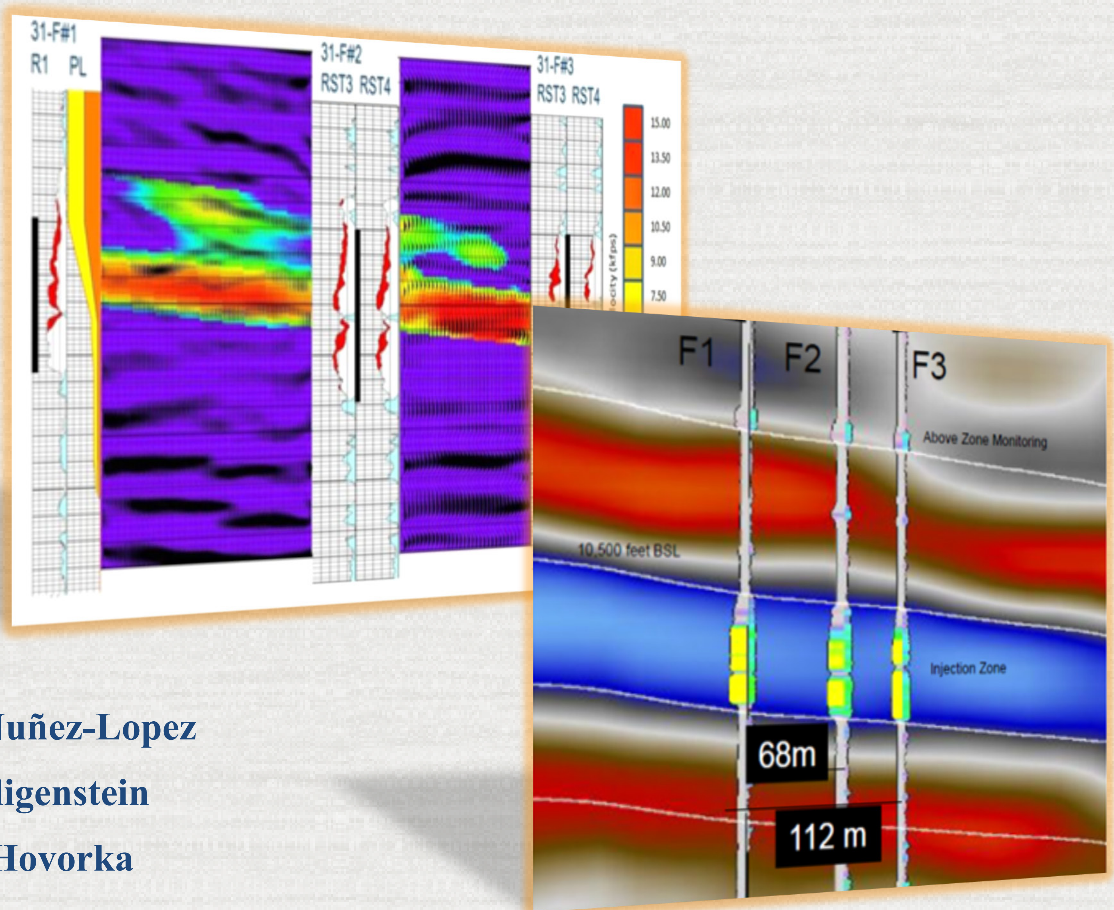
Final Report to Chevron Energy Technology Company on

Leveraging Geologic CO_2 Storage Technology for CO_2-EOR Management



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Introduction

Enhanced oil recovery (EOR) through CO_2 injection has evolved from the laboratory testing and field piloting phases in the early 1970s to the widespread and refined operations of today. Over the last 20 years, geological CO_2 storage (GCS) has emerged as a promising approach to dispose of large volumes of CO_2. Much of the early advances in the operational aspects of GCS were learned from CO_2-EOR. However, given its "newness" and the health, safety, and environment (HSE) concerns related to CO_2 emissions, considerable fundamental and applied research with heavily instrumented GCS field projects, from pilot to commercial scale, has produced data not ordinarily available from conventional CO_2-EOR studies. A key exception is the Weyburn-Midale CO_2-EOR project in Saskatchewan, Canada, which has had a dedicated characterization, reservoir dynamics and surveillance program in operation since 2000.

Even though many of the processes and workflows for these two operations are similar, significant differences do exist primarily because of the different objectives and regulatory environments that exist for CO_2-EOR and CO_2 storage projects. Fundamentally, CO_2 storage tools and processes are geared toward developing a much more detailed understanding of the storage system and the physical and chemical processes accompanying CO_2 injection, with monitoring and surveillance being conducted during the pre-operational, operational, and post-operational stages of a project. Pre-operational monitoring for a CO_2-EOR project is primarily focused on understanding the reservoir physical and petrophysical properties as well as the properties of the reservoir and injected fluids. Surveillance in the operational phase of an EOR flood is limited, with emphasis being placed on monitoring injection pressures and rates as well as the volumes and properties of the injected and produced fluids.

Lessons learned from GCS research and field tests will likely benefit CO_2-EOR project performance by employing aspects of characterization, simulation and surveillance. This study reviews the predictive and diagnostic tools currently applied to GCS projects and infers how their deployment might improve CO_2-EOR projects. These improvements might include project conformance, CO_2 utilization / oil produced, field management, and containment risks.

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Section 1

System Characterization

Site characterization is an essential element in the success of both hydrocarbon resource development and geological carbon storage (GCS). However, the nature of its purpose is different in each setting. In a hydrocarbon field, the fluids are in place and characterization is the tool used to locate them and optimize extraction. In GCS, characterization is needed to provide information on how CO_2 can be injected under conditions where it will be retained. In this section, we don't focus on technologies and strategies already dominated by the oil industry, but rather on evaluating lessons learned and characterization methods developed by GCS research and how they can be utilized in enhanced oil recovery operations (EOR) to increase hydrocarbon production rates and optimize CO_2 utilization. We conclude that the results of novel and field-tested site characterization developed for GCS over the last decade demonstrates that this body of work can enhance the understanding of CO_2/brine/hydrocarbon/rock interactions and deliver a valuable contribution toward solving the challenges of resource development, especially in tertiary recovery but potentially also in other settings where geotechnical guidance is key to successful exploitation.

Site characterization protocols for GCS predominantly revolve around assessing the injectivity, capacity, and containment effectiveness of the storage complex, while establishing a framework of field proven and repeatable monitoring methods capable of assessing the suitability of a sequestration site (S. J. Friedmann, 2007). A suitable storage site must provide effective trapping mechanisms, competent bounding seals, hydraulic isolation from overlying aquifers, an appropriate hydrogeological regime, and minimal potential pathways for both vertical and lateral CO_2 migration through faults or fractures (Whittaker, 2004). In GCS, these data are collected and quantified for input to models. In a typical oil reservoir development the collection of some of these data is not common practice, hence procedures and techniques have not been refined. Over the past decade, however, about a dozen GCS field tests conducted globally have provided a detailed look at the reservoir response to CO_2 injection and the fate of CO_2 at the operational time scale. GCS sites have provided four unique research data collection opportunities not typically available in EOR operations:

1. Simpler single-phase environment: Injection of a distinctive fluid (CO_2) into a pore space that is brine filled and not previously exploited provides an opportunity to assess the reservoir response in a way that cannot be done in an oilfield setting. It is much more difficult to detect, quantify, and image the CO_2 saturation evolution in a multi-phase environment (oil, water, possible methane + CO_2) than it is to do so in a water + CO_2 system. CO_2 injection in a saline aquifer provides the opportunity to collect a baseline against which to quantify change in the monitoring tool response when CO_2 is injected. Fields entering tertiary recovery have typically been highly perturbed by depletion, injection of brine and other fluids, and past tertiary recovery. Knowledge gained in simpler saline systems can inform the complex systems.

2. Closer, higher frequency data: GCS studies have been conducted as pilots, favoring the collection of dense and frequent data. The cost of obtaining CO_2 has limited the scale of most experiments. The close spacing, however, has allowed the detection of fluid flow and rock property interactions details that could not have been observed at the traditional EOR pattern-scale well spacing. In addition, limited amounts of CO_2 and the need to provide higher than traditional surveillance has favored collection of high frequency surveys, including real-time data and time-lapse repeats that are less available in field floods.

3. Assessment of the entire system: in GCS, the assessment of the storage system, including the boundaries (upper-seal, bottom-seal, and lateral barriers) is required. Whole-system thinking can add value to the design and optimization of EOR floods. For example, correct assumptions about pressure increase are needed to optimize purchase and recycle volumes, and water curtains.

4. Improved understanding of CO_2 partitioning: in traditional EOR, the fate of non-recyclable CO_2 is typically not actively assessed. Some CO_2 may be lost from the reservoir interval by invasion of the reservoir seal or by possible migration into non-produced compartments. Improved understanding of CO_2 trapping mechanisms (dissolution into brine, capillarity, etc.) from GCS research could result in better CO_2 management (Frykman and others, 2012).

5. Improved modeling: optimization of modeling tools which consider mass transfer with the reservoir brine was incentivized by GCS requirements and can be useful for CO_2-EOR projects.

In EOR, quantifying the saturation and distribution of the remaining oil is the key driver of commercial success. Once oil distribution is known, it is essential to drive the CO_2 to contact it; mobility ratios and flood conformance are the issues that have the most impact on the performance of solvent displacements. There exist other issues, however, that may diminish the effectiveness of a CO_2 flood. We will cover some of these issues in the following sections, which discuss how data from geologic storage projects have improved understanding and possibly management of CO_2 fate and non-recovery.

For example, the quality of the reservoir seal (known in CCS literature as caprock and in groundwater protection literature as confining system) is said to be demonstrated during oil accumulation. However, during production and injection chemical and geomechanical processes (sections 1.1.1 and 1.1.2) can alter the flow system, allowing fluid to migrate within and as well potentially out of the reservoir in ways that fluids did not originally flow. Errors in correctly assessing the boundary conditions in the reservoir (section 1.2) can lead to failure to attain the minimum miscibility pressure within the formation, resulting in the recovery of CO_2 via an immiscible process, which leaves behind undesirably high residual oil saturations and if not planned for and managed may fault short of commercial success. Lateral CO_2 losses can damage the commercial viability of the project and in some cases expose the operator to liability from undesired impact on adjacent production. Geologic storage research can also help improve EOR operations through incremental improvement of conceptualization of flow though the reservoir to better contact oil (section 1.3).

Lastly, improved understanding of the reservoir hydrocarbons is a current area of active research (section 1.4). Several strategies have been developed by the oil industry to reduce mobility ratios. Water alternating gas (WAG) injection strategies continue to be used as the mobility control technology of choice, where the relative CO_2 permeability is reduced by increasing reservoir water saturation ahead of CO_2 fronts. Other technologies, such as CO_2 foams and nanoparticles, have also been studied for mobility control (Zhang, 2010).

1.1 Reservoir & seal: interactions with injected CO_2 and their impact on flood performance and confining system integrity

One key innovation geologic storage research has to offer to the EOR industry is an assessment of the quality of the seal. Retention is a critical factor in GCS, and a significant unknown in saline sites. The large amount of research in GCS may be of value for EOR in three ways: (1) CO_2 usage optimization by improving flood conformance, (2) assurance of no damage to overlying resources (important in the public policy arena, where resources development is critically assessed by the public and the regulator), and (3) retention demonstration if EOR comes to derive part of its economic drive from CO_2 storage.

Two types of possible damage to the seal are considered:

When CO_2 and brine come into contact, a small amount of CO_2 dissolves in the aqueous phase, and a portion of that dissolved CO_2 dissociates and forms carbonic acid. When this occurs, the pH of the water drops to values less than 3, making it possible for the now acidic brine to react with and dissolve solid minerals present in the reservoir (exacerbating conformance control issues) and in the seal.

In the evolution of a reservoir from primary though secondary to tertiary processes, the change in reservoir pore pressure introduces geomechanical changes that alter the porosity and permeability of the reservoir and the behavior of fractures and faults. In this section we consider the impact of these changes on the seal.

1.1.1 CO_2-brine-rock chemical interactions

In EOR, any non-recyclable CO_2 (due to CO_2 subsurface loss) needs to be purchased to compensate for the loss and maintain the CO_2 injection rate. One form of CO_2 loss represents CO_2 entry into the seal, and can occur by three mechanisms: capillary breakthrough as supercritical CO_2, molecular diffusion as either supercritical CO_2 or dissolved CO_2, and as a dissolved constituent in vertically migrating brine (Liu and others, 2012). Reactivity between dry supercritical CO_2 and the seal is generally low, although the organic matter present could either sorb the CO_2 or be extracted by the supercritical CO_2 causing alteration of the pore structure (Okamoto and others, 2005; Busch and others, 2008).

CO_2 charged brines, however, will react with solid minerals in the matrix, with the fastest reactions occurring on the carbonate minerals because of their fast reaction kinetics. In the long run, the acidized brine may trigger reactions with the alumino-silicate minerals (feldspars and clays). Such reactions may occur in much longer time-scales, even hundreds or thousands of years, but they contribute significantly to porosity/permeability alterations because of their large percentage in the seal mineralogy (Armitage and others, 2011).

The insight garnered from confining system integrity analysis suggests, however, that the range of CO_2 diffusion into the seal is restricted to approximately the first few meters and that the chemical alteration of alumino-silicates in the seal actually decreases the porosity and permeability of the system, thus enhancing the strength of the seal in the long-term (Gaus and others, 2005). The geochemical reactions at sequestration sites sharing similar confining system mineralogy to Sleipner, North Sea, will largely depend on the amount of CO_2 diffusing into the basal portion of the seal (Lu and others, 2011). Ultimately, the volume of CO_2 permeating the hydrodynamic shale seal should prove to be minor because the effective diffusion coefficient of shale is extremely low and CO_2 diffusion is furthermore hindered by the geochemical reactions generated between immiscible CO_2 and the shale (Chadwick and others, 2008).

As it stands, carbonate dissolution is projected to only affect the basal portion of the confining system, which could produce an increase in porosity. However, alumino-silicates in succeeding elevations of the upper-confining system are expected to dictate those geochemical reactions, leading to only minor changes in porosity depending on the specific seal mineralogy (Chadwick and others, 2008).

In using a combination of thermodynamic batch modeling and diffusion reaction modeling for long-term confining system integrity analysis at Sleipner, Gaus and others (2005) demonstrated that an initial drop in reservoir brine pH caused by the dissolution of CO_2 in water was found to catalyze carbonate dissolution within the reservoir and in the lowermost portion of the upper-confining system. However, the effect of carbonate dissolution on the upper-confining system was determined to be minor due the slow rate of CO_2 diffusion into the seal and the rapid counterbalance of the drop in pH as the carbonate buffering system was established (I. Gaus, 2009). Only in areas of enhanced reservoir flow, such as in the vicinity of the injection well, does the potential exist for an increase in porosity owing to the chemical alteration of k-feldspar in the reservoir rock with large volumes of injected CO_2.

Thermodynamic equilibrium batch modeling also predicts the precipitation of chalcedony, kaolinite, k-feldspar and carbonate in the upper-confining system through the dissolution of smectites and illite. A potential weakness in the confining system develops as these reactions consume large quantities of formation water through the desiccation of water bearing clays in the seal. However, Gaus and others, (2005) notes equilibrium modeling alone is not recommended because it is not sufficient to interpret the net results of geochemical reactions over a long-term (yet geologically narrow) time-scale of CO_2 storage (>15,000 yrs.) In fact, confining system failure caused by the desiccation of clays is viewed as highly improbable over the long-term due to slow CO_2 diffusion and the inclusion of reaction kinetics.

Diffusion reaction modeling showed that albite had a minor impact on the geochemical reactions in the seal, with only the lowest 4 m of the upper confining system affected. No significant porosity changes occurred in the area of the seal, with only 6 m of elevated CO_2 concentration following 3,000 yrs. Anorthite effectively hinders the diffusion of dissolved CO_2 in the seal, with only 1 m of elevated CO_2 in lower caprock following 3,000 yrs. The precipitation of calcite and kaolinite stemming from the alteration of anorthite actually lowers the porosity in the lower 2 m and the maximum decrease in porosity is contingent on the total concentration of anorthite in the upper-confining system. Overall, as the diffusion rate decreases despite the high value of the diffusion coefficient, the porosity of the seal decreases and the seal strength of the Sleipner confining system is subsequently projected to increase (Gaus and others, 2005).

Porosity-permeability evolution governed by the dissolution-precipitation reactions between hydrodynamically trapped immiscible CO_2 at the contact of the reservoir sandstone and overlaying shale seal indicates that the alteration of k-feldspar in the shale to Fe-, Mg-, or calcium carbonate ($CaCO_3$) may enhance the seal of the upper confining system (J.W. Johnson and others, 2004). In a confining system analogous to the shale unit overlaying the reservoir sandstone at Sleipner, the extent of CO_2 diffusion into the shale seal during the operational phase of injection and storage is predictably limited to the lowermost 5-10 m. (Gaus and others,, 2005) Mineral trapping of CO_2 via the alteration of k-feldspar at the reservoir-confining system interface is enhanced by the consumption of Fe-Mg-bearing shale minerals:

$KAlSi_3O_8$ (k-feld.) + 2.5 $Mg_5Al_2Si_3O_{10}(OH)_8$ (Mg-chlorite) + 12.5 $CO_2(aq)$ $\leftrightarrow$ $KAl_3Si_3O_{10}(OH)_2$

+ 1.5 $Al_2Si_2O_5(OH)_4$ (kaolinite) + 12.5 $MgCO_3$ (magnesite) + 4.5 SiO_2 (qtz/chal) + 6 H_2O

Directed by the preceding chemical pathway, the porosity and permeability of the shale unit is effectively decreased by the precipitation of carbonates along the base and within the CO_2 saturated portion of the shale seal. Consequently, mineral trapping under this condition actually promotes the quality of the hydrodynamic seal integrity of the confining system and, thus, self-mitigates the risk of CO_2 leakage through the shale layer. See figure 1.1 (J.W. Johnson and others, 2004).

For pre-existing fractures at the base of the upper confining system, mineral dissolution of calcite and dolomite leads to an increase in fracture width. The largest increase in fracture width occurs where calcite grains directly contact the CO_2-rich brine, while smallest growth in fracture width occurs where silicates come in direct contact with the CO_2-rich brine. (Ellis et al 2011). Dissolution leads to calcite-depleted zones that alternatively exhibited a deposit of clay minerals in exchange, which may slow the calcite dissolution rate and subsequently the rate of fracture growth by regulating the migration of aqueous species between the CO_2-rich brine and calcite grains. The diminished reaction rates between the clay coatings along fracture walls and the brine phase indicates that the total clay content of a carbonate rock is a controlling factor on fracture permeability, despite the increased porosity arriving from calcite dissolution. This evidence would suggest that upper confining systems comprised of carbonate rock with high clay mineral content will prove more secure in confining CO_2-rich brine than those with low clay mineral content.

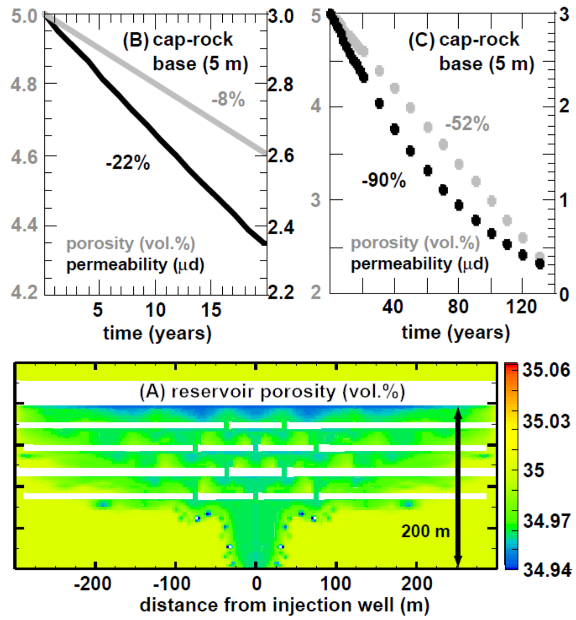

Figure 1.1: Porosity and permeability reduction due to trapping (A) after 20 years in reservoir (initial porosity: 35%; shales shown in white [off-scale low]) and (B-C) after 20 years and 130 years in the caprock. From Johnson and others, 2003a

Another consideration regarding CO_2-brine-rock interactions is the potential for permeability reduction at the periphery of an injection well due to the speed of CO_2-rock interactions and precipitation kinetics of salts from the brine solution. As supercritical CO_2 is injected, the brine is displaced and dissolution of water in the permeating dry CO_2 can cause formation dry-out in the vicinity of the injection well and lead to the precipitation of halite. This can lead to a reduction in injectivity and can introduce an additional hurdle in controlling CO_2 flood conformance as well as increasing the risk of a rapid pressure increase in the near well environment.

To mitigate this condition, K. Pruess (2009) recommends a slug of fresh water preceding the initiation of CO_2 injection in order to reduce salt precipitation and permeability loss in the near wellbore environment. However, this mitigation method can prove costly or pose adverse operational risks to the injection program (Ott and others, 2013). In an effort to expand upon the dearth of experimental data describing reservoir dry-out and succeeding salt precipitation, Ott and others (2011) conducted corefloods in order to observe the spatial and time evolution of saturation changes and salt precipitation as supercritical CO_2 was pumped into a brine saturated Berea sandstone.

Experiment results revealed that the salt accretion in the injected core was locally concentrated much higher than was present in the original saturating brine. This indicates that capillary-driven backflow of brine presumably explains the local salt precipitation. A decrease in the absolute permeability by a factor of four was observed in association with local salt accretion; yet, the effective permeability increased during the experiment by a factor of five and implies no reduction of injectivity within the core sample. Multiple µCT scans for cross sections of the sandstone core indicates that salt precipitation was largely isolated to the percolation pathways, thus preserving the CO_2-pathways. However, salt precipitation is not strictly due to local accretion, as a bimodal precipitation regime was revealed during a subsequent core-flood experiment employing variables in CO_2 injection rate (Ott and others, 2012). Above a determined critical volumetric flow rate q_{cr}, salt precipitated uniformly in conformity with dry-out front migration. At values below q_{cr}, a negative water saturation gradient develops as water increasingly evaporates in the near-well environment, which leads to the previously observed capillary backflow and local salt accretion (Figure 1.2).

$$q_{sc} p_{sc} X_{H2O,sc} = - q_{aq} p_{aq} X_{H2O,aq}$$

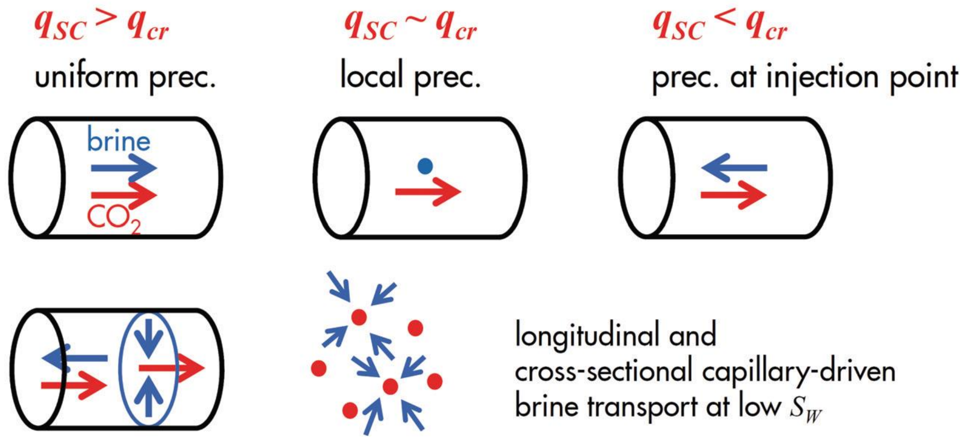

Figure 1.2: Top row: schematic view of the different flow regimes identified for simple pore systems (well sorted sandstone). The flow regimes determine the precipitation pattern and are characterized by the flow rate with respect to a critical flow rate q_{cr}. Bottom row: schematic cross-sectional capillary-driven brine transport as described in the text. (Ott and others, 2012)

In a follow-up investigation, Ott and others (2013) pursued the effects of reservoir dry-out owing to the injection of dry or under-saturated supercritical acid gas and/or CO_2 in a dolomite formation targeted for both EOR and disposal. Unlike in the previous investigation, where the Berea sandstone represented a single-porosity system, the core-flood tests conducted on dolomitic rock were used to characterize the effects of formation dry-out and salt precipitation in a multi-porosity system. Results from the investigation revealed that gas injectivity reduction in a dolomite reservoir depends on the mobility of the brine phase, with a potentially high injectivity reduction at high water saturations. The risk of injectivity loss is expected to be low in EOR reservoirs at irreducible water saturation (immobile brine phase) where the effective permeability is not affected, such as the reservoir in this study. The observed difference in changes of effective permeability in the near-well environment between sandstone and dolomite reservoirs is believed to be caused by the multi-porous dolomite rock matrix, where the micro-porous system stores and slowly contributes brine to the CO_2-conducting macro-porous system and effectively chokes the CO_2 pathway (Ott and others, 2013).

1.1.2 Geomechanical characterization

Geomechanical characterization is often neglected when considering hydrocarbon production. However, geomechanical effects often have a significant impact on production rates and ultimate recovery. As reservoir pressure changes during the life of the EOR project, the stress field is modified, altering the porosity and permeability of the reservoir and the behavior of fractures and faults.

Chiaramonte (2008) developed a geomechanical model of the Tensleep formation, a Pennsylvanian age eolian fractured sandstone that served as the target zone for a pilot CO_2-EOR/storage experiment in a three-way closure trap against a bounding fault. The analysis demonstrated that CO_2 injection would neither induce slip on the reservoir bounding fault nor fracture the caprock. However, the rising pore pressure would critically stress (activate) a network of minor faults, enhancing formation permeability and therefore CO_2 injectivity. The analysis also concluded that the potential for slip on these features could possibly compromise the top sealing capacity of the Tensleep formation should these minor faults extend up into the caprock (Figure 1.3).

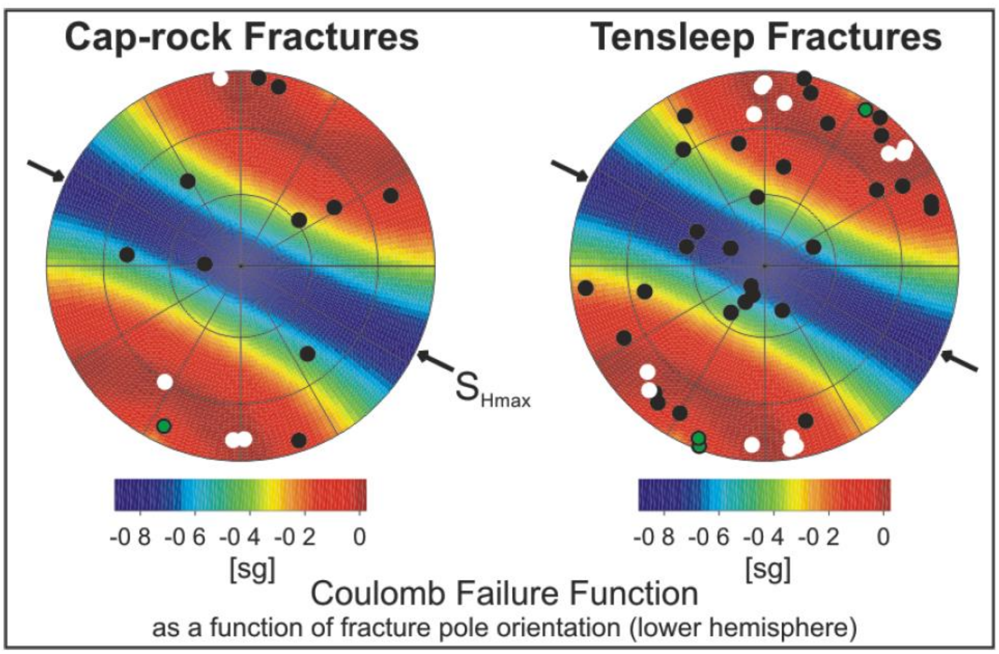

Figure 1.3: Observed Tensleep formation fractures (right) and caprock fractures (left) from three wells in the study area. White dots represent poles of the fractures that are critically stressed. From Chiaramonte (2008)

Chiaramonte also studied injection-induced microseismicity as a means to increase the permeability of tight formations. This technique starts by increasing the fluid pressure in the target formation in order to reduce the effective normal stress on optimally-oriented faults and fractures, triggering slip and, therefore, creating high permeability pathways within the reservoir. The study concludes by proposing the use of the technology for permeability and injectivity enhancement as well as the use of seismic monitoring to gather information about the permeability and the fracture network of reservoirs.

Rutvqvist and Tsang (2002) developed a study on the hydraulic, mechanical and hydromechanical effects to the confining system in response to CO_2 injection, including the spread of the CO_2 plume, effective stress changes, ground surface uplift, stress-induced permeability changes and mechanical failure analysis. The simulation model utilized a hypothetical sandstone aquifer covered by 100 m thick shale, then analyzed the effects of multi-phase flow coupled with heat transfer and rock deformation for reservoirs featuring a homogeneous upper-confining seal (See Figure 1.4).

The results of their study revealed that high CO_2 injection pressure influences the reduction of effective stress within the margin of the injection zone and seal, and that the hydromechanical changes generated by the change in mean effective stress pose the greatest risk to the lower part of the seal. The reduction in effective stress increased the potential for shear failure as fluid diffuses through the rock during the concomitant increase in pressure over time; creating poro-elastic stresses that reduce the shear strength and increase the shear stress simultaneously. The cumulative effect of these changes increased the reactivation of pre-existing faults and fractures primarily by means of shear failure. Furthermore, the potential for shear reactivation in the lower part of the seal is possible at injection pressures below the lithostatic pressure.

However, under such a scenario fault slip reactivation will likely be limited to this portion of the seal, while the effective stress of the upper seal remains unchanged and thus intact. Slow increases in reservoir pressure also favor shear failure over hydraulic fracturing, though, if the fluid pressure increases rapidly, the fluid could rapidly propagate through pre-existing fractures and diminish the effective stresses within these fractures. In this scenario, hydraulic fracturing can be induced, although fractures would be contained within the lower portion of the seal. Finally, in a scenario involving a vertical fault under the conditions of rapid fluid propagation, the upward migration through the upper portion of the confining system is accelerated due to the combination of relative permeability and viscosity changes as well as pressure-induced hydromechanical permeability changes.

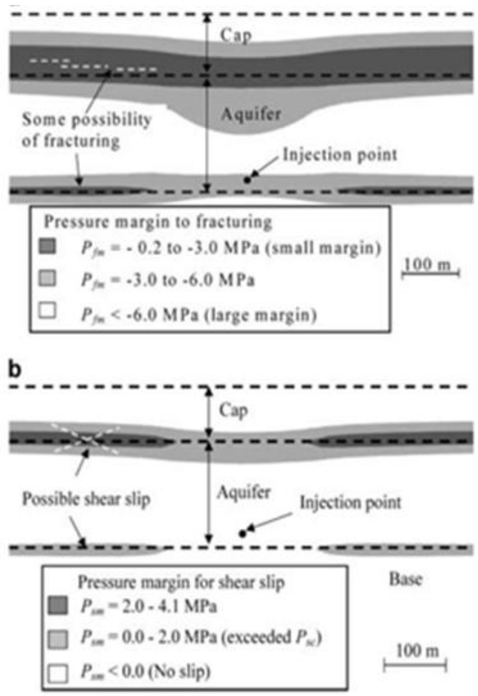

Figure 1.4: Pressure margins to (a) hydraulic fracturing and (b) shear slip in pre-existing faults after 10 years of CO_2 injection. From Rutvqvist and Tsang (2002)

A follow-up report by Rutqvist and others (2008) expands on the aforementioned study involving the hydromechanical changes in the confining system integrity of a homogenous injection aquifer and homogeneous seal, to include a multilayered reservoir-seal system. The study presents the results from coupled reservoir-geochemical simulations that estimate the potential for tensile and shear failure caused by CO_2-injection and further discusses possible guidelines for estimating the maximum sustainable injection pressure of an injection site. The major conclusion from the heterogeneous confining system study is that a simple calculation of the vertical lithostatic pressure is not enough in assessing confining system integrity, and that a full three-dimensional stress field needs to be carefully characterized. The determination of maximum sustainable reservoir pressure also needs to gauge the potential for shear failure along pre-existing fractures, not just tensile fracturing. The estimation of poroelastic stress in EOR projects needs a more robust approach, such as the one adopted in GCS studies, in order to avoid the overestimation of the maximum sustainable injection pressure.

Hawkes and others, (2009) concluded that reactivation of pre-existing faults and fractures can occur when the maximum shear stress working on the fault exceeds the shear strength of the fault plane. In this study, pore pressure determined the slip tendency of a pre-existing fault/fracture. Quantifying the maximum sustainable CO_2 injection pressure required a careful consideration of the permeability and thickness of the overlaying confining system. Furthermore, Rutqvist and others (2008) concluded that a vertical migration of fluid pressure stemming from leakage at the base of the reservoir culminates in the upper part of the confining system evolving into the area of highest tensile or shear failure potential. Further analysis indicated that a compressional injection-induced mechanical failure is preferred over an extensional failure because failure would occur along shallowly dipping fractures and not propagate through the uppermost seal.

1.1.3 Case Study: In Salah

A seal integrity study at Krechba, In Salah, Algeria, utilized a variety of field data to monitor and analyze the response of the reservoir and confining system to CO_2 injection. The study included core and log data, two 3D seismic surveys, microseismic data, wellhead gas pressures, flow rates, gas compositions and tracers, downhole fluid samples, surface gas flux, and satellite InSAR data (Gemmer and others, 2012). The reservoir and seal were mapped using 3D and 4D seismic interpretations, geological modeling, structural reconstructions, and analysis of the well data. An integrated geomechanical model for the Krechba field was then constructed using geometry obtained from available seismic interpretations. Rock mechanical properties for the stress and strain resulting from the pore pressure changes stemming from CO_2 injection and gas production were calculated utilizing available laboratory tests, logs and well data, and 2D finite element modeling. The geomechanical response to CO_2 injection was examined using pore pressure data obtained from well observations and the reservoir simulation model.

In 2010, a Quantified Risk Assessment (QRA) utilizing new seismic, InSAR data and dynamic/geomechanical models detected a dominant risk regarding the potential for vertical leakage in the upper confining system (Ringrose and others, 2013). A pre-injection baseline survey revealed a joint set of NW-SE trending linear fracture arrays in the vicinity of injection wells KB502 and KB503, wherein injection performance and plume development at well KB502 became a focus of concern. Following injection, combined results from satellite InSAR data and reservoir modeling demonstrated that the pressure increase caused by CO_2 injection led to reservoir expansion and displacement of the reservoir overburden interface amounting to ~1 cm after three years as well as minor displacement along the base of the reservoir. Meanwhile, the inferred surface uplift by InSAR is ~2 cm, and suggests that almost half of the observed surface uplift is owed to elastic deformation (Gemmer and others, (2012). The surface uplift suggests CO_2 injection has re-energized the pre-existing NW-SE fractures and potentially induced new hydraulic fractures within the reservoir. Accordingly, CO_2 injection pressure was reduced in June 2010 and later suspended in June 2011 (Ringrose and others, 2013). Presently, no leakage from the reservoir has been detected and the system is considered secure. Nevertheless, the future injection strategy is currently under review as CO_2 induced geomechanical response research is conducted (Ringrose and others, 2013).

Gemmer and others (2012) used a two-dimensional plane-strain finite element model (Abaqus) to simulate the effects of CO_2 injection into two (KB-502 and KB-503) of the three injection wells at Krechba (Figure 1.5). In this study, the effects of the rock mechanical properties on the surface displacement pattern were analyzed by and controlled through three sensitivity studies: Model 1, the reference case linear-elastic model; Model 2, the reference case with fault/fracture zones; and Model 3, Model 2 plus cohesion in the fault/fracture zone over the KB-502 injection well is decreased from 5 MPa to 3 MPa. KB-502 is of interest because this injection well exhibited a bimodal displacement soon after the onset of CO_2 injection that exhibits ~2 cm total uplift forming a rim, with a small ~1 cm depression at the interior of this vertical uplift.

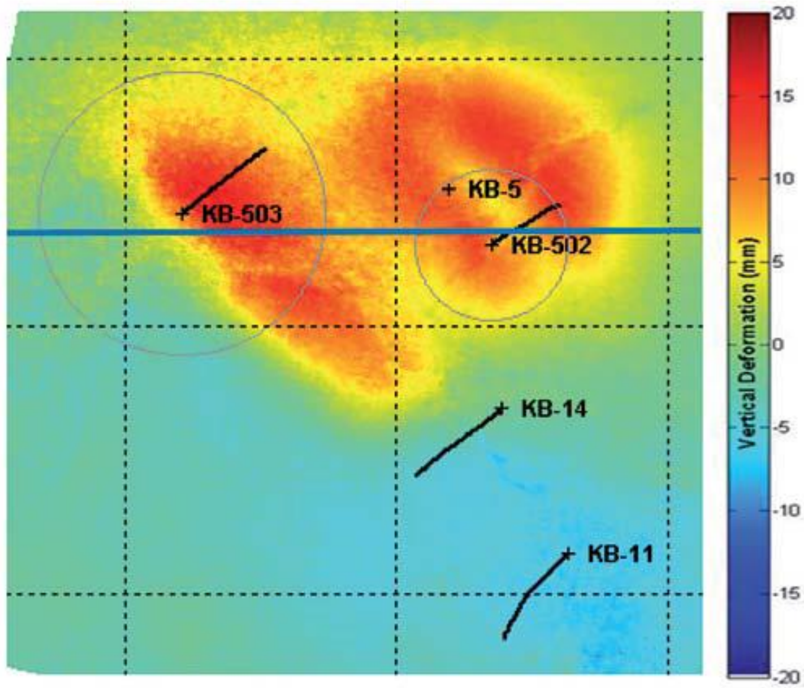

Figure 1.5. Location of geomechanical model (blue line) in relation to injection wells (KB-502 and KB-503) and InSAR vertical surface displacement pattern (mm) (at August 2009, red color indicates uplift of up to 20mm). From Gemmer and others (2012)

Results indicated that the surface displacement pattern depends on the rock mechanical properties, while the inclusion of fault/fracture zones leads to pore pressure increases, accompanied by a decrease in the effective stress and material failure in these zones. This leads to enhanced deformation and a doubling of the vertical and horizontal surface displacement amplitudes compared with the elastic model. However, under some circumstances, the enhanced horizontal displacements lead to local extension and surface subsidence in the center of the injection region, which may explain the observed surface displacement pattern around the KB-502 injection well (Gemmer and others, 2012).

1.1.4 Case Study: Sleipner

A valuable case study in the mechanisms of vertical and lateral plume spread is provided by monitoring plume growth at the Sleipner injection site in the North Sea using repeat 3-D seismic surveys.

The Sleipner gas field in the North Sea is a GCS site in operation since 1996 and has proved instrumental in establishing site characterization studies, testing and proving modeling and monitoring technology, and improving subsequent updates to enable better predictions of CO_2 plume evolution (Eiken and others, 2011). The injection environment is ideal to study the interaction of buoyancy of CO_2 with geologic media and improve modeling skills for this setting. These improved modeling skills can then be used in complex EOR settings to better assess and manage gravity override. At Sleipner, CO_2 was injected into a thick section of very high permeability sandstones of the Utsira Formation, which only has a few thin clayey interbeds in this area to retard vertical flow. In addition, CO_2 was injected at shallow depths, where its density contrast with formation water was high. No other injection or production is occurring in the Utsira Formation, and no pressure increase is occurring to complicate the fluid flow regime.

Movement of the CO_2 plume beneath the slightly deformed base of the seal has been imaged repeatedly, providing a series of plume-edge locations that can be matched using various model methods. Initial petrophysical and geophysical baseline surveys at Sleipner mapped reservoir heterogeneity and these data were utilized to develop the initial site integrity and fluid flow modeling predictions (Boait and others, 2012). Accordingly, the structural and stratigraphic detail surrounding the injection well has proved essential in understanding and predicting the long-term behavior of the CO_2 plume (Chadwick and others, 2004). Additional geophysical surveys have demonstrated the influence of interbedded shale layers within the reservoir sandstone on the vertical and lateral expression of the immiscible plume. These shale layers comprise an intra-reservoir permeability structure that impedes the vertical migration of the plume, while enhancing lateral migration and thus expanding the spatial extent of plume-aquifer interaction (J.W. Johnson, 2004). An analysis of the evolution of the immiscible plume by Boait and others (2011), provides evidence for a three stage growth sequence for each of the nine intra-reservoir horizons observed at Sleipner via an increase in the effective permeablities within the shale layers:

1. Fluid flows beneath a low permeability barrier leading to rapid lateral expansion and eventually the upward propagation through the mudstone layer as the hydrostatic pressure of the CO_2 increases.

2. The thickness of the draining fluid eventually exceeds the thickness of the low permeability layer. Having penetrated the low permeability layer, the buoyancy of the CO_2 contributes to the drainage velocity and halts the propagation of the gravity current.

3. When the weight of the overlying fluid dominates drainage, the lateral extent of the gravity current recedes to a steady state.

Cumulatively, the change in effective permeability along each intra-reservoir shale bed reduces the net flux of CO_2 into the deeper layers of the plume and is simultaneously increased along shallower layers that are now exhibiting rapid lateral propagation (Boait and others, (2011); figure 1.6).

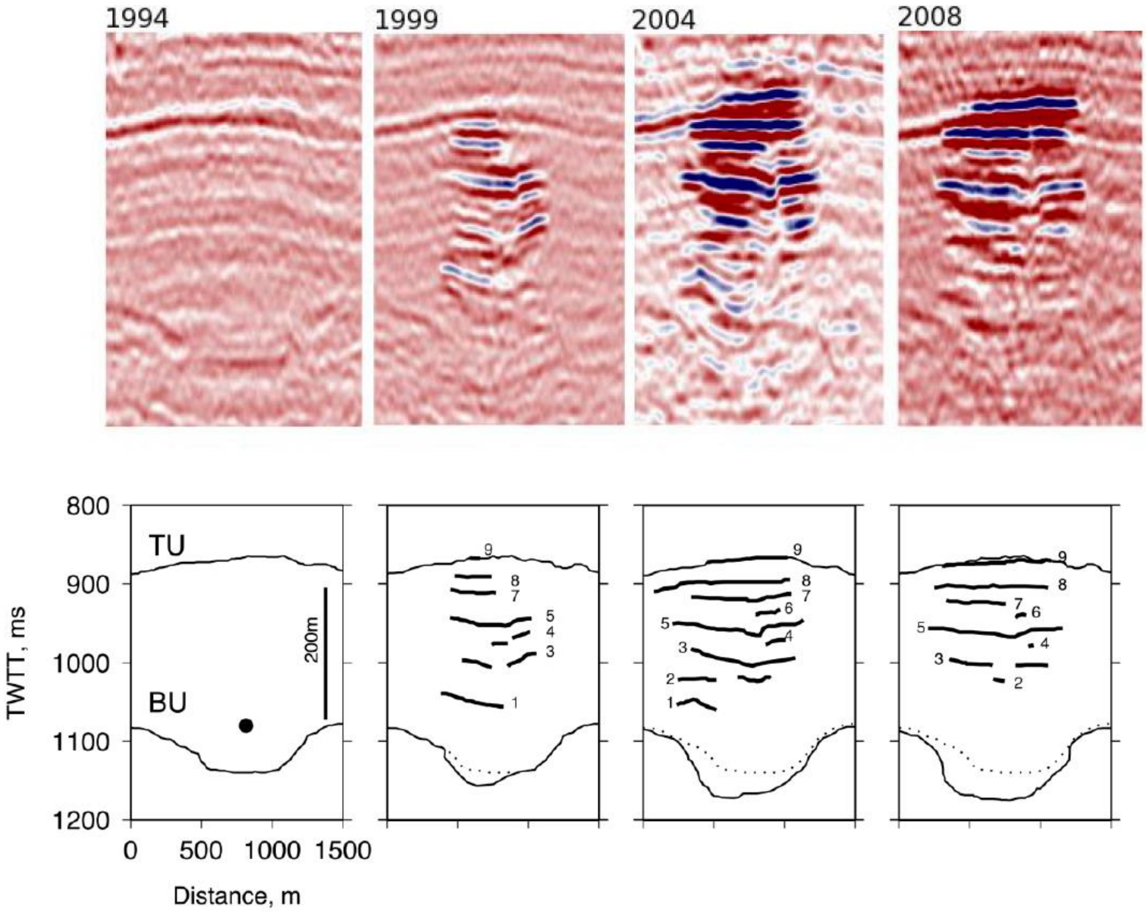

Figure 1.6: Vertical sections through the time-lapse seismic volumes. Upper panels: uninterpreted slices which clearly show growth of CO_2 plume. Note change in reflectivity and push down of deeper layers. Lower panels: line drawing interpretations. Numbered lines correspond to the mapped horizons; solid circle on 1994section = injection point; TU = top Utsira Sand; BU = base Utsira Sand; dotted line = BU from 1994 survey. Note vertical exaggeration. From Boait and others (2011)

Cavanagh (2013) compared migration (capillary flow) and black oil (Darcy flow) simulations to observed plume distributions in the Utsira formation from 1999 to 2008. Results show that a combination of modeling techniques is required to match the gravity-driven flow observed. The modeled rates in particular are not well-matched, however the data provides the constraints needed to improve modeling for this case. Both modeling approaches suggest that the CO_2 plume beneath the seal is likely to become immobile shortly after injection volume decrease, as the plume is considered to be in dynamic equilibrium, considerably reducing the risk of post-injection lateral migration.

1.2 Area of Review (AoR): CO_2 distribution and flow paths leading to CO_2 losses

One of the elements in conducting an effective EOR flood is the effective contact between the CO_2 and the oil. Significant research has been conducted in managing the physical constraints that limit the efficiency of the CO_2 displacement. The main causes of poor sweep efficiency are: (1) CO_2 mobility contrast with the reservoir fluids, which leads to fingering and preferential flow, and (2) gravity override of CO_2, which causes it to migrate to the top of the reservoir. One of the main mechanisms for mobility control in EOR is the injection of brine through the same CO_2 injection wells in a brine-CO_2 alternating manner (Water Alternating Gas, or WAG). Foams or other additives can also be used to reduce the CO_2/oil mobility ratio. Water can be injected to elevate pressure, favoring miscibility and focusing CO_2 to the areas selected for production, sometimes referred to as "water curtain".

For geologic storage, the efficient use of pore volume, similar in most ways to the EOR need for good sweep, is also very important. The major motivations for seeking good sweep are to limit lateral migration of CO_2 and improve storage capacity.

The risks of lateral migration associated with geologic storage of CO_2 in saline formations are defined under the Underground Injection Control Program (UIC), in the Class VI program. Two elements are recognized; the area underlain by CO_2 and the area of elevated pressure. Class VI requires that the operator identify any features that might allow migration of fluids to the freshwater, known in UIC program as underground sources of drinking water (USDW). Conduits for leakage to USDW can be natural (faults) or human made (wells). In the case of water injection under the UIC class I program, injection pressure is the driving force behind leakage. In the case of injection of a buoyant fluid, such as CO_2, gravity forces continue acting even after dissipation of pressure produced by injection. This phenomenon adds a third avenue for leakage, in which CO_2 migrates updip beneath the gently-dipping seal, potentially moving long distances latterly. Long migration paths may allow CO_2 to encounter upward connectivity of transmissive zones through, for example, loss of seal integrity, sand-against-sand fault compartments, or spill points where faults die off.

Understanding the potential for lateral migration requires a good understanding of the reservoir geology. Geologic storage modeling and field studies demonstrate how reservoir heterogeneity and gravitational segregation interact to control the vertical distribution of CO_2 within the reservoir and limit the lateral expansion of flow paths. Improved understanding of geological controls on lateral flow assists in selecting an adequate monitoring approach as well as in implementing a more effective injection strategy for a projected maximum and ultimate extent of the CO_2 plume.

Juanes and others (2006) studied the evolution of an immiscible CO_2 plume footprint in a homogenous aquifer. In this geological setting, the plume is governed by gravitational buoyance arising from the density difference between CO_2 and brine as well as the capillarity between reservoir fluids and rock that limits the lateral dimensions of the plume. As CO_2 is injected into the reservoir, the less wetting CO_2 displaces the more wetting brine via a drainage-like process. As gravity effects produce an upwelling of CO_2, the gas is displaced in an imbibition process while the backflow of brine at the trailing edge of the plume contributes to the distinctive shape of the plume-shaped gravity tongue (Juanes and others, 2009). As the plume encounters an impermeable confining system at the top of the reservoir, the CO_2 accumulates beneath the layer and hereafter rapidly spreads laterally.

Spatially heterogeneous rock properties (e.g. permeability and capillary pressure) can create preferential flow paths, which favor lateral plume propagation (Bryant and others 2008) and create large CO_2 footprints. Reservoir heterogeneity features can be a product of geological depositional history, post-depositional diagenetic processes, structural deformation or the precipitation of asphaltene and heavy oil "flocs" during CO_2-EOR operations at a site. All these factors have an influence on fluid flow, which can significantly affect channelization or fingering behavior of CO_2 and the overall character of the plume. A comprehensive assessment of reservoir heterogeneity characteristics will be important to establish an accurate projection of reservoir fluid flow evolution and to ultimately promote a more effective CO_2 flood conformance strategy. Two types of heterogeneity affect fluid flow: (1) heterogeneity in map view, in which the CO_2 plume grows preferentially in some rock volumes, such as along the channel-axis where high permeablities are found, leading to an elongated or spider-form plume, and (2) vertical heterogeneity, in which some zones of a rock sequence are more permeable and accept most of the CO_2, leading to a thick reservoir in which only a small part of the sequence accepts CO_2 , which then leads to large lateral spread. These factors have long been recognized in EOR floods as reasons for by-pass (Lake, 1989). However, monitoring floods in saline formations where the system is minimally modified by production improves the understanding of fluid flow processes and allows for effective modeling approaches.

A reservoir depositional history comprised of sedimentation along the lobes and branches of fluvial channels can also comprise a heterogeneity feature that can affect the plume shape evolution and migration characteristics. In such a system, the difference in permeability between channels and the surrounding sediment will dictate the preferred fluid flowpaths as the CO_2 will tend to migrate along higher permeability channel structures (Thatcher and others, 2011).

The preferred migration of CO_2 along fluvial channels has been observed in field studies during subsurface monitoring of CO_2 injection at SECARB's phase-III Cranfield site, where monitoring large volume injection into a heterogeneous amalgamated fluvial reservoir with wide lateral continuity but containing many internal high permeability zones, as well as likely zones that baffle flow (Figure 1.7), demonstrated some of the impacts of reservoir heterogeneity on fluid flow. Although this field was developed as an EOR flood, the development of the flood was excellent for making observations. Rather than being developed as a phase of water flood, Cranfield was abandoned and shut in in 1966, so that pressure and fluids could re-equilibrate prior to initiation of the flood in 2008. Additionally, the operator Denbury Onshore LLC, operates the field by continuous CO_2 injection (no WAG), and waits for CO_2 arrival and reservoir pressure to build to drive production. Therefore, the early stages of field development are simple injection, like a storage-only site.

Pressure response through the reservoir showed that pressure communication through the water phase was very good, with only a crestal graben fault segmenting the reservoir. However, CO_2 breakthrough showed strong evidence that two-phase flow was dominated by preferential flowpaths over short distances. At one monitoring well location (EGL7), CO_2 arrival was delayed compared to model predictions by almost a year and a half, unlike faster than modeled arrival at others wells. Another transect in which wells were placed close together and monitored repeatedly showed clear interaction of the two-phase fluid flow with reservoir heterogeneity. At high injection rates, CO_2 (measured with tracers) arrived faster at the more distant well located 100 meters downdip of the injector, by-passing the nearer observation well at 60 m. This behavior shows preferred flow through sinuous channel geometry. In addition, cross-well surveys show that the CO_2 accessed two layers of the possible 60 m-thick interval, by-passing much of the permeable reservoir formation (Lu and others, 2012; Hovorka, 2012). Modeling could not identify a single realization of the channel geometry that matched all required observations; however an array of realizations could bound the observed conditions (Hosseini and others, 2012)

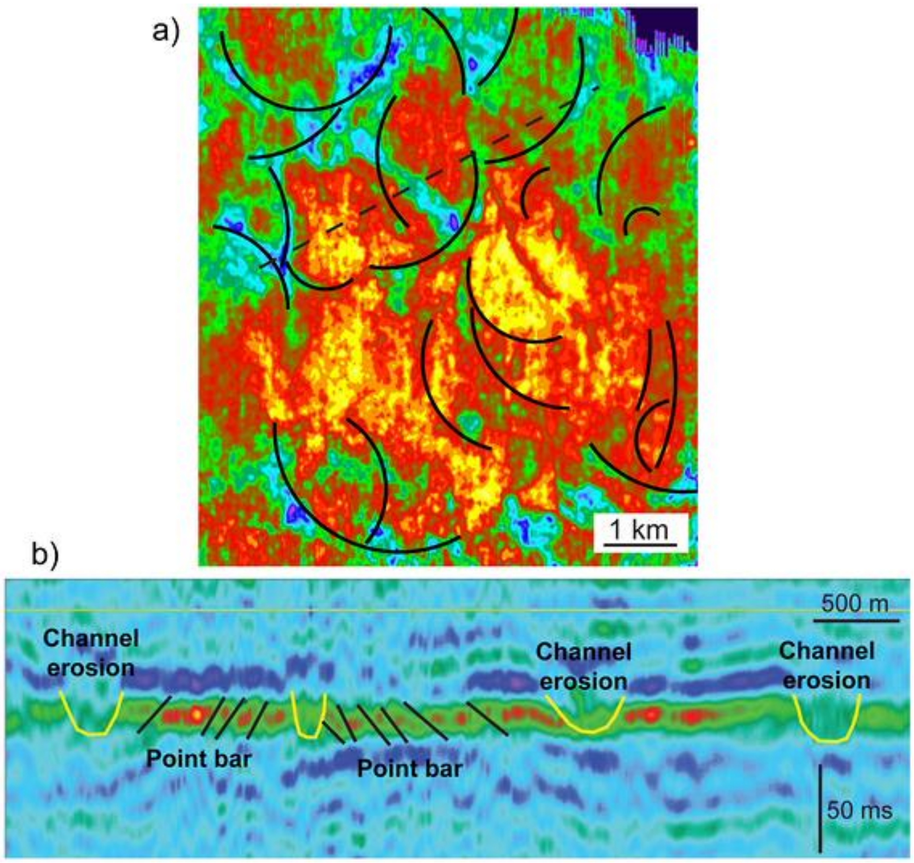

Figure 1.7. (a) Stratal slice of the 3-D seismic survey, with interpreted channel morphologies in the Lower Tuscaloosa Formation “D-E” interval showing high-amplitude (red) sinuous fluvial channel loops. Dashed line shows location of cross section in Figure. (b) Interpreted channel morphologies in seismic profile, showing general reservoir architecture of a fluvial point-bar plain. Sandstones (red) appear to be discontinuous laterally, suggesting sinuous deposition in 3-D. Location of cross section marked by dashed line in Figure a. (Lu and others, 2012)

Another important type of heterogeneity is structural heterogeneity. At the In Salah CO_2 storage site, Algeria, the influence of structural deformation on CO_2 migration in the subsurface has been demonstrated in relation to a network of intra-reservoir faults and fractures. The reservoir is extensively fractured along a predominant joint set (NW-SE) in close alignment with the present-day stress field and is also faulted by a series of strike-slip faults (E-W) stemming from basin inversion (Cavanagh and Ringrose, 2011). The Krechba reservoir at In Salah is comprised of a 20 m thick homogeneous sandstone with fluid flow from three injection sites (KB501, KB502 and KB-503) directed by and entrained at topographic traps along the reservoir-confining system interface (J.P. Deflandre and others. 2011). The network of faults at In Salah act as a barrier to fluid flow and simulations studies suggest they locally restrict the CO_2 around the injection wells and channelize flow toward topographic traps at the reservoir-confining system interface (Cavanagh and Ringrose, 2011).

CO_2-EOR projects may benefit from the required site characterization and modeling efforts developed for geologic storage operations in order to accurately predict flood conformance evolving from the injection of CO_2. An understanding of reservoir heterogeneity can provide key insight into performance of a CO_2 flood and enable the development of an injection well network and an injection rate strategy that will enhance hydrocarbon production rate as well as CO_2 utilization efficiency. However, the task of undertaking a site characterization study need not be strictly constrained to new CO_2-EOR sites. Older EOR fields with heavy infrastructure investment in CO_2 pipeline and separation facilities but declining production may be candidates for improved concepts of the intersections of fluid flow with reservoir heterogeneity to be employed to redesign patterns to access parts of the reservoir previously by-passed.

1.3 Hydrogeochemistry: rock-water-CO_2 interactions and understanding of flow processes

Chemical interactions between CO_2 and reservoir brines have traditionally been ignored by EOR operators, because of the dominant interaction of CO_2 and oil. However, storage projects where CO_2 containment needs to be assured have invested extensively in understanding rock-water interactions with introduced CO_2. Advances in CCS research, such as the inclusion of a water phase in compositional simulation which accounts for CO_2 dissolution, an important trapping mechanism, could enhance the accuracy of industry CO_2 flood modeling efforts. Hydrogeochemical reactions monitored during CCS pilot projects have demonstrated the timescale of CO_2-brine-rock trapping processes that lead to an increase in CO_2 storage and the long-term integrity for these sites; data which can be extrapolated to CO_2-EOR operations to furnish a better understanding of CO_2 recycling debits and an increase in CO_2 commodity efficiency.

Several trapping mechanisms secure supercritical CO_2 in saline aquifers: (1) residual gas trapping, (2) solubility trapping, (3) structural/stratigraphic trapping, (4) mineral trapping, and (5) ionic trapping. Residual trapping, or capillary trapping, occurs rapidly as the CO_2 initially displaces the brine throughout the porous rock and is subsequently trapped in the pore throat as brine reinvades the region. A surface tension (capillary force) secures CO_2 in an immobile state within the pore spaces of reservoir rock. Some solubility trapping occurs early during CO_2 injection when CO_2 contacts undersaturated brine, with the amount of dissolution dependent on pressure and salinity of formation water. Structural trapping occurs as the CO_2 plume accumulates underneath the seal as a free mobile phase, or generally up-dip within a geological structure or topographic high. Mineral trapping occurs over a long period of time and represents the conversion of CO_2 to mineral precipitates (Han and others, 2010)

A rapid geochemical reaction observed at the onset of CO_2 injection is a decrease in the pH of the reservoir brine caused by the dissolution of CO_2 in water to produce carbonic acid (H_2CO_3), which dissociates to bicarbonate HCO_3^- and a hydrogen ion (H^+). This rapid drop in the pH of the brine causes dissolution of reservoir minerals in the cement or rock, particularly carbonates, to produce bicarbonate and a calcium ion (Ca^{2+}), generating a buffered reaction that elevates the brine pH to a less acidic concentration. Over the long term, alumino-silicate minerals are also dissolved (I. Gaus, 2009). In this instance, dissolution reactions between the acidic brine and alumino-silicate minerals function as geochemical conduits to entrain CO_2 through ionic and mineral trapping:

(a) An example of ionic trapping can be represented by the dissolution of calcite:

$$CO_2\ (g) + H_2O + CaCO_3 \Rightarrow Ca^{2+} + 2HCO_3^-$$

(b) An example of mineral trapping is the alteration of albite or k-feldspar leading to the storage of CO2 in the product dawsonite:

$$NaAlSi_3O_8\ (\text{albite}) + CO_2\ (aq) + H_2O \leftrightarrow NaAlCO_3(OH)_2\ (\text{dawsonite}) + 3SiO_2;\ \text{or}$$

$$KAlSi_3O_8\ (\text{k-feldspar}) + Na^+ + CO_2\ (aq) + H_2O \leftrightarrow NaAlCO_3(OH)_2\ (\text{dawsonite}) + 3SiO_2 + K^+$$

Water becomes denser as it dissolves the CO_2 causing convective mixing that increases the dissolution of CO_2 in brine (Hassanzadeh and others, 2005). As the density contrast is small, the rate of convective mixing may be slow.

1.3.1 Case Studies

Frio

Evidence for the aforementioned buffering reaction was observed during the monitoring of fluid compositions conducted by the Gulf Coast Carbon Center at the University of Texas during the Frio brine pilot project. Prior to CO_2 injection, chemical analysis classified the Frio brine as a Na-Ca-Cl type water, with 93,000 mg/L total dissolved solids (TDS) and 40-45 molar mass of dissolved CH_4 at reservoir conditions (Kharaka, 2006) in a weakly-cemented sandstone reservoir. Fluid composition monitoring following the start of CO_2 injection revealed a sharp drop in the brine pH from 6.5 to 5.7 resulting from the dissolution of CO_2 in the formation brine. A sharp increase in alkalinity (100 to 3000 mg/L of HCO_3^-) as well as additional significant increases in Mn and Ca are observed, (Figure 1.8). These effects can be attributed to the dissolution of minor amounts of carbonate and iron oxyhydroxide minerals coating sand grains (Kharaka, 2006). High surface areas result in rapid but short-term reactions, duplicated in the lab (K, Knause, personal communication; Lu and others, 2012b)

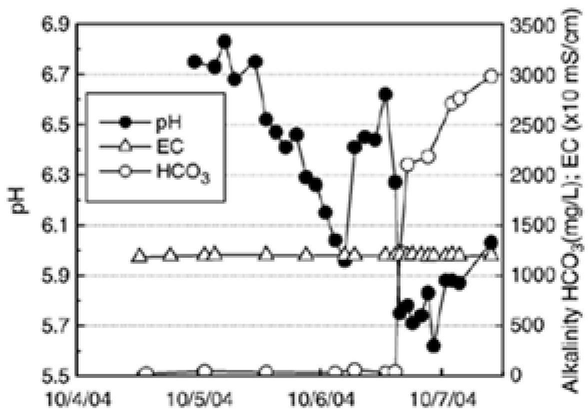

Figure 1.8: Electrical conductance (EC), pH and alkalinity of Frio brine from observation well determined on site during CO_2 injection. Note the sharp drop of pH and alkalinity increase with the breakthrough of CO_2. From Kharaka, 2006.

Weyburn-Midale

In this classic example of GCS research in an EOR environment, several techniques to quantify CO_2 losses and track CO_2 movement were tested. In addition to solubility trapping, the significance of ionic trapping as a short-term CO_2 storage mechanism was experimentally induced and observed during a 40 month period of injection into a dominantly carbonate hydrocarbon reservoir at the IEA Weyburn CO_2 Monitoring and Storage Project, Saskatchewan, Canada. Baseline data for CO_2 and HCO_3^- was determined through fluid samples collected from 4 production wells prior to CO_2 injection, and analyzed to obtain the HCO_3^- concentration understand the behavior of the low carbon isotope ratio ($\delta^{13}C$ value). Results from the geochemical monitoring program evidenced the magnitude of ionic trapping of CO_2 within the reservoir as the 4 production wells exhibited an increase in HCO_3^- concentration, a marked increase in mole% CO_2, and a decrease in the $\delta^{13}C$ values of HCO_3^- and CO_2 throughout the monitoring period. The increase in HCO_3^- concentration and mole% CO_2 in conjunction with the observed decrease in $\delta^{13}C$ HCO_3^- and CO_2 values demonstrates that a significant volume of injected CO_2 had dissolved in the reservoir brine and converted to HCO_3^- (Raistrick and others, 2006).

The Pembina Cardium CO_2 Monitoring Project in Alberta, Canada, also utilized the injection of CO_2 with a low carbon isotope ratio ($\delta^{13}C$) in order to determine CO_2 plume evolution and preferential flow paths in a hydrocarbon reservoir. This method successfully established a useful tracing technique to observe movement of CO_2 throughout the reservoir by detecting the early breakthrough of injected CO_2 in concentrations requiring only a minimum 10% difference between baseline and $\delta^{13}C$ values of injected CO_2 (Johnson and others, 2011).

A follow-up study conducted by Raistrick and others (2009) evaluated whether silicate mineral dissolution occurred in the first phase of the Weyburn-Midale project through modeling the potential impact of silicate mineral reactions for future CO_2 storage via ionic and mineral trapping. Geochemical data from twelve geochemical monitoring events were used to trace injected CO_2, quantify the mass of injected CO_2 stored as HCO_3 -, estimate molecular CO_2 storage in the reservoir fluids and evaluate CO_2-aqueous fluid-mineral reactions. Four years of production well monitoring at Weyburn measured changes in chemical and isotopic data for produced aqueous fluids and gases. These samples demonstrated an increase in Ca_2^+, Mg_2^+, K^+, SO_4^{2-}, HCO_3^-, and CO_2 concentrations in addition to a decrease in $\delta^{13}C$ HCO_3^- and $\delta^{13}C$ CO_2 values. The reaction pathways predicted by geochemical modeling of the CO_2-rock-water system were confirmed in the field~~.~~

Nagaoka

The Nagaoka Site, Japan, represents a pilot CO_2 storage project focusing on the performance of CO_2 during and after injection. This project has provided insight on the geochemical reactions between reservoir rock minerals and formation water as well as the significance of solubility trapping as the predominant early stage CO_2 storage mechanism. Prior to CO_2 injection, reservoir rock and formation water was sampled for laboratory analysis, then followed by a subsequent sample collection approximately one year after the cessation of CO_2 injection (Mito and others 2008). Post- CO_2 injection fluid samples collected from a depth interval located slightly below the CO_2 bearing zone were evaluated utilizing chemical analysis and revealed a significant increase in HCO_3^-, Ca, Mg, Fe, and Si concentrations compared to the composition of pre-CO_2 injection formation water. Further analysis of the chemical reaction mechanisms operating within the CO_2-rock-water system indicates that dissolution of CO_2 in formation water is the predominant reaction (over carbonate dissolution) leading to the increase in aqueous HCO_3^- (Mito and others, 2008).

The increase in Ca, Mg, Fe and Si in post-CO_2 injection fluid composition at the Nagaoka site developed from geochemical reactions governed by the interplay between mineral dissolution rates and the relative concentrations of minerals present in the reservoir rock (see figure 1.9). At Nagaoka, the reservoir rock is immature, with high feldspar content, and accessory minerals that include chlorite and carbonate , and likely represent the sources of Ca^{2+}, Mg^{2+}, Fe^{2+} and Si^{4+} in the early stage of CO_2 storage at the reservoir (Mito and others, 2008). Furthermore the dissolution of plagioclase and chlorite is expected to neutralize the acidification of formation water derived from the dissolution of CO_2, while the accumulation of Ca^{2+}, Mg^{2+} and Fe^{2+} in turn enhances the mineral trapping of CO_2 through the long-term precipitation (Mito and others, 2008).

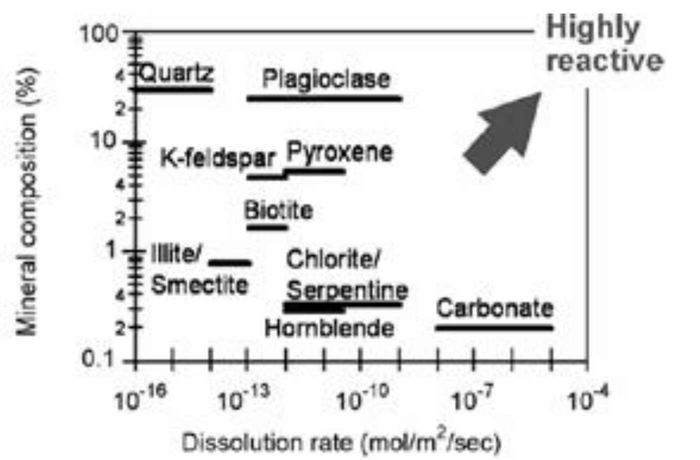

Figure 1.9: The dissolution rate of a mineral versus the amount of the mineral in the reservoir rock. From Mito and others 2008.

Cranfield

The capacity of this reservoir to entrain CO_2 via mineral trapping was found to be largely dependent on the mineralogical and petrographic properties of the reservoir during the geochemical monitoring program at the Cranfield CO_2-EOR site in Mississippi. The sandstones have been diagenetically stabilized prior to CO_2 injection at Cranfield, and are now composed of less reactive quartz and chert grains, abundant chlorite forms a pervasive grain-coating early cement, isolating grains from contact with pore fluids. Plagioclase, kaolinite and illite are present in minor amounts. Carbonate is somewhat isolated from major flow paths, forming nodules (Lu and others, 2012).

Fluid sampling conducted at the site confirms the limited reactivity of reservoir minerals with CO_2-saturated brine. TDS values for metals associated with carbonates following CO_2 injection, including Ca, Mg, Mn and Sr remained constant. Only alkalinity from HCO_3^- and Fe derived from iron oxyhydroxide grain coatings exhibited an increase in concentrations. The increase in HCO_3^- did buffer the drop in pH following an early decrease after CO_2 injection, but the concentration of metal cations remained unchanged and suggests that only limited mineral dissolution may have occurred in response to CO_2 -driven fluid composition changes (Lu and others, 2012). This leaves dissolution of CO_2 as the main geochemical trapping mechanism at Cranfield and suggests that EOR reservoirs of comparable mineralogy can expect an insignificant impact on reservoir brine chemistry and mineralogy.

1.4 Petroleum Geochemistry: interactions with reservoir hydrocarbons and impact on oil recovery and flow

1.4.1 Oil geochemical changes

The success of a CO_2-EOR project is largely shaped by the interfacial interactions that evolve between reservoir fluids, rock and the injected CO_2. Interfacial interactions are predominantly comprised by the interfacial tension (IFT), interfacial mass transfer, and wettability within these systems, which can severely affect the precipitation of asphaltene in the reservoir. Asphaltene precipitation demonstrates a commanding impact on recovery and flow concerns in a CO_2-EOR project when enough CO_2 is dissolved in the crude and as is often the case, asphaltene deposition in the porous medium may cause wettability alteration and reservoir plugging, thus limiting hydrocarbon production. An analysis of oil production samples collected from the McElroy Field, Texas, following the initiation of a pilot CO_2 flood project exhibited a significant ~50% decrease in asphaltene content as well as an increase in oil API gravity attributed to the deposition of heavy hydrocarbons from the oil phase (Hwang and Ortiz, 1998). A consequential reduction in injectivity at some injection wells stemming from the decrease in reservoir porosity and permeability is strongly attributed to asphaltene precipitation and deposition of heavy hydrocarbons in the form of "flocs" that severely restrict fluid flow within the reservoir.

In an effort to determine the mutual interactions between crude oil and CO_2 at reservoir conditions, M. Nobakht and others (2008) conducted a coreflood experiment utilizing axisymmetric drop shape analysis (ADSA) aimed at ascertaining the onset pressure of asphaltene precipitation for individual crude oil- CO_2 systems stemming from a simulated CO_2 flood. This procedure was then followed by an attempt to calculate the equilibrium interfacial tension between crude oil and CO_2 at different equilibrium pressures and a constant temperature T=27 °C, throughout which interfacial interactions were also recorded during the IFT measurements.

The crude oil- CO_2 system was tested in a see-through windowed high-pressure saturation cell to determine the onset pressure of asphaltene precipitation. The initial pressure P=2.0 MPa was incrementally increased to 4.5 MPa at T=27 °C, with no noticeable deposition of asphaltene within the CO_2-saturated oil layer. At P=4.5 to 5 MPa, asphaltene precipitation was observed, and further tests to lower the pressure to 3 MPa suggests that precipitation is irreversible. Later tests utilized smaller incremental pressure increases of 0.1 MPa in order to narrow the onset pressure range of asphaltene precipitation above 4.5 MPa, for which a range between 4.7 to 4.8 MPa at T=27 °C was successfully established.

The equilibrium IFTs between the crude oil and CO_2 were measured at 12 different equilibrium pressures and T=27 ◦C, where the minimum IFT approximately reduced in a linear trend with the equilibrium pressure, provided that the pressure remained lower than the 7.2 MPa threshold. This reduction in equilibrium IFT is ascribed to the improved solubility of CO_2 with crude oil at an increased equilibrium pressure. However, the equilibrium IFT is only marginally decreased with the equilibrium pressure as it exceeds the threshold pressure (figure 1.10). Oil-swelling due to the dissolution of CO_2 in to the oil phase occurred at equilibrium pressures equal to or lower than 6.0 MPa, whereupon light component extraction commenced at equilibrium pressures equal to or higher than 6.6 MPa. Thereby, it was determined that the onset pressure of initial light-component extraction is equal to 6.6 MPa.

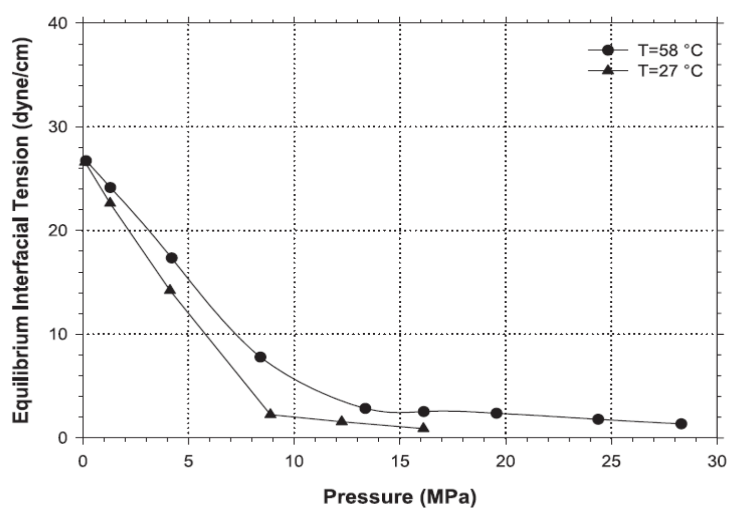

Figure 1.10: The measured equilibrium IFT of a crude-oil-CO_2 system versus pressure at two different temperatures. From Yang and Gu (2005)

In a comparable study on interfacial interactions utilizing ADSA, Yang and Gu (2005) measured the change in dynamic IFT between crude oil and CO_2 at high pressures and temperatures. Similarly, it was found that dynamic IFT versus time at T=27 °C and T=58 °C reduces to the equilibrium IFT at different pressures, for which dynamic IFT is achieved in less time at elevated temperatures (figure 1.11).

Moreover, it was found that the equilibrium IFT at higher temperatures is effectively elevated and can be attributed to reduced solubility of CO_2 in an oil phase as temperatures increase. However, the effect of pressure on equilibrium IFT supersedes the effect of temperature, and exhibits an equilibrium IFT decrease with increasing pressure.

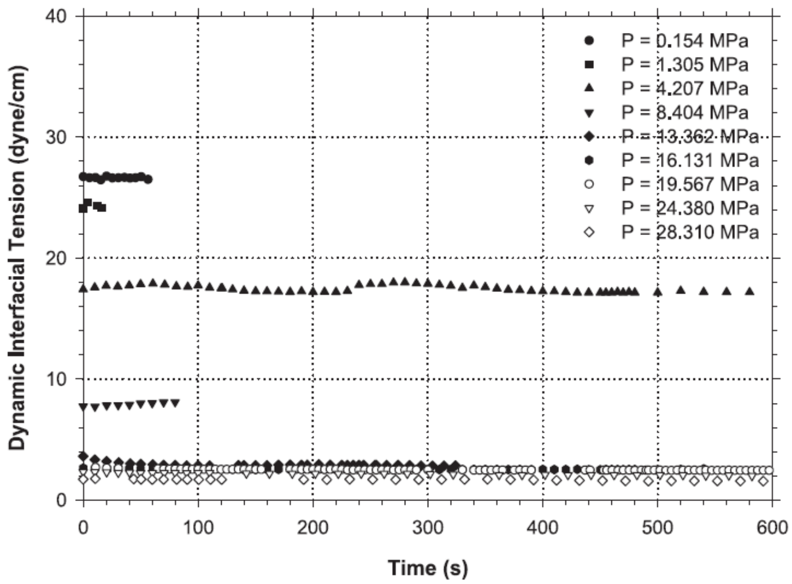

Figure 1.11. The measures dynamic IFT of a crude-oil-CO_2 system versus time under different pressures at T=58 ^{o}C. From Yang and Gu (2005)

An analysis of light-ends extraction was included in the IFT measurements by Yang and Gu (2005) in order to obtain a more comprehensive understanding of extraction dynamics in correlation with changes in pressure and temperature. Wherein, shortly after the onset of oil swelling due to the dissolution of CO_2, the oil shrinks as light-ends extraction initiates. When the operating pressure exceeds that of supercritical CO_2, initial turbulent mixing ensues and arrests oil swelling due to an acceleration in light-ends extraction. As temperatures increase, turbulent mixing will initiate at higher pressures and becomes more pronounced because of the lower solubility of CO_2 at elevated temperatures. Upon the exhaustion of light-ends extraction, the equilibrium IFT is achieved and the heavy-ends statically remain.

In an oil-wet reservoir the porosity and permeability are predicted to decrease as the deposited heavy-ends will develop a permanent coating on the grains of the porous reservoir rock, which will block the reservoir brine and CO_2 in the pores from coming in contact with the inner oil layers on the rock surface. However, in a water-wet reservoir, CO_2 saturated brine coats the porous media and keeps the CO2 in contact with the residual oil (Yang and Gu, 2005).

In order to determine the effect of injection pressure on CO_2-EOR, Nobakht and others (2008) conducted a total of seven CO_2 coreflood tests at different injection pressures, utilizing a constant volume injection rate and temperature (figure 1.12). Each CO_2 coreflood test was terminated after 1.5 pore volume (P.V.) of CO_2 was injected as the maximum volume of CO_2-EOR recovery attained at this level. For injection pressures less than or equal to 5.93 MPa, the potential for CO_2-EOR is low and independent of injection pressure as a result of early breakthrough caused by the low viscosity of CO_2. At pressures greater than 5.93, the CO_2-EOR significantly increases due to the increased viscosity of injected CO_2 and the subsequent decrease in the equilibrium IFT. When the CO_2 injection pressure exceeds 7.17 MPa, maximum CO_2-EOR production and residual oil saturation are realized. The study concluded that when the injection pressure exceeds threshold pressure, further defined as the maximum CO_2-EOR pressure, oil recovery at 1.5 P.V. of CO_2 is effectively independent of the injection pressure. All told, M. Nobakht el al. (2008) determined asphaltene precipitation is induced at 4.7-7.8 MPa, initial strong light-components extraction commences at 6.6 MPa, the minimum IFT pressure is achieved at 7.25 MPa and maximum CO_2-EOR productivity surmounts at 7.17 MPa.

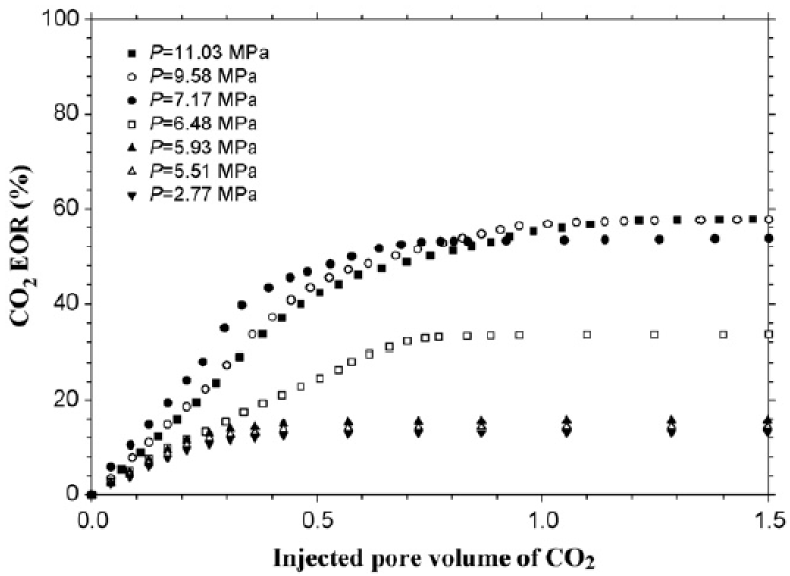

Figure 1.12: Measured CO_2-EOR versus the injected P.V. of CO_2 at qCO_2 = 0.5 cc/min and t = 27^{o}C. From Nobakht and others, 2008

An injection program aimed at implementing a "cocktail" strategy to maximize CO_2-EOR production, reduce CO_2 trapping and target stubborn heavy oil reserves potentially requires the re-characterization of existing and future CO_2-EOR projects in order to map where impermeable channels are or are likely to develop. Derakhshanafar and others (2012) has presented a simulation study on CO_2-assisted waterflooding for enhanced heavy hydrocarbon recovery that aims to improve the efficiency of CO_2 conformance and heavy hydrocarbon production by preventing the channelization of CO_2 through the oil zone, while simultaneously enhancing concomitant geologic storage of CO_2. The simulation model utilized three injection scenarios following an initial waterflooding in sand-packed coreflood tests:

1) Pure CO_2 slug.

2) Continuous carbonated water flooding.

3) CO_2 carbonated slug injection.

Should a goal of the project be to enhance oil recovery and simultaneously promote CO_2 recovery for repeated injection, then a pure CO_2 slug injected at high pressures would yield the highest heavy oil return and leave less CO_2 trapped in the reservoir. Conversely, a continuous carbonated flood would yield the highest heavy oil production at low pressure as well as geologically store the greatest amount of CO_2 for both high and low injection pressures.

1.4.2 Impact of CO_2 impurities on final recovery

In an EOR project, impurities in the CO_2 injection stream are mostly considered in terms of the damage they may cause on the EOR infrastructure, but rarely considered in terms of their impact on the final recovery of the EOR flood. GCS studies have demonstrated that the impact of impurities on miscibility, density, solubility, and the mobility ratio of displacing and displaced fluids (all crucial parameters that control the conformance of the CO_2 flood) is significant. The mix of impurities depends on the primary source of CO_2: (1) natural source, (2) anthropogenic flue gas, and (3) recycled CO_2-EOR gas. For example, captured flue gas may include N_2 and recycled or natural sources of CO_2 may contain CH_4 or natural gas liquids, while the inclusion of SO_2 or H_2S in the CO_2 injectant can be introduced by either (J.R. Wilkinson and others (2010). Given that CO_2 injection streams containing any combination of N_2, CH_4, H_2S, SO_x or NO_x can modify the performance CO_2-EOR flood conformance, special consideration should be given to determine the effects of such an injectant on oil field reservoir fluids.

Nicot and others (2008) examined CO_2 stream impurities involving CH_4 and N_2 and their coupled effects on (1) plume spread, (2) rate and extent of major trapping mechanisms, (3) CO_2 storage capacity, and (4) well injectivity. Trapping mechanisms included in the study were restricted to solubility and residual trapping as these trapping mechanisms as well as the range of plume migration are predominantly influenced by the composition of the injection stream. Compared to pure CO_2 stream, the inclusion of CH_4 and N_2 in an injection stream will profoundly affect the rate and extent of plume migration owing to a stronger solubility resistance than CO_2 and stronger gravitational buoyancy due to a greater difference in gas-brine viscosity. As CO_2 dissolves in the formation water, the concentration of these impurities within the plume accumulates, thus increasing the rate and range of plume spread. For the purpose of CO_2 storage, the addition of injection stream impurities may have the cumulative effect of prompter plume immobilization; however, the rapid evolution and greater AOR of the plume may inhibit CO_2-EOR flood conformance. Conversely, a pure CO_2 stream may prove beneficial in that the plume will not travel as far and stay mobile longer, allotting more time for CO_2-hydrocarbon contact. Ultimately, because CH_4 will remain in a gaseous state during the injection of supercritical CO_2, the greater buoyancy of this gas is a potential concern with regard to the overpressurization of the reservoir and should be considered in a site characterization for CO_2 sequestration/EOR projects (Klusman, 2003).

The impact of N_2, CH_4 and H_2S impurities minimum miscibility pressure (MMP), density and viscosity has been reported by J.R. Wilkinson and others (2010) by utilizing screening tools that analyze the cost benefit of stream purification. For instance, in examining the effect these impurities had on miscibility, a CO_2 injection stream containing 10% CH_4 or N_2 by volume was shown to increase the MMP by approximately 700 and 1100 psia respectively, while the concentration of H_2S decreased the gas MMP approximately 200 psia across a spectrum of pressures and temperatures ranges (see figure 1.13).

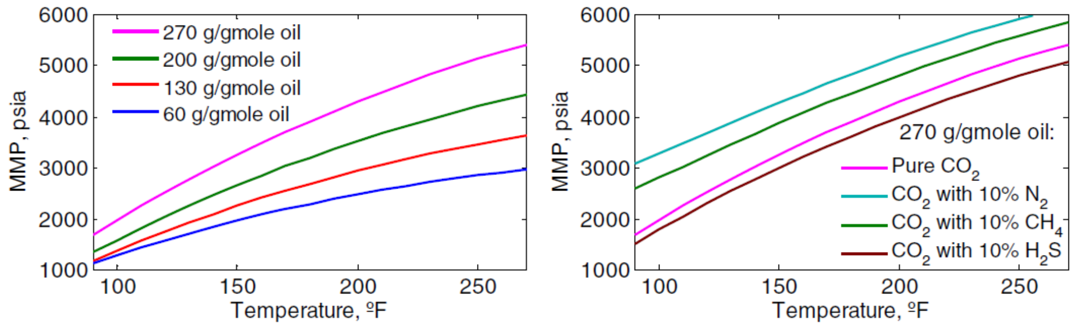

Figure 1.13: MMP variation with temperature and oil molecular weight for pure CO_2 (left) and with impurities (right). From J.R. Wilkinson and others 2010

Density changes in the injection fluid caused by the inclusion of N_2 and CH_4 correspond with the conclusions set forth by Nicot and others (2008) as the emphasized focus on EOR production in Wilkinson and others (2010) establishes a parallel conclusion regarding the reduction in sweep efficiency brought on by the greater magnitude of gravity segregation. Sweep efficiency is also largely dependent on the mobility ratio, whereby the increased gas mobility stimulated by the presence of CH_4 and N_2 leads to a marked reduction in sweep efficiency and, hence, a decline in the recovery factor. In contrast, the comparable sweep efficiency of pure CO_2 and adulterated CO_2-H_2S streams exhibit greater recovery factors (see figure 1.14).

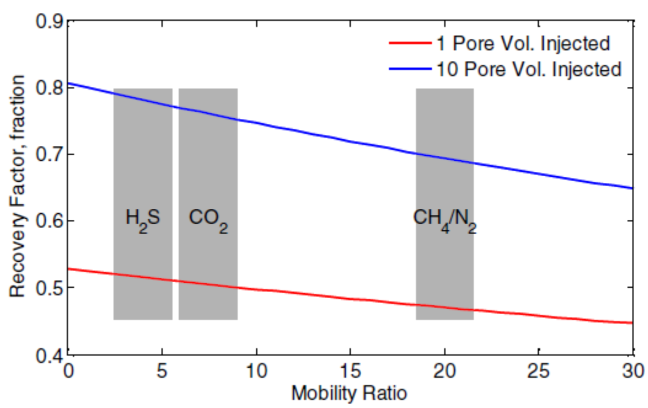

Figure 1.14: Recovery factor as a function of mobility ratio for different injected volumes. From J.R. Wilkinson and others, 2010.

The effects of SOx and NOx impurities in a CO_2 injection stream on well injectivity, rock properties and MMP was examined by Bryant and Lake (2005) to examine the geochemical reactions stimulated by the dissolution of CO_2 into subsurface brines. The aim was to also quantify the significance of their effects on permeability and injectivity in order to determine if the level of impurities typical of flue gasses (≤ 5 mole %) can be utilized as an EOR cost-cutting measure. Generally, the rock properties within a few meters of the wellbore usually control injectivity, while the presence of impurities in the CO_2 stream could increase rock alteration when considering SOx and NOx are more reactive than CO_2 when dissolved in brine (Bryant and Lake, 2005). Also, these impurities typically make the CO_2 solvent more “gas-like”, which tends to increase the MMP. The question, though, is what is the magnitude of these chemical processes and will the cost benefits of using impure CO_2 streams from industrial sources (i.e. coal) outweigh any potential loss in oil production.

Moreover, the presence of impurity concentrations at the levels in flue gas will only change the MMP a few percentage points from the pure- CO_2 value and is thus a viable cost-cutting alternative that could possibly accelerate the development of an EOR project. As for the geochemical effects, the presence of impurities in the CO_2 stream significantly decreases the pH of the formation fluids. This increase in acidity speeds up the dissolution of native minerals, but does not significantly alter the limit of changes in mineralogy and as a result should only lead to an incremental effect on injectivity (Lou and Bryant, 2008).

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Section 2

Dynamic modeling of GCS and its implications for CO_2-EOR

Modeling tools are considered highly important to properly evaluate the capacity, containment, and injectivity of CO_2 in saline aquifers by regulators and site developers (UIC Class VI rules). Capacity estimation depends on a variety of CO_2 trapping mechanisms including structural, residual, solubility, and mineral trapping. Injectivity and containment of CO_2 are controlled by geomechanical, geochemical, and fluid flow processes that need to be modeled. Available fluid flow simulation tools have been, and continue to be, tuned and validated against the results of GCS monitoring programs to consider the effect of these processes. Analytical models have been enhanced to consider coupled effects and to support quick scoping calculations.

While CO_2-EOR and GCS projects may not share the same goals, the optimization of tools incentivized by storage needs can be useful for CO_2-EOR projects. Validation, especially using a number of data sets that have been made public is and will continue to be a very significant contribution to the value and reliability of models. In drawing the lessons from geological storage for CO_2-EOR projects, one should note some major differences. First, that the time-scale over which the project goals need to be achieved differs greatly from CO_2-EOR (decades) to GCS (centuries) projects. Such long-term goals in GCS projects justify studying long-term processes over a wide region outside the storage target, which may not be directly relevant to CO_2-EOR studies.

The key long term element to be considered in GCS projects is the ultimate fate of CO_2, which may include long migrations paths (Gibson-Poole and others, 2008), dissolution via convective mixing, or mineral trapping. The time scale for mineral trapping mechanism (when carbonate minerals precipitate) can be thousands of years as shown in figure 2.1 (IPCC, 2005; Gunter and others, 1997). The potential for mineral trapping depends on the composition of the brine, the reservoir rock, temperature and pressure, the brine/rock contact area, and the rate of fluid flow through the rock. To focus on the processes that affect CO_2-EOR operations we only discuss processes relevant over the injection period. The area of focus will also be limited to the region covering production and injection wells.

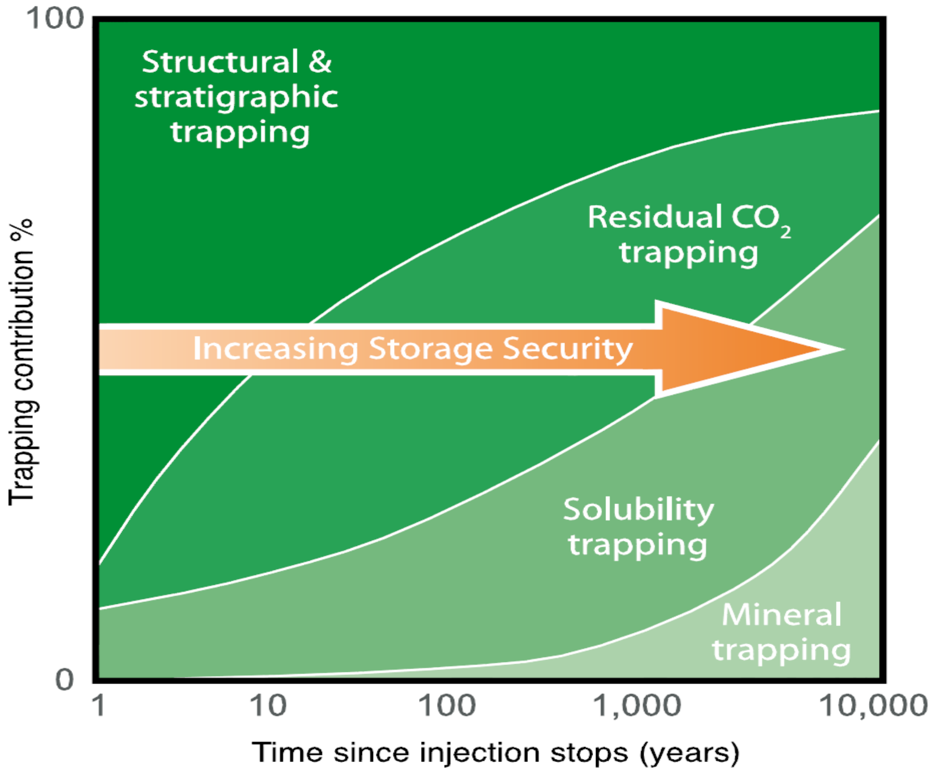

Figure 2.1: Contribution of different mechanisms in trapping CO_2 in saline aquifers (IPCC, 2005). Mineral trapping may not be important over the injection period.

The other difference that affects our learnings from GCS and their EOR applicability is the EOR flow dynamics that may be absent in GCS. In CO_2-EOR projects, fluids are produced at the same time CO_2 is injected. This increases the injectivity at the well and field scales and reduces the geomechanical effects. Pressure management through fluid extraction is also considered in GCS projects, although it increases the cost of the project. In this section, we focus on the processes that occur during the injection period and review major modeling achievements in GCS from which a CO_2-EOR project may benefit.

2.1 Fluid flow

The same numerical simulation tools that are used in the oil industry can be used for simulating GCS in saline aquifers. Proper gridding of the reservoir in radial and vertical directions is required to capture flow of CO_2 in the aquifer. Fine grid resolution close to the wellbore is required to ensure the accurate evaluation of injectivity (Huang and others, 2011). Vertical flow is significant and may be dominant in CO_2 injection due to lower CO_2 density and viscosity, compared to brine. Fine gridding at the top of the flow units is required to correctly evaluate the CO_2 plume thickness and extension. Low permeability layers (baffles) may be highly important in attenuation of CO_2 flow upward. Fine-scale gridding of such layers is required. Upward flow may be exaggerated when the aspect ratio of the simulation grids is high, sometimes referred to as the chute effect. The chute effect may be minimized by allowing for smooth attenuation of the transmissibilities of the grid (Teletzke and Lu, 2012).

Pressure propagation and plume size may also be calculated using analytical models that were developed considering simplified assumptions. Such models allow for quick Monte-Carlo type calculations without the need for space and time gridding. Such solutions are given for single-phase and two-phase flow, and may consider mutual dissolutions and leakage (e.g. Nordbotten and others, 2005; Mathias and others, 2008; Birkholzer and others, 2011; Zeidouni, 2012). Including more physics make the analytical solutions more complex and more difficult to use. Analytical models can also be used to evaluate injectivity.

To account for the mutual dissolution of CO_2 and brine, both black-oil and compositional models may be used. The reservoir can be initialized with 100% water to model an aquifer. However, mass transfer with the reservoir brine was not traditionally included in the simulation tools. Due to the importance of the CO_2 solubility, earlier studies modeled the solubility by initializing the reservoir with oil phase to which the properties of brine were assigned. However, such approach may be used only in black-oil simulations. For compositional simulations new PVT models have been developed.

2.2 Property (PVT) model

Cubic EOS's (Equation of State's) are not able to properly model the compositional properties of a CO_2-brine system. Further improvement has been made to allow for the calculation of the mutual dissolution of the water phase (brine) and gaseous phase (CO_2) without using a cubic EOS. The solubility is obtained by applying the thermodynamic equilibrium for which fugacity of CO_2 in gaseous the phase is evaluated based on a cubic EOS (e.g. Peng and Robinson, 1976) and fugacity of CO_2 in the aqueous phase is calculated based on Henry's law:

$$f_{CO2} = x_{CO2}.H_{CO2}$$

where x_{CO2} and H_{CO2} are the mole fraction of CO_2 in the aqueous phase and CO_2 Henry's constant respectively. H_{CO2} is a function of pressure, temperature and salinity. Variation of Henry's constant with pressure and temperature is obtained based on Harvey's (1996) correlation combined with that of Garcia (2001). The effect of salinity on Henry's constant is obtained as described by Bakker (2003). Thermodynamic equilibrium is applied to model H_2O vaporization in the gaseous phase for which the fugacity of H_2O in the gaseous phase is calculated based on the cubic EOS (CMG-GEM, 2012). The fugacity of water in the aqueous phase is calculated from the water mole fraction in the aqueous phase combined with equations given by Canjar and Manning (1967) and Saul and Wagner (1987). The above calculations are also used to extend the solubility calculations for a three-phase system including the oil phase. A cubic EOS is used to calculate the fugacity of oil components and CO_2 in the oil and gaseous phases.

Mass transfer between the injected CO_2 and brine is not only important in determining the CO_2 amount that has been trapped by dissolution, but also in the evaluation of salt dry-out close to the wellbore.

The salt dry-out during gas injection in porous media is a well-known process at the laboratory and the field scales (Kleinitz and others, 2001; Andre and others, 2007, Gaus and others, 2008; Pruess and Muller, 2009). The evaluation of the amount of salt precipitation is especially important for CO_2 injection in saline aquifers as salt precipitation can plug the reservoir and reduce CO_2 injectivity. Compositional simulation tools such as CMG-GEM are now capable of modeling salt dry-out and its effect on the porosity. Analytical models have also been developed to evaluate the salt dry-out (Zeidouni et al, 2009; Pruess, 2009). Using the analytical models one can calculate the amount of salt precipitation and translate it to porosity and permeability reduction. Zeidouni and others (2009) introduced a time-dependent skin factor to account for the effect of salt dry-out. That way one can account for the effect of salt dry-out even by using black-oil simulation tools.

Dominated by viscous flow, higher permeability layers will be most affected by salt dry-out. The lower permeability layers will have less salt dry-out due to higher capillarity, which imbibes the brine back into the dried-out pores. This will result in more evenly distributed CO_2 in the reservoir. These observations are in line with the experimental observations by Wang and others (2012) showing that salt first precipitates at fractures and pores. However, research has also shown the possibility of precipitation in pore throats. This complexity roots in the fact that distribution of the salt is also a function of CO_2 flux which is not well understood. In CO_2-EOR applications, salt dry-out might reduce the CO_2 injectivity when producing ROZ (Residual Oil Zone) or a reservoir that has gone through severe water flood prior to CO_2 injection. However, there is no field evidence of the importance of this effect.

As discussed in the previous section, the injected supercritical CO_2 displaces brine as it moves through the aquifer. CO_2 may flow upward due to gravity allowing the reservoir brine to reclaim the pore space. When the saturation of the CO_2 rich phase falls below a certain saturation it becomes disconnected –or residual– and immobile. As a result the CO_2 will be trapped. This trapping mechanism is referred to as residual trapping. Two-phase relative permeability hysteresis is sufficient to model the residual trapping for GCS. For CO_2-EOR three-phase hysteresis models may be required. Accounting for the hysteresis is also important due to its effect on the injectivity of CO_2 caused by reduced relative permeability of the aqueous phase.

2.3 Geochemistry

Field studies, discussed earlier (Weyburn, Frio, Nagaoka) have provided observation of early rock-water-CO_2 interactions. These projects provide insight into remaining gaps in modeling capacity, especially with regard to reaction rate, transport, and coupled geochemistry and geomechanics. Modeling augmented by laboratory and field observations remains the only way to make long-term predictions. Secondary mineral precipitation during CO_2 injection may occur when brine's cation concentrations are high (Newell and Carey, 2012). The way the newly formed precipitates are located at pore-scale may or may not affect the permeability while the porosity may remain constant (Shao and others, 2010; Jun and others, 2012). Geochemical processes occur on a much smaller scale than flow processes. making it difficult to couple the two. Upscaling remains a challenge due to the need for computational methods that are able to bridge processes at molecular, pore, and reservoir scales (Jun and others, 2012).

Most current reservoir simulation tools are not capable of accounting for the geochemical processes. Those that have such capability deal with the geochemical system with a limited number of unknowns and are unable to fully account for the geochemical processes. Examples are CMG-GEM, Shell's MoReS-

PHREEQC, and GPRS (Fan, 2012). Inclusion of more complex processes and coupling of organic and non-organic systems will require finer gridding, handling a large number of reactions and different reaction mechanisms, and thermodynamic database expansion over a larger range of pressures and temperatures (Zhang and Villegas, 2012).

The coexistence of hydrocarbons with brine and CO_2 in CO_2-EOR requires that oil be considered as a separate phase as well as a geochemical body. Oil can coat the rock surface affecting the geochemical processes. Oil coating effect on rock brine interactions – also referred to as wettability- is complex and a function of phase saturation. The development of models capable of accounting for oil wettability effects is required.

The near-wellbore region goes through more significant geochemical dynamics due to the injection and extraction of fluids which induce more pressure and temperature changes and mutual dissolutions (Azaroual and others, 2012; Gaus, 2010). This region may go through significant acidifications leading to corrosion. As noted above, salt dry-out also develops over this region. In theory, the development of a dry-out region in the vicinity of the wellbore should protect the wellbore against corrosion. However, due to imbibition of brine in lower permeability layers, carbonated water will still be in contact with the well casing and cement causing corrosion. Also, at the base and top of the injection zone where CO_2 is in contact with the wet sealing rocks high risk of corrosion may exist. Strong dissolution of near wellbore rock may lead to wellbore instability. While it is well known that clay may swell during water injection and WAG, it is also found that it can swell when CO_2 is involved. This process is not well studied and it can reduce porosity and permeability (Zhang and Villegas, 2012). Permeability variation due to change in porosity may be obtained based on various models but it is highly complex and further research is required (CMG-GEM, 2012; Pruess and others, 1999).

2.4 Thermal modeling

EOR modeling ignores the main thermal effect- CO_2 injected cold relative to rock and fluid temperatures in the reservoir. During CO_2 injection in saline aquifers the pressure at the well bore increases significantly. The pressure propagates in the reservoir and reduces as the radial distance from the wellbore increases. A smaller reservoir diffusivity coefficient causes the pressure to reduce over shorter distance. Under reservoir adiabatic conditions and at the limit $\Delta P \rightarrow 0$, the process is isenthalpic and the temperature change due to pressure reduction can be estimated by the Joule-Thompson (JT) coefficient:

$$\mu_{JT} = \lim_{\Delta P \to 0} \left(\frac{\Delta T}{\Delta P} \right)_H = \left(\frac{\partial T}{\partial P} \right)_H$$

Under the practical conditions encountered for CO_2 geological storage applications, the JT coefficient is a positive number for supercritical CO_2. Therefore, pressure reduction will be accompanied by thermal cooling. Thermal effects can also be caused by mutual dissolution of CO_2 and brine and heat losses to underburden/overburden.

Compositional simulation tools have been modified to account for the thermal response to CO_2 injection and leakage. The temperature distribution is calculated by solving the energy balance equation coupled with the flow equations. The enthalpy changes required are obtained based on ideal gas enthalpy at zero pressure and temperature and the excess enthalpy calculated from the Equation of State (EOS).

For the range of injection zone temperatures in GCS, the enthalpy of the aqueous phase decreases upon dissolution of CO_2 (heat is generated) and the enthalpy of the gaseous phase increases as water vaporizes into the gaseous phase and heat is consumed (Han and others, 2010; Koschel and others, 2006). Therefore, the temperature is likely to increase at the dissolution front and cooling may occur at the vaporization front close to the wellbore. CMG-GEM (2012) accounts for heat loss to the surrounding rock using the method of Vinsome and Westervled (1980). This heat loss is controlled by the cross-sectional area for heat loss, rock heat capacity, rock mass density, and rock thermal conductivity.

Temperature changes due to CO_2 injection may not be significant in the injection zone. However, CO_2 leakage can provide a significant temperature signature accompanied by significant expansion of CO_2. Such temperature response may be useful for monitoring the injected CO_2 (Han and others, 2012; Zeidouni and others, 2012; Pruess, 2011).

2.5 Geomechanics

The geomechanical effects of CO_2 injection in oil and gas reservoirs are well studied due to their impact on permeability and fracturing. For CO_2 injection in saline aquifers, changes in pressure and temperature may induce some stress-and-strain changes in and around the injection zone. This may result in permeability changes, uplift leading to ground-surface deformation, and micro seismic events. If the pressure becomes sufficiently high, some irreversible geomechanical events may be triggered including fracturing, opening of pathways in the cap-rock, and reactivation of faults (e.g. Rutqvist, 2012).

Numerical flow simulation tools including ECLIPSE, GEM, and TOUGH2 are now connected to geomechanical codes (e.g. Rohmer and Seyedi, 2010; Tran and others, 2010; Ferronato and others, 2010). The governing equations for the fluid flow and geomechanics are solved separately. The solution obtained from each set is imported to the other in an iterative manner. The changes in pressure and temperature are first evaluated at a time-step by solving the normal flow equations. Then the deformations, stress and strain are calculated using the geomechanics equations based on the pressure and temperature input from the flow equations. Next fracturing and changes in porosity and permeability are calculated. If a full coupling option is available the resulting changes should be passed to the flow equations again and the same process repeated until convergence is obtained within the time-step (Preisig and Prévost, 2011). However, full coupling may not be required and the resulting geomechanical changes can be transferred to the calculation of the flow equations in the next step. Such iterative coupling has proven to be a successful approach (Settari and Walters, 1999; Chin and others, 2002; Samier and others, 2007; Dean and others, 2003; Tran and others, 2009).

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Section 3

Flood Surveillance

Flood surveillance is one of the areas with the highest knowledge transfer potential from GCS research to commercial applications of CO_2-EOR. GCS has made significant advances in the surveillance of reservoir response to CO_2 injection, as well as the improved and additionally validated use of these observations for predictive modeling. CO_2 injection for geologic storage has connected with regulatory and public opinion concerns, which have resulted in elevated expectations toward the surveillance of the injected CO_2 and the pressure response of the reservoir, as compared to injection of CO_2 for EOR.

Storage demonstrations are providing data that have not generally been collected in commercial EOR projects. One reason for the generation of novel results is that for storage, CO_2 has been injected into brine-bearing formations. This single fluid environment is simpler than a system that contains hydrocarbons and brine. A significant contribution that storage monitoring can make to understanding EOR comes from the fact that the array of measurements in a brine setting can be made from a “baseline” under stable, single fluid conditions. The potential for making one or a series of measurements as CO_2 migrates and comes to a new equilibrium distribution provides a unique view of the dynamics of CO_2 injection by subtraction of successive stages of plume evolution. This process cannot be conducted as robustly in an EOR setting, because the presence of hydrocarbons and past production precludes measuring changes from a simple, stable baseline. CO_2 introduced into single fluid system is easier to interrogate and image with many modeling techniques, so that a novel and more precise view of the distribution of introduced CO_2 can be obtained.

One simplification typical of storage settings is that the environment has not previously been perturbed by production. Removal of complex fluid history allows changes resulting from injection to be clearly seen, in settings from the reservoir to near surface environments and in characterization of fluids, pressure, and geomechanical perturbation. Another simplification in storage operations is that simpler fluids create less complex conditions for modeling. Removing the complexities of oil-CO_2 interactions, raises the expectation that a more rigorous match between the observed and modeled response can be obtained. Modeling for EOR is typically dominated by the uncertainties in the saturation distribution of remaining hydrocarbons, as well as complex mutual solubility of CO_2 into oil and oil into CO_2. Injection into brine allows modelers to observe the interactions of CO_2 with rock petrophysics, pressure, and buoyancy more precisely, because other complexities are reduced.

The frequently low volumes of CO_2 utilized in storage projects, usually due to cost limitations, create conditions where observations are made at smaller scales than those of EOR projects, ranging from few 100’s of meters to core flood scales, enriching the knowledge base by adding information on small-scale flow, which is conventionally a source of uncertainty in pattern floods.

EOR surveillance programs are primarily designed with the goal of optimizing the performance of CO_2 floods in order to maximize oil production. Performance is improved by maximizing the effectiveness of the areal sweep, vertical conformance, and displacement efficiency of the miscible (or near-miscible) process. Numerical models of CO_2 floods are heavily reliant on the collection of primary, secondary, and sometimes tertiary production data, which can provide a rich source of information on reservoir geometry, rock properties, and fluid characteristics and distribution. These data are used in pre-injection modeling to provide guidance to investment decision makers, and inform the design and operation of the CO_2 flood. EOR monitoring during operations is usually driven by material balance techniques (Melzer, 2012), which aim to balance the volumes injected with those produced. Material balance is an effective optimization methodology because fluid flow during EOR is highly managed by the injector-producer patterns. Surveillance of pressure at wellhead by intermittent collection of down-hole pressure is also a common technique to assure that the flood is being conducted as planned. The operator may decide to conduct additional surveillance in order to manage the flood and deliver timely intervention to control unpredicted flow behavior. Unpredicted flow behavior results from the inherent complexity of the oil reservoir and typical adjustments, known as "balancing the flood" are required to maximize production.

Examples of additional surveillance are production or injection profiles, cased hole wireline logging for fluid saturation using pulsed neutron or sonic logging, and borehole or surface geophysics. Material balance and other types of surveillance are typically held proprietary. Only in select cases are data shown at professional conferences or published.

EOR operations are required to provide assurance that groundwater quality is being protected, under Class II of the Underground Injection Control Program (UIC). Typically the focus of the regulations is in correct construction and maintenance of wells in terms of mechanical integrity. Monitoring of above reservoir units or near surface is not a typical part of EOR projects.

The objectives of monitoring programs associated with carbon storage projects additionally include long term CO_2 containment within the target formation. Areal sweep, vertical conformance, and displacement efficiency continue to be important in carbon storage projects as these performance metrics relate to the effective use of the pore space, which translates into larger ultimate storage volumes and smaller footprints for volumes occupied by CO_2 for a project. Assuring long term CO_2 permanence, however, not only requires increasing the monitoring rigor within the target formation, but also broadens the area of study to include monitoring activities outside of the target formation (overburden, surface, or atmosphere), and adds the requirement of post operational monitoring and modeling activities.

As discussed in the Area of Review section, an integrated monitoring program starts with the delineation of the study area. Boundaries are defined by the predicted lateral extent of the CO_2 plume and the size of the associated pressure plume, but can be adapted to focus on the area currently underlain by CO_2, with increases in the area as the area underlain by the CO_2 plume and elevated pressure increase.

Heavy investment in model improvement for models in the public domain such as TOUGH2 (Transport of Unsaturated Groundwater and Heat) and STOMP (Subsurface Transport Over Multiple Phases) as well as addition and development of elements relevant to injection of CO_2 to commercial codes such as

CMG GEM (Computer Modeling Group's compositional reservoir simulator) have been a contribution from geological storage research. Improvements of codes that do not handle hydrocarbons have more indirect contributions than commercial codes. However, improvements in numerics, handling dry-out zones, near well-bore realization, rock-brine interaction, understanding the implications of boundary conditions and other fundamental code improvement will advance all modeling, including modeling for EOR (Hosseini et al, 2012; Nicot and Solano, 2011 and Oldenburg, 2009)

Monitoring is closely linked to modeling. Initial work on rock and fluid characterization and dynamic modeling of the CO_2 flood is needed to design the injection plan. Uncertainties in the characterization phase are used to create multiple probabilistic representations of the impact of these uncertainties on the performance of the flood, and uncertainties with potential to damage the performance of the flood in a material way are highlighted in the risk assessment. Risk assessment schemes are used to structure material uncertainties and stakeholder concerns in an orderly format, and can be loosely to closely integrated with modeling. Risk assessment then drives the definition of the monitoring strategy. Monitoring should be designed to reduce risk and uncertainties leading to material damage and to flood performance. Ideally, monitoring can be used to systematically reduce uncertainties, providing increasing confidence in the operation of the injection, and eventually leading to closure with high confidence in long term retention. Monitoring can also be designed to provide early warning of a trajectory that would lead to damages, allowing operation to be modified prior to any undesirable occurrence. Other types of risk however may be underlain by uncertainties that cannot be reduced by observations, and monitoring must continue over the lifespan of the project and in the closure period in sentinel mode, observing that no damage has occurred and that no mitigation is needed. Still other monitoring types are needed should an unexpected or damaging condition develop, in order to design mitigation and remediation plans, and assess any penalty incurred, such as loss of credit for storage.

The mechanism by which the implications of monitoring are assessed is via comparison of the observed response with the modeled response. In some situations that comparison can be a simple threshold, however other comparisons will be against output from an analytical model, a geochemical model, geomechanical model, a multiphysics model, or a geocellular fluid flow model. The robustness of the history matching capability depends heavily on the quality of the data collected. The high quality data needs can only be met with a carefully designed, carefully deployed, fit-for-purpose monitoring strategy.

In this section we examine geological storage research advances in geophysical and geochemical monitoring tools and techniques developed to understand subsurface multiphase fluid flow, predict storage capacities, and assess continued containment of injected CO_2. We evaluate how the deployment of these tools and techniques might improve CO_2-EOR projects. Let us examine first parameters that control the performance of a miscible displacement, and the advances toward reducing uncertainty in predictive models.

3.1 Monitoring for improved understanding of subsurface multiphase flow and CO_2 flood performance

Vertical and areal heterogeneities affect sweep efficiency, which controls CO_2 migration direction and ultimate extent of the plume (Yang and others, 2011). Vertical permeability contrast in the nearby injection location controls the CO_2 injectivity potential and the CO_2 breakthrough time at a closely spaced intra-well scale (Doughty and others, 2008). However, global areal connectivity and architecture of geological bodies play an important role at the scale of a typical EOR 5-spot pattern. Relative permeability end points are also critical parameters controlling subsurface multiphase flow of CO_2. But, the challenges surrounding the acquisition of these values introduce uncertainty in model predictions (Bennion, 2008).

3.1.1 Field data integration and reservoir modeling

In almost all reservoir settings, the complex fluid history introduces significant uncertainty in the distribution of reservoir properties, leading to mismatches between fluid-flow model predictions and observed reservoir response. In EOR, this uncertainty has important commercial consequences, for example in early- and late-responding wells. Early responding wells can lead to faster-than-optimal recycling of CO_2 and are indicators that large parts of the reservoir were not contacted by CO_2. Slow response leads to slow return on investment and may also indicate that CO_2 is not sweeping the reservoir as designed, but migrating to zones not targeted for flooding. Documentation of reservoir and fluid complexities under storage conditions therefore has good potential for improving flood design and response to non-optimum flood response in an EOR context.

An early and long running GCS project, with near ideal conditions for repeat seismic monitoring was conducted at the Sliepner gas field in the North sea, where CO_2 stripped from produced gas was re-injected to avoid a penalty for emission under Norwigian law (Chadwilk et al, 2004). A series of EU-funded monitoring efforts resulted in the collection of a superb repeat 3-D seismic survey (for example, Chadwick et al, 2006, Arts et al, 2004). The thick, high porosity injection interval in the Utsira Formation created a laboratory where the interactions between buoyancy-driven flow and stratigraphic barriers retarded CO_2 rise and caused lateral flow. In addition, the conditions of low density CO_2 at shallow depths and marine setting, with multiple repeat surveys created a high resolution monitoring output in terms of interpreted CO_2 distribution.

Because the data have been widely distributed, significant progress in modeling this revealing test has been realized. In addition, the confidence in 4-D seismic techniques increased after collection of complementary gravity surveys. Capillary and gravity-dominated flow modeling over-represent fingering and lateral spread and continuous media and dynamic pressure modeling under-represent fingering (Cavanagh, 2011). In addition, the process of retardation at mudstones, followed by breakthrough and migration into the next sandstone provides unique and still incompletely modeled information about the interactions of CO_2 with within-reservoir barriers. Use of this excellent and unique data set has the potential for improving the modeling of gravity-flood interactions, a key parameter in pattern flood design.

Another well studied 4-D seismic data set from which results are publicly accessible was collected as part of the research programs conducted at the EOR flood at Weyburn. At the initiation of this study, researchers were unsure if they could image a relatively thin CO_2 injection into the carbonates. Maps of velocity change resulting from introduction of CO_2 into the reservoir highlight an internal fracture that is intersected by horizontal wells (White, 2012). This example, which shows how the application of seismic for EOR could lead to the improved understanding of the subsurface, constitutes a key learning that carries obvious implications for EOR flood management. This data set was collected in EOR context but was densely analyzed and made publically available because of the significance of Weyburn as the first field to accept large volumes of CO_2 captured from a power plant. Funding available for research, among other advantages, provided a high value example of the interaction of porous media and fracture flow.

A similar data set considering the role of fractures in focusing flow was collected as part of a CO_2 storage project at InSalah, Algeria. This project was run by a consortium of BP, Sonatrac, and Statoil and included a significant research-oriented monitoring program. CO_2 separated from gas at the Krechba field and other fields in the region is injected into the water leg of the same thin sandstone that is produced. The model matching operation at this field is only weakly linked to seismic, because the pre-injection survey had relatively poor resolution, but rather to geomechanical modeling, to document the response of fractures to injection. Fractures lead both to preferential flow and faster than predicted arrival and to vertical loss of fluids into the lower part of the confining system. The interaction of fractures with storage is not believed to have damaged the ability of the field to retain CO_2. However, the migration of CO_2 along fractures in a similar setting for EOR could damage the economics of the project. Improved modeling of injection with fracture opening conducted for the storage project should improve management of EOR floods conducted in similar settings, by increasing confidence in predictive modeling of maximum pressure that could be induced without opening fractures and creating “thief” zones.

At the Cranfield oil field, 3.8 million metric tons of CO_2 have been injected into the oil bearing zone and associated down-dip water leg of the Lower Tuscaloosa formation as part of an ongoing EOR project (Figure 3.1). Part of the research oriented program at Cranfield (Figure 3.2) was designed as an inter-well scale laboratory in a Detailed Area of Study (DAS) consisting of 1 injector and 2 closely spaced observation wells (Figure 3.3). The program is currently observing multiphase fluid flow to assess sweep efficiency, testing technologies that document CO_2 containment, advancing techniques for capacity estimation, and understanding the operational design aspects of data acquisition (Hovorka, 2012). It is important to note that this program was designed to meet the objectives of the regional carbon sequestration partnerships (RCSP), and is not the kind of program needed to comply with EPA’s rules under the Clean Air Act or Underground Injection Control.

The reservoir architecture at Cranfield is superficially quite simple, with the reservoir composed of a 15- to 20 m thick conglomeritic sandstone interval that can be mapped over most of the field. As shown in Figure 3.1, only thin discontinuous dark mudstones compartmentalize the basal sandstone. However, observation at both the field scale and interwell scale studied at the DAS shows that CO_2 exhibits strong preferential flow. At the DAS, CO_2 arrival at the CFU31-F3 well 112 meters from the injection zone was shortly after arrival in the CFU31F2 well, only 68 m away, showing preferential flow. In addition, as injection rate increased, tracers arrived faster at the CFU31-F3 well than CFU31-F2 (Liu and others, 2012). However, this faster arrival was not linear with injection rate, but was retarded relative to what would have been extrapolated based on lower rates. Therefore at higher rates, more of the formation was accessed. This may demonstrate a mechanism by which pattern floods can augment production, in that developing plumes access additional pore volume in response to fluctuations in injection rate and fluid –pore interaction.

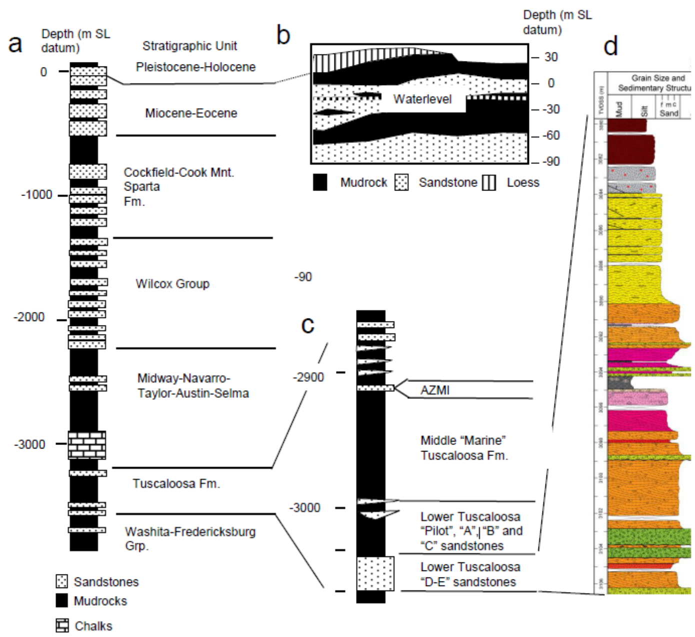

Figure 3.1: Cranfield stratigraphic section showing injection zone and near-surface. From Hovorka, 2012.

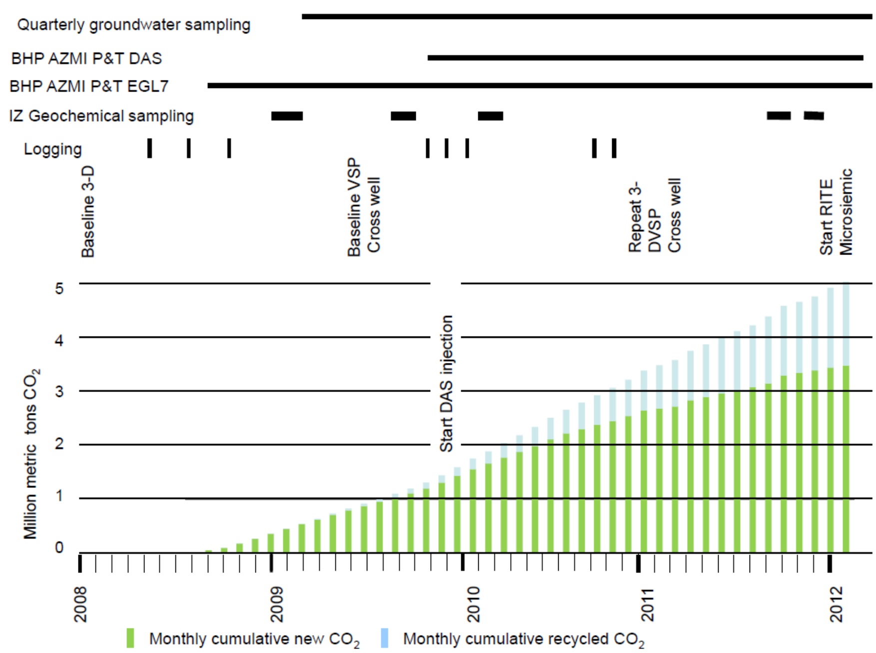

Figure 3.2: Timeline of injection and monitoring activities. IZ = injection zone; BHP = bottom hole pressure; AZMI = above zone monitoring interval; VSP = vertical seismic profile. From Hovorka, 2012.

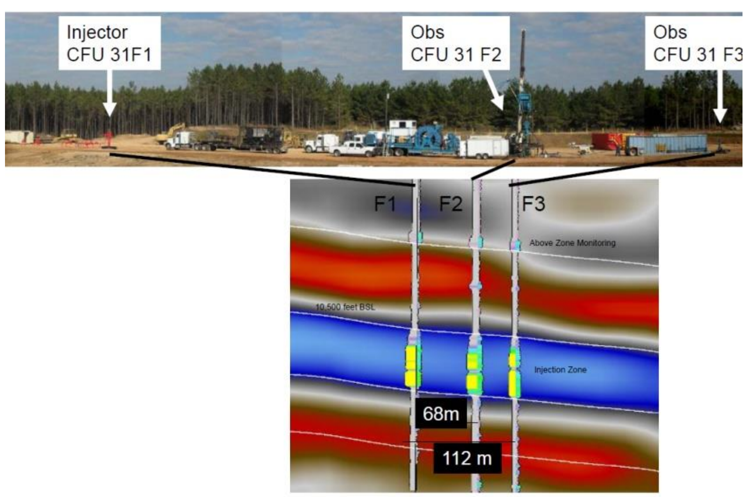

Figure 3.3: Transect of Detailed Area of Study (DAS). From Hovorka, 2012.

In an effort to reduce uncertainty, a step-by-step static and dynamic modeling approach was developed for Cranfield (Hosseini and others, 2012), where model parameter uncertainties are reduced by field data integration and multiple, sequential stochastic reservoir modeling (Figure 3.4). In this approach, the first step defines absolute permeability and porosity by modeling single phase flow with small-scale data obtained from a well test experiment. A second step addresses boundary conditions and global reservoir connectivity, focusing on the injection induced pressure rise. A third step studies injection and observation wells' bottom hole pressure (BHP). Only models that match field data move on through the steps.

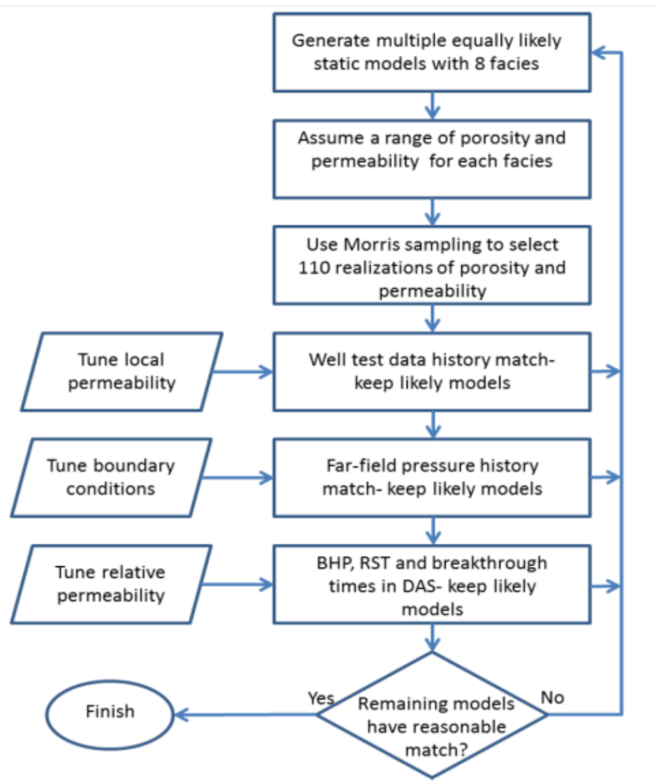

Figure 3.4: Flowchart used to improve Cranfield reservoir modeling by the integration of field data

The field observations, some not typically taken in EOR projects, used for relative permeability end points and local heterogeneity validation include injection zone pressure from pressure gauges installed in injection and observation wells, CO_2 saturation evolution from time-lapse reservoir saturation tool, or RST (a cased-hole pulsed neutron well logging tool later explained), and breakthrough time from U-tube gaseous-phase compositional samples. Time-lapse RST, proved useful in reducing the range of relative permeability model parameters, such as end-point saturations, which directly affect plume size and long-term estimates of residual trapped gas saturations. Assigning different relative permeablities and capillary-entry pressures to sand and shale facies helped in correctly addressing sweep efficiencies in the Lower Tuscaloosa formation.

At Cranfield, detailed cross-well surveillance at less than pattern scale showed how geologic heterogeneity led to preferential flow. At the inter-well scale, the CO_2 could only access a fraction of the 20-m-thick sandstone. Results from imaging tools and tracer tests show that the flowpaths evolved over time, with flow rate being influential. Boundary condition assumptions are crucial for pressure response matching. Caution is advised, however, as under multi-phase flow conditions several realizations can be matched to the reservoir pressure response (Hovorka, 2012). Results from these tools could be used to improve understanding of the subsurface, benefiting the management of a CO_2 flood in the EOR context.

3.1.2 Geophysical methods

3.1.2.1 Acoustic methods

Time-lapse 3-D seismic methods for imaging the extent of the CO_2 plume have been one of the breakthroughs of CCS monitoring. The collection of repeat surveys prior to CO_2 injection and as the injection volume increased at the Sleipner and Weyburn projects and making these data accessible to multiple research teams have advanced the rigor with which plume evolution can be predicted, as discussed in the previous section. In addition, the reliability of the system is increased. Changes in seismic velocity are sensitive to both changes in fluids and pressure, both important in reservoir management. Research conditions have been useful in separation of the two contributing elements (Ajo Franklin, written communication). 4- D seismic is now being proposed as a technique for managing many types of reservoirs. Validation in geologic storage research environments will advance the technology.

Geologic sequestration has provided acceleration to research and development of other types of geophysical measurements also. The combination of federally funded large research programs that engage many researchers and make results publically available and experiments conducted in simplified brine-only fluid settings has accelerated tool development and data analysis. One of the contributions made for seismic interpretation from research-oriented storage projects is combination of seismic with other instruments, including borehole deployed technologies and other types of measurements.

3.1.2.2 Cross-well seismic and VSP

Higher resolution well-based acoustic data are typically collected in reservoir settings to augment a seismic survey to provide improved depth resolution and higher frequency data. These include sonic logs where both source and receiver are placed in the well, vertical seismic profiling, where receivers are deployed in the well and sources are placed at the surface, and cross-well arrays where the source array is placed in one well and the receivers in another. Storage projects have added to improved understanding of the reservoir where these tools were linked to other methods.

For example time-lapse cross well tomography conducted at the Frio test and at Cranfield provided the most resolved image of the plume evolution, and was used to constrain fluid flow data collected using introduced and natural tracers. At Frio, the baseline was collected prior to the start of injection in 2004 and then about 3 months after the end of injection. These images showed that plumed swept fairly homogenously though the reservoir, however gravity effects cause pronounced thinning over the 100 foot well spacing. At Cranfield a baseline was acquired in both observation wells prior to perforation and tubing completion and a repeat was conducted 9 months after start of injection when the wellbore logging and the geochemical sampling programs were completed. Results revealed strong heterogeneity in the distribution of CO_2 (Hovorka and others, 2012).

Crosswell seismic data is valuable, and complementary to well-logging data, as it provides an inversion of the CO_2 distribution in the interwell (See Figure 3.5).

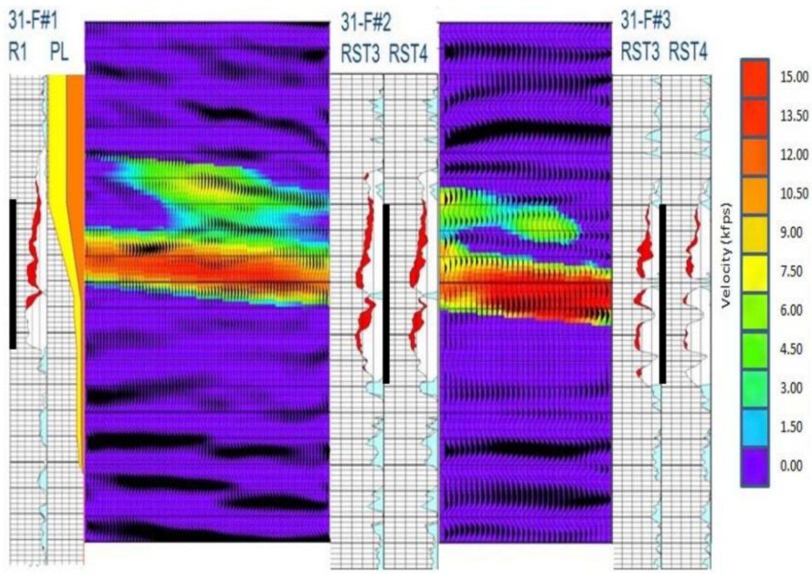

Figure 3.5: Crosswell seismic survey and RST integration at DAS. Injection well located on the left. From Butsch, 2012. I think maybe we should use Jonathan Ajo Franklins version, same volume.

Two other tests of cross-well seismic provide important information on the limits of sensitivity of this technique. At the Nagaoka, Niigata prefecture, Japan, in an onshore experimental site where 10,400 metric tons of CO_2 were injected, the plume was imaged by time-lapse cross-well seismic (Saito and others, 2006 and Zue and others, 2006). However the high frequency time-lapse logging (Mito and others, 2008) was able to resolve CO_2 arrival at wells when the cross-well seismic did not image it. In addition, inversion of the image did not eliminate the possibility that changes could have occurred outside the target zone. Cross-well seismic was deployed at the Gaylord, Michigan CO_2 injection site (Battelle, 2011), and showed perturbations related to substitution of CO_2 for brine and increase in pressure below a regional seal. However, the effect of fluid substitution and pressure could not be separated, and uncertainty remained about the extent to which CO_2 was confined to the target reservoir (Bass Island Dolomite) or invaded overlying less permeable units, the Bois Banc Formation. These limitations are valuable because (1) recognitions of limits avoids investment failure, in that reliance on these tools can be designed with limitations in mind, and (2) additional research can be focused on limitations.

Cross-well Continuous Active Seismic Source Monitoring -CASSM- (Daley and others, 2007) was designed to deal with issues raised by monitoring geologic storage. In particular, placing a source at depth in a site under CO_2 injection requires removing the tubing and packers, which in turn requires that the well be filled with dense brine "kill fluid" to offset the pressure and buoyancy of injected CO_2. This kill fluid dramatically changes the near-well bore environmental at the perforations, which damages the ability to measure saturation correctly with well based logging tools and may damage performance of other instrumentation. One solution to the need to kill the well is not to perforate the well in the injection zone, however this means that pressure and geochemical data cannot be collected. LBNL undertook designing a ceramic source conveyed on tubing (CASSM) to create a solution to this problem. The tubing is run though the source, providing access to the perforations as in a traditionally-completed well. The seismic source can be operated continuously, providing excellent repeatability and stacking. Multiple sources can be used in the same wellbore. CASSM was successfully deployed in the Frio test and documented the process of breakthrough. CASSM was undertaken between the two DAS observation wells at Cranfield to observe high frequency time-lapse changes in velocity caused by replacement of brine by CO_2. Valuable measurements of seismic response to pressure increase were obtained pre-injection during the hydrologic tests; however, failure of hydrophone seals prior to the CO_2 injection phase prevented data collection relevant to multiphase flow with this instrument (Hovorka, 2012). Additional deployment is recommended with improved receiver engineering that can withstand the downhole environment.

3.1.2.3 Electrical tomography

Electrical tomography methods have been traditionally, and successfully, used to monitor shallow subsurface fluid flow. Long-electrode electrical resistance tomography (LEERT) was evaluated for application at the Weyburn field (White, 2012). First, a numerical model was designed to assess the resolution and sensitivity of the method in a field environment. The modeling study indicated that none of the conditions that were considered produced data with adequate signal-to-noise ratio to image the resulting CO_2 plume. So, LEERT was concluded to be unsuited for direct CO_2 monitoring at the Weyburn field.

Placing an electrode array at depth greatly increases resolution; the main problem is to isolate the electrical field from the steel casing of the well. EM methods exist that are designed to be able to filter out the effect of the casing. A novel test was conducted at Lost Hills, during a water flood and CO_2 pilot, in which cross-well acoustic and EM were jointly inverted (Wilt and Morea, 2004; Lee and Uchida 2005) . However an attempt to use borehole EM in a CO_2 environment to image CO_2 at the Frio test (K. Dodds, 2004) was not able to extract signal from the noise created by steel casings.

Cross well and surface to-well electrical resistivity arrays were first used in a CO_2 storage monitoring environment at the GFZ Ketzin site (Schmidt-Hattenberger and others, 2011). The Vertical Electrical Resistivity Array (VERA) was successful in observing and inverting a significant resistivity increase at the approximate depth of the injection zone.

At Cranfield, cross-well continuous electrical resistivity tomography (ERT) was undertaken successfully between the two DAS observation wells (Carrigan and others, 2009; X. Yang and others, in press). The technology consists of measurements between pairs of electrodes that provide high-frequency updates on conductivity changes introduced by changing CO_2 saturation. The installation of such electrodes, however, requires nonconductive casing and a completion design that allows individual wires to be run from each electrode to the surface without damage. At Cranfield, installation caused high cost, suspected interference with other instruments (borehole seimsic and borehole resitivity logs), and lost of connection to about ¼ of the electrodes. Improved technologies are required for easier and reliable installation of ERT before this tool can be deployed commercially at reservoir depths (Hovorka and others, 2012).

Although not completely tested in the public domain, GCS research results seem to indicate that the applicability of these new techniques to EOR and production settings holds high promise. New geometries and instruments are currently in development.

3.1.3 Gravity

Gravity collected from airplane, surface, or ship has been a resource exploration tool since early in the 20th century, with the value resulting from areas where higher or lower rock density signaled locations where structures such as salt domes formed oil traps. In recent decades, improvements in the resolution of gravity measurement have resulted in the use of this method in time lapse for assessing changes in fluids. Measuring fluid changes in near surface systems such as ice and groundwater have been made with the GRACE Satellite based platform (Adams, 2002). Time lapse gravity has been used for tracking fluid changes in the subsurface. In some cases the measurements have been made from the surface, which has the advantage of allowing dense spatial coverage for a number of producing fields under waterflood (Brady and others, 2002; Krahenbuhl and others, 2010.)

Gravity was pioneered for CO_2 injection at Sleipner (Alnes and others, 2011), where it provided a complementary measurement to seismic (Arts and others, 2004). This use of two complementary techniques is part of the benefit of large scale research, which validates and improves quantification of each technique.

In other cases, the change in gravity is too small to be detected with existing instruments at the surface. Gravity instruments that can be deployed closer to the fluid substitution by lowering them into the well are available. Time-lapse borehole gravity measurements were collected within the detailed area of study (DAS) wells at Cranfield Field Mississippi, as a CCP monitoring study conducted at the SECARB Early test. The borehole gravimeter data were evaluated for sensitivity to both the larger scale geologic response and the smaller time-lapse signal from injected CO_2. All four data sets, two for each observation well, demonstrated distinct Poisson jumps at the boundaries of the Cranfield reservoir and are considered successful in reflecting the lower density of the reservoir of the site (Dodds, 2012). Assessment of the change in fluid is hampered by error in instrument relocation, noise and instrument drift. However final data are interpreted as showing a significant decrease in density within the reservoir as CO_2 was emplaced. Resolution is surprisingly good, showing the separation between the upper and lower flow units. These uses in research mode show promise for additional commercial applications, including direct measurement of fluid substitution during production.

3.1.4 Wireline logging

Wireline logging is a workhorse of reservoir characterization. Several novel elements are contributed from experiments in geologic storage monitoring. Simpler fluid environments provide the same benefit as noted in the section on seismic, to increase quantitative rigor of saturation detection. Pre-injection baseline logging in a setting with only brine as a pore fluid, followed by detailed assessment of the ability of the formation to transmit fluids adds greatly to confidence and precision of measurements. Confidence and precision can then be translated to perturbed and complex reservoir settings. Significant two-phase experiments have been conducted and put in the public domain, where cross-lab and cross method comparisons can be made, including some of the first sets of public domain assessments of CO_2 saturation in the lab (Bachu and Bennion, 2008; Benson Lab, 2013; Akbarabadi and Piri, 2011).

Pulse neutron logging is a well understood technology that has been used for many years to monitor fluid movement in reservoirs. Results from pulsed neutron measurements are often the standard to which other monitoring measurements are compared. The Frio test was one of the first test to use RST in an experimental CO_2–brine setting (Sakurai et al, 2005). In the Cranfield DAS wells, even with complex wellbores and difficult logging conditions, the Schlumberger reservoir saturation tool (RST), a pulse neutron based tool, was able to provide insight on the saturations and volumes of the different fluids in the reservoir, and how these were changing with time (Butsch et al, 2012). However, uncertainty is introduced when correcting for change in tubing fluids when brine is replaced by CO_2. Other wireline tools, such as sonic and resistivity, had difficulty with noise at the DAS wells, perhaps because of interference by complex completions. RST is presently being successfully used in Gulf Coast commercial EOR applications. Pulsed neutron data was also collected at the Gaylord Michigan test injection (Battelle, 2011). The Gaylord test illustrated some of the uncertainties with pulsed neutron techniques, in low permeability carbonates.

3.1.5 Temperature monitoring

Thermal response is a classic tool for tracking fluids, especially in cases where flow is focused in a narrow zone, because temperature measurements are easily made and relatively simple to interpret. However, in-reservoir use is limited because the thermal mass of the reservoir buffers signal.

Fiber optic cables were deployed at the Cranfield DAS for distributed temperature sensing (DTS). DTS is a technology that consists of sending a pulse of light down a fiber optic cable installed along the casing or tubing of a well from the surface to total depth and back. This technology produces quasi-continuous temperature profiles along the entire length of wells providing high temporal and spatial resolution. Borehole temperature data is used to determine the physical properties and the state of the CO_2 and to draw conclusions on flow processes inside the formation and along wells. At DAS, temperature measurements were acquired every meter along the wellbore, with sample rates that ranged from 2 to 15 minutes. Figure 3.6 shows more than three hundred million temperature measurement recorded from November 2009 to July 2010, (Nuñez-Lopez, 2011).

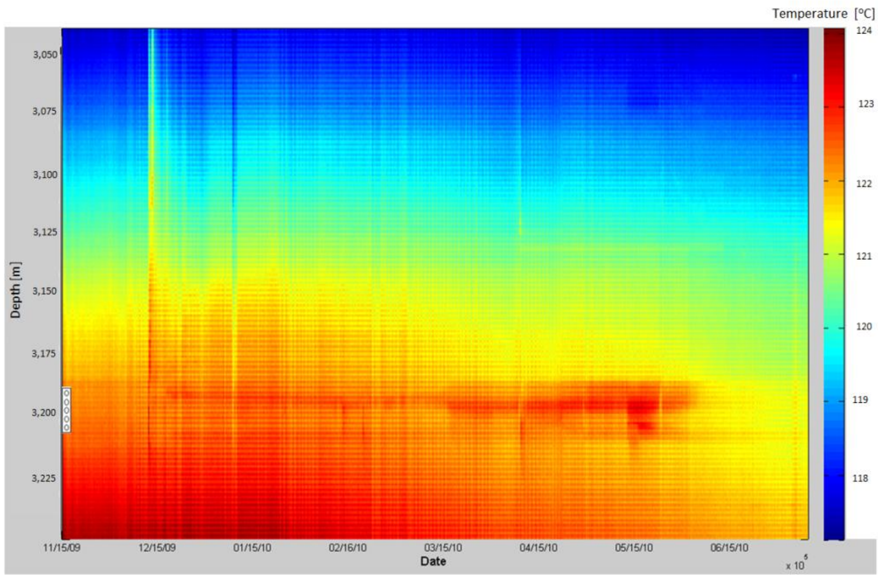

Figure 3.6: Temperature evolution, vertical distribution, and timing of temperature disturbances from Nov. 14th 2009 to July 7th 2010 at observation well F3.

A novel technique developed for a number of applications introduces a heater cable so that a controlled temperature increase can be induced. The speed of the recovery can be inverted to observe fluid flow and changes in the specific heat as the fluid composition changes. Perturbed pressure has been deployed at CO_2SINK project at the Ketzin field (Freifeld and others, 2007) and that the SECARB test at Citronelle. Perturbed temperature sensing has a potential applicability to EOR, to evaluate changes in fluid saturation that would be of high value in the assessment of the flood and in the modification of strategies as injection becomes mature. The demonstrations for CCS research provide information on the sensitivity of the method. Assessment of the validity of the method has not been undertaken in the EOR context.

3.1.6 Pressure monitoring

Pressure monitoring in the reservoir is essential for commercial production, and a classic surveillance tool used for the calibration of numerical fluid flow models. Geologic storage projects have added value to this method by collecting novel and publically accessible data sets. Novel elements provided by geologic storage experiments include data collected (1) in minimally perturbed environments, (2) in close spatial distances, and (3) at high frequency. Integration of pressure data with geomechanical evaluation is also a novel approach. The value of these data for commercial application has not been fully developed, but opportunities are opened.

EOR is almost always conducted in a highly perturbed environment, where regional pressure drawdown from prolonged production has been partly offset by water injection. In these settings pressure evolution is so complex that a relatively coarse observation, for example by making episodic downhole measurements in some patterns, is sufficient to document trends and constrain models. Storage tests have accessed relatively unperturbed fluid environments, which have allowed observation of much more subtle responses of the reservoir, which provide additional constrains to infer active processes in the reservoir. For example, the Frio tests at South Liberty Field Texas, Cranfield, Mississippi, Citronelle Alabama, and Gaylord Michigan tests were conducted in reservoir intervals that had not been produced for several decades prior to the test, allowing relatively simple measurements to be interpreted to high resolution not typically possible in the EOR context. Improved model matching methods can then be applied to more complex situations. Novel ideas, such as having a well out of the active pattern collect in-reservoir data that averages reservoir response and can be used to better calibrate the system come from these studies. For example, Verma and others (-in press-) have documented the value of an idle well in passively accumulating changes in fluid composition during breakthrough without the cost of active sampling. Hosseini (in preparation) has modeled and is field testing a concept that uses time lapse changes in fluid compressibility to assess replacement of water by CO_2 .

High-frequency pressure monitoring was confirmed as a highly valuable monitoring strategy at Cranfield. Pressure changes were observed in far-field wells, confirming reservoir architecture developed during characterization. Low cost pressure gauges installed in the well-heads of wells perforated in the injection zone can monitor pressure trends, as long as the pressure responses are calibrated to the density of the tubing fluids.

3.2 Environmental and Public Assurance

All injection for secondary and tertiary recovery is required under UIC rules to protect potable water resources. Traditionally, regulatory efforts have focused on proper maintenance of wells, which are the main risks of failure of isolation. However, with increasing societal concern about public and environmental protection, the burden on operators will increase, at least in some locations and for some types of operations. Geologic storage has been subjected to such high expectations, and has explored a portfolio of tools. Both highly successful and less successful outcomes of the test programs may be useful in future resource extraction operations, the successful methods as models and the unsuccessful methods to avoid pressure to make apparently reassuring but actually poor-performing measurements.

3.2.1 Above-zone pressure monitoring

Pressure surveillance in an above-zone monitoring interval (AZMI) has been used at gas storage sites for decades to assure that gas is not seeping out of the storage unit which is unacceptable both in terms of product loss and in terms of risk creation. This approach has been adapted for the same purposes for geologic storage. AZMI pressure monitoring is conducted under the principle that any fluid intrusion into a shallower layer would cause a pressure increase on the hydrostatic pressure gradient (Zeidouni, 2012; Zeidouni and Pooladi-Darvish, 2012a; Zeidouni and Pooladi-Darvish, 2012 b). An ideal AZMI is a laterally continuous thin zone that is sensitive to pressure perturbations. Careful selection of the AZMI is required as for this interval to be a successful monitoring element it needs to intercept as many hypothetical leakage paths as possible (Hovorka, 2012).

Conceptual and analytical models were developed for interpreting continuous AZMI pressure and temperature monitoring data (Figure 3. 7) in the case that the wellbore is the monitoring leakage path (Tao et al, 2012). Results from modeling the pressure response and temperature response were consistent and proved that wellbore permeability can be estimated. If the results contradict, as it was observed in the case of the high volume injection observation well (EGL7) at the Cranfield site, the wellbore is not the primary leakage pathway. The application to Cranfield data show that the dedicated observation well (EGL7) is unlikely to be leaking. However, this conclusion does not rule out the possibility that leakage can occur through other leakage pathways.

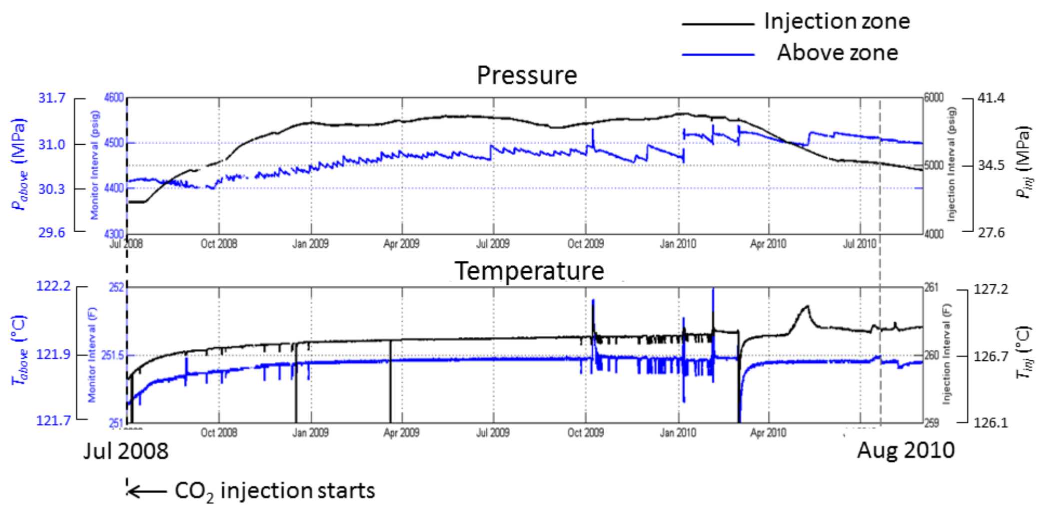

Figure 3.7: Plot of over 2 years (July 2008 to August 2010) of continuously recorded pressure and temperature data for the injection zone and AZMI (Meckel and Hovorka, 2010). Pressure in the injection zone rises within a month after CO_2 injection starts. Pressure in AZMI increases two months later, indicating a possible wellbore leak. Temperature data suggest a first-order isolation as both zones recover to distinct baselines, maintaining a linear correlation with a consistent differential of ~4.9°C (~8.8°F). From Tao, 2012.

It is well known that pressure-transient analysis provides information on the size and shape of the formation and its ability to produce/receive fluids. Pressure transients are also used as a metric for matching numerical flow model conformance with observed production/injection history. However, the identification of well leakage through pressure history matching can be challenging due to the subtle effects these leaks can have on the characteristic pressure magnitude evolution (Meckel, 2013).

At Cranfield, Meckel and others, (2010) developed a broadly applicable technique for the analysis of pressure transients in continuous time series. This technique uses a combination of theory, an analytically-derived synthetic reservoir pressure history example, and analysis of field pressure data. The analysis focuses on the second derivative (d2P/dt2) of the continuous pressure time series, and it shows that d2P/dt2 transients reveal consistent relationships with known (theoretical case) or induced (field case) pressure perturbations that are independent of prior pressure history. This fact makes the second derivative of the continuous pressure time series a very useful diagnostic tool for identifying and evaluating observed transients of unknown origin, such as well leakages.

A novel tool array, the Westbay multi-port sampler (Koch and Person, 2007), which has been deployed at a number of sites for monitoring high concern fresh-water aquifers, has recently been adapted for use at reservoir depths and pilot-tested at the Midwest Geological Sequestration Consortium's CO_2 injection test site at Decatur, IL (Schlumberger Water Services, 2011). In this setting it is used to separately isolate and measure pressure and fluids across the injection reservoir and above the lowest seal. This tool may prove useful for understanding the response of a thick, hydrologically interconnected reservoir to flooding. For example, installation of such a multi-level sampler would be useful to understand how to efficiently exploit the ROZ of the Permian Basin, but the EOR application has not been tested in the public domain.

3.2.2 Groundwater monitoring

Groundwater monitoring is required for some industries that use the subsurface, such as mining and various types of near-surface waste disposal and not part of the expectations for deeper uses of the subsurface, such as deep fluid disposal under UIC class I, or oil and gas operations. However, groundwater monitoring may come to be expected more widely of various industries, in response to public concern, and is an expected activity in carbon storage projects under the US EPA UIC class VI rules. Carbon storage therefore provides a pioneer effort into what is feasible and productive and what is not useful in providing the wanted pubic assurance. GCS advances in this area could be useful for EOR if groundwater monitoring is required in the future.

The naïve assumption is that making measurements of groundwater chemistry prior to industrial activity will provide the baseline needed to prove that no contamination to potable water has occurred as a result of the CO_2 injection (U.S. EPA, 2009). As experience with monitoring groundwater builds, information about the complexity of achieving the desired finding increases. Four reasons for failure of "baseline' style monitoring are noted (Wolaver and others, in preparation):

1) Noise in the system measured is higher than the leakage or failure signal.
2) Ambient or introduced trend in the system measured overlaps the trend that would be induced by failure. For example climate change or urbanization may cause systematic changes that mimic leakage.
3) Failure or damage does not significantly and reliably perturb the system measured. For example the failure signal could be too localized or too transient to be detected by the monitoring array.
4) Pre-injection data collected in a different area than where changes resulting from injection are observed

Robust and protective monitoring can only be achieved if the role of a pre-injection baseline in diagnosing indicators of loss of storage value or other damaging events is critically and quantitatively assessed. It is critical for monitoring success that characterization and explicit modeling of failure be conducted to define triggers that are to be detected by monitoring. One key function of pre-injection data collection is characterization and site-specific evaluation of noise, trends, frequency, and spatial variability of signal to determine the sensitivity of the monitoring array to leakage detection.

At the Weyburn field, more than 60 samples were collected during seven shallow groundwater surveys conducted between 2000 and 2009. Results (Figure 3.8) revealed a highly variable composition in the area, generally of the Ca-Mg-SO_4-HCO_3 type. (Johnson, 2012)

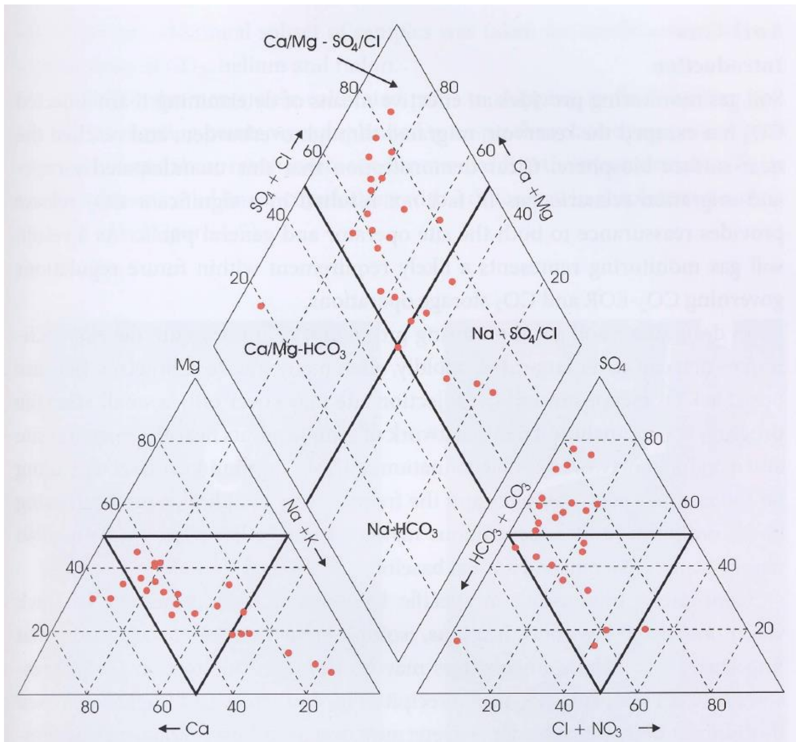

Figure 3.8: Piper plot of water composition from domestic and farm wells in the Weyburn project area. From Johnson, 2012.

An extensive sample-based study of groundwater geochemistry over SACROC did not find evidence that any leakage had occurred (Romanak and others, 2012), although the groundwater-rock-system is shown in models and in the lab to be sensitive to CO_2 leakage should it occur. However, Smyth (personal statement) warns that although the sampling data is quite dense and the signal well- assessed, a very strong statement that no leakage has occurred cannot be made, because reactive transport modeling to show the sample density needed to document no-leakage between sampling points, and deep sampling have not been conducted. Exhaustive consideration of the leakage options would include more intensive characterization, modeling, and possibly additional sampling. This study which collected a large number of samples over a multi-year period over a large and mature EOR site provides an important and widely applicable recommendation not to underestimate the investment in terms of characterization and number and types of samples collected needed to conduct a valid groundwater monitoring deployment.

At Cranfield, groundwater evolution trends have not been interpreted as leakage. To increase the robustness of the interpretation of the data as no evidence of leakage, a shallow "controlled leakage" push-pull experiment was conducted, where groundwater from a shallow aquifer was extracted, saturated with CO_2, and reinjected to measure the parameters changed by in-situ rock-water, dissolved CO_2 reaction. The test showed that the rock water reaction at in-situ conditions was slightly weaker, although still considered similar in scale, than the reaction observed in laboratory studies (Yang and others, 2012).

3.2.3 Soil gas monitoring

Soil gas measurements are a tool widely used for assessing natural migration of fluid out of the subsurface. They are also used at contaminated sites to map the extent of contamination in cases where contamination produced a diagnostic signal, such as volatile organic carbons from an oil spill. Because the goal of monitoring geologic storage is to demonstrate retention of CO_2 in the subsurface, monitoring soil gas flux across the soil-air interface was identified as an attractive monitoring technology (Klusman, 2003). In addition, a number of variations on the exploration tools testing gas in the vadose zone and soil profile were identified as monitoring prospects.

Soil gases have a number of advantages as a monitoring approach, in that they are low cost ways to get a broad overview of a dynamic system. However, their suitability for detection of leakage of CO_2 from a reservoir at depth is unproven. Uncertainties arise because 1) the transport distance is long, 2) transport mechanisms are understudied, 3) CO_2 is fairly soluble and natural analog studies (Gilfillan and others, 2010, Gilfillan and others, 2011) show that signals may be attenuated or delayed, 4) CO_2 generated by non-leakage processes may mimic or mask the leakage signal, and 5) the leakage signal may be focused in an area between sample points or outside of the sample pattern (Lewicki et al, 2005). Studies of natural analogs and controlled leakage experiments underway to support the development of this method may help to determine the usefulness and optimization of the methods.

The application to EOR might be limited to cases where storage falls under programs requiring such monitoring. However, other uses may become apparent as research matures. One potential benefit is Romanak's "process-base" method for addressing leak allegations, discussed later in the Stakeholders Interactions section (Romanak and others, 2012).

The first and most deeply studied controlled release site is the Zero Emission Research and Technology Center **(**ZERT) experiment, at the agricultural station at Montana State University, however a growing number of tests are underway internationally in a wide variety of settings (Spangler, 2012).

One interesting synthesis of reported preliminary results from controlled releases is that lateral transport has been greater than expected at a number of sites, with the emergence of the CO_2 not over the release site but laterally some distance away. This fits a model shown by natural spring and vents, which can be focused at intersections of geologic features and structures (Lewicki et al, 2007).

Also at Cranfield, typical background vadose zone gas compositions were obtained through a reconnaissance soil gas survey undertaken in 2008 near historic wells, and through a repeat survey in 2010. An elevated concentration of methane and CO_2 was identified during the first survey beneath a plugged and abandoned production well that was scheduled to be reactivated for production. This location was adopted as a study site (Yang et al, 2012). The anomaly was mapped utilizing an array of 3m-deep soil gas instruments deployed over an area of $100m^2$, referred to as the *P-site* (Figure 3.9).

Mud-logs were used to assess the sources of deep methane. Workover activities found the cement plugs in good condition; the source and transport mechanism for the thermogenic methane is not well understood. CO_2 is plausibly a biodegradation product from methane. Perfluorocarbon tracers (PFT) were placed at bottom-hole during completion, and monitoring of soil-gas composition and tracers is continuing to seek evidence of Jackson Dome CO_2 in soil gases. Production records indicate that CO_2 arrived in the reservoir in this area before August 2010. Monitoring continues to identify any compositional changes.

A novel "process-based" approach (Romanak and others, 2012) was developed as part of the Cranfield project for separating in-situ generated gases from exogenous gases. The process-based method considers the ratios of N_2, O_2, CO_2, and CH_4 to distinguish gases from processes that originated in the vadose zone from incoming gases that migrated from depth. An important value of this methodology over the traditional mapping of gas concentration is the reduced need for background measurements to identify leakage signals. Section 4.11 discusses the application of this method in Kerr Farm, a site in the vicinity of the Weyburn field, where farm owners claimed contamination with CO_2 from the EOR operation.

During Phase 1 of the Weyburn program, annual soil gas surveys were conducted from 2001 to 2005 and again in 2011, generally to measure CO_2 fluxes and stable isotopes. Three techniques were employed: (1) discontinuous gas measurements, (2) discontinuous depth profile measurements, and (3) continuous monitoring. Results indicate that stable isotope data on their own are inconclusive, but in combination with the measured soil gas CO_2 content indicate there is a clear isotopic depletion with increasing CO_2 concentration, which further supports the interpretation that the observed trend is caused by isotopic fractionation via biogenetic composition of organic matter (Johnson, 2012).

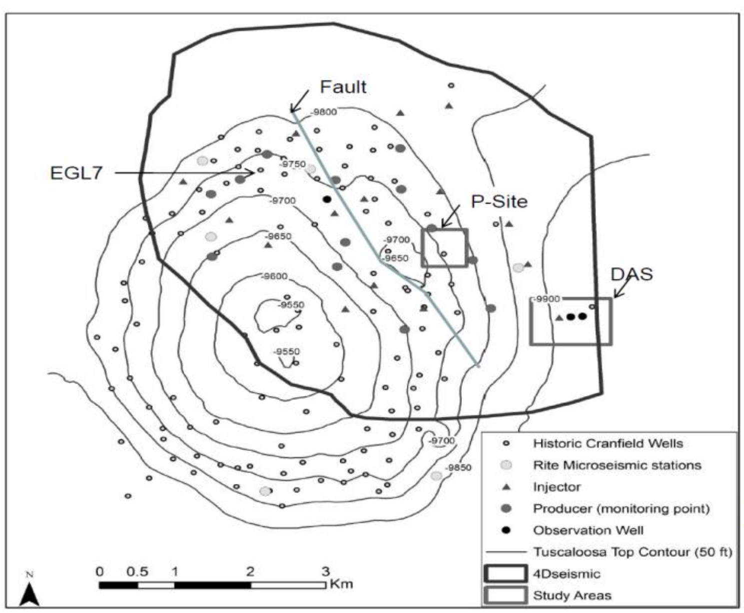

Figure 3.9: P-site and re-activated producer where the vadose zone was instrumented

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Section 4

Stakeholder Interactions

This section reviews how carbon storage research can reduce potential risk and damages during the course of development of CO_2 storage projects by promoting and improving communication and strategic involvement by all interested parties, or *stakeholders*. Stakeholder relationships have always been a challenge for energy production; all indications are that public concern will continue or increase. Learning how to communicate effectively and positively engage stakeholders regarding the new process of geologic storage may have a secondary benefit: it may assist the process of engaging stakeholders regarding conventional energy production, especially when innovations allow development of previously unexploited areas.

4.1 Stakeholder Issues and Engagement

According to the International Energy Agency (IEA, 2012a), stakeholder engagement and incentives driven through government policy are critical elements in ensuring successful development and deployment of CO_2 storage projects. The IEA defines a stakeholder in the broadest sense: an individual, group, or organization with an interest in CO_2 storage policy or in a specific project.

The National Energy Technology Laboratory (NETL) defines stakeholders, in the GCS and EOR context, as parties who believe they are affected by the decisions regarding a CCS or EOR project (NETL, 2009b).The NETL mentions that, while CO_2 storage projects may be viewed primarily as local concerns, they are also being carried out in the context of national and international debates (NETL, 2009b; IEA, 2012b; Crysostomidis, 2012). Therefore, it is likely that there will be stakeholders from outside the project's locality and regulatory jurisdiction.

According to NETL, at a local level, stakeholders may include elected and safety officials, regulators, landowners, citizens, civic groups, business leaders, media and community opinion leaders. Additionally, there are other potential stakeholders not directly involved in the site where the project is located. NETL classifies these actors as state or regional stakeholders which may include: elected and appointed officials, regulatory agencies, economic development groups, and environmental and business groups. At the national level, potential stakeholders can include government agencies, congressional leaders, committee/subcommittee chairs, national environmental groups, the financial sector, and the legal sector. Hammond and Shackley (2010) found that, regarding CO_2 storage projects, during the operational and short term period, the most important stakeholders seem to be the local public, local public groups, and local politicians

Stakeholders' concerns on CO_2 storage projects are associated with the fact whether the risks associated can be successfully managed. Potential risks linked with the leakage from CO_2 storage projects fall into two broad categories: global risks—climate change—and local risks—costs and damages to industry, human health, and the environment (IPCC, 2005). In most countries, the existing regulatory framework is unable to address these potential challenges. Because there exists no comprehensive set of regulations on CO_2 storage, there is a need for studies, procedures, and certification frameworks to manage potential risks. A sound process to select the site and characterize the bounds of safe operation is the single most important way to manage both short- and long-term risk from CO_2 storage activities. Knowledge of *ex-ante* and *ex-post* conditions of the CO_2 storage processes are among the basic elements needed to create legal frameworks, certification programs and public policies.

CO_2-EOR, as it is currently practiced, does not meet the necessary requirements for the development of CO_2 sequestration projects (Dooley and others, 2010). Marston and Moore (2008) noted that the U.S. oil and gas industry has been injecting CO_2 as part of EOR (also known as tertiary recovery) for nearly 40 years; this process is different from CO_2 storage. However, CO_2-EOR activities have served to develop and prove technology that will be included in future CCS systems (Dooley and others, 2010). Stakeholder involvement differs between CO_2-EOR and CCS in certain respects: (1) in EOR, stakeholders tend to have longstanding relationships, whereas in CCS the subsurface is either previously undeveloped -in the case of injection into a saline formation- or repurposed -in the case of CO_2 injection into a depleted reservoir for storage- (Plasynski and others, 2011); (2) the risk and the infrastructure requirements are different: EOR takes place in an area of established production with well-developed infrastructure, whereas CCS will at least require additional equipment, and may take place in an undeveloped area (Gale, 2002; Herzog, 2010), and (3) the regulatory environment is likely to be different, with EOR continuing to be operated under EPA's UIC Class II Program. In some cases it has been observed that EOR results in investment and cleanup of old and unsightly surface infrastructure. This may partly compensate for the adverse local effects, such as increased truck traffic or safety issues. It should not be assumed that stakeholder relations regarding EOR projects necessarily run parallel to CCS for purposes of storage (Marston and Moore, 2008; IEA, 2012a).

One of the challenges in promoting stakeholder engagement in CCS activities is determining who the relevant stakeholders are (IEA, 2012a). In a recent report, Environmental Resources Management (Chrysostomidis and others, 2012) established the following typology of stakeholders and areas of concern in CCS projects (Table 4.1):

Table 4.1 Stakeholders and areas of concern in CCS

CO_2 Storage Management Stakeholders and Concerns	
Stakeholder Groups	**Areas of Concern**
▪ Government and policymakers ▪ Legislative and regulators ▪ Industry ▪ Local communities ▪ Investors ▪ Public opinion and society ▪ NGOs and tought leaders ▪ Media ▪ Academia and research centers*	▪ Energy security ▪ Environment, health and safety (EHS) impacts ▪ Technical aspects ▪ Commercial and local development benefits ▪ Policy and legal issues ▪ Diversion from renewable energy ▪ Impacts on climate change ▪ Awareness and acceptance of CCS

*Additional stakeholders not considered by ERM.

Source: Modified from Chrysostomidis and others, 2012.

In the scenario described by Chrysostomedis and others, policymakers are at the center of stakeholder interactions because, for a typical CO_2-EOR or CO_2 storage project, the degree of interest that policymakers show, the regulatory framework they create, and the support they exhibit tend to influence other stakeholders (Figure 4.1). Potential interaction between policymakers and other stakeholders is essential and is generally associated with the scale and location of the project. For example, CO_2 storage sites lacking previous industrial development will require new infrastructure, appropriate site characterization and adequate operational programs to deploy the CCS activities.

The IEA (2010) identified 29 critical regulatory issues regarding CCS activities. These issues can be grouped into four categories: (1) broad regulatory issues, (2) existing regulatory issues applied to CCS, (3) specific regulatory issues, and (4) emerging regulatory issues.

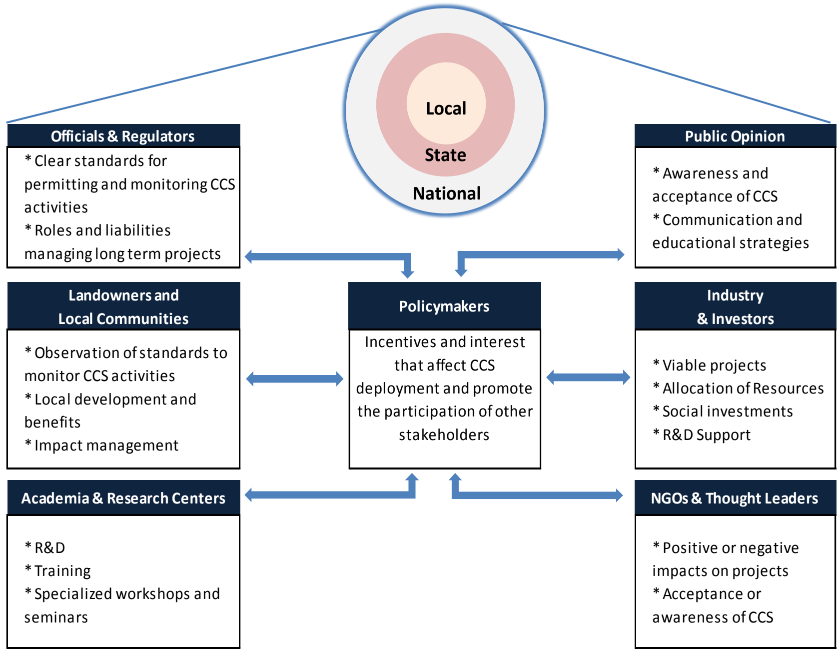

Figure 4.1 Stakeholder Interactions in a GCS project.
Source: Modified from Chrysostomidis and others, (2012) and IEA (2012a, 2012b).

Several factors, including uncertainties about CO_2 storage technologies, non-technical aspects of operations, scarcity of unbiased information reaching the general public, and potential technical risks have created an atmosphere of public hesitancy regarding CO_2 storage activities (IEA, 2007). However, on the practical side, technical experts, policy analysts, regulators, and lawyers have continued to work intensively to develop and deploy CO_2 storage activities in a manner that is economically and technically feasible as well as environmentally responsible (EPA, 2010). The role played by regulation in stakeholder engagement with CCS will be determined by consultation processes, legal provisions, and sharing of international case studies (NETL, 2009b, IEA, 2012a).

In recent years, a number of projects have encountered opposition from local communities and public opinion during the planning stages (Hammond and Shackley, 2010). In the United States, the Regional Carbon Sequestration Partnership has developed a best-practice protocol for community engagement (NETL, 2009b). The NETL has created a Best Practices Manual (BPM) which is a technical guide for monitoring, verification and accounting (MVA) of CO_2 stored in geologic formations (NETL, 2012). The creation of regulatory frameworks that address and manage environmental, health and safety issues can increase stakeholder acceptance of a prospective project (IEA, 2008). Hammond and Shackley (2010) provided the theory and practice for implementing good engagement and communication strategies and for maintaining positive developer and stakeholder relations. They define engagement as a two-way process: providing information and collecting responses to it. To foster this involvement, it is vital that policy that complements CCS begin in an early stage of the project (Van den Broek and others, 2011).

According to the NETL, as simulation models are refined with new data, public mistrust surrounding CCS will decrease.

Recently the Regional Carbon Sequestration Partnerships (RCSPs) concluded that public understanding of technical issues of CCS, *per se*; is less important than commonly believed by industry and government. Rather, public trust in the developer, regulators, and various levels of government to (1) deliver truthful information and a safe project, (2) operate a transparent and fair decision making process, (3) be accountable should things go wrong, and (4) treat the community fairly in the distribution of economic benefits and mitigation of hazards turned out to be more important than the dissemination to the public of detailed technical information on the project or the risk assessment (Hammond and Shackley, 2010).

This conclusion does not imply that hazards and risks are not of concern to communities. It does suggest, however, that the sense of empowerment enjoyed by a community—the degree to which it has a voice that is heard by the "those in charge" has a strong influence over the community's willingness to embrace unknown technologies. Successful engagement strategies often involve independent expert and stakeholder endorsement as well. In order to foster stakeholder involvement and create transparent and participative processes for CO_2 storage and CO_2-EOR projects, there exist different protocols and certification processes designed to identify and control potential risks (Marston and Moore, 2008; Oldenburg and Bryant, 2007; NETL, 2009a; NETL,2012; DNV, 2012).

4.2 Public Policy

CCS deployment is highly influenced by government policies (IEA, 2012b; IEA 2008). During the 2000s, the regulatory challenge to CO_2 storage was to establish the extent to which existing well regulations could be applied to the storage project system over the permitting, operations, and decommissioning phases (Imbus and others, 2009). CO_2 storage raises important legal questions that must be addressed before a national program, capable of effectively sequestering and mitigating large amounts of CO_2, can begin (Zadick, 2011). In the last several years, regulatory environments have been moving toward clarity. CCS regulatory frameworks have developed individually in countries and regions (in particular, the United States, Australia, and Europe, with China, Japan, and South Korea now creating their own CCS regulations). The support of financial and multilateral institutions such as the World Bank, the Asian Development Bank, the Carbon Sequestration Leadership Forum, and the Global CCS Institute has encouraged the sharing of legal and regulatory frameworks regarding CO_2 sequestration (IEA, 2010).

In the United States, federal and state governments have not reached a unified or consistent set of CO_2 regulatory policies (Anderson, 2009; Pollak, 2011). Nonetheless, there is an intensive effort to develop a comprehensive regulatory framework. For example, the Environmental Protection Agency (EPA) has taken a number of actions to design the regulatory system for geologic storage (IEA, 2012a). For example, in September 2011 the EPA finalized requirements for geologic sequestration and released the Announcement of Federal Underground Injection Control (UIC) Class VI Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells[1] (EPA, 2012). The EPA has also created, as a complementary

[1] The final Class VI Rule and other guidance documents are available at: http://water.epa.gov/type/groundwater/uic/wells_sequestration.cfm.

rulemaking, reporting requirements under the Greenhouse Gas Reporting Program. The EPA is also fostering the use of carbon capture and sequestration technologies by reducing barriers and regulation regarding CO_2 streams injected for this purpose (EPA, 2011).

Australia has started a program of precompetitive data acquisition and regional geological studies to assess sites for storage of CO_2 (IEA, 2010). This work is being conducted under two main programs: the National Low Emissions Coal Initiative (NLECI) and National CO_2 Infrastructure Plan (NCIP).[2] Australia also has established partnerships with other nations, including China, to facilitate technology transfer and share CCS procedures and best practices.

In the case of Europe, in March 2007 the European Council agreed to stimulate the construction and operation of multiple CCS demonstration projects by 2015 (IEA, 2010; CCSNetwork EU, 2013). The European Commission has also fostered the implementation of policy and regulatory frameworks. In June 2009, for example, the European Parliament enacted the Directive 2009/31/EC on the Geological Storage of Carbon Dioxide and amended previous regulations. This regulation offers the regulatory basis to ensure safe and environmentally sound storage and containment of CO_2. The next step for this legislation is deployment to the local regulatory framework of EU-member nations. In 2010, the European Union launched its European CO_2 Capture and Storage (CCS) Demonstration Project Network. This network seeks to increase public acceptance of CCS projects, mainly through a focus on safety, long-term liability, and environmental benefits of CO_2 sequestration.

The IEA (2010, 2012a) noted other local and regional experiences regarding local jurisdiction and public policy design and involvement; for example, in British Columbia and Alberta, Canada; Queen Island and Victoria, Australia; and Illinois, Texas, Oklahoma, New Mexico; U.S.A (Duncan et al, 2008a). In the United States, different local governments have made some progress in the regulation of geological storage of CO_2 (Duncan and others, 2008a; Anderson, 2009). In 2009, the 81st Texas Legislature enacted Senate Bill 1387 (The Legislature of the State of Texas, 2009) which regulates the implementation of projects for the capture, injection, sequestration, or geologic storage of anthropogenic CO_2.[3] SB 1387 requires the Railroad Commission of Texas (RRC) to adopt rules for geologic storage and associated injection of CO_2. The law also requires conducting, preparing, and filing two preliminary reports on the geologic storage of CO_2. In response to SB 1387, the RRC has promulgated new rules and guidelines.

Despite these efforts, the overall impact of the varied framework of CCS regulations on EOR activities remains uncertain, and regulatory specifics vary from place to place and are subject to sudden change. A key point of all these regulatory frameworks and policies is that they require stakeholders' engagement in the development of CO_2 storage projects (IEA, 2012a).

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[2] According to the Australian Government through Geoscience Australia. http://www.ga.gov.au/ghg/ccs-program.html

[3] This bill was enacted by the Legislature of the State of Texas and it took effect on September 1, 2009. http://www.capitol.state.tx.us/tlodocs/81R/billtext/html/SB01387F.htm and http://www.rrc.state.tx.us/forms/reports/notices/SB1387-FinalReport.pdf

4.3 Risk Assessment and Management

Carbon dioxide is used in a wide variety of industries and it is generally regarded as a safe and nontoxic inert gas. In a wide variety of industrial, commercial, and domestic settings, the hazards of CO_2 are well known and routinely handled (Benson and Surles, 2006; Benson, 2007). However, safety and good management require an exhaustive assessment of the risk of elevated concentrations of CO_2. In addition, geologic storage facilities investment and infrastructure would be damaged should CO_2 be unexpectedly released. Extensive industrial experience indicates that risks from geologic storage facilities are manageable using well-understood engineering controls and procedures (Benson, 2006; Benson and Surles, 2006; Duncan et al, 2008b; Trabucchi, 2008; Klass and Wilson, 2009; DNV, 2012). The application of lessons learned from comprehensive risk assessments that identify risks not commonly considered in routine oil and gas operations could be of benefit to industry.

The IPCC (2005) has stated that "observations from engineered and natural analogues as well as models suggest that the fraction of CO_2 retained in appropriately selected and managed geological reservoirs is very likely to exceed 99% over 100 years and it is likely to exceed 99% over 1,000 years." The trapping mechanisms involved in CO_2 storage are effective and well known. The local risks are thought to include two scenarios: (1) sudden and rapid CO_2-release events, control of which would be achieved by techniques currently used for containing well blow-outs, and (2) gradual and diffuse leakage through undetected faults, fractures, or leaking wells (Solomon, 2006; IPCC, 2005). Relatively simple metrics such as the number of wells, density of faults, or reservoir permeability can be used in different models to characterize CO_2 storage sites and identify potential risks as discussed in Section 3 (Figure 4.2)

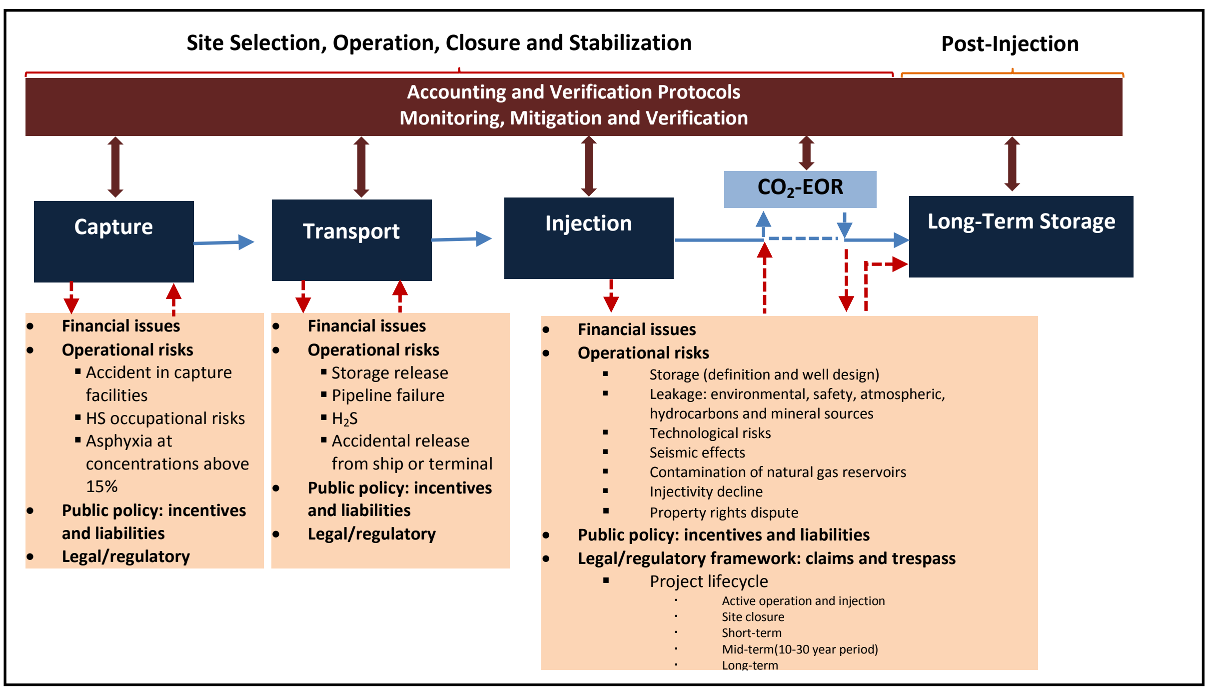

Figure 4.2: Stages of the CO_2 capture and storage/ CO_2-EOR lifecycle
Source: Leiss (2009); Marston and Moore (2008); Trabucchi and others, (2010); Adelman and Duncan (2011) and DNV (2012).

Best practices for CCS dictate that a site must be characterized, assessed for risk of leakage, and be covered by a monitoring plan (Chalaturnyk and Gunter, 2005; IPCC, 2005; IPCC, 2006; NETL, 2009a; NETL, 2012). Protocols must also be developed to deal with long-term effects of CO_2-rich conditions on the stability of well materials, geochemical and geomechanical interactions that might degrade the containment system, and the feasibility of CO_2 storage (Imbus and others, 2009). Risk assessment for CCS draws on a number of precedents: procedures developed by researchers and energy specialists at national laboratories, universities, and research centers which include, for example, the existing certification frameworks (Oldenburg and others, 2010; NETL, 2012; DNV, 2012). Risk assessment also draws on related experiences in the oil and gas industry, including for example: Schlumberger Carbon Services' risk assessment methodology, RISQUE methodology (Bowden and Rigg, 2004; Wyatt and others, 2009), and other protocols implemented in commercial projects such as Chevron's Gorgon Project (Beatty and others, 2010) or Shell's Quest CCS project.

One of the main objectives of research on CCS operations is to learn how best to employ geological storage of CO_2 as a viable option for mitigating greenhouse gas emissions to the atmosphere (Whittaker and others, 2011). There have also been efforts to integrate a best-practice manual for industry and government to conduct CCS activities (Figure 4.3)

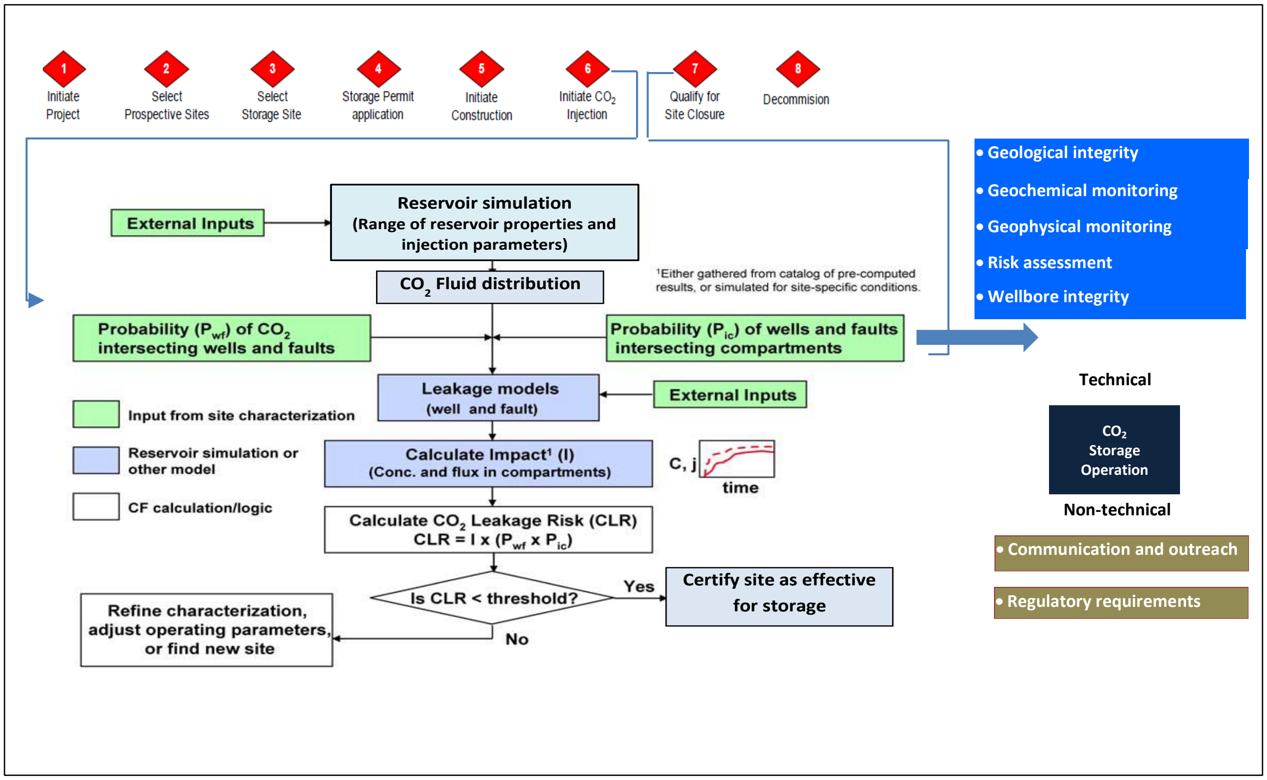

Figure 4.3: CO_2 storage lifecycle and certification framework: Technical and nontechnical issues.
Source: Oldenburg and others, (2010), Whittaker and others, (2011), DNV (2012).

However, the linkage between risk assessment and regulatory expectations is not yet complete. For example, injection regulations in the United States do not require a formal risk assessment. However, other factors such as commercial or investment expectations may drive the interest in these certification frameworks. In general, potential risks from the development and operations of CCS projects can be summarized in three categories: (1) transport of CO_2 streams, (2) injection operations, and (3) sequestration of CO_2 (O'Connor and others, 2011). A conceptual approach for an integrated risk management and its influence in designing public policy is set out in Figure 4.4.

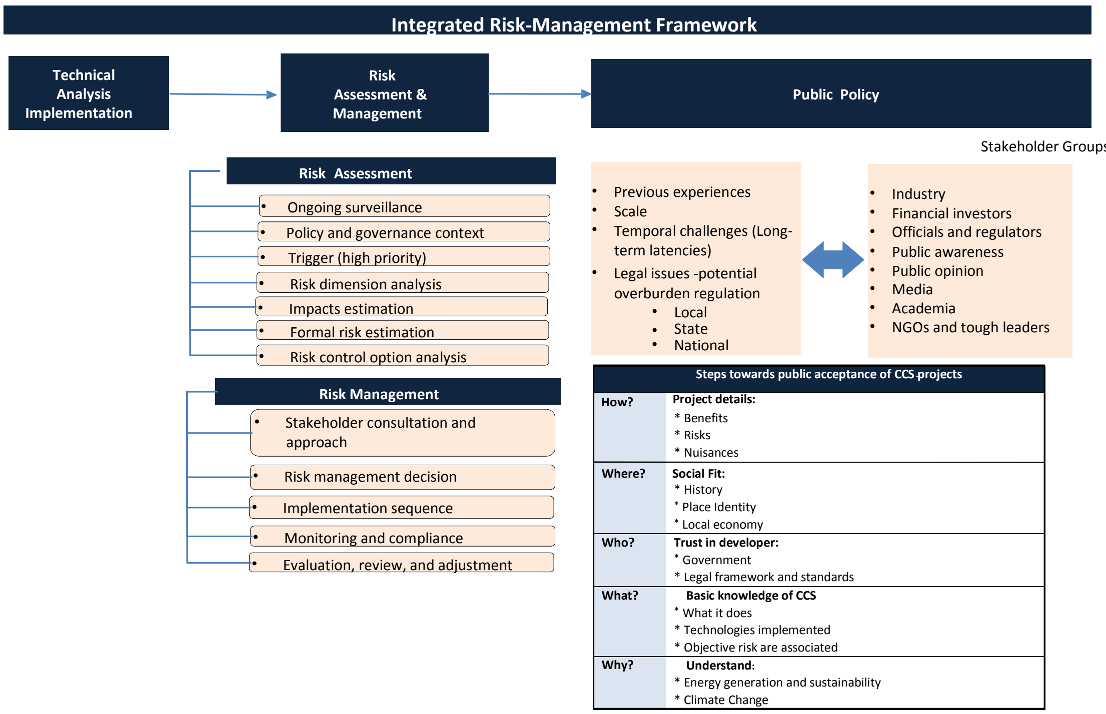

Figure 4.4: Integrated risk-management framework
Source: Modified from Leiss (2009) and Hammond and Shackley (2010).

Several efforts to certify safety and effectiveness of CO_2 sequestration projects are under development (Chalaturnyk and Gunter, 2005; Oldenburg and Bryant, 2007; NETL, 2009a; Nicot and others, 2010; NETL, 2012). Protocols from certain upstream activities in the oil industry are directly applicable to CO_2 storage and CO_2-EOR projects; however, the unique behaviors of large volumes of injected CO_2 and the need for "permanent" isolation from the atmosphere require additional consideration. Monitoring, Verification and Accounting protocols are important elements to document CO_2 retention during and after CO_2 sequestration (NETL, 2009a; NETL, 2012).

Recent works suggest that established subsurface characterization methods, reservoir modeling, and certification frameworks might be able to provide reasonable estimates of potential risks. Oldenburg and others (2010) enumerated five potential areas of risk from a CO_2 leakage: (1) near-surface environment, (2) health and safety, (3) atmospheric, (4) underground sources of drinking water and (5) hydrocarbon and mineral sources.

Wolaver and others (2013) made a distinction between *greenfields* and *brownfields* for CCS. The definitions consider only surface activities. Greenfield areas are not developed; brownfield areas are available for reuse. Greenfields are located in rural areas whereas brownfields are typically located in urban areas or large industrial complexes such as oil fields. Greenfields and brownfields differ in their risks and certainties, and mischaracterization can lead to inefficient investment, failure to identify a critical leakage risk, and ineffective monitoring programs.

4.4 Property rights and environmental and safety risks of CO_2 sequestration

As noted earlier, CO_2 storage and CO_2-EOR processes raise important legal and regulatory questions (Adelman and Duncan, 2011; Zadick, 2011). These legal concerns can be analyzed from two different perspectives: (1) in-situ operational concerns and (2) trespass issues under a neighboring-tract perspective (Anderson, 2009). The absence of a defined liability framework could impede the deployment of CO_2 storage and CO_2-EOR activities (Jacobs and Stump, 2010). CCS involves multiple property rights issues. These property rights are linked to ownership of the captured and stored CO_2, surface infrastructure and its access, subsurface pore space, the rights of adjacent users, intellectual property (as it relates to technology used), and characterization, modeling, and monitoring of the site (Robertson et al, 2006; Wilson and de Friguerido, 2006; IOGCC, 2007; Anderson, 2009; IEA, 2010; IEA, 2012a, 2012b).

As we discussed in Section 3.2, environmental protection and the preservation of drinking water resources are among the issues of greatest importance to some stakeholder groups, i.e. local communities, public opinion or government policy makers. Due to these concerns, certain projects have greatly emphasized monitoring of ground water and soil gas in order to gain support for the development of CCS activities (Gilfillan and others, 2011; Romanak and others, 2012; Spangler, 2012). Traditional regulatory efforts have concentrated on proper maintenance of wells and less public policy has been established regarding CO_2 sequestration integrity. There are different studies which demonstrate that CCS activities are technically and economically feasible activities that can be developed in accordance with environmental and safety standards (Gale, 2002; Bradshaw and Dance, 2004; IPCC, 2005; EPA, 2010; IEA 2012b) . These outcomes have served to increase stakeholder involvement and interest regarding CCS projects and their potential risk (NETL, 2009b; IEA, 2012a).

New results show that metal mobilization predicted by theoretical models does not occur in some settings already tested. Iron and manganese are the metals released in largest quantities; as contaminants in drinking water these elements pose a limited heath risk.

Monitoring of shallow ground-water chemistry above carbon-sequestration reservoirs has been proposed as a method to demonstrate that geological CO_2 storage does not endanger drinking water sources (EPA, 2008). Yang and others (2012) found that research on the potential impact of CO_2 migration into shallow groundwater had been focused mainly on (1) assessing geochemical outcomes of increased CO_2 and connected effects on drinking water quality, and (2) identifying geochemical parameters best suited for detecting CO_2 leakage signals at a geological CO_2 sequestration site.

Other potential concerns associated with CCS are: asphyxiation from CO_2 accumulations, soil damage, dislocation of animal or fish populations (Trabucchi et al, 2010) or potential impacts on ecosystems and local fauna (O'Connor and others, 2011). There are other well-known examples of venting systems where CO_2 releases occur, particularly in volcanic formation zones.[4] However, limnic eruptions and hazardous leaks occur in volcanic areas that are highly fractured and therefore unsuitable for CCS

[4] The best-know CO_2-related incident was the limbic eruption at Lake Nyos in Cameroon in 1986, in which the release of an enormous volume of CO_2 killed over 1,700 people and thousands of animals (Benson and others, 2002).

projects (Benson and others, 2002). Studying risk from natural CO_2 seeps can guide assessment of potential health risk from CO_2 onshore leaking.

CCS cannot operate at zero risk, but even if stored CO_2 were to leak to the surface as a result of containment failure, the risk of human death would be extremely low (Roberts and others, 2011). Offering opportunities to increase stakeholder's involvement on CCS may be vital to the advancement of CO_2 storage deployment. The experience of the Kerr Farm in Saskatchewan, Canada, provides another relevant case in point: at this farm, near an EOR project, a possible leakage of CO_2 was detected. Further analysis, employing a method developed for CCS, showed that the aberrant CO_2 level was the result of natural processes (Romanak and others, 2012).

There are several methods commonly used to foster public engagement on CCS: reporting, community meetings and workshops, dissemination of technical information, and formal and informal education (IEA, 2010; NETL, 2008b). Undoubtedly, to reduce stakeholder's concerns on CCS activities, it is essential to generate in all interest groups an informed participation supported on technical elements and on the cutting edge research findings.

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Conclusions

The rapid development of geologic carbon storage (GCS) technologies is due, in most part, to more than 40 years of CO_2 enhanced oil recovery (EOR) operational experience from which GCS has learned and benefited. However, GCS studies have gathered and analyzed significant amounts of field data (not commonly collected during EOR operations), which have been critical in the understanding of subsurface CO_2 flow.

One advantage of GCS projects is the simpler single-phase environment, where the injection of a distinctive fluid (CO_2) into a pore space that is brine filled and not previously exploited provides an opportunity to assess the reservoir response in a way that cannot be done in an oilfield setting. It is much more difficult to detect, quantify, and image the CO_2 saturation evolution in a multi-phase environment (oil, water, possible methane + CO_2) than it is to do so in a water + CO_2 one. CO_2 injection in a saline aquifer provides the opportunity to collect a baseline against which to quantify change in the response of a monitoring tool when CO_2 is injected. Fields entering tertiary recovery have typically been highly perturbed by depletion, injection of brine and other fluids, and past tertiary recovery. Knowledge gained in simpler saline systems can inform the complex systems. Furthermore, the close spacing and high frequency of data collection of GCS projects has allowed the detection of fluid flow and rock property interaction details that could not have been observed at the traditional EOR pattern-scale well spacing.

A lesson learned from GCS studies is the need for improved reservoir characterization. Geologic features that increase reservoir heterogeneity and decrease CO_2 sweep efficiency, such as high permeability channels (which can be a product of geological depositional history, post-depositional diagenetic processes, structural deformation, etc.), have long been recognized in EOR floods as reasons for CO_2 by-pass. Improved understanding of CO_2 trapping mechanisms (dissolution into brine, capillarity, etc.) from GCS research could also result in better CO_2 management.

Flood surveillance is one of the areas with the highest knowledge transfer potential from GCS research to commercial applications of CO_2-EOR. GCS has made significant advances in the surveillance of the reservoir response to CO_2 injection, as well as the improved and additionally validated use of these observations for predictive modeling. Improvements in numerics, handling dry-out zones, near well-bore realizations, rock-brine interactions, understanding the implications of boundary conditions and other fundamental code improvements will advance all modeling, including modeling for EOR.

Geologic sequestration has provided accelerated development of novel types of geophysical measurements. One of the contributions made for seismic interpretation from research-oriented storage projects is the combination of conventional seismic surveys with other instruments, including borehole deployed technologies such as cross-well seismic and vertical seismic profiles (VSP).

Pressure monitoring in the reservoir is essential for commercial production, and a classic surveillance tool used for the calibration of numerical fluid flow models. Correct assumptions of pressure increase are needed to optimize CO_2 purchase, recycle volumes, and water curtains. GCS has added value to this method by collecting novel and publically accessible data sets. Integration of pressure data with geomechanical evaluations is also a novel approach. The value of these data for commercial application has not been fully developed, but opportunities are opened.

Perturbed temperature sensing has a potential applicability to EOR. This technology can be used to evaluate changes in fluid saturation that would be of high value in the assessment of the flood and in the modification of strategies as injection becomes mature. The demonstrations for CCS research provide information on the sensitivity of the method. Assessment of the validity of the method has not been undertaken in the EOR context.

On non-technical aspects, the effective communication and stakeholder engagement required in GCS projects may have a secondary benefit. Lessons learned in this area may assist the process of engaging stakeholders regarding conventional energy production, especially when innovations allow development of previously unexploited areas. Learnings from comprehensive risk assessments that identify risks not commonly considered in routine oil and gas operations could also be of benefit to industry.

The experience of the Kerr Farm in Saskatchewan, Canada, a farm near the Weyburn EOR operation where a supposed leakage of CO_2 was detected, is one example where GCS research has been used in an EOR environment with great benefit. Further analysis, employing a method developed for CCS, showed that the abnormal CO_2 level was the result of natural processes.

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Appendix

Case Study: Kerr Farm (Weyburn EOR site)

In 2011, Cameron and Jane Kerr, owners of a farm in the vicinity of the Weyburn CO_2-EOR Project (WMP),[5] claimed that CO_2 was leaking into their property. They made the public allegation that CO_2 had leaked from the approved CO_2 area of the Weyburn Unit, near Goodwater, Saskatchewan, Canada.[6] The Weyburn area has been the site of extensive oil production in Canada since the 1950's. A geochemical soil-gas survey conducted by Petro-Find Geochem, identified high concentrations of CO_2, averaging between 23,000 ppm (2.3%) and 110,607 ppm (11%), in the location where the Weyburn Field is currently undergoing CCS operations.

Since no background data had been collected directly at the Kerr Farm, in order to respond to the allegation, a new technique for vadose-zone monitoring in CCS presented an opportunity to verify whether potential risk and liabilities were related to possible leakages from the WMP. The vadose-zone monitoring study not only demonstrated that CCS projects are technically and economically viable; it also showed that the WMP was being conducted in a safe way and that the area surrounding the Kerr Farm had not been affected by CO_2 from the storage site.

There had been at least five salt-water spills or leaks on the Kerr property. Over the years, Mr. and Mrs. Kerr had expressed their concerns regarding contamination of their property as a result of EOR and CO_2 storage activities (Table A.4.1).

[5] In January 2011, a consultant released a report that claimed to link high concentrations of CO_2 on the Kerrs' property to gas injected in the Weyburn Unit, http://www.cbc.ca/news/technology/story/2011/01/11/sk-carbon-complaint-1101.html. This report was based on a geochemical soil-gas survey conducted by Petro-Find Geochem Ltd. http://www.gasoilgeochem.com/reportcameron%20jane%20kerr.pdf

[6] Preston et al. (2005) compiled an integrated overview of the results from more than 50 individual technical research projects supported by the International Energy Agency Greenhouse Gas R&D Programme The WMP was created to predict and verify the ability of an oil reservoir to store CO_2 securely and economically.

Table A.4.1 Kerr Farm Case Concerns and Risks

Potential Concerns	Associated Risk
CO_2 transport, injection, and drilling activities	**Environmental, health, and soil contamination**
Seismicity	**Injection:** - Geological characterization
Contamination of drinking water	**Leakage and migration:** - Geological, physical, mechanical and chemical characterization -Environmental/biological - Hydrologic
Eutrophication	**Leakage and migration:** -Environmental/biological -Chemical
Health issues related to CO_2 injection, storage, and chemical contamination	**Injection, leakage and migration:** -Safety/biological -Health/biological
Corrosion	**Leakage and migration:** -Industrial -Neighboring tracs

Source: GCCC, 2012. The potential risks found coupled with the thermal, hydrologic, mechanical, chemical, and biological (THMCB) potential impacts of CO_2 injection addressed by the NETL (NETL, 2011).

Over the 13 years preceding the Kerr Farm Case, several studies had been conducted to address each of the concerns enumerated in Table A.4.1. These studies were summarized in a Final Report of the Kerr Project prepared by the International Assessment Centre for Geologic Storage of CO_2 (IPAC–CO_2, 2011a; IPAC–CO_2, 2011b). The Kerr Farm case confirmed that CCS projects are primarily viewed as local concern (IPCC, 2005; NETL, 2011) and they usually encounter opposition from local communities and local public opinion (Hammond and Shackley, 2010).

Petro-Find's studies also confirmed that different factors such as lack of information about the relevant technology or a poor understanding of crucial CCS processes contributes to misunderstand CO_2 storage projects (Koop and others, 2010). Petro-Find's initial results showed that soil CO_2 (≤~11 vol. %) and CH_4 (≤~30 ppm) at the Kerr Farm had originated from CCS operations. However, after a scrupulous study, the scientific community found critical flaws in this report.

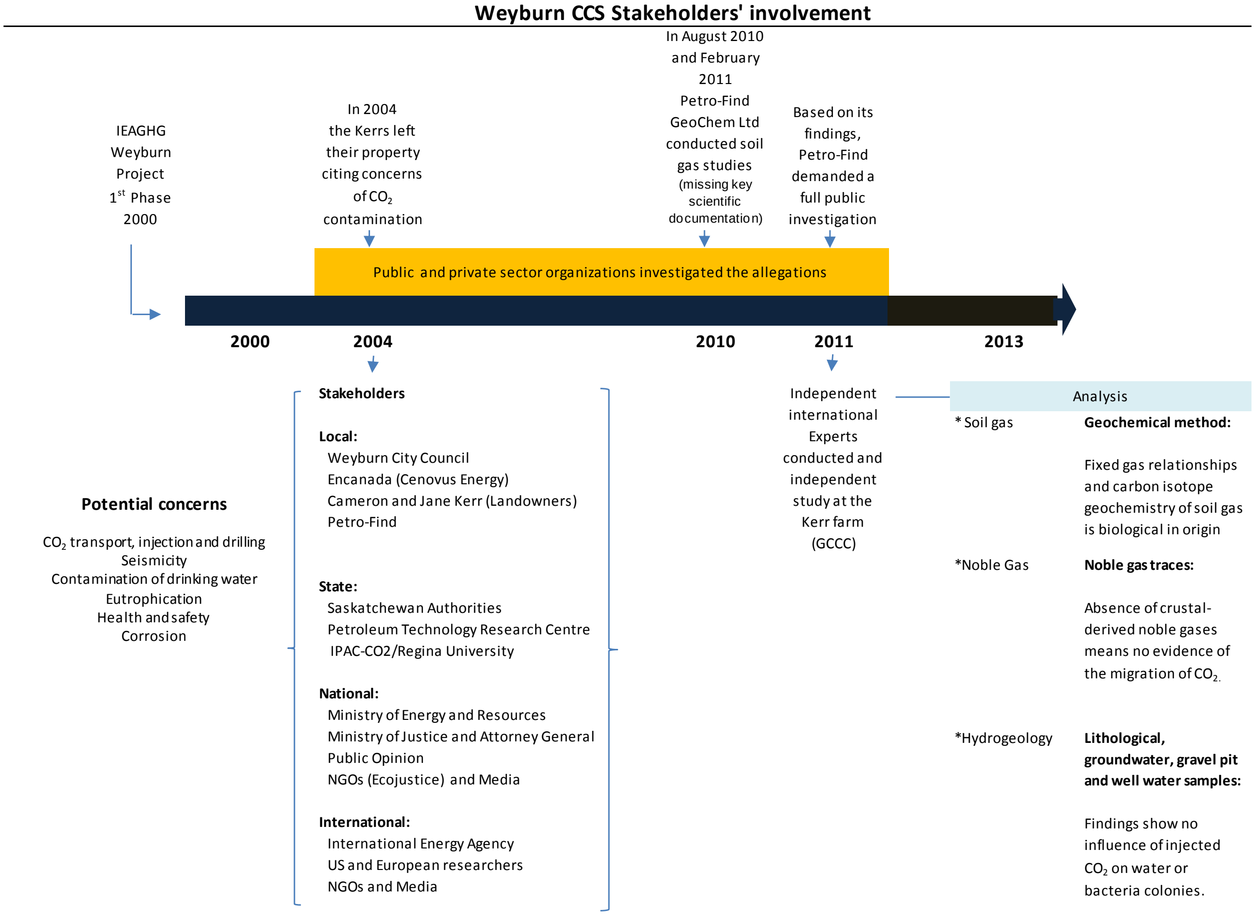

Figure A.4.1 WMP Stakeholders' Involvement
Source: GCCC, 2012.

The Kerr Farm controversy brought to the forefront an important question: How long will sequestered CO_2 stay trapped in the ground? (Benson and Surles, 2006) Because the Weyburn area had a long history of oil extraction, it was crucial to determine potential leakage mechanisms (Adelman and Duncan, 2011) and determine whether the anomalous CO_2 had leaked from the storage reservoir or from natural seeps, intermediate geologic zones, or other sources not related to CCS.

To confirm that all stages of CCS activities in the WMP are being done in an efficient way i.e. transport of CO_2 streams, injection operations, and sequestration of CO_2 (O'Connor and others, 2011), different stakeholders have been involved in determining the WMP efficiency (Figure A.4.2).

Two issues dominate the debate on CCS: (1) the risks posed by leakage of CO_2 from sequestration sites, and (2) management of the long-term liabilities, possibly extending hundreds of years. As it was discussed in section 4, a potential leakage could have different effects (Oldenburg and others, 2010; NETL, 2011). Recent studies from the IEA have found that, in the event that leakage does occur at a CCS site, lateral migration is unlikely to pose a problem. Vertical leakage is likely to be a problem only if the rate of leakage is relatively fast (IEA GHG, 2009).

In the Kerr Farm case, the regulatory framework was unable to address immediate liabilities and other potential risks associated with CCS at the time the complaint was made. Because of this inability, the IPAC-CO_2 commissioned a scientific study, which was led by Katherine Romanak, a research associate at the Gulf Coast Carbon Center (GCCC). Romanak and others, (2012) used a process-based method to analyze the vadose zone at the Kerr Farm in order to identify a potential leakage signal without the use of background monitoring.[7] This method is generally accepted for assessing whether a leakage of CO_2 from a storage reservoir has impacted the soil and the biosphere. The most challenging aspect of vadose-zone gas monitoring is identification of a leakage signal amidst the many interfering and fluctuating natural and anthropogenic sources.[8]

This method uses a geochemical approach to distinguish processes in the vadose zone overlying the CO_2 injection area of review, differentiating (1) biologic respiration, (2) CO_2 dissolution and reaction with soil carbonate, (3) CH_4 oxidation, (4) dilution of soil gas, and (5) leakage. Soil gas analysis results revealed that the gas on the Kerr property was biological in origin and not the result of leaks associated with the CCS activities at Weyburn.

A one-time characterization provides enough information to select those potential monitoring areas in a project. The ability to assess leakage and respond to any potential concern at any stage in the life cycle of a CCS project using process-based methods would greatly enhance the effectiveness of CO_2 storage. Using a process-based method has certain advantages, such as: (1) it does not require previous measurements (particularly advantageous for those areas where CCS projects have been implemented) and (2) this method increases the ability to monitor potential leakage. The process-based method also reduces the cost of shallow monitoring techniques.

The Kerrs also enumerated other potential damages caused by the presence of CO_2 on their property. These included threats to human health, damage to soil, and potential poisoning or dislocation of animal populations. Regarding the health concerns of the Kerrs, it is true that CCS cannot operate at zero risk; however, even if stored CO_2 did leak to the surface as a result of a failure of containment, the risk of death would be extremely low (Roberts and others, 2011). In this project, soil damage and the risk of dislocation of animal populations were not characterized.

After the Kerr Farm case, the Alberta government launched an extensive campaign to educate the public about climate change and also issued one of the first carbon sequestration tenure regulations.[9] This rule stipulates that, before the Ministry of Energy approves any permit for a monitoring, measurement, and verification plan for a CCS project, the plan must

> *set out the monitoring, measurement and verification activities that the permittee will undertake for the term of the permit, contains an analysis of the likelihood that the operations or activities that may be conducted under the permit will interfere with mineral recovery based on geological*

[7] These results agreed with two other studies conducted at the Kerr site (Riding and Rochelle, 2005; Cenovus Energy, 2011). The vadose-zone method uses a geochemical approach to CO_2 leakage monitoring that does not compare soil gas concentrations to previous characterization data but instead uses sequential relationships among coexisting major gases to identify the processes acting in the vadose zone.

[8] There are many potential sources of gas in the vadose zone and the reactive geochemistry of these gases require that care be taken when assessing a CCS site for storage permanence using soil-gas measurements.

[9] Alberta's Ministry of Energy.
http://www.qp.alberta.ca/documents/orders/orders_in_council/2011/411/2011_179.html

interpretations and calculations of the lease, and contains any other information request by the Minister. A permittee must not conduct any operations or activities under the evaluation permit unless a monitoring, measurement and verification plan has been approved in relation to the permit, and the permittee complies with the approved plan.

This tenure regulation is set to expire in April 30, 2016, a deadline set in order to ensure its review. Although this tenure regulation is a good start, it does not establish any legislative sanction and recommends that the official statues and regulations be consulted for all purposes of interpreting and applying the law.

One effect of the Weyburn experience was to underscore the importance of stakeholder engagement in any CCS deployment. Two of the central questions remaining are: (1) What is the role of the government in CCS projects? and (2) In the event of a leak, how will liabilities be assigned and how will the responsible stakeholders deal with those potential issues? (IEA, 2012a,b)[10]

For all future CCS projects, it is recommended that a baseline set of data on water, soil, and geophysical measurements be established so that the area around the project can be monitored for leakage. If it is not possible to have a previous characterization of the CCS site, there are some methods, such as vadose-zone monitoring, which can help to identify potential leakages of CO_2. In case of harm to the environment, health, or property, strict liability is usually triggered when a defendant owns or operates a facility from which a harmful substance was released, regardless of whether the defendant was negligent (Klass, 2004). This was not the case in the Kerr Farm because there was no CO_2 released from the WMP.

[10] In July 2012, the International Energy Agency published a report on Carbon Capture and Storage Legal and Regulatory Review, which aims to help policymakers and regulators develop their own regulatory frameworks by documenting and analyzing recent CCS legal and regulatory developments. In the case of Alberta, operators are now allowed to evaluate a potential storage site to investigate the geology and determine if this site is suitable to develop CCS projects.