), each consisting of 15 toroidal steel electrodes with a spacing of about 10 m, have been installed in all three wells at depths between about 590 and 730 m. Outside the injection string of Ktzi 201 a P–T gauge at 550 m and an additional DTS are installed. Insets left of well drawings indicate depths of top and base of Stuttgart Formation and sandstone reservoir intervals. (*Source*: compiled and re-drawn with additions after Prevedel *et al.*, 2008, 2009; Förster *et al.*, 2010.)

shallow 50 m wells with a spacing of about 10 m have been drilled and 4C and 3C receivers for continuous passive seismic recording have been buried in the wells at depths of 50 and ~1 m, respectively (Arts *et al.*, 2011). These receivers are also used during active seismic campaigns.

12.3.2 Injection process

The injection process at the Ketzin pilot site consists of a stepwise pre-conditioning of the CO_2 to the desired injection pressure and temperature conditions (Fig. 12.5): Liquid CO_2 is delivered by road tankers and first stored in the two storage tanks at ~ −18°C/2 MPa. The plunger pumps isothermally raise pressure according to the reservoir driven injection pressure. Pre-heating of the CO_2 is done by the four large ambient air-heaters installed downstream of the pumps. Outlet temperatures of the ambient air-heaters depend on ambient temperature conditions and vary from slightly below 0°C to above 20°C. Final heating up to the desired injection temperature with concomitant evaporation of the CO_2 is done by the electrical heater. Pressure and temperature conditions, at the outlet of the electrical heater, are set to match around 45°C and 6.0–6.5 MPa. Along the injection pipeline to the injection wellhead at Ktzi 201 pressure and temperature slightly decrease. Within the injection well, pressure continuously rises with

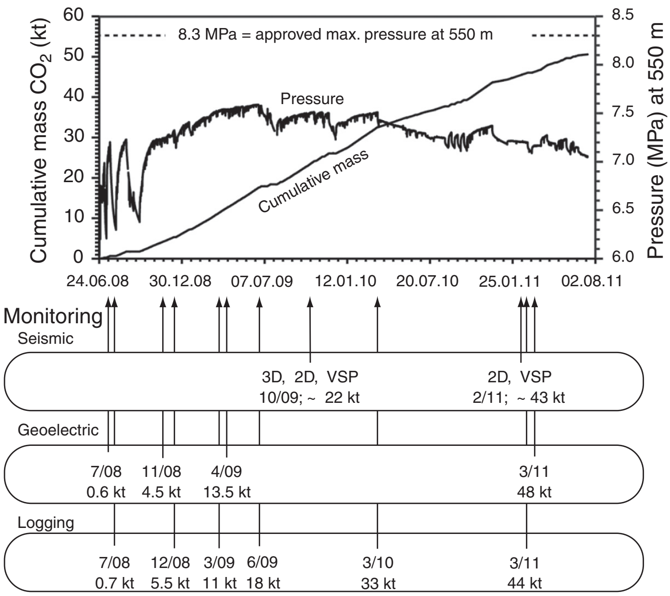


12.5 Schematic diagram showing the pressure–temperature–density conditions of the injection process at Ketzin; actual pressure and temperature conditions depend on injection rate and ambient weather conditions. CO_2 is stored in two storage tanks as delivered by road tankers at ~ −18°C/2 MPa (1). Plunger pumps raise pressure isothermally up to required injection pressure of ~6.3 MPa (2). Pre-heating of pressurized CO_2 occurs by four large ambient air-heaters (3). Final heating to desired injection temperature of ~38°C and evaporation from liquid to gaseous CO_2 is done by aid of a 300 kW electrical heater (4). On its way to the injection wellhead along the injection pipeline, pressure and temperature of CO_2 slightly drop (5). Within the injection well, pressure continuously increases up to reservoir conditions whereas temperature first decreases in the upper part of the well due to cooling from the surroundings and then increases along the normal Ketzin geotherm up to reservoir conditions (6). Thin lines are isodensity lines with CO_2 density given in kg/m^3, the thick curve is the liquid–vapour equilibrium for CO_2 and the dot is the critical point for CO_2. (*Source*: after Span and Wagner, 1996.)

increasing depth due to the continuously increasing weight of the CO_2 column whereas temperature first decreases in the upper parts due to cooling from the surroundings and then increases along the normal geotherm of the Ketzin pilot site. Typical injection temperatures are 33–34°C at reservoir depth.

A test phase with continuous injection of CO_2 started on 30 June 2008. Before the start, several mechanical tests of the injection facility were run during the commissioning phase. This phase also included first injections of small amounts of CO_2 to test shut-in procedure as well as admission of N_2 during shut-in phases. Test runs lasted until 24 September 2008, when injection entered normal operation. During test run, the injection is characterized by varying injection rates and several shut-in phases of different durations due to seismic campaigns or technical reasons. With the start of normal operation, injection rates were ramped up stepwise from 2000 to 2600 kg/h and finally to a maximum rate of about 3200 kg/h by March 2009. Maximum injection rate was run until March 2010 with only a few exceptions due to monitoring campaigns and injection tests. From March to August 2010, injection rate was lowered to 1500 kg/h and from August to October 2010 a four-cycle injection and pressure response test was performed followed by maximum injection rate until December 2010. From December 2010 to August 2011 average injection rate was again 1500 kg/h. Cumulative mass of injected CO_2 continuously increased up to 67.3 kt by August 2013, when injection ended (Fig. 12.6). Except for 4 May to 11 June 2011, when 1515 t of technical CO_2 from the Oxyfuel pilot plant Schwarze Pumpe (Brandenburg, Germany) had been injected, the CO_2 was generally of food-grade quality with purity > 99.9% delivered by Linde AG. Purity of the technical CO_2 from the Oxyfuel pilot plant Schwarze Pumpe was >99.7%.

During the test phase, the pressure evolution as recorded by the pressure gauge at 550 m depth in the injection well Ktzi 201 was highly unsteady due to the varying injection rates and several shut-in phases (Fig. 12.6). The start of CO_2 injection was on June 30th, 2008. The initial reservoir pressure of 6.1 MPa increased to 7.2 MPa after 5 days of injection. During subsequent shut-in phases the observed pressure drops were likewise fast and each time pressure decreased again to almost initial conditions within only about 13 days. However, with the onset of normal operation and continuous injection, the pressure at 550 m depth in Ktzi 201 stabilized at between about 7.3 and 7.6 MPa corresponding to an increase in reservoir pressure by about 1.2–1.5 MPa due to the injection. With overall lowering of the injection rate by March 2010, pressure decreased smoothly by about 0.2 MPa and again stabilized at about 7.1–7.3 MPa (Fig. 12.6). The observed pressure and temperature conditions within the reservoir correspond to a CO_2 density between about 270 and 400 kg/m^3 (Span and Wagner, 1996). Maximum permitted reservoir pressure as defined in the licensing notice of the mining



12.6 Cumulative mass of injected CO_2, evolution of reservoir pressure and main monitoring campaigns during first three years of injection. For the monitoring campaigns, the cumulative amount of injected CO_2 is given. VSP, vertical seismic profiling.

authority is 8.5 MPa at 630 m depth. This transforms into 8.3 MPa at 550 m depth, that is, installation depth of the pressure gauge.The data clearly show that the injection process ran smooth and safely and that the increased reservoir pressure due to the injection process was significantly below the maximum approved pressure (Fig. 12.6). Numerical simulations that applied and tested different numerical simulation codes were able to history match the observed pressure evolution in the reservoir and the arrival of the injected CO_2 at the first observation well Ktzi 200 (Kempka *et al.*, 2010). Arrival of the injected CO_2 at the two observation wells has been determined with aid of a new gas membrane sensor (Zimmer *et al.*, 2011a) and occurred on 15 July 2008, at Ktzi 200 and on 21 March 2009, at Ktzi 202 after injected amounts of CO_2 of 0.53 kt for Ktzi 200 and 11.2 kt for Ktzi 202.

12.4 Integrated operational and scientific monitoring

An integrated world-class operational and scientific monitoring programme forms the heart of the R&D work done at the Ketzin pilot site. This monitoring programme pursues the objectives to ensure a smooth and safe injection process ('operational monitoring') and to detect and track the subsurface behaviour of injected CO_2 ('scientific monitoring'). The programme includes geophysical, geochemical and microbiological monitoring techniques applied to surface, shallow subsurface and reservoir depths (Giese *et al.*, 2009). The different techniques have different temporal and spatial resolution and their combination allows for detailed monitoring of the different aspects of CO_2 storage.

12.4.1 Operational monitoring

To allow for steering and monitoring the injection operation as well as the pressure response of the reservoir the following operational data are recorded (Liebscher *et al.*, 2013): (i) nominal and actual flow rate, levels of storage tanks 1 and 2, outlet pressure and temperature for the injection plant, (ii) wellhead pressure (WHP), bottom hole pressure (BHP; at 550 m depth), bottom hole temperature (BHT; at 550 m depth), distributed temperature sensing (DTS) along injection string, and casing pressures 1 and 2 for injection well Ktzi 201, (iii) WHP and casing pressures 1 and 2 for observation well Ktzi 200 and (iv) WHP and BHP (since 26 March 2010) and casing pressures 1 and 2 for observation well Ktzi 202. The data are continuously recorded online and displayed and updated on the operator's screen. Additionally, all data are stored in the site Supervisory Control and Data Acquisition (SCADA) system as the arithmetic mean over a time span of 5 min.

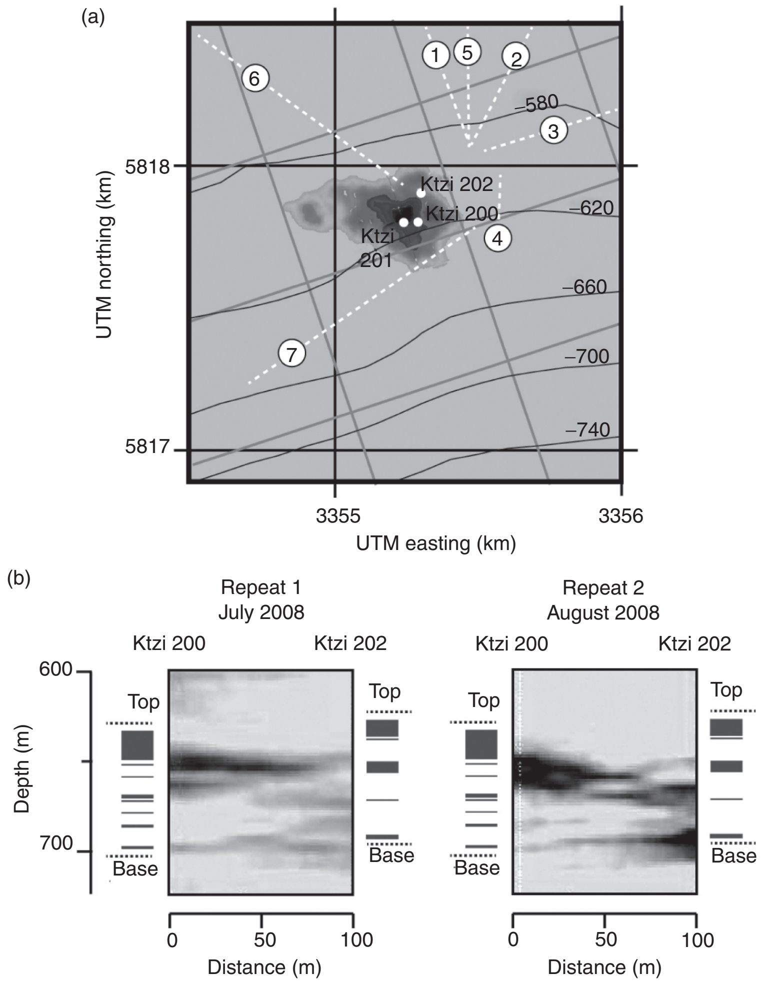
12.4.2 Surface monitoring

To identify and monitor upward migration of CO_2 with potential leakage to the surface, a comprehensive surface monitoring network has been established at the Ketzin pilot site. The network consists of 20 sampling locations for soil CO_2 gas flux, soil moisture, and temperature measurements covering an area larger than the expected dimension of the CO_2 plume (Zimmer *et al.*, 2011b). The monitoring network aims at distinguishing between natural background CO_2 flux and its temporal and spatial variations and impacts of potential CO_2 leakage. For this purpose, baseline measurements started already in 2005, 3 years before the start of injection, with sampling done once a month. In addition to soil CO_2 gas flux, soil moisture, and temperature measurements, soil samples were taken and analysed for their organic carbon and nitrogen contents. Since the start of injection, no change in soil CO_2 gas flux could be detected in comparison to the pre-injection baseline. Mean CO_2 flux as averaged over all sampling sites ranged from 2.4 to 3.5 $\mu mol/m^2s$ for the pre-injection period and from 2.2 to 2.5 $\mu mol/m^2s$ after start of injection (Zimmer *et al.*, 2011b). The spatial variability of soil CO_2 gas flux is 1.0–4.5 $\mu mol/m^2s$ among all sampling sites reflecting different soil's organic carbon and nitrogen contents. Overall, the data show that soil temperature and its annual variation is the predominant factor controlling CO_2 flux rate and that diurnal temperature variations and soil moisture have no significant influence. Measured spatial variability of soil CO_2 gas flux sums up to 1400–6300 t/km^{2}year and places a lower limit on leakage rate that may be detected by soil CO_2 gas flux measurements.

Besides soil CO_2 gas flux measurements, surface monitoring at Ketzin also includes InSAR monitoring. For this purpose, four corner reflectors have been installed at the Ketzin pilot site in Spring 2011 to ensure precisely defined reflection points. InSAR monitoring makes use of the TerraSAR X satellite, which provides photos of the pilot site taken every 11 days, with further analysis under way.

12.4.3 Active and passive seismic monitoring

Active seismic monitoring performed at Ketzin includes surface, surface to downhole and cross-hole tomographic surveys thus covering notably different spatial resolutions. Baselines for 3D and 2D surface monitoring were acquired in Autumn 2005 with a subsurface coverage for the 3D survey of about 12 km^2 (Juhlin *et al.*, 2007). 2D surveys are done along 7 profile lines oriented about radially around the injection well ('2D star'). First 3D and 2D repeats were acquired during September to November 2009 after injection of 22–25 kt CO_2; a second 2D repeat was acquired during February 2011 after injection of about 43 kt CO_2 (Fig. 12.6; Lüth *et al.*, 2010). Subsurface coverage of 3D repeat was only about 5 km^2 and focused on the near injection well area. For preliminary data interpretation, amplitudes of repeat and baseline were normalized to reflections of a prominent, about 20 m thick anhydrite layer (so-called 'K2 layer') about 70 m above the top of the Stuttgart Formation. Normalized reflection amplitudes picked up at travel times 42 ms later than K2 travel times approximately correspond to reflections from the top of the Stuttgart Formation (Juhlin *et al.*, 2010; Lüth *et al.*, 2010). For these reflections a normalized amplitude difference map between baseline and repeat has been calculated and provides a preliminary description of the extension of the CO_2 in the reservoir (Fig. 12.7; Juhlin *et al.*, 2010). Amplitude differences are highest in the immediate vicinity of the injection well and decrease with increasing distance to the injector. The data indicate an elliptic, roughly west–northwest to east–southeast striking geometry of the CO_2 plume with dimensions of about 400 × 250 m. Time lapse processing of the 2D baseline and first repeat including amplitude versus offset analysis did not show any time lapse effects for the 2D data in accordance with the results from the 3D repeat that indicated that CO_2 plume extension is insufficient to reach the area covered by the 2D star lines (Fig. 12.7; Bergmann *et al.*, 2011).



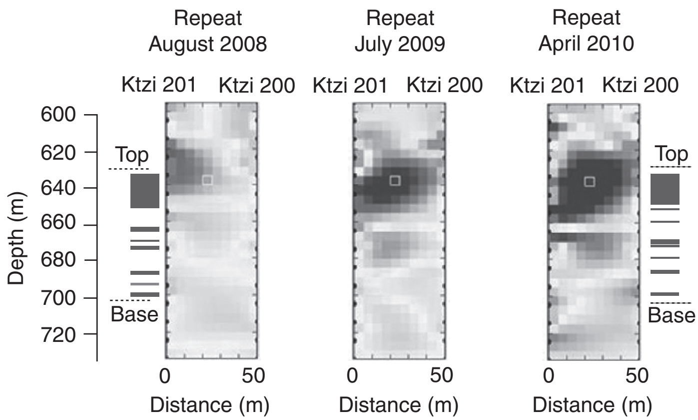
12.7 Results from the active seismic monitoring campaigns at the Ketzin pilot site. (a) The results from the first repeat of the 3D seismic survey are given as a normalized amplitude difference map for baseline minus repeat. The shown depth slice approximately corresponds to the top of the injection horizon. The degree of grey shading correlates with the degree of amplitude difference. For clarity, only significant changes in amplitudes are shown, minor amplitude differences due to background noise were manually suppressed by use of a uniform grey shading. Dashed white lines indicate surface positions of the profile lines for the 2D star surveys. (b) Differences between baseline and first (left) and second (right) repeat of cross-hole seismic surveys as determined by covariance tomographic reconstruction. Cross-hole seismic measurements were performed between Ktzi 200 and Ktzi 202. The degree of grey shading correlates with the degree of changes in seismic signal. Insets left and right of the cross-hole plane indicate base and top of the Stuttgart Formation and position of the different sandstone horizons. (*Source*: compiled and re-drawn with additions after Juhlin *et al.*, 2007, 2010; Förster *et al.*, 2010; Lüth *et al.*, 2010.)

Mere surface monitoring methods often have a low resolution for deep and especially thin structures. To overcome this problem and also to test for less cost intensive and less logistically demanding monitoring methods, additional surface to downhole and cross-hole tomography methods have been applied at the Ketzin pilot site (Giese *et al.*, 2009; Lüth *et al.*, 2010). So far, two repeats of surface to downhole measurements have been performed in October 2009 and February 2011 after injection of about 22 and 43 kt CO_2, respectively. Surface to downhole surveys allowed a more detailed characterization of the near injection well area and especially were able to image coherent reflections from the base and top of the Stuttgart Formation, features that were not resolvable in the 3D data (Lüth *et al.*, 2010). Baseline measurements for the cross-hole tomography were performed during Spring 2008 and repeats were acquired in July and August 2008 and July 2009 after injection of about 0.63, 1.75 and 19 kt CO_2. The first two repeats were done within only 6 weeks after the arrival of CO_2 at the first observation well Ktzi 200 and the amount of CO_2 was insufficient to create a significant time lapse effect due to changes in travel time. However, a more detailed and sensitive processing of the data showed slight changes in the amplitudes of transmitted seismic waves, which mirrored the spreading of the injected CO_2 between the two observation wells (Fig. 12.7; Lüth *et al.*, 2010).

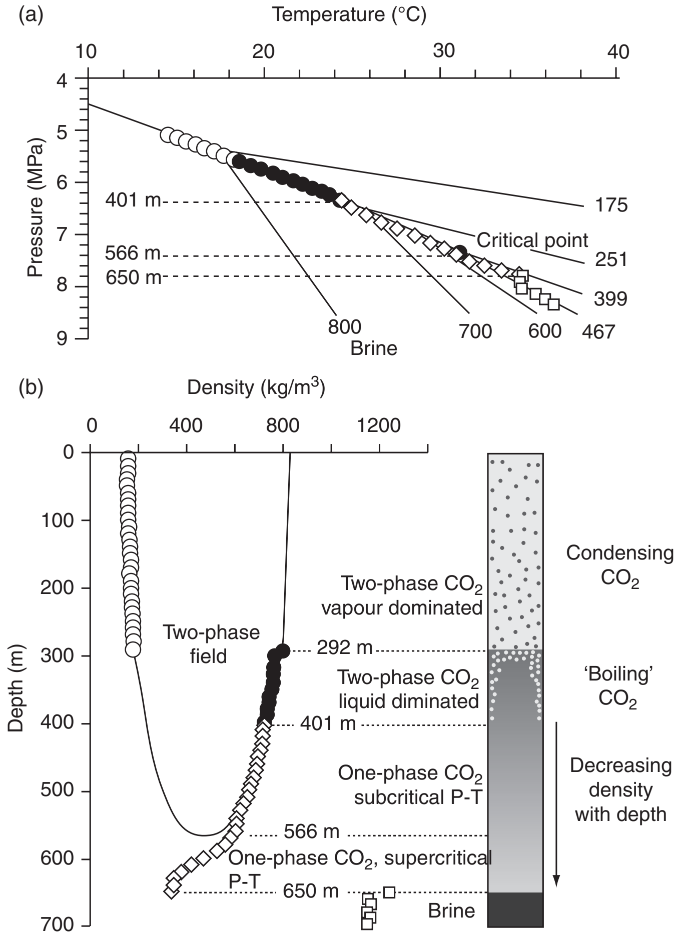
Passive seismic monitoring is so far restricted to the 13 shallow wells containing the permanently buried multi-component seismic array, which was installed in August 2009 (Arts *et al.*, 2011). For this array therefore no pre-injection baseline exists, which makes time lapse interpretation challenging. The array has also been used for an active seismic survey acquired in November 2009. This survey resulted in an about 230 m long 2D seismic profile that roughly passed through the observation well Ktzi 202. First results of this active seismic survey showed an increased frequency content of the data up to 300 Hz when compared with the conventional surface 3D data. The results also allowed imaging internal structures of the Stuttgart Formation although detection of the injected CO_2 is hindered by the lack of a baseline survey (Arts *et al.*, 2011).

12.4.4 Geoelectric monitoring

Geoelectric monitoring consists of the permanently installed VERA system, which is deployed at the Ketzin pilot site as cross-hole configuration for monitoring the in-between wells area at depths between about 590 to 735 m as well as part of the surface to downhole measurements. For surface to downhole measurements 16 surface dipoles with dipole length of 150 m are placed on two concentric circles around the injection well with radii of about 800 and 1500 m, respectively, and combined with potential dipoles in all three wells from the VERA system (Kiessling *et al.*, 2010). Baseline data were acquired in June 2008 for the cross-hole measurements and in October 2007 and April 2008 for the surface to downhole measurements. Due to the permanent installation of the VERA system, repeat surveys were performed on a daily basis in June and July 2008, twice a week until December 2008 and on a weekly basis from January 2009 onwards. Four surface to downhole repeat surveys were acquired in July and November 2008, April 2009 and March 2011 after injection of 0.6, 4.5, 13.7 and 45 kt CO_2 (Fig. 12.6; Kiessling *et al.*, 2010). Cross-hole electrical resistivity tomography (ERT) with the permanently installed VERA system was capable of imaging the evolving CO_2 plume from the injection towards the observation wells (Fig. 12.8). However, sensitivity studies indicated that sensitivity is highest within only few tens of metres around the wells and cross-hole ERT is therefore only significant for the near-well area or for closely spaced wells as is the case for the Ketzin site.



12.8 Results from geoelectric monitoring at the Ketzin pilot site. The cross-hole electrical resistivity tomography for observation plane Ktzi 201–Ktzi 200 is based on the permanently installed VERA system. Grey shadings correlate with increasing resistivity ratios between repeat and baseline surveys with darkest shadings corresponding to an about fourfold resistivity increase. The data clearly image the spread of high-resistivity CO_2 from the injection well Ktzi 201 towards the observation well Ktzi 200 with time and increasing amount of injected CO_2. Small insets left and right indicate base and top of the Stuttgart Formation and the positions of the different sandstone horizons in Ktzi 200 and Ktzi 201. (*Source*: Compiled and re-drawn with additions after Förster *et al.*, 2010; Schmidt-Hattenberger *et al.*, 2011.)



12.9 Pressure–temperature–density–depth conditions within observation well Ktzi 200 as measured during the logging campaign in March 2009. Since December 2008 observation well Ktzi 200 has been completely filled with CO_2 down to a depth of ~650 m and measured pressure–temperature data therefore directly reflect the different fluid properties of CO_2 within the well. (a) Down to a depth of 401 m, the measured P–T conditions follow the vapour saturation curve for CO_2 after Span and Wagner (1996) and indicate two-phase fluid conditions within the well. Below 401 m depth, measured pressure is slightly higher than vapour saturated pressure for CO_2 and indicates one-phase fluid conditions with liquid CO_2 above 566 m depth and supercritical pressure–temperature conditions below 566 m depth. Between 401 and 650 m, CO_2 density decreases with depth. Below 650 m the observation well Ktzi 200 is filled with brine. (b) Interpretation of measured pressure–temperature–depth data in terms of CO_2 fluid properties. Pressure data were converted to effective CO_2 density whereas temperature data were used to calculate CO_2 liquid–vapour phase relations as a function of depth according to the equation of state of Span and Wagner (1996). Down to a depth of 292 m the well is dominated by vapour CO_2 with condensing droplets of liquid CO_2, whereas between 292 and 401 m depth the well is dominated by boiling liquid CO_2 with rising bubbles of vapour CO_2.

12.4.5 Wellbore monitoring

Wellbore monitoring at Ketzin focuses on determination of CO_2 saturation in the near-well area and determination of pressure and temperature conditions in all wells. Corresponding logging campaigns were performed in August and December 2008, March and June 2009, March 2010 and March 2011 after injection of about 0.7, 5.5, 11, 18, 33 and 44 kt CO_2 (Fig. 12.6). Saturation measurements imaged the CO_2 accumulation within the reservoir sandstone horizons but gave no hints to any upward migration of CO_2 along the wellbores. Measured pressure and temperature data helped to determine the different CO_2 fluid states within the observation wells (Henninges *et al.*, 2011). Wellhead pressures recorded for the observation wells Ktzi 200 and Ktzi 202 in the frame of operational monitoring after arrival of CO_2 showed notable deviations from expected values and could not be explained by a single-phase CO_2 column throughout the wells. Pressure–temperature logs in combination with thermodynamic properties of CO_2 yielded a complex picture of different CO_2 fluid states in the observation wells (Fig. 12.9). In the upper parts of the wells liquid and gaseous CO_2 coexist but due to their different densities try to separate from each other. This results in a vapour dominated region in the uppermost part where droplets of liquid CO_2 condense and sink downwards and a liquid dominated region below where bubbles of gaseous CO_2 boil off and ascend upwards. These conditions result in heat-pipe-like phenomena with higher than normal temperatures in the upper parts and lower than normal temperatures in the lower parts of the wells (Henninges *et al.*, 2011). Below the two-phase region, CO_2 is single-phase down to the brine table, however, exhibits inverted density profiles with decreasing density with increasing depth and pressure. These wellbore fluid states derived from pressure and temperature data were then proved in a spectacular manner by video inspections of the observation wells. Due to these two-phase fluid conditions in the observation wells the wellhead pressures are decoupled from the actual reservoir pressure. Furthermore, operational data showed that wellhead and reservoir pressure are inversely correlated and increasing reservoir pressure resulted in decreasing wellhead pressure. These phenomena make calculation of reservoir pressure based on wellhead measurements, as is typically done in natural gas storage operations, impossible. As long as two-phase fluid conditions in the observation wells prevail precise information on reservoir pressure could only be gathered by the aid of pressure sensors directly installed at reservoir depth.

12.5 Lessons learned from the Ketzin pilot site

Since beginning of injection in June 2008, the injection of CO_2 at the Ketzin pilot site ran reliably and safely. All technical and monitoring installations have proven their capacity. Up to now all monitoring results indicate that the injected CO_2 behaves in the predicted and foreseen manner. Especially, the monitoring results give no hints to any migration or leakage of the CO_2 out of the reservoir. The most important results gained at the Ketzin pilot site in terms of large scale implementation of CO_2 storage are: (i) The combination of different monitoring techniques applied at Ketzin is capable of detecting and imaging the CO_2 in the subsurface. (ii) Results from active seismic measurements indicate that cost intensive and logistically demanding 3D seismic acquisitions may potentially be displaced by other seismic methods at an acceptable degree of spatial coverage and resolution at reservoir depths. (iii) In terms of reservoir depth, pressure and CO_2 density, Ketzin is an analogue for a shallow aquifer or the 'indicator horizon' located above the cap rock of a future large scale storage site, which will exhibit greater reservoir depth and higher pressure with correspondingly higher CO_2 density. In this regard, injection at Ketzin illustrates the potential accumulation of upward migrating CO_2 that has leaked from an underlying reservoir and results gained at Ketzin place constraints on the detectability of such a leakage scenario. Hence, for well-defined monitoring layouts small accumulations of a few thousand (geoelectric data) to a few tens of thousands (seismic data) tons are certainly to be detected. Given injection rates of a million to several million tons of CO_2 per year for large scale industrial storage sites, the results transfer into detectable leakage rates of notably < 1%/year. (iv) Pressure monitoring at reservoir depth is highly recommended. Although reservoirs at future large scale storage projects will be located at greater depth and higher pressure conditions than at the Ketzin pilot site, two-phase fluid conditions in the observation wells may nevertheless occur. Only for rather deep and high pressure reservoirs, CO_2 phase transitions in the observation wells can be excluded. Such two-phase fluid conditions preclude pressure monitoring via simple measure of wellhead pressure. Calculated reservoir pressures based on such an approach will be flawed and may lead to wrong engineering of the reservoir. Precise knowledge of the reservoir pressure is not only important with regard to potential effects on the reservoir and cap rock integrity but is also an important input parameter for the interpretation of the different geophysical monitoring techniques.

12.6 Future trends

In terms of large scale implementation of CO_2 storage, up-scaling of results gained at test or pilot sites like Ketzin is indispensable and there is a clear need for R&D related demonstration storage projects in the next step. However, test or pilot sites like Ketzin will still have an important role to fulfil. It is at these sites where test and field experiments can be performed that are not feasible at demonstration or industrial projects. Such tests and field experiments include but are not limited to (i) testing of impurities in the CO_2 stream at various levels and with regard to qualities from different sources, (ii) testing of different types of wellbore leakage and failure that may even include the risk of losing a well, (iii) targeted fracturing of the cap rock or reactivation of faults for monitoring leakage or testing remediation methods, (iv) testing of different strategies and types of well closure and abandonment, and (v) testing of re-production of injected CO_2 either as a remediation method or in the frame of CCU technologies.

12.7 Acknowledgements

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13
The K12-B CO_2 injection project in the Netherlands

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Abstract: The Netherlands Government is investigating to what extent CO_2 emissions could be reduced by CO_2 storage in the deep subsurface and supports feasibility and implementation studies in this area. GDF SUEZ E&P Nederland B.V. (GPN) produces natural gas from the Dutch North Sea continental shelf and supports the idea of using depleted gas fields for long-term storage of CO_2. In this chapter, the results of the ORC project – Offshore Re-injection of CO_2 – at the K12-B GPN platform are presented, including the actual injection test and injection-monitoring results. The ultimate goal is to develop the K12-B gas field into a full injection site for underground CO_2 storage.

Key words: CO_2 storage, offshore, North Sea, tracer, history match, enhanced gas recovery.

13.1 Introduction

GDF SUEZ E&P Nederland B.V. (hereinafter called GPN) currently produces natural gas from various gas production installations at the Dutch continental shelf of the North Sea. In line with the Dutch Climate Policy on the implementation of the Kyoto Protocol, the Netherlands Government has in the past investigated and continues to investigate to what extent Dutch CO_2 emissions could be reduced by CO_2 storage in the deep subsurface. As a stimulation measure the Minister of Economic Affairs published on 7 February 2002 a specific subsidy to support the execution of studies into the feasibility and implementation of CO_2 injection and storage in the subsurface including the associated required infrastructure and organization (BSE-2002-CRUST subsidy, CATO subsidy).

The gas produced at one of GPN's platforms, the KI2-B platform, has a relatively high CO_2 content (up to 13%). This CO_2 was separated from the produced natural gas and vented to the atmosphere, thus contributing to the climate change. Preliminary studies show that re-injecting this CO_2 into the Rotliegend sandstone gas reservoir, as an alternative to venting, may be relatively easy. The reservoir is located at a depth of some 3800 m; with a formation temperature of 129°C. Hence, GPN's KI2-B platform offers a good opportunity to study the technical requirements of CO_2 injection into the deep subsurface, including the behaviour of the gas reservoir itself.

This chapter reports on the results of phases 1 and 2 of the ORC project – Offshore Re-injection of CO_2, a project into CO_2 storage supported by the Netherlands Government. Phase 1 included a desk feasibility study into the possibility of underground CO_2 injection at the K12-B platform, as well as an analysis of the necessary equipment and techniques. During phase 2, a relatively small amount of CO_2 was injected into two reservoir compartments that are part of the Rotliegend reservoir sequence. The major results and conclusions and lessons learned from this pilot project (6 years injection) are presented in this chapter.

13.1.1 Project purpose and outline

The purpose of this project is to investigate the feasibility of CO_2 injection in depleted or nearly depleted natural gas fields with the objective of realizing in the long term an industrial size CO_2 injection and storage facility. Relevant aspects to be investigated during the project include:

- the necessary surface and subsurface equipment;
- the behaviour of the gas field;
- economics of the underground injection and storage;
- legal, regulatory and social aspects;
- health, safety and environmental aspects.

The name of the associated overall project is the ORC project: Offshore Re-injection of CO_2. The project consists of three phases:

- Phase 1 of the ORC project consists of investigating the feasibility of underground CO_2 injection by using existing installations, equipment and techniques.
- Phase 2 subsequently consists of the actual demonstration of offshore underground CO_2 re-injection. The purpose of this phase is to gain experience with respect to all aspects of underground injection and storage, including but not limited to technical, operational, safety, environmental, financial and company-strategy points of view.
- Phase 3 includes the scale-up of the demonstration installation to a full-scale industrial size CO_2 injection installation including the investigation of possibilities for re-use of the injected CO_2.

This additional CO_2 for the scaled up phase can originate from the treatment at K12-B of CO_2 containing gas from adjacent gas fields or can be transported from other onshore or offshore locations. The potential available storage volume at the K12-B location is estimated to amount to about 12.64 billion Nm^3 (i.e. ca. 25.02 Mt CO_2, Nm^3 stands for normal cubic metres). Anticipated possible applications for the re-use of the stored CO_2 are Enhanced Oil Recovery-projects, for 'mature' oilfields in the North Sea.

The base case for the design and evaluation of the required facilities is that the amount of CO_2 that is currently released to atmosphere is re-injected. For the scale up phase it is however anticipated that a far larger quantity will be injected. Therefore the following two cases are distinguished:

(1) Base case; re-injection of 30 000 Nm^3 CO_2 per day (59 ton/day or 20 kton/yr assuming 8000 running hours per year), that is, the quantity that is released at the CO_2 removal unit at K12-B over the period from 2004 until 2010.
(2) Future large-scale case; re-injection of 20 000–30 000 Nm^3 CO_2 per hour (925–1425 ton/day or 310–475 kton/yr), that is, the quantity that can be separated from natural gas at maximum throughout through the gas treatment and CO_2 removal units. This case was studied in a qualitative manner with the purpose of looking ahead to the anticipated scale-up of the units in phase 3.

13.1.2 Overview of the site and project drivers

Geophysical aspects of K12-B geology

The K12-B field is located in an area (Fig. 13.1) where the main components (source, reservoir and seal) for successful natural gas exploration are provided by stacked sequences. The Late Carboniferous coals are the principal source of gas for the fields. The Southern Permian basin developed during the early Permian. Along the southern margin of this basin, clastics of the Rotliegend Group were deposited under desert and desert-lake conditions as a number of alluvial fans, which graded northwards into the sands (Slochteren Sandstone Formation), shales and further north into red beds and evaporites. In the K-blocks the Rotliegend is a sand/shale sequence. The sandstones generally have porosities of 13% and average permeabilities of 2–10 md (extremes may reach up to 1000 md). Periodic restrictions of water influx and an arid climate during the Late Permian resulted in the deposition of four Zechstein evaporite sequences. The Zechstein salts form an excellent seal for the Rotliegend reservoir.

13.1 Location map of the K12-B field.

K12-B wells and gas production

The K12-B structure was discovered in 1981 by drilling the K12-6 exploration well. As the gas reserves proved to be economically recoverable, a number of wells were drilled to develop the K12-B field. The installation of the surface facilities (including CO_2 removal system) and the drilling of the initial development wells started in 1985. The gas bearing formations are located at a depth of some 3800 m sub-sea (SS), and well behaviour has shown that the reservoir has been subdivided by more or less sealing faults into a number of compartments (Plate IX in colour section between pages 214 and 215).

Enhanced gas recovery (EGR)

CO_2 injection might be used to enhance the gas production from the existing reservoir, so-called enhanced gas recovery (EGR). The principle of EGR is that an injected fluid (e.g. CO_2) forms a front that pushes the natural gas to the production wells. The K12-B field however consists of relatively thin sand/shale sequences with different permeabilities. After years of gas production the more permeable productive layers show much more depletion (lower pressures) than the less permeable layers. When considering injecting CO_2 for EGR, this is a disadvantage, because the injected CO_2 will follow the path of lowest resistance, namely the depleted sand layers of high permeability, instead of creating a wide front pushing forward the gas towards a producing well. The CO_2 might flow relatively directly to a well producing natural gas, thus more or less re-circulating the gas and possibly harming the production of this well.

Obtaining field experience

In any planning phase of a potential CO_2 storage site, the following aspects need to be considered:

- sealing properties;
- geomechanical phenomena;
- chemical phenomena;
- CO_2 dissolution;
- mixing and enhanced CH_4 recovery;
- CO_2 recovery;
- CO_2 storage capacity.

It appeared from the initial assessments that the K12-B is very suitable to store CO_2 and many of the phenomena and field behaviours can be predicted from theory. There remained however quite a number of interesting points where knowledge on the exact behaviour cannot be predicted theoretically and field experience was considered imperative. The phase 2 demonstration project did indeed produce valuable information that is not only applicable for the K12-B reservoir but also for other developments with CO_2 injection in depleted natural gas reservoirs. Emphasis during the demonstration phase was concentrated on factors that could not be predicted from theory that might influence the injectivity, for example, possible loosening of scale from inside the tubing or mobilization of fine material in the reservoir such as illite. Apart from the normal gas measurement at the wellheads of the producing and injection wells, extra attention has been paid to 'produced gas ratios' (CO_2 vs CH_4), and the chemical tracers that have been used. Since it was likely that during the demonstration phase not all questions with respect to the learning points could be answered it was recommended to perform more detailed (computer) modelling before the start of phase 3. Phase behaviour in the well and in the reservoir related to injectivity is a particularly important issue.

13.2 Site characterization

13.2.1 Facilities

The existing K12-B platform is located on the Dutch continental shelf about 150 km north-west of the city of Amsterdam and consists of two bridge-linked platforms. The main production platform includes facilities for natural gas treatment (separation of liquids, drying and CO_2 removal), compression of natural gas, power generation, and accommodation for the platform staff, etc. At the bridge-linked wellhead platform there are eight wells for gas production, as well as well test facilities. K12-B treats gas from a nearby subsea well as well as gas from its own wellhead platform.

K12-B produces natural gas with a relatively high CO_2 concentration of about 13 vol. %. In order to meet the export pipeline specification, the CO_2 is separated at K12-B from the natural gas until there is a residual concentration of about 2%. The treated natural gas is subsequently transported to shore by the NGT pipeline. Before the project started, the separated CO_2-rich stream with a CO_2 concentration of about 95%, and 5% of other components used to be released to the atmosphere via a vent pipe. The average gas production at the K12-B platform amounts to ca. 300 000 Nm^3/day and the associated CO_2 emissions amounted to about 30 000 Nm^3/day (i.e. ca. 60 ton CO_2/day).

The CO_2 is stored in the K12-B reservoir located at a depth of about 3744 m. From this reservoir currently gas is produced but the field is almost depleted. CO_2 has been injected into the field via well K12-B8 and is currently being injected via well B6, and methane gas is produced by means of wells K12-B1 and B5 at the flank of the field. Because the field is currently operating the injection wells were readily available for the CO_2 storage project and only minor modifications were required. In principle the storage in the K12 reservoir can be considered as permanent both for the small-scale demonstration phase and the full-scale phase. The risk that the stored CO_2 escapes to the atmosphere is considered negligible, as the gas field has proven to be gas tight over the past million years. It remains possible to re-enter the gas field to re-use the stored CO_2, however, should there be a useful application for the gas in the future.

13.2.2 Operational aspects

The general philosophy for the control and safeguarding of the injection facilities is that the unit operates continuously and that the process is, as much as possible, automatically controlled. To meet these objectives the injection facilities were designed with all the control and safety equipment required. Regular inspections of the unit and intervention in cases of upset are handled by the existing platform personnel. In instances of failure or malfunction, the process control and/or operator have restored the normal operation without endangering overall safety. However, the safety policy for the injection facilities is that if there is a major upset, the facilities will be shut down and the CO_2 will be passed directly to the vent. The wells will also be brought into a safe position.

13.2.3 Compressor unit

To facilitate the injection, the CO_2 is to be extracted downstream of the existing cooler and separator at a temperature of about 35°C and an almost atmospheric pressure. The facilities were designed to prevent air ingress from the vent pipe, as oxygen will damage the installations and reservoir. The CO_2 rich stream is supplied to a compression unit that compresses the gas to the required pressure for injection into the reservoir (the anticipated required pressure is 40–45 bars). The compression unit consists of an electrically driven three stage reciprocating compressor, with the required process control and safety devices. Between and after the compression stages the gas needs to be cooled and condensed liquids should be separated. For this purpose intercoolers are used. If there is an insufficient CO_2 supply, CO_2 will be re-circulated in order to keep the unit running and to prevent air ingress.

The compression unit is a skid-mounted unit that is constructed and tested at an onshore yard in order to minimize the required activities offshore. The skid includes the compressor, electric motor, coolers, separators, lubrication system, instrumentation, etc. The existing power generators on the platform have sufficient capacity to meet the facilities' electricity demand (approximately 250 kW). All equipment is proven in offshore application and meets the applicable industrial standards for offshore gas production. The compression unit, including an air cooler, is located at the wellhead platform. All required control and safety facilities are available at the well and wellheads to control the wells and prevent hazardous events.

By the use of a skid-mounted compression unit, changes to the existing installations at the platform were limited. The main changes included the tie-in at the existing CO_2 line to bring the CO_2 rich stream to the compressor and the connection of the pipeline for the compressed CO_2 at the wells.

13.2.4 Compressor unit for the 30000 Nm^3 CO_2 per hour case

The 30000 Nm^3 CO_2 per hour case operates, in principle, by the same process, but of course the size of the required equipment is larger. However, one essential difference is that a centrifugal-type compressor, which is driven by a gas turbine, will need to be used; the existing power generator does not have sufficient capacity to drive the compressor electrically. To operate the larger case and supply sufficient CO_2 gas to the injection unit requires K12-B to produce more CO_2 rich gas, or source additional CO_2 from elsewhere, such as from the shore.

The compressor unit for the 30 000 Nm^3 CO_2 per hour case will be installed on the wellhead platform, because there is insufficient space available for such a large unit on the main platform. The larger size of the compression unit may require several skids to be mounted on, rather than just the one for the demonstration case.

13.3 Site characterization: legal and social aspects

Any CO_2 injection project will be controlled and restricted by environmental rules and regulatory issues, many of these will be locally and country/state dependable.

13.3.1 Legal aspects and regulatory issues

The following conclusions were valid at the time the project was initiated (2003), in conjunction with the underlying report 'Legal aspects of the application of offshore re-injection of CO_2' and are conditional to further insights into the operational circumstances, decisions and the exact activities to be undertaken for this project and can be drawn with respect to the legal analysis performed for the ORC-feasibility study:

(New) Mining Act

1. It was unlikely that GPN's request for an injection and storage licence for K12-B would be refused by the Minister of Economic Affairs, if it were required.
2. An injection plan for K12-B was subsequently developed and issued to the Minister of Economic Affairs, in accordance with the rules laid out in art. 35 of the Mining Act.
3. On the basis of transitional arrangements in the Mining Act, the K12-B platform will be the rightful 'owner' of an environmental mining permit as required according to art. 40, paragraph 5b, of the Mining Act, from the starting date of that Act.
4. The ownership of substances linked to the (presence of an) injection and storage licence and the Mining Act only refers to the ownership when substances are retrieved ('teruggehaald'). This leaves doubt on

the exact ownership of any substance that has been put underground (and remains underground for the time being, either temporarily or permanently); the Mining Act itself does not explicitly specify the status of the ownership in those instances.

Environmental Management Act

5. An Environmental Impact Assessment-duty ('Mer-plicht') stemming from the Environmental Management Act and Annex 'B', part C, of the EIA-Decree could be required for the ORC phase 2 and phase 3 activities, if both phases are classified as an installation placing non-hazardous waste underground. If the activity is considered as returning the reservoir's own substances, the activity probably requires no EIA (Environmental Impact Assessment-appraisal). It is expected that injecting CO_2 should not be considered under the (EU) definition of hazardous waste, in which case no EIA would be required for phase 2.
6. An EIA obligation ('Mer-beoordelingsplicht') stemming from Annex 'B', part D, of the Environmental Management Act and the EIA-Decree could be required to be performed by the Minister of Economic Affairs for activities that are possibly to be undertaken under the ORC project (a particular possibility in phase 3), like drilling or the laying of interconnection pipelines to transport CO_2 or natural gas to K12-B. This could lead to the possible decision by the authorities that an EIA is to be executed by GPN. This was not the case.

(Existing) Mining legislation

7. The existing mining legislation does not include specific restrictions or prescriptions applicable to the ORC phase 2 small-scale testing phase.
8. With the actual start of the large-scale operations planned in phase 3 of the ORC project only expected to be initiated some years from now, it is likely that in this instance the new Mining Act has come into force and will thus apply.

The OSPAR Convention

9. The re-injection or injection of CO_2 into the deeper underground, with total absence of marine life or other legitimate use, does not seem to relate to activities falling under the definition of 'pollution' (ex. art. 1d, OSPAR Convention) or 'maritime area' (ex. art. 1a, OSPAR Convention).

10. Neither does it seem likely that activities under the ORC project would fall under the definition of 'dumping' as specified in art. 1 f and 1 g of the OSPAR Convention.
11. The (re)-injection of CO_2 within the context of the ORC project (either in the second or the third phase) is not performed with the objective of the mere disposal of it, but with the objective of reducing CO_2 emissions, and the possible re-use of the CO_2, that is, positive effects to the environment and the maritime area.
12. The Convention is aimed at (preventing) adverse effects of human activities. Following from the previous conclusion, it can therefore be deduced that there are as such no obligations for Contracting Parties stemming from the OSPAR Conventions to 'individually and jointly, adopt programs and measures and [to] harmonize their policies and strategies' (as prescribed in art. 2 paragraph 1 (OSPAR), in the area of CO_2-(re-)injection.
13. Without prejudice to what has been concluded above, with regard to the activity 'injection into reservoirs' OSPAR has taken the lead with respect to the development of a so-called 'holistic evaluation' approach. One of these 'holistic evaluations' includes the re-injection of such cuttings (and, in effect, of produced water) into a subsurface reservoir.
14. OSPAR does provide the use of injection of drill cuttings and produced water as being a possibility to reduce the impact of human activities to the maritime area in the case of offshore oil and gas production. As such the (re-)injection of CO_2 would compare to these as an acceptable activity. This leaves aside the question whether in principle the OSPAR Convention does apply to offshore re-injection of CO_2 into the underground, based on the definitions used and the aim of the Convention.

13.3.2 Social aspects

An important aspect in the realization of the K12-B CO_2 offshore re-injection project was the social acceptance of this technique. It had to be proven that the chosen technique is an effective, efficient and acceptable solution to reduce the emission of greenhouse gases (GHGs) into the atmosphere. This issue should as such form part of the overall analysis to provide insight into the possibilities, conditions and limitations of an offshore CO_2 project in the near future.

It should be realized that at this stage in the ORC project the analysis as performed in this publication has a limited scope only; the main goal was to see if there were significant or insurmountable issues or problems with regard to the possible development of an underground demonstration CO_2 facility off the coast of the Netherlands. Clearly, if this had been the case, the question whether or not it is technically possible or economically attractive would not have had to be answered, and efforts to solve the GHG-problem would have been better spent on other projects or in other areas.

National and international policies on the reduction of greenhouse gases

Most European countries, and the European Union itself, have signed and ratified the Kyoto Protocol, with the total number of ratifications and accessions worldwide amounting to 88 (status August 2002). For countries participating in this Protocol, stringent emission targets with respect to GHGs (consisting of the gases CO_2, CH_4, N_2O, HCFC, PFC and SF6) have been set. For EU countries the total CO_2 equivalent reduction target is set at 8% reduction in the period 2008–2012, compared to the absolute emissions over the years 1990–1995. In addition, the European Union itself has been an active participant in stimulating the goal of both the Protocol and the Treaty by supporting many initiatives and legislative instruments to reduce the emission of CO_2 in the European Union.

In the Netherlands, there has been a growing interest in developments regarding the emission of GHGs since the introduction of the Kyoto Protocol (Kyoto, 1997) as part of the Climate Treaty (New York, 1992). For the Netherlands the total target is set at 6% reduction in the period 2008–2012, compared with the emissions over the years 1990–1995. Effectively, this relates to an absolute reduction of CO_2 'equivalents' of 50 Megaton (Mton) in 2010, a number which has been derived from the Ministry of Public Housing, Spatial Planning and Environment ('VROM') in its 'Execution Note on Climate Policy' 12. The awareness and promotion of CO_2 reduction projects in the Netherlands is being undertaken by the Minister of Public Housing, Spatial Planning and Environment, in many cases in close cooperation with the Ministry of Economic Affairs.

Stakeholder viewpoints

Following from the analysis performed regarding the viewpoints of non-governmental organizations the only negative perception regarding the possibilities involving the application of underground CO_2 (re-) injection found was voiced by the national branch of the environmental organization Friends of the Earth (i.e. Milieudefensie). They do not differentiate between offshore and onshore application. Their argument is based on two grounds: that the process is not technically feasible (with uncertain outcome), and that it distorts other methods/plans regarding the reduction of CO_2 emission. No other environmental parties or any of the larger political parties have taken a formal standpoint towards the introduction of CO_2 storage/injection underground, but on the contrary seem to be determined to actively participate in meeting the Netherlands CO_2 reduction targets for the period 2008–2012. This was the outcome of investigations performed around 2003. During 2010 and 2011 it became clear that the political support for CO_2 storage onshore had diminished. Popular unrest of people living on or close by potential or planned CO_2 storage locations (Barendrecht, and Nord Netherlands) were able to change the mood in the Dutch parliament to force a ministerial stop on all onshore CO_2 storage activities (2011). It is clear that a combination of relative (relevant) small protest in combination with electoral circumstances can have a devastating effect on the CO_2 storage realization process.

13.4 Test cycles and monitoring

Two complete test cycles have been performed. During 2004 CO_2 has been injected into the gas-depleted compartment 4 by means of well K12-B8. At the end of 2004, injection was stopped for 2 years, and this shut-in period has been followed by gas production during 2007 and 2008. For the second cycle, CO_2 injection was moved from the B8 well to the gas-producing compartment 3, and well K12-B6. This injection activity has been continued to the present day (mid-2012). During this period injection has been interrupted several times, for short and long time periods, mainly due to mechanical problems of the injection installation.

During the CO_2 injection phases, attempts have been made to test and monitor effects of the varying processes as much as possible. The following parts will report on most of them. Some are part of larger integrated studies; others are more solitary activities with possible follow-up activities in the future. A short overview of the specific monitoring activities is given in Table 13.1.

In the framework of the EU-funded CASTOR project, TNO and the British Geological Survey have evaluated the monitoring plan for the CO_2 storage at K12-B. The evaluation was based upon the monitoring programme defined in the MONK project as well as the monitoring project active during the ORC project. The conclusion of the evaluation was that the monitoring strategies applied during MONK and ORC were adequate to fulfil the objectives. The complete results can be found in the 'Evaluation of the K12-B monitoring plan' report under WP 3.4. of the CASTOR report.[1]

Table 13.1 Overview of monitoring activities

Main category	Type of measurement	Purpose of measurement	Results
Well integrity	Multi-finger caliper	Assessment of the tubing integrity	The tubing has been found in good condition, but scaling is likely to disturb the accuracy of the measurements.
	Cement bond log	Cement bond quality	Failed due to (at that time) unknown obstruction.
	Down-hole video	Image tubing and obstruction	Tubing and obstruction successfully visually inspected.
Reservoir characterization and EGR	Wellhead measurements	Input data for the reservoir simulation	All available data have been gathered and used in the reservoir simulations.
	Composition of production gas	Validation and tuning of the reservoir model	All available data have been gathered and used to validate the reservoir simulations.
	Composition of injected gas	Input data for the reservoir simulation, and possibly well integrity research	All available data have been gathered and used in the reservoir simulations.
	Composition of production water	Input data for future chemical modelling and well integrity research	Moderately successful. New samples need to be gathered in a different way.
	MPLT	Establish a flowing profile of the productive formation	Partial success, measurements for the K12-B8 failed, but measurements for the K12-B1 and B5 were successful.
	Down-hole pressure and temperature profiling	Validate and create PVT tables for coming reservoir studies	The data have been used to validate the lift tables and for the history match.
	Chemical tracer analysis	Validation and tuning of the reservoir model	All available data have been gathered and used to validate reservoir simulations.

MPLT, memory production log; PVT, pressure–volume–temperature.

13.4.1 The integrity of well K12-B6

An important issue in CO_2 storage is the integrity of the wells. Due to the acidic nature of CO_2 in water and uncertainties about the actual down-hole conditions, establishing and monitoring any change in the integrity of the injection well is of great importance.

Multi-finger caliper survey

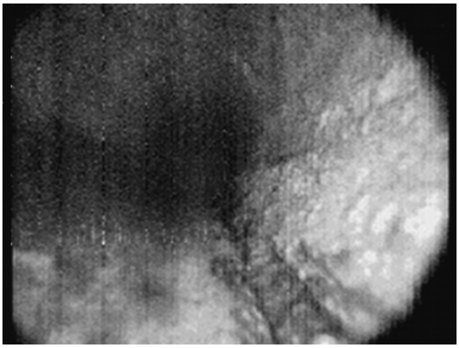
A time lapse multi-finger caliper survey took place in March 2007 and was conducted in order to determine the condition of the 4.5″, 12.75 lb/ft and the 3.5″ 9.2 lb/ft injection tubing of the K12-B6 well and to compare its condition with previous multi-finger caliper surveys from February 2005 to January 2006. The tubing has been found in good condition. The largest penetration point is found at 2592.9 m (8506.8 ft) and equates to 26.2% of the nominal wall thickness. This feature is located immediately above a connection and in fact represents ovalization of the tubing, probably as a result of pipe handling. The pit depth chart (Plate X in colour section between pages 214 and 215) shows a good agreement between all three conducted surveys (2005, 2006, 2007) in the upper 2000 m. Below this level the measurements start indicating severe deviations over time. The area between 2000 and 2600 m indicates an increase of pitting depth over the years 2005 and 2006, whereas it indicates a decrease over the subsequent year 2007.
Possible explanations given by the logging company where:

- There was a problem with the 2006 survey that affected the data over this short section, but this seems unlikely as there was a very close correlation both above and below the area in question.
- The determination of the inner diameter (ID) over this section may be affected by the presence (and occasional absence) of thin films on the tubing walls (waxes etc.).

After having examined pictures taken by a down-hole video tool we think another and more plausible explanation is that scaling and tracks in the scaling, like those visible in Fig. 13.2, are responsible for the erratic results of the caliper fingers. The scaling, a halite or halite-like mineral precipitation, is a relic of the time when well K12-B6 was used as a producer well.

Cement bond log survey

The well casing is bonded to the reservoir rock by Portland cement. In order to inspect the cement condition, a cement bond log (CBL) tool was lowered in well K12-B6 in May 2007.



13.2 Down-hole video image from K12-B6 at approximately 3700 m depth (AH WLM). Bright, cloudy structured scale on the liner walls is clearly visible. The straight feature in the scale is probably a drag mark of centralizer arms of logging tools.

At a depth of 3696 m AH WLM (along-hole wire-line measured), the CBL tool got stuck. This is 25 m below the top of the perforations. Numerous efforts and attempts were made to lower the tool further towards the target depth (slightly above the holdup depth of 3837 m AH WLM) to no success.

Finally the conclusion was drawn that the CBL operation had failed to record any cement bond quality data due to not reaching its target depth. The cause of this was an obstruction at 3696 m, unknown at the time of logging. The nature of the obstruction has subsequently been found.

Down-hole video survey

Because the CBL tool ran into an unknown obstruction during an attempt to determine the cement bond quality in well K12-B6, a down-hole video (DHV) survey was performed in August 2007. The DHV was to image the nature of the obstruction, which could have several causes, for example, a deformation of the pipe, debris or the result of accreted scaling. Two runs have been performed with the DHV tool: the first going upward from 3706 to 3694 m depth AH WLM and the second going downward from 3680 to 3704 m depth AH WLM.

The DHV tool could not be lowered below 3706 m AH WLM. This is near the level at which the CBL got stuck during its operations in May 2007. During the video runs, clear images of the liner were made. These showed that a lot of scaling accretion had taken place (Fig. 13.2), probably resulting from the time when the K12-B6 well was producing natural gas. The obstruction is the same obstruction that denied the CBL tool further entry into the well. The obstruction is interpreted to consist of accreted scale, from a probably halite-resembling mineral.

The halite or halite-resembling scale is not likely to cause any negative effects, either on the integrity of the well or on the injectivity of the well; at least not for the current injection rate of 30 000 cm/d. The obstruction simply prohibits the lowering of larger (well logging) tools.

13.4.2 Injection- and production-related measurements

At gas production sites in general, various measurements are performed in order to keep track of the general state of the reservoir and its wells. Some of these are standard, like wellhead pressures; some are less standard, like gas composition analyses. These measurements serve to keep track of gas production, monitor field performance and establish production forecasts, etc. Measurements like these are hence of great value to the storage project, especially their acquisition over longer periods of time and used in combination with reservoir models. Some also relate to EGR. A brief description of these measurements is given below.

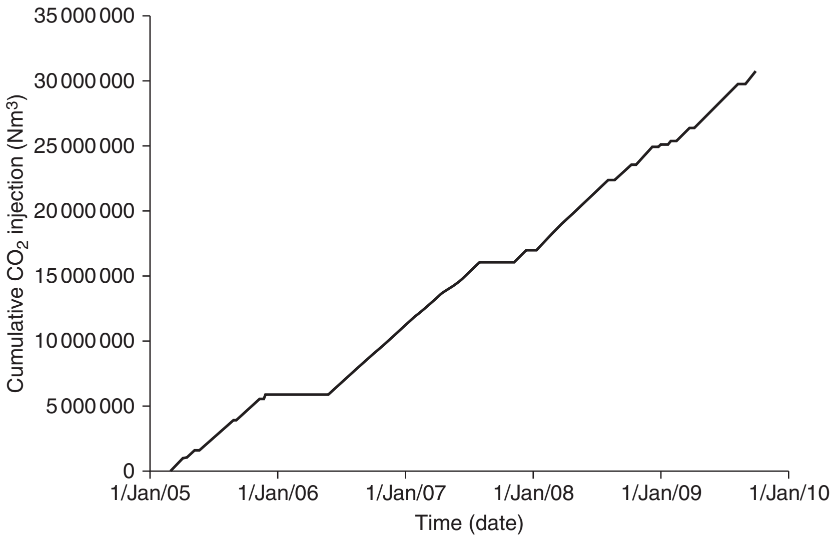
Amount of CO_2 injected

Production data of all wells from the start of production until January 2011 have been supplied by GPN.

Figure 13.3 shows the cumulative injection of CO_2 as a function of time. Over the years of CO_2 injection, two longer interruptions in the injection took place. The first interruption was due to a malfunctioning compressor, and the second was due to installation of a new production monitoring system on the platform. The increased amount of CO_2 injected during the larger part of 2008 is due to the back-production from the former CO_2-injection well K12-B8. This back-production caused extra gas to be produced, which resulted in a larger supply of CO_2.

Production gas composition analysis

At regular intervals samples were taken from the production gas stream from wells K12-B1 and -B5. Due to some errors in storage and handling, a large amount of samples have been lost before they could be examined. This has been compensated by analysing additional, younger samples. These samples where tested in accordance with ISO 6974. The results of these analyses were used in order to improve our understanding of the reservoir dynamics and to evaluate our reservoir model.



13.3 Cumulative CO_2 injection as a function of time.

Injection gas (CO_2) composition analysis

Two gas samples were taken from the gas stream of the injection well K12-B6. This was done in order to assess the composition of the injected gas, which consisted mainly of CO_2 (92%) and CH_4 (6%) and traces of some other hydrocarbons, N_2 and O_2. The samples contained little or no water vapour, which would make the injected gas corrosive, if present. The samples underwent the same procedure as the natural gas samples from the wells K12-B1 and -B5. The composition of the injected gas is used in the reservoir modelling and is important data when examining the behaviour of the gas in the well.

Production water analysis

A production water analysis was performed on a sample taken in December 2007. In the past, several of these samples have been investigated but no coherency in the data has been found: the composition of the production water varies wildly. This is probably because pulses of water rise irregularly with the gas stream, dissolving and precipitating chemical components on the way up. The analysis of production water did not lead to any conclusion other than that sampling water at the platform does not give much information about the down-hole conditions. Consequently, in order to effectively analyse reservoir chemistry and possible processes down-hole, it is advised to perform down-hole measurements and to analyse down-hole samples.

Memory production log (MPLT) surveys

In order to analyse bottom hole flowing conditions during the production of the K12-B wells, a memory production log (MPLT) survey was conducted in January 2008. This memory production log survey took place in the wells K12-B1/B5/B8. The first well to be surveyed was well K12-B8, and later the other two wells (B1 and B5). During the logging operations in the B8 it was impossible to lower the tool down to the perforation level as the tool got stuck at a depth of 4854 m. The B1 and B5 wells posed no problem. The wells were produced with minimum flowing wellhead pressure during the MPLT production period, prior for the actual production run, for one hour. As an example, the MPLT log of the K12-B1 is displayed in Plate XI (in the colour section between pages 214 and 215). The righthand graph shows the actual spin-count of the instrument. Two zones with a relatively large gas inflow can be observed at 3763 and 3781 m absolute height rotary Kelly bushing (AH RKB). The bottom interval is therefore the most productive part of the well. Further upward the amount of gas increases only slightly and quite gradually until it gets to its full quantity.

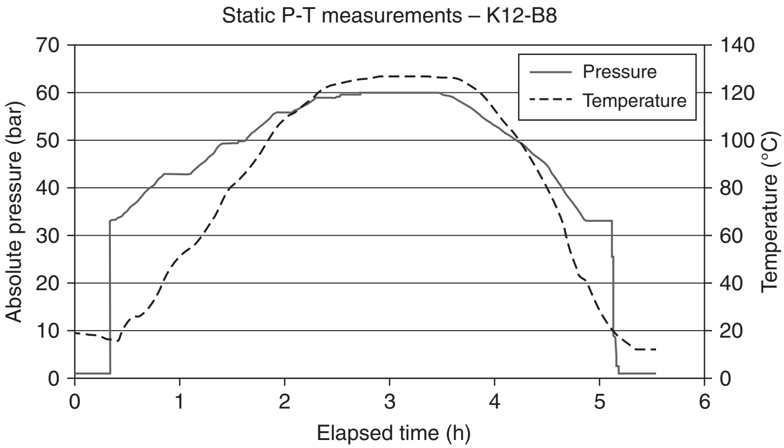
The MPLT data (Plate XI) did not show any significant phenomena or irregularities. The MPLT data can (and should) be used in order improve future geological and reservoir models.

Pressure–temperature profiling

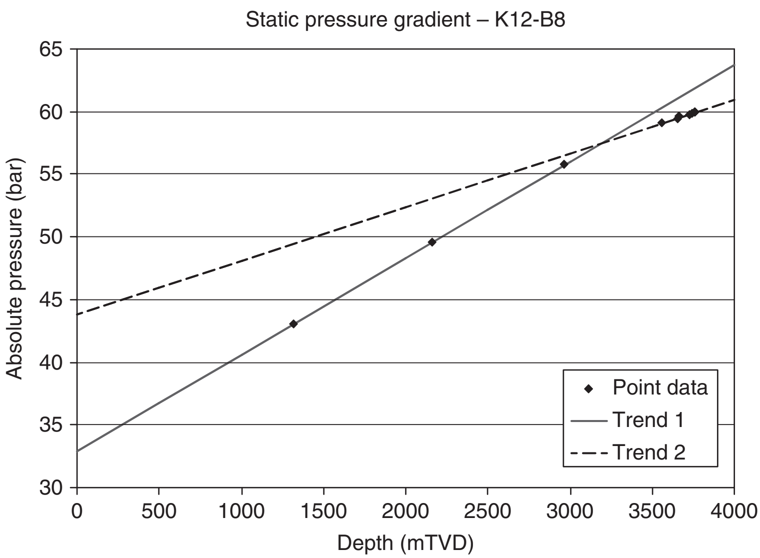
Early December 2007, pressure and temperature measurements were performed in well K12-B8. The measurements can be used in order to validate PVT tables used in reservoir modelling. The illustration below shows the static pressure and temperature measurements of a single wireline run (Fig. 13.4).

During the measurement, pressure and temperature gauges are run down and up in the wellbore, keeping them at certain depths for some time in order to adapt to the local conditions, in order to take precise measurements. This is represented by the short horizontal sections in the graph, meaning that the pressure remains constant for a short period of time. These constant pressures at certain depths are indicated with dots in Fig. 13.5.

Two trend lines can be deducted from the data points in Fig. 13.5. The first trend line (Trend 1) has a slope of 0.0077 and an intercept of 32.90 and a second trend line (Trend 2) has a slope of 0.0043 and an intercept of 43.78. The material density represented by the slope in trend 1 equals 77 kg/m^3, the density represented by the slope in trend 2 equals 44 kg/m^3. The transition level is located at a depth of 3200 m and the pressure at that depth is 57.54 bars during shut-ins. The pressure ranges and densities observed in the media associated with these pressures indicate that the whole wellbore is gas filled.



13.4 Static pressure gradient and temperature measurements of the K12-B8 well.



13.5 Static pressure gradient in well K12-B8. TVD, true vertical depth.

Tracer analysis

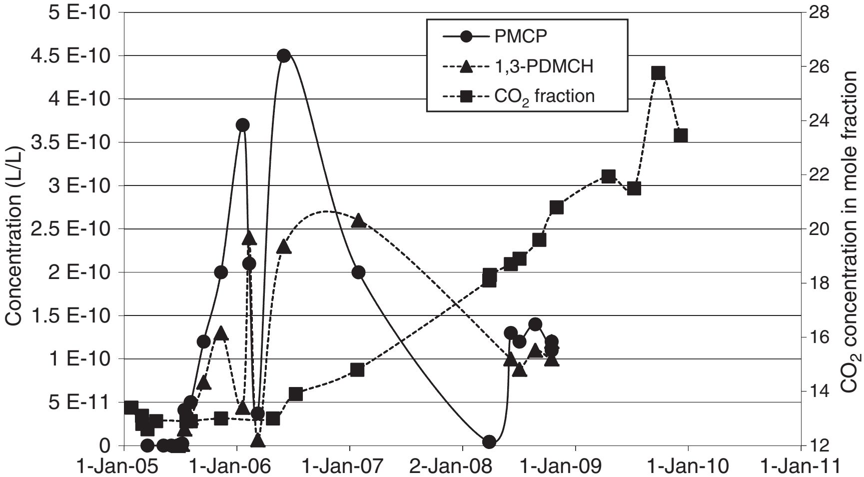
Since the injected CO_2 originates from the same reservoir to which it is being re-injected, a tracer substance was needed in order to enable investigating EGR, flow paths within the reservoir, the partitioning behaviour of the CO_2 and CH_4 and indirectly monitoring the breakthrough moment of injected CO_2. On 1 March 2005, 1 kg of two chemical tracers were injected into well K12-B6. The selected tracers were perfluorocarbons: 1,3-perfluorodimethylcyclo-hexane (1,3-PDMCH) and perfluoromethylcyclopentane (PMCP). The first objective was to accurately assess the flow behaviour in the reservoir and the associated sweep efficiency of the injected CO_2. Without the tracers it would be difficult to accurately determine the flow between injector and producers.

The second objective was the investigation of the rate of migration of the CO_2 versus that of CH_4. These rates may differ significantly. The low injection rates of CO_2 and the corresponding slow flow of the gaseous phase can be expected to allow for some degree of interaction with the aqueous phase (connate water) within the gas cap. As the solubility of CO_2 (mass fraction ≈ 0.010) is much higher than the solubility of methane (mass fraction is negligible), this should lead to a stronger interaction of the CO_2 with the connate water in the reservoir, and thus additional retardation of the CO_2 with respect to the methane. Both tracers mentioned are water insoluble and thus follow the behaviour of the methane, which hardly interacts with the ambient water in the reservoir. If the possible effect of the retardation is significant, this should lead to arrival of the tracer front before that of the injected CO_2 front.

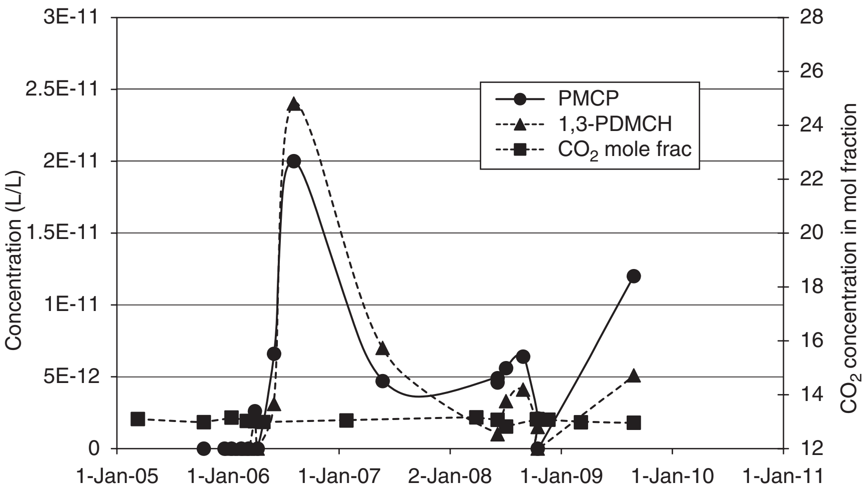
Results of the tracer analysis

Measured breakthrough data (Figs 13.6 and 13.7) of both tracers at K12-B1 and K12-B5 show breakthrough after 130 (August 2005) and 463 days (June 2006), respectively. The measurements of the tracers in both producers prove that the injected particles have reached the producers. There is some difference in the tracer concentration results. As can be observed the tracer concentrations in general are very small. So differences could be simple explained as inaccuracies of the sampling procedure and the measurements.

The breakthrough of both tracers at B1 shows a rather erratic pattern. This was attributed to a temporary stop of CO_2-injection due to a breakdown of the compressor. During injection, there is a larger pressure gradient between the injection well and the closest production well. This well will therefore produce relatively more gas from the direction of the injection well. During a shut-in of the injection well, this pressure gradient will decrease and the production well will produce gas from a more radial pattern around the well, thus containing less tracers. The latest data show that the tracer amounts in the gas are very low. Apparently, most of the tracers between the injection and the production well have been removed after almost 4 years. Unfortunately, there were no data obtained during most of 2007 or the early part of 2008.



13.6 Tracer detection as a function of time at the B1 well.



13.7 Tracer detection as a function of time at the B5 well. Note the difference in vertical scale compared to Fig. 13.6. Based on the available data, the tracer's fractions at the B5 well appear to remain rather low. This could indicate a lot of dispersion during the flow.

The measured CO_2 fraction of the produced gas at B1 is shown in Fig. 13.6. It must be emphasized that the increase of the CO_2 fraction during breakthrough has to be significant before it can be distinguished from the normal concentration of the resident CO_2 in the gas (13%). Over 6 years of injection, the concentration of CO_2 rose to almost 26%. Analysis of the produced gas in the B5 well (until November 2008) revealed that the concentration of CO_2 remained constant (Fig. 13.7) at 13% until then, indicating that the amount of re-injected CO_2 which has reached the B5 well is negligible.

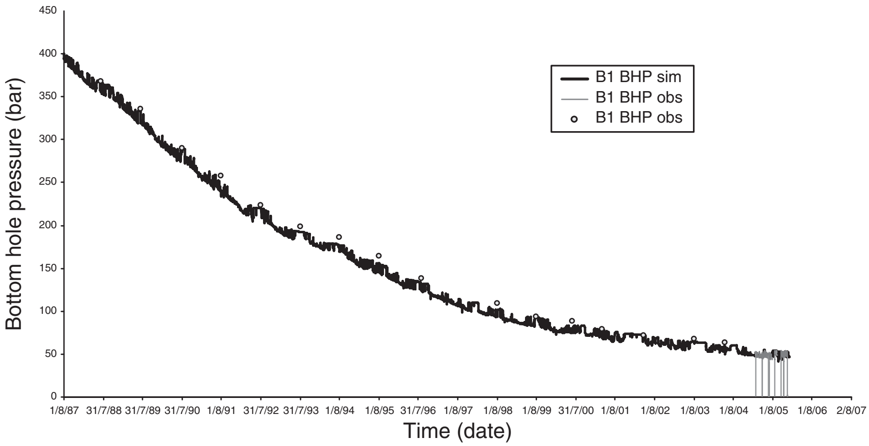
The tracer experiment at K12-B has now been going on for almost 6 years and a lot of field data have been gathered. The data provide insight into the flow and behaviour of CO_2 in a depleted gas reservoir, and serves as input for reservoir modelling.

13.5 Reservoir modelling

During the project several simulation studies were performed; each study was a continuation of the previous one. The first simulation study consists of a history matching (HM) exercise of a natural gas production period of the K12-B compartment 3, comprising wells K12-B1, -B5 and -B6, and a little less than one year CO_2 injection activity into the converted K12-B6 well. The production of this compartment started in early 1987, so a total of 18 years of both production and injection were covered. For a full description of all 2006 simulation activities we refer to the TNO report 2006-U-R0011/B. For the sake of completeness, we will repeat the most important data items, assumptions made, procedures used and conclusions drawn from the ORC study. Some of these factors are further explained or defined due to the increased knowledge of the K12-B reservoir.

For the ORC study a completely new geological interpretation[2] of all K12-B reservoir compartments was made based on seismic data and all petrophysical data available for all wells in the K12-B area and its surroundings. Furthermore, the assumption was made that compartment 3 of the K12-B field is isolated from the rest of the field by sealing faults. A new reservoir simulation model was built, containing 27 742 active grid cells out of a total matrix of 48 × 68 × 20 grid cells. All orthogonal grid cells have a size of 43 by 46 m. This model was initialized with a gas water contact at 3840.5 m true vertical depth sub-sea (TVDSS) with an initial pressure of 401 bars at this level. The resulting IGIP (initial gas in place) was nearly 7 billion cubic metres (bcm), but from gas production data it was already concluded that this number could be too conservative. An IGIP of nearly 8.125 bcm was more likely. This reservoir simulation model is shown in Plate XII in the colour section.

During the 2006 HM activity it was found that the modelled overall pressure behaviour was most sensitive to the IGIP (and its components, such as pore volume and gas saturation). For all the three wells an excellent pressure match (Fig. 13.8) was achieved after the IGIP was increased to 8.125 bcm. The pressure response to rapid rate changes could be modelled with changes in the local permeabilities or relative permeabilities. More local effects such as the amplitude between static and flowing bottom hole pressures were matched by changes in local permeabilities and well skin factors.



13.8 Pressure history match of well K12-B1. BHP, bottom hole pressure.

During this matching exercise, a large number of smaller discrepancies were found in the reported production data. Basically, the daily production data over a number of days did not match with the measured bottom hole pressure profile for the same time interval. Assuming that the measured pressure profile represents the most accurate measurement, we can conclude a misinterpretation of the production or injection volumes for these time intervals. Such inaccuracies are rather normal. In particular, back allocation of total plant gas production to daily production rates for individual wells is difficult and the accuracy of these data often depends on parameters that are poorly constrained. During the history match activity we have concentrated our efforts on the overall shape of the pressure curve.

The most important part of the ORC history match is the period with CO_2 injection in well K12-B6 in the year 2005. Plate XIII in the colour section, displaying bottom hole pressures of the producing well K12-B1 for the year 2005, shows that the simulated bottom hole pressure (yellow curve) comes in at the same level as the down-hole measured pressure data (turquoise curve). The gauge pressure data are representative of a stable and a very little increasing production rate. Overall, the match between the observed and simulated bottom hole pressures is excellent. However, there are some small discrepancies between the observed and simulated bottom hole pressures, due to inaccuracies in the reported production rates as explained before. For instance, circle A in Plate XIII highlights a period of missing production rates: the well is shut according to the reported production data, but the gauge data are the response to a non-zero production rate. The highlighted periods B and C show a very good match, in contrast with the period just before the C, where a too large production rate is reported. Overall it can be concluded that an excellent pressure match is achieved.

Another remarkable fact is shown in Plate XIII. In the lower part of the plot we have plotted the observed tracer breakthrough in combination with the simulated incremental CO_2 production (above natural level, 13%) of well B1. As can be seen there is an excellent match in tracer breakthrough time between the tracer data and the simulator results. It was impossible to verify this incremental CO_2 production by laboratory analyses, as this incremental (or reproduced re-injected) CO_2 is not detectable in the produced gas volume. This is because of the extremely small volume of incremental CO_2 but also due to the same isotope fingerprint of the CO_2.

13.6 Challenges and lessons learned

From the start of all activities related to the re-injection of CO_2 into the K12B reservoir everybody involved was aware of the experimental character of these activities. Many activities were set up as test cases or had a large experimental component. In this section we will report on some of the lessons learned.

13.6.1 Results of the 2011 simulation activities

During the first quarter of 2011 a new simulation update was made of compartment 3 of the K12-B field and CO_2 injection activities. All available data up to the end of January 2011 were used. The result of this activity show:

- A declining bottom hole pressure as a result of continuing gas production. The average gas production from production wells B1 and B5 together is some 275 000 Nm^3/day
- In general a normal behaviour.

Looking at Plates XIV and XVI in the colour section, showing the incremental CO_2 production for well K12-B1, one can observe:

- Plate XIV shows an underestimation by the simulation of the incremental CO_2 production (solid blue line) compared with the field observed values (dots).
- Plate XVI shows a nearly perfect match of the simulation of the incremental CO_2 production, this all as a direct result of the adopted new concept.

A further remarkable fact, which is shown in Plate XV, is that the calculated BHP (yellow curve) for injection well K12-B6 decreases over time, while the CO_2 injection rate (red curve) and the THP (dark blue curve) are increasing. Also note that during shut-ins the calculated BHP (yellow curve) represents a block pressure and not the actual bottom hole pressure. This is a simulation artefact and due to the status of the well in the reservoir simulation software. Both injection rate and THP are considered reliable data and 'normally' the declining BHP fits in with the average reservoir pressure decline as a result of the substantial gas production level. The calculated BHP during shut-in periods is following this trend. But in our case we have the situation that this pressure (calculated BHP at shut-in, yellow curve) becomes lower than the reported THP. This suspicious behaviour and the formerly (in ORC) recorded high shut-in down-hole pressures, forced us to devise a drastic change in concept of the situation around the K12-B6 injection well.

As already mentioned, the behaviour of well K12-B6 could not be explained using 'standard' explanations. Something happened here that needed an unorthodox approach. First some assumptions were made.

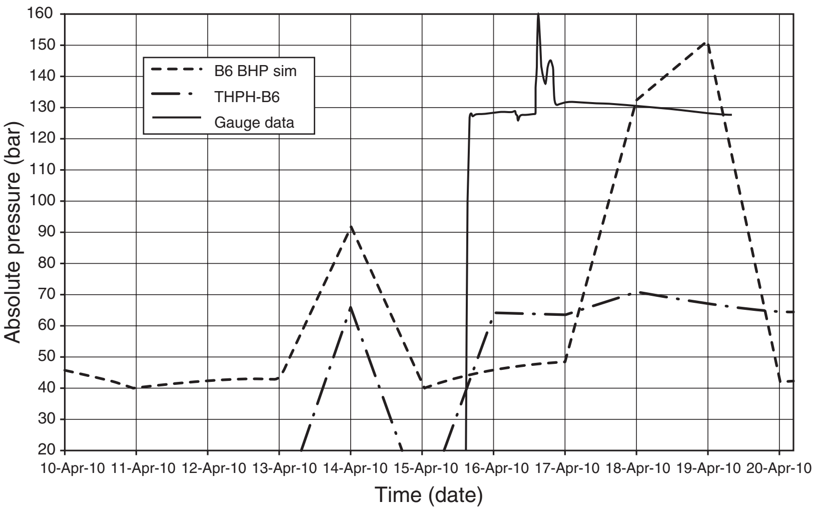
1. Water flow or some sort of aquifer support in the Upper Slochteren formation is extremely unlikely.
2. Due to the quality of the cement sheath behind casing and formation water can seep from the Lower Slochteren to the Upper Slochteren. This even in spite of plugging the well.

By inserting an additional Neumann boundary condition in the existing model the following results were obtained as can be seen in Plates XVI and XVII in the colour section.

Plate XVI shows that the simulated incremental CO_2 production for well K12-B1 has improved and is matching the laboratory measured data very well (blue line and dots). For well K12-B5 we observe a very small increase in CO_2 concentration starting around January 2007. Figure 13.9 shows the detailed injection data for well K12-B6 and we can see an increasing calculated BHP which is in line with the observed increasing THP and increasing injection rate.

13.6.2 Lessons learned

From all the work performed, we have learned a couple of lessons. The first thing we have learned, related to the use of a depleted gas field and its infrastructure, is the fact that the possible 20 years of gas production has made its wear and tear to the status of the equipment. In the case of the K12-B



13.9 Detailed BHP plot of well K12-B6 for the April 2010 pressure test.

field the actual small CO_2 injection was not hampered as such, but all the well monitoring work was hindered by the fact that the old gas production well, with a history of problems, was used as an injector. Secondly, we have learned that conventional oil field reservoir simulation can be used to research and test certain unforeseen operational conditions, such as well problems, material balance problems, and quality control on measured and observed data.

For all K12-B reservoir simulation work we have used only daily observed data for the total CO_2 injection period. It is normal oil industry practice to average measured production data over longer periods such as weeks or months in order to enable fast simulator running times. Here we have used minimum time steps of one day. If we look at Fig. 13.9 we observe now the upcoming dilemma that relatively cheap down-hole measurements are too accurate for the one-day time step simulator results. The solid curve is the down-hole gauge data, with accurate measurements on a second's time scale in complete disproportion to the simulated daily pressures. Some re-thinking is needed in the near future.

13.7 Sources of further information and advice

The website www.K12-B.nl went online early 2007. Since then it is getting hundreds of visitors and thousands of page visits each month. Currently it is actively indexed by all the major search engines, for example, Google, Yahoo, Live Search (Microsoft) and is highly ranked in relevant search queries as K12-B, CO_2 Injection, etc.

Readers can find general information about K12-B and the CO_2 injection as well as download articles and presentations about the CO_2 injection at K12-B.

13.8 Acknowledgements

The author expresses his gratitude to Gaz de France SUEZ E&P Nederland B.V. and TNO for their permission to publish this work and relevant information. Furthermore, the K12-B project is made possible by the financial support of the Dutch Government (CRUST, CATO), and the European Commission (FP6, CASTOR).

13.9 References

1. Arts *et al*. (2007), Evaluation of the K12-B monitoring plan, WP 3.4 CASTOR report.
2. Geel *et al*. (2005), Improved geological model of the K12-B Gas Field (CATO_WP3.1_D1.1 & CATO_WP5_D1.4). TNO Restricted Report: NITG05-179-B1209.

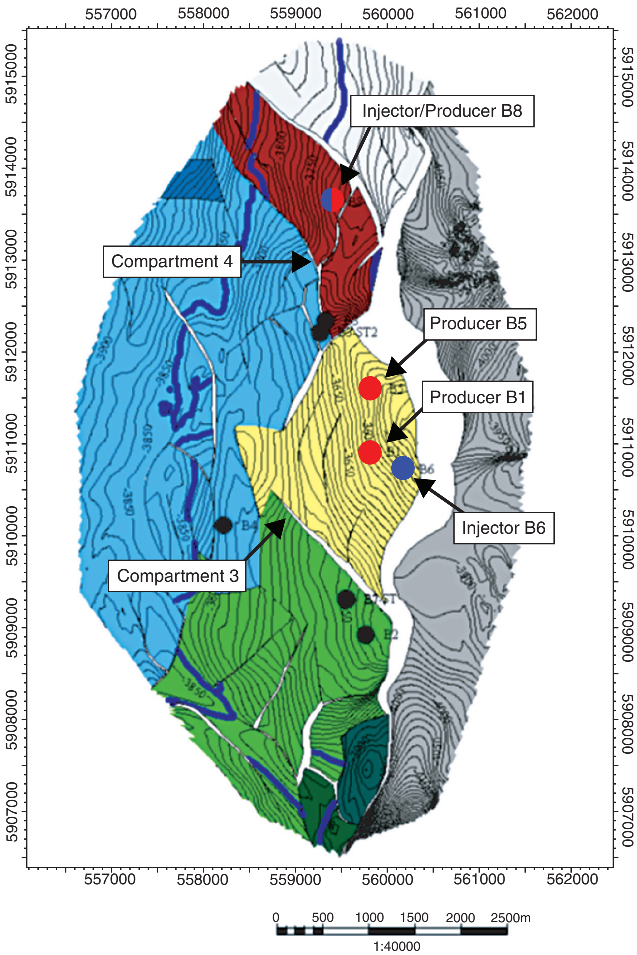


Plate IX (Chapter 13) Location of K12-B faults, wells and compartments. The units are in metres.

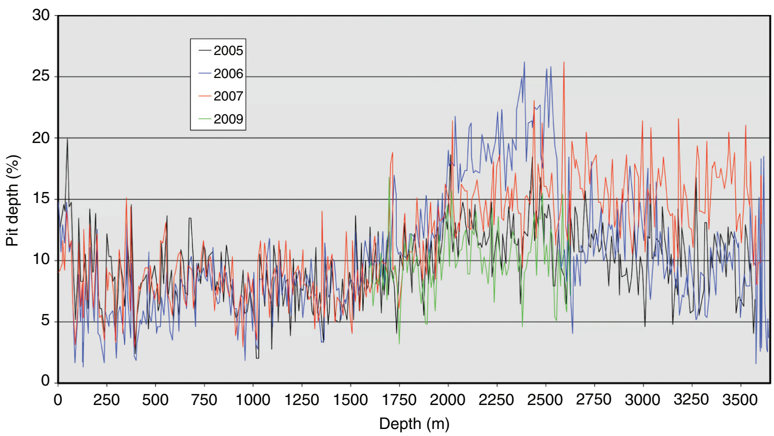


Plate X (Chapter 13) Pit depth chart of well K12-B6 generated using multi-finger caliper data.

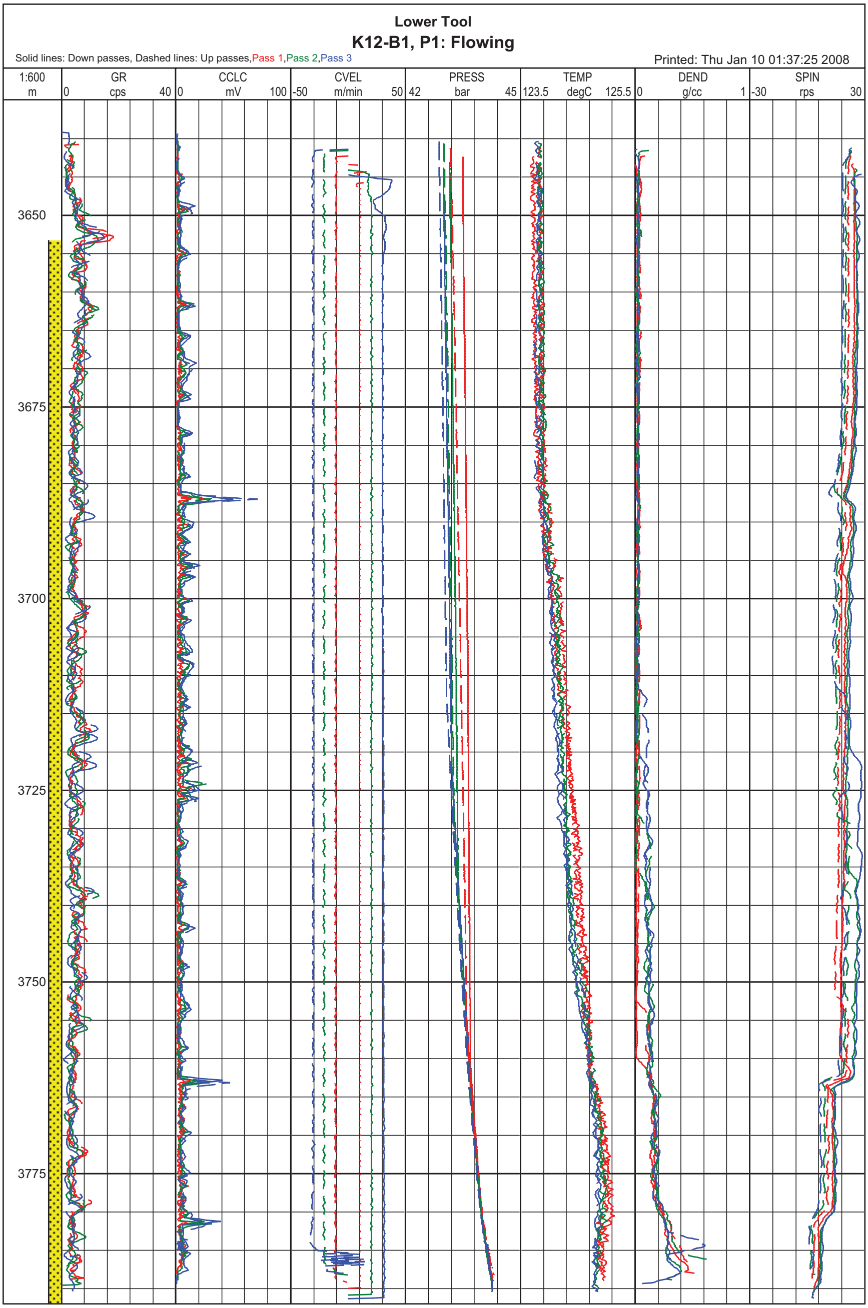
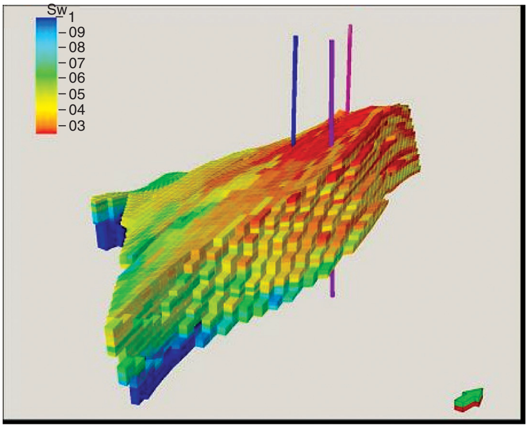


Plate XI (Chapter 13) MPLT log from well K12-B1.



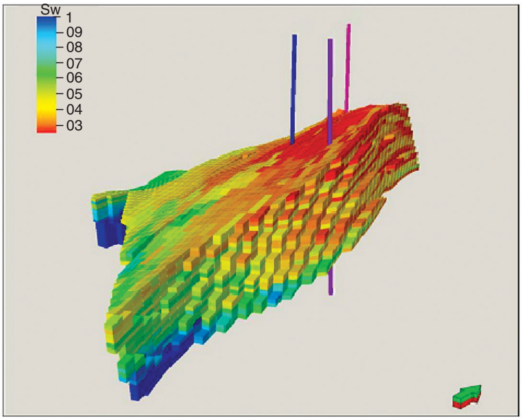


Plate XII (Chapter 13) Initial water saturation of the reservoir simulation model.The three vertical lines represent wells B1, B6, and B5. Sw = water saturation (fraction).

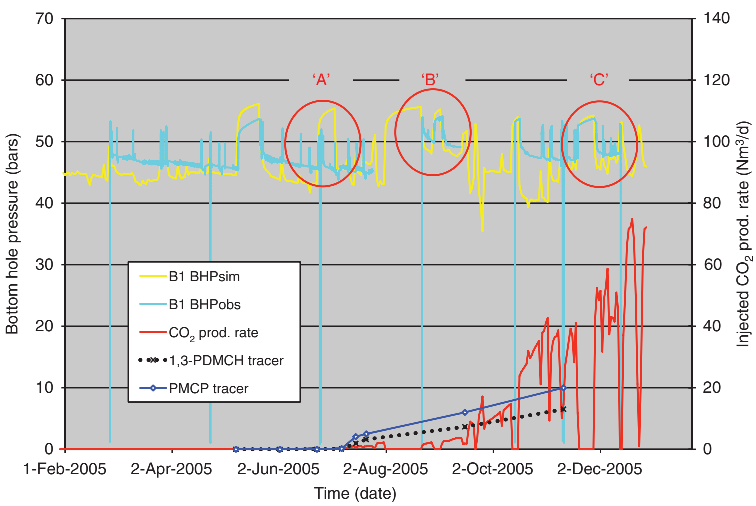


Plate XIII (Chapter 13) History match of the 2005 CO_2 injection period of well K12-B1.

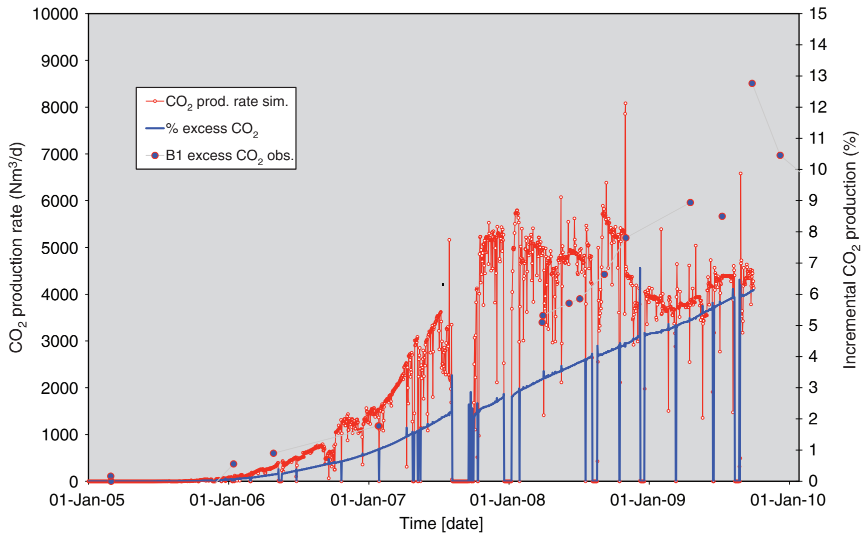


Plate XIV (Chapter 13) Well K12-B1 detailed CO_2 production plot, 2010 update of 2008 plot.

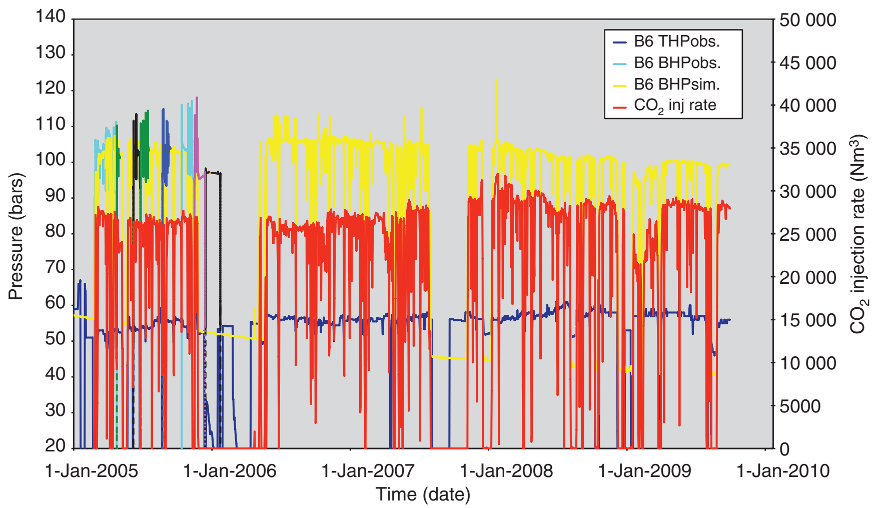


Plate XV (Chapter 13) Well K12-B6 detailed CO_2 injection plot, 2010 update of 2008 plot (yellow curve = simulated BHP, multicoloured curves = subsequent BHP gauge data, red curve = CO_2 injection rate and dark blue (curve) = measured THP).

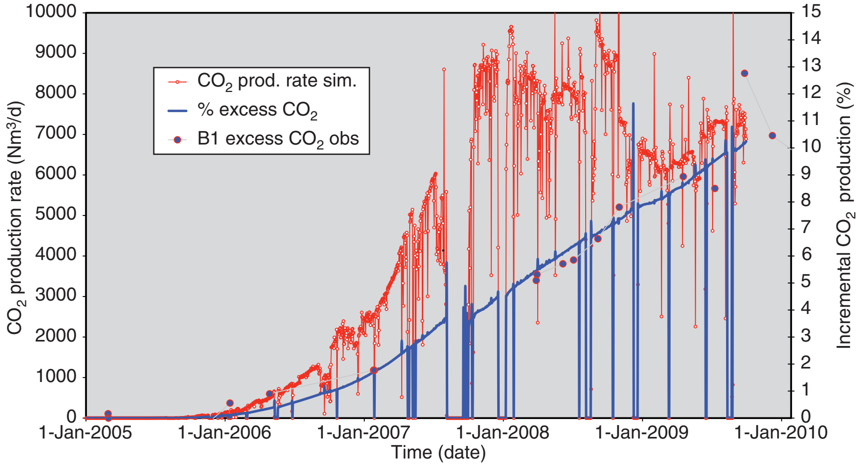


Plate XVI (Chapter 13) Well K12-B1 detailed CO_2 production plot, 2011 update and new concept.

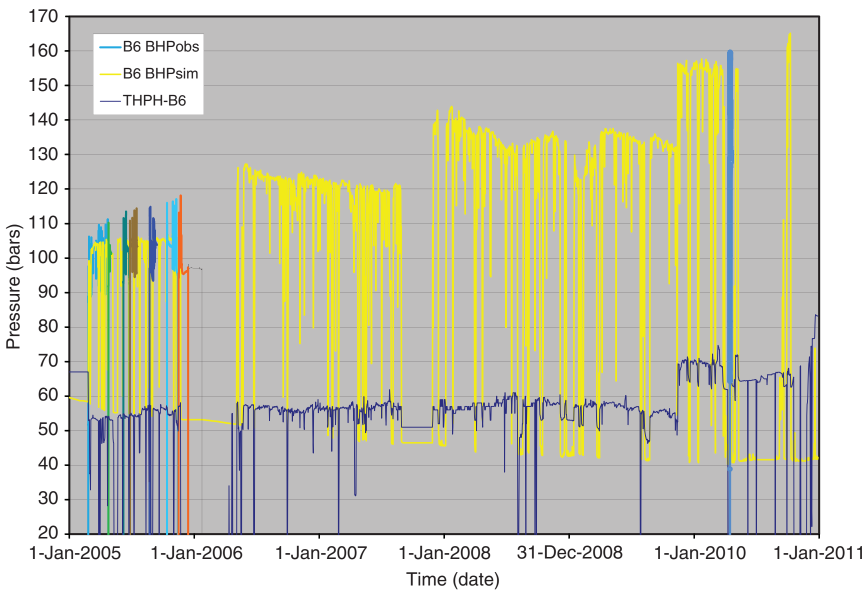


Plate XVII (Chapter 13) Well K12-B6 detailed CO_2 injection plot, 2011 update and new concept.

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