UNITED
Carbon Sequestration Council
STATES

March 7, 2011

Global Status of Geologic CO_2 Storage Technology Development

Larry Myer

The USCSC would like to thank the IEA Clean Coal Centre for providing financial support for this paper.

IEA CLEAN COAL CENTRE

Introduction

This paper discusses carbon dioxide (CO_2) capture and storage (CCS), which involves capture of CO_2 at large power generating and industrial facilities, compression and transport by pipeline, and injection into the deep subsurface for permanent storage. For over 20 years, scientists have been investigating CCS as one option for mitigation of CO_2 emissions. During the past decade, CCS has gained recognition amongst the broader global scientific community, as well as policymakers, as one means of reducing greenhouse gas (GHG) emissions. The United Nations Intergovernmental Panel on Climate Change (IPCC - a Nobel Prize winning organization) concluded in its *Fourth Assessment* report on climate change (IPCC 2007) that CCS was a technology with the potential for important contributions to mitigation by 2030. The report listed CCS as a key technology for mitigation in both the energy and industrial sectors. In 2008 in Tokyo (Japan), the G8 leaders stated: "We strongly support the launching of 20 large-scale CCS demonstration projects globally by 2010, taking into account various national circumstances, with a view to beginning broad deployment of CCS by 2020."

While significant progress has been made over the past decade, there remain a number of challenges to the broad global deployment of CCS. When IPCC released its "*Special Report on Carbon Capture and Storage"* in 2005, they found no major technical or knowledge barriers to the adoption of geological storage of captured CO_2. The report concluded that technologies for the capture of CO_2 are relatively well understood based on prior experience in hydrogen production and CO_2 separation for natural gas processing. The report also concluded that commercial technologies, including enhanced oil recovery (EOR) using CO_2, acid gas disposal, and natural gas storage, provide substantial knowledge basis for transport and storage of CO_2. Nevertheless, permanent geological storage integrated with power plants and industrial facilities was recognized as an emerging technology, and several key technology gaps were identified where additional work would reduce uncertainty and facilitate decision making about large-scale deployment. Specifically, IPCC saw the need for (IPCC 2005):

- Integration of capture, transport, and storage in full-scale projects.
- Demonstration of CO_2 capture on coal-based and natural gas plants at the several hundred megawatts (or several $MtCO_2$) scale to establish the reliability and environmental performance of CCS on different types of power systems, to reduce the costs of CCS, and to improve confidence in cost estimates.
- Large-scale implementation in industrial processes such as the cement and steel industries that have little or no experience with CO_2 capture.
- An improved picture of the proximity of major CO_2 sources to suitable storage sites to evaluate how well large CO_2 emission sources (both current and future) match suitable storage options that can store the volumes required.

- More pilot and demonstration storage projects in a range of geological and economic settings to gain a better understanding of long-term storage, migration, and leakage processes.
- An enhanced ability to monitor and verify the behavior of geologically stored CO_2.
- R&D for emerging concepts and enabling technologies for CO_2 capture that have the potential to significantly reduce the costs of capture for new and existing facilities.

The World Resources Institute (WRI 2007) summarized the major challenges to broad global deployment of CCS as:

- the need for policy drivers to incentivize deployment;
- the need to further refine a flexible and adaptable regulatory framework which addresses capture; transport; site characterization and permitting; operating standards, including monitoring, measurement, and verification and remediation plans; crediting of mitigated CO_2; and measures to deal with long-term stewardship;
- the need for consistent funding for large-scale demonstration projects to test and better understand the cost and performance of capture technologies and storage reservoirs, with specific focus on reducing capture costs, achieving a better understanding of the behavior of injected CO_2 in deep saline reservoirs, advancing monitoring and verification technologies, and integrating the various components of the entire system; and
- the need to continue to address public acceptability.

In order to gain public acceptance of CCS, the potential risks to the environment and the general population must be deemed reasonable. On the issue of risk, the IPCC 2005 *Special Report* concluded: *"With appropriate site selection informed by available subsurface information, a monitoring program to detect problems, a regulatory system, and the appropriate use of remediation methods to stop or control CO_2 releases if they arise, the local health, safety, and environment risks of geological storage would be comparable to risks of current activities such as natural gas storage, EOR, and deep underground disposal of acid gas."* The U.S. DOE/NETL has similarly concluded (www.netl.doe.gov/technologies/carbon_seq/index.html): *"With proper site selection based on available subsurface information, a monitoring and verification program, regulatory system, and appropriate mitigation to stop or control CO_2 releases should they arise, environmental and safety concerns are minimal. Local health, safety, and environmental risks of geological storage would be less than the risks of current activities such as natural gas storage and enhanced oil recovery due to the fact that CO_2 is not toxic, flammable, or explosive."*

This paper will address the storage aspects of CCS and will examine the technical advances being made to enable broad, global, geologic storage of CO_2. The life cycle of a storage site includes the following key steps: 1) selection of a site of appropriate size and with appropriate geologic characteristics; 2) detailed characterization of selected sites to verify and further define its geologic characteristics (it is likely that some selected sites will be determined, upon further investigation, to be unsuitable); 3) careful engineering of the injection facility, and the injection process, to ensure the best environmental controls; and 4) comprehensive monitoring over both the short and long term to be sure the CO_2 stays in place. A good understanding of the behavior of the stored CO_2, especially being able to predict and monitor CO_2 plume migration, will be essential to successfully carrying out these steps; this paper will emphasize the advances being made on prediction and monitoring of plume migration. Of particular relevance is the experience provided by several CO_2 storage demonstration projects which have been carried out in different countries throughout the world.

While this paper does not explicitly address non-technical and policy issues, an understanding of the behavior of stored CO_2, and prediction and monitoring of the plume, is relevant to many of these issues. The risks of storage, and public perception of those risks, will be influenced by the demonstrated ability to predict and monitor plumes. Policymakers, regulators, and the public all want assurance that the injected CO_2 will stay in place within a known, defined area, over the long term.

Review of World-wide CCS Efforts

During the past decade CCS has gained great momentum with billions of dollars committed world-wide to research, development, and demonstration (RD&D) projects in an effort to prove and improve the technology in time for full-scale commercial use. Although CO_2 injection has been used for enhanced oil and gas production for decades, permanent geological storage integrated with power plants and industrial facilities is considered to be emerging technology. Most experts agree that CCS must be successfully demonstrated at commercial scale in various geological formations and geographic regions before the technology is considered ready for wide-scale deployment. A previous USCSC paper (USCSC, 2009) concluded:

"There is consensus that CO_2 storage in deep underground geologic formations has great technological potential and may be deployable on a widespread basis. However, there are still substantial financial, institutional, regulatory, and technical challenges that remain. To address these challenges, multiple integrated CO_2 capture and storage system projects are needed to prove out the technology. Also needed is an array of small, and intermediate and large-scale CO_2 injection field tests in diverse geologies to adequately characterize and validate the U.S. geologic resource."

In the United States, building on the extensive experience with EOR and natural gas storage, the U.S. Department of Energy, led by NETL, is pursuing the Sequestration Research, Development, and Demonstration Program in partnership with industry and academia. A key element of the Program is the Regional Carbon Sequestration Partnership (RCSP) program, which encompasses 43 states and 4 Canadian provinces represented by seven RCSPs. This program includes key field tests throughout the United States and Canada to fully characterize geologic storage sites, to validate models, to validate prior findings, to develop Measurement, Verification, and Accounting (MVA) instrumentation. The field-scale investigations underway as part of the RCSP program will provide direct observations on the behavior of CO_2 underground, building confidence that the key phenomena are well understood and that CO_2 can be injected and stored safely. U.S. DOE is initiating a comprehensive effort on risk assessment that will utilize these investigations (along with a strong science base) to develop a sound framework for ensuring that each specific storage site is properly chosen and developed for safe, long-term storage.

In addition, the United States has initiated several commercial demonstration projects under its multibillion dollar Clean Coal Power Initiative (CCPI) Program, which have been enabled by the work of the seven RCSPs to advance the knowledge on geologic storage of CO_2 (the RCSP program was the subject of a recent USCSC educational paper).

Globally, there is an enormous amount of activity surrounding the development of CCS projects, though a large portion of the activity is currently in the planning stage. As of April 2010 the Global CCS Institute (GCCSI) had identified 238 CCS projects worldwide that were either planned or active (GCCSI, 2010). Of these, 151 were identified as being integrated, that is, involving all three steps of the CCS process − capture, transport, and storage. The GCCSI identified 80 of these projects as being large-scale integrated projects (LSIPs), where large scale was defined as 0.8 Mt per annum or more CO_2 for coal-fired power generation, or 0.4 Mt per annum or more CO_2 for other source types. The distribution of these projects worldwide is shown in Figure 1, which shows that the majority are in North America and Europe. Forty-four projects are planned for the power generation sector. Of the 80 LSIPs, 33 employ pre-combustion capture, 22 employ post-combustion, and 13 are gas processing plants (remainder are either not specified or other capture processes) (GCCSI, 2010). On the storage side, the 80 projects are split evenly between EOR and other geologic formations such as saline formations and depleted oil and gas reservoirs (GCCSI, 2010).

Only nine of the 80 LSIPs identified by GCCSI are operating and two are under construction, and all of them occur in, or have linkages to, the oil and gas sector. Five of the nine operating projects are EOR projects in which the source of the CO_2 is anthropogenic, but the commercial focus of the projects is hydrocarbon recovery and not long-term storage of the CO_2. There are just four commercial-scale CO_2 storage projects in operation today: the Sleipner and Snøhvit projects in the North Sea, offshore of Norway; the In Salah project in Algeria; and the Weyburn project in Saskatchewan, Canada. The Sleipner project, which was the first of its kind in the world, began in 1996, and pumps about 1 million tonnes per year of CO_2 into a saline formation. The Snøhvit project, which began operations in 2008, injects 700,000 tonnes per year into a saline formation, and the In Salah project, onshore Algeria, which began operations in 2004, injects about 1 million tonnes per year into a saline formation. In all three cases, the CO_2 is produced along with methane from a natural gas reservoir, and separated from the methane in a gas processing plant before re-injection into the subsurface. The Weyburn project is a commercial CO_2 EOR project which has injected between 1 and 2 million tonnes CO_2 per year into an oil reservoir since 2000. The source of the CO_2 for the Weyburn project is the Dakota Gasification Great Plains Synfuels Plant, North Dakota, USA. All of these projects have been monitored by international research teams and have demonstrated safe and effective storage at each of the sites. In addition, these projects have provided extensive experience and knowledge about plume movement and monitoring, which will be reviewed in this paper.

In terms of scale, the storage of all CO_2 emissions from a 500 MW coal-fired power plant would be from 2 to 3 times larger than the existing storage projects (though only about 1/2 the size of the largest CO_2 EOR projects). The similar size of these projects suggests that much about practical engineering, as well as risks, of CO_2 storage can be learned from existing CO_2 injection operations.

Though smaller in scale, there are a number of other CO_2 injection field projects worldwide which have provided valuable new knowledge about CO_2 behavior in the subsurface, plume migration, and monitoring. These include the CO_2SINK, Ketzin project in Germany, the Otway project in Victoria, Australia, the Nagaoka, Japan project, as well as the Frio and Regional Partnership projects in the United States. Results of these projects will also be reviewed in this paper.

Types of Storage Reservoirs

Key geologic formations for CO_2 storage include: (1) depleted or near-depleted oil and gas reservoirs, (2) saline formations (rocks containing non-potable high salinity water) and (3) deep unmineable coal seams. These targets occur in deep sedimentary basins, places where sand and mud accumulated in layers to great thickness over many millions of years and compacted under pressure to form rock. Sedimentary basins are good places to explore for CO_2 storage sites because they typically contain both layers of permeable rocks, such as sandstone, which have the capacity to hold large amounts of CO_2 in the pore spaces of the rock, and layers of impermeable rocks, such as shale, which overlie the sandstones and form seals that prevent the CO_2 from escaping upward. Both oil and gas reservoirs and saline formations derive from the same lithified sand and mud, so the physical properties of the rocks of relevance to CO_2 storage, such as the porosity and permeability of the sandstones, and impermeability of the shale seals, are the same in both cases. Oil and gas reservoirs can be thought of as local regions within saline formations where hydrocarbons fill most of the pore space between the sand grains.

Mature oil fields are very promising for early CCS applications for several reasons: first, use of CO_2 for enhanced oil recovery (CO_2 EOR) is a commercial technology; there may be revenues obtained from CO_2 EOR to offset storage costs; second, infrastructure is already in place in some regions; third, the existence of the hydrocarbon reservoir demonstrates that there are geologic attributes favorable for CO_2 storage; and fourth, the geologic data accumulated during the exploration and primary production is directly relevant to development of the reservoir for storage. The IPCC (2005) estimated the worldwide storage potential of discovered oil and gas reservoirs as ranging from 675-900Gt CO_2. However, use of mature oil (and gas) fields for storage also raises concerns: the presence of pre-existing wells drilled for primary production increases the risk of leakage because of the sheer number of wells, and because the wells were likely not engineered for long-term integrity. In addition, the process of extraction may have damaged the seals, again increasing the risk of leakage. The challenges associated with long-term storage mean that demonstrations are required to build the confidence needed for broad application of the technology.

Saline formations are considered by many to be the most promising target for storage, and, ultimately, the formations which will constitute the primary storage resource for widespread application of CCS. This is because of the broad availability of saline formations worldwide, and the potentially large storage resource that they represent − the IPCC (2005) reported an upper estimate of saline formation storage of ten times that of oil/gas field storage. There is, however, large uncertainty in the storage capacity of saline formations. The range in potential worldwide saline formation storage given by the IPCC (2005) was 1,000 – "possibly" 10,000Gt, whereas the NETL Atlas (U.S. DOE 2010) assessment of storage potential in the United States, alone, ranged from 1,653 - 20,213Gt. There are some differences in the assumptions and methods used for calculating storage potential, but, to a large extent, the uncertainty in saline storage potential arises from the lack of data on the geologic structure and properties of these formations. There are many sedimentary basins in which few, if any, deep wells have been drilled, or seismic data collected, which are the two primary sources of quantitative data about the subsurface. In addition, the subsurface is inherently variable and heterogeneous, so that there is uncertainty in extrapolation of data from one location to another.

Lack of data and geologic variability also represent one of the main challenges in large-scale deployment of the technology. Geologic variability means that a number of research projects will be needed to predict the potential of this type of reservoir to store CO_2. One important source of variability is the original environment in which the sediments were deposited (e.g., marine shorelines or deltas, rivers, lakes, wind-blown, etc.). Each depositional environment imparts distinct architectural characteristics to the geologic formations which influence injectivity, plume movement, and trapping of $CO_{2.}$ The NETL has carried out a comprehensive assessment of depositional environments and their impact on storage in the United States (NETL 2010a). Lack of pre-existing data increases the cost of acquiring data to characterize the subsurface and the risk that selected sites will be unsuitable for storage.

Coal formations are also found in sedimentary basins, and, at depths greater than can be reached by conventional mining methods, also are targets for CO_2 storage. Many coal formations contain methane, and extraction of this methane using wells drilled from the surface is a commercial technology (coalbed methane, or CBM). It is known that CO_2 will displace, by the physicochemical process of adsorption, methane from coal. Storage of CO_2 in coal formations therefore offers the potential advantage of revenue from methane production to offset storage costs. The process is referred to as enhanced coal bed methane recovery (ECBM). Low injectivity represents one of the significant challenges in using coal for CO_2 storage. Many coal formations exhibit low permeability, requiring use of techniques like hydro-fracturing to enable injection of the CO_2. In addition, coals tend to swell in the presence of CO_2, which causes a reduction of injectivity over time. There is also considerable uncertainty in estimates of potential storage capacity of coal formations. The IPCC (2005) estimated the worldwide storage potential as ranging from a low value of 3-15Gt to a high value of 200Gt. For coal formations in 21 U.S. states and 1 Canadian province, the NETL Atlas (U.S. DOE 2010) estimated a storage potential of 60-117Gt.

The potential of basalt and organic shale formations for CO_2 is being investigated, but these formations are not currently considered to be primary targets. Shales are also found in sedimentary basins, and have attracted significant attention in the past few years as sources of natural gas. Since CO_2 also adsorbs to organic-rich shale, there is the possibility that CO_2 could be stored in conjunction with methane production.

Basalt formations are the product of volcanic eruptions and are therefore, geologically speaking, in a category distinct from sediments. Basalt is of interest for CO_2 storage because these formations are prevalent where sedimentary basins are not, such as the Pacific Northwest in the United States, and most of the entire sub-continent of India. An advantage of basalt is that it is chemically reactive with CO_2 and offers the potential of very secure storage by conversion of CO_2 stable carbonate mineral forms of $CaCO_3$ and dolomite ($CaMg(CO_3)_2$). However, basalts are extremely heterogeneous, and there are many challenges in characterizing, predicting, and monitoring CO_2 movement through them. Research in the United States includes a field pilot CO_2 injection in basalt in Washington State, carried out as part of the NETL Regional Carbon Sequestration Partnership program.

Trapping Mechanisms

The set of geologic characteristics that are important to the long-term storage of CO_2 includes: (1) reservoir capacity, (2) reservoir injectivity, and (3) containment properties and processes.

The storage capacity of a reservoir depends most fundamentally upon the porosity of the rock, and the thickness and areal extent of the reservoir. All of these properties vary among different formations, and spatially within formations, and must be characterized at each site considered for storage. Porosity is the percentage of the rock volume which consists of open space. Common values of porosity for sandstone, which would be considered as very good for storage, range from $20 - 30\%$. Other factors which influence the storage capacity of the reservoir include the contrast in properties between CO_2 and the fluids present in the rock, and the heterogeneity in properties and structure of the reservoir. These factors influence the efficiency with which the porosity is filled, and the ultimate "footprint" of the plume. For purposes of a national resource assessment, the NETL determined that an efficiency factor of 1 − 4% was appropriate for saline formations (U.S. DOE 2010). However, site-specific data will be needed to assess the storage efficiency for any particular project, and will be a major focus of reservoir modeling studies performed for the project. The status of tools and approaches for carrying out these assessments is covered in later sections of this report.

The injectivity of the reservoir determines CO_2 injection rates, which therefore determines the number of injection wells, and, to a large extent, the cost of injection. Injectivity depends on the thickness of the reservoir and the permeability of the rock, where permeability is a measure of the ease with which a fluid can move through the rock. The permeability of rocks ranges over many orders of magnitude and is dependent upon many factors. It is the primary distinguishing property between a suitable reservoir and a seal. Low permeability is desired for a sealing formation and high permeability is desired for the reservoir. Permeability varies among formations, regionally, and locally within formations. Determination of the permeability of the reservoir and seal rocks, and how it varies across the storage site, is an important part of site characterization for a CO_2 storage project.

The third requirement of a suitable site for long-term storage is containment, meaning those properties and processes which will keep the CO_2 securely stored. The primary containment mechanism is the presence of one or more low permeability formations above the reservoir interval. In order to understand why this is a primary containment mechanism, it is necessary to understand the properties of injected CO_2. In almost all circumstances, the CO_2 will be less dense than the native formation water and the resulting buoyant force will tend to push the CO_2 upward. In order to make the most efficient use of underground pore space, and to maximize the vertical separation between storage formations and potable water, the target depth for CO_2 storage is generally considered to be anything greater than 800 meters, about 2,500 feet, below the surface. In most places, the ambient pressures and temperatures below this depth result in CO_2 being in the supercritical phase, which occupies much less volume than gaseous phase CO_2 captured at the surface. This change in volume with depth is illustrated in Figure 2. Under supercritical conditions, the density of CO_2 will range from 50 − 80% of the density of water.

Over time, several additional trapping mechanisms work to immobilize the CO_2 in the reservoir: (1) dissolution into the formation water, (2) capillary trapping as a residual phase in small pores, and (3) mineral trapping as the CO_2 chemically reacts with the mineral matter. Collectively, these are referred to as "secondary" trapping mechanisms.

Though termed "secondary," these trapping mechanisms, particularly capillary trapping in the residual phase, can be of primary importance for containment. Low permeability formations prevent upward movement of the CO_2, but they do not prevent lateral movement unless they are geometrically configured to do so. If CO_2 is injected beneath a dipping seal, as illustrated in

Figure 3, the buoyant force imparts lateral as well as vertical movement to the CO_2. The CO_2 will continue to move updip until it is either completely dissolved into the water, or trapped in the residual phase.

As noted above, the long-term containment of CO_2 is dependent on the robustness and integrity of the geologic seals. In addition to low permeability, the seal must be free of fractures and faults which might act as leakage pathways for CO_2. Fractures and faults both represent cracks, or breaks in the rock, and the formal distinction between them is that a fault is a crack in which one side of the crack has slid on the other. Generally, fractures are of lesser concern because they are not as big as faults. Faults can be present at any scale, but the ones of greatest concern for leakage are those which cut across multiple formations. Not all faults, however, represent leakage pathways. Faults are a component of the trap of many hydrocarbon reservoirs, demonstrating that they have prevented migration of buoyant fluids for geologic time. Even active faults, those which are currently capable of earthquakes, can be effective seals, as evidenced by many hydrocarbon reservoirs in California. The determination of the potential for a fault to be a leakage path must be made on a case-by-case basis.

The potential for leakage through fractures and faults means that detection and characterization of fractures and faults is an important activity in evaluating potential sites for storage. Because faults and fractures can impact hydrocarbon production, considerable effort has been put into development of detection and characterization methodologies. Nonetheless, it often can be a challenging undertaking. For example, the spatial distribution of vertical fractures, which are common, is not well sampled by vertical wells. Also, interpretation of seismic data, which is commonly used to infer information about fracturing, is subject to ambiguities and limitations.

A containment process which is unique to coal and organic shales is adsorption. In this process, molecules of CO_2 are chemically bound to the surfaces of the coal within the coal matrix. Methane is also adsorbed by coal, but, since CO_2 is more strongly bound than CH_4, injected CO_2 will displace the adsorbed CH_4. This preferential adsorption is what makes the idea of ECBM production appealing. It also means that coal seam storage of CO_2 in the adsorbed phase should be very secure. However, there is a need for further studies to validate the long-term security of CO_2 storage in coal.

All of the geologic characteristics responsible for containment vary regionally and locally, and must be well understood before injection begins. But, there will always be a level of uncertainty in this understanding because of limitations in the technology available for subsurface characterization. A primary motivation for monitoring is, therefore, to confirm that containment is occurring as predicted. This has also been a major objective of major field tests carried out to date.

In addition to geologic characteristics, operational aspects of storage projects can also impact long-term containment. Pre-existing wells are recognized as potential leakage pathways, and will have to be located and remediated as part of the process of developing a storage project. New wells are also potential leakage pathways. There are decades of experience in well construction for oil and gas production, including EOR using CO_2, which can be drawn upon to assure that wells constructed for storage projects won't leak during the operational life of the site. When sites are closed, however, new procedures will have to be developed to assure that leaks will not develop in the long term.

CO_2 will be injected under pressure, and the magnitude of this pressure, and the length of time that it persists, impact containment of the CO_2. In order for CO_2 to enter the pores of the rock, it must displace the native water, and this means that the minimum injection pressure must be greater than the ambient water pressure in the reservoir. The ambient water pressure varies with depth, and under normal conditions, is equal to a column of water extending from the injection point to the surface. The excess pressure above ambient becomes a driving force, in addition to buoyancy, for movement of the CO_2 and potential leakage. After injection stops, the excess pressure will begin to dissipate. The rate of pressure dissipation, as well as its long-term equilibrium value, varies according to a number of factors. The excess pressures resulting from injection can be modeled, but need also to be monitored.

If injection pressures become too large, the rock can be fractured. This could result in a containment issue if the fracture were to cross the seal above the reservoir. Because of this risk, in the United States, the maximum injection pressure will be set by regulation, and procedures have been developed to determine the allowable injection pressure at each injection site.

It is common practice in the petroleum industry to purposely fracture ("hydrofracture") a reservoir in order to increase its permeability and productivity. It is particularly common in production of natural gas from coal beds because these formations very often exhibit low permeability. For CO_2 storage, the injectivity of a reservoir would be increased if hydrofracturing were allowed. Project economics are directly impacted since reservoir injectivity determines the number of wells required for a project.

Simulation Tools

Computer modeling to predict the behavior of CO_2 in the subsurface will be an integral part of the selection, design, operation, and monitoring of storage projects. Generally speaking, computer modeling technology for CO_2 storage has required adaptation of existing tools, not development of new ones. Many decades of research and development have resulted in highly sophisticated codes, in the commercial sector as well as in the research sector, for applications to hydrocarbon production (including CO_2 EOR), geothermal energy production, and groundwater resource management. Methods for representation of the physical domain (the subsurface) in a numerical model, techniques for solving equations, and methods for processing and displaying results are directly applicable to modeling of CO_2 storage. The relevant fundamental equations for heat and fluid flow, mechanical deformation, and chemical interactions, are also common among all these applications. Much of the effort in adapting tools for simulation of CO_2 storage has been focused on modifications to enable solution of these equations for the specific properties, conditions, and processes relevant to storage of CO_2.

Related to long-term containment, there are a few processes of primary importance, which have been incorporated into codes. The properties of CO_2 are very distinct from other fluids, and vary in a complex manner with temperature and pressure, requiring codes that handle multiple phases under non-isothermal conditions. Modeling of plume migration requires calculation of the amount of CO_2 that is dissolved, which means that the code must couple the chemical process of dissolution with the multiphase flow process. Plume migration also depends upon calculation of the amount of CO_2 trapped in the residual phase, and this requires that the codes incorporate complex hysteretic flow processes.

There is a long list of chemical processes relevant to storage, including aqueous speciation, dissolution/precipitation, ion-exchange between solutions and minerals, surface chemical reactions occurring at phase interfaces (i.e., surface complexation, sorption), the effects of these processes on porosity and permeability, coupling with mechanical effects (e.g., water-assisted creep and crack growth; fracture healing, clay mineral swelling) as well as transport (advection, dispersion, and multicomponent diffusion) and multiphase flow and reaction. There is no one code which incorporates all these processes, nor is there consensus about the importance of all of them on long-term containment.

Unique to coal (and organic shales) is the need to couple the chemical process of CO_2 sorption with multiphase flow processes, and there are simulation tools which do this. In addition, it has been recognized in laboratory tests that sorption of CO_2 causes coal to swell, which can reduce its permeability, but the degree to which this process affects flow at field scale remains uncertain.

The process of injection will result in increases in stress in the reservoir and seals. If the stresses become too large the rock might fracture, or pre-existing fractures or faults might move, affecting containment. So, codes are needed, and are available, which can calculate the stress changes accompanying CO_2 injection.

Much more information about simulation tools and their capabilities for modeling behavior of CO_2 in the subsurface can be found in a new report from the U.S. DOE/NETL, titled “Risk Analysis and Simulation for Geologic Storage of CO_2” (NETL 2010b).

Though many advances have been made, it is unclear that all important processes related to long-term containment have been incorporated into simulation tools. Measurements and observations from field tests are essential in addressing this issue.

Another issue of great practical importance in assessing the status of simulation tools for CO_2 storage is the quality of the data that is input to the models. The steps involved in carrying out a simulation include: 1) building a geologic model; 2) conversion of the physical geologic model to a gridded numerical model; 3) applying parameters and properties to the numerical grid; 4) solving equations which describe processes; and 5) displaying the results. Results of the simulations are only as good as the data used to complete the first three steps. In step 1, as discussed in a previous section, the inherent variability, heterogeneity, and lack of access to the subsurface continues to represent a challenge in developing an accurate model of the types of rock and the structure of formations in the subsurface. In step 2, constraints in computing capacity will limit the amount of geologic detail that can be incorporated into the numerical model. Technology for computing capacity continues to advance rapidly, but the large scale of storage projects presents a particular challenge in this area. In step 3, as in step 1, description of the variability in properties such as porosity, relative permeability, mineralogy, fluid chemistry, etc., remains a challenge. Once again, experience from field testing will shed light on the practical implications of limited data on long-term containment.

Monitoring Tools

Monitoring will be key to verifying that projects perform as expected, and that long-term containment is achieved. Successful demonstration of monitoring technologies will also be key to enabling broad, global, geologic storage of CO_2. Many of the measurement technologies for monitoring geologic storage are drawn from other applications such as the oil and gas industry, natural gas storage, disposal of liquid and hazardous waste in deep geologic formations, groundwater monitoring, and ecosystem research. Some technologies, such as seismic imaging, have reached a highly sophisticated level due to many decades of research, development, and application in the petroleum industry.

In general, however, there has been limited monitoring experience (even taking into account CO_2 EOR), specific to assuring containment of CO_2 in the subsurface. Hence a focus of many current research and development activities has been to evaluate how well existing technologies work, and to adapt them to the specific requirements for CO_2 storage. Since the performance of some techniques is significantly affected by various geologic characteristics, a continuing challenge is to determine which technologies work best in which geologic environments.

The best approach for monitoring appears to be to develop numerous measurement approaches and options—a monitoring toolbox—which enables tailored, flexible, monitoring programs for storage projects. The value of a tailored approach to monitoring is threefold: first, optimum performance of many techniques depends on site-specific geologic attributes; second, the risks that need to be monitored will vary from site to site; and third, a tailored approach will enable the most cost-effective use of monitoring resources.

Another challenge is quantification of leakage, should it occur. In general, quantification of leakage is more challenging than leak detection, and more experience and study is needed before definitive statements can be made about minimum detectable volumes. Many, if not most, techniques which can be used to detect a subsurface leak, also provide information which can be further analyzed to quantify the leak, though additional assumptions and data from other measurements are often needed. Site-specific conditions, once again, will heavily influence the sensitivity and uncertainty in results.

Establishing a baseline will be an essential early step for monitoring of geologic storage. Since CO_2 is ubiquitous in the environment, both at the surface and in the subsurface, it is important to establish initial levels before injection operations begin. Moreover, many of the parameters that can be used to monitor a storage project are not uniquely and directly indicative of the presence of CO_2; instead, it is the changes in these parameters over time that can be used to detect and track migration of CO_2 and its reaction products. For this reason, a well-defined baseline includes not only the average value of these parameters, but accounts for how they vary in space and over time before the project begins. Referred to as "time-lapse," this approach is the foundation for monitoring CO_2 storage projects. Without time-lapse measurements, it may not be possible to separate storage-related changes in the environment from the naturally occurring spatial and temporal variations as seen in the monitoring parameters. For most CCS projects, baseline data will be obtained during the pre-injection phase of the project. This is particularly important for storage projects in deep saline formations, for which there is less prior data than for depleted oil and gas fields.

Collection and analysis of monitoring data continues throughout the injection phase and into the post-injection and site closure phases. It is a dynamic and iterative process in which model predictions play a critical role. One of the key outputs of site characterization is a subsurface model. Comparisons of monitoring measurements with model predictions are made repeatedly to determine if the project is performing as expected, and what adjustments can be taken if it is not. Monitoring data is used to improve the initial subsurface model, which leads to increased confidence in subsequent model predictions. As knowledge and confidence in the performance of a project increase, monitoring may be scaled back, and the spatial and temporal frequency of monitoring measurements and types of measurement may be changed to reflect this increased understanding.

Comprehensive discussions of monitoring techniques and applications to geologic storage can be found in reports by Benson et al. (2005), U.S. DOE (2009), and elsewhere. Advances in monitoring resulting from major field demonstrations conducted globally will be discussed in later sections. As a prelude, the following discussion summarizes a number of approaches specifically related to long-term containment.

Wellbores that intersect the storage formation could provide pathways for CO_2 migration. Petroleum industry experience suggests that leakage from the injection well itself is one of the most significant risks for injection projects (IPCC, 2005). Approaches for monitoring for wellbore leakage include:

- Pressure monitoring
  - In a closed well to establish that the casing is not leaking.
  - In overlying formations, where leakage of CO_2 will result in an increase in pressure in the water in the rock.
- Careful monitoring of temperature profiles along the well to identify temperature anomalies that indicate leakage.
- Geophysical wireline logs, used routinely in the petroleum industry, provide data on the integrity of the cement filling the space between the well casing and the rock. If CO_2 were to leak through the cement between the casing and the rock, it could enter rock formations above the injection interval. Geophysical wireline logs and can detect the presence of CO_2 in the rock within about a meter of the wellbore.
- Tracers can be injected behind the casing and their movement monitored to indicate the presence of leak paths at the casing-cement-rock interface.
- Water samples
  - Extracted from formations and analyzed for CO_2, or for tracers, if any have been injected with the CO_2.
  - Shallow groundwater samples obtained from existing water wells, or for-purpose drilled wells, and analyzed for CO_2 and or CO_2-water-rock reaction products.
- Sensors placed at ground surface in the vicinity of the well to measure CO_2 concentrations in the air.

The second major category of potential leak paths, as mentioned in previous sections, is subsurface geologic structural features, of which fractures and faults are considered to represent the greatest risks. Approaches to mapping the movement of CO_2 in the subsurface, which can also detect leakage out of the storage reservoir from fractures and faults, include:

- Geophysical monitoring methods: seismic, electromagnetic, and gravity
  - Seismic surveys produce images of subsurface properties by generating and recording induced sound waves as they travel through the earth. Seismic methods are generally considered able to provide higher resolution data about the presence of CO_2 in the subsurface between wells than any other technique. Seismic methods include surface seismic methods in which the source and recording instrumentation are both at the surface, vertical seismic profiling, in which the

source is at the surface but the recording instruments are in wells, and crosswell seismic in which both the source and recording instruments are in wells.

  – Gravity and electrical methods create lower-resolution images of the subsurface, and are less widely tested for CO_2 applications, but should provide additional information on movement of the CO_2 plume. Gravity methods use the difference in density between CO_2 and water as a means of detection, whereas electrical methods use the difference in electrical conductivity between CO_2 and water, which is generally assumed to be saline for the purposes of CO_2 storage.

- Land-surface deformation, satellite, and airplane-based monitoring: injection of CO_2 into the reservoir causes increases in the pressure of the water in the rock, which extend far beyond the extent of the CO_2 plume. Small ground surface displacements, measurable from satellite-based systems, can be translated into images that show the migration of the CO_2, and would be able to show leakage via fractures and faults.

- Other approaches to monitoring for leakage due to fractures and faults require access to formations overlying the reservoir via wells. As discussed above, water samples, temperature and pressure measurement, and geophysical wireline logs can be employed in such wells.

Monitoring costs will depend on many factors including plume size, regulatory requirements, duration of monitoring, geologic site conditions, and the particular methods selected for application. There is limited real-world information available on costs for monitoring CCS projects. Using data from analogous industry applications, Benson et al. (2005) estimated life-cycle monitoring costs for two scenarios: (1) storage in an oil field with EOR, and (2) storage in a saline formation. The scenarios were not developed to be prescriptive of what a monitoring program should be, but are representative of plausible examples. For each scenario, cost estimates were developed for a "basic" and an "enhanced" monitoring program. The basic monitoring program included periodic 3-D seismic surveys, microseismic measurements, wellhead pressure, and injection rate monitoring. The enhanced monitoring program added periodic well logging, surface CO_2 flux monitoring, and other advanced technologies. The assumed duration of monitoring included a 30-year injection period, as well as a post-injection monitoring period of 20 years for the EOR scenario and 50 years for the saline formation scenario. For the basic monitoring program, the undiscounted cost for both scenarios was \$0.16 − \$0.19/ton CO_2. For the enhanced program, the undiscounted cost was \$0.27 – \$0.30/ton CO_2. More data, based on real projects, is needed in order to validate these early estimates, but they do show that monitoring is unlikely to be a significant portion of the total cost of CCS, on a per ton basis, for most types of projects.

Results from Field Projects

The following sections summarize the findings of the major CO_2 storage projects, worldwide, and examine the technical advances they have made toward enabling broad, global, geologic storage of CO_2. The projects discussed are: Sleipner and Snøhvit, offshore Europe; Ketzin, onshore Europe; In Salah, Africa; Otway, Australia: Nagaoka, Japan; and Weyburn-Midale, Frio and other U.S. Regional Partnership sites, North America.

Sleipner

Project Overview

The Sleipner CO_2 storage project is the world's longest running geologic storage project. Since 1996, 12 million tonnes of CO_2 have been injected from a single well drilled into the saline water-saturated Utsira Formation (Alnes et al., 2010). The Sleipner storage project is being carried out in conjunction with a commercial natural gas production project operated by Statoil. Located about 240 km off the coast of Norway in the North Sea, natural gas is produced from the Sleipner West field from a reservoir below the Utsira. In order for the natural gas to be sold, its CO_2 content is reduced from about 9 − 2.5% (Nooner et al., 2007).

The regional geometry of the Utsira and overlying units was well defined from interpretation of nearly 14,000 line kilometres of 2D seismic data and over 300 wells (Figure 4) (Chadwick et al., 2000). The Utsira sand is a tabular, basin-restricted unit stretching about 450 km from north to south and 40-90 km west to east. It lies at depths of about 800 – 1100 m below the sea floor with a thickness of about 250m around the injection site (Arts et al., 2008). Overlying the Utsira sand is the Nordland shale, which, in the Sleipner area is between 200 and 300 m think (Arts et al., 2008). Immediately overlying the sand is a shale drape, which is a tabular, basin-restricted, seal (Chadwick et al., 2000). The Utsira sand is poorly consolidated, highly porous (30 – 40%) and very permeable (1 – 3 Darcy) (Arts et al., 2008). The very high permeability, high porosity, and large reservoir volume has resulted in negligible pressure increases in the reservoir.

Seismic Monitoring and Reservoir Modeling

One of the most significant findings of the Sleipner project has been the effect of internal structure and heterogeneity of a reservoir on the movement of the plume. The internal structure of the Utsira can be loosely described as a layer cake of sand layers on the order of 30 m thick separated by mudstone layers on the order of 1 m thick. The mudstone layers, which are not laterally discontinuous, baffle the upward migration of the CO_2 within the reservoir, having a significant effect on the storage efficiency of the reservoir (Figure 5).

This baffling effect was recognized because of the success of the seismic monitoring program at Sleipner. The existence of the mudstone layers were known from well logs in exploration wells, but they were not visible in the pre-injection seismic data (collected in 1994) and their significance not recognized until the first repeat 3D seismic survey carried out in 1999. That survey clearly showed reflections from CO_2 in a stack of layers (Figure 6), which were then correlated with the mudstone layers observed in the well logs.

Though the conditions for application of seismic are nearly ideal at Sleipner (offshore, high porosity, thick, poorly consolidated, structurally simple sand), it was the first project to clearly demonstrate the potential utility of seismic surveys for monitoring CO_2 storage. Repeat 3D seismic data were acquired in 1999, 2001, 2002, 2004, 2006, and 2008 (Eiken et al., 2010). Figure 7 is a plan view of the seismic amplitudes at the top of the Utsira, showing the steady expansion of the plume over time. Amplitudes increase in the central part of the plume, as would be expected; the sum of the seismic amplitudes has been observed to track linearly with the volume of CO_2 injected (Eiken et al., 2010). The threshold for use of seismic acquisition and processing at this site to detect leaks is considered to be on the order of 1Kt of CO_2 (Eiken et al., 2010).

At Sleipner, in addition to the mudstone baffles, the expansion of the plume is significantly influenced by the topography of the interface between the sand reservoir and the caprock. This interface undulates, creating topographic highs. Under buoyancy drive, the CO_2 fills one high spot before spilling laterally to fill the next. This process can be monitored using the seismic data, as shown in Figure 7, and was used by Singh et al. (2010) as a basis for validation and refinement of numerical simulators used to model the plume migration. These authors compared the results of two commonly used commercial simulators, Eclipse 100 and Eclipse 300, and an invasion percolation code, MPath Migration, with the migration of the plume as described by the time lapse seismic measurement. Eclipse 100 assumes the reservoir fluids consist of three components: water, oil, and gas in a three-phase system. Eclipse 300 is a compositional simulator with cubic equations of state representing the fluid phase behavior, and MPath Migration is a three-phase invasion percolation simulator, which assumes that gravity and capillary forces dominate flow. All three simulators were able to reproduce the plume migration reasonably well, though the northern migration was best matched by the MPath Migration simulator while the Eclipse simulators better matched the southern migration pattern.

<u>Other Monitoring at Sleipner</u>

Sleipner is also the first and, thus far, only project to employ gravity methods as part of the monitoring program. Gravity measurements have much lower spatial resolution than seismic measurements. However, gravity can provide information in situations where seismic methods do not work as well, and gravity measurements can be used to assess the amount of dissolved CO_2, to which seismic measurements are insensitive.

At Sleipner, precision gravity measurements (supported by the U.S. DOE NETL) were carried out using a ROVDOG (Remotely Operated Vehicle deployable Deep Ocean Gravimeter) at 30 seafloor stations above the CO_2 plume in the years 2002, 2005, and 2009 (Nooner et al., 2007, Alnes et al., 2010). About 5.88 million tonnes of CO_2 had been injected over this time period. Inversion for average density using geometry constraints from seismic gave 675- 715 kg/m^3 for the density of the separate phase CO_2 in the reservoir. Combining this with temperature measurements, Alnes et al. (2010) concluded that the rate of dissolution of the CO_2 into the water did not exceed 1.8% per year.

A Controlled Source Electromagnetic (CSEM) survey was carried out in 2008, but yielded no interpretable results, possibly due to pipeline noise as well as a moderate response from the plume (Eiken et al., 2010).

The seafloor has been mapped with multibeam echo sounding and side-scan sonar, and videos have been taken by ROV, to look for bubbles, but none have been observed (Eiken et al., 2010).

Snøhvit

<u>Overview</u>

The Snøhvit project is a commercial natural gas production project in which natural gas, produced from three offshore fields, Snøhvit, Albatross, and Askeladd, is pipelined onshore and processed into liquefied natural gas (LNG), condensate, and liquefied petroleum gas (LPG). It is located offshore Norway, to the northeast of the Sleipner project, in the Barents Sea. Like Sleipner, the natural gas contains CO_2 (5 − 8 mole %), which must be removed, and the CO_2 is being stored in a saline formation associated with one of the offshore fields. However, Snøhvit's geology is quite different from Sleipner's, presenting different challenges with regard to CO_2 storage.

The plan for the Snøhvit CO_2 storage project is to inject about 23 million tonnes of CO_2 over a 30-year life of the project, using one injection well completed in the Tubåen Formation, which is a saline formation located at a depth of about 2400m below the seafloor, and underneath the natural gas producing reservoirs in the Snøhvit field (Maldal and Tappel, 2004). About 0.8 million tonnes of CO_2 have been injected since operations commenced in 2008 (Eiken et al., 2010).

The selection of the Tubåen Formation was influenced in part by data availability, with 15 wells having been drilled into it for hydrocarbon exploration purposes. The formation is primarily sandstone with a thickness ranging from 45 – 75m and a porosity of about 13%. The Tubåen Formation is overlain by the Nordmela Formation, which is primarily shale and is considered, based on geologic data and other evidence, to be an adequate seal against vertical migration of the CO_2. One piece of geologic evidence is that the Tubåen, updip from the injection point, contains natural gas, which is trapped by the Nordmela Formation. Above the Nordmela is the Stø Formation, which contains the main gas bearing reservoir of the Snøhvit field. Above the

Stø are two additional sealing formations, the Fuglen and the Hekkingen. There is extensive faulting in the region, adding considerable complexity to the geologic structure of the project.

Reservoir Studies

The variability in reservoir properties and the complex faulting have resulted in a challenge in evaluation of the injection design CO_2 storage capacity at Snøhvit. Though the Tubåen is 80 – 90% sandstone, the distribution of the shale, which constituted the remaining 10 – 20% of the formation, could not be well defined based on available data prior to injection. This means that there is uncertainty about how well the porous sand bodies in the reservoir are connected. In addition, the sandstones also have small-scale fractures, which enhance permeability, and "stylolites," which decrease permeability, but the distribution of which is uncertain (Basquet et al., 2008).

Faulting effectively divides the reservoir into compartments. The hydrologic properties of the faults can significantly influence how much can be stored and the migration of the CO_2 plume. At Snøhvit there is considerable uncertainty about the degree to which bounding faults are sealed. Results of seismic data collected prior to injection suggested that the faults were not completely sealed (Linjordit et al., 1992).

The effects of the variability in reservoir properties and faulting have been the subject of extensive reservoir modeling for Snøhvit. Prior to drilling of the injection well, reservoir simulations were carried out in which the faults were assumed to be sealed, but the reservoir properties were homogeneous, allowing good access to all portions of the reservoir. This result showed a modest pressure increase in the formation because of the sealed faults (Mildal and Tappel, 2004). Subsequent modeling by Pham et al. (2010), in which heterogeneity in porosity and permeability, derived from well logs, was included in the reservoir model along with sealed faults, showed that planned injection rates from a single well would result in excessive pressure build-up greatly in excess of the pressure required to fracture the formation.

Estublier and Lackner (2009) performed a number of simulations to evaluate the long-term behavior of the CO_2 plume at Snøhvit. These studies also concluded that it was highly unlikely that all 23 million tonnes could be stored if the faults were sealed. If the faults are not sealed, depending on various assumptions for reservoir properties and fault permeability, the CO_2 could migrate up into the Stø formation. The implication of this result is that the long-term containment of the CO_2 at Snøhvit could be dependent upon the sealing capacity of the formations overlying the Stø. An example result of one of these simulations is shown in Figure 8.

Monitoring

At Snøhvit, down-hole pressures and temperatures are measured 800m above the reservoir at the injection well. A series of pressure build-ups and fall-offs have been observed due to frequent injection stops at the site (figure 9). Pressure increase over the 2.5 year injection period, combined with the fact that pressure did not stabilize over a 4 month injection stop, indicates there is moderate effective permeability in the reservoir. The value is lower than initially expected from the pre-injection data, but are not sufficient to use to draw conclusions about overall storage capacity (Eiken et al., 2010).

A 4D seismic data set collected in 2009 shows clear anomalies related to both CO_2 and pressurized water, with amplitudes decaying away from the injection well. The seismic results also suggest that only a fraction of the main formation is receiving most of the CO_2. The spatial variability shown in the 4D map in Figure 9 (right) suggests lateral heterogeneities play an important role, and that barriers related to channeling significantly reduce the effective permeability.

In Salah

Project Overview

The In Salah project, located at the Krechba Central Processing Facility in the central Algeria Sahara, is a joint venture (JV) of BP, Statoil, and Sonatrach. It is a commercial natural gas production project in which CO_2 is removed from the natural gas in order to meet the gas export specification of 0.3% CO_2. The CO_2 content of the natural gas is 5 – 10%. From 2004 to 2010 more than 3 million tonnes have been stored, with an ultimate goal of storing 17 million tonnes of CO_2 over the life of the project. An extensive monitoring program has been undertaken, both to meet the commercial needs of the project, and to support development of monitoring technologies. Monitoring provided by the Joint Industry Project (JIP), is funded by BP, Sonatrach, EU DG Research, and the U.S. Department of Energy NETL. This project is an interesting case history because of the unique monitoring technologies applied, and because of a small amount of leakage which occurred due to the unexpected migration of CO_2 to an exploration well drilled more than 20 years prior to project start-up. There were no adverse impacts from the leakage.

The Krechba Carboniferous reservoir is a sandstone rock which on average is 20m thick with a porosity of about 13% and a permeability of 10mD. Structurally, it is a four-way dip (dome-like) closure, in which the hydrocarbons have accumulated at the high part of the dome. Downdip from the natural gas, the rock is saturated with saline water, and the CO_2 is injected in this portion of the reservoir at a depth of about 1950m. A schematic cross section of the subsurface at Krechba is shown in Figure 10. There are currently three CO_2 injection wells at Krechba, injecting up to 50mmscfd of CO_2. The reservoir is overlain by about 900m of mudstone rock which acts as a seal against vertical migration of both the natural gas and the CO_2.

Understanding the Behavior of the CO_2 in the Subsurface

The Carboniferous reservoir was selected using the standard oil-industry Capital Value Process. An exploration well, designated KB5, which intersected the Carboniferous, had been drilled in 1980. An extensive 3D seismic survey was then carried out in 1997. This survey defined the overall structure of the reservoir and also provided information about its internal architecture and distribution of the sandy portions with the best porosity and permeability. No significant faults were identified in this survey (Iding and Ringrose, 2009).

Using this available data as input, reservoir simulations were carried out during the design phase of the project in 2001 to model both the production of natural gas and the injection of CO_2 into the reservoir. The reservoir simulations confirmed the need for a development plan utilizing a number of horizontal wells for production and injection into the relatively thin, low permeability reservoir. These simulations indicated that the CO_2 would not migrate very far in the direction of the old exploration well, KB5.

In 2002, when drilling began in the development phase of the project, it became evident that fractures and faults could play a role in production and injection operations (Iding and Ringrose, 2009). Data from the wells suggested that the injection horizon and the immediate overburden is naturally fractured with a preferred NW-SE orientation. Because of the large thickness of the mudstone seal, the fractures are not considered a significant risk to the long-term containment of the CO_2. The horizontal injection wells were drilled perpendicular to the dominant fracture orientation in order to maximize injection capacity.

After injection started and monitoring data became available, additional focus was placed on understanding the impact of fractures and faults on the movement of the CO_2 in the subsurface, and this focus intensified after the leak was discovered at KB5. The geologic model of an area around one of the CO_2 injectors, KB-14, was modified to incorporate a network of fractures. The 3D seismic data was reprocessed using techniques designed to help identify faulting, and a possible fault was identified which trended from another injector, KB-502, toward the leaking well, KB5. This fault was incorporated into a numerical model of the reservoir as a high permeability corridor and the commercial reservoir simulator, Eclipse, was used to demonstrate that the unexpected, rapid migration of the plume to KB5 could be explained by the presence of such a feature (Iding and Ringrose, 2009).

In further analyses, geomechancial simulations were coupled to the fluid flow simulations (Rutqvist et al., 2010). These analyses calculate the stresses and displacements that would occur everywhere in the rock due to the injection of the CO_2, and they showed that the pattern of uplift of the ground surface (discussed further in the subsection on monitoring at In Salah) was consistent with injection-induced deformation in a fault zone as described above.

The geomechanical analyses further show that the stresses induced by the injection are not sufficient to cause the fault to slip. Thus, even though a fault is present, the integrity of the seal, and long-term containment of the CO_2, is not threatened by movement on the fault.

Monitoring at In Salah

The original monitoring program, prior to injection, was designed with several key risks in mind. Table 1 presents the key risks that were identified, along with monitoring technologies deemed appropriate for mitigation of the risk. Of the five key risks, four were related to leakage and long-term containment. Two risks were associated with wellbore leakage, and one with leakage though the seal. Early CO_2 breakthrough, as can be caused by flow along a fault, can also result in less effective use of the storage space in the reservoir, affecting its ultimate storage capacity.

Key Risk	Monitoring Technologies
Injection Well Problems	Ongoing pressure monitoring, continuous wellhead and annual down-hole or through casing logging
Early CO_2 Breakthrough	Modeling, tracers, seismic imaging, observation wells, fluid sampling, wellhead and annulus monitoring
Vertical leakage	Seismic imaging, microseismic, shallow aquifer monitoring, soil gas sampling, surface flux, gravity, tiltmeters, satellite imagery
Wellbore leakage	Annulus monitoring, soil gas sampling, through casing logging.
Old wellbore integrity	Annulus pressure monitoring and CO_2 surface flux monitoring

Table 1: Key Risks and Monitoring Technologies (Mathieson A. et al., 2010).

To help select specific technologies, the JIP also used a "Boston Square," which allows a comparison of techniques based on two criteria – cost and benefit to the project (Wright et al., 2010). The JIP assessed 29 monitoring technology options using a Boston Square. Technologies chosen by the JIP for the initial program included:

- wellhead and annulus monitoring, including physical surveillance,
- well bore fluid sampling,
- tracers,
- wireling logging,
- shallow water sampling,
- InSAR satellite detection, and
- 3D seismic.

Of the assessed technologies, repeat 3D surface seismic technology had the highest benefit and the highest cost. The use of surface seismic technology is challenging at Krechba. The Krechba sandstone storage domain is onshore, deep, thin, and has low porosity and permeability compared to other sites, such as Sleipner. Because seismic is challenging, other methods, such as InSAR, which can provide information on the behavior of the plume at large distances from wells, take on greater importance in the monitoring program.

The tracer monitoring approach involved injection of small amounts of perflurocarbons along with the CO_2, and sampling of well bore fluids in observation wells. Different perflurocarbons were used to 'tag' the CO_2 injected at each injection well, so that any CO_2 detected can be differentiated from the natural CO_2 in the subsurface and traced back to an individual injection well.

The In Salah project is the first application of satellite InSAR technology for monitoring of geologic storage. InSAR, which stands for satellite airborne radar interferometry, detects changes in elevation at the earth's surface. Injection of the CO_2 causes an increase in the pressure of the water in the reservoir, and that pressure increase results in small displacements at the ground surface above the reservoir. The amount of surface displacement depends on the magnitude of the pressure, as well as geometry of the pressurized region, depth, and rock properties.

One advantage of InSAR data is the relative low cost and ease of acquisition compared to seismic data. The satellite is collecting data all the time, so the frequency with which data is available for a specific site is related to the orbit of the satellite and how often it passes over the site of interest.

A major challenge in application of this technology is to be able to resolve the very small surface displacements associated with CO_2 injection. At In Salah, the surface uplift due to CO_2 injection is about 3 – 5 mm/year, compared to approximately 200mm per day due to earth tides. Methodologies for processing the satellite data to obtain higher resolution displacement measurements continue to evolve. PSInSAR (Permanent Scatterer InSAR), which has been applied at In Salah, gives an accuracy of around 5 mm/year and up to 1 mm/year for a longer term average (Ringrose et al., 2009).

Monitoring Results and Current Status

The first step of the monitoring program was to assemble baseline data. This data included the 3D seismic data acquired during the exploration phase of the project, and InSAR data which had also been acquired prior to injection. Additional data acquisition prior to injection included extensive sampling and logging programs (including image logs) in the new development wells, saline aquifer sampling and headspace gas sampling through the overburden, soil gas surveys around each of the new wells, and soil gas sampling from the shallow aquifer water wells.

InSAR data collected in 2006 and 2007 suggested that CO_2 was migrating quickly in the direction of KB5 (Figure 11). Based on this information, a close inspection of the well was carried out during a routine surveillance visit. The presence of CO_2 was detected by a leak through a missing flange, which was quickly fixed (details on the leak are in the following section). Subsequently, the results of the perfluorocarbon tracer measurements confirmed that the CO_2 had migrated from the injection well KB502 to KB5.

A JIP was set up in 2005 to monitor the CO_2 storage process using a variety of geochemical, geophysical, and production techniques over a 5-year period.

The current monitoring and verification technologies used at Krechba have been developed over the past 5 years, taking into account and adjusting for circumstances such as the breakthrough at KB5. Table 2 presents the current monitoring and verification program.

Monitoring technology	Risk to Monitor	Action/Status
Repeat 3D seismic	Plume migration Subsurface characterisation	• Initial survey in 1997 • High resolution repeat 3D survey acquired in 2009 • Being interpreted at present. • May show some time lapse (4D) effects
Microseismic	Caprock integrity	• 500m test well drilled and recording information above KB502 – encouraging results to date
InSAR monitoring	Plume migration Caprock integrity Pressure Development	• Images captured using X-band (8 days) and C-band (32 days) • Use to develop time lapse deformation images
Tiltmeters/GPS	Plume migration Caprock integrity Pressure Development	• Currently collecting data – 18 month collection period to end 2011 • Use to calibrate satellite data
Shallow aquifer wells	Caprock Integrity Potable aquifer contamination	• 5 wells drilled to 350m – one beside each injector, one remote and one between KB5 and KB502. • Two sampling programmes to date
Wellhead/annulus samples	Wellbore integrity Plume migration	• 2 monthly sampling since 2005
Tracers	Plume migration	• Different perflourocarbon tracers into each injector • Implemented 2006
Surface Flux/Soil Gas	Surface seepage	• Initial survey pre-injection • Two surveys in 2009 around key risk wells
Microbiology	Surface seepage	• First samples collected in late 2009/early 2010
Wireline Logging/sampling	Subsurface characterization	• Overburden samples and logs in new • Geomechanical and geochemical modeling

Table 2: Current Monitoring and Verification Technologies (Mathieson A. et al., 2010).

Shallow soil gas and flux measurements were difficult because of the hard ground, but not impossible. Loose sand and gravel was found where the ground was not hard and these loose materials also presented difficulties because of the potential for contamination of samples due to movement of atmospheric gases through the highly permeable materials. Despite these difficulties, elevated CO_2 soil gas and flux measurements were observed near the KB-5 well (Jones et al., 2010).

Soil gas and flux measurements also provided some data on background CO_2 levels in a harsh desert environment. In comparison with more vegetated sites from temperate regions, the soil gas values were found to be lower by at least an order of magnitude compared with vegetated sites from temperate regions.

Changes which occur in plants in response to elevated levels of CO_2 in the soil, though not a direct measure of CO_2, are considered to be another indicator of leaking CO_2. Finally, it has been proposed that elevated levels of CO_2 in the soil might also affect microbial communities. At In Salah, vegetative cover is very low, commonly 10% or less, though somewhat higher in topographic lows, reflecting the desert environment. Some of the plants represented species which might be affected by CO_2, if exposed to elevated soil gas concentrations. Microbial populations were also low, but were present (Jones et al., 2010).

Development of a detailed picture of the injected CO_2 plume continues to be a focus of the combined monitoring and subsurface modeling activities at In Salah. Although still being processed, the repeat 3D seismic has provided images of the overburden and injection horizon, which, combined with satellite data, will improve the accuracy of forward and inverse modeling of plume migration. Annulus and wellhead monitoring, including tracer analysis and pressure monitoring, combined with history matching and data acquired from the breakthrough at KB5 have helped to construct the image of the CO_2 plume.

Evaluation of the rate and pattern of surface deformation detected by satellite technology has also provided an understanding of subsurface CO_2 plume movement and geomechanical response to the injected CO_2. An integration of InSAR data with geomechanical models along with seismic and fracture data has been studied to better determine plume migration direction.

<u>History of the Leak at KB5</u>

The history of the leak at KB5 has been summarized by Ringrose et al. (2009). KB5 was drilled by Total in 1980. When Total relinquished their hydrocarbon lease, ownership of the well reverted to the State. When the In Salah Gas Joint Venture (BP, Sonatrach, Statoil), referred to as the In Salah JV, was formed, ownership of KB5 (and other legacy wells) remained with the State. Under Algerian hydrocarbon regulations, suspended wells should be decommissioned within 2 years.

The KB5 well intersected the water saturated portion of the Carboniferous formation, which was the same formation into which CO_2 would be injected. It was not plugged with cement in the Carboniferous, because, at the time it was drilled, it was a hydrocarbon exploration well, and cementing was not required if hydrocarbons were not found.

Using available data, during the design phase of the JV project in 2001, reservoir simulations indicated that CO_2 would not migrate very far in the direction of KB5 from the closest injector, KB502. After injection started (injection into KB 502 started in 2005) and monitoring data became available, additional simulations, coupled with satellite observations of surface deformation in 2006 and 2007 suggested that CO_2 was migrating more quickly than expected in the direction of KB5.

A perfluorocarbon tracer was injected into KB502 on June 1, 2007, and a close inspection of the KB5 well was carried out during a routine surveillance visit on June 28, 2007. (The previous surveillance visit in August of 2006 had not reported any leakage). The presence of CO_2 was detected by a leak through a missing flange. The well is located in an insecure area and military escort is required for site visits. Ideally, the presence of CO_2 in the well would have been detected by pressure on a gauge without any leak, but both the flange and the gauge had been stolen. The operators estimated the leak as a few ft^3/day – a very small volume compared to the approximately 30 million ft^3/ day being injected (Ringrose et al., 2009).

Subsequently, well KB5 has been completely decommissioned, and re-injection recommenced. Surface flux and soil gas monitoring are currently ongoing at KB5.

Weyburn-Midale

Project Overview

The IEA GHG Weyburn-Midale CO_2 Monitoring and Storage Project began in 2000 in close collaboration with EnCana, which is the operator of the CO_2 EOR project in the Weyburn Field in Saskatchewan, Canada. While CO_2 EOR is considered a commercial technology, this project is unique because of its research focus on storage in conjunction with EOR. The Weyburn CO_2 EOR flood is likely the most intensely studied operation of its kind in the world.

The CO_2 EOR reservoir is the Midale beds of the Charles Formation. The Midale consists of a layer <30m thick of fractured carbonate rock at a depth of about 1500m. The reservoir is comprised of vuggy limestone ("Vuggy") and overlying marly dolostone ("Marly") (Figure 12). The reservoir is overlain by a seal of evaporate rocks (anhydritic dolostones and anhydrites). Above these are a series of additional sealing formations, including the Lower Watrous Member, which forms the most extensive primary seal to the Weyburn system (Whittaker, 2004).

The Midale reservoir has been under oil production for decades. At the end of primary production in 1964, water flooding was begun to enhance production. Further field development, including application of horizontal wells, began in 1991 (Preston et al., 2005), and CO_2 injection began in 2000. Since then, more than 15 million tonnes of CO_2 have been stored, with current total field injection rates (new and recycled CO_2) of 13,000 tonnes per day (White 2010). The CO_2 (a byproduct of gasification of lignite) is purchased from the Dakota Gasification synthetic fuel plant in Beulah, North Dakota, and transported through a 320 km pipeline to Weyburn.

The IEA GHG Weyburn-Midale CO_2 Monitoring and Storage Project has been carried out in two Phases, with Phase II continuing and Phase I being completed in 2004. The research efforts for Phase I were organized into four main "themes" (Preston et al., 2005):

- Geological characterization of the geosphere and biosphere,
- Prediction, monitoring, and verification of CO_2 movements,
- CO_2 storage capacity and distribution predictions and the application of economic limits, and
- Long-term risk assessments of the storage site.

Activities in Phase II have focused on developing additional information on the geology, geohydrology, and geochemistry of the Weyburn field (Jensen et al., 2010; Johnson, 2010; Rostron and Whittaker, 2010). Additional geophysical monitoring data has been collected and work done to extract as much information as possible from the new and existing monitoring data (White, 2010).

<u>Reservoir Modeling</u>

Reservoir simulation using a multi-phase, multi-component compositional computer simulation package (Preston et al., 2005, Law, 2004) was key in predicting the movement of the CO_2, design of the CO_2 injection strategy, and evaluation of the storage capacity of the reservoir. The CO_2 EOR project was divided into 75 patterns, or groups of injection and production wells. Eventually, in the subsurface, the pressure and fluid movements of patterns interact with one another, but initially, the injection and production operations for each pattern are managed separately. Reservoir simulation was carried out at different scales, from a single pattern, to the complete 75 pattern assembly (Figure 13).

The reservoir simulation was built upon a detailed geologic model derived from data from the dense network of wells put in place for primary and secondary oil production. The detail of the geologic model was more than could be reasonably accommodated in the reservoir simulation, even for the single pattern model, so a process of upscaling, or averaging of properties over specific volumes of rock, was carried out. Additional upscaling was needed in order to model multiple patterns. The upscaling from the single pattern fine-grid reservoir model proceeded in two steps: (1) from three fine-grid single-pattern models to coarse-grid models of the same patterns, and (2) from three coarse-grid single-pattern models to a 75-pattern model using the same grid resolution (Preston et al., 2005).

The reservoir simulations were validated, and the geologic model refined, by both laboratory-scale and field-scale measurements. In the laboratory, CO_2 coreflood experiments were simulated. At field scale, production histories from three different patterns with different injection strategies were history-matched. Further "ground-truthing" of the reservoir models was provided by seismic and other monitoring data, as will be discussed further in the next section.

In addition to reservoir simulation, geochemical modeling was also carried out, which predicted that in 5000 years, no free-phase CO_2 would be present in the reservoir (Gunter et al., 2004). Further reactive-transport modeling is being carried out in phase II (Johnson et al., 2010). Coupled fluid flow and geomechanical modeling has also been carried out to understand the impact of fluid pressure increases resulting from CO_2 injection.

<u>Monitoring Activities in the Weyburn-Midale Project</u>

Monitoring methodologies investigated as part of the project included:

- geochemical fluid sampling,
- surface seismic, augmented by VSP,
- passive seismic,
- shallow well monitoring and sampling,
- soil gas surveys, and
- tracers.

Unique among the global storage demonstrations is the geochemical fluid sampling campaign at Weyburn. Over a 10-year span, a baseline and samples have been collected on 15 occasions from a suite of 50-60 wells. Samples of produced brines were analyzed for over 40 compositional and isotopic parameters, generating a unique, comprehensive database. The spatial and temporal changes in pH, alkalinity, concentrations of Ca and Mg, and carbon isotopes were found useful in monitoring the movement of the CO_2 in the subsurface and providing indication of incipient CO_2 breakthrough at wells (Emberley et al., 2005, Gunter et al., 2004). Figure 14 shows results for the pH and alkalinity. Samples of produced hydrocarbons were also analyzed in order to refine the equation of state for the specific hydrocarbon-CO_2 mixture in the Midale reservoir.

Advances in the application of surface seismic technology for monitoring were also made in the Weyburn-Midale project. The Midale reservoir was a challenging surface seismic because of its thinness and rock properties, but, through application of advanced acquisition and processing methods (such as pre-stack impedance inversion), it has proved generally successful. 3D, three-component, time-lapse seismic data were acquired over a portion of the project area in 1999 (baseline survey), 2001, 2002, 2004, and 2007. Travel time and amplitude anomalies were found to correlate well with injection in well patterns where significant volumes of CO_2 had been injected (~3–14% hydrocarbon pore volume) (White, 2009). In most cases, there is generally good agreement between the injection volumes and the areal extent and/or intensity of the anomaly (Figure 15).

The 3D time-lapse seismic data was also analyzed to evaluate caprock integrity and to look for CO_2 which might have migrated vertically from the reservoir (White, 2010). Anisotropy in caprock velocities was mapped using amplitude-versus-offset-and-azimuth techniques. Such anisotropy is often caused by fractures, and though there is no corroborating evidence to prove their existence, the results identify areas for focused surveillance in ongoing monitoring activities. Time-lapse interval travel times were analyzed for anomalies which might indicate the presence of CO_2 in the overburden. While some were found between the reservoir and the regional seal (Watrous formation), few (if any) significant anomalies were found above it (White, 2010).

Though limited in array size, passive seismic, or microseismic monitoring has been underway since 2003 in the Weyburn-Midale project. During this time period, about 100 events occurred, with 97% of these prior to early 2006 during the early stages of CO_2 injection (White, 2010). The microseimicity rates were found to correlate with periods of elevated CO_2 injection rates, and also with changes in production activities in nearby wells (Verdon et al., 2009). Coupled fluid flow-geomechanical simulations for a Weyburn-based model concluded that the seismicity was likely due to stress-arching effects rather than CO_2 escaping from the reservoir (White, 2010).

Otway

Overview

The Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC) Otway Project is Australia's first CCS demonstration project and the first intensely monitored pilot site for CO_2 storage in a depleted gas reservoir. The Otway Project site is located in the onshore Otway Basin in southeastern Australia. To date, 65,000 tonnes of CO_2-rich gas (80% CO_2; 20% methane) have been injected into the reservoir (Sharma et al., 2010). The CO_2 is produced from the nearby Buttress Field, compressed at the surface, then transported 2.25 km in an underground pipeline and injected into the depleted Naylor Gas Field. The reservoir is the Waarre C formation, a 25 m thick sandstone located at a depth of about 2 km. It is a 0.5 km^2 compartment located in a tilted fault block, with migration prevented by faults and the overlying Belfast Mudstone.

Reservoir Studies

One of the objectives of the Otway project has been to improve capabilities for predicting CO_2 plume movement in saline reservoirs. The initial pre-injection geologic model was primarily based upon 3D seismic data and information from two wells (Bouquet et al., 2009, Ennis-King et al., 2010). Using data from the injection well drilled for the project, a suite of models was developed based on different choices for the depositional environment and permeability variograms. The numerical simulation models were then validated and refined by history-matching with monitoring data. At Otway this history matching was done in stages (Ennis-King, 2010). First, the numerical models derived from the geological models were matched to data from the original production of methane from the reservoir – the production rates, the (converted) reservoir pressures during production, and the pressure and gas-water contact during the post-production pressure recovery. These adjusted models were used to predict the field observations during CO_2 injection, and were initially used to determine the placement of the injection well. Additional history-matching was carried out after breakthrough of the CO_2 at the observation well. The predicted breakthrough time was 6 months, or less, and the observed breakthrough occurred between 4 and 4½ months after CO_2 injection (Ennis-King et al., 2010).

Among the many parameter variations explored, adjustments to the overall reservoir permeability were the most effective at improving the history match with the pressure data (Ennis-King et al., 2010). These authors also concluded that the use of multiple geostatistical realizations of heterogeneity demonstrated the importance of capturing the range of uncertainty in the geology, and the consequent scatter in forward predictions. Bouquet et al., 2009, found that rock compressibility, in addition to relative permeability, was important in improving the history match.

Monitoring at Otway

The monitoring plan at Otway includes several Environmental and Sub-surface activities. The environmental plan involves the following (Sharma et al., 2010):

1) Atmospheric CO_2, C-13, and methane concentration measurements;
2) Groundwater pH, electrical conductivity, temperature, DO, redox potential, reduced iron, and alkalinity measurements;
3) Soil and gas measurements analyzed for molecular and isotopic composition; and
4) Micro-seismic monitoring.

The subsurface plan involves the following:

1) Subsurface geochemical sampling with the use of a U tube assembly to predict plume migration time windows; and
2) Subsurface geophysical monitoring using 4D seismic.

Use of seismic methods was challenging at Otway for two reasons. First, the reservoir is small, located relatively deep, and thin. Second, injection of CO_2 into a depleted gas reservoir would not be expected to generate significant changes in the seismic signals because changes in the elasticity of the reservoir rock would be small (Urosevic et al., 2010). The first challenge was overcome by combining 3D VSP with 3D surface seismic, and through use of high spatial data density, high fold, and high quality processing of the data. The second challenge could not be overcome, and it was concluded that the time-lapse response was too small to be reliably estimated and analyzed from repeated seismic measurements (Urosevic et al., 2010).

If CO_2 were to migrate into formations overlying the Waarre C Formation, the changes in elasticity of the rock would not be an issue since the rock is saturated with water. An extensive study of the seismic response over the Belfast shales and Paaratte saline aquifer was carried out to verify absence of leaks. By comparing the differences between time-lapse 3D seismic surveys over Paaratte interval to the modeling results, it was demonstrated that no significant amount of CO_2 has escaped Waarre C reservoir and migrated up the fault into overlain strata (Urosevic et al., 2010).

At Otway, the pressure measurements and fluid samples collected in the observation well provided the best monitoring information on the behavior of the CO_2 in the reservoir. The fluid sampling was carried out with a unique device called a U-tube (Underschultz et al., 2009). This enabled the design of a fluid sampling program to : a) provide physical evidence of the CO_2 arrival at a specific location within the reservoir; b) provide a measurement of the travel time for the injected CO_2 between the injection and observation well; c) provide a timing and thus an injection volume for the filling of the depleted gas reservoir; d) measure the partitioning of the injected gas between the existing water and CH_4 phases; e) provide a measure of concentrations and partitioning injected with the CO_2; f) provide a measure of the isotopic composition and mixing of the injected CO_2 and in-situ CO_2; and, g) provide a measure of the formation water chemistry evolution with gas injection. As discussed above, these data were important in validation and refinement of the reservoir models used at Otway.

Ketzin

The pilot CO_2 injection project in Ketzin, Germany, is a major research effort funded through the European Union's CO2SINK Project. The project is managed by the German Research Centre for Geosciences (GFZ,) in cooperation with 18 partners from nine countries, and involves the injection of about 60,000 tonnes of CO_2 into a saline formation. The target formation for CO_2 injection is the Stuttgart Formation, located at a depth of about 650 m. The Stuttgart Formation is on average 80 m thick and is heterogeneous, consisting of sandstone rocks of good reservoir properties alternating with shaley rocks of poor reservoir quality (Arts et al., 2010). Understanding the detailed geometry of these alternating layers, and their impact on flow and other monitoring measurements, has represented a major challenge at Ketzin. Overlying the Stuttgart Formation is the Weser Formation, consisting of mostly mudstone, clayey siltstone, and anhydrite, which forms the regional seal. At Ketzin, one injection well and two observation wells were drilled to a depth of 750 m to 800 m at a distance of 50 m to 100 m from each other.

The Ketzin pilot is interesting because of the heterogeneity of the geology and the unique technologies that have been employed in reservoir modeling and monitoring. For reservoir simulation, a commercial 3D streamline simulator was used (Pamukcu et al., 2010). For situations of incompressible or slightly compressible flow, streamline simulation has greater computational speed and efficiency than standard finite difference approaches. At Ketzin, predicted bottom hole pressures and CO_2 breakthrough times at the observation wells were compared to measurements. A good match was achieved in predicting the bottom hole pressure of the injection well and CO_2 breakthrough time at the first observation well (by reducing overall permeability by a factor of 10), but not the second (Pamukcu et al., 2010). The observed breakthrough time at the second well was considerably less than expected, bringing into question the accuracy of the description of the heterogeneity in sandstone and shale layering in the reservoir.

The unique monitoring approach applied at Ketzin is the use of electrical geophysical methods. For monitoring of CO_2 in saline formations, electrical methods should be applicable because CO_2 has a much lower electrical conductivity than saline water; hence electrical measurements should be sensitive to the saturation of the CO_2. Since seismic measurements are not very sensitive to saturation, use of electrical measurements in conjunction with seismic measurements could provide additional understanding of the movement and distribution of the CO_2 in the subsurface.

At Ketzin, a permanent downhole electrode array (called the Vetical Electrical Resistivity Array (VERA)) was placed behind casing in the injection and two observation wells. Electrical Resistivity Tomography (ERT) was then carried out in a crosswell configuration in order to image the spatial extent of the CO_2 plume (Schmidt-Hattenberger et al., 2010). As shown in Figure 16, the time lapse sequence of ERT measurements from 2008 to 2010 shows a significant increase in resistivity over time at the approximate depth of the reservoir target zone.

In addition to time-lapse ERT measurements, time-lapse CSEM measurements have also been carried out at Ketzin, though this data is still be analyzed (Girard et al., 2010).

Nagaoka

In Japan, the one CO_2 injection pilot completed to date was carried out at Nagaoka, where 10,400 tonnes of CO_2 was injected into a saline reservoir between 2003 and 2005. The sandstone reservoir was about 60 m thick and at a depth of about 1100 m. Extensive reservoir modeling has been carried out, including reactive chemical transport, as well as conventional fluid flow simulations (Sato et al., 2006). Using three observation wells, an extensive monitoring program, including time-lapse cross-well seismic tomography, well logging, pressure and temperature measurements, geochemical monitoring, and micro-seismic measurements was carried out (Michael et al., 2010). The arrival of CO_2 at the observation wells was detected by neutron logging, sonic logging, and induction logging. Time-lapse well logging carried out post injection from 2005 to 2009 showed essentially no changes (Mito and Xue, 2009). The interpretation of this result is that the CO_2 did not migrate away, suggesting the action of secondary trapping mechanisms in keeping the CO_2 in place.

U.S. DOE Frio Test Pilot

The first pilot injection of CO_2 into a saline formation in the United States was the Frio test, located about 60 km from Houston, Texas. The Frio pilot was carried out in two phases. The first phase was initiated in 2004, and approximately 1600 tonnes of CO_2 was injected at a depth of about 1500 m into a sandstone reservoir. In 2006 the second phase commenced with an injection of 250 tonnes into a sandstone at about 1650 m depth. Prior to injection, a detailed geologic model was developed based on seismic data and available well logs. Detailed reservoir simulations were conducted before injection and results compared favorably with post injection field results, including the breakthrough time at the observation well. A comprehensive suite of monitoring measurements were collected and included: geochemical fluid sampling, cross-well seismic, vertical seismic profiling (VSP), tracer injection, bottom hole pressure and temperature, cross-well electromagnetic, and soil-gas measurements. The second phase injection test featured a cross-sell seismic system configured so that data could be collected continuously during and after injection. An important, and surprising (based on initial modeling), result of the monitoring program was the large time-lapse change in the VSP measurements produced by only 1600 tonnes of CO_2 (Doughty et al., 2008).

U. S. DOE Regional Carbon Sequestration Partnership (RCSP) Initiative

In 2003 the DOE through the Sequestration Program initiated the Regional Carbon Sequestration Partnership (RCSP) Initiative, which is managed by the National Energy Technology Laboratory. The RCSP Initiative is collaboration between government, industry, and research entities to determine the most suitable technologies, regulations, and infrastructure needs for future commercialization of CCS. The RCSP Initiative is being implemented in three interrelated phases:

1. The Characterization Phase (FY 2003 – FY 2005). Completed in 2005, this phase focused on characterizing regional opportunities for CCS, identifying regional CO_2 sources, and identifying priority opportunities for field tests. As part of this phase, each RCSP developed GIS information systems that house regional geologic data on CO_2.
2. The Validation Phase (FY 2005 – 2011). The focus of this phase has been on field tests to validate the predictability of CO_2 when injected into a variety of geological storage types throughout the United States and Canada. Using the extensive data and information gathered during the Characterization Phase, the seven RCSPs identified

the most promising opportunities for CCS projects in their regions and are completing the last of 20 small-scale injection tests. In addition, the RCSPs are verifying potential CO_2 storage resources in various storage types, satisfying project permitting requirements, and conducting public outreach and education activities.

3. The Development Phase (FY 2008 – FY 2018+). This phase is working to establish at large scale that CO_2 capture, transport, injection, and storage can be achieved safely, permanently, and economically. Large-scale injection tests carried out during the Development Phase will address practical issues, such as sustainable injectivity, well design for both integrity and increased capacity, and reservoir behavior with respect to prolonged injection. Regional variations among the RCSPs will provide vitally important information and experience as they field test injection and monitoring technologies in a variety of geologic settings.

Following is a summary of the technical advances made in several of the RCSP Validation Phase field tests, which have previously been discussed as part of a USCSC white paper (USCSC, 2010).

<u>Midwest Regional Carbon Sequestration Partnership (MRCSP)</u>
<u>Cincinnati Arch Geologic Test</u>

The Midwest Regional Carbon Sequestration Partnership (MRCSP) injected approximately 900 tonnes of CO_2 into Mount Simon Sandstone at Duke Energy's East Bend Generating Station near the town of Rabbit Hash, KY, in September 2009. Predictions, based in part on reservoir simulations, of the geological structure and injectivity potential at the site proved to be largely consistent with field observations. Injection rates neared 50 tonnes per hour of CO_2 (equivalent to 1,200 tonnes per day) and were limited by the capacity of the injection equipment at the site, not the reservoir, indicating good injectivity for this segment of the Mount Simon Sandstone. This finding is significant because the Mount Simon is a deep saline formation, which is widespread under much of the Midwestern United States, and is believed to be a very large storage resource. This short-termed small-scale injection also included various field monitoring activities such as ground water monitoring, surface CO_2 pressure and temperature monitoring, as well as downhole pressure and temperature monitoring. A baseline water quality test was conducted on 11 shallow groundwater wells and monitoring will continue in those wells for the next 2 years to confirm that the CO_2 does not migrate into drinking water supplies. The project is the first-ever such injection into the Mount Simon formation and significantly adds to the understanding of its CO_2 storage potential.

Midwest Regional Carbon Sequestration Partnership (MRCSP)
Michigan Basin Geologic Test

The MRCSP also conducted an injection of 60,000 tonnes of CO_2 into the Bass Islands formation at approximately 1050 meters depth in the Michigan Basin. The Bass Islands formation consists of dolomitic rock that is overlain by the Amhertburg-Lucas Formations (Gupta et al., 2010), which forms the confining zone. Initial geologic models were based on limited information, so reservoir simulations used for project planning were based on very simple, homogeneous, formation properties. However, later models were more refined and based on newly acquired geologic data from injection and monitoring wells. Hydraulic properties from core samples were analyzed using geostatistical methods, and more sophisticated reservoir simulations modeled the injectivity and storage potential of the formation. After CO_2 was injected, the model was further calibrated using fluid pressures observed in the injection and monitoring wells. In addition, a variety of other measurements were carried out to provide additional information on the subsurface behavior of the CO_2, including: wireline logging, reservoir brine sampling, perfluorcarbon (PFT) tracer injection, and crosswell seismic measurements. Conclusions from the field activities indicate that injection and storage at rates exceeding 1000 tonnes/day/well, which are necessary to support commercial-scale applications, should be possible in the Bass Islands formation (Gupta et al., 2010).

The Plains CO_2 Reduction Partnership (PCOR)
North Dakota (ND) Lignite Test

The Plains CO_2 Reduction Partnership (PCOR) in 2009 injected about 80 tonnes of CO_2 at approximately 366 meters depth into an unmineable lignite coal seam in Burke County, ND. The purpose of this test was to study the behavior of CO_2 in lignite and to determine the potential for coal bed methane recovery. It is significant because it is the first pilot test of storage in lignites, providing new information about the potential for storage in such formations. During the injection, researchers used sampling techniques to indicate the presence of gas in the vicinity of the coal seam. Indications are that the injected CO_2 migrated along the cleat direction of the coal and has been contained within the expected injection zone.

Southwest Regional Partnership on Carbon Sequestration (SWP)
Aneth Oil Field EOR Test

From 2007 to early 2010, the Southwest Regional Partnership on Carbon Sequestration (SWP) conducted an EOR, combined with sequestration injection, into the Paradox Basin. SWP injected approximately 630,000 tonnes into the Deep Creek and Ismay zones in the Paradox Formation, which is approximately 5,800 feet deep, in the Aneth Oil Field in San Juan County near Bluff, UT. The injection schedule ran for over 2 years and post-injection monitoring continues. The source of CO_2 for this project comes from the McElmo Dome, a natural CO_2 reservoir located in southwestern Colorado.

Southwest Regional Partnership on Carbon Sequestration (SWP)
San Juan Basin ECBM Test

In 2009, approximately 16,700 tonnes of CO_2 was injected into the unmineable coal seams at depths greater than 900 meters, in the Upper Cretaceous Fruitland Formation. One of the observations of this test was a declining injection rate, which was attributed to coal swelling. As discussed previously, swelling can be a result of the CO_2 being adsorbed onto the coal while it is displacing methane. A variety of MVA methods were deployed to track the CO_2 plume migration, including tilt meters, CO_2 sensors, and tracers, which were injected along with the CO_2. The arrival of perfluorocarbon tracers at offset wells, in conjunction with observed nitrogen increases, provided indications of preferential breakthrough paths. Analysis of available 3D seismic data did not reveal any faults or fracture zones that could provide leakage pathways. A very thorough simulation model was built and was able to replicate the production and injection behavior of the injection zone, showing an incremental methane production of 26MMscf due to injection.

Southeast Regional Carbon Sequestration Partnership (SECARB)
Gulf Coast Stacked Storage Project

The Southeast Regional Carbon Sequestration Partnership's (SECARB) Gulf Coast Stacked Storage project has demonstrated the concept of phased use of subsurface storage volume. This sequestration approach combines the early use of CO_2 for EOR with subsequent injection into associated saline formations, resulting in both short- and long-term benefits. There is the immediate commercial benefit of EOR as a result of the injection of CO_2 (offsetting infrastructure development costs), followed by large volume, long-term storage of CO_2 in saline-bearing formations. As part of the RCSP Validation Phase, over 627,000 tonnes of CO_2 has been injected into the lower Tuscaloosa Formation in the Cranfield unit, located in southwestern Mississippi, at a depth of 10,300 feet. CMG-GEM, a multiphase compositional flow simulator, has been used for modeling the behavior of the CO_2 in the reservoir (Choi et al., 2010). As part of the monitoring program, high resolution pressure data, collected in the reservoir at a dedicated observation well, showed a response to increased injection rates at a distance of over 1 km. Results showed that, although the fluvial reservoir is stratigraphically complex with multiple incised channels, pressure communication is good (Hovorka et al., 2010). This project is significant in that it has demonstrated the capability and value of utilizing pressure data collected in monitoring wells to establish compartment boundaries. This would be of particular value in future sequestration projects which lack production history. This project is being followed with a large-volume injection into the brine bearing formations down dip of the oil ring during the RCSP Development Phase.

Southeast Regional Carbon Sequestration Partnership (SECARB)
Gulf Coast Stacked Storage Project

In 2008, SECARB also conducted an additional small-scale injection test at Mississippi Power Company's Plant Daniel located near Escatawpa, Mississippi. The project injected 2,720 tonnes of CO_2 into the lower Tuscaloosa Formation at an approximate depth of 2895 meters. Although testing the same formation as the Gulf Coast Stacked Storage test, this test was significant because it evaluated a suitable saline formation for storage of CO_2 in close proximity to a large coal-fired power plant along the Mississippi Gulf Coast. As part of the characterization activities, the project team developed detailed geological and reservoir maps to assess the test site and conducted reservoir simulations to estimate injectivity, storage capacity, and long-term fate of injected CO_2.

Midwest Regional Carbon Sequestration Partnership (MRCSP) and West Coast Regional Carbon Sequestration Partnership (WESTCARB)
Appalachian Basin and Northern Arizona Geologic Tests

The Validation Phase activities are analogous to exploration activities in the petroleum industry. Two of the Validation Phase tests, the Appalachian Basin First Energy R.E. Burger Power Plant and the Northern Arizona Project near the Cholla Power Plant, both demonstrated that subsurface conditions may not always prove to be as anticipated, particularly in areas with little prior oil and gas exploration. In both cases, there was sparse information on the subsurface geology prior to drilling, and in both cases insufficient porosity and permeability were found for CO_2 injection. The findings at these specific sites do not preclude the potential for storage in the regions surrounding the sites; instead, the tests confirm the complex nature of the formations within the basins. The work demonstrates the importance of extensive drilling, formation evaluation, and testing to characterize and identify appropriate formations for CO_2 storage nationwide prior to injection.

Discussion of Field Study Results

The projects discussed in the preceding section do not represent an exhaustive documentation of every CO_2 injection test and do not include the numerous CO_2 EOR projects in which long-term storage is not a project focus. Nonetheless, these projects represent the major CO_2 storage efforts, worldwide, and in aggregate, represent the storage of more than 31 million tonnes of CO_2. Of this total, more than 16 million tonnes have been stored in saline formations, with 15.8 million being stored in the three commercial storage projects, Sleipner, In Salah, and Snøhvit. All of the projects have been the focus of intense scientific study and public scrutiny and none, except In Salah, has experienced any leakage to the near-surface environment. While the leak from an abandoned well at In Salah was unfortunate, it was very small, and was discovered and mitigated without causing any adverse impacts to the environment or the public, illustrating both the need, and success, of an effective monitoring program.

The results of these field projects have clearly yielded many advances in geologic storage through validation of existing tools, and demonstration and testing of new ones. A number of different simulation tools have been validated by history-matching and comparison of predictions with monitoring data in the various geologic environments represented by the field projects. The generally positive outcome of these efforts shows that there are a robust set of simulation tools available to model the behavior of CO_2 in the subsurface**.** The field experience also shows, however, that the validity of the model predictions was highly dependent upon the quality of the input data. The accuracy of the geologic model was paramount, and, of all the numerous physical property input requirements, permeability, both intrinsic and relative, was repeatedly mentioned in case history discussions as the most important variable. It is clear that development of accurate pre-injection geologic models and hydrologic properties of the storage formation remains a challenge and should be given high priority in planning of projects.

Very significant advances were also made in validation and demonstration of monitoring technologies. A diverse set of technologies for measurements at the surface and in the subsurface have been field tested. Technologies conventionally used by the oil and gas industry have been validated for application to monitoring of CO_2, and some unique new technologies have been demonstrated. The successful application of seismic techniques for monitoring the movement of CO_2 in the reservoir was clearly demonstrated. Positive results were obtained not only under "ideal" conditions like those at Sleipner, but elsewhere, under more challenging conditions associated with thin, deep, reservoirs. It was equally valuable to show that active seismic methods will probably not be useful for monitoring of storage in depleted gas reservoirs. Several studies also used seismic measurements to demonstrate that CO_2 has not migrated above confining zones. Though more work is needed, these studies have also provided some insight on the leakage volume detection threshold of surface seismic methods.

Though seismic methods have the highest resolution of the geophysical monitoring methods, it is clear that there are some circumstances where their applicability is limited, and the field studies also showed that other methods can provide complimentary information to improve understanding of plume behavior. Field projects have now demonstrated successful use of satellite-based surface deformation, gravimetry, and electrical techniques, though more work is needed to better determine how broadly applicable they will be. Based on field performance in major pilots and some modeling, Fabriol et al., 2010, have offered the following comparative assessment of seismic, electrical, and gravimetric techniques (Table 3):

Method	Minimum quantity for verification (at reservoir depth > 800 m)	Minimum quantity for leakage detection (at reservoir depth)	Secondary reservoir detection (at depth ca. 200-300 m)	Minimum quantity in theory detectable in secondary reservoir	Geological limitations (specific to CO_2 storage)
4D seismic	Hundreds of Kts	Few Kts	Yes	Few hundreds of tons	Reservoir : Low porosity, layers thickness (decreases the tuning effect)
Electrical CSEM	1 Mt Few tens of Kts (at Ketzin at 600-700 m deep)	Not yet proved	Yes	Few tens of Kts	Low resistivity, thin layers (either resistive or conductive)
Gravimetry	1 Mt	Not yet proved	Yes	Few tens of Kts	Seasonal surface variations

Table 3. Comparison of performance of geophysical monitoring methods (Fabriol et al., 2010)

In addition to geophysical monitoring, the field tests have also demonstrated the value of other types of monitoring measurements, including pressure and temperature, tracers, fluid sampling for geochemical analyses, and well logs of many kinds. Geophysical monitoring is generally considered to be the most expensive type of monitoring, and it is noted that cost effective technologies such as wellhead and annulus monitoring were also proven to be useful.

While the field tests indicate that a portfolio of monitoring technologies is available, they do not yield a single prescriptive list of technologies which are applicable, or necessarily sufficient, for all situations. In fact, the experience to date suggests that monitoring programs will need to be developed to accommodate the unique geology, and risks, associated with each site.

Another observation, not only related to monitoring, but more generally to overall technical management of storage operations, is that injection strategies and monitoring plans need to be adaptable, and should be expected to evolve as experience and monitoring data becomes available during operation of the project. In none of the reviewed projects was the behavior of the CO_2 in the reservoir exactly as predicted before injection began.

The overall experience represented by the reviewed projects shows that geologic storage of CO_2 is technologically feasible in a diverse set of geologic environments. Given the geology-specific nature of the technology, this experience is not sufficient, however, to draw conclusions about all geologic environments. Further work is needed to assess the technical feasibility across the spectrum of depositional environments that might be considered, including coal beds. In addition, very little data has been developed about the post-injection behavior of CO_2 in the reservoir. The same simulation and monitoring tools used during the operational phase of storage are applicable to post-injection phase, but field demonstrations of the processes that lead to plume stabilization and long-term trapping are needed.

Conclusions

During the past decade, CCS has gained recognition amongst the broader global scientific community, as well as policymakers, as one means of mitigating the effects of GHG emissions on climate change. Accompanying this has been rapid development of the underlying subsurface science and technology needed to make CCS a commercial reality. The attributes of geologic formations that might be suitable for storage have been defined and, although uncertain, estimates suggest a very large storage potential. The physical processes, which should trap the CO_2 in the subsurface upon injection, and ultimately for the long term, have been identified. Drawing upon past experience in other subsurface applications, powerful tools have been developed to predict the behavior of CO_2 in the reservoir, and a portfolio of tools with the potential for monitoring all aspects of storage projects has developed. This science and technology must however, be field tested, validated, and demonstrated before commercial subsurface storage can be broadly deployed.

Since the mid-1990's a number of storage research and development projects, both commercial and small scale, have been undertaken worldwide. Only considering projects in which storage of CO_2 is a major focus, more than 31 million tonnes of CO_2 has been safely stored. The results of these field projects have clearly yielded many advances in geologic storage through validation of existing tools, and demonstration and testing of new ones. A number of different simulation tools have been validated by history-matching and comparison of predictions with monitoring data in the various geologic environments represented by the field projects. A diverse set of technologies for monitoring at the surface and in the subsurface have been field tested, with the experience to date suggesting that monitoring programs will need to be developed to accommodate the unique geology, and risks, associated with each site.

The overall experience represented by the global field projects shows that geologic storage of CO_2 is technologically feasible in a diverse set of geologic environments. However, challenges remain.

- Further work is needed to assess the technical feasibility across the spectrum of depositional environments that might be considered, including coal beds.
- Development of accurate pre-injection geologic models and well defined hydrologic properties of the storage formation remains a challenge.
- Very little data has been developed about the post-injection behavior of CO_2 in the reservoir. Field assessments of the processes that lead to plume stabilization and long-term trapping are needed.
- Further work is needed to determine the leakage volume detection threshold of subsurface monitoring techniques.

Finally, it must be remembered that technology advances alone are insufficient to enable broad global deployment of CCS. Of equal, if not greater importance, are the policy, regulatory, and public acceptance challenges that must continue to be resolved.

References

Alnes, H., Eiken, O., S. Nooner, G. Sasagawa, T. Stenvold, and M. Zumberge (2010), *Results from Sleipner gravity monitoring: updated density and temperature distribution of the* CO_2 *plume*, to be published in Energy Procedia, © Elsevier, Proceedings of 10th International Conference on Greenhouse Gas Control Technologies, IEA Greenhouse Gas Programme, Amsterdam, The Netherlands.

Arts, R., A. Chadwick, O. Eiken, S. Thibeau, and S. Nooner (2008), *Ten year's experience of monitoring* CO_2 *injection in the Utsira Sand at Sleipner, offshore Norway*, First Break, Vol. 26, pp. 65 – 72.

Arts, R. J., J. Meekes, J. Brouwer, M. van der Werf, R. Noorlandt, B. Paap, W. Visser, V. Vandeweijer, S. Luth, R. Giese, and J. Maas (2010), *Results of a monitoring pilot with a permanent buried multi-component seismic array at Ketzin,* to be published in Energy Procedia, © Elsevier, Proceedings of 10th International conference on Greenhouse Gas Control Technologies, IEA Greenhouse Gas Programme, Amsterdam, The Netherlands.

Basquet, R., L. Rennan, J. Ringen, and O. Wennberg (2008), *Fluid Flow Simulations on Core Samples Containing Natural Fractures and Stylooites*, SPE 113530, presented at SPE Europec/EAGE Annual Conference and Exhibition, Rome, Italy.

Benson, S. M., M. Hoversten, E. Gasperikova, and M. Haines (2005), *Monitoring Protocols and Life-Cycle Costs for Geologic Storage of Carbon Dioxide*, In, E.S. Rubin, D.W. Keith and C.F. Gilboy (Eds.), Proceedings of 7th International Conference on Greenhouse Gas Control Technologies, IEA Greenhouse Gas Programme, Vancouver, BC, Vol. II, p. 1259-1265.

Bouquet, S. A. Gendrin, D. Labregere, I. Le Nir, T. Dance, J. Xu, and Y. Cinar (2009), *CO2CRC Otway Project, Australia: Parameters Influencing Dynamic Modeling of* CO_2 *Injection into a Depleted Gas Reservoir,* SPE 124298, presented at SPE Offshore Europe Oil & Gas Conference & Exhibition, Aberdeen, UK.

Chadwick, R., S. Holloway, G. Kirby, U. Gregersen, and P. Johannessen (2000), *The Utsira Sand, Central North Sea – An Assessment of its Potential for Regional* CO_2 *Disposal,* Proceedings of 5th International Conference on Greenhouse Gas Control Technologies, IEA Greenhouse Gas Programme, Cairns, Australia.

Choi, J.-W., J.-P. Nicot, T. Meckel, and S. Hovorka (2010), *Numerical modeling of CO2 injection into a typical U.S. Gulf Coast anticline structure*, to be published in Energy Procedia, © Elsevier, Proceedings of 10th International Conference on Greenhouse Gas Control Technologies, IEA Greenhouse Gas Programme, Amsterdam, The Netherlands.

Doughty, C., B. Freifeld, and R.Trautz (2008), *Site characterization for CO_2 geologic storage and vice versa: the Frio brine pilot, Texas, USA as a case study,* Environmental Geology, Vol. 54, pp. 1635 – 1656.

Eiken, O., P. Ringrose, C. Hermanrud, B. Nazarian, T. Torp, and L. Hoier (2010), *Lessons Learned from 14 years of CCS Operations: Sleipner, In Salah, and Snøhvit,* to be published in Energy Procedia, © Elsevier, Proceedings of 10th International Conference on Greenhouse Gas Control Technologies, IEA Greenhouse Gas Programme, Amsterdam, The Netherlands.

Emberley, S., I. Hutcheon, M. Shevalier, K. Durocher, B. Mayer, W. Gunter, and E. Perkins (2005), *Monitoring of fluid-rock interaction and CO_2 storage at the Weyburn CO_2-injection enhanced oil recovery site, Saskatchewan, Canada,* Applied Geochemistry, Vol. 20, No. 6, pp. 1131- 1157.

Ennis-King, J., T. Dance, J. Xu, C. Boreham, B. Freifeld, C. Jenkins, L. Paterson, S. Sharma, L. Stalker, and J. Underschultz (2010), *The role of heterogeneity in CO_2 storage in a depleted gas field: history matching of simulation models to field data for the CO2CRC Otway Project, Australia,* to be published in Energy Procedia, © Elsevier, Proceedings of 10th International Conference on Greenhouse Gas Control Technologies, IEA Greenhouse Gas Programme, Amsterdam, The Netherlands.

Estublier, A., and A. Lackner (2009), *Long-term simulation of the Snøhvit CO_2 storage,* Proceedings of 9th International Conference on Greenhouse Gas Control Technologies, IEA Greenhouse Gas Programme, Energy Procedia 1, © Elsevier, pp. 3221 – 3228.

Fabriol, H., A. Bitri, B. Bourgeois, M. Delatre, J. Giorard, G. Pajot, and J. Rohmer (2010), *Geophysical methods for CO_2 plume imaging: comparison of performances,* to be published in Energy Procedia, © Elsevier, Proceedings of 10th International Conference on Greenhouse Gas Control Technologies, IEA Greenhouse Gas Programme, Amsterdam, The Netherlands.

GCCSI (2010), *The status of CCS Projects Interim report 2010*, available at: http://www.globalccsinstitute.com/news/publications.html.

Girard, J., N. Coppo, J. Rohmer, B. Bourgeois, V. Naudet, and C. Schmidt-Hattenberger (2010), *Time-lapse CSEM monitoring of the Ketzin (Germany) CO_2 injection using 2xMAM configuration*, to be published in Energy Procedia, © Elsevier, Proceedings of 10th International conference on Greenhouse Gas Control Technologies, IEA Greenhouse Gas Programme, Amsterdam, The Netherlands.

Gunter, B., and E. Perkins (2004), *Geochemical monitoring and modeling,* Proceedings of 7th International Conference on Greenhouse Gas Control Technologies, IEA Greenhouse Gas Programme, Vancouver, Canada.

Gupta, N., Ball, D., J. Sminchak, J. Gerst, M. Kelly, M. Place, J. Bradbury, and L. Cumming (2010), *Geologic storage field tests in multiple basins in Midwestern USA – lessons learned and implications for commercial deployment,* to be published in Energy Procedia, © Elsevier, Proceedings of 10th International Conference on Greenhouse Gas Control Technologies, IEA Greenhouse Gas Programme, Amsterdam, The Netherlands.

Hovorka, S., T. Meckel, R. Trevino, J. Lu, J.-P. Nicot, J.-W. Choi, D. Freeman, P. Cook, T. Daley , J. Ajo-Franklin, B. Freifeild, C. Doughty, C. Carrigan, D. La Brecque, Y. Kharaka, J. Thordsen, T. Phelps, C. Yang, K. Romanak, T. Zhang, R. Holt, J. Lindler, R. Butsch (2010), *Monitoring a large volume CO2 injection: Year two results from SECARB project at Denbury's Cranfield, Mississippi, USA*, to be published in Energy Procedia, © Elsevier, Proceedings of 10th International Conference on Greenhouse Gas Control Technologies, IEA Greenhouse Gas Programme, Amsterdam, The Netherlands.

Iding, M., and P. Ringrose (2009), *Evaluating the impact of fractures on the long-term performance of the In Salah CO_2 Storage Site,* Proceedings of 9th International Conference on Greenhouse Gas Control Technologies, IEA Greenhouse Gas Programme, Energy Prodedia 1, pp. 2021 – 2028.

IPCC (2007) *Climate Change 2007: Mitigation. Contribution of Working Group III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change* [B. Metz, O.R. Davidson, P.R. Bosch, R. Dave, L.A. Meyer (eds)], Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.

IPCC(2005), *Special Report on Carbon Dioxide Capture and Storage*, published for the Intergovernmental Panel on Climate Change, Cambridge University Press, New York, NY, 2005.

Jensen, G., E. Nickel, S. Whittaker, and B. Rostron (2010), *Site assessment update at Weyburn-Midal CO_2 sequestration project, Saskatchewan, Canada: new results at a active CO_2 sequestration site,* to be published in Energy Procedia, © Elsevier, Proceedings of 10th International Conference on Greenhouse Gas Control Technologies, IEA Greenhouse Gas Programme, Amsterdam, The Netherlands.

Johnson, J., for the Weyburn Geochemical Research Team (2010), *Geochemical assessment of isolation performance during 10 years of CO_2 EOR at Weyburn,* to be published in Energy Procedia, © Elsevier, Proceedings of 10th International Conference on Greenhouse Gas Control Technologies, IEA Greenhouse Gas Programme, Amsterdam, The Netherlands.

Jones, D., T. Lister, D. Smith, J. West, P. Coombs, A. Gadalia, M. Brach, A. Annunziatellis, and S. Lombardi (2010), *In Salah Gas CO_2 Storage JIP: Surface Gas and Biological Monitoring,* to be published in Energy Procedia, © Elsevier, Proceedings of 10th International Conference on Greenhouse Gas Control Technologies, IEA Greenhouse Gas Programme, Amsterdam, The Netherlands.

Juanes, R., E. Spiteri, F. M. Orr Jr., and M. Blunt (2006), *Impact of relative permeability hysteresis on geological CO_2 storage*, Water Resources Research, Vol. 42, W12418.

Law, D., (2004), *Reservoir simulation and economic modeling*, Proceedings of 7th International Conference on Greenhouse Gas Control Technologies, IEA Greenhouse Gas Programme, Vancouver, Canada.

Linjordet, A., and R. Olsen (1992), *The Jurassic Snøhvit Gas Field, Hammerfest Basin, Offshore Northern Norway* In: Giant oil and gas fields of the decade 1978-1988. AAPG Memoir 54, pp. 349-370, Tulsa, Oklahoma. The American Association of Petroleum Geologists. 1992.

Maldal, T. and I. Tappel (2004), *CO_2 Underground storage for Snøhvit gas field development*, Energy 29, pp. 1403-1411.

Mathieson, A., J. Midgely, I. Wright, N. Saoula, and P. Ringrose (2010), *In Salah CO_2 Storage JIP: CO_2 sequestration monitoring and verification technologies applied at Krechba, Algeria*, to be published in Energy Procedia, © Elsevier, Proceedings of 10th International Conference on Greenhouse Gas Control Technologies, IEA Greenhouse Gas Programme, Amsterdam, The Netherlands.

Michael, K., A. Golab, V. Shulakova, J. Ennis-King, G. Allinson, S. Sharma, and T. Eiken (2010), *Geological storage of CO_2 in saline aquifers – A review of the experience from existing storage operations*, International Journal of Greenhouse Gas Control, Vol. 4, pp. 659 – 667.

Mito, S., and Xue, Z. (2009), *Monitoring and verification of stored CO_2 at the Nagaoka pilot injection site*, http://www.co2geonet.com/UserFiles/file/ESF/36-S-Mito-Adachi_Monitoring-and-verification-of-stored-CO2-at-the-Nagaoka-pilot-injection-site.pdf.

NETL (2009), *Monitoring, Verification, and Accounting of CO2 Stored in Deep Geologic Formations*, http://www.netl.doe.gov/technologies/carbon_seq/refshelf/MVA_Document.pdf

NETL (2010a), *Geologic Storage Formation Classifications: Understanding Its Importance and Impacts on CCS Opportunities in the United States*
http://www.netl.doe.gov/technologies/carbon_seq/refshelf/Geologic_Storage.pdf

NETL (2010b), *Risk Analysis and Simulation for Geologic Storage of CO_2*, http://www.netl.doe.gov/technologies/carbon_seq/refshelf/BPM_RiskAnalysisSimulation.pdf.

Nooner, S., O. Eiken, C. Hermanrud, G. Sasagawa, . Stenvold, and M. Zumberge (2007), *Constraints on the in situ density of CO_2 within the Utsira formation from time-lapse seafloor gravity measurements*, International Journal of Greenhouse Gas Control, Vol. 1, pp. 198 – 214.

Pamukcu, Y., S. Hurter, P. Frykman, and F. Moeller (2010), *Dynamic simulation and history matching at Ketzin (CO2SINK)*, to be published in Energy Procedia, © Elsevier, Proceedings of

10th International Conference on Greenhouse Gas Control Technologies, IEA Greenhouse Gas Programme, Amsterdam, The Netherlands.

Pham, T., T. Maast, H. Hellevang, and P. Aagaard (2010), *Numerical modeling including hysteresis properties for CO_2 storage in Tubåen formation, Snøhvit field, Barents sea*, to be published in Energy Procedia, © Elsevier, Proceedings of 10th International Conference on Greenhouse Gas Control Technologies, IEA Greenhouse Gas Programme, Amsterdam, The Netherlands.

Preston, C., M. Monea, W. Jazrawi, K. Brown, S. Whittaker, D. White, D. Law, R. Chalaturnyk, and B. Rostron (2005), *IEA GHG Weyburn CO_2 monitoring and storage project*, Fuel Processing Technology, © Elsevier, Vol. 86, pp. 1547 – 1568.

Ringrose, P., M. Atbi, D. Mason, M. Espinassous, O. Myhrer, M. Iding, A. Mathieson, and I. Wright (2009), *Plume development around well KB-502 at the In Salah CO_2 Storage Site,* First Break, Vol. 27, pp. 85 – 89.

Roston, B., and S. Whittaker (2010), *10+ years of the IEA-GHG Weyburn-Midale CO_2 monitoring and storage project; success and lessons learned from multiple hydrogeological investigations,* to be published in Energy Procedia, © Elsevier, Proceedings of 10th International Conference on Greenhouse Gas Control Technologies, IEA Greenhouse Gas Programme, Amsterdam, The Netherlands.

Rutqvist, J., H.H. Liu, D. Vasco, L Pan, K Kappler, and E. Majer (2010), *Coupled non-isothermal, multiphase fluid flow, and geomechanical modeling of ground surface deformations and potential for induced micro-seismicity at the In Salah CO_2 storage operation*, to be published in Energy Procedia, © Elsevier, Proceedings of 10th International Conference on Greenhouse Gas Control Technologies, IEA Greenhouse Gas Programme, Amsterdam, The Netherlands.

Sato, T., S. White, and S. Xue (2006), *Numerical modeling of CO_2 injection test at Nagaoka test site in Nigata, Japan*, Proceedings, TOUGH Symposium, Lawrence Berkeley National Laboratory, Berkeley, CA.

Schmidt-Hattenberger, C., P. Bergmann, D. Kiebling, K. Kruger, C. Rucker, H. Schutt, and Ketzin Group (2010), *Application of a Vertical Electrical Resistivity Array (VRA) for Monitoring CO_2 Migration at the Ketzin Site: First Performance Evaluation*, to be published in Energy Procedia, © Elsevier, Proceedings of 10th International Conference on Greenhouse Gas Control Technologies, IEA Greenhouse Gas Programme, Amsterdam, The Netherlands.

Sharma, S., P. Cook, C. Jenkins, T. Steeper, M. Lees, and N. Ranasinghe (2010), *The CO2CRC Otway Project: Leveraging experience and exploiting new opportunities at Australia's first CCS project site*, to be published in Energy Procedia, © Elsevier, Proceedings of 10th International

Conference on Greenhouse Gas Control Technologies, IEA Greenhouse Gas Programme, Amsterdam, The Netherlands.

Sing, V., A. Cavanagh, H. Hansen, B. Nazarian, M. Iding, and P. Ringrose (2010), *Reservoir Modeling of CO_2 Plume Behavior Calibrated Against Monitoring Data from Sleipner, Norway,* SPE 134891, presented at SPE Annual Technical Conference and Exhibition, Florence, Italy.

Smith, S.A., J. Sorensen, E. Steadman, and J. Harju (2009), *Acid gas injection and monitoring at the Zama oil field in Alberta, Canada: A case study in demonstration-scale carbon dioxide sequestration*. Energy Procedia, Vol. 1, Issue 1, February 2009, pp 1981-1988. Greenhouse Gas Control Technologies 9, Proceedings of the 9th International Conference on Greenhouse Gas Control Technologies, November 18-20, 2008, Washington DC, USA.

Underschultz, J. R., B. Freifeld, C. Boreham, L. Stalker, and D. Kirste (2009), *Geochemical and hydrological monitoring and verification of carbon storage in a depleted gas reservoir: examples from the Otway Project, Australia*, AAPG Search and Discovery Article #90103, AAPG Hedberg Conference, Aug. 16-19, 2009, Vancouver, Canada.

USCSC (2009), *Is CO_2 Sequestration Safe?*, United States Carbon Sequestration Council, www.uscs.org/. USCSC (2010), *CO_2 Sequestration Capability: Where Are We?*, United States Carbon Sequestration Council, www.uscs.org/.

Urosevic, M., R. Pevzner, V. Shulakova, A. Kepic, E. Caspari, and S. Sharma (2010), *Seismic monitoring of CO_2 injection into a depleted gas reservoir – Otway Basin Pilot Project, Australia*, to be published in Energy Procedia, © Elsevier, Proceedings of 10th International Conference on Greenhouse Gas Control Technologies, IEA Greenhouse Gas Programme, Amsterdam, The Netherlands.

U.S. Department of Energy (DOE), Office of Fossil Energy, National Energy Technology Laboratory (2009), *Monitoring, Verification, and Accounting of CO2 Stored in Deep Geologic Formations*, available at: http://www.netl.doe.gov/technologies/carbon_seq/refshelf/MVA_Document.pdf.

U.S. Department of Energy (DOE), Office of Fossil Energy, National Energy Technology Laboratory (2010), *Carbon Sequestration Atlas of the United States and Canada - Third Edition (Atlas III),* available at: http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlasIII/index.html.

Verdon, J., J. Kendall, D. White, D. Angus, Q. Fisher, and T. Urbanic (2010), *Passive seismic monitoring of carbon dioxide storage at Weyburn,* The Leading Edge, February, pp. 936 – 942.

White, D., (2009), *Monitoring CO_2 storage during EOR at the Weyburn-Midale Field,* The Leading Edge, July, pp. 838 – 842.

White, D., for the Weyburn Geophysical Monitoring Team (2010), *Geophysical monitoring of the Weyburn CO_2 flood: Results during 10 years of injection*, to be published in Energy Procedia, © Elsevier, Proceedings of 10th International Conference on Greenhouse Gas Control Technologies, IEA Greenhouse Gas Programme, Amsterdam, The Netherlands.

Whittaker, S., (2004), *Geological framework*, Proceedings of 7th International Conference on Greenhouse Gas Control Technologies, IEA Greenhouse Gas Programme, Vancouver, Canada.

WRI (2007), *Opportunities and Challenges for Carbon Capture and Sequestration*, J. Logan, J. Venezia, and K. Larsen, WRI Issue Brief, October

Wright, I., A. Mathieson, F. Riddiford, and C. Bishop (2010), *In Salah CO_2 JIP: Site Selection, Management, Field Development Plan and Monitoring Overview*, to be published in Energy Procedia, © Elsevier, Proceedings of 10th International Conference on Greenhouse Gas Control Technologies, IEA Greenhouse Gas Programme, Amsterdam, The Netherlands.

Figure 1. Global map showing proposed and on-going large-scale integrated CCS projects, numbered for site identification (not shown) (GCCSI 2010).

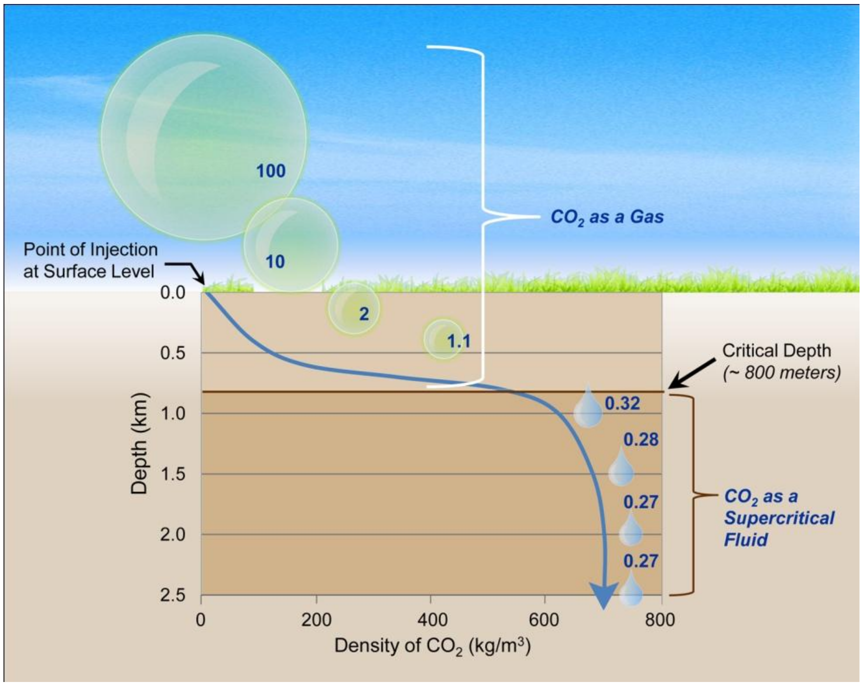

Figure 2. Illustration of change in volume of CO_2 accompanying density increase with depth of injection (U.S. DOE 2010).

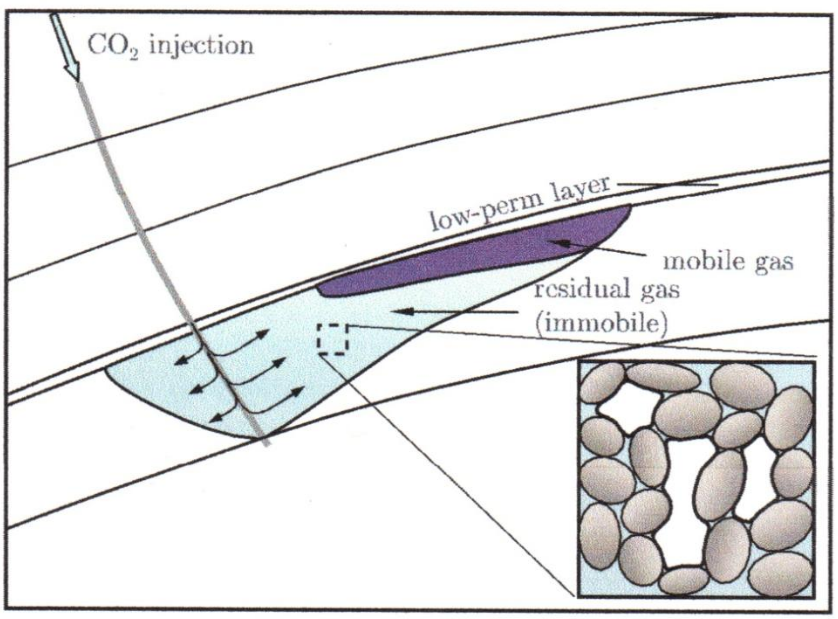

Figure 3. Illustration of spread of a CO_2 plume under a dipping layer and immobilization through residual trapping (Juanes et al., 2006).

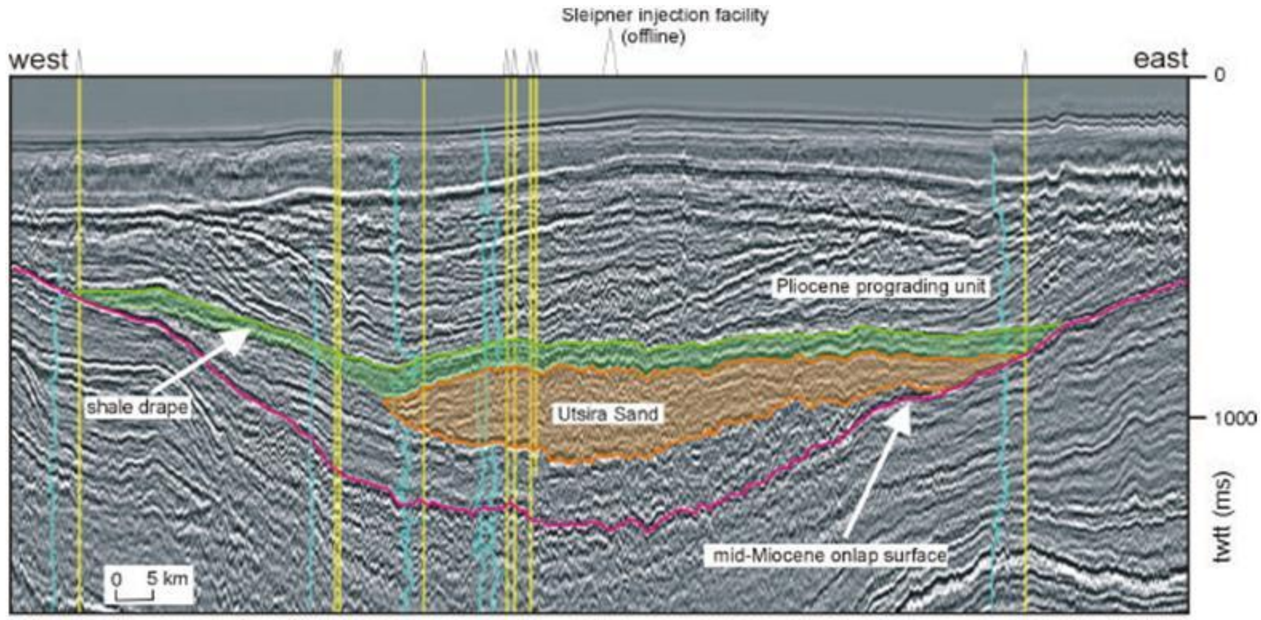

Figure 4. Seismic cross-section with the Utsira Sand and overlying shale drape highlighted. Also shown are wells (and well logs) which lie in the plane of the cross-section. (Chadwick et al., 2000, seismic data courtesy of WesternGeco).

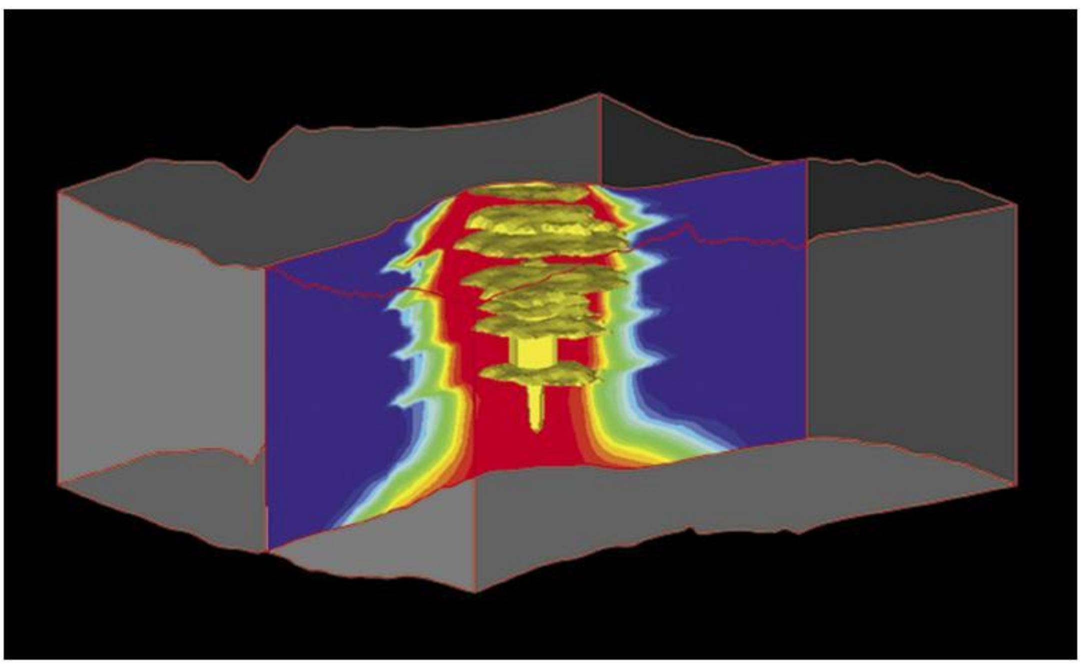

Figure 5. Results of a reservoir simulation of the CO_2 plume at Sleipner, showing the effect of discontinuous mudstone layers on the upward movement of the plume. Yellow is free phase CO_2 and red is dissolved CO_2 (Arts et al., 2008, illustration courtesy of First Break and EAGE).

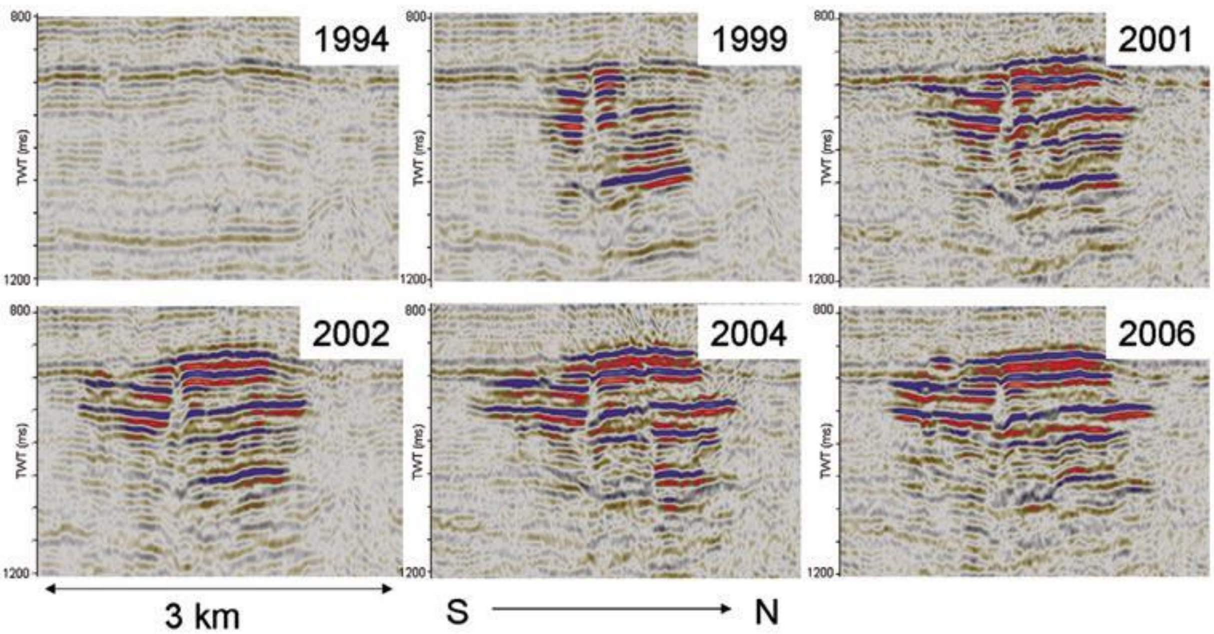

Figure 6. One cross-section of time lapse seismic results for Sleipner, with color intensity related to strength of reflections, and showing location of CO_2. (Arts et al., 2008, illustration courtesy of First Break and EAGE).

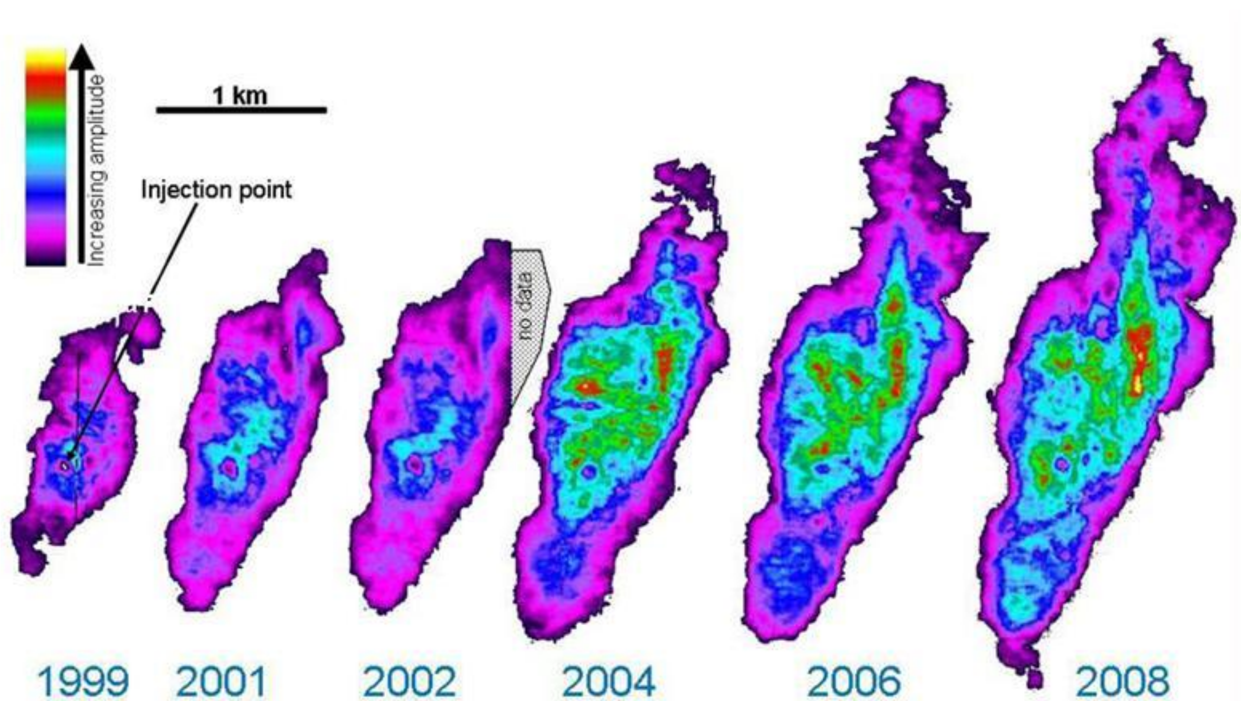

Figure 7. A plan view of the seismic amplitudes at the top of the Utsira, showing the steady expansion of the plume over time (Eiken et al., 2010).

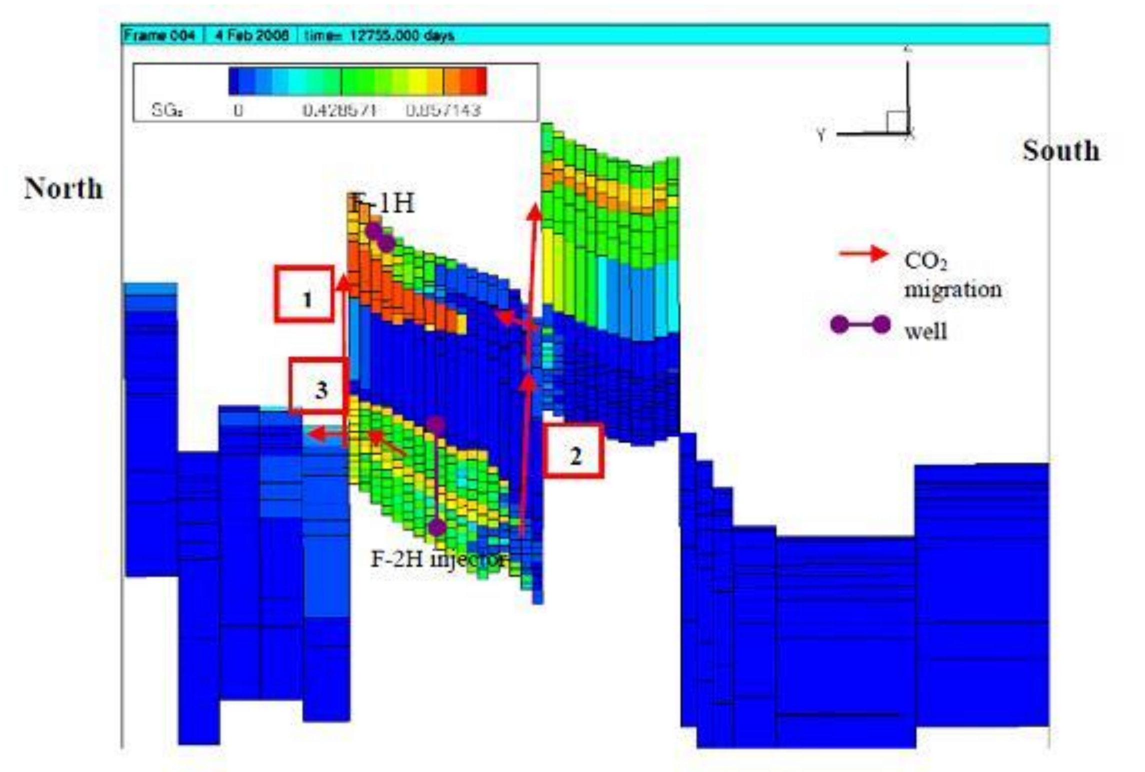

Figure 8. Cross section view of a reservoir simulation showing CO_2 saturation and plume migration after 23 million tonnes of injected CO_2 at Snøhvit, assuming permeable faults bounding main storage block (Estublier and Lackner, 2009).

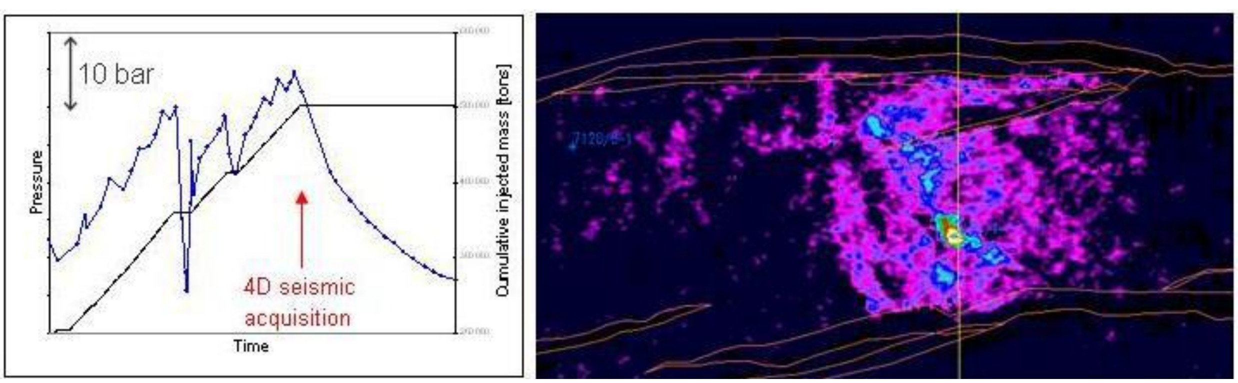

Figure 9. Pressure and injection data (left), and 4D seismic difference amplitude map (right) at Snøhvit. (Eiken et al., 2010).

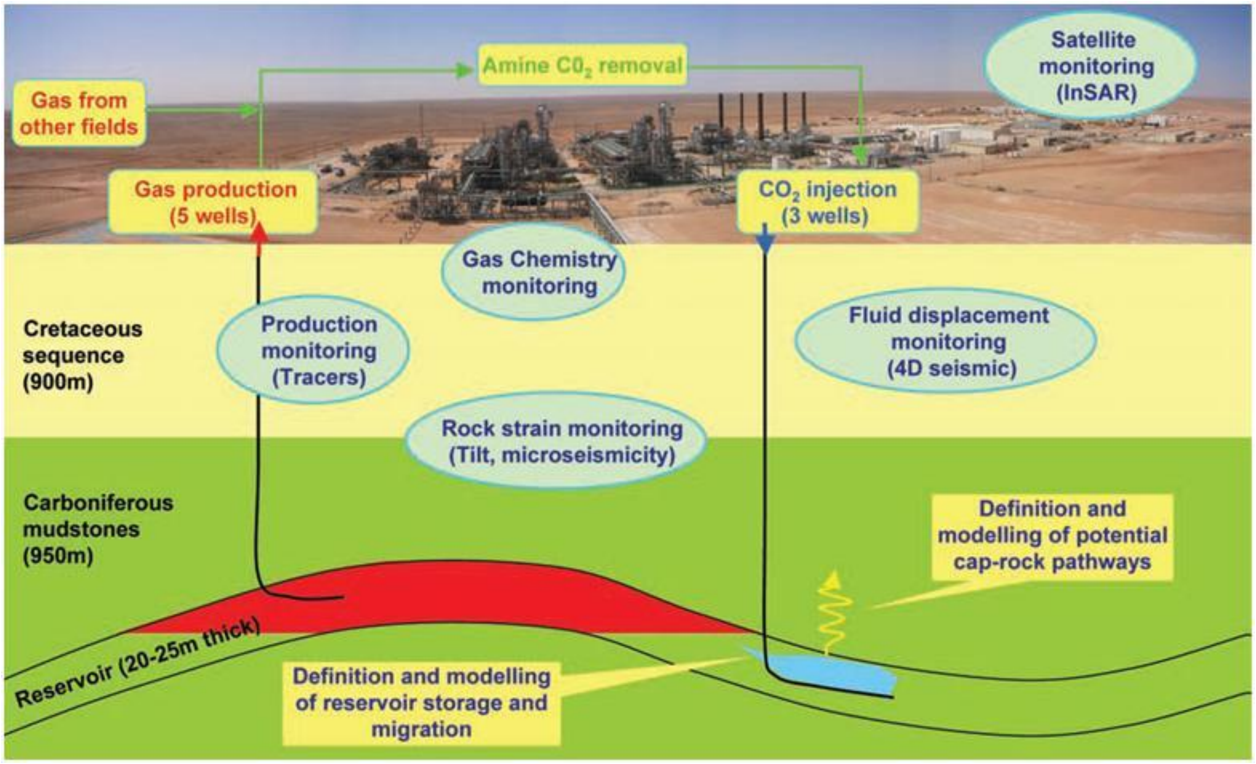

Figure 10. Illustration of In Salah project, showing surface facilities, schematic representation of reservoir formation, and monitoring approaches (Ringrose et al., 2009, illustration courtesy of First Break and EAGE).

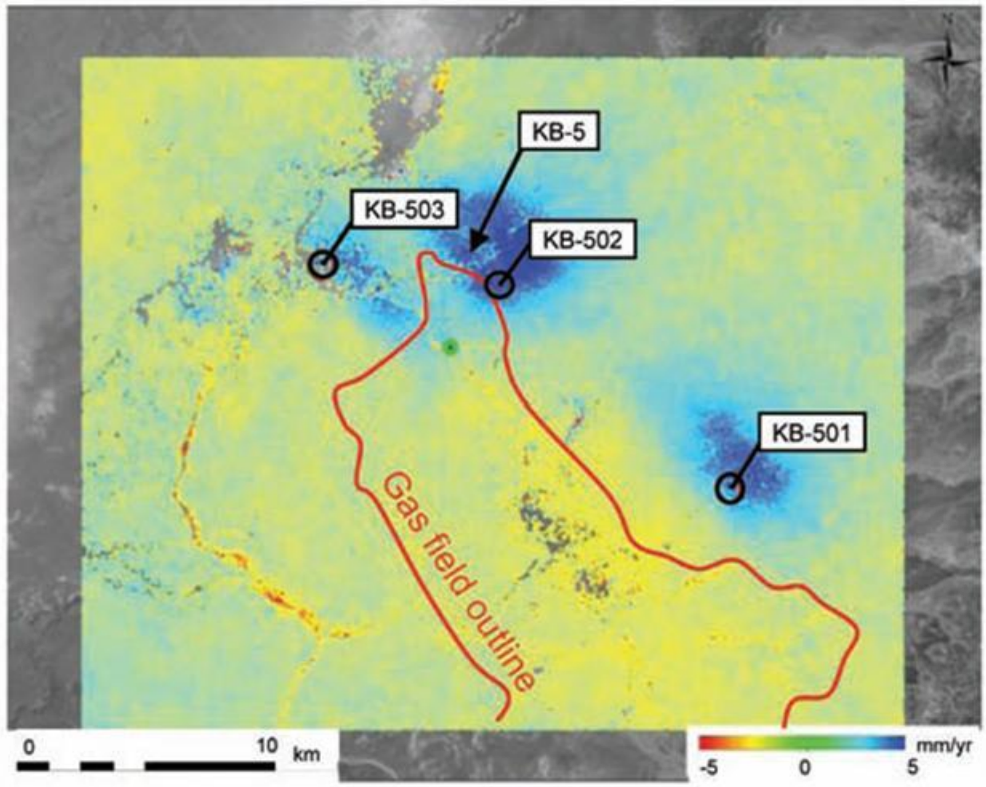

Figure 11. InSAR surface elevation map at In Salah, with blue indicating surface uplift at CO_2 injection wells (Ringrose et al., 2009, illustration courtesy of First Break and EAGE).

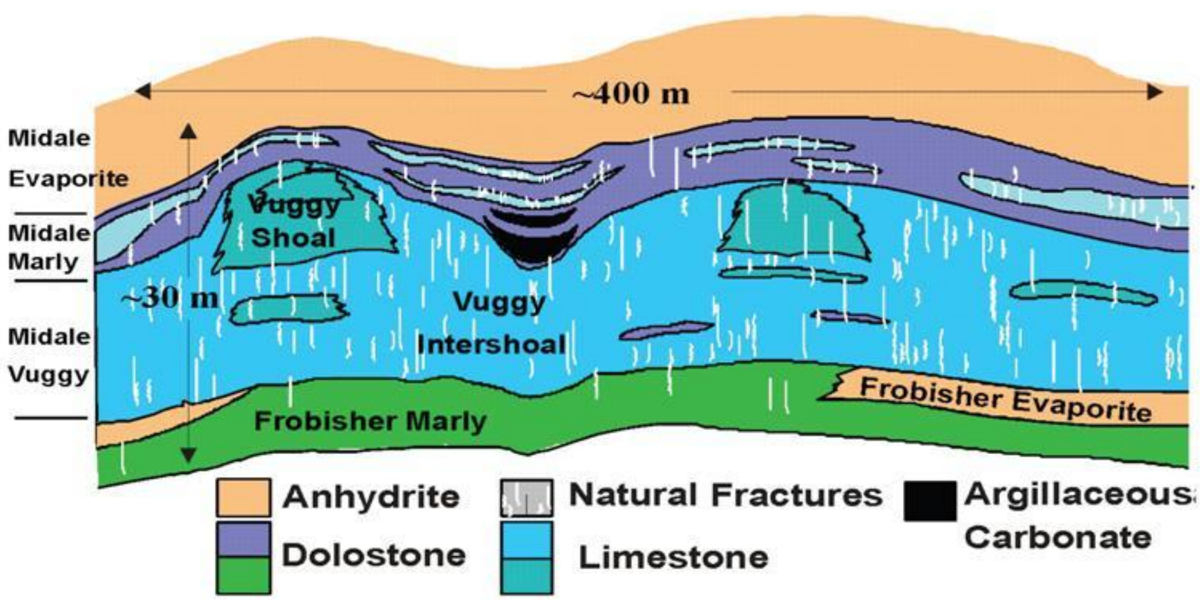

Figure 12. Schematic geologic cross-section for the Weyburn-Midale project (modified from Verdon et al., 2010).

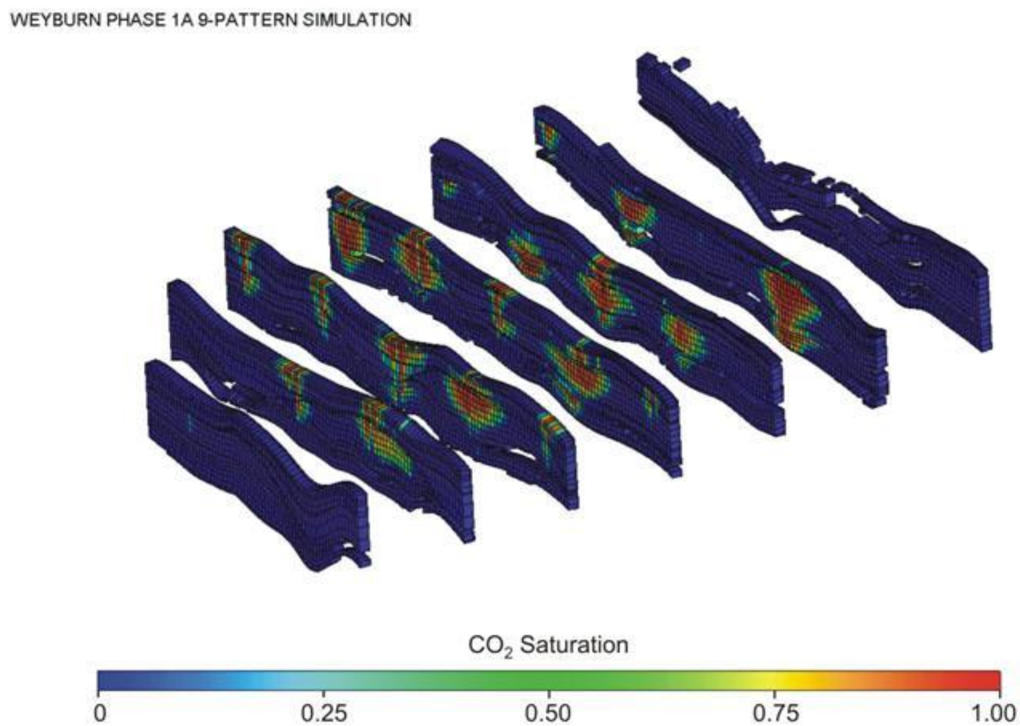

Figure 13. Series of cross-sections showing CO_2 saturation after 26 months of injection predicted by reservoir simulation for a portion of the study area containing 9 patterns (Preston et al., 2005).

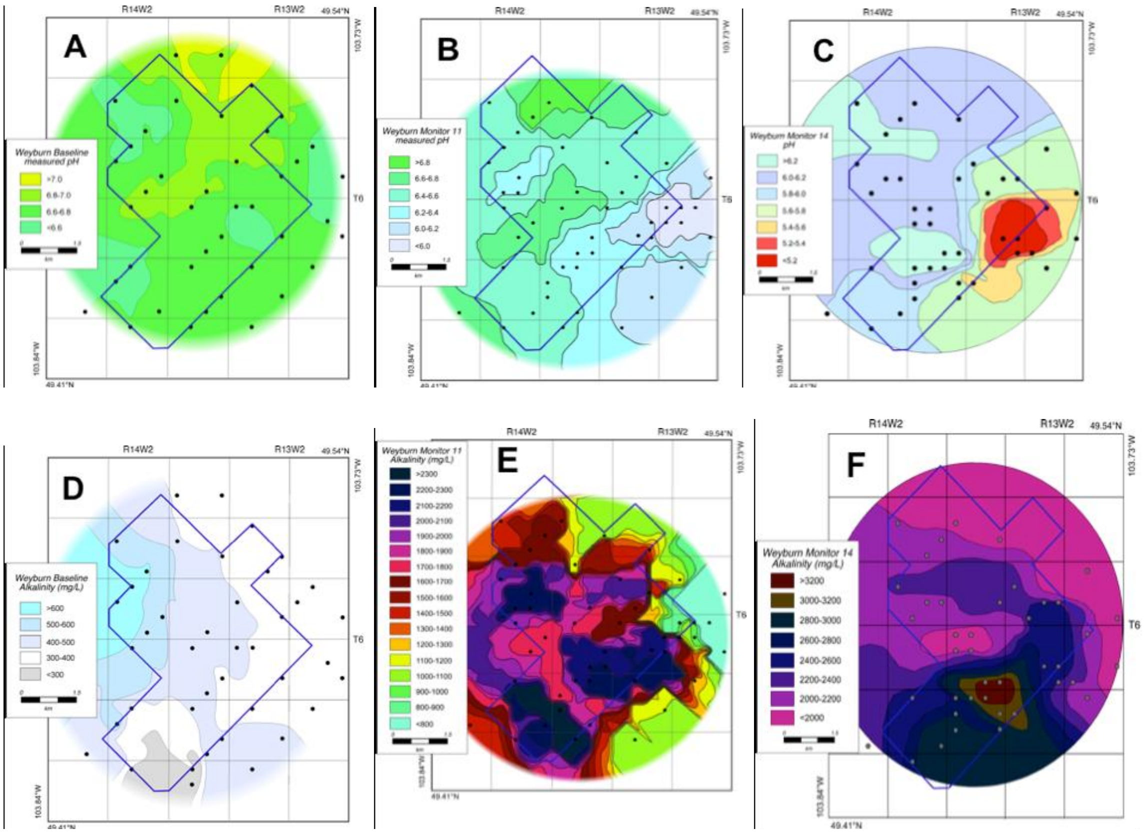

Figure 14. Evolution of reservoir pH (A-C) and alkalinity (D-F) from 2000 to 2009 covering same area as model results in Figure 13 (Johnson, 2010).

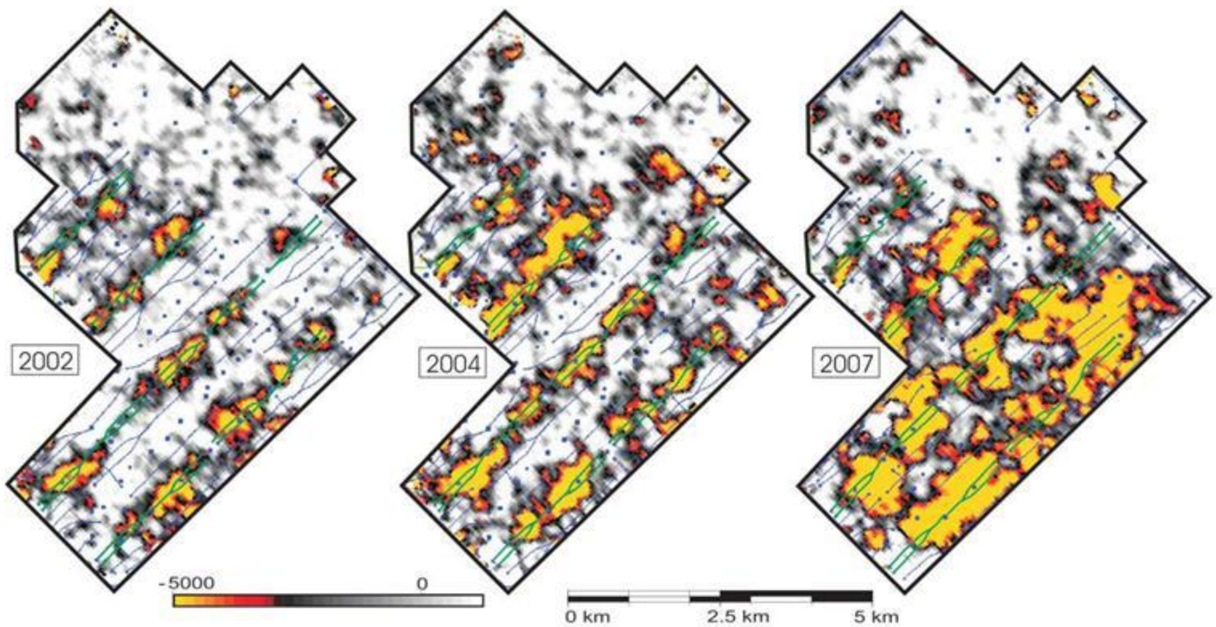

Figure 15. Time-lapse seismic amplitude difference maps for the Midale Marly horizon, over same area as in previous figures; colors indicate relative degrees ("high" to "low") of CO_2 saturation. Overlain are traces of the horizontal CO_2 injection wells (green) and oil production wells (black) (White, 2009).

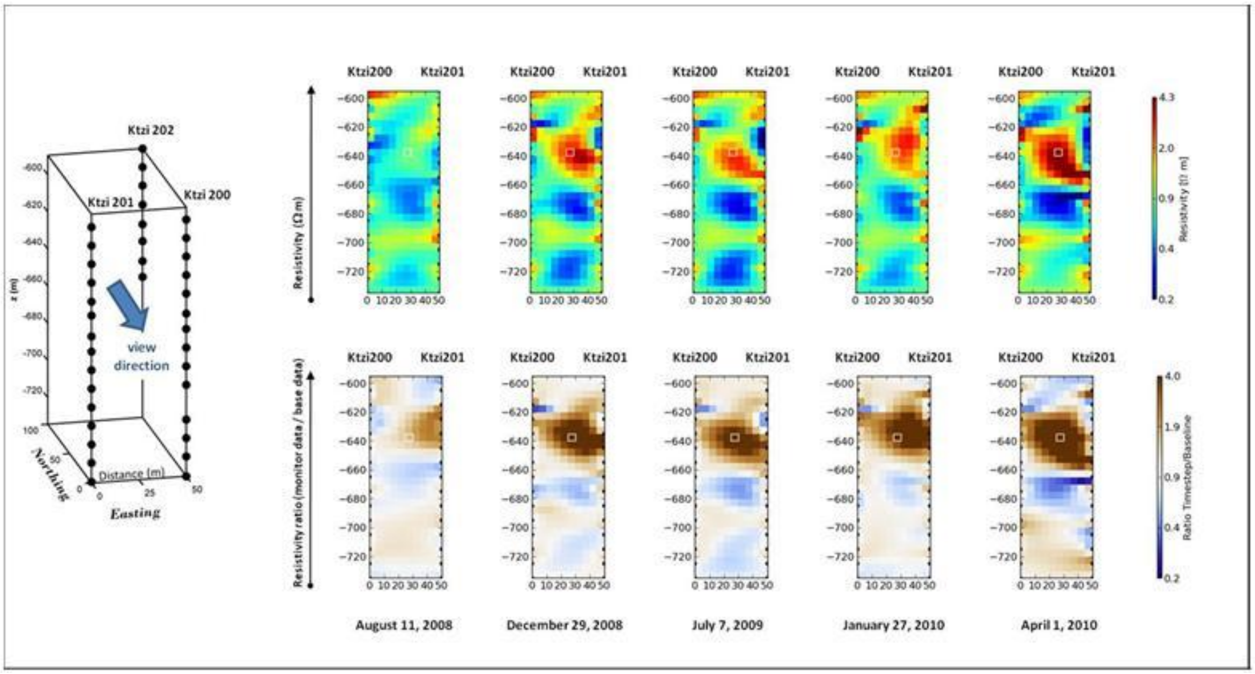

Figure 16. Results of time-lapse crosshole ERT measurements between two wells at Ketzin; upper panels show distribution of resistivity over time; lower panels show the percent change from baseline (Schmidt-Hattenberger et al., 2010).