

Example model of long-term migration of a CO₂ plume from injection wells towards the top of storage structure

A Technical Basis For Carbon Dioxide Storage

Members of the CO₂ Capture Project
Edited by: Cal Cooper, ConocoPhillips

A TECHNICAL BASIS FOR CARBON DIOXIDE STORAGE

Prepared by members of the CO₂ Capture Project®
2009



FOREWORD

This book has been prepared by the CO₂ Capture Project, an international effort funded by eight of the world's leading energy companies that seeks to address the issue of reducing greenhouse gas emissions in a manner that will contribute to an environmentally acceptable and competitively priced continuous energy supply for the world.

The intent is to provide a guide to the major technical issues related to the subsurface geological storage of carbon dioxide. The target audience is people interested in CO₂ capture and storage (CCS). It contains both general information and specific details about technologies and applications that are likely to be used in CCS. We hope that it will engage a wide range of people including policy-makers, the public, and even many of our energy industry colleagues who are less familiar with CCS. The authors offer their insights on expectations for CCS based on many years of cumulative experience developing analogous oil and gas projects, complemented by knowledge gained by the first eight years of the CO₂ Capture Project.

Within this publication a number of case studies are summarized to give a deeper insight into the technical issues involved.

ACKNOWLEDGEMENTS

The manuscript is the product of much collaboration and discussion between staff of CCP2 sponsor companies. It has benefited from champions, committed technical experts, and colleagues who have offered insight and guidance. Among them:

Coordinating author and project champion: Cal Cooper.

Lead Authors:

Introduction:

Cal Cooper, *ConocoPhillips*; Iain Wright, *BP*

Chapter 1:

Philip Ringrose, *StatoilHydro* & Alessandra Simone, *Shell*

Chapter 2:

Walter Crow, *BP*; Craig Gardner, *Chevron*; Charlie Williams, *Shell*;

H.G. (Gary) Limb, *ConocoPhillips*; Heath Nevels, *Shell*; Alan Young, *Suncor*

Chapter 3:

Cal Cooper, *ConocoPhillips*; Kevin Dodds, *BP*; Randy McKnight, *ConocoPhillips*

Chapter 4:

Scott Imbus, *Chevron*; Scott Rennie, *ConocoPhillips*

Substantial Contributors:

Charles Christopher, *BP-retired*; Ola Eiken, *StatoilHydro*; Guy Flanagan, *ConocoPhillips*; Nigel Jenvey, *formerly Shell*; Arthur Lee, *Chevron*; Daniele Marzorati, *Eni*; Nadja Muller, *Shell*; Jeff Roedell, *Chevron*; Khalid Soofi, *ConocoPhillips*; Brian Williams, *BP*; Luca Zuccolo, *Eni*.

Internal Reviewers:

Barry J. Katz, *Chevron*; Brian Williams, *BP*; Rodolfo Dino, *Petrobras*; Mario Marchionna, *Eni*; Lou Burke, *ConocoPhillips*; Mark Trupp, *Chevron*; Ken Tubman, *ConocoPhillips*; Brad Bankhead, *ConocoPhillips*; Bill Graham, *ConocoPhillips*; George Armistead, *Chevron*; Claus Otto, *Shell*; Martin Jagger, *Shell*; Jim Provias, *Suncor*; Olav Kårstad, *StatoilHydro*; Tore Tørp, *StatoilHydro*; Ian Sharp, *StatoilHydro*.

Published in the UK by CPL Press, Tall Gables, The Sydings, Speen, Newbury, Berks RG14 1RZ
www.cplpress.com

ISBN: 978-1-872691-48-0

Printed in the UK and USA by Chris Fowler International, London and New York

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CONTENTS

INTRODUCTION	7
1 SITE SELECTION	
1.1 Introduction	11
1.2 Modes of CO ₂ storage	12
1.3 Desirable geological characteristics of storage sites	13
1.4 CO ₂ trapping mechanisms	15
1.5 Subsurface characterization workflow	19
1.6 Quantifying subsurface uncertainties	19
1.7 Special site characterization issues for CO ₂ storage	20
1.8 Concluding remarks	25
2 WELL CONSTRUCTION AND INTEGRITY	
2.1 Introduction	29
2.2 Life cycle stages	29
2.3 Site selection & development	30
2.4 Operations	42
2.5 Closure	45
2.6 Post-closure	45
2.7 Concluding Remarks	45
3 MONITORING PROGRAMS FOR CO₂ STORAGE	
3.1 Introduction	51
3.2 Selecting monitoring tools and techniques	51
3.3 Models for performance monitoring	52
3.4 Limits of measurement and concern	53
3.5 Monitoring tools and techniques	53
3.6 Examples of monitoring techniques in action	55
3.7 Concluding remarks	68
4 DEVELOPMENT, OPERATION AND CLOSURE OF CO₂ STORAGE FACILITIES	
4.1 Introduction: Oil and gas field lifecycle analogy	73
4.2 CO ₂ storage project lifecycle: Project certification and uncertainty management	74

INTRODUCTION

The geological storage of carbon dioxide (CO₂) may enable real progress in the global effort to make meaningful near-term reductions in greenhouse gas (GHG) emissions especially from large-point source emitters such as power plants, refineries, cement plants and steel mills. CO₂ Capture and Storage (CCS) is not a panacea, but it does offer a tangible means to deal with large volumes of gas emissions by using technologies already in-hand, and improving them.

CCS is a bridging technology during the transition to an alternative energy future. Optimism for its success is based on industrial experience, but even proponents acknowledge that there are several issues that need to be addressed before it can achieve widespread application.

Typically, CCS or CO₂ capture and storage is defined as the integrated process of gas separation at industrial plants, transportation to storage sites, and injection into subsurface formations. US government agencies will use the word “sequestration” instead of “storage”, but the meaning is the same and the acronym for all, including many international organizations, is CCS. When CO₂ is stored or

CCS offers a tangible means to deal with large volumes of gas emissions by using technologies already in-hand

sequestered, it is injected into the pore space of rocks deep in the earth’s subsurface (at depths typically greater than 1,000 meters) and carefully designed operational protocols are observed to provide for safe operations. Once the CO₂ is safely injected in the ground, it is expected to remain there for a geological period of time.

Drawing on the wide variety of practical experience in the oil and gas industry, this document addresses key technical aspects and technological innovations used in the geological storage of CO₂. The text cites numerous examples of

projects comparable in size and scope to large CCS operations. The document is not a comprehensive review of geological storage or industry best practice, but in its four chapters addresses frequently discussed areas where there is likely to be particular value in sharing industry knowledge.

Chapter one examines fundamental questions:

- How is a storage site selected?
- What criteria matter most and what data is collected to evaluate objectively the suitability of a proposed site?
- What makes some locations inherently better choices than others for storage based on geological context, knowledge and data availability?
- What processes are involved in geological storage?

The second chapter focuses on wells and the potential for CO₂ to leak from existing wells into aquifers or to escape to the surface due to open conduits or cement deterioration. The issues surrounding well integrity, cement and well construction techniques for wells exposed to CO₂, and results from recent field and laboratory experiments are discussed. Analysis suggests that due diligence coupled with proper well testing and good science, transforms this potential problem into a very manageable issue.

The third chapter examines monitoring and verification techniques. Effective monitoring is accomplished mainly through data acquisition and establishing systems to model the position of CO₂ in the subsurface. By design, monitoring addresses key questions about potential concerns and provides substantial project performance data. A good monitoring program will serve to avoid potential problems

CCS is a bridging technology during the transition to an alternative energy future

as opposed to providing indication of problems that have already occurred.

The issues arising from operations and eventual closure of a storage site are assessed in Chapter 4. Some regulators have considerable experience with the closure of oil and gas operations. Based on those practices, practical regulations can be created that provide realistic assurance that the process will be safe and effective. In addition, the maximum storage potential of given systems and what this means for injection rates and pressures is examined.

The CCS process is similar to the natural gas business running in reverse. It is worth noting that CO₂ is non-flammable, non-toxic and not dangerous except in high concentrations. The entire biosphere depends on CO₂ for life. In the atmosphere, it disperses very quickly. The challenge of managing gas like CO₂, deeply buried in the subsurface, is not without precedent and experience. A successful CCS program will ultimately depend on the establishment of standards and expectations to provide a framework for operators, governments and the public, to ensure there is no harm to life, water or the environment.

CCS is an efficient way to deal with emissions from fossil fuel combustion. Eventually, CCS may be implemented at power generation facilities that use waste biomass feedstock. Storing the CO₂ released by the combustion of biomass could create a process even more effective than renewables for reducing atmospheric CO₂ loads. This scenario offers the prospect of generating power and taking net CO₂ out of the air at the same time – not utopia, just progress.

Large commercial-scale CCS projects are rare today because the basic business fundamentals are lacking. In most jurisdictions, it is not yet legal to carry out CCS, with the exception of enhanced oil recovery (EOR) operations (where CCS processes have been used for years). More importantly, there is no mechanism to monetize reduced CO₂ emissions using CCS. For a company selling a commodity (such as electricity, power, oil, gas, refined products, cement, or steel), embarking on CCS on a unilateral basis makes no business sense. Until stored CO₂ has commercial value, this is unlikely to change. Fortunately, several jurisdictions around the world are beginning to assemble the required legal and regulatory frameworks to enable CCS by amending existing regula-

tions and creating new ones. Industry already has the technology, skills and capabilities to execute industrial-scale

CCS is an efficient way to deal with emissions from fossil fuel combustion

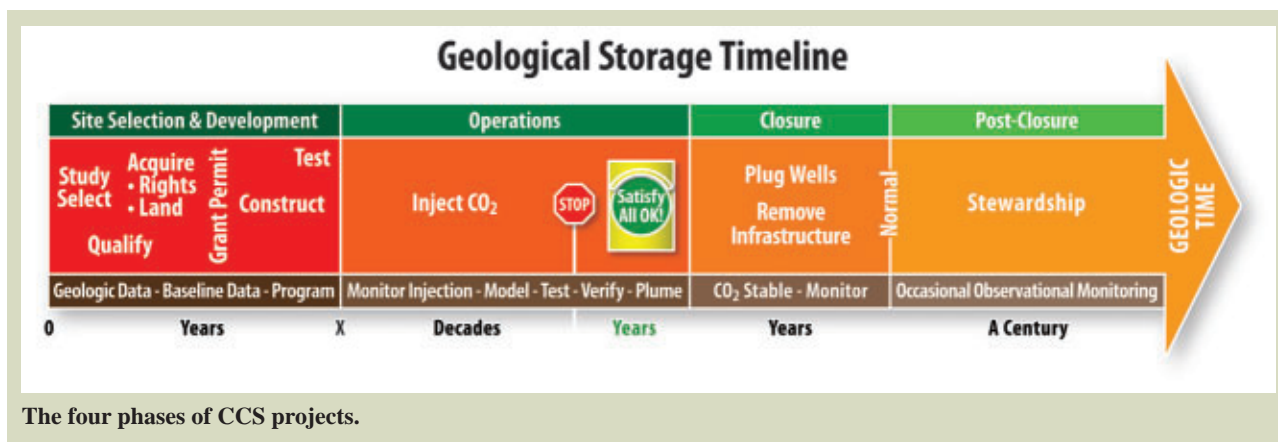
CCS projects, and the commercial reason to deploy the technology looks likely to materialize.

Operators of CCS projects will need:

- Access to quality storage sites and unambiguous rights to use storage space.
- A legal framework and license process to grant permission to inject.
- Financial institutions willing to provide normal business financing facilities.
- Clear expectations for eventual legal project closure.
- Management of the long-term responsibility for the stored CO₂ (stewardship).
- Expectation of a reasonable return on investment.

Individual CCS projects are likely to have four distinct phases with regulatory transitions:

- **Site selection and development** (approximately 3-10 years): The site is identified based on a geological evaluation, commercial factors and regulatory expectations. Space for surface facilities is secured and primary subsurface storage space is purchased or leased from its owner (an entity or government). A permit to store is granted, infrastructure is constructed (e.g. wells, flowlines, compressors), and operational capacity is verified.
- **Operation** (over decades): The entire period of gas injection, plus some years of additional monitoring, as technically appropriate.
- **Closure** (over years): This phase begins when sufficient monitoring indicates that the injected CO₂ has been well-managed and should cause no problems. Regulators may choose to maintain observation wells or other facilities for very long time frames. Most wells are plugged and the infrastructure is removed. The site is then considered normal.
- **Post-closure**: The expected permanence of CO₂ in the reservoir is established. The operator is no longer involved.



There are risks. For CCS to succeed, risk must be managed objectively and responsibly by both operators and regulators. It is possible to over-regulate falsely perceived risks and under-regulate real but unrecognized dangers. Having the right regulatory mix will help the CCS process succeed.

It is an important technical consideration that “risk” associated with injected CO₂ is not constant with time. The probability of an unexpected event increases as injection volumes and subsurface pressure ramp up and this requires close monitoring during the operations phase. After injection stops, as pressure equilibrates, and natural trapping mechanisms take effect, the injected CO₂ becomes progressively more immobile.

For operators and regulators, the most effective way to minimize unexpected consequences is to start with wisely-chosen storage sites. The factors that make a site a good and safe place to inject and store CO₂ are the subject of Chapter 1, on site selection. Then sound practice must be used to construct the storage project, especially construction of new wells and evaluation and/or remediation of existing wells, the technical basis for which is discussed in Chapter 2. Monitoring of the project, including both baseline and operational measurements, is key during the operational phase to optimize performance and catch potential problems early; as discussed in Chapter 3. Finally, a successful project will integrate intelligent design, strong operational controls and robust planning including the operator and regulators. This will enable a smooth transition into the closure and post closure phases, as explained in Chapter 4.

1



SITE SELECTION

1.1 Introduction

Successful storage of CO₂ requires a secure geological container. A site selection process starts with asking some fundamental questions about the geology and target rock formations. This is a staged process involving initial study of the target region and then later focusing on particular target formations. As the site characterization process evolves we gain confidence in establishing storage site capabilities, and we identify further actions for more detailed investigation.

To do this we need to understand the essential elements of CO₂ storage – capacity, containment, and injectivity – and to quantify the role of the various trapping mechanisms.

Many routine oil and gas industry practices are used in this process. These are reviewed here, but we give special focus to factors of special relevance to CO₂ storage.

We build on previous work on the geological storage of CO₂, including the pioneering document produced by the Intergovernmental Panel on Climate Change (IPCC).¹

Oil and gas field developments routinely involve rigorous subsurface characterization work, designed to inform the investment decision-making process. This same subsurface characterization work is fundamental to the identification of potential geological units for CO₂ storage. Without understanding the properties of the rocks and fluids of specific subsurface sites, it would be impossible to assess and predict the behaviour of CO₂ after injection. This is even more essential when it comes to assuring the long-term security of underground storage of CO₂.

Geoscientists and petroleum engineers who specialize in the study of the subsurface are normally tasked with evaluating all available data, and when necessary obtaining additional data, to generate potential scenarios for field development. Many of the techniques developed in the oil industry will form the keystone of the growing CCS industry.

Typically large quantities of data are generated in the process – including several generations of seismic data, numerous wells - each with a specific suite of logging runs and core sampling programmes - and many maps, 3-D models of geology and dynamic flow simulations. The oil industry has developed comprehensive routines for handling the enormous quantities of data (in the range of 100 to 1,000 gigabytes of data) and more importantly a quality management and decision tracking process. Oil and gas reservoir databases, and therefore also CO₂ storage site databases, are large and “living” entities which require constant attention, updating and management.

In addition to the above-mentioned data used in characterization studies, the oil and gas industry has historically compiled (and made publicly available) study results and data from existing oil and gas fields and geological formations from all over the world. Normally, enough similarities can be found between new and existing fields so that existing data and concepts can be extracted to apply in new studies. For instance, natural CO₂ accumulations, existing in different geological basins, have been studied in order to understand the processes and seal types that have enabled CO₂ containment over geological time.^{2,3}

It should also be appreciated that even after a thorough subsurface characterization process, a degree of uncertainty always remains. It is therefore important to select a representative range of potential geological scenarios to test

any planned development. Best industry practices identify the minimum requirements for each development allowing for the inherent variability that nature brings. There is no “one-size fits all” solution.

1.2 Modes of CO₂ storage

The storage of CO₂ involves essentially the same geological basins that have been the focus of oil and gas exploration and development. As with oilfield exploration, we are searching for an impermeable rock unit capable of containing oil or gas for geological lengths of time. CO₂ storage sites tend to be in the same areas as productive oil and gas basins, both onshore and offshore. However, other factors, such as proximity to anthropogenic CO₂ sources, play a role.

There are several generic modes of geological CO₂ storage, including:

- Depleted oil and gas reservoirs.
- Deep saline aquifer formations.
- Storage in association with CO₂ Enhanced Oil Recovery (EOR) projects.
- Coalbed formations.

Depleted reservoirs will provide one of the most readily available storage solutions, because:

- These reservoirs have been thoroughly characterized and consequently have a large amount of data available that can be directly applied to understanding the dynamics of CO₂ storage.
- They offer generally suitable pressure regimes for CO₂ injection and storage.
- Existing wells allow immediate access to the reservoir, although potential well integrity problems may require additional evaluation, remediation and monitoring. (These issues are discussed in detail in Chapter 2).

Depleted reservoirs will provide one of the most readily available storage solutions

Deep saline formations also offer promising storage opportunities due to their wider regional coverage and potential proximity to CO₂ capture sites. Deep saline formations with good storage potential will generally be present in the same basins as oil and gas reservoirs, and the site characterization methods are essentially similar. Variants on the deep saline formation mode include:

- Deep saline formations in the same stratigraphic unit as a known oil or gas reservoir (i.e. the downdip aquifer of an oil field). The In Salah CO₂ storage site in Algeria is an example of this type.

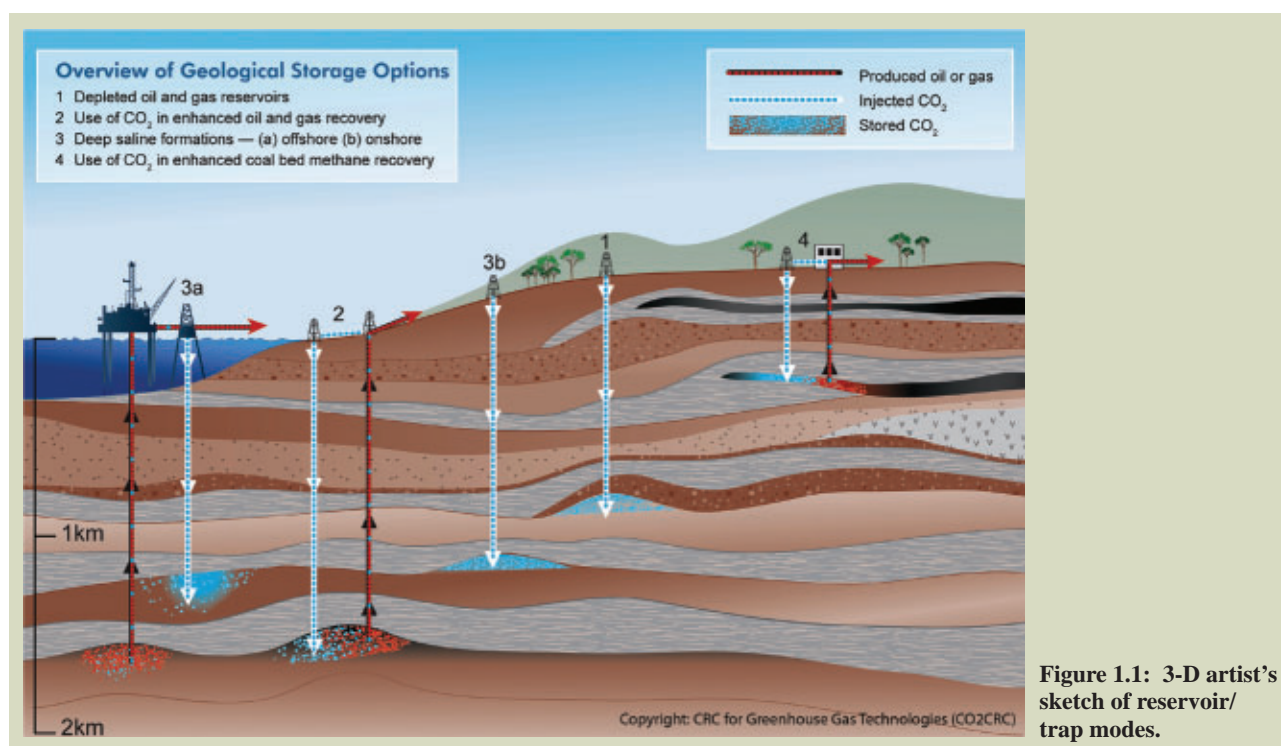


Figure 1.1: 3-D artist's sketch of reservoir/trap modes.

- Shallow saline formations above known oil or gas reservoirs, such as the Utsira Formation, offshore Norway (the Sleipner project).
- Deep saline formations below known oil or gas reservoirs, such as the Snøhvit project where CO₂ is stored in the Tubåsen formation beneath the hydrocarbon reservoir.
- Deep saline formations far from oil and gas provinces but with essentially similar reservoir properties.

The use of coalbed formations is a special case that is not examined here.

These modes of storage are illustrated in Figure 1.1. The principal advantage of CO₂ storage in, or close to, producing oil and gas fields is the maturity of the initial database. In such cases, site characterization comprises additional data acquisition targeted at specific containment issues. In contrast, storage in pristine deep saline formations will generally require new data acquisition analogous to the exploration and appraisal of an oilfield.

1.3 Desirable geological characteristics of storage sites

To consider a CO₂ geological storage technically feasible, three elements are considered to be essential:

- The unit must have sufficient pore volume to store all the gas (capacity).
- An overlying sealing package must be present to ensure containment of all fluids (containment).
- The formation characteristics must be such that sufficient injection of CO₂ from the wellbore is possible (injectivity).

The ideal geological characteristics for each of these overall factors are described below. Each geological unit is unique and so tailored solutions are generally required to address site-specific issues. In general, it is desirable to store CO₂ at depths below approximately 800-1,000m where CO₂ is compressed to a super-critical (dense) phase. Storing CO₂ as dense phase enhances both the storage capacity and the containment ability (via reduced fluid mobility).

Capacity

The definition of the pore volume available for containment depends primarily on five parameters⁴: formation thickness (amount of porous rock available for storage); area of storage site; rock porosity (ϕ , % of voids per bulk

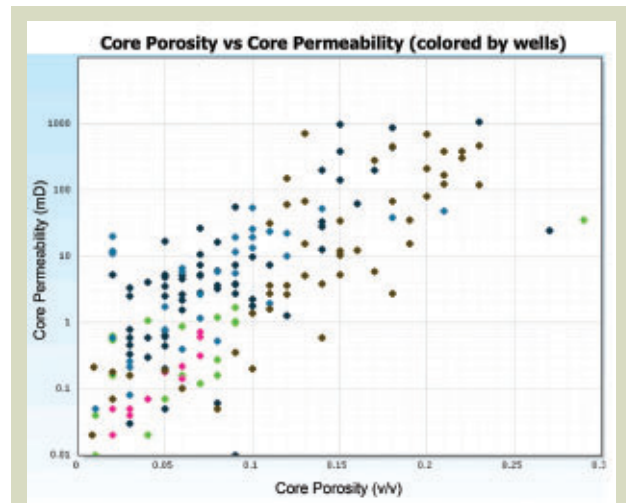


Figure 1.2: Core Porosity versus Core Permeability measurements – indicating an inherent relationship between these two properties.

volume); the density of CO₂; and storage efficiency. In this case storage efficiency is defined as the fraction of pore volume actually saturated by CO₂. Normally CO₂ does not completely displace the pore-filled saline fluid (brine).

For a given storage concept, storage efficiency remains relatively constant whereas the other parameters can vary significantly. A key parameter is porosity, which determines how the pore volume is distributed in the formation. Porosity values greater than around 10% in carbonate formations or 15% in clastic formations are generally desirable. Injectivity is determined by permeability, which is closely related to porosity (Figure 1.2 shows their correlation, where permeability is displayed logarithmically on the Y axis and porosity is displayed linearly on the X axis). In general, the better the porosity, the better the permeability (and thus injectivity) - however, large variations in permeability mean that porosity and permeability variations need to be mapped in detail.

Sufficient formation thickness is also essential for a successful injection operation. Deviated or horizontal drilling can also be used to improve access to the formation. Normally, a formation thickness of around 20 meters would be considered as a minimum requirement, but this varies with injection volume requirements. Lateral continuity of good quality rock units may also be an important factor controlling the site capacity.

Containment and potential flaws in containment

Containment depends on the geometry and distribution of rocks and pressure systems that limit fluid flow in the subsurface. In the simplest geometrical case – known as a four-way dip closure - one competent sealing package drapes and encloses the reservoir and thereby limits flow in any upward direction. In reality just like oil and gas fields, there will be many variations of effective seal geometries that limit the movement of CO₂ in the subsurface including lateral and vertical variations in the reservoir and complex geometries of the ultimate seal, including flow barriers such as faults and naturally overpressured zones. Because of the inherently variable nature of rock units it is best to think in terms of a storage complex and a sealing system – each containing many geological elements. The goal is to show that the geological containment system as a whole is secure.

The role of faults and fractures and their impact on the containment of fluids including CO₂ is complicated and are often misunderstood. The presence of a fault does not imply a leakage problem. Most rock units are faulted and fractured in some way over geological time. The critical question for CO₂ storage is whether there are any faults or fractures that could provide leakage pathways under present-day geological conditions. In addition to the basic geometry of connected rocks and flow paths, this involves the study of geomechanics, stress fields and fracture behavior. Simply put many “faults” do not leak at all and many huge oil and gas fields that include faults prove the point. It is also true that the subsurface extent of hydrocarbon accumulations may be limited by faults. However, fluids do not directly flow to the surface along faults that define the limits of hydrocarbon accumulations because faults are not unimpeded leakage pathways to the surface. Trace amounts do sometimes very slowly seep to the surface and advanced geochemical techniques are used to identify these trace amounts.

The link between faults and earthquakes is also an important issue that is commonly misunderstood. Many people are convinced that we want to avoid seismically-active areas for CO₂ storage. In reality there are very large natural gas fields associated with some of the planet’s major fault zones. For instance Indonesia and Malaysia have many examples, and so does California. Earthquakes in these areas have never been associated with sudden emissions of significant quantities of natural gas or oil from deep reservoirs.

Another commonly misunderstood concept is micro-seismicity. These are very tiny seismic events often responding to subsurface fluid flow and relative pressure changes. All parts of the earth’s crust are in continuous movement and generate micro-seismic events, and the analysis of micro-seismicity offers unique insights into subsurface properties. But it is not something to fear.

Demonstrating site containment thus involves understanding a geological containment system, which involves establishing negligible risk of leakage along possible fracture systems under the present-day stress conditions.

Furthermore, the basic fluid dynamic properties of CO₂ offer us another substantial containment and trapping mechanism. As CO₂ migrates in the subsurface a significant portion of it is “left-behind” which is immobilized as residual gas and trapped as discontinuous “bubbles” in pore space. This mechanism can constitute a significant factor to reducing the volume of gas that flows in the subsurface and eventually accumulates in structural or stratigraphic traps. Residual gas saturation is enhanced by heterogeneity in the reservoir (spatial variations in porosity and permeability) because this creates a more tortuous flow path, and thereby lengthens the migration conduit and increases the trapped CO₂ volumes. This phenomenon is described in greater detail on pages 16-17.

Injectivity

Permeability (k), measures the ability of fluids to flow through a formation. High values indicate a well-connected pore space while low values indicate convoluted conduits that disconnect the pores. Porous rocks have a wide range in permeability between around 0.1 milli-Darcy (for very tight rocks) to several Darcies (for very permeable formations). The oil industry usually uses the milli-Darcy unit (mD) for permeability, where 1mD is approximately 10⁻¹⁵ m² (the Standard International unit more often used in the groundwater industry).

Ideally, CO₂ storage requires high permeabilities (>100 mD) to ensure near well bore injectivities for quick access to the pore space. However, this is not always possible and near wellbore permeabilities may need to be enhanced by artificially stimulating the wells to allow for improved injectivity. Permeability is estimated from core sample analysis, interpretation of wireline log data and well testing (downhole flow and pressure analysis). These different forms of data may give conflicting results, due to the different scales and methods of measurement. There is generally a gradual process in integrating these data to build up a true picture of the large and small-scale variation in permeability within the formation.

While high permeabilities are generally desirable, very high permeability pathways or conduits can enhance CO₂ migration along concentrated pathways reducing the effective storage within the target formation. CO₂ also reacts geochemically with the rocks and fluids in the formation, and these reactions can affect permeability. In general, permeability may be enhanced in carbonate formations but is more likely to be impaired in clastic formations (sands and shales), particularly with high salinity brines. For example, halite precipitation has been observed in reservoirs with low permeability (<10 mD), and high salinity brines.⁵ These effects can be mitigated by modifying injection rates, displacing the saline formation water with low salinity brine or by stimulating the wells with a designed chemical mix (inhibitors) prior to or during injection.

1.4 CO₂ trapping mechanisms

Trapping mechanisms involve both physical and geochemical factors. A number of key components dictate the effectiveness of a CO₂ trap:

- Basin-scale aspects, including regional structure, basin history and pressure regimes.
- Physical trapping mechanisms, comprising the geometry of structural and stratigraphic traps.
- CO₂ residual gas trapping – the retention of CO₂ as a residual phase.
- Geochemical trapping mechanisms, including:
 - CO₂ dissolution in brine
 - CO₂ precipitation as mineral phases
 - CO₂ sorption (e.g. on clay minerals)
 - CO₂ adsorption (especially in coalbed formations).

With the exception of CO₂ adsorption (specific to coals), each of these storage mechanisms will be active within most formations but to different degrees - their relative importance being site-specific.

Basin-scale aspects

Each formation will invariably be part of a larger system, for which basin-wide fluid flow and storage mechanisms need to be understood in order to determine the permanence of CO₂ in the system. The study of the migration and trapping of hydrocarbons as well as understanding the system hydrogeology (the study of groundwater movement in the subsurface) is fundamental to determining connectivity of the storage units with the system (laterally and vertically).

Hydrostratigraphic units are classified by their rock and flow properties (Figure 1.3).⁵

- **Aquifers:** commonly characterized as permeable geological units that allow the flow of considerable

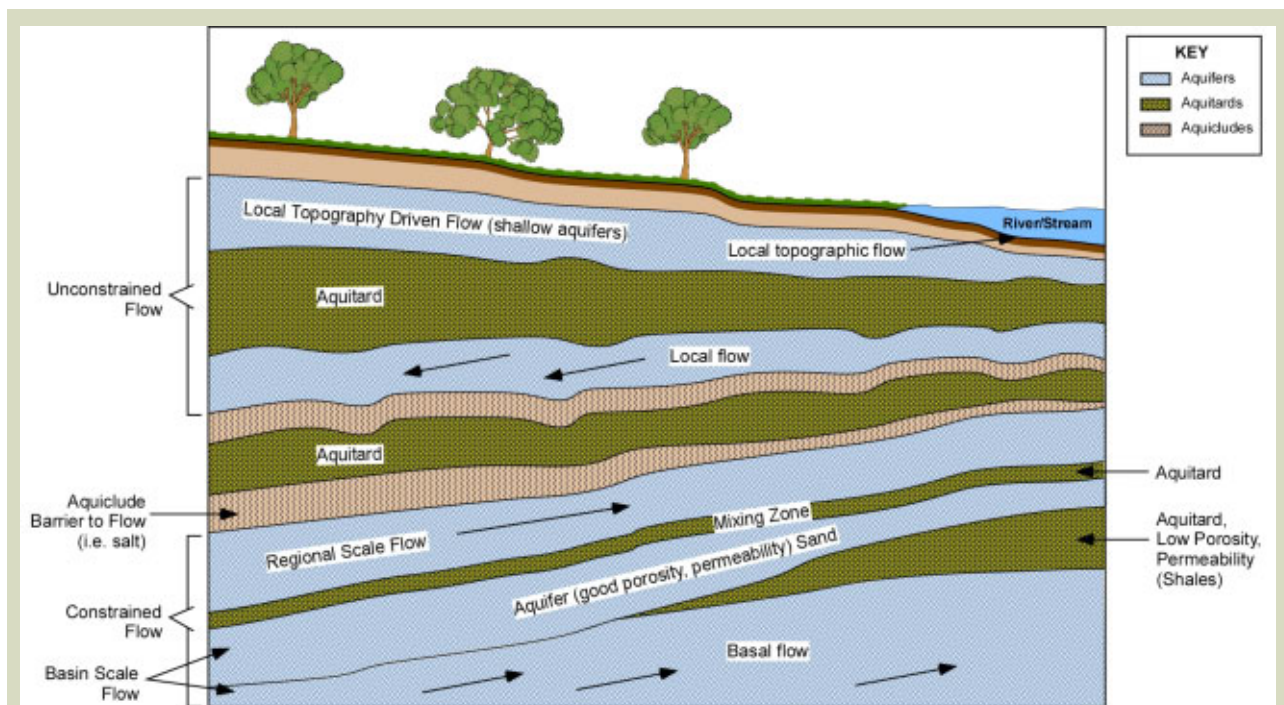


Figure 1.3: Illustration of hydrogeological systems and hydrostratigraphic units.

volumes of water under normal hydraulic conditions (e.g. sandstones, limestones, dolomites).

- **Aquitards:** less-permeable units with limited flow in the context of fields, but significant enough to feed nearby aquifers over time (e.g. high shale content).
- **Aquicludes:** very low permeability units that act as barriers to flow under normal hydraulic conditions (e.g. evaporites such as anhydrites and halites).

Flow in hydrogeological systems can be defined as regional, local, or intermediate, based on their recharge and discharge areas:⁶

- **Regional:** recharge at a major topographic high (mountain chain), with discharge to the major topographic low of the basin.
- **Local:** recharge at local topographic highs (e.g. hills and higher areas) which discharge to the adjacent topographic low.
- **Intermediate:** combining the characteristics of regional and local flow systems.

An essential part of site characterization is therefore to ascertain the direction and rate of natural groundwater flows in the vicinity of the potential storage site. As groundwater fluxes decrease significantly with depth, deeper formations will generally have very low groundwater fluxes. The higher salinity of deep aquifers is, generally, an indication of very low or insignificant throughput of meteoric waters.

Regional aquifers are principally characterized using groundwater well data, where water table height, pressure and flow data are used to map the hydraulic gradients in each aquifer. Dissolved salts and natural isotopes are used to characterize the origin and age of groundwaters in each aquifer.

Physical trapping mechanisms

Physical trapping mechanisms comprise both structural and stratigraphic traps with characteristics well known in oil and gas exploration.⁷ Structural traps can be grouped into “tectonic fault-block systems” (where a series of faults enclose an area creating a “compartment”, effectively preventing flow in or out of the block) and anticlines (four-way dip closures, where a fold of impermeable rock material encases geological units).

Stratigraphic traps depend on a lateral “facies” change (where permeable and porous material encounters impermeable material that prevents lateral flow of the formation fluids) and on unconformities or pinch-outs that erode the porous and permeable material and provide direct contact

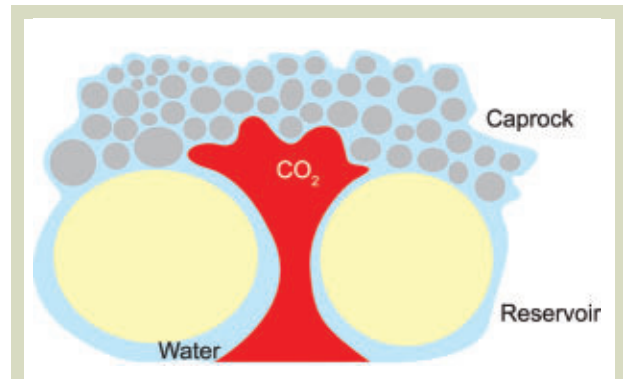


Figure 1.4: Illustration of capillary trapping of CO₂, in which narrow pore throats prevent the CO₂ from migrating up from the larger pores in the reservoir formation. The strength of this force depends on the pore radius and on the interfacial tension at the interface between the two fluids.

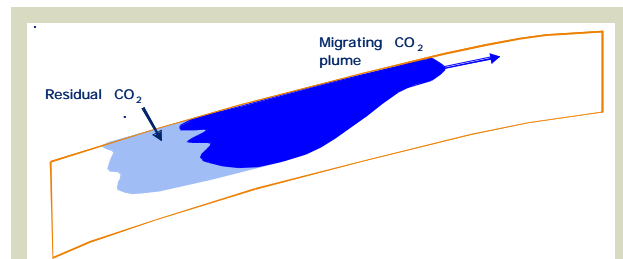


Figure 1.5: Sketch of residual CO₂ trapping mechanism.

to an impermeable layer that traps the formation fluids. Issues concerning the effectiveness of the physical trap are considered to be well-understood and form a part of routine reservoir appraisal analysis (mapping from geological and geophysical data). These issues are not considered further here.

Apart from the geometry, the essence of the physical trap is the presence of low permeability formations or faults. No rocks have zero porosity, but the pore throats can be so narrow as to provide an effective barrier to the flow of a gas phase. An essential concept is that of the capillary seal, illustrated in Figure 1.4. The sealing layer (e.g. mudstone, claystone, shale, evaporites) provides a seal because the pore throats are too small to permit the gas (non-wetting phase) to enter the water-filled pores.

Additionally, capillary forces occur as a fluid enters a cylinder - or pore throat - where another fluid is present. The strength of capillary forces depends on the radius of the cylinder and the molecular forces between the two fluids at their point of contact (i.e. interface). Capillary forces and pore throat sizes are effectively what make certain rock materials impermeable.

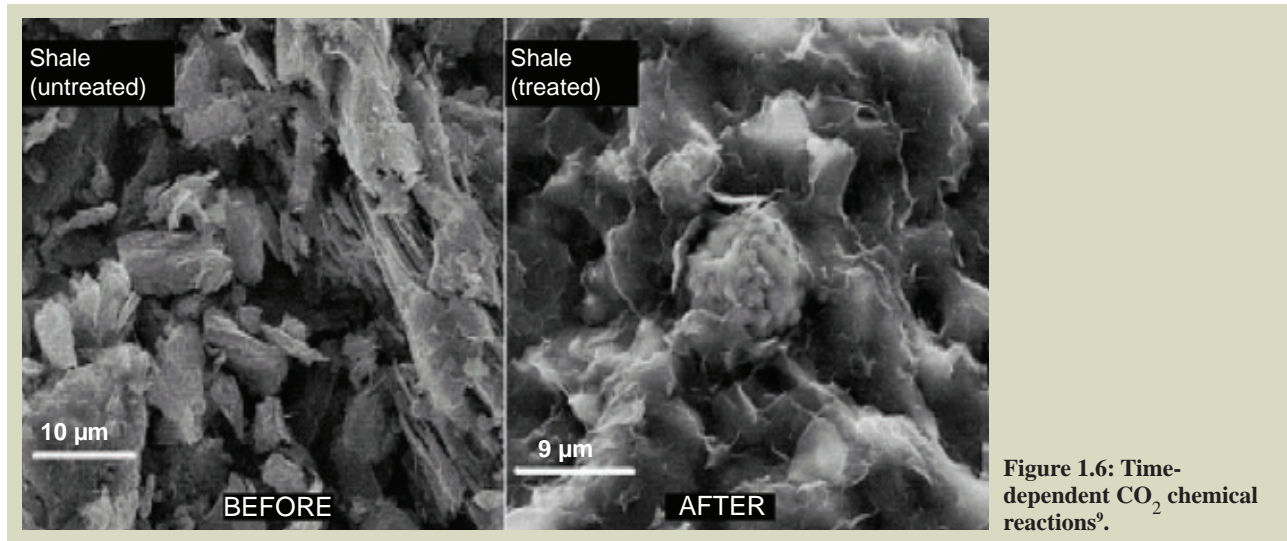


Figure 1.6: Time-dependent CO₂ chemical reactions⁹.

The capillary sealing capacity is characterized in the laboratory by using mercury intrusion experiments (where the amount of pressure required for the fluid to enter the pore throats is measured) and microscope pore-throat analysis.

Residual gas trapping

Physically, residual gas trapping occurs when the saturation of the (non-wetting) gas phase is decreasing and the saturation of the (wetting) water phase is increasing. The overall effect of residual gas trapping is that a migrating volume of CO₂ will leave behind a considerable volume of CO₂ trapped as a residual phase (Figure 1.5) which can thereby limit the extent of travel of the CO₂ plume and act as an important storage mechanism.

Geochemical trapping

Geochemical trapping mechanisms comprise a series of reactions of CO₂ with natural fluids and minerals that may lead to permanent storage of CO₂ in the subsurface (Figure 1.6). These principally comprise:

- CO₂ dissolution in aquifer brine (also referred to as solubility trapping).
- CO₂ precipitation as mineral phases (referred to as mineral trapping).
- CO₂ sorption in clay minerals (with significant rates observed during some experiments)⁸, (Figure 1.7).

There is considerable uncertainty about the rates and reactions involved in these mechanisms and indeed much current scientific research is devoted to developing improved understanding of the processes involved. In the context of site characterization, it is useful to list the types of studies (laboratory, petrophysical and reservoir engineering analyses) that may be required to better quantify these

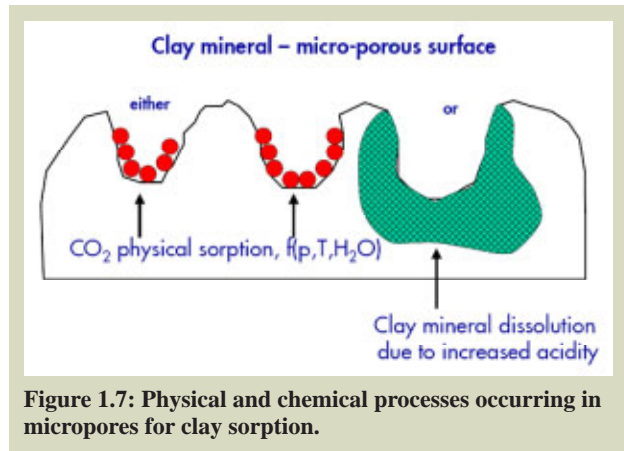


Figure 1.7: Physical and chemical processes occurring in micropores for clay sorption.

geochemical trapping mechanisms for the site in question. Table 1.1 documents some of the key questions and associated measurements that may be required.

Detailed petrographic analyses (i.e. the detailed description of mineral content and rock texture at a microscopic level) of sedimentary (original) and diagenetic (altered) minerals (Figure 1.8) in the storage reservoir are an essential pre-requisite to understanding a complex geochemical system. Potential reactive minerals are identified during pre-injection studies in order to identify geochemical processes that will alter rock properties (such as porosity and permeability - Section 1.7.)

Technical issue	Characterization methods
What minerals and clays are naturally present in the reservoir pore space?	Petrography from thin section, Petrography using Environmental Scanning Electron Microscope (ESEM), Quantitative X-Ray Diffraction (QXRD).
What is the solubility of CO ₂ in the formation brine?	<i>In situ</i> temperature, pressure and water chemistry measurements to determine water salinity and composition. Rates of solution can be estimated from published datasets and site specific laboratory measurements.
What is the amount of CO ₂ residual gas trapping behind a migrating plume of CO ₂ ?	Residual CO ₂ saturation can be measured in a special core analysis (SCAL) lab. Multi-phase flow modeling is needed to determine the residual CO ₂ trapped volume as this is highly dependent on plume dynamics.
How fast will CO ₂ precipitate as a mineral phase?	Estimates vary between days for some carbonate minerals to thousands of years for silicate minerals. Requires geochemical modeling of each specific rock fluid system. Preliminary estimates can be made using simplifying assumptions (e.g. Perkins et al 2005) ¹⁰ .

Table 1.1: Geochemical characterization issues and methods.

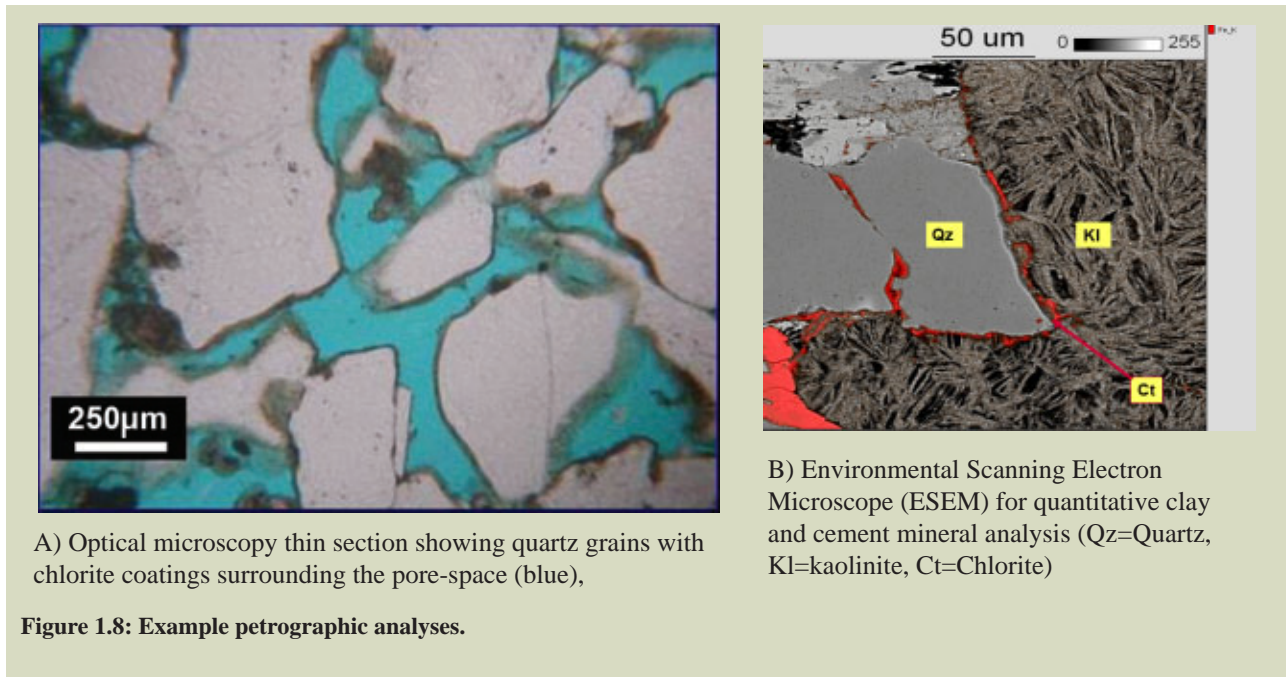


Figure 1.8: Example petrographic analyses.



Figure 1.9: Overall subsurface characterization workflow (DG = Decision Gate).

1.5 Subsurface characterization workflow

Given this understanding of the CO₂ storage system, how do we put it all together? This process is called the subsurface characterization workflow and is closely linked to the decision making process. Several subsurface characterization techniques have been developed through decades of exploration and production of oil and gas. These are widely applied and constantly evolving. Regardless of available technology, the overriding project goals are central to the way storage opportunities are evaluated and matured in order to meet the ultimate project objectives. Each authority/region will have its own regulations governing development phases and decision gates. However, three generic phases can be identified (Figure 1.9) that will be common to all settings.

Site selection

At the initial stages, regional screening studies are carried out to identify potential areas of interest for injection and storage of CO₂ (analogous to the identification of potential production areas in traditional oil and gas exploration and production). Given data limitations, these are normally carried out with a large degree of uncertainty, and rely on available:

- Geophysical data: seismic, magnetic or gravity surveys.
- Existing well data: electrical logs, cores, well tests.
- Regional geological models.
- Analogue formations and fields.
- Preliminary subsurface models.

Regional maps and models of subsurface properties are created upon evaluation of available data, forming the basis for further area appraisal and development. At this initial stage, a high-level understanding of the regional geology (and hydrogeology in the case of CO₂ storage studies) must be achieved. A preliminary risk assessment of potential sites is carried out using the limited data available. The goal is to identify one or more sites for detailed site qualification.

Site qualification

Following site identification, detailed subsurface studies, models and tests are required in order to demonstrate the feasibility of injection and storage of CO₂ in a safe and detectable manner. In this stage, appraisal drilling would normally take place in order to enhance subsurface understanding (from target to sealing formations) and to test different storage scenarios prior to commercial implementa-

tion. Data acquisition at this stage may include (but would not be limited to):

- Open hole well log data.
- Core data (whole core or core plug sampling).
- Well injectivity and leak off tests.
- Formation pressures and fluid samples.

In addition, planned monitoring concepts (see Chapter 3) require base-line tests during appraisal in order to test their applicability and provide an initial state to which operational measurements can be compared. A risk assessment of the site is prepared at this stage, and the decision to proceed to the operational phase is based on establishing sufficient evidence for site integrity and the economic viability of the project. All projects proceed with some uncertainties, and data acquisition and monitoring strategies are set in place to further reduce these uncertainties during the operational phase.

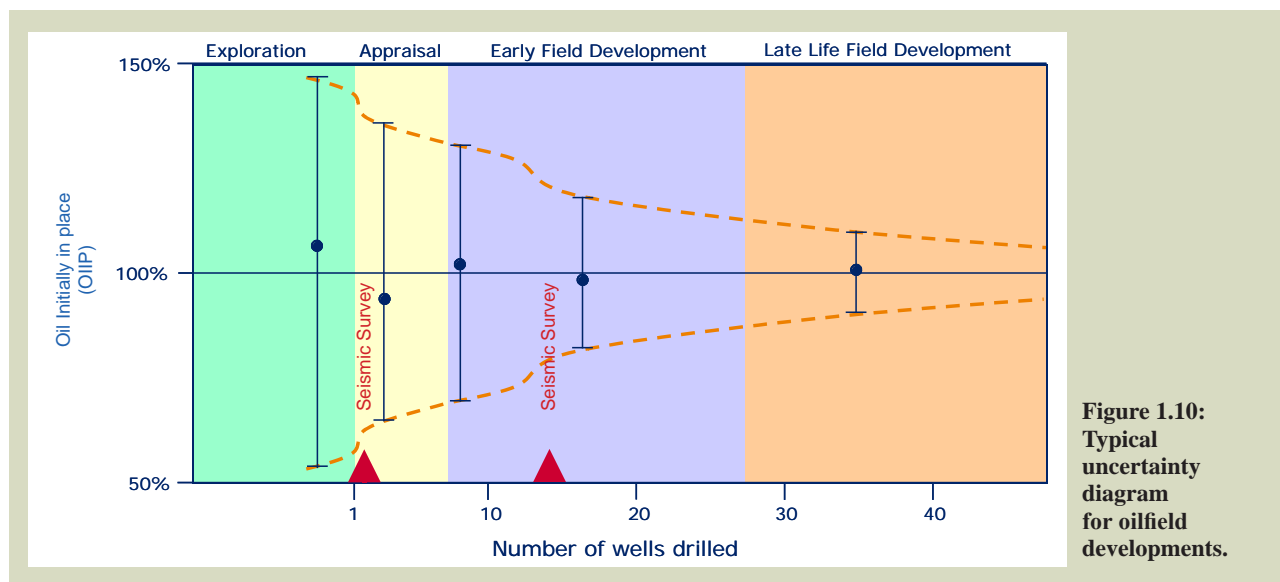
Operational phase

Site characterization activities will necessarily continue into the operational phase in concert with monitoring and operational activities. During this phase, the field development plan is refined and uncertainties are reduced. More precise details of target formations are established (e.g. petrophysical properties, injection capacity). This phase is discussed fully in Chapter 4.

1.6 Quantifying subsurface uncertainties

The oil and gas industry has a long history of, and significant experience with managing risk and uncertainty in the context of geological assessment and oil field development. This experience can be applied when considering geological CO₂ storage sites where a realistic degree of uncertainty must be accepted. Figure 1.10 illustrates the typical level of uncertainty during an oil field development. Uncertainties are reduced as more wells are drilled, additional well data is acquired and seismic surveys improve subsurface mapping. However, typical uncertainties are at least 50% in the early stages and seldom fall below 10% even after many wells are drilled to cover the oilfield.

Decision gates for CO₂ storage site selection and qualification (i.e. points where key study milestones are achieved), must therefore accept realistic levels of uncertainty especially in view of limited well coverage when compared to mature oilfields.



1.7 Special site characterization issues for CO₂ storage

Best practices for reservoir characterization are used routinely in the oil and gas industry and can be adapted to characterize potential CO₂ storage sites. These include 2-D and 3-D seismic interpretation (to map geological structures), stratigraphic mapping and correlation, facies analysis (i.e. distinction of rock units with similar characteristics) and petrophysical property characterization (i.e. the study of rock properties such as porosity and permeability, amongst others). These data are then combined in conceptual and quantitative 3-D geological models. Such analyses typically integrate available well data, seismic data and fluid dynamic data into a Shared Earth Model (SEM), and these models evolve with time as more data becomes available.

Figure 1.11 shows an example site characterization dataset from the In Salah CO₂ storage project. Conventional wireline log, core analysis and seismic interpretation are used, with special emphasis on characterization of the caprock and pre-injection fluid distribution (including *in situ* CO₂ gases).

Geological models characterize the static properties of the formation and are normally followed by dynamic reservoir models (Figure 1.12), which test the effect of fluid flow under *in-situ* conditions using different well configurations. Given the nature of subsurface characterization work, where limited data from different sources is integrated to derive models of large volumes of rock, a large degree of uncertainty always remains in geological models. As a result, a number of possible geological scenarios always need to be considered during tests. The potential outcomes are normally constrained by matching the modeled flow

to the measured field history (i.e. production), resulting in calibrated models that are carried forward for future predictions. However, the lack of experience in the case of CO₂ injection presents a challenge for model calibration.

Likewise, CO₂ is a highly dynamic fluid under *in-situ* conditions (normally supercritical): CO₂ reacts sometimes rapidly with the formation fluids, and can have geochemical and geomechanical effects on the rock. CO₂ mixing with other fluids and gases, leads to modified multiphase flow behavior that is not fully understood. Although a large amount of experience of CO₂ flow modeling has been acquired through decades of CO₂ EOR, storage-monitoring requirements involve a higher degree of complexity in modeling all the coupled effects of CO₂ flow in the reservoir. This is currently an active area of research, and from a background of mature oil and gas flow reservoir engineering technology, the modeling of CO₂ behavior in the subsurface can proceed on a sound basis.

Best practices for reservoir characterization are used routinely in the oil and gas industry and can be adapted to characterize potential CO₂ storage sites

As noted, existing hydrocarbon fields normally have the advantage of an abundance of data. This is not the case, however, for many deep saline formations currently under study. Regional aquifer screening is normally carried out with very limited data, followed (upon site identification) by concerted efforts for further data acquisition (principally seismic surveys and drilling of appraisal wells). Special ap-



Figure 1.11: Illustration of aquifer and caprock characterization from well data at the In Salah CO₂ storage site. CO₂ injection wells are shown in blue. Appraisal wells with porosity (red), caliper (gray), gamma (color) logs, pre-injection CO₂ gas distribution (purple) and core sample (insert). Section shows reservoir and caprock porosity. Surface shows base reservoir mapped from seismic data.

praisal campaigns are designed to test identified aquifers as part of the requirements to demonstrate storage feasibility.

Securing safe long-term storage of CO₂ requires additional focus on special issues beyond their typical role in conventional reservoir characterization. The principal special topics of concern are:

- Data limitations.
- Dynamic modeling of CO₂ in the subsurface.
- Seal characterization.
- CO₂ subsurface processes.

The issues are considered below in terms of the special data acquisition and analysis efforts that may be required.

Seal characterization

Essentially there are two types of seal that limit fluid migration in the subsurface. The most effective are evaporates, especially salt. The second group of seals are mudstone sequences which can be very variable, and generally require some detailed investigation. Mudstone sequence may also include some evaporate layers. Studies of mudstone caprock sequences are often conducted as a part of basin exploration analyses to determine petroleum trap integrity. However, they are frequently of a rather general nature. For a CO₂ storage site, special attention is needed to quantify the petrophysical properties of low-permeability rock formations. These measurements are not routinely made and require special laboratory methods (Figure 1.13).

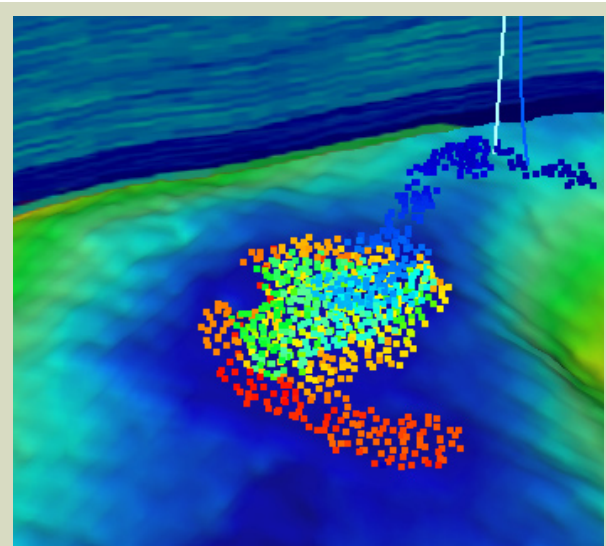


Figure 1.12: Example model of long-term migration of a CO₂ plume from injection wells towards the top of the storage structure. Color indicates CO₂ migration time sequence from start of injection (blue) to about 40 years of injection (red).

Permeabilities lower than about 0.01 milliDarcys (mD) can be measured using pulse-decay permeameters on samples set under restored stress conditions.¹¹ Under these conditions, assuring the mechanical integrity of the sample is often difficult, and in practice low permeability measurements must be integrated with rock permeability analyses. Furthermore, where rock matrix permeabilities are very low, fracture permeability often becomes equally important.

Measurement of capillary threshold pressures and capillary pressure (P_c) curves are an essential component of assessing the long-term containment ability of a caprock unit. These measurements are again quite standard for permeable rocks, but are more challenging for very low permeability formations. An alternative for low permeability rocks is to characterize the pore size distribution using petrographic analysis (Figure 1.8) and then to reconstruct the P_c curve using pore-network modeling methods. Methods for estimating P_c curves from wireline log analysis are also now fairly well established.

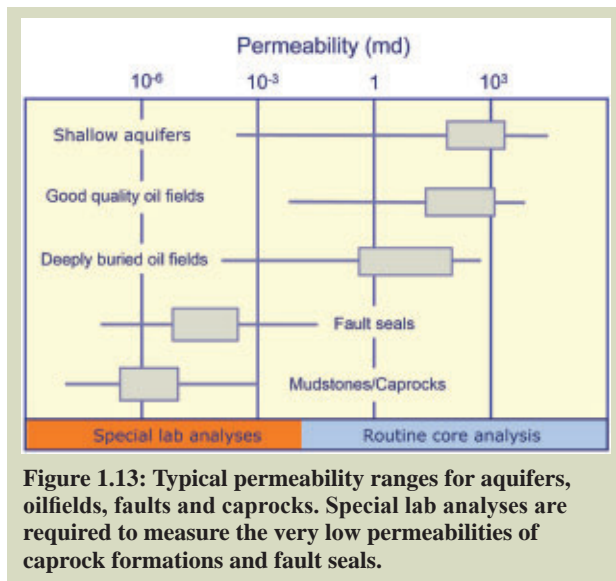


Figure 1.13: Typical permeability ranges for aquifers, oilfields, faults and caprocks. Special lab analyses are required to measure the very low permeabilities of caprock formations and fault seals.

CO₂ subsurface processes

There are many published studies on CO₂ processes in the subsurface, which offer an insight into the natural subsurface processes that pertain to CO₂ storage and provide information on how it reacts with formation rocks and fluids. This section highlights three key elements of subsurface characterization:

- Model calibration.
- Seal characteristics of natural CO₂ accumulations.
- Near wellbore injectivity reduction due to geochemical reactions.

Model calibration

Experience obtained through a number of CO₂ storage pilots and commercial projects has built understanding of CO₂ subsurface processes. Most of the emphasis has been on calibrating models with experimental measurements and actual subsurface CO₂ flow monitoring. These calibrations improve the capability of models to predict the direction and extent of the CO₂ flow, which is fundamental for field development, reservoir management and surveillance. The Frio Brine pilot, lead by Dr. Susan Hovorka of the Bureau of Economic Geology in Texas, is a publicly available example of such model calibration.¹²

During the Frio Brine pilot, a small volume of CO₂ (1,600 tons) was injected into highly permeable (i.e. 2 Darcy) water-bearing sand at 1,500 meters for a ten-day period. A monitoring well was placed approximately 30 meters updip from the injector, and comprehensive monitoring including cross-well seismic tomography, wireline logging, pressures, temperatures and repeated sample collection was carried out in order to understand the CO₂ movement in the reservoir. This post-CO₂ injection data allowed for good understanding of the real processes taking place in the reservoir as the CO₂ was injected.

Figure 1.14 shows Reservoir Saturation Tool measurements (RST) taken over time, before and after injection. This tool is able to measure CO₂ saturations in the formation. The aim was to compare results from the predictive model against the actual location of the CO₂ in the formation. The results indicate a preference of the CO₂ to flow through a higher permeability layer located beneath the predicted best zone.

The same flow distribution observed underneath the top-most layer on the RST measurements was seen during the cross-well seismic tomography (a technique that takes repeated seismic surveys over the same intervals to compare responses over time). In the Frio case, this survey was taken before injection and then six weeks after injection. The comparison against the initial model (Figures 1.15 and 1.16) illustrates the difference between the modeled and measured flow path, and the presence of undetectable internal layering acting as barrier to the flow. The calibration of the model ultimately affects the predicted shape and extent of the CO₂ volume.

Seal characteristics of natural CO₂ accumulations

There are many naturally occurring CO₂ accumulations found in sedimentary basins around the world. It is important that these natural accumulations can be characterized by the same principles as hydrocarbons: a source, a

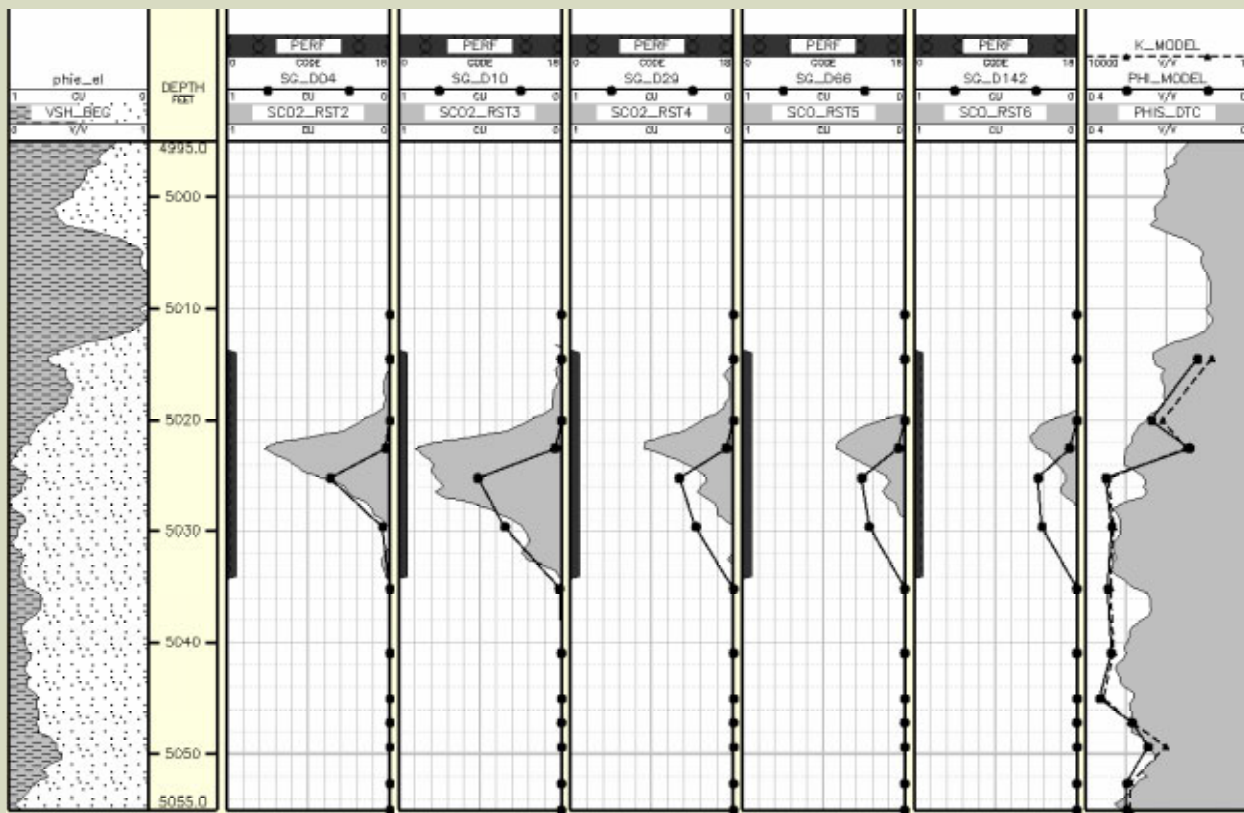


Figure 1.14: CO₂ saturation at the observation well calculated from RST logs, compared with modeled changes in saturation per layer (plotted at layer midpoint). Porosity from log is compared with simplified model input porosity.¹²

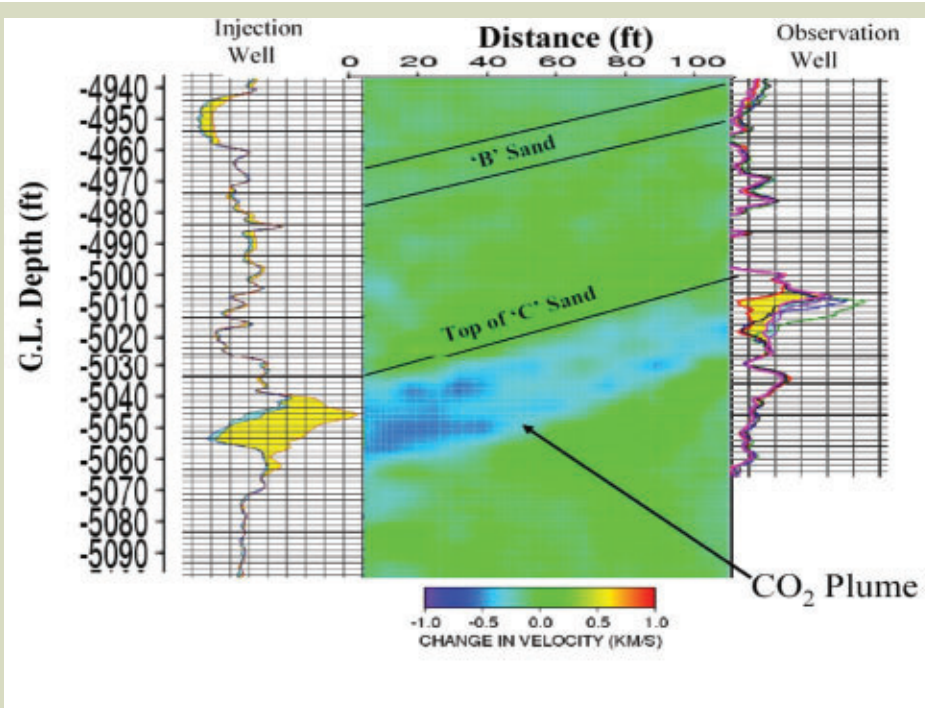


Figure 1.15: Cross-well seismic difference tomogram (Day 57). Saturation values calculated from RST logs for each well are aligned with the tomogram.”¹²

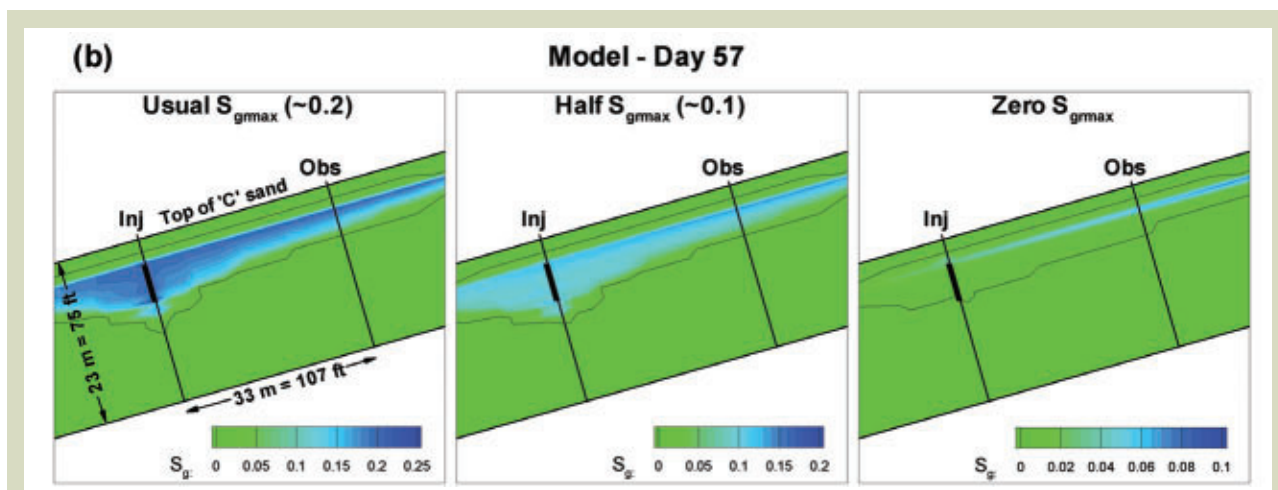


Figure 1.16: Modeled CO_2 distributions in the plane between the wells for the 8-m sand model considering different values of maximum residual gas saturation or $S_{g\max}$. Note the different color scales for each case. The single black contour line shows $S_g = 0$, an indication of the historical maximum extent of the CO_2 plume.¹³

migration path, a reservoir rock, a seal and a trap to inhibit flow of the CO_2 . Oil and gas accumulations are therefore an important analogue for CO_2 storage.

The general characteristics needed for successful CO_2 storage can be inferred from natural CO_2 accumulations. Clearly they have much in common with natural gas accumulations. Seals for these natural CO_2 accumulations include a wide variety of mudstones, anhydrite, marine sediments, shale, and marly clay. The caprock of the largest CO_2 accumulation (McElmo Dome) is a salt layer, on top of an erosional surface overlying the reservoir rock. Depths for known natural major CO_2 fields range from 200 meters (St.Johns-Springerville Dome) to 5,000 meters (Jackson Dome). The only parameter that clearly exhibits a systematic significance in terms of sealing capacity is accumulation depth – the deeper the accumulation the more secure the seal.

Most of the accumulations do not have detectable surface leakages. However, natural seepages do exist over some sites – especially near volcanic areas. For example, the St.Johns-Springerville Dome has bi-carbonate rich springs, and at the Latera Caldera in Italy, CO_2 escapes via springs and gas vents to the surface. Importantly, neither case endangers people.

Injectivity reductions due to geo-chemical reactions

The injection of dry supercritical CO_2 into brine aquifers has the potential to dry formation waters, due to evaporation effects.¹⁴ Dry supercritical carbon dioxide has the ability to “evaporate” (or dissolve) small amounts of water.¹⁵ This can lead to increases in salinity and salt precipitation

and could impair injection rates of CO_2 , as has been noted in gas-storage reservoirs.

Solids are normally present in deep formation water solution, usually in the form of dissolved salts. As the water is removed into the flowing CO_2 stream, salt concentration increases and eventually reaches the solubility limit, giving rise to precipitation of halite. The precipitated solids reduce the pore space available to the fluids, potentially blocking the pore throats in the sedimentary rock. The blocked pore throats can lead to a positive skin, that is, the impairment of the permeability near wellbore, which prevents fluid movement through the pores and may hinder any further injection of carbon dioxide. The phenomenon occurs at the CO_2 injection points, in and close to the borehole.

The physical processes involved are complex and include counter flow of aqueous and CO_2 -rich phases due to capillary effects, molecular diffusion of dissolved solids in the aqueous phase, and effects from increased density and viscosity of the aqueous phase at the evaporation front. Factors in the reservoir believed to be conducive for halite precipitation are:¹⁶

- Low permeability, linked to high capillary forces.
- Low injection rate, where fluid flow is similar to the capillary forces.

Simple reservoir engineering solutions can overcome this issue. One of the solutions is to inject fresh water prior to the CO_2 injection, thus flushing the formation brine from the injection point, where the evaporation occurs most significantly. Another solution lies in using high injection

rates, thus overcoming the capillary forces with high fluid pressures. This solution is limited by the supply of CO₂, the surface facility specifications and the fracture gradient of the caprock, as the injection pressure is not to exceed the fracture pressure of the seal.

1.8 Concluding remarks

Site characterization for CO₂ storage thus employs many well-established practices from the oil and gas industry, but also involves several new and evolving topics related to understanding the physical and chemical behavior of CO₂ in rock systems. The elements of CO₂ storage that need to be quantified in the site characterization process are capacity, containment, and injectivity. To do this, we require a wide range of subsurface measurement, mapping and modeling tools. Those engaged in the site selection process (decision makers and technical teams) need to gain a realistic understanding of what parameters can be estimated reliably along with the inherent uncertainties of natural rock systems. In the following chapter we look at the range of techniques that allow us to monitor CO₂ during the injection phase of a CO₂ storage site.

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Figures

Introduction: The four phases of CCS projects. Illustration courtesy of ConocoPhillips.

Figure 1.1: 3-D artist's sketch of reservoir/trap modes. Reproduction authorized by CO2CRC.

Figure 1.2: Core Porosity versus Core Permeability measurements – indicating an inherent relationship between these two properties. Figure courtesy of Shell.

Figure 1.3: Illustration of hydrogeological systems and hydrostratigraphic units. Figure courtesy of Shell.

Figure 1.4: Illustration of capillary trapping of CO₂, in which narrow pore throats prevent the CO₂ from migrating up from the larger pores in the reservoir formation. Illustration courtesy of StatoilHydro.

Figure 1.5: Sketch of residual CO₂ trapping mechanism. Illustration courtesy of StatoilHydro.

Figure 1.6: Time-dependent CO₂ chemical reactions. Reproduced with permission of Elsevier B.V., The Netherlands (Kaszuba et al., 2003).

Figure 1.7: Physical and chemical processes occurring in micropores for clay sorption. A. Busch, personal communication.

Figure 1.8: Example petrographic analyses. Examples courtesy of StatoilHydro.

Figure 1.9: Overall subsurface characterization workflow (DG = Decision Gate). Produced by the CO₂ Capture Project.

Figure 1.10: Typical uncertainty diagram for oilfield developments. Produced by the CO₂ Capture Project.

Figure 1.11: Illustration of aquifer and caprock characterization from well data at the In Salah CO₂ storage site. Figure courtesy of the In Salah CO₂ project: Sonatrach, BP and StatoilHydro.

Figure 1.12: Example model of long-term migration of a CO₂ plume from injection wells towards the top of the storage structure. Figure produced by CO₂ Capture Project.

Figure 1.13: Typical permeability ranges for aquifers, oilfields, faults and caprocks. Produced by the CO₂ Capture Project.

Figure 1.14: CO₂ saturation at the observation well ... compared with modeled changes in saturation per layer (plotted at layer midpoint). Doughty, et al. 2008. Used with permission from Environmental Geology.

Figure 1.15: Cross-well seismic difference tomogram (Day 57). Hovorka, et al., 2006.

Figure 1.16: Modeled CO₂ distributions in the plane between the wells for the 8-m sand model considering different values of Sgrmax. Doughty, et al., 2008. Used with permission from Environmental Geology.

Tables

Table 1.1: Geochemical characterization issues and methods. Produced by the CO₂ Capture Project.

2

WELL CONSTRUCTION AND INTEGRITY

2.1 Introduction

Wells, by necessity, must penetrate the sealing formation above the target reservoir. This fact alone means stringent analysis and execution of well construction and integrity is of key importance in eliminating potential leak paths in storage projects. Despite the risk of potential leak paths from the wells penetrating the seal, the industry has successfully drilled and produced in very high CO₂ concentrations and commercially injected CO₂ for enhanced oil recovery (EOR) for well over 35 years.

The first commercial CO₂ EOR project began at SACROC (Scurry Area Canyon Reef Operators Committee) in Texas in 1972.¹ In the US today, there are currently 80 projects using CO₂ for EOR. Conventional well production experience includes successful and extensive operations in highly aggressive environments of CO₂, many of these having been produced with high pressures and temperatures. For historic reference, the literature is extensive. A search of the Society of Petroleum Engineers' publication database for the keyword "CO₂" returned 4,590 papers.² The American Petroleum Institute recently published an excellent background report 'Summary of Carbon Dioxide Enhanced Oil Recovery (CO₂EOR) Injection Well Technology'.³ The key to this success has been the application of existing industry best practices in well design and construction and the fit-for-purpose use of new technologies.

2.2 Life cycle stages

Since an injection well must access the target injection zone, it must be drilled through the overlying geologic seals. The well must have functional barriers that provide isolation between each geological interval (of key importance the primary seal), between the well annuli, and between the well at the surface and the external environment.

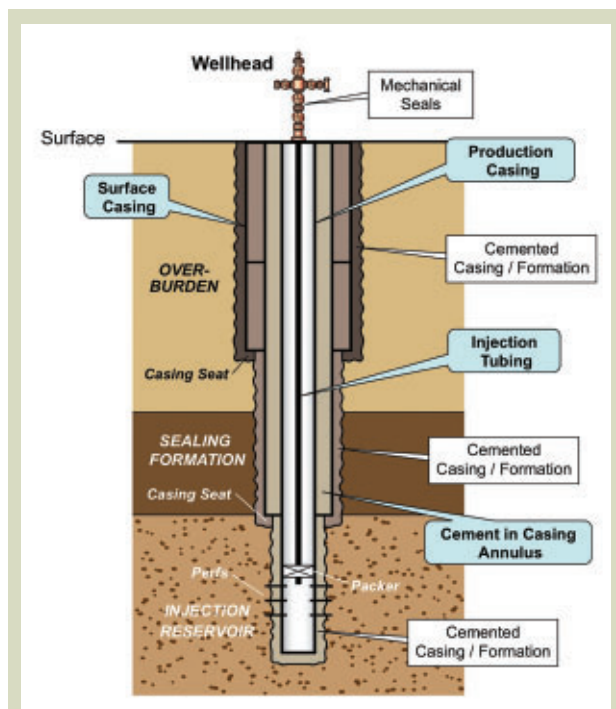


Figure 2.1: Schematic components of a well constructed for CO₂ service showing both natural and mechanical barriers to flow.⁴ No scale intended.

Typical CCS projects have distinct stages (outlined in Table 2.1) that incorporate a well "Life Cycle" encompassing site selection and development, operations, closure, and post-closure.

Successful wells of all types are designed and executed based on the sub-activities listed in Table 2.1 under each CCS life cycle stage. The successful application of best practices in these technical areas when constructing CCS wells will result in the desired integrity. The remainder of this chapter discusses each stage of the life cycle, and highlights the key issues which arise.

Site Selection and Development	Operations	Closure	Post-Closure
<ul style="list-style-type: none"> • Determine location and prepare site. • Specify storage requirements for project considering the source, injectant and geological system container. • Create Basis of Design for wells to meet performance-based storage requirements. • Risk assessment. • Obtain regulatory approval of operations plan including monitoring. • Transition existing wells from prior service for injection / monitoring. • Drill new wells as needed. • Baseline monitoring for current conditions of barrier system and zones in project area. 	<ul style="list-style-type: none"> • Injection begins. • Monitor for migration along barrier and test to verify integrity. • Corrosion monitoring and prevention. • Conduct maintenance for injectivity and well performance. • Conduct drilling, workover and abandonment operations as needed to support operational objectives. • Report monitoring results. 	<ul style="list-style-type: none"> • Injection ceases. • Validate barrier integrity of wells. • Request regulatory approval to abandon wells. • Abandon wells in the project area. • Validate abandonment quality. • At closure, regulatory approval gained to close the site. 	<ul style="list-style-type: none"> • Expected permanence of CO₂ in the reservoir is established. • Site fully closed. • Limited monitoring may be required, by exception, during post-closure period to verify site integrity.

Table 2.1: Storage Project Life Cycle stages related to wells.

2.3 Site selection & development

Basis of Design

A “Basis of Design” is established to determine the storage requirements and provide a reference for well construction, completion, operation and abandonment needs. Considerations within the Basis of Design should include:

- The expected duration of the stages of operation, closure and post-closure periods. From a well integrity standpoint, it is important to understand that the operation period is relatively short (the order of magnitude being tens of years). The performance of materials should be considered for the duration of the stage.
- Injection rate, injection index, pressure, reservoir fluid saturation and geochemistry, volume, viscosity and content of injectant(s).
- The number and type of wells (injection, monitor, or appraisal) required to meet the storage needs including performance efficiency and monitoring.
- The completion type required to provide injectivity to meet performance requirements and optimize the number of penetrations through the caprock(s).
- The mechanical properties of the tubulars, connections and seals must meet the design injection pressure over the life of the project.
- Operating conditions of each system node (from CO₂ source to reservoir).
- Barrier system components include tubulars, elastomers and metal seals, and the wellhead system. Design of cement and/or other isolation material should provide an effective seal that prevents migration for new, existing and abandoned wells.
- New wells should have a Basis of Design for their construction that emphasizes barrier performance using fundamentals of wellbore preparation, mud removal and cement placement to provide tight interfaces that inhibit fluid migration. Material selection of cement and metallurgy are important, but should be considered secondary to the process of cement placement. The performance of the barrier system is most important through the caprock formation(s).
- During the injection (operation) period, the pressure may increase in the zone of injection and is considered to be the period of highest risk to the well barriers. After injection has stopped, the risk of leakage decreases.
- During the closure period, the pressure will gradually decrease. Wells will be abandoned during this stage but the barrier system is expected to perform for many years. Abandonment materials should be chosen accordingly. The monitoring plan should verify the barrier performance to assess well abandonment.
- Post-closure, the site will revert to long-term stewardship.
- A corrosion monitoring program and mitigation plan should be provided including acceptance criteria for the corrosion life of the system (wells and surface) for each stage of the project life.
- Safety system requirements (surface and downhole) should be specified if they are required.
- Well servicing, such as stimulation or remedial activities, should be considered for their impact on well integrity and material selection.

The Basis of Design should be used to guide the well design and construction or remediation activity that takes place in the site selection stage.

Materials selection

CCS projects will be designed and operated so that the injected CO₂ has been adequately dehydrated and is in a supercritical state. Therefore, the stream will not be corrosive. Dehydration must be sufficient so that water is not condensed within the well under normal operating conditions. If the injectant contains O₂, H₂S, and/or hydrocarbons, it can negatively alter the dew point of the stream. If liquid water is present in normal operating conditions, corrosion of the materials may occur.

Well tubulars & other CO₂ exposed equipment

Material selection for well tubulars and equipment for an environment exposed to CO₂ injectant and/or mixtures requires an understanding of:

- The chemical composition and phase behavior of the injectant.
- Reservoir fluid, rock chemistry and composition.
- Pressure and temperature profile over the expected life of the well.
- Expected service life.
- Service requirements post abandonment.
- Expected injection rate or velocity of injectant.

The composition of the injected fluid determines dehydration requirements and if sour resistant metallurgy is required. Additionally, different compositions have different phase behaviors, which impacts not only compression requirements but also velocity limits.

The reservoir fluid affects corrosivity near the wellbore and compaction resistance design where formation dissolution has occurred. In significant dissolution cases, the well tubulars must be designed to resist column buckling in the injection interval.

The pressure and temperature profile is required to understand dehydration requirements and compression limits because the intention is to keep the stream in a supercritical state.

Casing must be designed with sufficient life to assure the integrity of the well after its abandonment. In some cases a corrosion-resistant alloy (CRA) may be recommended in certain geological intervals. This would include areas where potential potable aquifers exist or where the potential corrosion of internal and external casing is identified.

Velocity of injection is a key design limit with respect to potential erosion to the materials seen by the CO₂ stream. If the injection exceeds the erosional velocity, then selection of a material such as CRA may be more appropriate.

There are a few additional “special” conditions, which may require CRA consideration for corrosion mitigation:

- When injector wells are shut-in due to operational maintenance or upsets, it is possible that water could condense or water from the reservoir could flow back to the wellbore. However, even though corrosion could occur in these circumstances, the rate of corrosion would be insignificant because fluids are not dynamic and shut-ins are generally for short periods.
- Sufficient quantities of H₂S may be present in the stream to create a “sour” environment for the materials. In “sour” environments, materials are susceptible to sulfide stress cracking. In these cases, materials will need to be specified for NACE (National Association of Corrosion Engineers) compliance.
- If the injection system is not able to sustain adequate dehydration due to constant down time or lack of system capacity resulting in wet injected fluids, then CRA should be considered.

In most CCS projects, where the above circumstances are not encountered, standard oilfield metallurgy will deliver satisfactory well integrity. Below we consider and contrast two cases of materials selection and well design. The first is a hypothetical case of high volume injection into a saline formation where corrosion resistant alloys as well as NACE compliant alloys would be considered. The second is the more typical injection experience from the Rangely Weber oilfield. Both examples clearly indicate that:

- The material selection process is complex and needs to consider many operating parameters in a project as well as the reservoir conditions and injected fluid composition.
- There are a number of solutions for material selection as well as many material types that can successfully address the specific conditions.
- A wide variety of casing design, materials, and cementing programs have been used successfully and have quite a long history.

CASE STUDY

Hypothetical Well - materials selection case study

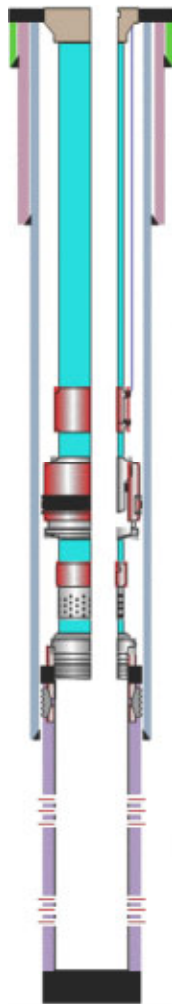
The table below is a hypothetical basis of design for an injection well. The design assumes both operational upsets (i.e. plant not able to achieve design dehydration rates or inadvertent shut-down) and provision for back-washing that could result in high water content and flowing conditions at the production liner. Additionally, H₂S is assumed to be mixed with the CO₂ in amounts that make NACE requirements and other considerations in the design important. The design shows how thoughtful choices can address all issues.

The normal operating premise is that there will be no water condensation at or in the injectors under expected operating conditions and thus there will be no corrosion to the carbon steel portions. Additionally dehydrated supercritical CO₂ can absorb a large amount of free water.

Table 2.2: Possible well design conditions

	CO ₂ injection wells	Comments
Reservoir Fluid Type	Water / CO ₂	CO ₂ Supercritical phase
Design Life	+/- 50 years	
Design Rate (Max)	50 MMscfd Injection	
Bottomhole Temperature (Static)	250 degrees F	
Typical Tubing head Pressure	4,000 psi	
Bottomhole Pressure (Reservoir / Static)	3,500 psi Final	Will not exceed a pressure that would allow loss of containment in injection zone
CO ₂ (max)	99.9 mol%	Partial pressure at wellbore – 3,841 psi (264.8 bar)
H ₂ S (max)	Assume will exceed NACE limit	
H ₂ O (max)	Assume will exceed capacity of supercritical CO ₂ to dehydrate	This is based on provision for back-flushing and potential production upsets

Table 2.3: Possible well design conditions



Description	Potential Risks and Concerns	Materials
Tubing Hanger	CO ₂ corrosion may be associated with well back-flushing provision and process interruptions.	CRA - Generally high Nickel Content
Conductor Casing	Some aquifers have a potential external corrosion risk.	Carbon steel - consider external coating.
Surface Casing		Carbon steel.
Injection Tubing	Provision for periodic back-flushing and process up-sets may yield water exceeding 8,000 mpy	GRE lined Carbon Steel or CRA.
Production Casing	Metallurgy in accordance with industry standards for any contaminants in CO ₂ .	Carbon Steel - Surface to immediately above base of sealing formation.
Production Liner	Process upsets & provision for back-flushing may result in high water content CO ₂ in the injection zone. Also there may be contaminants in the CO ₂ such as H ₂ S.	CRA. Industry standard if required for applicable contaminants.

Abbreviations used: CRA = Corrosion Resistant Alloy; GRE = resin epoxy; NACE = National Association of Corrosion Engineers.

CASE STUDY

Materials selection case study: the Rangely Weber field experience

Chevron operates the Rangely Weber Field, in Colorado. The field was discovered in 1933 but was not commercialized until 1943 when the need for oil in World War II spurred development. The field was unitized in 1957 so water flooding could begin in 1958. CO₂ injection began in 1986. Rangely is a good example of a CO₂ project where old (1940s vintage) wells have been used successfully.

The field contains 942 wells (343 injectors, 466 producers and 133 abandoned). The general well construction consists of surface casing at 1,000 to 2,000 feet and production casing at 6,500 feet. Production casing is typically 7" K or J-55, though N-80 was used from about 5,500 ft to TD in the 1970s-1980s. Production tubulars are plastic coated, and injection tubulars are either cement or fiberglass lined. Since H₂S is present along with corrosive water (high chlorides) and CO₂, NACE MRO-175 trim is typically used for valve trim. On injection wells that may be exposed to both CO₂ and water, trees, meter runs and affected wellhead components are constructed of 316 or other stainless alloys. Downhole equipment (packers, submersible pumps, etc.) are usually plastic coated.

The wells drilled in Rangely can be categorized in three groups:

- The initial 40 acre wells (478 wells drilled between 1944 and 1949).
- The 20 acre infill wells (416 wells drilled, mostly between 1966 and 1987).
- The modern wells (48 wells drilled as missing 20 acre wells, 10 acre trial wells, replacement wells or edge wells).

The initial 40 acre wells were predominately cemented with what was described as 'Halliburton bulk cement with 2% gel.' The 20 acre and modern wells typically used Class G or H cement - sometimes in a Portland cement-fly ash mixture. While obtaining cement to surface was always the objective, actual cement tops range from surface to 3,000 feet.

Of the 478 original 40 acre wells, 122 were plugged and abandoned (P&A) over the life of the field but few were related to well integrity problems. Most were associated with

parts of the field that were determined to be uneconomic, or high public risk. Approximately 22 of the abandoned wells originally drilled in 1940 have been successfully re-entered for production or injection as part of CO₂ projects. Of the 378 remaining 40 acre wells, approximately 193 are currently injectors - many of those CO₂ (actually WAG - Water Alternating Gas) injectors.

By contrast, only 11 of the 464 - 20 acre and modern wells have been plugged and abandoned to date. However, 20 acre wells were not drilled in areas that were considered uneconomic or high risk - areas where 40 acre wells had been originally drilled and subsequently abandoned. Approximately 150 of these 20 acre wells are injectors.

Rangely is a good example of a CO₂ project where old (1940s vintage) wells have been used successfully

Rangely recycles about 160 MMCF of CO₂ each day, and adds another 40 MMCFD to that volume through purchases - bringing the daily injection to about 200 MMCF. To date, Rangely has injected 1.4 TCF of gas, of which 504 BCF (26 MM metric tons) was purchased CO₂ and the remainder recycled gas.

The Rangely field operates under US Class II Underground Injection Control (UIC) regulations under the authority of the Colorado Oil and Gas Conservation Commission. While minor UIC issues do arise (as they do with all Class II injection projects), there have not been the dramatic failure rates and catastrophic failures that were predicted with the CO₂ flood in the aging wellbores. On average, the injection wells have about a 10-year mean time between failure for UIC. Failures are typically caused by packer or tubing failures causing pressure in the tubing/casing annulus and are repaired by running new or inspected tubing with a new downhole assembly (packers, tailpipe, etc.). On occasion, a liner is run in the 7" casing to ensure wellbore integrity. Interestingly, this happens most often in the 20 acre infill wells where N-80 casing was run on the bottom of the casing string.

Well hardware

Well hardware for CCS wells generally includes:

- Wellhead and Tree.
- Tubing and casing.
- Safety Valve.
- Packer.
- Packer Fluid.
- Elastomers.
- Sand Control.

All of this hardware must meet all applicable industry standards and provide sufficient integrity and redundancies to ensure surface isolation of the well from the environment. Considerations outlined in the material selection apply to other well hardware.

In CO₂ injectors, the design of the packer assembly should take into consideration the importance of limited or no movement of the packer seal assembly while providing the ability to regularly pull the tubing for inspection.

Since supercritical CO₂ is a solvent, many elastomers, plastics, rubber, or resins present in a well could be subject to chemical attack or dissolution. When designing a CO₂ injector, materials should be selected based on performance expectations.

Elastomers, in particular, are a common part of well hardware used to seal different components. Elastomers must be made of material that is chemically compatible or inert to the injection fluid, and must be of sufficient strength or adequately anchored to withstand the differential pressure and explosive decompression that might exist across a seal. Since the physical and performance characteristics of many elastomer materials change with pressure and temperature, the elastomer must be able to perform reliably across the full range of differential pressures and temperatures expected throughout the design life of the well at the location of the seal within the well.

Sand control for injectors is necessary in environments where the reservoir is unconsolidated and there is potential for sand blocking when the wellbore is shut in for maintenance or upsets. This can be a problem even when gravel packs are installed due to the high injection rates and the displacement of the gravel deep into the formation.

Other considerations in a CO₂ injection environment include dissolution of sand control resins (if present) and dehydration and deposition of gravel pack contents that cannot be displaced or removed from the well.

Cementing and zonal isolation

Cements have been used for isolation and well integrity for more than a hundred years. Cement isolation is a fundamental part of corrosion protection for casing. Best practices have been developed and are well-documented. CCS projects must follow these practices.

Placement of the slurry completely around the casing and to the design height is one of the primary factors in achieving successful zonal isolation and integrity. Good isolation requires tight cement interfaces with the formation and casing. To achieve this, it is necessary to properly design, blend, mix, test and clean tubulars, displace, and pump the cement, and use best practices such as pipe rotation and centralization. A frequent discussion point is whether cement is required to be placed back to surface on each casing string. This is necessary only in some cases to ensure well integrity. When cementing back to the surface is carried out, special practices should be considered. Utilizing lightweight slurries or cementing tie-backs above liners are ways to mitigate the risk of excessive cement slurry loss and loss of cement integrity.

It is important to understand that the cement interfaces between the borehole and the casing through the caprock are the key to well integrity and seal integrity. Effective seals at these interfaces prevent migration paths. Thus cement degradation, if any, will not allow significant flow. This has been demonstrated on conventional, Portland-based cements in field studies from CO₂ injection in West Texas and a CCP well integrity survey discussed below.

Recent experimental data⁵ provide information about the capacity of specialty cement to protect against cement interaction with the CO₂. However, these cements were tested in laboratory conditions of immersed and continuously refreshed exposure to CO₂ and brine which is not representative of well conditions.

In cases where specialty cements are desired, reduced Portland or non-Portland designs are available. However, issues relating to the compatibility of non-Portland cements and conventional cements arise.

CASE STUDY

CCP Comprehensive wellbore field study

- **Cement interfaces, *not* cement matrix are the most likely path for migration.**
- **Standard Portland-based cements and carbon steel casing provide long-term hydraulic isolation.**

This study was conducted to evaluate the barrier conditions of a wellbore exposed to CO₂. The findings of this work indicate that Portland-based cement (including fly-ash) and carbon steel have provided an effective barrier for the life of this well.

The significance of this study is its finding that emphasis should be on cement placement rather than selection of a CO₂ resistant cement to provide an effective barrier. The key is to minimize migration potential at the cement interfaces with casing and formation. The following outline from the study provides the context for these conclusions.

A comprehensive well integrity survey program was conducted on a natural CO₂ production well located in Colorado to evaluate the barrier condition under long term exposure⁶. The study showed that effective cement placement provided an effective hydraulic barrier using a Portland-based cement system with carbon steel (Figure 2.2). The well was constructed with carbon steel tubulars and Portland cement blended with 50% fly ash and had a 30 year life in a field that produced 96% CO₂ with water saturation of approximately 20 percent. There was no significant corrosion before the well was abandoned in 2006.

Emphasis should be on cement placement rather than selection of a CO₂ resistant cement to provide an effective barrier The well was completed in a sandstone formation at approximately 4,500' True Vertical Depth (TVD) whose thickness is 130 vertical feet. The producing formation is overlaid by shale (130' vertical thickness) and shale/limestone (75' vertical thickness) formations.

The well was drilled and completed nine years prior to initial production due to pipeline availability. Initial reservoir conditions were approximately normal gradient (1,480 psi and 136 °F at 4,560' TVD) at the top of the CO₂ formation. The well produced for 20 years until it was permanently shut in due to normal pressure depletion and associated water influx. It had no reported annulus pressure over its operating life. The production interval was cased with 7",

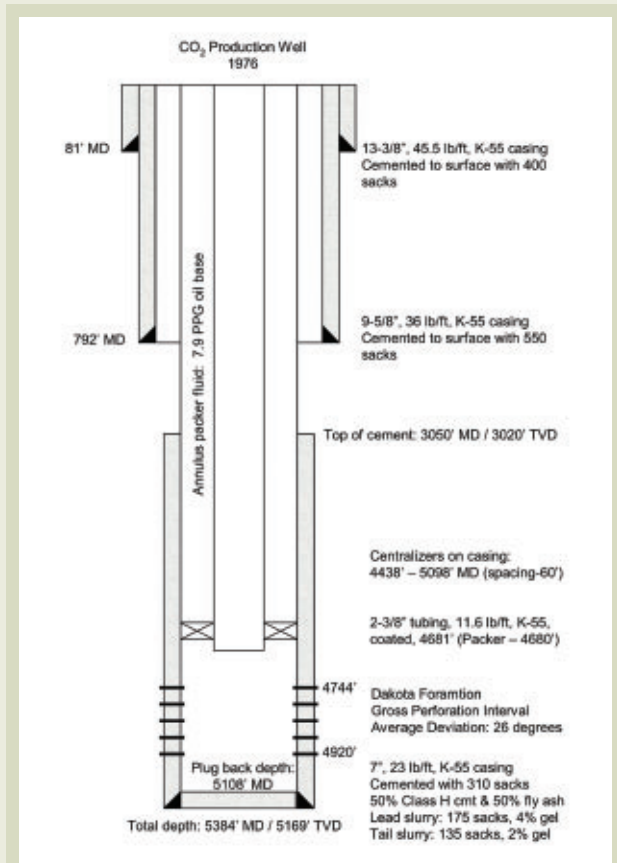


Figure 2.2: Completion design and well construction outline from a natural CO₂ production well in a sandstone reservoir. The cement design was a Portland blend with 50% fly ash. Metallurgical components were carbon steel casing and plastic-coated carbon tubing.

K55 grade casing and cemented with a blend of 50% Class G (Portland) cement and 50% fly ash with approximately 3% bentonite gel. Casing centralizers were placed from the producing formation through the caprock which is 25° wellbore deviation. A well survey program was conducted to collect information and cement samples from the CO₂ formation and the overlying caprock.

It featured:

- Cement evaluation and casing inspection logs.
- Fluid/gas saturation detection, with neutron logs and lithology measured with gamma spectroscopy tools.
- Fluid sample collection from the formation for geochemical analysis and pressure/temperature measurements using a test tool.

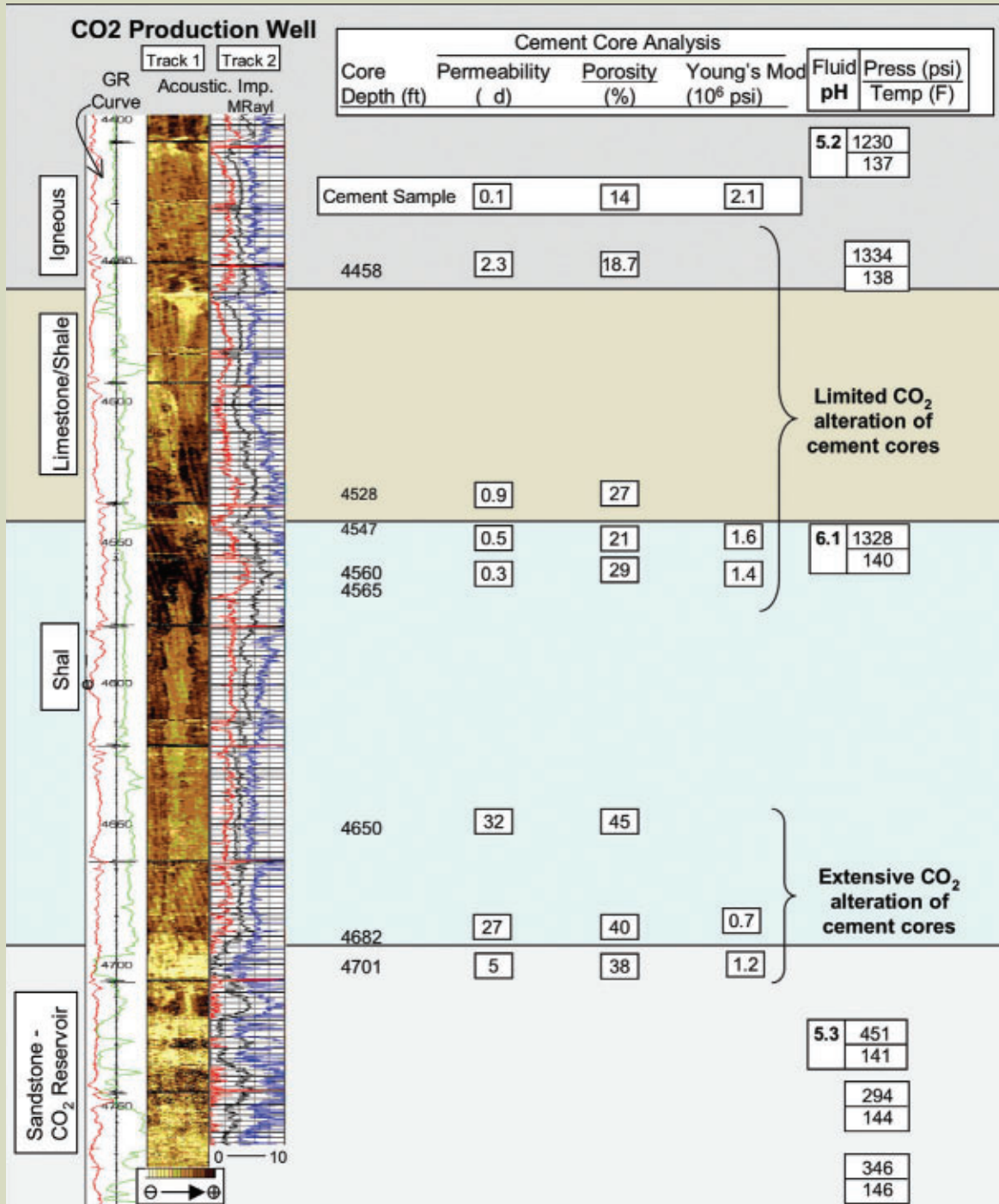


Figure 2.3: The log section represents the cement bond measured by Raw Acoustic Impedance which is superimposed over the geological formations and is presented with core properties, fluid pH and formation pressure/temperature. Hydraulic isolation is maintained across the shale caprock based on the depleted formation pressure below compared to normal original gradient above that zone.

- An in-situ evaluation of the effective permeability of the cement using a dual packer isolation tool with applied surface pressure.
- Sidewall cores of the casing, cement and formation were collected for mineral and hydrologic analysis.

A summary of the cement core properties, fluid samples, pressure/temperature data and cement log evaluation is provided in Figure 2.3. The pressure in/near the CO₂ formation shows depletion to approximately 300 psi compared to 1,300 psi above the shale caprock. The permeability and porosity are higher for the cement cores near the CO₂ formation. Fluid samples indicate a slightly acidic environment based on a pH range of 5.2 to 6.1 along the

entire section from the CO₂ interval through the caprock. Mineral analysis of the cores shows that they are rich in calcium carbonate at depths in/near the CO₂ formation (at 4,650' MD). Cement cores at or above the top of the caprock (at 4,560' MD) have only limited calcium carbonate which indicates there is minimal alteration of the cement in that region. There are two possible scenarios for cement alteration at the top of the caprock. One is that migration has occurred through defects in the cement interface with the casing and/or formation followed by diffusion into the cement sheath. A second possibility is that a limited amount of CO₂ was present in the shale before the well was drilled as a result of long-term diffusion from the Dakota formation or the presence of carbonates. Although some

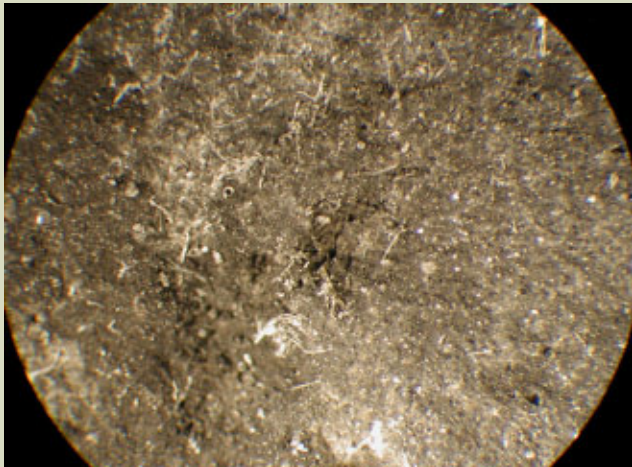


Figure 2.4: The surface of cement core from 4722' in contact with formation has a thin layer of carbonate crystals (view is 4 mm in width).



Figure 2.5: Surface of cement core from 4528' depth showing black pieces of shale adhering to the cement surface (view is 5 mm in width).



Figure 2.6: Optical view of core from 4560'. An intact contact between casing and cement was preserved during recovery (left image). The surface of the cement plug facing the casing (Right image) had a piece of corroded steel attached to it (orange area). The surface of the cement also had a layer of minute (< 100 nm) reflective crystals (calcium carbonate).

CO₂ could have been present in the formation, there is still potential for limited migration along defects in the cement barrier that were measured during this survey.

There were no significant mineral deposits along interfaces recovered in any of the cores. Assembly of core pieces (casing, cement, and formation) was consistent with tight interfaces in the system (Figures 2.4 and 2.5). There were no indications of filter cake deposits or other significant debris accumulation at the cement formation interfaces.

In one sample of core from 4,560' (Figure 2.6), the bond between casing and cement was preserved during recovery but separated at the lab upon minimal handling. The interface was free of any significant deposits but contained a thin coating of minute carbonate crystals. A small region of mild corrosion of the casing was present at the interface which adhered to the cement.

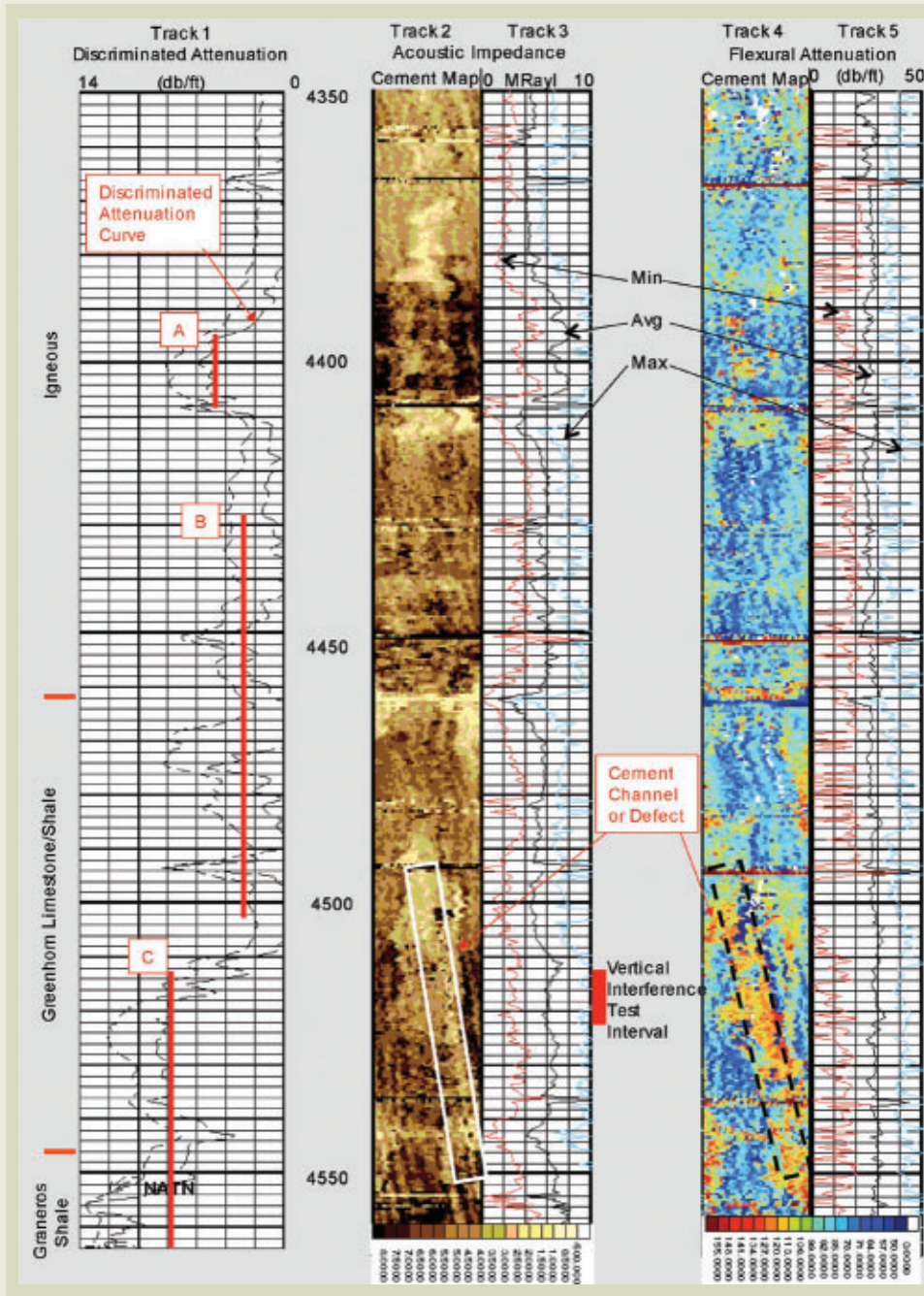


Figure 2.7: Comparison of cement evaluation logs with the interval of the Vertical Interference Test shown near a suspected cement defect.

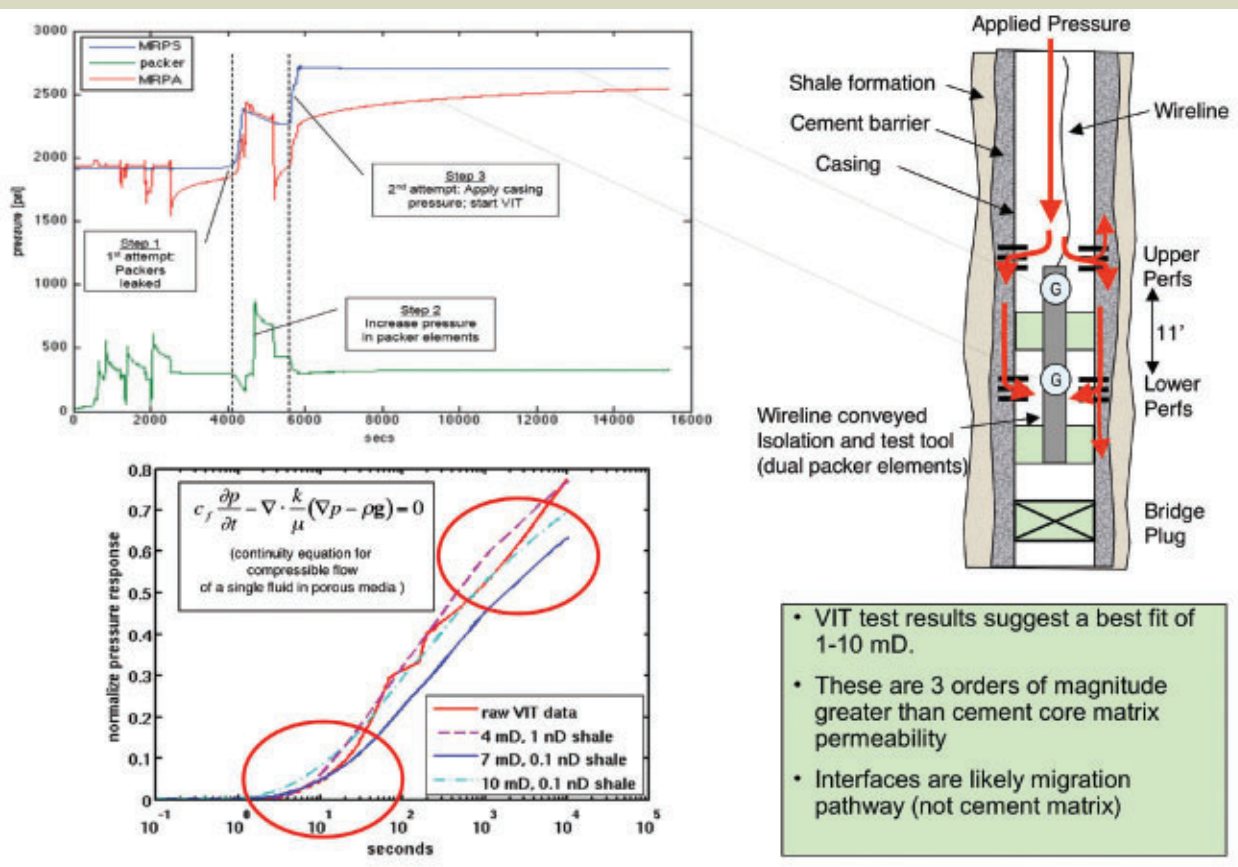


Figure 2.8: Pressure data collected at the two sets of perforations and a simulation comparison shows the best match to be 1-10 mDarcy permeability.

Comparison of the CBL attenuation curves (Track 1), Acoustic Impedance (Tracks 2 and 3) and the Flexural Attenuation (Tracks 4 and 5) in Figure 2.7 show areas of relatively good cement bond based on the logging tools.

A Vertical Interference Test (VIT) provided a measurement of the effective permeability of the barrier including defects at the cement interfaces with the casing and formation. This measurement was conducted at in situ reservoir conditions. Figure 2.8 shows the schematic of the dual isolation packer on the lower set of perfs to monitor the pressure response to applied pressure from surface as the transient passes through the barrier system. Although simulated data does not perfectly match the test data the best approximation suggest the barrier permeability could be as much as 1-10 mD. This is approximately 3 orders of magnitude higher than the lab measurement of 1 μD (1 μD = 10⁻⁶ Darcy) for the cement core that was collected from the depth of the VIT (4,528' MD). Therefore, the interfaces are believed to be the primary path for CO₂ movement that

might occur along the barrier system. For this particular test, it may not be possible to resolve variations between test data and simulation results if the assumptions for symmetry and homogeneity do not match the physical system. However, results do generally represent that migration potential in the barrier system is greatest along cement interfaces. The methodology and analytical approach for this test are being refined with additional surveys.

Results from this survey indicate that Portland-based cement systems can provide effective isolation in the presence of CO₂ even though it may be somewhat altered after years of direct exposure.

The summary results are:

- Current technologies can be used to determine barrier condition. Logging results from the survey correlate with the performance measurement of the large-scale VIT and the small-scale cement core properties.
- The barrier system in this well appears to provide hydraulic isolation across the caprock based on formation pressure measurements (tabulated in Figure 2.3).
- Cement carbonation has been observed in varying degrees in cores from this well. This indicates that cement was exposed to a CO₂ environment during well history. Our hypothesis is that the CO₂ has caused carbonation of cement and acidification of fluids in and near the Dakota formation. Although CO₂ could have been present in some minor amount near the top of the caprock intervals, the in-situ effective permeability was measured and indicates migration potential that could account for some mineral migration which could explain the observed alteration of the cement.
- The casing is in very good condition, consistent with good cement coverage and limited circulation of reservoir fluids along the casing-cement interface during well operations.
- Cement interfaces with casing and formation appear to be tight and do not have significant calcium carbonate deposition. However, comparison of cement core and barrier system permeability indicates that the preferential migration path for CO₂ was along the interface(s) and carbonation of cement resulted from diffusion of CO₂ from the interface into the cement.
- Based on the results of the surveys in this well, conventional Portland cement-fly ash systems can inhibit CO₂ migration even after carbonation of the cement because permeability remains relatively low and capillary resistance is relatively high. The cement interfaces with the casing and formation are the areas of greatest concern for barrier system integrity; however these interfaces appear to provide sufficient flow restriction between formations in this well based on the VIT results, the lack of corrosion in the well, and the lack of sustained casing pressure.
- The effective permeability of the barrier system was evaluated from the VIT data which considers the cement interfaces and is the preferred method to analyze in-situ migration potential. Since the results of the VIT (1-10 mD) are up to 3 orders of magnitude

greater than the cement core permeability, the interfaces are believed to be the primary path for CO₂ movement that might occur along the cement interfaces with casing and/or formation.

Conventional Portland cement-fly ash systems can inhibit CO₂ migration even after carbonation of the cement because permeability remains relatively low and capillary resistance is relatively high

2.4 Operations

In CCS projects key success factors are ensuring well integrity via appropriate strategies, as well as surveillance and monitoring; real time response to analyzed data; and operational results. Key areas of focus include maintenance and well monitoring.

Maintenance

This covers issues relating to start-up, shut-downs, interventions and stimulation.

Start-up

In CCS projects, start-up can be different than conventional applications. There are a few areas to consider:

- Once the well is completed, impairment implications of the fluids or non-fluids left in the wellbore will need to be considered. Fluids left in the wellbore for extended amounts of time could potentially corrode the tubulars, drop out precipitants, or cause bacterial growth.
- Another consideration is the displacement of any fluids into the reservoir during start-up and the effect of injectivity resulting from the introduction of the fluids.
- Finally, the prevention of hydrate formation in the well will need to be considered. It is likely that methanol spacers will need to be used.

Shut-downs

Shut-downs occur due to maintenance or operational upsets. When shutting down a CO₂ injector it is important to consider that:

- Hydrates potentially could form when starting back up. During the process of shutting down, measures should be taken to mitigate the formation of hydrates when starting back up. Often, a methanol “cap” is pumped in the top of the tubulars.
- Facilities sometimes do not have sufficient pressures to re-start injection. In these cases, injection tubing should be loaded with sufficient fluids to allow for a re-start.

Interventions

Interventions are usually performed when there has been a mechanical failure causing loss of injectivity. In CO₂ injectors it is necessary to consider the following when intervening:

- As a consequence of well control using a brine or similar fluid, there can be intermixing of the

CO₂ and the well control fluid that could result in hydrate formation or hydrate blocks. Using hydrate inhibited fluids or having operational practices that minimize the amount of CO₂ inflow during workovers should be considered.

- Due to the criticality of maintaining high injection rates, it is important to minimize the negative effects of procedures for fluid loss control and negative effects of the lost fluid itself with respect to injectivity or near wellbore damage.
- Well control procedures during workovers must provide for the unique phase behavior of any CO₂ being circulated out.

Stimulation

Some CO₂ injector wells may need to be stimulated due to loss of injectivity over time. When designing stimulation treatments, it is important to understand the objective of the stimulation procedure. There are many stimulation designs with different objectives to increase permeability around the near-wellbore region. Once a stimulation design has been selected, there are a number of outcomes to consider:

- Fracturing may occur in some of the different treatments. The fractures should not compromise the reservoir seal.
- Stimulation fluids should be carefully selected in terms of compatibility with the well materials, workover materials, and reservoir.

Well monitoring

Generally, an asset (a well, pipeline or compressor, for example) can be said to have ‘integrity’ when it performs as intended and is operated and maintained within its design parameters at an acceptable risk over its entire service life. More specific to a CO₂ injection well, the well has integrity when it is operated in such a manner as to reduce the risk of uncontrolled release and/or unintended movement of CO₂ throughout its service life. Well monitoring is a proactive verification that integrity is maintained as designed. Well monitoring for CO₂ storage seeks confident validation that:

- Cement integrity and bond is maintained.
- Pressure isolation barriers are maintained and functioning.
- Corrosion is being controlled.
- The CO₂ injection profile is being maintained.
- Barriers after plug and abandonment provide confidence.

Well monitoring can be seen as a fit-for-purpose data collection process done as part of an ongoing scientific evaluation. Monitoring spans the entire time horizon of the well service life. By necessity, the components and intensity of monitoring change with time. Monitoring starts with base line measurements before any CO₂ is injected. Once injection begins, it focuses on well containment. Monitoring changes focus as injection stops and subsurface pressures naturally diminish. Good well monitoring selects the right tool for the job and requires harnessing the appropriate techniques to provide the right information. It will also depend on the type of access permitted, the time frame, the need for repeated measurements, and even cost.

The discussion which follows presents selected technologies to illustrate their utility, but make no pretense of presenting a comprehensive catalogue of techniques and technology applications. While new technologies and new well monitoring techniques may be interesting and appropriate, traditional and routine techniques are often just as good. The selected types of well monitoring include:

- Cased Hole Logging.
- Cement Integrity Logging.
- Mechanical Integrity Tests and Annular Pressure Monitoring.

Cased hole logging

There are a variety of cased hole logs that can be used to monitor well integrity. Some of these include:

The leak detection log (LDL)

The objective of an LDL is to define the leak point location in the wellbore to clarify potential repair options. There are many situations where LDLs cannot be run or will not provide answers. Anomalies should be logged to verify their exact location and determine their nature, if possible. Multiple leaks are common and changes in pump rate, fluid type, or inside diameter changes may appear to be leaks or may mask leaks. All LDL logs are based on the same principle: fluid is pumped into the suspect or adjacent tubular and a downhole tool is used to detect the leak point. There are various tools that can be used for LDL including spinner/temperature logs, video logs, and ultrasonic noise logs. These tools are characterized in the differences in how flow is measured, the depth, and accuracy of the measurements.

Tubular inspection logs

A variety of tools can be run in the well to assess the mechanical condition of the tubulars and potential leaks. For the most part, these logs will only provide data for the tubular in which they are run. The tool types include caliper logs that mechanically measure the inside diameter, and pipe inspection logs that use magnetic flux leakage or ultrasonics to determine the condition of the tubular.

Production profile logs

Production profile logs can be used to measure injectivity and the injection profile across the interval. These can be run with or without tracers. These tools are combination strings that can be combined with spinner and temperature tools mentioned above.

Neutron, neutron decay, and spectral logs

These logs can be used to measure near wellbore fluid content for the purposes of monitoring the phase behavior of the CO₂, the location of CO₂, and the presence of water.

Cement integrity logging

It is important to remember that cement evaluation logs cannot be considered in isolation. All of the available well information should be reviewed thoroughly when assessing the integrity of a well's cement sheath. Such information includes drilling reports, drilling fluid reports, cement design and related laboratory reports, open hole log information including caliper logs, cement placement information including centralizer program, placement simulations and job logs, results of mechanical integrity tests performed on the well and other information such as the presence or absence of sustained casing pressure. The availability of this information can vary greatly depending on factors such as the age of the well.

Cement integrity logs are designed to detect defects caused by by-passed mud channels (caused by ineffective cement slurry placement), gas and other formation fluids mixing with the cement and micro-annuli at the cement/casing and cement/formation interfaces (caused by factors such as changes in wellbore pressures or cement shrinkage). Current cement evaluation logs do not have sufficient resolution to detect micro-fractures in the cement sheath. Cement integrity logs are used to aid in evaluating these potential problems and the condition of the cement sheath in the annular space between the casing and the formation. Diffusion of CO₂ through a cement matrix presents little

threat to well integrity. The defects mentioned above are more likely to be migration paths for CO₂. Extensive information is available in the literature detailing the physics and operation of the tools.⁷

Cement integrity tools vary by their depth of investigation, area of investigation, and nature of the cement defects they can detect. Additionally, the tools can be used in various operational conditions, for example with and without casing pressure. This could aid in indicating a micro annulus that may not appear in normal operating conditions. Thus the right choice and application of the tool is crucial.

Mechanical integrity testing and annular pressure monitoring

A mechanical integrity test is used to determine the mechanical integrity of tubulars and other well equipment.

Initially during well drilling, positive or negative pressure tests that can be part of normal well construction may determine the casing and shoe integrity. During the injection phase, casing integrity is inferred by showing there is no leakage into the “A” annulus, or between the “A” annulus and “B” annulus and formation by monitoring these pressures.

Upon completion and during injection, the tubing/packer integrity is demonstrated by showing there is no leakage of injected fluids through the tubing or packer into the “A” Annulus.

It is important to monitor these annular pressures during formation injectivity testing to help determine a potential leak. If the annulus is being charged with gas, an analysis of the gas content may give an indication of the source and the nature of a potential leak.

Maximum and minimum allowable annular surface pressures should be assigned to all annuli and should consider the type of gradient in each. These upper and lower limits establish the safe working range of pressures for normal operation in the well’s current service and should be considered “Do Not Exceed” limits. A description is provided in Figure 2.9 for the reference to the naming convention for annuli. The “A” Annulus is adjacent to the tubing.

Wellhead seal tests are conducted to test the mechanical integrity of the sealing elements (including valve gates and seats) and determine if they are capable of sealing against well pressure. A pressure test of the wellhead seal system can determine if the source of communication is at the surface between the annuli.

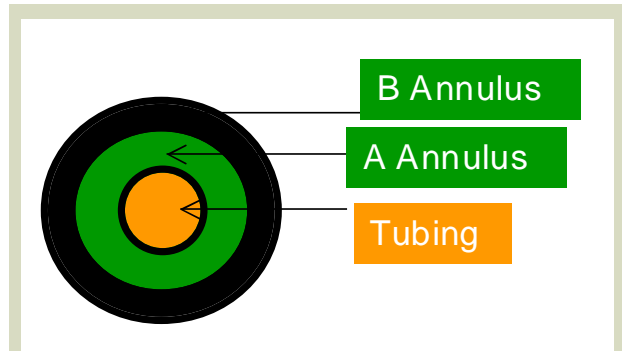


Figure 2.9: The annuli are named from “A” to “B” or higher starting adjacent to the tubing.

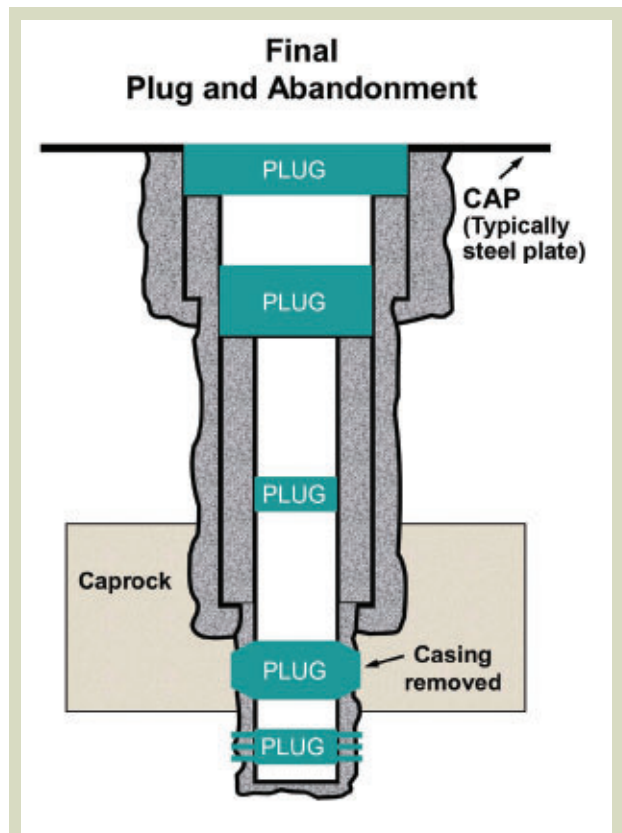


Figure 2.10: Typical Plug and Abandonment. Showing from bottom-up: plugged injection zone, plug in caprock interval which includes drilled casing; plug above caprock, plugs at top of casing and steel plate at surface.

When equipment is removed from a well or depressurized for maintenance, a breakdown or visual inspection should be conducted to document the condition of the equipment after being in CO₂ service. For example, if tubing is pulled from a CO₂ injection well, it should be inspected for corrosion/erosion damage. While the tubing is out of the well, a casing inspection log should be considered to verify its condition.

2.5 Closure

When injection has stopped, the injectant plume will stabilize and the reservoir pressure will begin to decline. The time required for pressure stabilization will depend on the individual characteristics of each site. Plug and abandonment of wells can begin at the end of the injection phase. By the end of the closure period, all remaining wells will have been plugged and abandoned with the possible exception of wells that may be needed for monitoring.

The objective of plug and abandonment is to form a vertical barrier to flow or migration to ensure the long term integrity requirements for closure. Figure 2.10 illustrates a typical well abandonment which may include the following:

- Remove tubing and packer. (see Figure 2.1.)
- Permanently seal the formation with a fluid that reduces permeability.
- Place plugs of cement or other material for isolation.
- Test the plugs.
- Place a cap on the casing at the surface.
- Backfill with soil and accurately record well location.

When the wells have been abandoned and the surface facilities removed, the site may be closed. The next phase is the post-closure.

2.6 Post-closure

No well activities occur in the Post-closure phase.

2.7 Concluding Remarks

Due to the inherent risks and costs of penetrating the top seal with multiple injector wells, it is best to consider strategies to reduce well count. In more recent years, the oil and gas industry has been progressively reducing its well counts by introducing new well technologies to ensure well productivity/injectivity is optimized. As the productivity/injectivity of a well is determined mainly by the formation permeability and the amount of formation penetrated, all the newer techniques basically improve the amount of formation penetrated/contacted by different mechanisms including horizontal wells, hydraulically fractured wells and multi-lateral wells.

Geomechanical stress should be evaluated for the impact on wells related to production depletion and the increase in pressure that will result from re-charging during CO₂ injection. The changes that occur in formation compressibility due to fluid/gas extraction during the injection or production life of a well can be modeled. This information will serve to define the baseline state prior to CO₂ storage.

Assuring CO₂ injector integrity requires thorough quality assurance and properly executed operations. The choice of well equipment and materials must be carefully considered to achieve the desired integrity. A complete and well-considered operations and well monitoring plan must be in place and fully executed. Both existing and new wells must be fully evaluated and tested for integrity. Finally, abandonment and closure must technically assure the long-term integrity objectives.

Cementing Process

Cementing is an activity that consists of many engineering components. Much has been written about effective cement slurry placement.^{8,9,10,11} Important considerations include:

- Good drilling practices to achieve a useable wellbore.
- Good hole geometry resulting from good drilling practice.
- Drilling fluid selection.
- Casing hardware, including float equipment, centralizers, stage tools etc.
- Proper rheological and density hierarchy of each fluid.
- Spacer design and volume.
- Casing movement – rotation and/or reciprocation.
- Casing centralization.
- Computer simulation and other planning to optimize placement procedure.
- Slurry design.
- Slurry density.
- Thickening time.
- Fluid loss control.
- Slurry stability - free fluid and sedimentation control.
- Expansion or shrinkage of set cement.
- Static gel strength development.
- Compressive strength development.
- Fluid compatibility (cement, mud, spacer).
- Well preparation (hole cleaning, wiper trips, and lost circulation control).
- Good cement testing.
- Good practice at mixing, blending, and pumping in the field.

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Figures

Figure 2.1: Schematic components of a well constructed for CO₂ service showing both natural and mechanical barriers to flow. No scale intended. Figure courtesy of J. Cooper⁴, modified by ConocoPhillips.

Figure 2.2: Completion design and well construction outline from a natural CO₂ production well in a sandstone reservoir. Produced by the CO₂ Capture Project.

Figure 2.3: The log section represents the cement bond measured by Raw Acoustic Impedance ... and is presented with core properties, fluid pH and formation pressure/temperature. Produced by the CO₂ Capture Project.

Figure 2.4: The surface of cement core from 4722' in contact with formation has a thin layer of carbonate crystals (view is 4 mm in width). Produced by the CO₂ Capture Project.

Figure 2.5: Surface of cement core from 4528' depth showing black pieces of shale adhering to the cement surface (view is 5 mm in width). Produced by the CO₂ Capture Project.

Figure 2.6: Optical view of core from 4560'. Produced by the CO₂ Capture Project.

Figure 2.7: Comparison of cement evaluation logs with the interval of the Vertical Interference Test shown near a suspected cement defect. Produced by the CO₂ Capture Project.

Figure 2.8: Pressure data collected at the two sets of perforations and a simulation comparison shows the best match to be 1-10 mDarcy permeability. Produced by the CO₂ Capture Project.

Figure 2.9: The annuli are named from "A" to "B" or higher starting adjacent to the tubing. Produced by the CO₂ Capture Project.

Figure 2.10: Typical Plug and Abandonment. Produced by the CO₂ Capture Project.

Tables

Table 2.1: Storage Project Life Cycle stages related to wells. Produced by the CO₂ Capture Project.

Table 2.2: Possible well design conditions. Produced by the CO₂ Capture Project.

Table 2.3: Possible well design conditions. Produced by the CO₂ Capture Project.

3



MONITORING PROGRAMS FOR CO₂ STORAGE

3.1 Introduction

Monitoring is about proactive verification that storage is working as expected. By itself monitoring cannot guarantee safety, and it is not intended as an alarm system that signals imminent danger; although sensors might be adapted for that purpose. Monitoring is like the speedometer on your car. It contributes to your safety but other factors are more important such as the design and maintenance of the car itself, road conditions and how you drive.

Monitoring for storage seeks confident validation that injected fluids:

- Actually go into the intended subsurface interval.
- Remain in the geological interval where they are intended to go, and do not breach the containment system.
- Can be appropriately tracked in the subsurface over time.

Geoscientists think of subsurface monitoring as a fit-for-purpose data collection process done as part of an ongoing scientific evaluation. By design, it tests the effectiveness or performance of a model constructed to understand complex subsurface relationships and verify expectations for the location and movement of fluids and gas with time.

This process can also be thought of as performance testing to address known or perceived risks. With performance data, the models can also be used to evaluate hypothetical situations. The goal is to be reasonably certain that we understand what is happening to injected CO₂. It is impossible to track what is happening to every molecule of it, and fortunately there is no need for that level of precision.

The imperative is to know enough to be sure there is no tangible danger.

Monitoring spans the entire time horizon of geological storage and by necessity the components and intensity of monitoring change with time. It starts with site characterization, and includes extensive baseline measurements before CO₂ gets injected. Once injection begins, monitoring addresses immediate injection performance and focuses on the ongoing reservoir and containment properties. Monitoring changes intensity as injection stops and subsurface pressures naturally diminish to ensure stability of the injected plume. It continues in some reduced manner post-closure to provide confidence that everything is behaving as planned.

3.2 Selecting monitoring tools and techniques

Successful monitoring depends on selecting the right tool for the job and it requires harnessing the appropriate techniques to provide the needed information. The preferred combination will depend on factors such as the depth, temperature and compositional characteristics of the reservoir and the properties of the injected CO₂. It will also depend on the type of access permitted, the time frame, the need for repeated measurements, and even cost. The characteristics of the surface above the storage site will also play a huge role in the selection process. Whether on land or offshore, in a desert, a forest, farmland or tundra, the surface conditions will impose both practical limitations and technical constraints. Some tools and techniques will be especially useful for certain situations and almost worthless in others. In this section, we discuss a few selected applications to

illustrate their utility, but make no pretense of presenting a comprehensive catalogue of tools and their corresponding technical applicability or effectiveness. Keep in mind that while new technologies and new monitoring techniques may be very interesting and appropriate, the traditional and routine techniques are often just as good.

Achieving a well planned, integrated monitoring design is clearly of value. In oilfields, ineffective monitoring might result in missed or lost production which really means lost revenues. For CO₂ storage, inappropriate monitoring might suggest either a false sense of security or a false alarm for issues that do not exist. Quality monitoring is in the public interest and responsible operators and regulators are sure to demand good quality performance in monitoring design.

Direct monitoring tools and techniques

Monitoring occurs at many different scales and positions. Some techniques directly measure CO₂ concentrations or other properties such as pressure or fluid composition in the injected storage formation. Direct techniques usually require access from well-bores that penetrate the containment system into the storage reservoir. Generally the concept is to minimize such penetrations because they are, by default, potential leakage pathways. On the other hand, direct measurements can also be obtained from observation wells at shallower horizons above an expected seal. Wells of this type might provide direct and early indications of unexpected movement; or better yet, they may demonstrate that significant vertical movement is not occurring.

Measuring emissions at the surface above an injection site is another form of direct monitoring. This might be useful if a specific pathway is suspected of leaking, but general

Monitoring choices change with time in response to the type and complexity of technical concerns

widespread increases in CO₂ emissions of a high enough concentration to indicate ‘failure’ at the surface should be detected much earlier using other techniques. Significant baseline studies would need to be done to quantify and validate the range of gas emissions from the ground as a natural phenomenon based on biological processes having nothing to do with CO₂ storage.

Apart from data obtained from injection wells in the storage formation and observation wells above or around the containment system, techniques using direct measurement of the position of the injected CO₂ in the

subsurface will be used with discretion and even with reluctance. The methodology of choice will be to use multiple indirect measurement techniques, compare the results and minimize their technical uncertainty. Carrying out an approach of this type is something which the oil and gas industry considers routine.

Indirect monitoring tools and techniques

Most monitoring is accomplished by repeated indirect measurements. The major tools for indirect monitoring are geophysical, and include applications of seismic data, gravity, and even electromagnetics. Surface tiltmeters and satellite-derived surface elevation data are especially useful for land based storage systems as opposed to offshore sites.

3.3 Models for performance monitoring

Monitoring techniques are dynamic and normally specific monitoring choices change with time in response to the type and complexity of technical concerns. To understand monitoring techniques it helps to consider the underlying model and evaluate how it is being tested.

Everyone understands that we simply cannot directly observe what is going on kilometers below the earth’s surface. The best we can do is access isolated points and take measurements. Geoscientists and engineers address this reality by creating elaborate 3-D computer models that serve as proxies for visualization of what cannot be seen. These models bring to bear enormous amounts of data on the distribution of subsurface properties with mathematical simulations of the flow behavior of fluids and gases, chemical reactions and rock mechanics. Robust models are verified by monitoring techniques, and frequently the models are improved based on rigorous analysis of performance. Models, therefore, mature with input from monitoring.

Subsurface models for fields that have been aggressively monitored and studied for 5-10 years of operations tend to be highly reliable, and subtle performance features can be discerned that were not initially possible. The range of outcomes is rationally limited. Monitoring provides the basis for developing high confidence so that operators can understand what is going on in the subsurface. Some monitoring techniques can provide direct data about a situation, such as an observation well where CO₂ presence could be confirmed and quantified at a particular point, but the data is more valuable when it is understood in the context of a model.

3.4 Limits of measurement and concern

It is important to recall that CO₂ forms a fundamental and natural part of the biosphere and the subsurface. It is not something to fear inherently, like nuclear waste. It is something we breathe. The goal is to significantly slow emissions to the atmosphere, not eliminate them. With even the most advanced monitoring techniques we cannot possibly know the absolute position, concentration, phase, mobility, and migration path of every CO₂ molecule a kilometer below the surface. We will be challenged to know the low concentration parts on the edges of a plume. Fortunately, we do not need to know everything to be safe. Most of us do not give a second thought to the volumes of gas that are already circulating within the subsurface in natural systems. As we illustrate with examples later in this chapter, it is quite common for CO₂ to be part of underground hydrocarbon systems.

Another reality to consider is that geophysical techniques to view the situation are especially challenged beneath some of the best containment systems on the planet—such as thick salt layers. This raises the question of whether people feel more comfortable storing CO₂ in more perfect, “leak-proof” containers that are more difficult to monitor, or if they will prefer to “observe” it carefully in a container that might be less perfect but more transparent.

3.5 Monitoring tools and techniques

Applications of down-hole techniques - pressure

There are a multitude of measurement tools used to verify the operational characteristics of well systems and some are considered in Chapter 2. Here we consider monitoring of the reservoir, reservoir compartments and the larger storage system and we begin with the most important, key aspects of pressure measurement techniques.

Pressure monitoring is a standard practice of field management and it will certainly be a key aspect of monitoring CO₂ storage sites. Using pressure to verify the performance of the mechanical systems of a well was described in Chapter 2. Pressure is also used to monitor reservoir performance and to better understand the detailed connectivity of flow systems in the subsurface. For decades the standard practice has been to insert down-hole gauges that sample or measure well pressure at some programmed time interval over weeks or months and analyzed at a later date when the gauges are pulled out of the well. Sometimes, multiple

gauges are employed for repeatability or to capture data at a different sampling rate. In more recent years, with advanced completion techniques, some wells have been outfitted with sensors that continuously measure pressure at a given point, and when linked to the surface (using, for instance, fiber-optic cables) they can provide real time instantaneous data. However, in some cases, the physical existence of fiber-optic cables can cause unwanted complications for well maintenance and interventions.

For CO₂ storage wells, it seems plausible to imagine fixed, permanent pressure sensors in otherwise completely shut-in observation wells in order to minimize re-entering the reservoir. From time to time, instead of measuring passive or static pressure changes, a specific test is designed, known as a Pressure Transient Test (PTA). The idea is to create a pressure pulse by injecting a fluid (water, supercritical CO₂) originating from one or more wells and then to measure the pressure response as that pressure pulse moves out to more distant wells. As a pressure transient test is carried out by design, it is usually contrived to test some specific parameters or flow paths, and can be done in a way to evaluate a large portion of reservoir. Gauges are considered reliable to about 0.01 psi. Pressure data, especially transient tests, can be incorporated into reservoir models to improve the quality of the model.

Applications of industry seismic imaging techniques

Seismic imaging serves as the workhorse of the petroleum industry for establishing subsurface relationships. Fundamentally, the technique uses information obtained from reflected sound waves, and its form is altered by the intrinsic properties and boundaries of the subsurface rocks. Seismic imaging has evolved into a highly-sophisticated tool that excels at revealing geometries and distributions of rock volumes, relative pressures and fluid types. It is fundamental to modern subsurface mapping of large areas, and is especially effective for highlighting lateral changes, defining large scale features including large faults and compartments, and indicating the distribution of major rock properties. It cannot, however, resolve small features.

The petroleum industry standard is 3-D seismic, which often reveals subtle relationships. 3-D volume displays or “cubes” are rendered as colorful images that non-specialists can easily see and appreciate.

Although seismic imaging is an extremely powerful tool, it is not an invincible champion and it simply cannot provide the complete answer to every subsurface question. Oil companies have plenty of experience with dry holes and

are acutely aware of the limitations of the seismic technique. Vertical resolution is inherently limited such that features less than about 10 meters thick can rarely be discerned. Spatial placement depends on a velocity model which can be less precise than desired and which will be more reliable with better subsurface data. Data processing algorithms tend to maximize preservation of information in defined bands at the expense of others, so knowing the target is helpful.

Seismic techniques depend fundamentally on the reflection of sound energy. Some rock types including salt, thick carbonates and basalts, greatly inhibit this process and render images taken below them relatively unreliable. For CO₂ storage, the sub-salt imaging challenge is especially vexing, particularly when some of the best potential geological storage sites based on top seal are in depleted gas fields below thick salt, where seismic techniques are unlikely to easily yield the size and location of CO₂ plumes.

The nature of the seismic acquisition techniques also limits the quality of seismic data. Generally, volumes obtained in marine environments are of much higher quality than volumes obtained on land over identical rock types, and this means more sophisticated and reliable algorithms can be used to extract information from the data set. Onshore, land usage patterns, vegetation, topography and even near-

surface rock types can create significant challenges for quality seismic acquisition. Economics also plays a part. Marine acquisition is far cheaper on a unit basis than land data, which will encourage its application offshore.

Recent innovations in time lapse or 4-D seismic have been shown to be an especially valuable tool for monitoring CO₂ at the Sleipner field. This type of application relies on a baseline seismic survey over an area, and then compares data from repeated acquisition over time to determine differences. Changes in elastic properties of rocks such as the distribution of fluids, stress and pressure are highlighted by the difference between repeated surveys. Such changes are exactly what would be expected for CO₂ displacing saline water in quality reservoirs such as the Utsira formation at Sleipner. However, if CO₂ were to displace gas, the technique would probably be much less sensitive. Likewise deep, low-porosity reservoirs would only show subtle and probably undetectable responses to changes in elastic properties.

Recent innovations in time lapse or 4-D seismic have been shown to be an especially valuable tool for monitoring CO₂ at the Sleipner field

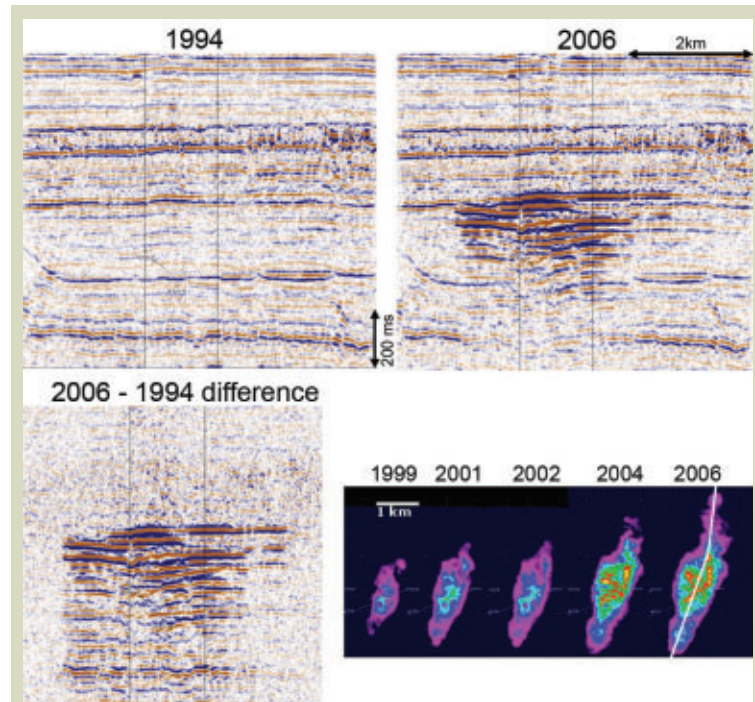


Figure 3.1: Seismic monitoring of CO₂ injection at Sleipner: showing (a) the pre-injection seismic from 1994, (b) the corresponding 2006 image, (c) the time-lapse difference image and (d) the evolving plume as seen in amplitude maps. 8.4 million tons of CO₂ have been injected in period 1996-2006.

From a practical point of view, 4-D time lapse seismic monitoring when used over an extended time period can be costly and requires considerable oversight. Onshore it can conflict with land use priorities and be restricted from certain locations. Its use, therefore, should be judicious, where clear need and purpose dictate; done in the context of its expected contribution to the monitoring strategy of a storage site

Gravity surveys for CO₂ detection

Gravity measurements reveal changes in density for a calculated vertical column of rock. In the case of CO₂ monitoring, careful gravity measurements will detect where CO₂ displaces saline brine in a subsurface reservoir because that displacement will lower the average column density. The more CO₂ that flows into a given rock volume, the greater the density contrast and the easier it will be to detect. Therefore gravity techniques are more effective detecting CO₂ movements in reservoirs with higher porosity and greater thickness. Also, these techniques are more effective for shallow reservoirs.

As a notional rule of thumb, CO₂ filled reservoirs, with less than 10% porosity, thicknesses of less than 10 meters and depths greater than 2,500 meters will be very difficult to resolve even with the best gravity data and mathematical inversion techniques.

Computational modeling tools exist to predict the expected gravity response for the vast majority of situations and these models are most reliable when they start with high-quality information about the subsurface. It is standard practice to evaluate the utility of the technique before committing to acquire data and apply it.

For gravity surveys to be useful for CO₂ monitoring programs the data needs to be very precisely and carefully obtained. The change in gravity signal for even large gas fields tends to be in the 50-100 micro-gal range which is so small that it is close to the reliability limits of instruments. Currently available standard gravimeters are capable of making repeat measurements valid to about 5 micro-gals. Fixed sea-floor gravimeters are essentially capable of the same.¹

Corrections for motion are required for gravity data acquired from airplanes, boats and floating streamers. For many applications this still leaves plenty of room to discern variations in gravity signal. However, for CO₂ applications the corrections for motion are greater than the range of the measured gravity signal, so especially for detecting lower saturations, the quality of data required can normally be obtained only by fixed systems. A change of only 1 cm of elevation will yield a difference of 3 micro-gals. Studies of oil fields have found that fixed permanent surface gravity monuments (i.e. stations) are essential to maximize repeatability. In some very special cases, high resolution gravimeters have been deployed in boreholes and have been proven to be sensitive enough to respond to changes in CO₂ saturation.

The highest quality gravity data comes from absolute gravimeters, which allow the calculation of absolute gravity and eliminate the need for referencing a base station or making adjustments for variable effects like tidal corrections and elevation corrections relative to a perfect geoid. Absolute gravimeters work by repeatedly dropping a mass about 10 cm, and use an optical laser interferometer to measure acceleration about 1,000 times in 20 minutes. Theoretically these instruments have a repeatability of <2 micro-gals. Oil field applications have found them very good at 5 micro-gals.^{2,3} Currently, the instruments are limited to land based applications.

Gravity techniques require special technical conditions to distinguish injected CO₂ from residual natural gas in depleted gas fields because the density of the residual gas

does not have sufficient contrast with the density of CO₂. However, gravity is much more likely to be useful for detecting CO₂ movement beyond the limits of the gas field, laterally into a saline formation.

Satellite techniques for CO₂: InSAR

InSAR is the current state-of-the-art, satellite platform, radar based technique to measure vertical ground elevations and relative elevation changes with time. It exploits the change in phase of returned microwave energy caused by vertical distance change⁴ and provides excellent data for mapping surface deformation changes over time.⁵ Validation studies have shown that uplifts of 1-3 mm can be reliably and repeatedly measured when sites make use of special corner reflectors for calibration purposes.⁶ A number of groups have made detailed studies of ground uplift or subsidence with oil production. Learnings suggest that changes in vegetation, especially seasonal growth, need to be carefully factored into design of the survey.⁷ The In Salah partnership has made effective use of this technique to monitor CO₂ injection in the desert of Algeria (See In Salah case study). Surface tiltmeters can provide even more precision, and arrays of tiltmeters may be very useful over modest sized areas but the logistical practicality needs to be evaluated in every case.

Perhaps the crucial matter to consider with this monitoring technique is what quantity of CO₂ injection would cause a relative uplift of more than a millimeter, especially over a wide area. The answer to that will depend on the characteristics of the overburden, which is the rock units overlying the storage site. In some basins it may be desirable to perform specific controlled injection tests to determine the range of response and calibrate the utility of monitoring techniques like InSAR beyond the normal computational predictions.

3.6 Examples of monitoring techniques in action

Monitoring is a major part of long-term field management. What follows is a collection of examples from hydrocarbon production where more advanced techniques of monitoring have proved their value to observe and manage highly complex situations. The examples have been chosen to show the range and diversity of the techniques and how they precisely target issues. It includes six producing fields and one natural gas storage field which provides a good operational analogue for CO₂ storage. It includes some geological context for the fields, a description of the monitoring techniques that were used and illustrations of how different techniques are adapted depending on the type and depth of reservoir and overall size.

CASE STUDY

The In Salah CO₂ Storage project, Krechba, Algeria

- Storage of CO₂ from natural gas separation.
- Saline reservoir down dip of producing interval.
- Major test site for a wide variety of CO₂ monitoring techniques.
- InSAR highly valuable when integrated with 3-D seismic volume.

The In Salah project in Algeria is an industrial-scale CO₂ storage project, operated as a Joint Venture comprising BP, Sonatrach and StatoilHydro. Since 2004, natural gas has been produced from three fields (Krechba, Teg and Reg) with a CO₂ content of 5-10%. In order to meet the sales gas export specification of 0.3% CO₂ the difference must be separated from the natural gas. Rather than venting it to the atmosphere, the Joint Venture invested an incremental \$100 million to enable facilities that compress, dehydrate, transport and inject the CO₂ into a deep saline formation downdip of the producing gas horizon. Currently up to one million tons of CO₂ are annually injected via three fit-for-purpose horizontal wells. Over the life of the project, 17 million tons of CO₂ is expected to be re-injected and stored at Krechba. The European Union recognizes the

project as one of three global industrial-scale sites for the development of technologies and techniques for monitoring and verifying the long-term safe storage of CO₂ in the subsurface.

The CO₂ is injected *Up to one million tons of CO₂ are annually injected via three fit-for-purpose horizontal wells*

and stored within a 20 meter thick Carboniferous sandstone interval about 1,850 meters below ground which has fair porosity (13-20%), and relatively low permeability (around 10mD). The injection reservoir is directly overlain by 950 meters of Carboniferous mudstones which are also the regional seal of the petroleum system. The mudstones are unconformably overlain by approximately 900 meters of a mixed Cretaceous age sequence of sandstone and minor mudstones (Figure 3.2) which includes the regional potable aquifer. Surface outcrop consists mostly of Cretaceous carbonates. On the surface, the strata appear to be flat lying with little visible structural disturbance though some surface lineaments are apparent from aerial photographs, possibly suggesting deeper rooted structural faulting or fracturing.

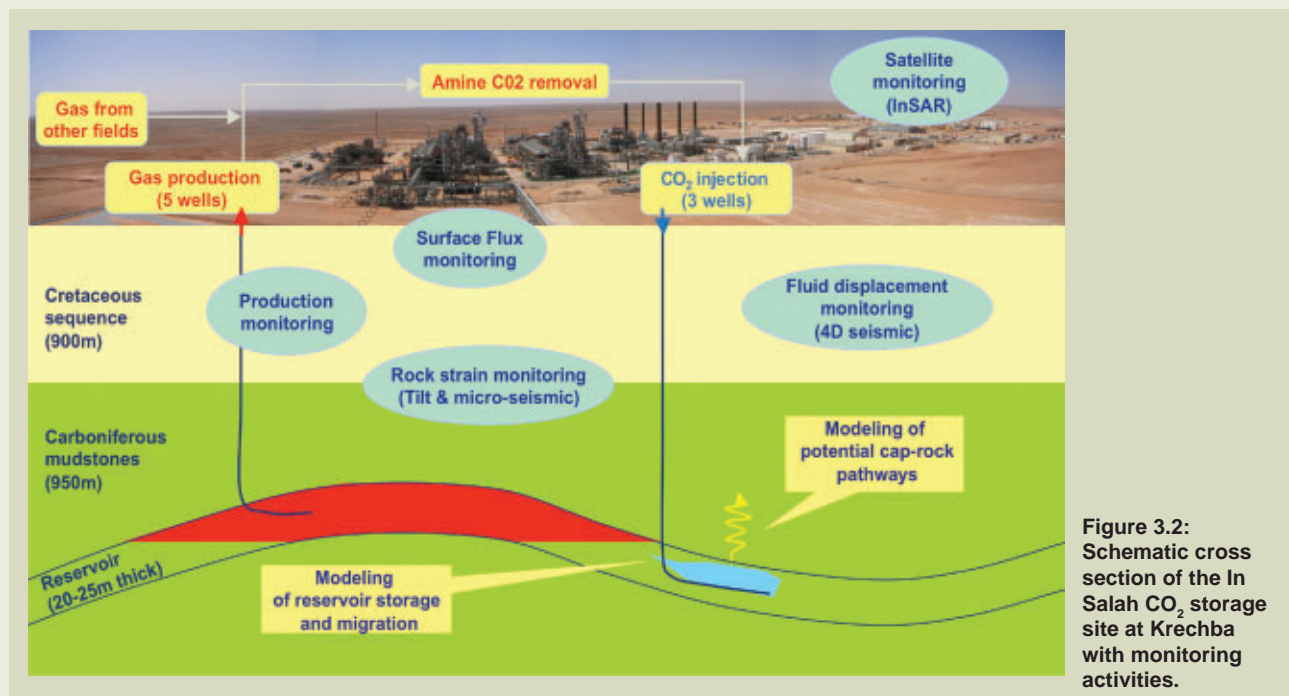


Figure 3.2: Schematic cross section of the In Salah CO₂ storage site at Krechba with monitoring activities.

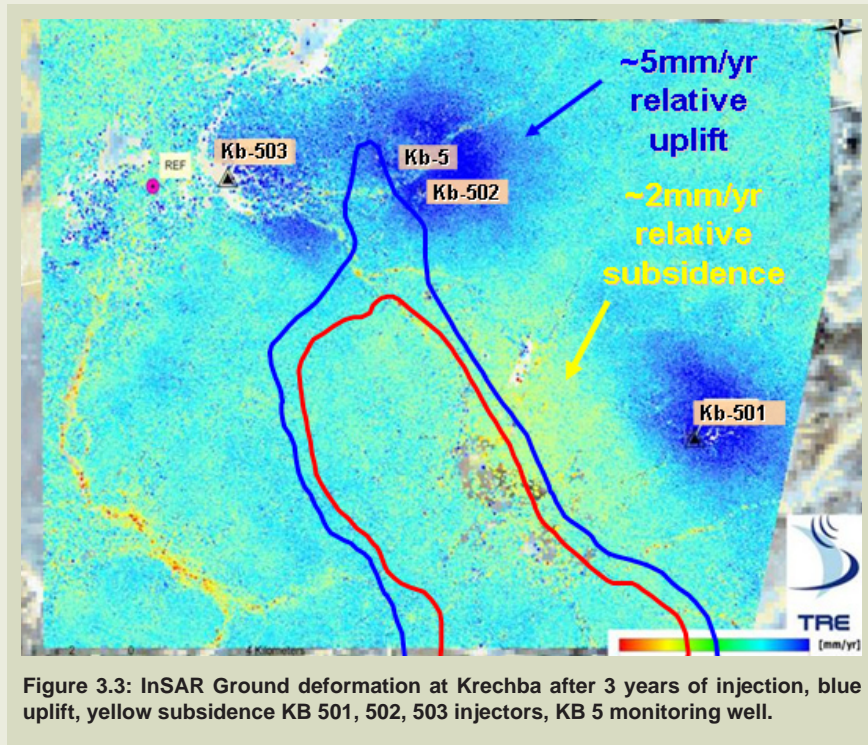


Figure 3.3: InSAR Ground deformation at Krechba after 3 years of injection, blue uplift, yellow subsidence KB 501, 502, 503 injectors, KB 5 monitoring well.

A Joint Industry Project was formed in 2004 to evaluate the suitability and efficiency of selected monitoring technologies that might be intensely applied for a short term (< 10 years) to establish confidence that the storage system should perform for very long periods of time (>1,000 years). Many exploration and production technologies were screened for scientific performance criteria and their probability of success given site specific impacts such as remote location, logistics, environment and security. The resulting list of techniques includes tracers, satellite imagery, wellhead pressure, annulus and soil gas sampling and surface flux monitoring programs that were adopted early in the project.

Plans are now underway to utilize in place micro-seismic detectors, gravity measurements and tiltmeters with GPS. Equally important has been the acquisition of reservoir and overburden geochemical and geomechanical data for input to dynamic models of plume evolution and behavior.

The pre injection 3-D seismic survey was acquired in 1997 and the acquisition parameters were focused principally on the deeper reservoir sections. The 1997 3-D has proved valuable for mapping lateral variations in reservoir quality. Reprocessing in 2006 reduced noise and sharpened the image of the immediate overburden. There is no evidence of major faulting within the thick shale section.

Plans are now in place to acquire a repeat 3D seismic survey over the northern part of the field during 2009. The repeat survey will provide improved imaging of the reservoir and overburden, by using tighter receiver spacing, whilst also giving time-lapse imaging of fluid displacements, by using the same source lines as the 1997 survey.

Satellite image data (InSAR) acquired since injection started in August 2004 has been interpreted to show surface deformation around the injectors of around 5 mm/year⁸ (in blue on Figure 3.3), while the production area has shown subsidence of around 2-3 mm/year (yellowish areas on Figure 3.3).

Integration of the data from 3-D seismic cubes with the InSAR analysis suggests that very deep geological structures at Krechba, especially faults below the reservoir, may have influenced the subsequent development of fracture swarms oriented NW-SE along the east and possibly along the west flanks of the field. Other information such as tracers and well head fluid samples and pressure data also confirm this interpretation. These data are now being incorporated into detailed overburden models, incorporating discrete fracture networks, for long-term modeling of expected plume behavior.⁹

CASE STUDY

Vacuum Field, Permian Basin, New Mexico, USA

- **Classic hydrocarbon production area.**
- **Old and new well bores.**
- **Tertiary recovery-water alternating CO₂ gas injection.**
- **Advanced seismic techniques identify CO₂ location after injection.**

The Vacuum Field is located 20 miles west of the city of Hobbs, New Mexico on the northern shelf of the hydrocarbon rich Permian Basin. The field was discovered in 1929 and has estimated reserves of 550 million barrels of oil. Geometrically it consists of a dip closure and pinchout within a faulted anticline that overlies a Lower Permian reef trend. Most production comes from the upper San Andres carbonate formation at about 4,300 to 4,800 feet (1,500 meters). This formation is laterally discontinuous capped by low permeability anhydrites. The reservoir porosity is between 5-20% with permeability of 5-100mD but with some intervals exceeding 350mD. Vertical and lateral connectivity is poor due to faulting and lateral changes in formation properties.

Like many older fields, various production strategies have been employed at different times; and the field has a dense pattern of well penetrations. In the 1990s, a water alternating gas (WAG) tertiary recovery process, using CO₂ as a miscible injectant, was instituted and extended across the field. Interestingly, most of the wells did not even exhibit CO₂ breakthrough (arrival at producing wells) except in the more geologically heterogeneous areas (highly fractured and displaced rocks).

Most commonly-used 3-D seismic techniques provide excellent insight into the geometry of structural and stratigraphic components in the subsurface. However, for some subsurface formations, and under certain conditions, a great deal more information can be obtained using multi-component seismic acquisition and processing methods.¹⁰ Multi-component surveys are more sensitive to subtle changes in fluid properties such as those associated with flow around fractures and especially changes associated with pore pressure. Knowledge of this behavior can be exploited to map relative fluid pressure, fluid flow and

stress effects caused by injection. The Vacuum field study provided additional insight into the subsurface gained by repeated application of the multi-component seismic surveys acquired before and after the injection of CO₂. This study demonstrated a practical verification of the value of the technique. It was expected that a number of dynamic changes to the reservoir properties would occur as a result of CO₂ injection. Reservoir pressure increased, which locally lowered the effective stress; fluid properties were altered and reservoir fluids became segregated, forming different areas of varying fluid composition and properties. It was also observed that fractures within the reservoir significantly affected the fluid flow processes. The study was considered a success and offered interpretative data on the evolution of pressure and flow around fractures in the subsurface.

The Vacuum field study provided insight into the subsurface by repeated application of the multi-component seismic surveys

For example, near injector wells, CO₂ imparts higher pressure and locally exhibits greater density than oil saturated conditions. The higher fluid pressure environment opens up the crack-like pore space. These effects diminish away from an injector. The net result is a variation of the state of stress in the horizontal plane, possibly with a closure of the crack-like pore space leading to higher velocity across the crack.

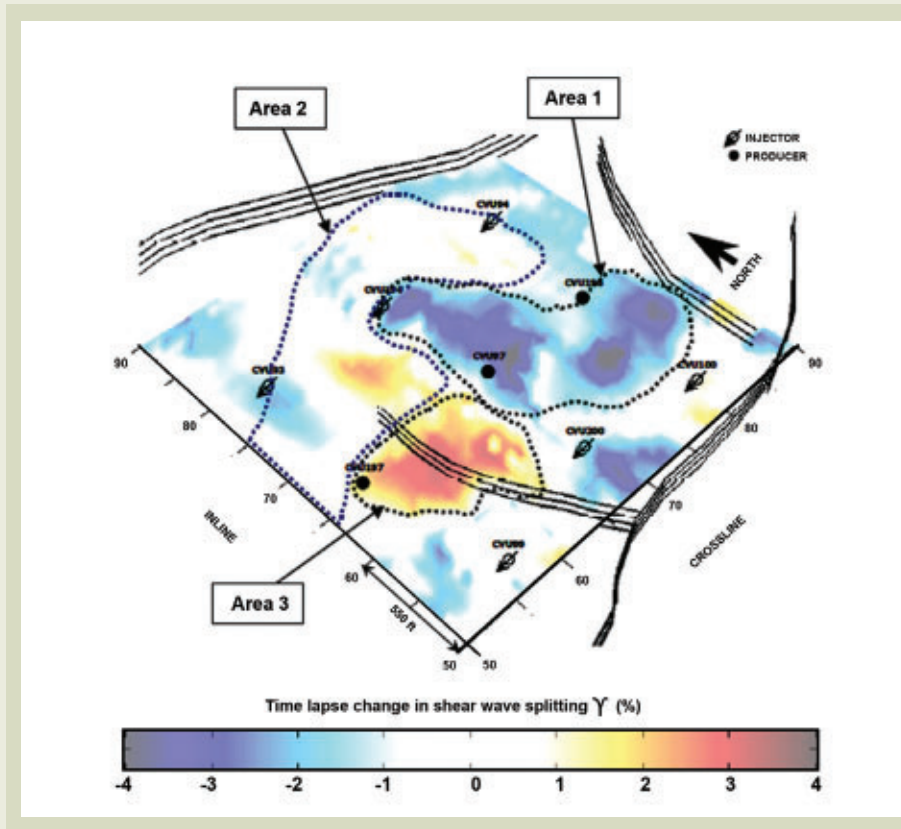


Figure 3.4: Subdivision of San Andres reservoir in three interpreted areas of comparable dynamic behavior derived from time-lapse change in shear wave splitting factor ' γ '. Black lines are faults cutting reservoir section.¹¹

CASE STUDY

Kuparuk Field, North Slope, Alaska, USA

- **Large highly faulted and fractured field.**
- **Successful water alternating gas (WAG) injection to enhance production.**
- **4-D Time lapse seismic demonstrates fault transmissivity and pressure conditions.**

Located 40 miles west of Prudhoe Bay on the North Slope of Alaska, the Kuparuk River Field, discovered in 1969, is the second-largest onshore producing oil field in the United States. Production began in late 1981 and, as of 2006, the field has produced more than 2 billion barrels of oil and has remaining reserves of about 800 million barrels of oil and 1 trillion cubic feet of natural gas.¹² The main producing formation contains 24° API oil and is around 6,000 feet deep. The field is highly faulted and compartmentalized. About 2,000 directional and horizontal wells have been drilled in the field.

The producing interval is comprised of a sequence of clastic sediments deposited on a shallow marine shelf during Early Cretaceous time. As shown in Figure 3.5, the reservoir is divided into Upper (units D and C) and Lower (units

B and A) stratigraphic units which are separated by an area-wide unconformity. Porosity and permeability average 21% and 90 mD, respectively.

In developing the Kuparuk field, a mixture of recovery mechanisms have been used. As the field has been produced, oil is separated from natural gas and water. Produced water, supplemented with seawater has been injected across the field since the 1980s as a secondary recovery mechanism. The natural gas is either used for fuel or mixed with enriching components then compressed and re-injected along with water to enhance oil recovery. This water alternating gas (WAG) recovery strategy has been implemented across much of the field.

This experience provides an excellent analogue for developing technology, procedures and techniques applicable to CO₂ injection processes.

3-D surface seismic surveys have been used to delineate reservoir geology and, more recently, monitor the performance of the water-flood and re-injected gas. Monitoring, or 4-D time-lapse surveying, is accomplished by comparing

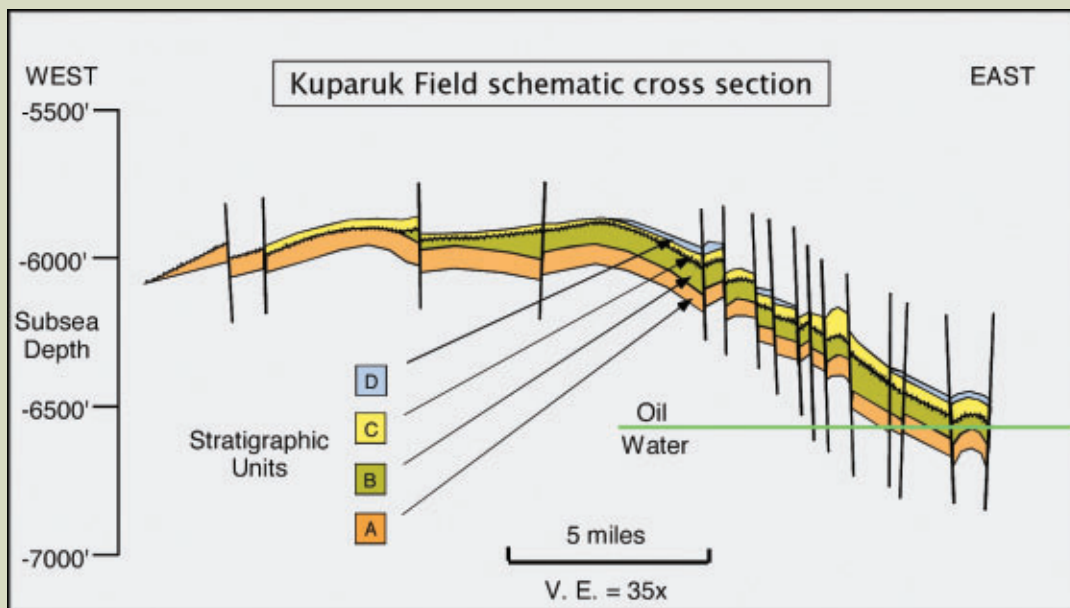


Figure 3.5: Schematic structural cross section Kuparuk River Formation. The oil water contact is indicated by the green line on the right of the figure. 500ft intervals are about 150m, -6000ft ≈ -1830m, -6500ft ≈ -1980m.

the latest 3-D survey with either a baseline or previous monitor surveys.

Figure 3.6 shows Top Kuparuk horizon from a sector of the field with faults indicated in the black lines.¹³ The colors come from the seismic amplitude at the producing unit. Negative amplitudes, reds and yellows, indicate increase in pressure or increase in fluid compressibility and generally correspond to injector locations. Gas injection, in this case mostly methane gas from the reservoir, increases the compressibility of the fluid phase and leads towards brighter amplitudes. Blues and purples indicate reduction in pressure and correspond to producer locations.

This image illustrates that 4-D seismic data can be used to infer variations in fluid pressure and determine where faults provide an effective lateral seal and where they do not. Used in a multi-disciplinary approach, the 4-D seismic data can be employed to better understand production results and predict future performance.

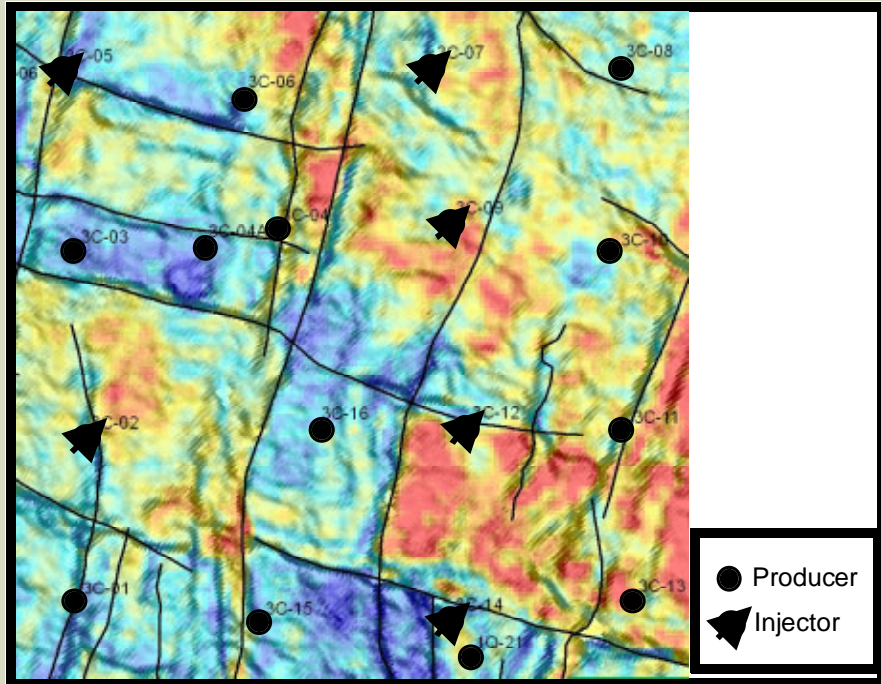


Figure 3.6: Seismic horizon of the Top Kuparuk. Faults are outlined in black lines and colors indicate pressure changes – red for higher pressure and blue for lower pressure.



Figure 3.7: Surface facilities at Kuparuk Field, Alaska.

CASE STUDY

Prudhoe Bay Field, Alaska, USA

- **North America's largest field.**
- **Enormous volumes of re-injected gas, including CO₂.**
- **Successful surface gravity monitoring of water injection into gas.**

Prudhoe Bay Field, located 650 miles north of Anchorage and 400 miles north of Fairbanks Alaska, is the largest oil field in North America and is among the 20 largest in the world. At the end of 2007, it had produced more than 11 billion barrels of oil. The field is especially significant as an operational analogy for CO₂ injection. In order to maintain reservoir pressure to facilitate production and preserve the associated natural gas for eventual sale, the “gas-cap” has been reinjected into the reservoir since start-up of production. Cumulative gas recycling exceeds the original gas in place by about a factor of two. To date, almost 49 TCF of gas has been reinjected, which is about 12 % CO₂ by volume.

The field was discovered in 1968. With the completion of the Trans Alaskan Pipeline in 1977, regular production began, peaked ten years later, and since then has been declining at an average rate of about 8% per year. The field, however, still contains estimated reserves of about 2.2 billion barrels of oil and 23 trillion cubic feet of associated and non-associated natural gas.¹²

The main Prudhoe Bay oil pool is comprised of three Triassic-aged units at an average depth of 9,000 feet (≈ 2750m) collectively known as the Ivishak sandstone. The upper most unit, the Sadlerochit formation, consists of sandstone and conglomerate; the middle unit, the Shublik consists of organic-and phosphate-rich sandstone, muddy sandstone, mudstone, silty limestone and limestone; the lower most unit, the Sag River formation is a sandstone. The assemblage is overlain by shale and mudstone of the Kingak formation. The oil has an API gravity of 27° degrees and in initial gas-oil-ratio of 780 scf/bbl. Porosity ranges from 18 to 28% and permeability averages 450 mD.

In order to maintain reservoir pressure, in the late 1990s a water injection program was started, with injection directly into the gas cap. In 2002, a program to monitor the injected water using both high quality standard and absolute gravimeters was initiated. Although gravity monitoring has lower spatial resolution than seismic methods, it can give fairly accurate estimates of the changes in subsurface density and thus allow mapping of the current position of injected water.

In 2002 and 2003, baseline surveys were obtained for both absolute and relative gravity. From 2005, yearly monitoring measurements were made to estimate the time-varying density changes in the subsurface.

Figure 3.9 shows three time intervals from the 2002 baseline, where the pink to red color indicates the highest mass and blue the background value. These maps indicate both the actual mass density and the movement of the injected water.

Although the water injection into the gas cap is the opposite of CO₂ injection into a saline reservoir, or depleted reservoir, the important concept is that non-invasive monitoring techniques like gravity have the potential to be very discerning to map subsurface CO₂ plumes.

The field is especially significant as an operational analogy for CO₂ injection

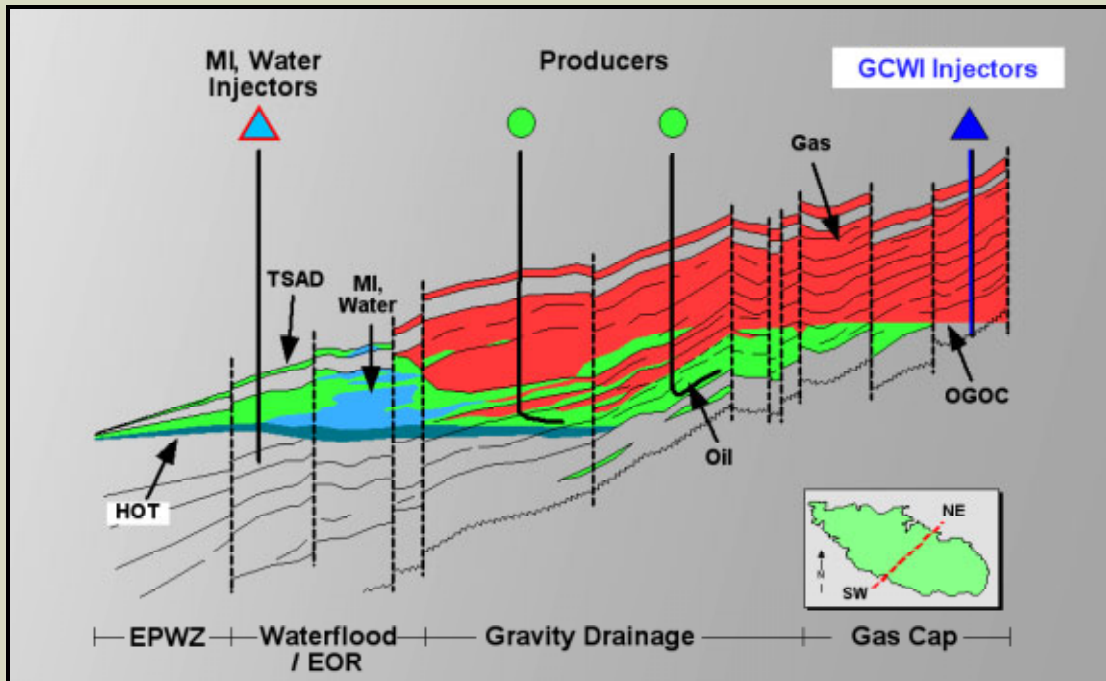


Figure 3.8: Schematic cross-section of the gas cap at Prudhoe Bay Field, Alaska. Abbreviations used: MI = Miscible Injectant; OGOC = Oil Gas Oil Contract.

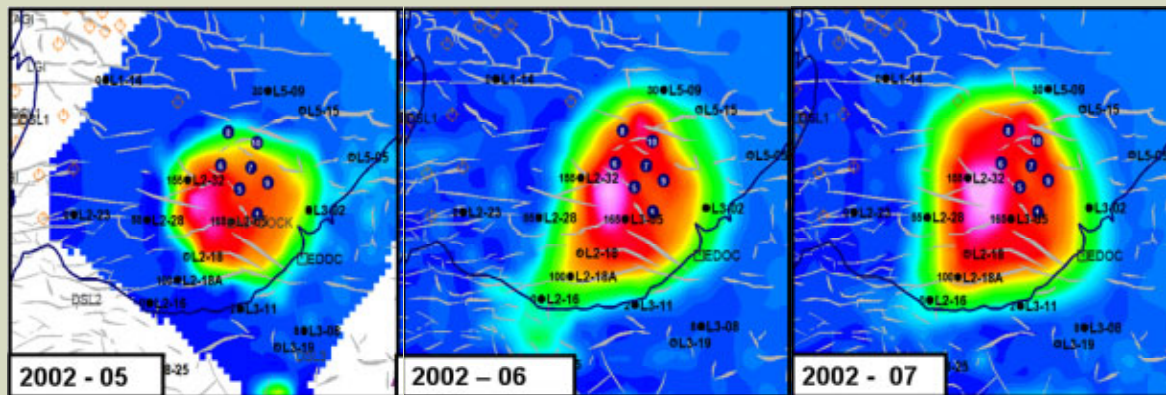


Figure 3.9: Monitoring water injection into gas cap with gravity techniques. Inversion Mass Models (Total Mass) Intervals 2002-05, 2002-06 and 2002-07, the coastline and injection wells are indicated.

CASE STUDY

Pinedale Field, Wyoming, USA

- **Advanced monitoring to enable gas production.**
- **Integration of stress field data with development plan.**
- **Micro-seismic monitoring technology for fracture analysis.**

Located in the Upper Green River Valley of west central Wyoming, the Pinedale Anticline field and other nearby fields hold substantial potential for natural gas production. Today, more than 200 wells have been drilled and production exceeds 500 mmcfpd of natural gas. At a depth of about 4,000 meters, these Upper Cretaceous age producing formations are comprised of up to 1,800 meters of fluvial sandstones, siltstones and shale. While first discovered in 1939, it was only in the mid-to-late 1990s that hydraulic fracturing technology enabled these tight-gas wells to be stimulated and produced economically. The key to a successful project in this area is to understand the distribution and concentration of natural gas and how it changes with time. To accomplish this, a combination of reservoir monitoring techniques was used; techniques that could be adapted to other gases like CO₂.

Data acquisition efforts began with special core analysis and advanced well logging. On the geophysical side, reprocessing of seismic data was carried out along with studies of the natural fractures and outcrops to better understand the underlying stress field. This data was supplemented with drilling a horizontal well to interrogate the natural fracture network. An external casing and perforating technique, in which perforating guns are run external to the casing and the firing heads are actuated hydraulically, was used for both perforating and reservoir monitoring. The technology for completing wells resulted in a successful areal 4-D pressure monitoring which were used to determine well spacing and drainage patterns.

Additionally, micro-seismic diagnostic monitoring technology was used to reveal the direction and length of hydraulic fractures to better understand fracture effectiveness and drainage area.

The asset team used these reservoir monitoring technologies, combined with production data analysis and periodic production logs, to develop models that show the location, movement, and gas concentration/pressure changes in the formations.



Figure 3.10: Surface facilities for monitoring down-hole pressure and temperature.

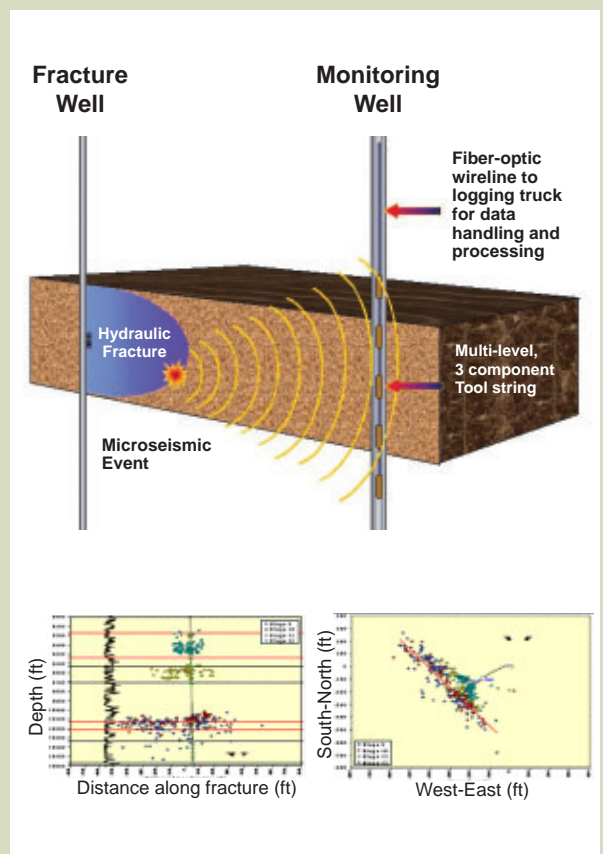


Figure 3.11. Micro-seismic field layout and data.

CASE STUDY

Peace River, North Western Alberta, Canada

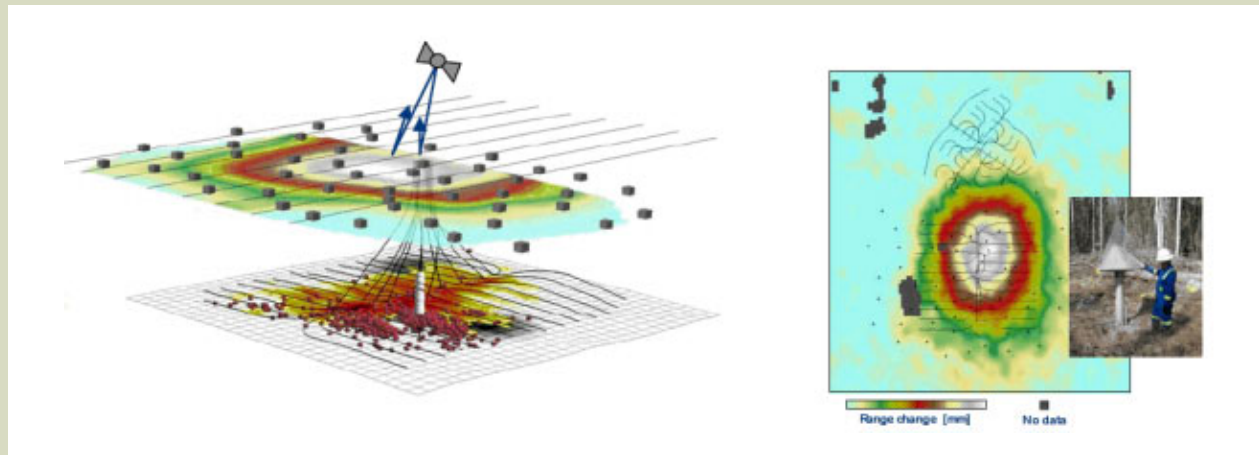


Figure 3.12: Down-hole micro-seismic measurements and surface tiltmeter configurations and data overlays.

- **Heavy Oil Production.**
- **Monitor injected fluids with temperature and pressure.**
- **Microseismic, 3-D VSP and 4-D seismic.**
- **Surface tiltmeters very effective to resolve reservoir geology.**

Operations near Peace River in North Western Alberta use specially configured wells to extract bitumen (lower Cretaceous heavy, viscous oil) that is too deep for surface mining. The oil deposits are trapped in a 30 meter thick semi-consolidated sand layer buried at a depth of about 600 meters. In-situ heating is used to enable the highly viscous oil to flow. Current production strategy is to use multi-lateral horizontal wells to steam the bitumen-saturated units and to then use the same wells to produce mobilized oil.

The production of any reservoir results in physical property changes within the reservoir - this is particularly true for heavy oil production where injection of heated fluids imparts changes in both pressure and temperature. Reservoir pressures and temperatures repeatedly increase and decrease during the production cycle. Monitoring these changes provides a reliable means to track the location and concentration of hydrocarbons and the injected fluids.

At the Peace River site both micro-seismic and tiltmeter monitoring programs were conducted from late 2002 until

mid 2004. The areal extent and volumes of the injected steam can be traced using tiltmeter data. Volume changes induced within the reservoir can cause uplift of the earth's surface some 600 meters above. The total increase in reservoir pore volume detected by the tiltmeter array is equal to the total metered volume of cold water injected as steam into the reservoir. Based on the data and interpreted results, it was found that steam injection can be a highly heterogeneous process leading to uneven distribution of heat in the reservoir and poor recovery of the bitumen.

To further facilitate monitoring steam conformity and reservoir processes, an extensive seismic monitoring program was conducted over the development area. Time-lapse swaths, 3-D VSP and 4-D seismic programs were used at several of the producing pads to monitor steam conformance. This was supplemented by information from permanent downhole arrays for micro-seismic monitoring and surface tiltmeter arrays.

Monitoring movement of reservoir fluid volumes during cyclic steam stimulation and continuous, long-term monitoring of cumulative reservoir volume changes has been achieved using a surface array of precision tiltmeters. The resulting areal distribution of volume changes inside the reservoir is heterogeneous and exposes previously unrecognizable geological features.

CASE STUDY

Underground Storage of Natural Gas – A model for CO₂ storage operations and monitoring

- **Large scale analogue to CO₂ storage systems.**
- **Depleted gas fields easily monitored with advanced technologies and field knowledge.**
- **Operational pressures commonly exceed pressure of original gas-in-place.**

The underground storage of natural gas (NG) is an important part of managing reliable supply for regional gas distribution systems. For this reason underground storage sites are widespread in Europe and North America, and most make use of old depleted fields. The underground storage business offers excellent analogues to CO₂ storage in terms of facilities and operations including extensive performance monitoring. The current Eni-Stogit system in Italy consists of eight storage fields (at depths of between 1,000 and 1,500 meters) distributed throughout Italy with available storage capacity of about 13.6 Gsm³ (480 BCF) that were all formerly NG fields. The transition from Italian gas producing to NG storage entails a comprehensive technical re-evaluation of the reservoir and facilities very similar to proposed studies for CO₂ storage.

Late life 3-D seismic surveys are acquired to provide “baseline” information about the conditions of the reservoir nearing depletion and to verify it is suitable for storage purposes. Geological data and physical parameters measured or obtained during primary reservoir production are vital to predict the performance of a storage site.

Technical controls and injection tests are carried out on available wells and this includes continuously monitoring its pressure and allowing a preliminary estimate of storage capacity. Even if the reservoir is well-understood and the seal (shale) has been proven by initial gas field pressures, more basic data has proven useful to collect. Samples of the seal are taken in new wells using mechanical coring methods and lab tests are carried out to assess the maximum gas pressure the rock can bear.

A 3-D mathematical model is constructed to predict the dynamic behavior of the field in the subsequent cyclic storage stages based on geodynamic data gathered during both the exploration-production stage and the data from the technical controls.

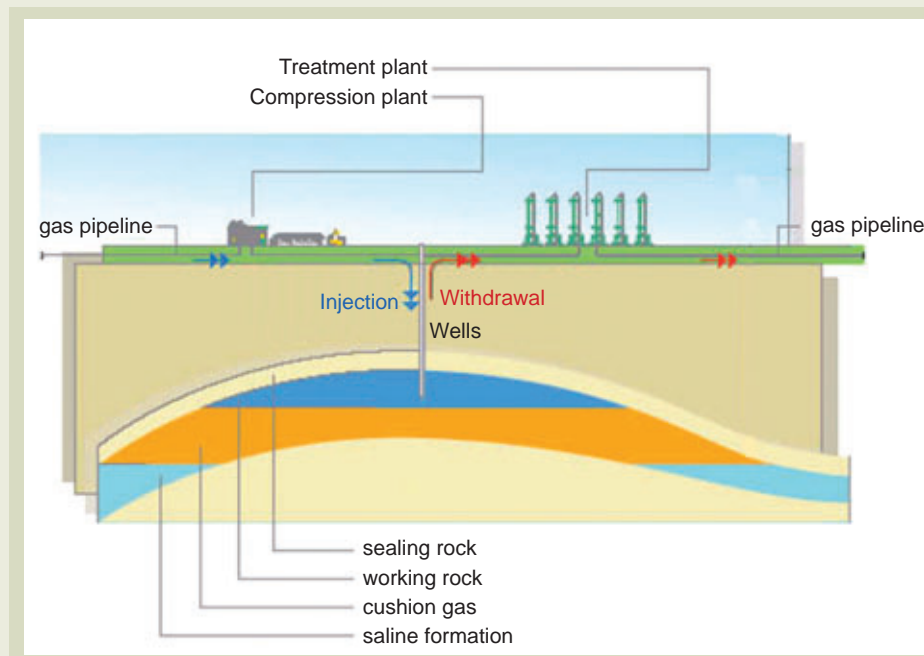


Figure 3.13: Illustration of underground storage of natural gas.

The resulting geodynamic simulation provides an estimate of the storage capacity for the maximum operating pressure and calculates the volume of gas that must remain permanently in the reservoir while it is used for storage (cushion gas) and the volume of gas that can be cyclically injected and withdrawn during the year (working gas) based on expectations of the peak daily and hourly demand. The study also provides the necessary engineering data to plan the development of the storage reservoir: new wells, the capacity requirements for the surface facilities based on production capacity, and construction of a compression station for gas injection.

Gas handling or treatment plants comprise all the systems used to make the gas withdrawn from the reservoir compliant with transmission specifications. This includes the preliminary separation of liquids (water and heavy hydrocarbons) associated with the gas and absorption of the water vapor saturated in the gas. The plants also have connection pipeline networks and other surface (process or auxiliary) facilities. Although CO₂ gas handling would precede injection, facilities to meet transmission requirements are likely to be largely similar, just in a different order.



Figure 3.14: Gas storage plant.

Natural gas arriving from the transport system for re-injection in the storage reservoirs is compressed at these plants.

Specifically, the compression plants raise pressures from a maximum pressure of approximately 75 bar in the pipeline to pressures of up to 150-180 bar using high head centrifugal compressors powered by gas turbines or reciprocating compressors powered by diesel engines or electric motors.

One of the most cost-effective ways to increase deliverability and working capacity in gas storage reservoirs is to operate at higher operating pressures. An important special case is to exceed the initial formation pressure of the original gas field (referred to as delta-pressuring).

With careful testing, operating conditions of 7% delta-pressuring were successfully achieved at the Settala Storage Field, and this corresponds to a 45% increase of storage capacity or 500 MSm³ (17 BCF). Detailed monitoring activity at the start-up and at the end of annual injection phases has been ongoing since 2002, including continuous pres-

sure data acquisitions, static pressure profiles, RST logs on monitoring wells and a time-lapse microgravimetry survey (4-D Micro-Gravity Gradient).

The monitoring management of delta-pressure combines several methods of verification and includes some high-technology surveys, which include techniques to:

- Measure cap-rock strain by means of a geophysical survey based on surface and subsurface microseismic monitoring.
- Define the possible distribution and quantify variations of gas volumes for each storage cycle in the reservoir with time-lapse microgravimetry survey and to detect the possible occurrence of gas leakage phenomena.
- Periodically assess large areas with remote sensing surveys based on geochemical and environmental analyses.
- Manage all the available information in an integrated database for the implementation of geomechanical studies and modeling.

In addition there are ongoing research and development activities for the development of new monitoring technologies based on geochemical and environmental surveys, on time-lapse microgravimetry-density and on geomechanical cap-rock studies in dedicated wells that should have applications for CO₂ monitoring.

Finally, Stogit's Cortemaggiore field will be the site for a CO₂ injection pilot project that will evaluate the possible alternative use of CO₂ as cushion gas with NG storage systems.

3.7 Concluding remarks

Monitoring the behavior of CO₂ in subsurface reservoirs for long-term storage will be an intense scientific undertaking. Operators will adapt and improve some fairly sophisticated monitoring techniques developed in the oil and gas industry. Regulators will need to appreciate fit-for-purpose designs and performance expectations. With operators and regulators working for a common purpose, it is reasonable to expect that monitoring of even very large CO₂ storage sites will be done in a highly effective manner.

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Figures

Figure 3.1: Seismic monitoring of CO₂ injection at Sleipner: showing (a) the pre-injection seismic from 1994, (b) the corresponding 2006 image, (c) the time-lapse difference image and (d) the evolving plume as seen in amplitude maps. Figure courtesy of StatoilHydro.

Figure 3.2: Schematic cross section of the In Salah CO₂ storage site at Krechba with monitoring activities. Modified from Ringrose et al, 2009.⁹ Used by permission EAGE, First Break.

Figure 3.3: InSAR Ground deformation at Krechba after 3 years of injection, blue uplift, yellow subsidence KB 501, 502, 503 injectors, KB 5 monitoring well. Figure courtesy of the In Salah CO₂ project: Sonatrach, BP and StatoilHydro.

Figure 3.4: Subdivision of San Andres reservoir in three interpreted areas of comparable dynamic behavior derived from time-lapse change in shear wave splitting factor ' γ '. Figure courtesy of L. Duranti. Based on L. Duranti, 2001 Time-lapse multicomponent seismic analysis of reservoir dynamics. PhD thesis, Colorado School of Mines. <http://www.mines.edu/academic/geophysics/rcp/theses/Duranti-2001.pdf>

Figure 3.5: Schematic structural cross section Kuparuk River Formation. Figure courtesy of ConocoPhillips.

Figure 3.6: Seismic horizon of the Top Kuparuk. Faults are outlined in black lines and colors indicate pressure changes – red for higher pressure and blue for lower pressure. Figure courtesy of ConocoPhillips.

Figure 3.7: Surface facilities at Kuparuk Field, Alaska. Figure courtesy of ConocoPhillips, Alaska

Figure 3.8: Schematic cross-section of the gas cap at Prudhoe Bay Field, Alaska. Used with permission from Alaska Department of Natural Resources, Division of Oil and Gas Annual 2007 Report.

Figure 3.9: Monitoring water injection into gas cap with gravity techniques. Figure courtesy of ConocoPhillips. Also reproduced in Brady et al., 2008.

Figure 3.10: Surface facilities for monitoring down-hole pressure and temperature. Image courtesy of Shell.

Figure 3.11: Micro-seismic field layout and data. Figure courtesy of Shell.

Figure 3.12: Down-hole micro-seismic measurements and surface tiltmeter configurations and data overlays. Figure courtesy of Shell.

Figure 3.13: Illustration of underground storage of natural gas. Figure courtesy of Eni.

Figure 3.14: Gas storage plant. Image courtesy of Eni-Stogit.

4



DEVELOPMENT, OPERATION AND CLOSURE OF CO₂ STORAGE FACILITIES

4.1 Introduction: Oil and gas field lifecycle analogy

Applying oil and gas industry practices to the development, operation and closure of CO₂ storage facilities will be a key part of the effort to manage CO₂ storage facilities successfully and prepare for the end-of-life closure and post-closure periods.

The oil and gas industry has more than a century of experience managing fields from development concepts and subsurface installations to operations and decommissioning. Economic imperatives have led to technical advances in reservoir characterization and surveillance that predict and continuously improve hydrocarbon extraction for the life of a field. Therefore, at the end of a field's productive life, a comprehensive understanding of the reservoir and subsurface behavior of fluids is available. Such reservoir management concepts and lifecycle case studies are available in the literature.¹ Widely accepted health, safety and environment (HSE) related principles for hydrocarbon field development, production and decommissioning are also available.²

Injection of CO₂ for tertiary oil recovery has become increasingly common since the first such project in West Texas in 1972. In this process (known as Enhanced Oil Recovery, or EOR) oil, water and a portion of injected CO₂ are produced, and the CO₂ is separated and re-injected. The retention of a substantial portion of injected CO₂ in the reservoir encourages the concept of offsetting the costs of CO₂ capture, transportation and storage through enhanced oil production. Although CO₂ EOR has provided a wealth of experience in CO₂ flood management, this closest industrial analog to dedicated CO₂ storage (i.e., storage 'only') differs in terms of fluid management (i.e. no production) and the ultimate disposition of the field. CO₂

EOR floods have not typically been subject to substantial monitoring by imaging, sensing or sampling. Whereas operating wells are routinely monitored for annular leakage and to gauge flood performance, plugged and abandoned (P&A) EOR wells have not been monitored. To date, there is no example of a decommissioned CO₂ EOR field, primarily because the economic limits of CO₂ production have not been reached. Should such a field undergo decommissioning in the United States, the US Underground Injection Control (UIC) Class II well P&A regulations would apply.

The characterization, development, operation and closure of CO₂ storage facilities will be similar to CO₂ EOR and other oil and gas field lifecycles, although specific details will differ. Central to this chapter's discussion of the project life cycle is the feedback loop during development and operation that enables continuous improvement in understanding and operation of a CO₂ storage project. This loop, in which operational and monitoring data inform improvements to the earth model and dynamic model, which in turn inform operational response, is common in the oil and gas industry (Figure 4.1). Appropriate application enables uncertainty management and project optimization. It leads, over the project life, to a high degree of confidence in the earth system and project outcomes. The feedback loop concept is also integral to performance-based decommissioning, implying that the closure and post-closure stages of a CO₂ storage project begin with a highly characterized system.

Guidelines or best practices for all or part of the CO₂ storage lifecycle have been proposed by a number of organizations.^{3,4} Regulatory proposals have been issued, most notably, in the United States⁵ and Europe.⁶ A number of risk assessment protocols, currently applied on a variety of industrial endeavors but adapted to CO₂ stor-

age, have been promoted in recent years.^{7,8} The purpose of the present contribution is not to summarize these works but to frame major points in the context of oil and gas exploration and production (E&P) experience and activity. The key driver for such considerations is to promote the technical and economic feasibility of CO₂ storage through rational, risk-based facility development, operation and decommissioning.

4.2 CO₂ storage project lifecycle: Project certification and uncertainty management

Project phasing and certification principles

CO₂ storage projects are functionally staged into four phases (though these may vary in detail depending on source):

- Site selection and development (appraisal, certification and construction).
- Operation (injection plus some post-injection monitoring period).
- Closure (site decommissioning*).
- Post-closure (post-decommissioning to very long term).

Relative to typical oil and gas E&P, the post-closure phase is unique to CO₂ storage. At the end of production in a typical oil or gas field, wells are plugged and abandoned pursuant to prescribed regulations. The operator generally has no further responsibility for the facility unless negligence is determined. However, as with oil and gas operations, the technical, economic and regulatory feasibility of a CO₂ storage project will rely on successful execution of the first three phases - for which we can draw fruitfully from the experience of more than a century of relevant experience.

To assess the feasibility of a CO₂ storage project, a number of widely-applied tools from the oil and gas sphere are available. Geological and geophysical workflows integrate well log, seismic, core, analog and outcrop data to develop an earth model for site characterization. Petroleum engineering software integrates dynamic data and uses the earth model to predict plume movement and trapping mechanisms under different well configurations and injection rates and volumes. Finally, widely used processes for identifying, characterizing and in some cases, quantifying containment risk are available.

* The term decommissioning can be used to refer to the entire post-operational period depending on the final details of now-emerging regulations. Generally, post-closure is the period during which an entity other than the owner-operator may continue some level of monitoring.

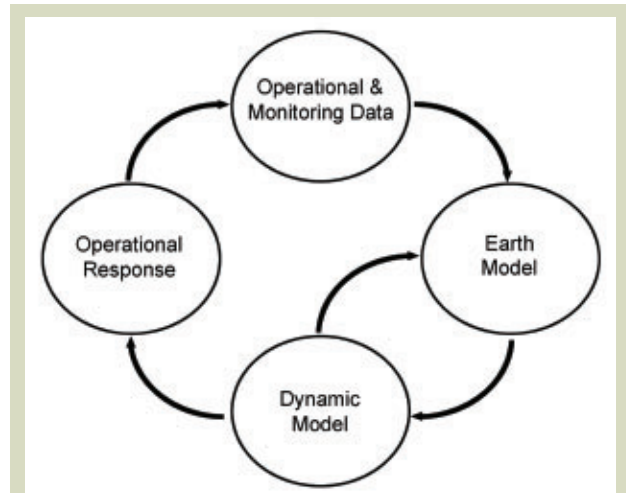


Figure 4.1: A Feedback Loop model for optimization and uncertainty management in CO₂ storage projects.

Project assessments for CO₂ storage are analogous to oil and gas E&P, with several significant differences:

- The need for the long-term containment ('permanence') of an injected fluid with complex properties.
- Oil and gas accumulations are usually restricted to defined geologic closures. In contrast, CO₂ injection into saline formations will result in a supercritical plume, with attendant fluid (brine) displacement and pressure transients that will expand from the injection site until immobilized by well-defined trapping mechanisms (permeability barriers, attenuation by capillary trapping and dissolution in water or mineralization).

The key driver is to promote the technical and economic feasibility of CO₂ storage through rational, risk-based facility development, operation and decommissioning

- Oil and gas production typically reduces hydrocarbon volume and areal extent, and thus reservoir pressure. CO₂ injection into depleted oil and gas fields essentially reverses this process, returning the system towards pre-production pressures. These types of CO₂ storage projects are closely analogous to natural gas storage facilities.⁹ In the case of CO₂ injection projects into saline formations, the pressure of the injection reservoir will increase until operation ceases, but will decrease from that point and eventually approach original pressure over decades to millennia, depending on the volume injected, the size of the storage venue and the type and rate of trapping.

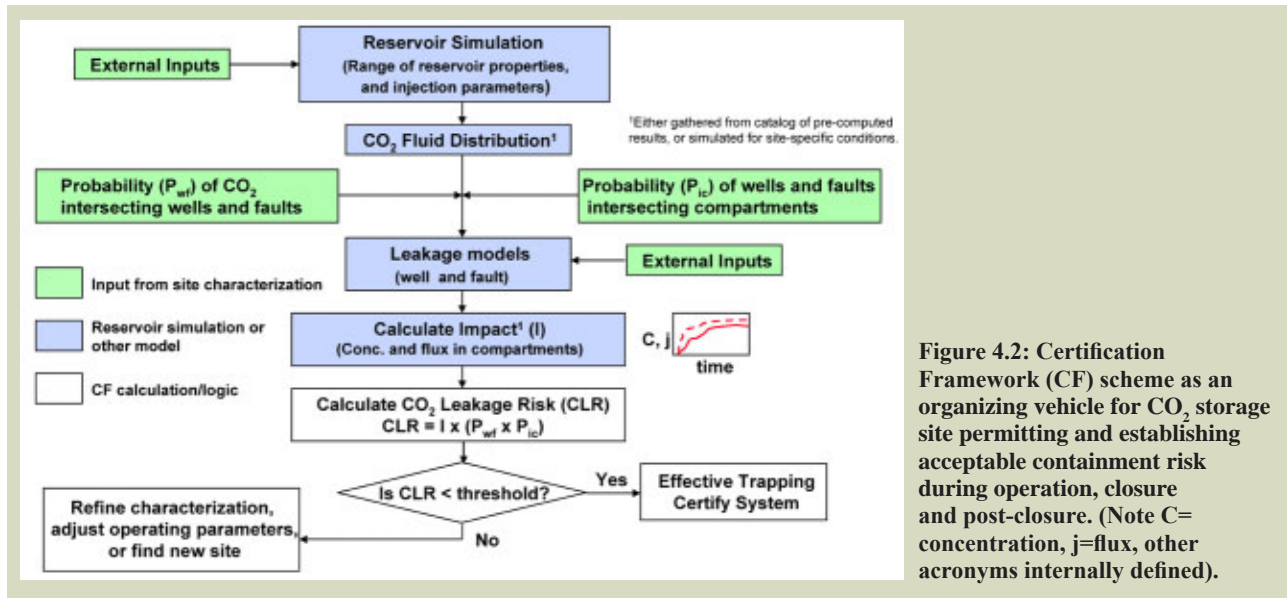


Figure 4.2: Certification Framework (CF) scheme as an organizing vehicle for CO₂ storage site permitting and establishing acceptable containment risk during operation, closure and post-closure. (Note C= concentration, j=flux, other acronyms internally defined).

Phenomena associated with CO₂ injection, such as brine displacement and transient pressure effects are considered a potential threat to containment with possible impacts on groundwater, mineral resources or the near-surface environment. These effects, and CO₂ migration, diminish once injection ceases although the length of time for injected CO₂ to stabilize will vary widely depending on specific features of the geologic system. Other phenomena such as propagation of fractures or reactivation of faults through the confining system may or may not be consequential, but again are more likely to occur during operation than after injection. The risk to containment by artificial penetrations (wells) persists in the post-injection period under certain circumstances.

These considerations call for a robust approach to assessing CO₂ storage projects. Such assessments might be organized using a “certification framework” approach (Figure 4.2). This approach integrates CO₂ storage site data into a probabilistic, risk-based framework that assesses the probability of injected CO₂ intersecting ‘features’ such as wells and faults that could pose a risk to containment. It then evaluates the risk posed by intersected features based on their character, for example, well integrity or fault orientation. The transparent communication of risk enabled by the certification framework can facilitate communication among stakeholders including operators and regulators, and serve as a foundation on which to base certification decisions for CO₂ storage projects. This approach, after first being applied during the site characterization/permitting phase, would be updated with improved data through the operational phase and in preparation for decommissioning and thus serve as a beneficial communication and decision-making tool through the life of a CO₂ storage project.

Risk assessment and uncertainty management

The volume of CO₂ that needs to be injected to achieve meaningful reductions in global GHG emissions has placed considerable attention on HSE risk assessment. Risk management has been successfully applied to numerous human endeavors, many of which present substantially higher real or potential hazard levels than are likely to arise in CO₂ storage projects. The subsurface behavior of CO₂, the very large potential scale of injection and the need for long-term containment, however, warrant robust due diligence in the area of risk and uncertainty management.

Risk is commonly defined as the product of probability and impact. The basis for risk assessment is information (e.g., characterization, monitoring or operational data) and an understanding of natural features, events and processes (FEPs) that could affect or be affected by injected CO₂. For example, one dimension of a risk assessment might focus on the risk of CO₂ migrating from the premised project area. The probability of occurrence would be estimated using data and models developed for the project. The impact of occurrence would then be estimated - for example, the volume and flux of CO₂ and its potential impact on protected resources or human health and safety. The product of numerical expressions of probability of occurrence and impact resulting from the occurrence represents the risk. Where probabilities are difficult to quantify owing to limited characterization data or the limited track record of CO₂ storage, they can be estimated from our understanding of well-known subsurface processes and industrial operational analogs.

A critical part of risk assessment is the development of actions or plans to mitigate possible, untoward events. Mitigation may be proactive or reactive, i.e., action to prevent occurrence or reduce risk, or action to remediate or limit the impact of occurrence. In the example above (of CO₂ migration from a designated project area), mitigation actions might include additional data collection to improve characterization, certification of a larger project area, or modification of the injection strategy. Risk assessment also helps to identify where unacceptable risks may be present. If such risks cannot be managed by obtaining additional data, changing injection parameters or otherwise appropriately mitigated, the project should not be pursued, or should be stopped if already in progress.

Earth and dynamic models are central to the risk assessment process. They can be used to test the rate and extent of CO₂ migration and trapping processes, under various operational conditions, relative to system features that might be affected by encountering CO₂ or its ancillary effects. The resulting scenarios identify uncertainties requiring the acquisition of additional data and tests or alternative operating schemes that minimize untoward events.

Risk assessment enables the development of an uncertainty management plan, common in oil and gas E&P, and in other industries (Figure 4.3). The uncertainty management plan is used, and kept evergreen, through the stages of a project to guide design, development and operational response. It helps to balance risk and cost, identifying the point of diminishing returns of additional data acquisition (in conjunction with the commonly used “value of information”, or VOI process).¹⁰ Appropriately applied, an uncertainty management plan can serve to reduce risk substantially, in-

form project and monitoring program design, and define contingency actions to manage unexpected events.

The overall goal of CO₂ storage project characterization and operations is to build site-specific knowledge and an experience base that will optimize flood performance, minimize risk and establish the technical basis for closure and a framework for post-closure care.

Field development and operations

Chapter 1 describes the essentials and rationale of site characterization activities and workflows for CO₂ storage projects. The database and models developed during this stage inform project development planning and execution, which in many ways will parallel oil and gas field development. With the initial development complete and the project certified, the operational phase begins. The feedback loop concept introduced in Figure 4.1 is central to a discussion of the development and operation of a CO₂ storage project. While site assessment provides enough data to determine feasibility and enable project permitting and design, the wealth of additional data gained during development and operations enables ongoing optimization and detailed understanding of the CO₂ storage system.

It is important to note that commercial CO₂ storage operations will be at the scale of large – and eventually giant – oil and gas fields. For example, a project injecting CO₂ captured from a 1,000 MW coal-fired power plant over a nominal 30 year life will inject over 3 TCF (over 150 MM metric tons) of CO₂ at a rate of over 300 MMscf/day (over 6 MM metric tons/year). As with significant oil and gas

fields, a project of this scale will require robust operations management (including information systems and humans) and, more than likely, ongoing development activity.

Field planning and development

CO₂ storage field development planning involves a number of activities. Key among these is using the earth and dynamic models developed in the site assessment phase to determine well design, well count, injection strategy and operational parameters (especially pressure). These design variables will be optimized against desired out-

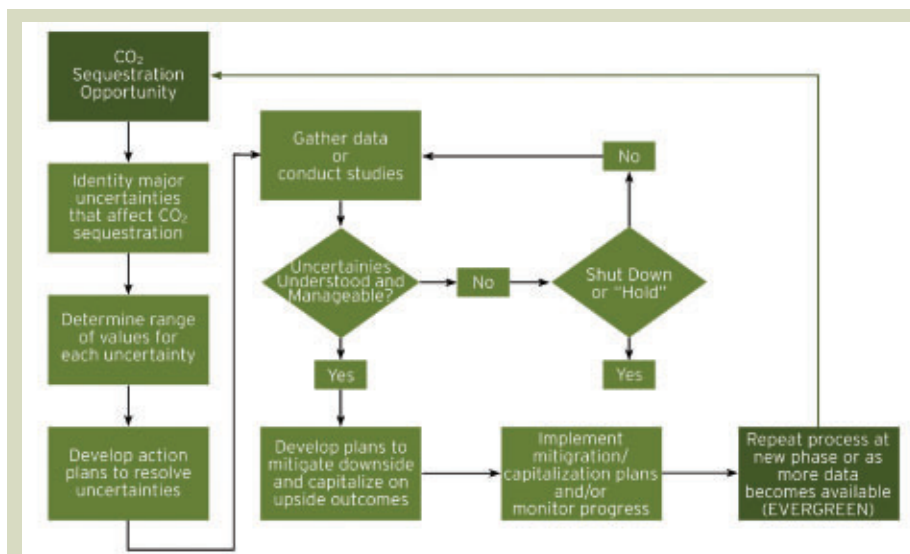


Figure 4.3: Uncertainty management model for assessing CO₂ storage projects (from Gorgon Development Draft EIS/ERMP).

comes including efficient use of pore space, enabling efficient trapping of CO₂ in immobile phases, managing pressure evolution, limiting CO₂ plume footprint, and avoiding geologic or artificial features vulnerable to leakage.

Well designs have matured greatly over the last 20 years, and horizontal and multi-lateral wells have enabled improved development in many oil and gas fields. In some cases, these advanced well designs may have benefits for CO₂ storage projects by improving individual well rate, reducing near wellbore pressure impact, and distributing CO₂. For the In Salah CO₂ storage project (BP operated, in central Algeria), horizontal wells are necessary to inject needed volumes (approximately 1 MM metric tons/year) into a thin, low permeability reservoir. In other cases, for example in very thick or layered reservoirs, more conventional vertical or deviated wells may be a better choice. Well stimulation techniques such as hydraulic fracturing and acidizing are also well-developed, and can improve per-well injectivity by removing or bypassing near wellbore permeability reduction caused by the drilling process, or improving flow pathways into the reservoir. In particular, hydraulic fracturing techniques to limit fracture height growth have

The most important operating parameter for CO₂ storage projects will be the maximum bottom hole injection pressure

density are additional important design considerations depending on needed injection rate and volume relative to reservoir characteristics. In high permeability, well-connected reservoirs, rapid pressure dissipation will minimize the number of wells needed and permit high injection rates. In moderate to low permeability, or poorly-connected reservoirs, a higher well density will be needed to limit pressure evolution and allow for efficient injection.

The injection strategy will also be affected by reservoir characteristics such as heterogeneity, dip, and vertical/horizontal permeability ratios. In many cases it may be best to inject at the highest rate possible within injection pressure limitations to improve pore space utilization.¹¹ In other situations, a strategy of ‘inject low and let rise’¹² will be best. In still others, the best strategy may be to inject into the entire thickness of the reservoir, for example to take advantage of reservoir layering. Strategies involving alternating injection of water and CO₂ gas (WAG) have also been proposed to enhance dissolution and residual trapping.¹³ The WAG approach is typically applied in CO₂ EOR to minimize CO₂ use (as it is purchased) and to avoid early breakthrough of CO₂. For the purpose of CO₂ storage, simulations that include detailed reservoir features

can determine optimal injection programs (rates, well type and configuration) that maximize utilization of pore space while avoiding excessive pressure buildup.

Operational parameters must also be established to enable robust well construction and infrastructure design. For example, individual well rates and pressures will determine tubular size and grade and other elements of well design. (See Chapter 2 for discussion of well design for CO₂ storage.) Wellhead pressure requirements over time will inform the need for initial or later installation of in-field compression units.

Perhaps the most important operating parameter for CO₂ storage projects will be the maximum bottom hole injection pressure. This will be limited by engineering best practice or regulation to avoid compromising the containment of injected CO₂. From an engineering standpoint, we note that injection at pressure greater than the storage reservoir fracture pressure will in many cases not threaten the containment of injected CO₂. The critical pressure to avoid exceeding is the fracture pressure of the confining interval above the reservoir, which is normally higher than the fracture pressure in the injection interval. Injecting above the fracture pressure of the storage reservoir will improve the injection rate and affect the CO₂ migration pattern, but will not typically compromise the integrity of the containment system. A maximum injection pressure lower than that established by prudent engineering, such as a pressure limit based on fracture pressure of the injection interval, may be established by regulations. An artificially low injection pressure limit may require drilling additional injection wells, resulting in the unintended consequence of creating additional artificial penetrations of the containment system.

Contingency may be incorporated into project design to account for uncertainty. In general, well and surface components will be built with ‘maximum expected’ conditions in mind. Operators of CO₂ storage projects may incorporate excess injection capacity (i.e. spare wells) to permit continued injection during planned or unplanned well downtime. The operator should be able to choose between this and another option, such as agreement with the regulator that a set portion of CO₂ delivered for storage (e.g. 80%) be injected. This would avoid the capital costs incurred in providing excess capacity that may not be needed.

All these project design considerations can be approached using well-developed oil and gas industry workflows. Dynamic reservoir modeling using a range of possible geologic scenarios will be run with a number of design and operating configurations to establish an optimal development design. Once established, the development scenario

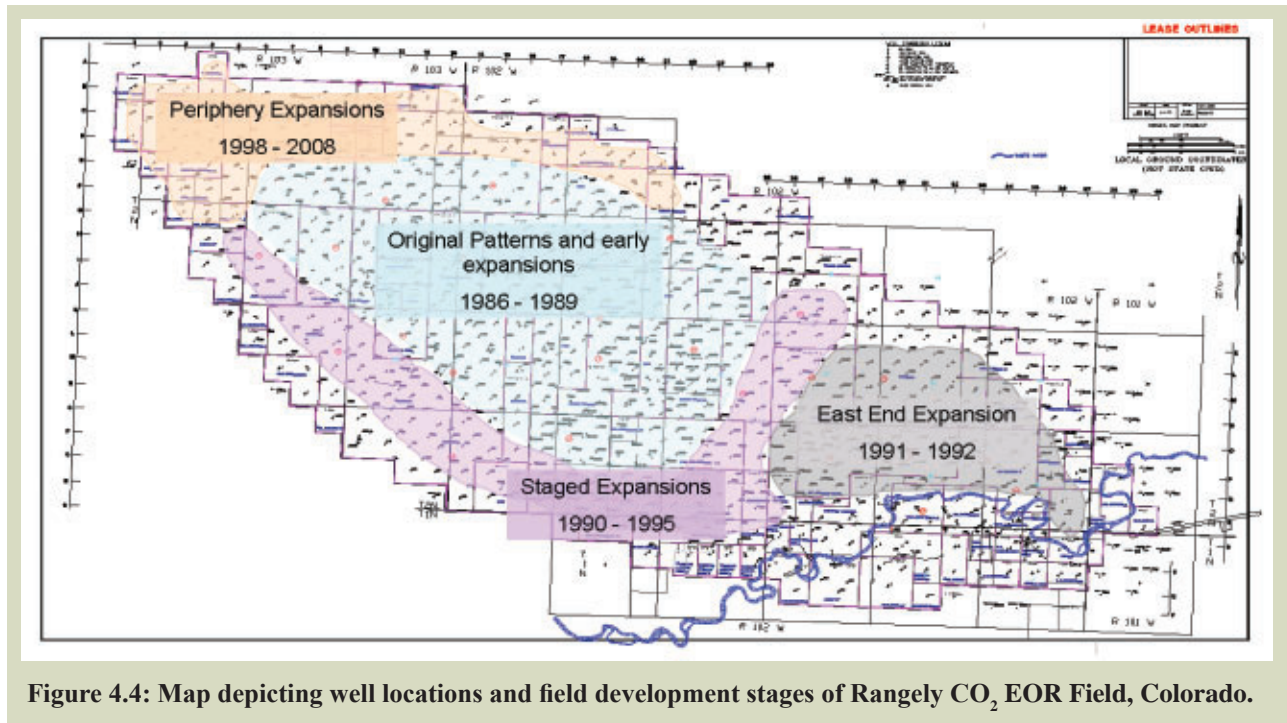


Figure 4.4: Map depicting well locations and field development stages of Rangely CO₂ EOR Field, Colorado.

chosen for implementation will, along with other considerations, help to design the most logical and cost-effective monitoring plan (see Chapter 3 for discussion of monitoring tools and strategies).

While the development principles outlined above will be common to most CO₂ storage projects, greenfield and brownfield developments are characterized by different opportunities and challenges. Brownfield developments, for example in mature oil and gas fields, will offer the benefit of beginning with a well-characterized system and a significant amount of infrastructure. However, field re-developments for CO₂ storage will require a significant amount of work to assess the integrity and re-usability of existing wells, flowlines and facilities.

Development in these fields can be expected to include a significant number of well re-completions, abandonment and possibly re-abandonment of old wells, new drilling, and upgrades to surface infrastructure. Chevron's Rangely Field in Colorado, for example, was discovered in 1933 and has been under production since 1944. After primary recovery, the field has progressed from hydrocarbon gas injection and water flooding to the present CO₂ flood (since 1986). Through infill drilling and meticulous reservoir management, production decline has slowed and most recently, reversed. Forward planning for mature field development includes review of historical production with model updates, identification of additional opportunities for recovery (e.g. new field sectors or infill drilling) and improved processes (injection parameters and surveil-

lance). Figure 4.4 shows the staged development of the CO₂ flood from 1986 to present day.

Greenfield development, for example in regional saline formations, will require construction of significant new infrastructure and additional initial characterization work. Early monitoring systems may be more extensive to supplement data collected during the site assessment phase. Notably, a steeper learning curve is to be expected, and modifications to an initial development plan may occur as additional knowledge is gained during early development work. Nevertheless, the initial and forward characterization and monitoring plans should be limited to what is needed for the project's success.

The notion of learning through the development process is an important one. Development of major oil and gas fields is generally not a single point event as improvements to the development plan are common. The same can be expected of major CO₂ storage field developments. In many cases, phased development will occur – potentially throughout the field life. Knowledge gained from earlier development wells and operational results will facilitate improved decision-making as development proceeds. Additionally, phased development offers the opportunity to employ new technologies as they mature.

Data collection from development wells is fundamental to learning through development. Typically a suite of well logs will be acquired during drilling or prior to completion. In multi-well developments, such as can be expected

of large CO₂ storage projects, enhanced log suites, cores, fluid samples and dynamic tests are generally acquired on selected wells to enhance the data set. Where numerous wells are present, a statistically valid subset of wells could be the focus of enhanced characterization and testing. This would provide information that is applicable field-wide while controlling costs.

At the end of the operational phase, there is a deep understanding of the subsurface system and processes affecting the injection and migration of CO₂

In summary, the development of CO₂ storage fields will parallel the development of oil and gas fields in many ways. Drawing from this extensive experience will be central to success. Field re-development for CO₂ storage will draw beneficially from the experience of the oil and gas industry in re-developing mature fields for installation of waterflood and EOR projects. The lessons of phased development and learning through development should be considered in planning for CCS deployment and accommodated by regulators.

Field operations

Although under-represented in discussions of CCS, the operational phase of a CO₂ storage project is the most significant in terms of management of CO₂, and importantly, in applying operational and monitoring data to enhance subsurface knowledge and manage risk. The operational phase is where the virtuous feedback loop applies most clearly. Ongoing data collection leads to enhancement of site-specific earth and dynamic models which in turn enables flood optimization, operational response and improved risk management. At the end of the operational phase, there is a deep understanding of the subsurface system and processes affecting the injection and migration of CO₂.

Successful management of CO₂ storage projects, as with oil and gas fields, involves continuous, close coordination between operations, engineering and geotechnical staff. Field operations staff monitor day-to-day field performance using the basic monitoring data collected by data management systems (e.g. supervisory control and data acquisition systems - SCADA) such as flow rates, pressures and temperatures. Field staff implement and monitor corrosion management programs, well maintenance, and other activities. When operational or monitoring data indicate an operational change is needed or desired, these personnel work to implement changes.

Production and reservoir engineering staff interpret operational data to understand well and reservoir performance, including results of monitoring activities such as injection logging and pressure transient analyses. Data and interpretation will inform analysis of and updates to the project's dynamic model, which will monitor and predict CO₂ plume evolution (known as "history matching"). The dynamic model will be used to recommend additional development needs and modifications to the injection strategy, and will be used to plan for eventual decommissioning.

Geotechnical staff will use operational and monitoring data including plume imaging and monitoring well data to enhance the project's geologic model, gaining an increasingly detailed understanding of the subsurface system and processes affecting CO₂ injection and migration. Successive updates to the geologic model will be fed through to the dynamic model to improve predictive capability.

CASE STUDY

Experience Managing Gas in the Subsurface: Kuparuk Field, Alaska

- **Gas management requires sensitive handling in this field.**
- **Careful management of miscible injectant assists in maximizing production.**
- **Computing tools help manage data.**

An example of oil field operational management is provided by the giant Kuparuk field in Alaska. The field has been under production since 1981, waterflooded since 1983, and miscibly flooded with an enriched hydrocarbon gas in a water-alternating gas (WAG) sequence since 1988 (analogous to CO₂ EOR). The field currently processes 120,000 barrels of oil per day; 500,000 barrels of water per day; and 490 MMscfd of hydrocarbon gas through over 1,000 wells on 43 drill sites; and three processing stations. Over 1 TCF of miscible injectant (MI) has been injected to date.

Gas management is a particularly delicate issue in the field. Produced gas is separated, then used either as fuel for artificial lift, or is blended with enriching components for injection in the WAG flood. Given that the processing facilities are running at or near capacity, at any given time limitations on production may result from gas production rates, gas injection capacity, gas-lift compression capacity, or water handling capacity. These limits vary by processing facility and also seasonally, as the warmer summer temperatures reduce compressor efficiency and hence gas processing capacity.

In order to fulfill the field's primary purpose of maximizing oil production, allocation of the MI among injection wells and the two producing reservoirs must be managed carefully. Fortunately, the different reservoir characteristics of the "A" and "C" sand reservoirs facilitates gas management. The higher permeability "C" sand processes gas from injector to producer faster, so it is flooded preferentially in the winter when gas processing capacity is high. The lower permeability "A" sand, with its slower processing rate, is used preferentially in the summer to "store" gas and reduce load on the surface facilities. Other strategies are to either vary the "slug size," or volume of gas or water injected in each cycle; or the WAG ratio, which is the ratio of water injected per cycle to gas injected per cycle (for example, 1:1, 3:1 or 5:1).

Dedicated flood management engineers have developed specialized computing tools that assist with analysis of a large volume of data from multiple sources. On a weekly basis they communicate with field operations staff about the necessary actions, including rate changes, water-to-gas or gas-to-water swaps, and data gathering. At a higher level, engineers and geotechnicians work to ensure that weekly operations are consistent with the field's long-term development plan. Monitoring, surveillance and timely action are keys to efficient operation of this complex project.

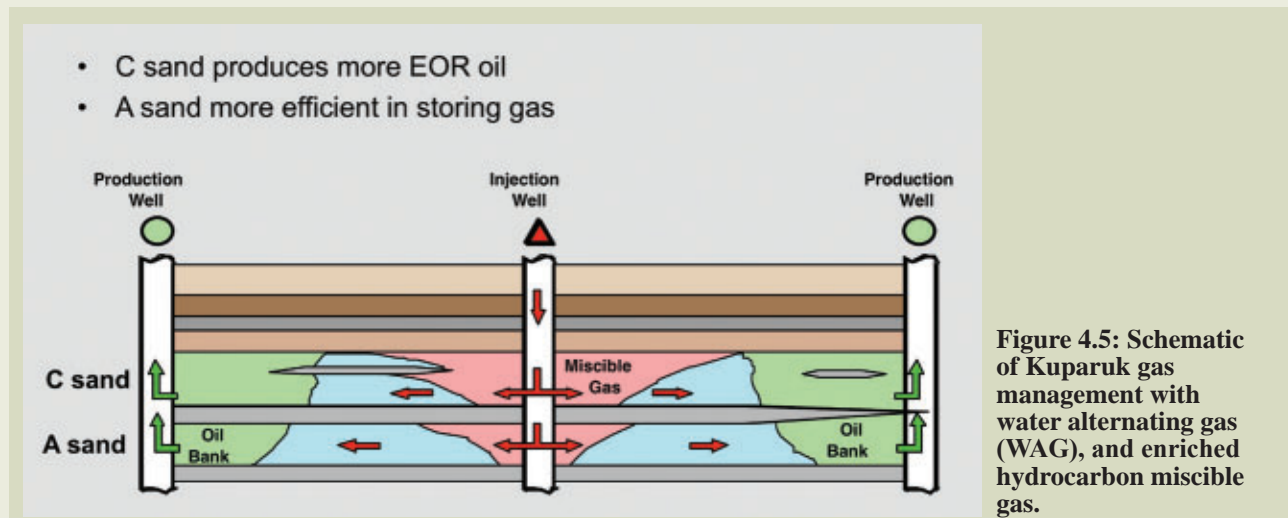


Figure 4.5: Schematic of Kuparuk gas management with water alternating gas (WAG), and enriched hydrocarbon miscible gas.

Monitoring programs should be staged, with initial phase results informing subsequent phase design. The earliest and most direct monitoring information routinely used in injection projects is flow rate, pressure and temperature. These data give early indication of flood performance, including potential issues such as near-wellbore formation damage and reservoir compartmentalization. Early imaging surveys, especially cross-well seismic or vertical seismic profiling, may indicate initial lateral versus vertical plume movement. Pressure sensors at monitoring wells can provide early indications of plume symmetry and potential compartmentalization. Later, imaging and observation well sensors/sampling may be able to identify the plume front and, in some cases, relative CO₂ saturation over time and space.

Monitoring CO₂ floods is typically regarded as a means of providing early warning for unexpected CO₂ migration or leakage whereas it should more properly be regarded as a flood performance indicator that, with corrective action, can improve performance and reduce leakage risk. Site-specific monitoring, aimed at assessing performance and containment criteria with specific responses to detected variances, will be essential to the technical, economic and regulatory success of a project. Indeed, the development of a signposting and response plan will build stakeholder confidence in the storage operation as well as facilitate regulatory approvals for continued operation, closure and post-closure.

An example of operations management and failure mode signposting/response planning is available in Chapter 13 of the 2005 Draft Gorgon Development Environmental Impact Statement/Environmental Review and Management Programme (EIS/ERMP), submitted as part of the environmental approval process by the Commonwealth of Australia and Western Australia.¹⁴ The Gorgon project was previously introduced in Chapter 2. CO₂ injection management entails (note that management of both low and high cases are needed):

- Identifying subsurface risks with evaluations of their uncertainty, management options, surveillance needed and response planning for unexpected outcomes.
- Evaluating impacts including HSE, containment, ability to monitor, injectivity, capacity, resource risk and cost.
- Mitigation and realization planning, including establishing event indicators/signposts with required monitoring and verification, the likely timeframe of occurrence, mitigation options and the probability of mitigation success.

Major operational issues include CO₂ injection impacts on existing wells, unexpected migration and realization of higher than expected pressure. Subsurface failure modes include insufficient performance of baffles and barriers, fault leakage, well leakage and reduced injectivity. Table 4.1 outlines a synopsis of signposting and response proposed in the Gorgon development EIS/ERMP document. A document of this kind is key to uncertainty management during operations. Properly used, it will help avoid problems while limiting the impact of unexpected events through effective mitigation.

Effective operational management leads in the later stages of a project to a well-understood subsurface system and robust models with accurate forecasting capability. This knowledge base sets the stage for effective decommissioning by enabling prediction of post-injection CO₂ plume evolution, the identification of potentially vulnerable features, and hence the design of a robust and cost-effective monitoring strategy for the closure and post-closure periods.

Issue	Unexpected Outcome	Signpost	Monitoring	Timing	Management Action
Well Injectivity	Unable to inject CO ₂ at required rate	Unexpected BHP increase	Well head & downhole P gauges & flow rate gauges	< 6 mos.	Once verified, several actions including recompletion, reperforation, drill new wells with different design, consider alternative storage reservoir
	Initial injection rate meets expectations but overall pore space is limited	Gradual increase in BHP	As above	10 years	Consider producing water & reinjecting into another reservoir
	CO ₂ cannot be injected at required rates due to formation damage	Unexpected BHP increase and change in formation fluid chemistry	As above & fluid samples/analyses	Ongoing	Workover well & acid or fracture stimulate
Existing Well Failure	CO ₂ migrates to overlying formation(s)	Indications of CO ₂ in shallower stratigraphy	Surface & borehole geophysics	Ongoing	After validation, assess ability of shallow formations to trap CO ₂ ; if not, remediate wells or modify injection pattern
	CO ₂ leakage at surface	Elevated CO ₂ present in vicinity of well(s)	Surface soil & atmospheric gas	Ongoing	Remediate well. Implement appropriate environmental remediation
	Leakage of displaced formation water in shallower stratigraphy	Elevated CO ₂ detected near well in shallower horizons	Surface & borehole geophysics. Geophysics sampling	Ongoing	Assess impact on overall containment. If needed, remediate leaking wells (particularly if along projected plume path)
Top Seal Failure	CO ₂ migrates to overlying formation(s)	Detection of CO ₂ above injection formation not associated with wells	Seismic and/or borehole geophysics	Ongoing	Focus monitoring to verify. If needed modify injection pattern or produce water and reinject into another formation
	Seal integrity compromised due to pressure increase from CO ₂ injection	Pressure drop during injection or seismic or borehole geophysical indications	Wellhead pressure and downhole pressure & flow gauges; seismic and borehole geophysics; tiltmeter; passive seismic	Ongoing	Focus monitoring to verify. If necessary modify injection pattern, lower injection rates or produce water & reinject into another formation
Fault Seal Failure	Faults transmit CO ₂ to shallower formations	Detection of CO ₂ above injection formation in proximity of fault	Surface and borehole geophysics; fluid sampling, downhole gauges	Ongoing	Focus monitoring to verify. if necessary modify injection pattern, lower injection rates or produce water from vicinity of fault to reduce pore pressure
	Faults transmit CO ₂ to the surface	Elevated CO ₂ present in vicinity of well(s). Ecological impacts	Soil & atmospheric monitoring. Ecological changes.	Ongoing	Focus monitoring to verify. if necessary modify injection pattern, lower injection rates or produce water from vicinity of fault to reduce pore pressure
	Faults are vertically & laterally impermeable	Unexpected pressure increase in part of formation thought to be isolated	See Compartmentalization	See Compartmentalization	See Compartmentalization
Pore Volume & Distribution	Reduced pore volume or distribution limiting CO ₂ injection	Rate of long-term pressure build-up greater than expected	Well head and downhole P gauges & flow rate gauges. Multicomponent seismic for pressure	10-30 years	Focus monitoring to verify. If necessary modify complete injection well over entire length of reservoir, produce water & reinject elsewhere or reduce total CO ₂ injection volume
Permeability Heterogeneity	CO ₂ cannot be injected at required rates	Unexpected bottomhole pressure increase	Wellhead & downhole P gauges & flow rate gauges	See Well Injectivity	See Well Injectivity
	Unexpected migration of CO ₂ plume	Detection of unexpected plume distribution possibly related to stratigraphic or depositional geometry (otherwise structure, high permeability layers or hydrodynamic flow) Lower than expected BHP	Seismic imaging. Surface and downhole pressure. Production logging	1-10 years	Focus monitoring to verify. If necessary re-enter well & squeeze off perforations associated with high permeability units. Lower injection rate/drill additional wells or relocate injection wells
Structure (Primarily Geometry of Base Seal)	CO ₂ migration diverges from expected path	Significant CO ₂ volumes migrate off structure	Surface and borehole geophysics	Ongoing	Focus monitoring to verify. If necessary modify injection pattern or water production wells to drive migration in desired direction
	Insufficient capacity for planned injected volume of CO ₂	Unexpected pressure increase during injection	See Pore Volume	See Pore Volume	See Pore Volume
Compartmentalization (Fault or Stratigraphic controlled)	CO ₂ migration restricted to an isolated part of the formation	Unexpected BHP increase. Pressure transient analysis suggests hydraulically isolated wells	Surface & borehole monitoring	Ongoing	Focus monitoring to verify. If necessary modify complete injection well over entire length of reservoir, produce water & reinject elsewhere or drill additional wells outside of the isolated area
High Permeability Layers	CO ₂ migrates rapidly & preferentially along a specific stratigraphic horizon (possibly off structure)	Indications of rapid migration through a restricted stratigraphic horizon. Lower than expected downhole pressure & flow rate	Surface seismic or borehole (production logging) monitoring. Wellhead & bottom hole pressure/flow	6-12 mos. to Ongoing	Focus monitoring to verify. If necessary reenter well & squeeze off perforations associated with high permeability units, modify injection pattern to accommodate or reduce planned total injection volumes
Hydrodynamic Gradients	CO ₂ migration path diverges from expected	Significant CO ₂ volumes migrate off structure	Surface and borehole monitoring	0-10 years	Focus monitoring to verify. If necessary modify injection pattern or water production wells to drive migration in desired direction
Monitoring (Seismic Resolution)	Subsurface CO ₂ is not seismically resolvable	Limited or absence of plume images via seismic	Borehole geophysics	5-10 years	Alter monitoring activities to determine if alternative geophysical methods are effective or develop an alternative observation well-based strategy
Micro Seismicity	Excessive microseismicity attributed to CO ₂ injection	Subsidence and seismicity above background levels	Passive seismic/tilt meters	Ongoing	Focus monitoring to verify. If necessary undertake actions to reduce pore pressure & distribution
	Seismicity induced as result of CO ₂ injection	Indications of significant fracturing/faulting	Passive seismic/tilt meters	Ongoing	Focus monitoring to verify. If necessary undertake actions to reduce pore pressure (injection pattern, water production or reduced injection volume)
Residual Oil Saturation	Poor injectivity due to oil presence reduction of relative permeability to CO ₂	Unexpected BHP increase	Well head & downhole P gauges & flow rate gauges	0-5 years	Focus monitoring to verify. Undertake actions to reduce pressure increase (see Injectivity)

Table 4.1: Performance and containment issue signposting, monitoring and management examples.

Closure and post-closure

Technical requirements for the closure of a CO₂ storage facility are likely to be enumerated by existing and new regulations. As with other phases of the development process, these regulations draw a strong basis from oil and gas industry experience in decommissioning depleted fields. Plugging and abandonment of wells and the final disposition of surface infrastructure will be a significant undertaking, but one that is well-understood by operators and regulators. In many cases, the processes will include public involvement. Earth and dynamic models, which are well developed by the closure phase, will be used to establish the present and probable future status of the CO₂ plume, identify key vulnerabilities if they exist, and establish the level of future risk to the public, natural resources and the environment. Model predictions will be used to develop appropriate and cost-effective monitoring and intervention plans for the closure and post-closure periods.

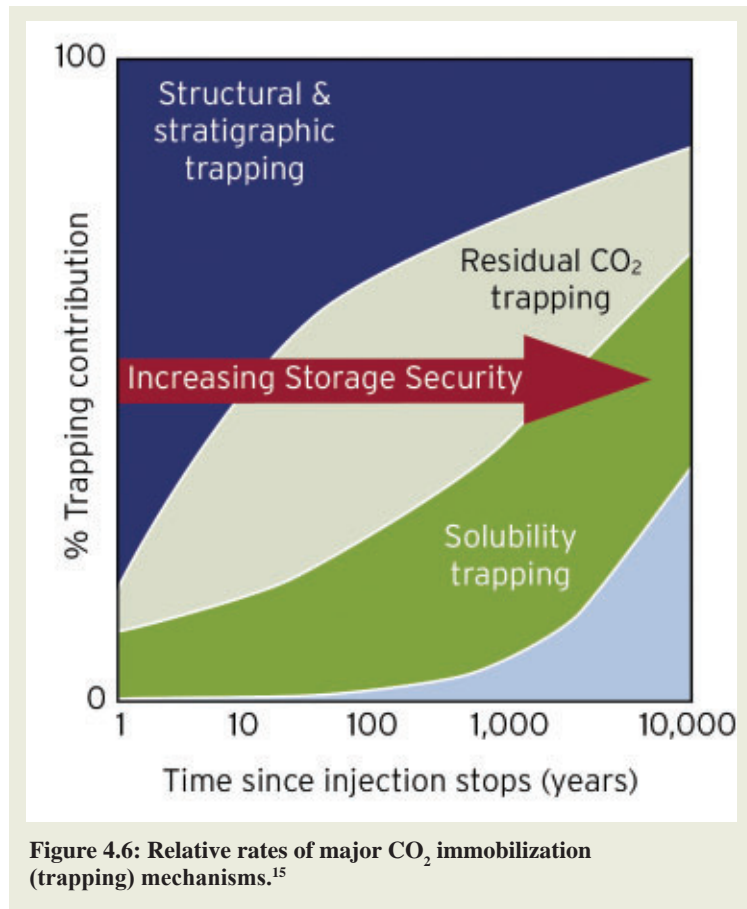
In general, it is appropriate that a CO₂ storage project operator maintains responsibility for the CO₂ plume for some period following the close of injection. The length of this period should be determined by the size, type and risk profile of the project and the quality of forward predictions of subsurface CO₂ behavior based on history matching, rather than by default time periods. Driving this assertion is the fact that the major physico-chemical mechanisms leading towards the immobilization of CO₂ begin during injection, but will be completed long after injection has ceased (Figure 4.6):

- Residual trapping of CO₂ in small pore spaces occurs in areas of decreasing CO₂ saturation as the plume migrates.
- Dissolution of CO₂ in native formation fluids including brine will occur during the injection phase, but early observation of post-injection behavior will improve predictive capacity.
- While viscous forces are important during the injection phase, buoyancy and capillary forces will dominate during the post-injection phase and thus warrant early observation.

Assuming a well-calibrated model of the subsurface environment and the CO₂ plume at the beginning of the post-injection period, and building in early observation of post-injection processes, it can be expected that robust predictions of the eventual fate of the CO₂ plume can be made within a space of years following the end of injection.

A comprehensive history matching database, the forward projection of which indicates very low likelihood of endangerment to protected systems or human health and safety, should obviate the need for long-term (e.g. decades long) monitoring and intervention programs.

Residual risks, such as encountering wells or faults over the very long term (decades-centuries), should be qualified in terms of the probability of untoward migration and endangerment (of natural resources, the environment or humans) using fluid transmissivity models. The transient presence of CO₂-rich fluids in the vicinity of potential conduits, the trend towards reduced pore pressure with time, and the self-limiting nature of leakage should be considered when establishing long-term monitoring and intervention contingency plans. In this context, the continued application of a risk management model which balances the probability of occurrence and the impact of occurrence



against incurred cost is important to designing a rational plan for the closure and post-closure periods.

The owner/operator will be responsible for a space of years after the end of injection. The entity accepting responsibility for long-term stewardship of the site will as-

sume less risk as formation pressure will approach natural levels, and CO₂ will increasingly be stored in immobile phases. The ability to decommission a CO₂ storage site without open-ended financial responsibility will be important to enabling deployment of CCS. A balance should be struck between the need to safeguard the public and the environment on the one hand, and limiting the project owner's financial commitment to a time period customary for large private and public works on the other. Indeed, consideration of the duration of operator responsibility after the close of injection needs to take into account how for-profit enterprises will handle potentially long periods of continuing cost with no offsetting revenue stream.

A number of model regulations, best practices and other works variously addressing CO₂ storage site assessment, operations, monitoring and remediation, decommissioning, and liability models have been issued or are in development. Elements of these are covered in previous sections of this work. Liability issues associated with CO₂ storage have been examined by de Figueiredo¹⁶ (2007). Major lessons learned include:

- Successful resolution of liability requires combined understanding of physical and regulatory models.
- The prospect of liability will influence the implementation of predictive modeling and monitoring to detect leakage.
- The siting of CO₂ storage projects will be influenced by the jurisdictional level of liability exposure.
- The development of liability rules will influence and be influenced by the emergence of a CCS industry.
- Complying with regulations cannot guarantee safe harbor from liability.
- Exposure to liability is not necessarily perpetual, owing to statutes of limitations and repose.

One potential model for handling long-term management of closed CO₂ storage projects is a CO₂ Storage Fund, as proposed for the USA by model CCS regulations issued by the US Interstate Oil and Gas Compact Commission (IOGCC).⁴ Such a model would enable financial resources to be set aside during the revenue-generating phase of a project to enable a long-term management entity to fulfill its obligations and manage long-term risk. The implications of this and other long-term stewardship models on the feasibility of CO₂ storage projects should be carefully considered by policy makers and regulators.

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Figures

Figure 4.1: A Feedback Loop model for optimization and uncertainty management in CO₂ storage projects. Produced by the CO₂ Capture Project.

Figure 4.2: Certification Framework (CF) scheme as an organizing vehicle for CO₂ storage site permitting and establishing acceptable containment risk during operation, closure and post-closure. Produced by the CO₂ Capture Project.

Figure 4.3: Uncertainty management model for assessing CO₂ storage projects (from Gorgon Development Draft EIS/ERMP). Courtesy of Chevron.

Figure 4.4: Map depicting well locations and field development stages of Rangely CO₂ EOR Field, Colorado. Courtesy of Chevron.

Figure 4.5: Schematic of Kuparuk field gas management. Courtesy of ConocoPhillips, Alaska Inc.

Figure 4.6: Relative rates of major CO₂ immobilization (trapping) mechanisms. IPCC, 2005.

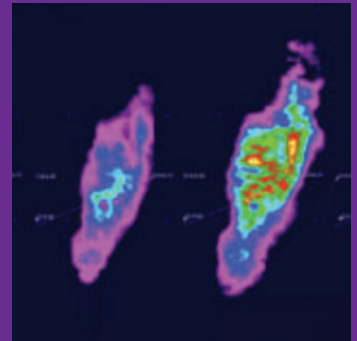
Tables

Table 4.1: Performance and containment issue signposting, monitoring and management examples. Produced by the CO₂ Capture Project. Modified from Chevron Gorgon Project documents, see Figure 4.3.

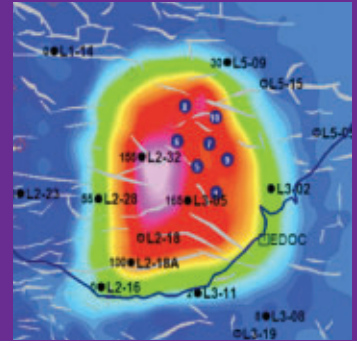
A Technical Basis For Carbon Dioxide Storage

This book has been prepared by the CO₂ Capture Project[®], an international effort funded by eight of the world's leading energy companies that seeks to address the issue of reducing greenhouse gas emissions in a manner that will contribute to an environmentally acceptable and competitively priced continuous energy supply for the world.

The intent is to provide a guide to the major technical issues related to the subsurface geological storage of carbon dioxide. The target audience is people interested in CO₂ capture and storage (CCS). It contains both general information and specific details about technologies and applications that are likely to be used in CCS. We hope that it will engage a wide range of people including policy-makers, the public, and even many of our energy industry colleagues who are less familiar with CCS. The authors offer their insights on expectations for CCS based on many years of cumulative experience developing analogous oil and gas projects, complemented by knowledge gained by the first eight years of the CO₂ Capture Project.



The evolving CO₂ plume at Sleipner as seen in amplitude maps (Figure courtesy of StatoilHydro)



Inversion Mass Model. Prudhoe Bay, Alaska (Figure courtesy of ConocoPhillips)



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