Surface Dissolution: Addressing Technical Challenges of CO₂ Injection and Storage in Brine Aquifers

by

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Dedication

To Starr,

for sticking with me through thick and thin.
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My experience at the University of Texas at Austin has been a stretching experience for me. My understanding of the foundations of science, research, and education has indelibly been shaped. I would like to thank all those who took the time to teach me and showed me passion for the science and respect for the world.

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Abstract

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Sequestration of CO₂ in geologic formations will be part of any campaign to mitigate greenhouse gas emissions. The risk of leakage from the target formation must be weighed against economic feasibilities for this technology to gain stakeholder acceptance. The standard approach to large-scale geologic sequestration assumes that CO₂ will be injected as a bulk phase into a saline aquifer. The primary driver for leakage in this approach is the buoyancy of CO₂ under typical deep reservoir conditions. This research investigates an alternative storage approach that eliminates the buoyant leakage concern and addresses other injection and storage concerns. The tradeoff for this added storage assurance is increased cost, which is quantified and compared to the standard approach.

The prototypical surface dissolution process uses the brine extracted from the target aquifer as a solvent. Captured CO₂ is dissolved into this brine in a surface facility prior to injection into the aquifer. The CO₂-laden brine is slightly denser than brine
containing no CO₂, so ensuring the complete dissolution of all CO₂ into brine at the surface eliminates the risk of buoyancy-driven leakage.

The displacement volume is about 30% smaller than the volume of water displaced in the standard approach, so surface dissolution reduces the overall impact on groundwater resources. However, the operational costs of the surface dissolution process are about 10-18% greater than for the standard process. Also, the capital costs are about 25%-50% greater, mainly because of the larger number of wells needed. In terms of $/t-CO₂, the surface dissolution process will be about 20% more than the standard approach to geologic sequestration. This alternative strategy is particularly attractive in shallow aquifers (2,000 to 4,000 ft) which are less likely targets for the standard approach. The potential risk of buoyant migration along faults and the complications of multi-phase flow are not concerns for surface dissolution.

Two bulk phase storage and injection issues are discussed in conjunction with the surface dissolution. First, natural geologic uncertainty like fault conductivity poses important risk to buoyant mobile CO₂. As time progresses, more fault-prone sites are likely to be selected as the need for storage space increases. In this research, methods currently used to determine fault sealing behavior and studies of petrophysical fault zone descriptions are presented and discussed in detail. Also, during bulk phase CO₂ injection, salt precipitation and multi-phase flow effects can reduce the injectivity. An injectivity model was developed to help understand the injectivity mechanisms and determine the potential injectivity reduction because of near wellbore drying and phase interaction.
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CHAPTER 1: INTRODUCTION

Human emissions of greenhouse gases through fossil fuel combustion have become a concerning and pressing global issue. Carbon dioxide and other emitted greenhouse gases are widely believed to be the main culprit of the increasing atmospheric concentration and the recent increase in global temperature (IPCC, 2007). With annual global emission in now in excess of 7 Gt-C/yr (billion tons of carbon) and emissions expected to grow between 40-100% over year 2000 levels by 2030, many individuals and organizations believe action should be taken to reduce these levels (EPA, 2007; NPC, 2007; IPCC, 2007). Collective action to mitigate greenhouse gas emission is not without resistance. Some argue the immense history of climate change has not been put into proper perspective compared to the short history of human emissions and that important climate drivers like the sun are not well understood (Gerhard and Hanson, 2000, Robinson et al., 2007). Even with some unanswered questions, the consensus is that responsible action must be taken to change the way energy is viewed and used in an emerging carbon constrained world (Bachu, 2003).

At the same time as carbon policies are being suggested, economic growth is surging and fossil fuels are projected to meet over 80% of the energy growth in the next decades (Caruso, 2005; Rogner, 1997; NPC, 2007). Coal, which has the largest carbon emissions and has the largest reserves, is expected to have the largest growth in the energy mix. Oil and gas are projected to remain a large and important part of the energy mix amidst projections of diminishing reserves and increasing price pressure (NPC, 2007). Therefore, current and future carbon emissions amplify the need for carbon management strategies that focus on fossil fuel emission capture and storage.
Leading strategies for carbon management focus on capturing CO₂ from large stationary emission sources and then storing or sequestering the CO₂ deep in the subsurface (Fisher et al., 2005; Yamasaki, 2003). Two-thirds of CO₂ emissions come from stationary sources and 40% come from electricity generation (EPA, 2007). Coal-fired electricity generation is of special interest because coal is the largest carbon emitter per unit of energy produced. A leading near term strategy includes retrofitting the coal power plant to capture the emissions. The CO₂ is separated from the exhaust or flue gas of coal plant and compressed to supercritical pressure for transportation. The CO₂ is transported and injected into a geologic target. Different targets like oil and gas fields, unminable coal beds, and saline aquifers have been proposed as possible storage sites. Saline aquifers are an important and leading option as they are the most widely available onshore option and have the largest potential volume for storage (Ennis-King and Paterson, 2002; Yamasaki, 2003; DOE/NELT, 2007). Petroleum engineering tools can be employed to predict the subsurface movements in saline aquifers. The same principles and mechanisms that apply to hydrocarbon extraction apply to CO₂ injection. The cost of CO₂ capture, compression, and storage will be significant with the capture cost being the largest part of both capital and energy requirements.

Saline aquifer storage does have several technical challenges. Buoyant CO₂ leaking out of the subsurface is the most important potential problem (Oldenburg and Lewicki, 2004; Hesse, 2006). Because buoyant-driven movement can increase the amount of immobilized CO₂ (Kumar et al., 2005), leakage in this research is defined as that leaving the intended storage boundaries. Simulated of the subsurface migration have characterized the travel and trapping mechanisms of buoyant CO₂ (Kumar, 2005; Ozah et al., 2005). Injecting this fluid will result in two-phase flow and drying in the near-wellbore region (Noh et al., 2007) and will result in the displacement of large volumes of
regional water. Monitoring at storage site and assignment of liability for the buoyant CO₂ will be required during the decades of injection and for decades after injection (Oldenburg and Lewicki, 2004; Benson, 2006). Predicting interaction with in-situ subsurface features like faults, wells, and the top seal of the aquifer will be important and new scientific understanding will be required to adequately characterize the potential for leakage (Benson, 2006). Wells in some areas are densely spaced, making deeper storage targets preferable (Nicot et al., 2006). Faults are present in every basin, so fault-fluid interaction is important to understand and predict. The technical challenges are important in addition to the economic challenges associated with the liability of buoyant CO₂, monitoring and verification of storage, and remediation in the event leakage occurs.

This chapter (Chapter 1) contains the main objectives of this work in addressing the challenges of saline aquifer storage and a literature review of sequestration targets and strategies. Chapter 2 presents a literature review of the natural and human influenced climate drivers including atmosphere greenhouse gas sources, trends, and projected impacts on global temperature. Also reviewed are energy and economic expectations which should be considered in making decisions which impact both quality of human life and the environment. Chapter 3 contains the approaches and challenges to fault-fluid flow interaction with particular emphasis on sealing algorithms and petrophysical descriptions in clastic sequences. The shale gouge ratio (SGR) has been used as a predictive algorithm to determine if across-fault fluid flow will occur. Several studies provide descriptions of the petrophysical properties along and across a fault which provide a starting place for fault characterization within a simulator. Chapter 4 develops a predictive method for the injectivity of bulk-phase CO₂ (pure CO₂ stream) into a simple saline aquifer model. This method includes the cumulative effects of drying in the near-wellbore region, the two-phase interaction, and the displacement of regional brine. The
results and accompanying sensitivity studies using measured relative permeability curves are also shown in this chapter. Chapter 5 describes an alternative approach to saline aquifer storage called surface dissolution. Surface dissolution is a process in which all the CO\textsubscript{2} is dissolved in brine which was previously extracted from the target aquifer. The CO\textsubscript{2}-saturated brine is then injected back into the brine aquifer at a different location than it was extracted. This chapter contains the results of a comparison made between the standard approach and the surface dissolution approach on economic and technical issues.

1.1. OBJECTIVE

The main objectives of this work are the following:

- to review the context of carbon management in the science of climate change,
- to address the technical geologic challenges of CO\textsubscript{2} injection and storage, specifically the injectivity of CO\textsubscript{2} in bulk phase and the predictive methods for determining fault impact, and
- to introduce the surface dissolution approach as a potential low-liability storage strategy.

1.2. LITERATURE REVIEW OF CARBON SEQUESTRATION

In order to stabilize the atmospheric concentration of greenhouse gases, human emissions need to stop increasing. To reduce atmospheric concentration to pre-industrial levels, human emission must be reduced substantially. During the next century, Lackner (2003) estimates that 600 Gt-C will be emitted by humans, so storage capacity must be large if fossil fuels are continuously used.

Lackner (2003) has proposed mineralization as carbon sink because it has the capacity to store more carbon than could ever be produced. Calcium, magnesium,
sodium, and potassium under the right conditions form stable carbonates and bicarbonates. Olivine and serpentines can be used to neutralize the CO$_2$ and form stable compounds effectively storing the carbon for thousands or millions of years. The reaction rates are very slow so high temperatures or high pressures would be required to speed the reactions to economical pace. House et al. (2006) state that the cost of mineralization would be 3 to 10 times the cost of geologic sequestration.

Yamasaki (2003) estimates the storage capacity of the oceans to be between 1,400 - 20,000 Gt-C. Three areas of storage are possible in the ocean: the near surface environment, below the thermocline, and in the sediments of the deep sea. By fertilizing the algae in the near surface, the uptake of CO$_2$ in the ocean would increase. As a result, other greenhouse gases would be emitted and the ecosystems would be changed. Lackner (2003) suggests that this strategy will not be pursued because of the potential changes to the involved ecosystems. Below the thermocline, the sea water is under-saturated with gases at a lower temperatures and higher pressure. CO$_2$ could be injected, allowed to rise and contact the sea water, and dissolve in the seawater. Lackner points out that the changes to the water pH and the ecosystem along with the 100 to 1,000 year turnover of the ocean make this less attractive as a long-term carbon sink. Last, the sea floor sediments in the deep ocean (below 3000 m) off the continental shelf (100 – 200 miles from shore) have several properties that make them attractive. At high pressure and low temperature of the deep ocean, the density of CO$_2$ is greater than that of seawater, and CO$_2$ hydrates form (House et al., 2006). Negative buoyancy and hydrate formation would prevent CO$_2$ from returning to the atmosphere. Pipelines to the site and working at these water depths are expensive and technically challenging.

Geologic storage is possible in several different subsurface targets: oil and gas fields, unminable coal seams, and saline aquifers (See Fig. 1.1). The capacity of geologic
storage in the United States and Canada is estimated to be between 300 - 900 Gt-C (DOE/NETL, 2007b). The capacity of the oil and gas fields is the smallest of the geologic onshore options for the US and Canada at 22 Gt-C. The seal in these targets has been proven for millions of years. As well, the benefits of EOR can add value to the reservoir and store carbon at the same time. Unminable coal has a slightly larger capacity at 43 - 50 Gt-C in seams that are too deep or small for economical recovery. The injected CO₂ is partially adsorbed by the coal and, in some cases, can be used to enhance the recovery of coal bed methane.

![Geologic Carbon Storage Map](image)

**Figure 1.1:** The geologic capacity in the US and Canada is between 300 - 900 Gt-C. The target sinks for carbon (shown as stripes and solids) are generally located near electrical generation (shown as circles) which in most cases is carbon emitting (NPC, 2007).

Saline aquifers provide the largest capacity geologic carbon sink, estimated between 250 - 850 Gt-C in the US and Canada. As shown in Fig. 1.1, saline aquifers are
the widely available and close to CO₂ generation. There have been several key areas of
development in saline aquifer storage strategy development. Equations-of-state (EOS)
have been fit for the solubility of CO₂ in brine. The Peng-Robinson EOS was tuned as
shown in Kumar (2004) and Ozah et al. (2005) for reservoir simulation use. Hangx
(2005) tuned the Duan EOS for CO₂-brine solubility.

The key trapping mechanisms in saline aquifers are: structural, dissolution,
residual, and mineral trapping. Structural trapping is accomplished by using an anticline
with high capillary entry pressure top seal, or sealing fault to prevent upward CO₂
migration. Structural uncertainty must be weighed as a risk to buoyant leakage, and, in
some situations, low risk structural traps are not available. Dissolution trapping is
accomplished by dissolving CO₂ into the resident brine. The CO₂-saturated brine is
expected to be denser than the native brine (Kumar, 2004). Ennis-King and Paterson
(2002) studied convection currents in the aquifer to determine the time scales and
movements as CO₂ dissolves into the brine solution. Ennis-King and Paterson (2002) and
Ozah et al. (2005) have shown that this process is very slow (on the order of 100’s of
years) to dissolve all or most of the CO₂ into the brine. Georgescu et al. (2006) have
suggested co-injection of supercritical CO₂ and water can increase dissolution trapping.
Residual trapping is trapping the gas phase, which is mainly CO₂, in the pore space.
Bryant et al. (2006) proposed the “inject deep and let rise” strategy for maximizing
residual trapping. By injecting into the bottom half of the target zone and allowing the
plume to migrate vertically, large percentages of CO₂ will be trapped as residual phase.
Noh et al. (2007) proposed chasing the injected CO₂ with water for additional residual
trapping. Ozah et al. (2006) and Noh et al. (2007) studied mineral trapping in saline
aquifers and showed the mineral trapping was only a small percentage due mainly to the
slow nature of the mineral-fluid reactions. The amount of mineral trapping increases with
time, but is too slow to depend on for substantial trapping; Lackner (2003) suggested alkali-rich formation as mineralization targets where the hydroxyl ions neutralize the carbonic acid created when CO₂ dissolves into brine causing divalent cations to precipitate as carbonate minerals.

Of the sequestration strategies, the geologic storage sites are widely available and are in many cases the lowest cost option for carbon storage. The saline aquifer is the most widely available and is lower cost than oceanic or surface mineralization projects. There is active research in these areas even though the costs are several times that of geologic storage, suggesting the risks of geologic storage are important enough to consider other options. Hence, the focus of this thesis is an assessment of risk (leakage through faults), operational uncertainty (effects of fluid/rock properties on injectivity), and a promising alternative (surface dissolution).
CHAPTER 2: KEY ISSUES OF THE GLOBAL WARMING DEBATE

2.1. THE ENVIRONMENT

A traditional view of the climate consists of heat engines and heat distribution systems. The energy from the sun (called insolation) and from the inner earth provides energy to the climate while the oceans and atmosphere move that energy around (Gerhard and Hanson, 2000). The atmosphere is complex and is affected by solar, biological, ocean, and recently by human activity. Changes in the atmosphere lead to changes in the biosphere and in the ocean. Three processes are responsible for heat transfer in the lower atmosphere (Khilyuh and Chilingar, 2004). Convection currents (hot air rising and cold air falling) are responsible for ~67%. Condensation of water vapor is ~22% of the heat transfer, and radiation is the remaining ~11%. Radiation varies depending upon the amount of greenhouse gases and the amount of radiative forcing they create in the atmosphere. Radiative forcing is a measure of the energy coming into and out of the atmosphere and is often reported in W/m² (watts per square meter).

2.1.1 Greenhouse Gases

There are several greenhouse gases in the atmosphere. They are discussed here in order of importance. The most important greenhouse gas in the atmosphere is water (EPA, 2007). Water vapor plays important dual roles. As a greenhouse gas, it traps radiation. When it condenses to forms clouds, it reflects solar radiation. Clouds add to the albedo of the Earth, which is the ability of the Earth to reflect radiation back to space. Humans emit water during hydrocarbon combustion but it is not studied or reported as a
destructive greenhouse gas. The most important human emitted greenhouse gases are carbon dioxide (CO₂), methane (CH₄), and nitrous oxide (N₂O). The 10,000 year atmospheric concentrations and radiative forcings above year 1800 levels are summarized in Fig. 2.1 by the IPCC (2007).

Figure 2.1: The units on the vertical axes are concentration and radiative forcing for the three greenhouse gases listed. The previous 10,000 years and the previous 200 years are shown. Notice the anomalous jump in each plot at the dawn of the industrial revolution (IPCC, 2007).
**Carbon Dioxide**

The second most important greenhouse gas in the atmosphere is carbon dioxide which has a life in the atmosphere of hundreds of years (Khilyuh and Chilingar, 2004). Atmospheric concentrations have ranged from 250 to 280 ppm (part per million of volume) in the last 10,000 years and between 180 to 300 ppm in the last 400,000 years. The current level is 379 ppm in 2005 (IPCC, 2007) which is outside of these long term natural ranges. As shown in Fig. 2.2, carbon cycles in and out of the biosphere and the ocean, but the recent increase in concentration is due to human emission and changing land use (EPA, 2007; IPCC, 2007).

![Figure 2.2: Carbon cycles in and out of the atmosphere, ocean, and the vegetation. The arrows are the carbon fluxes and rectangles are the amounts stored, all at year 2000 values. Human activities directly affect the carbon cycle through changing land use and fossil fuel combustion. The surface ocean absorbs about 2 Gt-C/yr acting as a shock absorber to human greenhouse gas emissions (Yamasaki, 2003). The atmosphere contains 750 Gt-C. (Figure adapted from NPC, 2007).](image)
In the US, carbon dioxide emissions have increased 16% from 1990 to 2005 and represent 84% of our greenhouse gas emission (EPA, 2007). At 1.6 Gt-C/yr, the US produces approximately one fourth of the world emissions. Fig. 2.3 shows the emission sources and rates, and Fig. 2.4 shows the emission breakdown by sector. Fossil fuel combustion is by far the largest source of carbon emissions. Coal and gas combustion emissions are primarily from stationary targets in all sectors except transportation. These stationary targets could potentially have emissions captured.

![Figure 2.3: As reported by the EPA (2007), the US emissions of carbon dioxide are primarily from fossil fuel combustion although many different sources also contribute. Note 1,000 Mt-C = 1 Gt-C.](image)

Natural sources of carbon dioxide emission include seepage or out-gassing of the Earth particularly at the spreading centers of the ocean and from natural carbon dioxide accumulations that exist in the subsurface like gas and oil accumulations (Khilyuh and Chilingar, 2004). Volcanic eruption emits large volumes as well, but the rate of emission from natural sources was not studied.
Carbon dioxide is the most important human emitted greenhouse gas. The levels in the atmosphere have risen since the industrial revolution from 280 to 379 ppm in 2005 (Fig 2.2). The current level is significantly larger than any time during the last 400,000 years, and the general evidence points to human activity as the cause of the increase (IPCC, 2007). As a result of human activity, the radiative forcing in the atmosphere has increased by ~1.6 W/m² which is the hypothesized cause of global temperature increase.


**Methane**

The third most important greenhouse gas in the atmosphere is methane which produces 21 times the radiative forcing as carbon dioxide on a per mole basis (EPA, 2007) and is suspected of having a short 7-10 year life span in the atmosphere (Khilyuh and Chilingar, 2004). US emissions are 0.14 Gt-C/yr equivalent in 2005 or 7.4% of greenhouse gas emissions (EPA, 2007). (Carbon equivalent is the amount of carbon that would have to be emitted as carbon dioxide to produce the same radiative forcing). The EPA (2007) states that the major sources are landfills, agriculture, and fossil fuel production (coal mining and oil and gas production).

Methane levels in the atmosphere are 1700 ppb (parts per billion of volume) which is outside of the 10,000 year range of 320 to 790 ppb (Fig. 2.1; IPCC, 2007). Interestingly, atmospheric concentrations have increased far less from 1980 to 2005 and seem to be leveling off (Robinson *et al*., 2007). Nevertheless, the radiative forcing has increased 0.5 W/m² as a result of post-1800 methane emissions (IPCC, 2007).

**Nitrous Oxide and Halocarbons**

The next important greenhouse gas is nitrous oxide which causes 310 times the radiative forcing as carbon dioxide. The US emissions are 0.12 Gt-C/yr equivalent in 2005 and make up 6.5% of the US greenhouse emissions (EPA, 2007). The main sources are agriculture and byproducts of hydrocarbon combustion (EPA, 2007). The levels have increased above the 270ppb 10,000 year historical range and produces radiative forcing of an additional 0.17W/m² to the atmosphere (IPCC, 2007).

Other greenhouse gases of importance are the halocarbons which cause 140 to 20,000 times the radiative forcing as carbon dioxide and have extremely long lives in the atmosphere. They were used to replace ozone destroying substances. The US emitted 0.03 Gt-C/yr equivalent in 2005 or 2.2% of greenhouse gas emissions.
Projected Carbon Emissions

Human emissions are expected to increase in the future even if currently discussed carbon restricting policies are implemented. Projections published by the government agencies are compared in Fig. 2.5 and are expected to grow by 40% to 100% by the year 2030 from year 2000 values (NPC, 2007). If the proposed carbon restricting policies are implemented and economies grow as projected, emissions will grow from the current 6.5 Gt-C/yr to 9 Gt-C/yr in 2030. In the case that economic growth is high and no restrictions are set, emissions could grow to 14 Gt-C/yr. In the US, emissions are projected to grow from 1.6 Gt-C/yr in 2000 to 1.7 – 2.5 Gt-C/yr in 2030 (NPC, 2007). Looking globally, substantial emission growth is expected in developing countries like India and China. Consumption shares are expected to grow substantially in Asia, the Middle East, and Africa, but Europe and North America should lose shares in the energy mix (NPC, 2007). (Shares are percentages of the total energy consumed during a period of time.)
Figure 2.5: Depending on the economic growth and energy policies, carbon emissions are expected to grow. The historic emissions have grown at 1.3% per year and are expected to grow at 1.2% to 2.5% per year (NPC, 2007).

2.1.2 Human and Natural Radiative Forcing

Greenhouse gas emissions have caused the radiative forcing of the atmosphere to increase between 2.07 and 2.53 W/m² (Fig. 2.6; IPCC, 2007). Several human activities are suspected to have changed local and global radiative forcings; some cause warming and some cooling (see Fig 2.6). The only source of natural radiative forcing shown in Fig 2.6 is that of solar irradiance.
Natural forcing of the atmosphere normally comes from the sun. The IPCC (2007) report shows that natural radiative forcing has increased slightly above year 1800 levels (see Fig. 2.6 the “Solar irradiance” line) meaning a small part of the recent temperature increase is a result of changes in the sun. Others authors conclude the correlation and causation between the sun and temperature is much stronger (Robinson et al., 2007).
study by Usoskin et al. (2005) correlated solar variations (sunspot number and cosmic ray flux) with northern hemisphere temperature (Fig. 2.7).

The cosmic ray flux is interpreted from carbon 14 ($^{14}$C) and other isotopes. Cosmic rays are particles, typically protons and electrons, from the sun that strike the earth. Sunspots are low temperature spots that appear on the surface of the sun. Shown in Fig. 2.7 are the sunspots interpreted from the geologic record by Usoskin et al. (2005). The temperature, sunspot number, and cosmic ray data were fit with a 6th order polynomial for correlation purposes.

Figure 2.7: The top figure is the sunspot number (SN) and temperature comparison, and the bottom is the cosmic ray flux (CR) and temperature (Usoskin et al., 2005). Notice the correlation between the data and between the polynomial curves fit to the data.
Usoskin et al. (2005) concluded that the solar radiation has an important influence on the terrestrial climate, and that sunspot number and cosmic ray flux correlate well with northern hemisphere temperature. Usoskin et al. noted that the reconstruction of the sunspot and cosmic ray data are debatable. Also, correlation does not necessarily imply causation but can lead to increased understanding. The implications of studies of natural forcing are important. More data can assist in climate modeling and history matching where there is a possibility for similarly trending variables to compensate for one another (greenhouse gas emission vs. solar irradiance). Therefore, it is important to understand the effect of the main driving forces on the climate.

2.1.3 Temperature History

Some authors argue that the immense history of the climate has not been put into proper perspective compared to the period of human industrialization (Gerhard and Hanson, 2000, Robinson et al., 2007). Presented here are a few different perspectives of temperature and atmospheric carbon dioxide concentrations.

_Hundred Year Perspective_

Although there is no simple way to measure temperature everywhere and take the appropriate average, measurements are taken all over the world and interpolated for areas with no measurements available (NCDC, 2006).
Figure 2.8: The temperature increase for land, ocean, and land & ocean is shown (NCDC, 2006). The carbon dioxide concentration expressed in units of ppm is also shown (IPCC, 2007). The correlation between temperature and carbon dioxide concentration is obvious during some periods (1920’s to 1940’s and 1980’s to current) and not so obvious during other periods.

Temperature is expressed as temperature anomaly meaning above or below the 1950-1970 average (Fig. 2.8). Land temperature has increased ~1°C from middle of 20th century, and ocean temperature has increased ~0.4°C over the same time period. The ocean and land average has increased ~0.6°C from the middle of the 20th century. The temperature increases generally in Fig. 2.8, but the temperature cooled slightly between 1940 and 1980 when global cooling was discussed (Robinson et al., 2007). Although the correlation is strong, this is probably oversimplification and narrow view of climate change.

Thousand Year Perspective

Fig. 2.7 shows 1,000 years of northern hemisphere temperature, and in addition, Fig. 2.9 shows 3,000 years of temperature from the Sargosa sea which is a 2 million square mile region of the Atlantic (Keigwin, 1996).
The temperature data interpreted by Keigwin (1996) for the Sargosa sea shows a decreasing trend (Linear Best Fit line). The last data point in 1975 is below the 3,000 year average. The variability in temperature over the 3,000 year period is ~3°C.

Several authors propose that temperatures today are 1 – 2°C less than they were during the medieval warming event which occurred during years 1100 - 1300 when much of medieval northern Europe was developed (Fig. 2.9; Keigwin, 1996; Gerhard and Hanson, 2000). The implications of Fig. 2.9 are that the temperature range was about ~3°C during the last 3,000 years, and that current temperature is within the natural range. Fig. 2.9 shows an overall decreasing trend in temperature. It should not be overlooked that these data are a large local mean of the Sargosa Sea and might not represent a global average. Also, the warming event in Fig. 2.9 does not appear in the Usoskin et al. (2005) average data of the northern hemisphere (Fig 2.8).

400,000 Year Perspective

The Vostok ice cores from Antarctica have added considerable information to the greenhouse gas and temperature record (Jouzel, et al., 1993; Jouzel, et al., 1987; Jouzel, et al., 1996; Petit, et al., 1999).
Figure 2.10: Vostok ice core from Antarctica revealed the atmospheric concentration levels of the past 400,000 years. The 400,000 year historic levels are between 180 ppm to 300 ppm compared to the present day level of 375 ppm. Notice the obvious correlation between temperature and carbon dioxide concentration. The temperature variation is ~12°C over this period of history. (Data downloaded from ftp://cdiac.esd.ornl.gov/pub/trends).

Fig. 2.10 again shows the strong correlation between carbon dioxide and temperature, and that the current level of carbon dioxide in the atmosphere is above the 400,000 year maximum. The carbon dioxide concentration being outside of its natural range creates a new situation for scientists to study and predict. Analog situation for anomalous greenhouse gas increases and the observed impact on the climate might be few and far between.

**Millions of Years Perspective**

Data from deep ocean sediment core is one source of information about temperature and climate on scales of millions of years. Zachos et al. (2001) reported the temperature data for the last 68 million years as shown in Figure 2.11. Two dramatic climate events occurred during the Oligocene.
Figure 2.11: Zachos et al., (2001) reported the temperature interpretation of deep oceanic sediment core. The temperature has been generally decreasing for the last 50 million years. (Notice the inverted temperature scale on the left vertical axis). The range of temperatures over this period is approximately 20°C.

One of the events Zachos et al. (2001) focused upon in his discussion is an event which occurred at about 56 million years ago (Ma) named the Late Paleocene Thermal Maximum (LPTM). A better view of the event is shown in Figure 2.12. Zachos et al. (2001) attribute this anomalous temperature spike to a release of up to 2,600 Gt of clathrate or gas-hydrate methane. Because methane provides 21 times the radiative forcing as carbon dioxide on a per mole basis (or 57 times on a per mass basis), that release would be equivalent of up to 150,000 Gt-CO$_2$ or 41,000 Gt-C. That increase in greenhouse gas leads to an increase in temperature of ~3-5°C over an apparently short period of time (0 to 50,000 years). Interestingly, the temperature appears to then return to the previous trend after about 200,000 (see Fig 2.11 and Fig. 2.12).
Figure 2.12: Zachos et al. (2001) show the Late Paleocene Thermal Maximum which is an extremely rapid temperature increase. It appears that temperature rose a 3-5°C as a result of a release of up to 2,600 Gt-methane.

If the interpretation is correct, the implications of the LPTM are important to the global warming debate. First, it shows that an anomalous increase in greenhouse gases can lead to a rapid increase in temperature. Second, it provides an analog and example for time scales and temperature increases associated with increasing greenhouse gas concentration.

Temperature fluctuations of the climate exist at different scales over different time periods. Over the last hundred years, they have varied by ~1°C and by ~3°C over the last 3000 years. Looking deeper into history, temperature has varied by ~12°C over the last 400,000 years and ~20°C in the last 68 million years.

2.1.4 Connection between Carbon Dioxide and Temperature

Correlation

The connection between carbon dioxide concentration in the atmosphere and temperature appears evident from Figs. 2.8 and 2.10, but correlation does not equal causation. Two obvious connections exist between atmospheric carbon dioxide and
temperature. First, an increase in atmospheric carbon dioxide increases the radiative forcing in the atmosphere eventually increasing temperature. IPCC (2007) report states that our understanding of this phenomenon is high. Second, an increase in temperature changes the solubility of CO$_2$ in seawater. As the temperature increases, solubility of seawater decreases causing gases to come out of solution. The implications are that extrapolating the correlation between carbon dioxide and temperature is not an appropriate measure of expected climate change.

**Climate Modeling**

In order to understand the connection between temperature and human emissions, climate models are employed to take into account a large number of relevant variables. Climate models help answer two questions: how much will the temperature rise and over what time period will the increase occur. The IPCC (2007) reports increasing confidence in climate models.

To answer the first question of how much the temperature will increase, climate sensitivity models are employed to estimate the equilibrium temperature if the carbon dioxide concentration increased and the climate were allowed to come to equilibrium. The models predict on average an increase of 3°C in global temperature and an increase of no less than 1.5°C if atmospheric CO$_2$ were doubled (IPCC, 2007). This is not a projection of temperature only an equilibrium model. The model is most sensitive to water vapor.
Figure 2.13: The predictions of the land and ocean temperature are shown for temperature prediction with and without human emitted greenhouse gas forcing for different regions of the world. The bottom three figures show the recent global temperature increase occurred because of human emissions. The wide grey lines are predictions and the black line is the measured value (IPCC, 2007).

To answer over what time period will the increase occur, climate modelers predict the changes that have already occurred and project future trends. Fig. 2.13 shows the variation in temperature over the last century with and without the forcing effects of carbon emissions. In 1990, the models predicted an increase of between 0.15 and 0.3°C per decade. Between 1990 and 2005, the measured temperature increase was 0.2°C per decade, so the short term prediction was right. Future increase is expected to be 0.1°C per decade. By 2090 to 2099, global temperature is expected to be 1 - 6°C greater than...
current temperature (IPCC, 2007). The most uncertain input to these climate models are the cloud feedback.

One objection to climate models is that the uncertainties are larger than the influence of greenhouse gases (Robinson et al., 2007). Recall, the combine influence of human activities is an increase of the radiative forcing by 1.6 W/m² (Fig. 2.5). Robinson et al., (2007) suggest that uncertainty in ocean surface flux, humidity, and clouds are greater than radiative effects of human emissions. As well, the underestimation of solar influence could lead to an over estimation of greenhouse gases when history matching.

**Implications of Increasing Temperature**

Rising temperature is an important metric for the climate and controls several important phenomena. Global sea level rise is caused by the expansion of water as temperature increases and by melting snow cover, ice caps, ice sheets, and glaciers. The rate of sea level rise has increased from 1 inch every 16 years to 1 inch every 8 years (IPCC, 2007). If the polar caps completely melt, sea level will rise 4 to 6 meters. Projected sea level will be 7 to 23 inches higher by the end of the 21st century (IPCC, 2007). Storms are expected to get stronger with higher temperature. No increase in wind speed or frequency of landfall has been observed for hurricanes over the past 100 years (IPCC, 2007; Robinson et al., 2007). For tornados, IPCC (2007) states that the data is insufficient to determine change, yet Robinson et al. (2007) shows a decreasing trend for severe tornados in the US over the past 60 years. Long term precipitation pattern can shift and have shifted, bringing drought to tropic and subtropic regions (IPCC, 2007).

**2.2. ENERGY AND ECONOMIC ESSENTIALS**

Energy is an important part of daily life and has an impact on economies and the environment. Coal, oil, and gas will not be replaced in the near future and will continue
to increase in volume consumed further intensifying the carbon emissions. Alternative energy sources will increase in size and importance but maintain or lose shares of the energy mix (NPC, 2007).

2.2.1 Economic Growth

Economic growth is driven by growing populations and expanding per capita income. Projections made for future world economic growth are shown in Fig. 2.14.

![Projected World Economic Growth](image)

Figure 2.14: The projected world economic growth in year 2000 US dollar is historically 3.1% per year and is expected to grow at 3.0% to 4.4% in the next 20 years. The IEA reference case and the IEA alternative policy case imply that they believe that economic growth would not be hindered by carbon constrained policy.

2.2.2 Energy growth

Three major inputs are behind the energy demand models: population, economic growth, and energy policies (NPC, 2007). Population growth is expected to be lower than historical rates, but 2030 world population is expected to be over 8 billion. The only energy policy specifically mentioned is carbon-constrained alternative policy case, and
economic growth was described previously. Energy growth in the US is expected to be slower than in the rest of the world (NPC, 2007).

Historically, carbon emission growth has been the same as energy growth and is projected to be the same. Carbon reduction policies will increase energy related costs and change the energy mix.

**Fossil Fuels**

Hydrocarbon demand is increasing and supply concerns are being raised as they have been for more than half of a century (Caruso, 2005). Our fossil fuel endowment is the total reserves, resources, and in place volumes of oil, gas, and coal. Reserves are currently commercially recoverable volumes, whereas resources are only expected to be commercially recoverable. In place volumes are not expected to be recovered.

**Oil Supply and Demand**

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Figure 2.15: The global energy consumption growth in quadrillion BTUs is expected to be between 1.2% per year to 2.5% per year for the next 30 years. The difference between 1.2% and 2.5% is half of the energy currently consumed. Previously growth averaged 1.7% per year. The trends of this figure are similar to Fig 2.5 because emissions have historically grown at the same rate as energy.
Many estimates have been made for oil production and endowment (Caruso, 2005; NPC, 2007; Rogner, 1997). Endowment estimates generally increase with time as technology improves, price increases, and as new trends and fields are discovered. Two estimates of oil endowment are shown in Fig 2.16.

![Diagram](image)

**Figure 2.16**: Of the many different projections of oil supply, two are shown. NPC (2007) projects four trillion barrels of oil are expected to be recovered with another four trillion permanently left in place. Rogner (1997) expects six trillion will be recovered and 12 trillion will be eventually left in place.

Oil demand in 2000 was 76 million barrels per day (bbl/d) and is expected to be between 98 to 138 million bbl/d in 2030. Carbon constraining policy will increase share of oil in the energy mix as shares are steered away from coal (NPC, 2007).

Out of interest, a simplified prediction of carbon emission from 2008 to the end of the 21st century is determined. The emission for oil is 76.4 Gt-C per trillion barrels (EIA, 2008; 76.4 Gt-C per trillion barrels assumes ¾ of each barrel becomes gasoline because EIA, 2008 does not report crude oil). If 76 million bbl/d (year 2000 consumption) were consumed every day between now and 2200, 200 Gt-C will be cumulatively emitted to the atmosphere by the end of the 21st century.

**Natural Gas Supply and Demand**
Similar to oil projections, natural gas endowments are shown in Fig. 2.17 based on NPC (2007) and Rogner (1997). In 2000 according to the NPC (2007), the world demanded 243 billion standard cubic feet per day (bcf/d). That is projected to increase to between 356 to 581 bcf/d by 2030.

For gas, the cumulative emissions from gas consumption are predicted using the year 2000 rate of 243 bcf/d and the conversion of 14.9 Gt-C/Qcf (EIA, 2008; Qcf is a quadrillion standard cubic feet). In the next century, over 120 Gt-C will be emitted to the atmosphere by burning 243 bcf/d.

![Gas Endowment Bar Chart](image)

**Figure 2.17**: Gas endowments are ~50 quadrillion standard cubic feet (Qcf) in both cases. The expected recoverable gas (resources and reserves) is 34 Qcf by Rogner (1997) and 15 Qcf by NPC (2007).

**Coal Supply and Demand**

The coal endowment is shown in Fig 2.18, and coal is the most plentiful fossil fuel available in terms of energy. Demand projections were not available, but the IEA (2007) reports that production has grown dramatically from 2000 to 2006. Production increases are primarily due to the Chinese demand. As of 2006, coal production is up
140% since 1973 and up 46% since 2000. The year 2000 supply rate was 3,700 million tonne per year.

Consuming 3.7 Gt/yr each year between 2008 and 2200, 200 Gt-C will be emitted using the conversion of 0.584 Gt-C/Gt-coal (EIA, 2008; 0.584 Gt-C/Gt-coal is the average of four main coal types in EIA, 2008).

Figure 2.18: Both Rogner (1997) and NPC (2007) predict about 4 trillion tonne of coal will be mined and consumed. The endowment predictions differ between 5 trillion tonne and 13 trillion tonne, respectively.

**Fossil Fuel Resource Base**

Coal is projected to be important in meeting the energy demands because the restrictions on production seem less pervasive compared to oil and gas (see Fig 2.19). Coal is expected to be an increasing portion of the energy mix except in the alternative energy policy case (NPC, 2007). Oil will grow as the transportation demands grow in the world and in the US. Fossil fuels are projected to be used to meet 83% to 87% of the future energy demand and maintain shares in the energy mix (NPC, 2007). Energy
distributed in the world will change as Asia’s portion of the energy demand grows by 10% and North America and Europe lose 11% of world energy demand (NPC, 2007).

Coal and hydrocarbons are expected to remain a vital part of the energy consumption in the next few decades. Estimates of emissions in the next century are 900 Gt-C, using previously outlined estimates, which is larger than 600 Gt-C predicted by Lackner (2003). As is evident in Fig. 2.19, carbon emissions are not likely to be constrained by diminishing reserves and resources in the near future. Carbon capture and storage strategies will play an important role in disposing much of those emissions if the goal of shrinking emissions is to be met and fossil fuels continued to be used.

**Conservation and Alternative Energy**

One conservation study, looking at the time required for implementation of energy savings, concluded that all US energy growth and 75% of the world energy growth could be made up though conservation and energy improvements in the near
future (NPC, 2007). Efficiency could be improved in the residential, commercial, and industrial sectors. Only a small amount of improvement is available in the electrical generation sector (NPC, 2007). It is no surprise that transportation represents the largest available sector for reducing oil consumption.

Nuclear-based power is expected to grow more slowly than annual energy demand, and, therefore, it will lose shares in the energy mix. Biofuels, wind, and solar are expected to grow in volume, but maintain their small fraction of the energy mix.

In the IEA Alternative Energy Policy case, economic growth would not be hindered by policy changes (see Fig. 2.14). This case takes into account the alternative energy and carbon-constraining initiatives currently proposed by different nations (NPC, 2007). In this case, global emission in 2030 would decrease by 1.6 Gt-C/yr (from 10.9 to 9.3 Gt-C/yr). This is an important decrease, but emissions in 2030 are still on the rise and over 240 Gt-C will have been emitted in the mean time. Of the 240 Gt-C, 80 Gt-C will end up in the ocean and 160 Gt-C in the atmosphere. Because of the policy shift coal would be used less because of carbon intensity, and oil and gas would be used more to compensate, putting further pressure on these markets. In all cases except the alternative energy case, petroleum products liquids grow in volume but lose in the energy mix.

2.3. HUMAN NEEDS

The world population is expected to reach over 8 billion in 2030 from today’s 6+ billion (NPC, 2007). Humans consume 100 times more energy than is needed to sustain our life (Paztek, 2006). Energy is part of the daily life of every human, and the way energy is used has an impact on the quality of life. Per capita income is one measure of quality of life. Based on IEA (2007) data, Fig 2.20 displays the 2006 per capita income in year 2000 dollars of purchasing parity power (PPP) and the 2006 energy supplied per
capita in barrels of oil equivalent (boe) with particular emphasis on the 11 largest economies. Fig 2.21 shows the CO₂ emissions per capita vs. year 2000 PPP per capita.

The recent surge in the economies of China and India has substantially improved their quality of life, and this improvement is a reasonable ambition which should be supported (IEA/OCED, 2007). The consequence and opportunities for carbon reductions and quality of life improvements are important to consider. Carbon emissions will change the climate, but the time scale of this change is important to consider. The negative consequences of climate change are drought and a worst-case scenario of a two foot sea level rise over next 90 years. The costs and benefits of environmental and economic issues must be considered when offsetting climate change.

Figure 2.20: Assuming the energy supplied is similar to the energy consumed, the relationship between energy and income is clear. The light squares are the 11 largest economies, and the dark square are all others. 8 of the top 11 economies are in the higher section of per capita income (IEA, 2007). China and India are in the left-hand corner of the plot and make up 39% of world population. The grey line is an approximate linear best fit to the data to help visualize the trend in the data.
Figure 2.21: Carbon emissions are similar to energy consumption. European countries emission rates are left of the trend. Canadian emissions per capita are lower than the US, yet Canadian energy consumption per capita is higher. Again, China and India are in the left-hand corner. The grey line is an approximate linear best fit to the data to help visualize the trend in the data.

2.4. SUMMARY

Although there many things connected to the issues of global climate, the connections between the fossil fuel energy industry and the environment are important and intertwined. The natural and human influenced climate drivers and our level of understanding about them have been reviewed along with historical, current, and projected greenhouse gas emissions. Perspectives of climate variation have many time scales and temperature scales. Climate models, although challenged, predict significant human induced temperature increases of 1-6°C in the next century on top of the 1°C caused by human activity in this century. An analog example of greenhouse gas release occurred in the Paleocene. The equivalent of 41,000 Gt-C was released causing an sudden increase in temperature of 3 to 5°C over 50 million years ago (Zachos et al., 2001).
Because energy plays an important part in quality of life, surging energy demands and concerns about future supplies are an important part of the discussion of greenhouse gas mitigation. The cost and benefits of several topics must be considered by responsible governments and individuals in the development of environmental policies and practices: offsetting environmental and economic issues associated with changing climate, mitigating carbon emissions to discourage further climate change, demand and pressure on supply chains, and human aspirations for life improvements. As cumulative emissions in this century could exceed 500 Gt-C (based on oil emissions of 200 Gt-C, natural gas emissions of 120 Gt-C, and coal emissions of 200 Gt-C) with fossil fuel reserves still to be developed, carbon capture and storage technologies can play a mediating role in controlling emissions while meeting energy needs.
CHAPTER 3: FAULT AND FLUID FLOW INTERACTION

The primary requirement of storing carbon dioxide in the subsurface is that it stays stored in the subsurface. Faults could be potential pathways from storage formations back to the atmosphere or into other compartments of the subsurface containing other resources (underground sources of drinking water, oil, natural gas, etc.). As faults exist in every sedimentary basin of the world, it is important to understand fault-fluid flow interaction. This chapter reviews the factors governing this interaction. There are two groups of information that are valuable: indicators like a barrier vs. conduit classification (Evans et al., 1997; Yielding et al., 1997), and a petrophysical description of the fault region (Jourde et al., 2002; Eichhubl et al., 2005; Shipton et al., 2002). A barrier is a fault that does not allow flow along or across a fault, and a conduit does allow this fluid flow. Discussed in detail are barrier-conduit indicators used in the petroleum industry under the name fault-seal analysis.

Several petrophysical properties are of interest in the fault region: across-fault permeability (perpendicular to the fault plane), across-fault capillary entry pressure, and the same properties in the vertical direction (usually parallel to the fault plane).

Geologists such as Eichhubl et al. (2005) use the terms hydraulic sealing and membrane sealing when describing fault fluid behavior. Hydraulic sealing is determined by the fracture or matrix permeability which acts not to stop flow but to limit the flow. Membrane sealing is the capillary entry pressure which prevents the non-wetting phase (hydrocarbon or CO₂) from entering the largest connected pore throat in the fault core. (The fault core often contains finely ground particles and accommodates most of the slip). Membrane sealing is thought to play an important role in hydrocarbon trapping (Eichhubl et al., 2005). Regardless of the classification—membrane/hydraulic sealing or
capillary pressure/ permeability—the object is to understand the movement of buoyant CO₂ in the region of a fault. Ultimately, two questions should be answered: what time scales are associated with migration from the reservoir to the surface, and how much fluid will move into permeable formations intersected by the primary fault thus reducing how much reaches the surface? The studies and approaches presented in this chapter focus on different parts of the solution.

3.1. FAULT BASICS

3.1.1 Lithology

Different types of lithologies are targeted for sequestration projects including clastic and carbonate sequences. Clastic sequences of shales and sands are very common. Shales are thought to play an important role in the sealing capacity of a fault (Yielding et al., 1997; Eichhubl et al., 2005). The sealing role of a fault has special interest in the petroleum industry as it can determine the height of hydrocarbon accumulations or the movement of fluids across a fault as a field is put on production (Eichhubl et al., 2005; Shipton et al., 2002). In the future carbon sequestration industry, sealing capacity of a fault will be needed in the context of storage assurance and leakage rate limitations. Many clastic reservoir are targeted for sequestration like the Texas Gulf Coast, Illinois Basin, Alberta Basin, and many more (Bennion and Bachu, 2005; Nicot et al., 2006; DOE/NETL, 2007). Although there are many carbonate reservoirs targeted for sequestration with fault-related issues, this research only discusses faulting issues in clastic sequences. Although there are many different types of faults, only normal and strike-slip faults are studied here (Eichhubl et al., 2005; Shipton et al., 2002; Dockrill, 2005; Jourde et al., 2002)
3.1.2 Fault Structure

Evans et al. (1997) give the description of a fault zone (see Fig 3.1). The host rock is the original rock which has not been deformed or damaged by the fault. The damage zone makes the gradual transition from the host rock and accommodates only a small amount of the slip. The damage zone can vary in size and not all faults have a damage zone (Evans et al., 1997). The fault core makes an abrupt transition from the damage zone and accommodates most of the slip. The core contains finely crushed and smeared rock which is often called *gouge*.

![Figure 3.1: The host rock is the original undamaged rock. The damage zone transitions gradually from the host rock and accommodates a small amount of the slip. The fault core transitions abruptly from the damage zone and accommodates most of the slip of the fault (Evans et al., 1997).](image)

3.1.3 Sealing Mechanisms

The general processes responsible for the sealing are described by Evans et al. (1997): structural setting and history, fluid migration history in the region of the fault, and the mechanical and petrophysical properties of the rock. To make a prediction of the fluid flow characteristics of the fault, a lot of detailed structural information could be
gathered. Were the shales ductile or brittle during the faulting period? Were the sands consolidated? What were the temperature, pressure, and the rock properties at those conditions? Fluid migration could also be important. Did fluids migrate through during the history of a fault? Were minerals precipitated? Although these general mechanisms should be acknowledged, they may not be available or practical to study in order to make fluid flow predictions.

More specific mechanisms have been studied as indicators of fault sealing behavior and are described by Yielding *et al.* (1997): diagenesis, cataclasis, juxtaposition, and shale seal.

**Diagenesis**

Diagenesis is a physical or chemical change caused by pressure and temperature in the presence of fluid (Dockrill, 2005). During the history of a fault, fluid could have precipitated minerals or dissolved part of the host rock in fault region effectively altering the pore space. The fractures or matrix permeability and porosity could have been enhanced or destroyed. Dockrill (2005) states that there are no specific algorithms available for prediction of petrophysical properties or sealing indicator as a result of diagenesis.

**Cataclasis**

Cataclasis is when grains, typically sandstone or reservoir rock, along the fault are crushed or ground reducing the pore space and the pore sizes (Dockrill, 2005; Yielding *et al.*, 1997). Permeabilities can be reduced by up to $10^4$ from the source rock permeability (Evans *et al.*, 1997). Shipton *et al.* (2002) and Jourde *et al.* (2002) have measured petrophysical properties in faults where the gouge is composed of crushed sandstone. Cataclasis is also referred to here as sandstone-derived gouge.
**Juxtaposition**

Juxtaposition is identifying areas of the fault where one reservoir rock unit is directly across from another reservoir rock unit (Dockrill, 2005; Yielding et al., 1997). These areas have a higher potential for fluid movement than when reservoir rock is directly across from a non-reservoir unit. In practice, the fault zone is mapped to identify reservoir/reservoir juxtapositions as a potential fluid pathway. This ignores the potential for shale- or sandstone-derived gouge to provide a seal.

**Shale Seal**

Argillaceous or shale seal has become an important topic in identifying sealing characteristics of a fault in clastic sequences. Similar to juxtaposition, reservoir/reservoir units are identified on a map of the fault plane, but it is not assumed automatically that a leak will occur. Additional attempts are made to determine the sealing capacity provided by the shale entrainment in the fault core. Although there are several algorithms to predict sealing capacity of shale-derived gouge, the most prevalent algorithm, shale gouge ratio (SGR), developed by Yielding et al. in 1997, is still used widely. SGR applications and derivation will be discussed in section 3.2.1.

**3.1.4 Petrophysical Description Challenges**

Specific permeability distribution challenges exist in the region of a fault. Permeability can vary several orders of magnitude in features that are next to each other on a very small scale. This makes simulation and upscaling a challenge (Jourde et al., 2002). As with all reservoirs, the fault rock of interest is buried hundreds of feet below the surface. Heterogeneity of the fault rock varies several orders of magnitude more than the reservoir rock (Jourde et al., 2002, Shipton et al., 2002). Strong permeability anisotropy does exist in the damage zone and in the fault core.
A few study methods have been employed to understand true fault properties. Sampling of fault rock at depth is rarely done in practice because it might be desirable to maintain the integrity of the fault. Also, it could be unclear what information should be gathered and the value of that information is often uncertain. Shallow fault core has been recovered and tested by Shipton et al., (2002).

Outcrop studies have been done by Dockrill (2005), Jourde et al. (2002), Eichhubl et al. (2005), and many others because they are much easier. Micro-permeability measurements, core samples, and mapping the fault core and damage zone features can be accomplished at outcrop. Fault outcrop studies might have slightly different evolution paths than those of interest in the subsurface, and weathering could have changed some of the fault properties. Outcrops can provide a lot of information.

In-situ measurement can be made to determine the influence of a fault. Shipton et al. (2002) made traditional logging measurements and probe permeability measurements after core was taken from the borehole though a faulted region. Yielding et al. (1997) interpreted from pressure measurements from wells placed on either side of a fault. Pressure differentials revealed some of the barriers and compartments created by the fault. This technique might not always be economic or might not reveal relevant information.

3.2. FAULT SEAL AND PETROPHYSICAL ANALYSIS

In this section, the tools and descriptions used to predict and understand faulting in clastic sequences are presented along with rebuttals and suggestions for further study and understanding.
3.2.1 Shale Gouge Ratio

Basic Description

Yielding et al. (1997) developed the shale gouge ratio (SGR). SGR is an estimate of the shale content in the fault zone based upon a simple mixing rule (Eichhubl et al., 2005). The more shale in the fault core; the more likely the fault is to provide an effective seal. It is used as a barrier-conduit indicator in clastic sequences. Figure 3.2 shows how the shale gouge ratio is computed. Several other algorithms for shale smear or gouge are available, but this one has gained general acceptance (Dockrill, 2005).

\[
SGR = \frac{\sum z_i V_{S_i}}{\text{Throw}} \times 100\%
\]

- \(V_{S_i}\) = Shale concentration in layer \(i\)
- \(z_i\) = Thickness of layer \(i\)

Figure 3.2: Three key components are needed for the calculation of the shale gouge ratio: the volume concentration of shale in each stratigraphic layer, the thickness of shale in each layer, and the throw of the fault (Yielding et al, 1997). Fault throw is the offset of the fault perpendicular to the bedding plane. SGR is the sum of the (height)-(volume of shale) product divided by the throw.
SGR diagrams

Two different diagrams are used in SGR analysis: juxtaposition and Allan diagrams (see Fig 3.3 and 3.4). Descriptions and figures for these diagrams are based on Dockrill (2005). SGR is used because the information necessary to use it is simple to obtain in most clastic sequences. The gamma ray log can be used to estimate the shale concentration and the thickness of the stratigraphic unit. The variation in throw can be predicted from outcrop or seismic interpretation of the fault.
Figure 3.3: Figures from Dockrill (2005) review a juxtaposition diagram. The top view (A) is a three dimensional view of how the stratigraphic layers align as the throw increases. Notice the hanging wall and the footwall have the same layers. The letters AD mean that layer A on the hanging wall is juxtaposed against layer D on the footwall, hence, the name juxtaposition diagram. The trace XX’ is one throw along the fault. The bottom view (B) is a two dimensional view of the fault plane. Again notice that AD is layer A juxtaposed against layer D. The hanging wall throw at the far left of the diagram is zero and increases to the right until is equal to the thickness of the stratigraphic unit of the far right of the diagram. XX’ is just one throw of interest.
Figure 3.4: Images from Dockrill (2005) show the Allan diagram. The top view is a three dimensional view of how the stratigraphic layers are interpreted to line up. Again the hanging wall and the footwall have the same layers. The bottom view is a two-dimensional view of the fault plane and a good view of how the fault actually looks. Reservoir/reservoir juxtapositions can be identified, and the SGR applied to those locations.
**SGR Calibration and Additional Observations**

Yielding *et al.* (1997) originally calibrated the SGR using three case studies. The pressure differential was determined in one of two ways. The first method was accomplished by measuring the pore pressure in the hanging wall and the foot wall with a repeat formation tester. The pressure differential for the reservoir/reservoir juxtapositions was plotted. Regions of large difference indicate a locally sealing fault to across-fault flow. The second method was calculating pressure gradient based on hydrocarbon accumulation height. If those heights differed on either side of the fault, a pressure differential must exist and was interpreted accordingly. SGR calculations were made using an Allan diagram. The shale concentration and pressure data were integrated for three example reservoirs: Nun field, Niger delta; Brent province, North Sea; and Columbus basin, Trinidad. The Nun field contains stacked intervals of hydrocarbon accumulations, and there are no instances where hydrocarbons are connected vertically through shales. The Brent province example is of a single interval of hydrocarbon accumulation where the water is hydraulically connected through the fault, but the gas and oil intervals are not (see Fig 3.5). The hydrocarbon column is connected vertically through a few layers of shale. The Columbus basin is a single interval of hydrocarbon accumulation, but it was unclear how the stratigraphy units sit. Hydrocarbon accumulations were in areas where the SGR was high (Yielding *et al.*, 1997). The benchmark values from this and subsequent work are that an SGR of 20% should seal and below 15% should leak (Dockrill, 2005).

Yielding *et al.* (1997) did not focus on the vertical barriers to migration only the across-fault barriers. By observing the across-fault pressure difference and hydrocarbon accumulations, something could be learned about the ability of overlying shales to provide a seal; something could also be learned about the damage zone of the shale in
addition to the information about the fault core. The Brent province example is especially interesting. Several shales were in hydraulic communication vertically; the reservoir rock above and below were saturated with hydrocarbons. One shale layer did trap the hydrocarbons eventually, but several were breached (see Fig. 3.5). The same shales that breached also provided an effective seal in the fault, hence, allowing the determination of the SGR.

Figure 3.5: Interpreted from Yielding et al. (1997), shales 1-3 on the footwall (left) are communicating hydraulically meaning they have been breached. Because the gas-oil contact and the oil-water contact on either side of the fault are different the fault is not communicating hydraulically, hence the determination that the SGR is sufficient to seal. The same entrained shales that create an across-fault seal fail to provide a seal in the vertical direction.
In the Nun field example, it appears all hydrocarbon accumulations are sealed above by shale layers and are trapped against the fault. No examples of breached shales are evident unlike in the Brent province. No stratigraphy was available in the Columbus basin in Yielding et al. (1997) to observe the shale beds, but it could very likely be similar to the Brent province example.

**SGR Rebuttal**

A case study was conducted on a normal fault outcrop with a few meters of throw to study the shale entrainment and mechanical wear hypothesis of SGR (Eichhubl et al., 2005). Samples were taken from the attenuated or deformed shales in the fault core and from the undeformed shales in the host shale layers. The deformation zone in the shales was called by Eichhubl et al. (2005) the transition zone, but no measurements were taken in it.

There were several key points made by the Eichhubl et al. (2005) study. First, the capillary entry pressure was on average 30% higher in the deformed shale in the fault core than in the undeformed shales of the host layers. The deformed shale of the fault core had a preferential structure to act as a seal as a result of faulting. Also, the percent of shale calculated by the SGR (13%) is significantly different than the measured percent of shale (47%). A compositional analysis of the samples revealed that on average only 3% more quartz was added to the deformed shales than in the undeformed source shales, so the mechanical mixing was not an influential process during faulting. The SGR for the fault was calculated to be 13% which would be a leaking fault by the previous prescribed criteria. The actual clay content was 47% from the core measurements which is a significant difference.

Eichhubl et al. (2005) state that the ability of the SGR to predict seal quality is uncertain. They suggest that the following criteria must be considered when predicting
fluid flow properties with shale deformation: fault structure, mechanism of shale deformation (they discuss four deformation mechanisms including simple mixing), and properties of the deformed shale especially the depositional and diagenetic properties. They also conclude that sealing capacity is not a linear function of clay content. They suggest that a predictive algorithm should include the following: shale composition in each layer, the effect of changing fault deformation mechanisms on the shale and the anisotropy in the fault core, and the burial diagenetic history. They offer no such algorithm.

With that said, the SGR is easy to criticize but difficult to replace. SGR is easy to use, and no improved alternatives algorithms have been proposed. The required information to use the SGR is routinely available, and Eichhubl et al. (2005) suggested data might not be available or economical for their alternative approach.

Interestingly, in this example the fault core (deformed shale) would provide a better seal than the overlying shale layers. This supports the insights from Brent province example that a shale entrainment can provide an across-fault barrier than that of the source or overlying shale.

**SGR Application on a Field Case**

Dockrill (2005) investigated faults in central Utah near Crystal geyser that were naturally charged with CO₂ which was leaking to the surface. In this clastic sequence, three faulted areas were of interest: Little Grand Wash fault, Salt Wash graben, and Ten Mile graben.

**Fault Description**

According to Dockrill (2005), the throw on each of these normal faults is hundreds of meters: 260 m on the Little Grand Wash fault (LGWF), and 366 m on the Salt Wash graben (SWG). As summarized from the study by Dockrill (2005), the fault
core of these faults is typically 1 to 3 m wide at the outcrop. The core is composed of entrained rock, sandstone-derived gouge, shale-derived gouge, and slip surfaces. The damage zone extends 100 to 150 m away from the fault core where measured. The fracture network in the damage zone is very complex especially near the fault and near structural complexities. The fluid flow properties of the damage zone are a function of the fracture density, fracture aperture, and connectivity of the fractures. The fracture density was greatest around the structural complexities. The fracture aperture and connectivity was not studied by Dockrill (2005). This study did focus on the orientation and frequency of fractures at several locations which were not studied for the purpose of learning about the petrophysical properties.

**CO₂ Migration**

Evidence of CO₂ migration was found in several locations in particular Crystal geyser which is charged by CO₂ and the travertine deposits that line the faults (Dockrill, 2005). Crystal geyser is an abandoned exploration well which routinely releases CO₂. The travertine deposits along the faults have been forming for the last 78,000 years (see Fig 3.6 for an areal view of LGWF). The faults in this region have leaked an estimated 2 Gt-CO₂ or 0.5 Gt-C over the last 78,000 years.

![Figure 3.6: Areal view of the Little Grand Wash fault as mapped by Dockrill (2005). The outcropping stratigraphic units as they appear today are abbreviated with two or three letters (Jc, Jmb, Kcd, etc.). Travertine deposits (grey shapes) are generally appear on the north side which is the footwall side and where the CO₂ is probably charging from. Notice the proximity of deposits near the anticlinal structure.](image)
Fault Seal Analysis for the Crystal Geyser Area

The shale gouge ratio (SGR) was computed for the Little Grand Wash fault (LGWF) and the Salt Wash graben (SWG) by Dockrill (2005). Those results are shown in the juxtaposition diagram (Fig 3.7). An Allan diagram is shown for SWG (Fig 3.8).

Figure 3.7: Axes: The stratigraphic units are listed on the left side from Cretaceous to Permian. Notice the darker the grey the more shale (Kcm vs. Jc for example). The right hand vertical axis is the thickness of each layer, and the horizontal axis is the throw of the fault. Center juxtapositions: The black represents a non-reservoir/non-reservoir juxtaposition or a reservoir/non-reservoir juxtaposition where no across-fault leaks are expected. The SGR is calculated for all reservoir/reservoir juxtapositions, and the scale for the SGR is shown in the top corner.
Discussing Fig 3.7, the lowest SGR readings (below 15% which is a leak) are on the left where the throw has not been great enough offset the reservoir rock past itself. Some areas of 15% to 20% (where unit Jw is juxtaposed Jn) are found in the 200 – 400 m throw range. The trace for the Little Grand Wash fault is shown; the throw of interest for this fault is 260 m, hence the line at this location. The throw on the Salt Wash graben is 366 m, and Salt Wash graben is always greater than 20% SGR. Dockrill (2005) interpreted that both the Little Grand Wash fault and Salt Wash graben will seal against across-fault flow. The surface evidence seems to confirm these findings as travertine appears to be migrating up the footwall. An Allan diagram was also made for each of the faults, but only an example of the Little Grand Wash fault is shown from Dockrill (2005) in Fig. 3.8.

![Figure 3.8: Both views shown are of the fault plane for the Little Grand Wash Fault. On either side are the stratigraphic units listed. In the top view, areas of reservoir/reservoir juxtapositions are shown in black. In the bottom view, the SGR for those juxtapositions are shown and labeled 18%, 25%, and 35% for each layer of reservoir/reservoir juxtaposition.](image)

The juxtaposition and Allan diagrams relate the same information, but the Allan diagram makes it a little easier to view. The SGR is high enough that no CO₂ should flow
across the fault (Dockrill, 2005). The precipitation of minerals at the surface may be indicative of precipitation along the leakage path. Cataclasis or grinding of the massive sandstone units was apparent, but no additional sealing information was added to the SGR for the cataclasis or diagenesis effects.

From the Crystal geyser example, there are interesting conclusions to draw. CO\textsubscript{2} migrates up the regional dip to the faulted region which is the structural high. The CO\textsubscript{2} migrates up the footwall of the fault as evidenced by travertine deposits on both the Little Grand Wash fault and the Sand Wash graben (Dockrill, 2005). SGR fault seal analysis provides the explanation for the footwall-only migration. Dockrill (2005) concludes that the faults have leaked large volumes to the surface through the damage zone and around structural complexities. This is a clear example of how SGR is not an indicator for all kinds of sealing, only for sealing in the across-fault direction.

**Summary of SGR**

SGR was calibrated to indicate if fluid would cross a fault in clastic sequences. It is used in the petroleum industry. SGR was not calibrated for the other half of the hydrocarbon trap: the overlying shale. Eichhubl *et al.* (2005) points out some of the weaknesses specifically that the SGR does not predict entrained shale volume and does not include all the shale-related factors. SGR strengths include its basis on multiple observations and the simple idea and implementation given generally available information.

When considering a CO\textsubscript{2} fault leak analysis, the overlying shale layers (or the damage zone of the shales) should be considered as a target study similar to the calibration studies for SGR. Even using the same data sets, the capacity of the shale layers to allow communication both across the fault and vertically could be studied. Indicators of leaking faults, like SGR, are not necessarily intended for simulator
applications, but in the next section will cover the petrophysical description more specifically.

### 3.2.2 Petrophysical Fault Zone Description

Up to this point, fault seal analysis has only been described as an indicator: either leak or no leak. Although this analysis can help answer the question of whether the fault will leak, it says nothing about the rate or the time scale associated with such leaks. As previously described, two important questions to answer for geologic CO\textsubscript{2} storage are how long will it take to reach the surface and how much will reach the surface?

**Introduction**

What properties are needed for a reservoir simulator to determine time to the surface in the presence of a fault? Certain properties are reasonable to obtain. A description of the stratigraphy including the dimensions of the stratigraphic layers (in particular thickness) and a range of petrophysical properties for the undeformed shale and sand layers are reasonable to obtain. The fault description including the throw and the dip can be obtained. Estimates for the initial temperature, pressure, and salinity profiles used with an equation of state can be obtained. The identification and the best work done on the more difficult areas of a fault are the focus of this work. The three areas needing petrophysical description for clastic sequences are: damage zone of sandstones, damage zone of shales, and the fault core. The sources of information summarized here are based on outcrop, core sampling, and well log studies.

**Damage Zone of Sandstones**

Several studies have been made to determine the permeability and permeability anisotropy in the damage zone of sandstones. The Aztec sandstone in Nevada was studied by Jourde et al. (2002). This sandstone has an average permeability of 200 md, high
porosity, and poor to medium cementation. Strike-slip faults cut through the Aztec sandstone. Second, a study of normal fault cut through the Navajo Sandstone in Utah was studied by Shipton et al. (2002). The permeability ranges from 100 to 1000 md, and the porosity is high partially due to poor cementation.

Jourde et al. (2002) outlines the key structural features associated with the damage zone of strike-slip faults in Fig 3.9, but many of the features are found in the normal faults of Shipton et al. (2002). Also in Fig. 3.9, Jourde et al. (2002) outlines a method used to upscale the small scale heterogeneities to an equivalent reservoir grid block size.

The features specified for a strike-slip fault are similar to those found in a normal fault, with the exception of joints (Shipton et al., 2002), but the point is that high and low permeability features and strong anisotropy are created across the fault. The method of assigning permeabilities was based upon minipermeameter measurements and petrographic image analysis (Jourde et al., 2002). (Petrographic image analysis uses thin section and the Carman-Kozeny relationship to assign permeabilities especially to fractures).
Figure 3.9: High and low permeability features varying seven orders of magnitude can exist in the region of a fault in very close proximity. The porosity, on the other hand, will only vary one order of magnitude. According to Jourde et al. (2002), the map (a) of, in this case, a strike-slip is assigned features. Those features are assigned permeabilities (b). The map is then digitized into pixels (c) and upscaled to grid block equivalent permeability (d).

Specific Fault Features

The specific fault features in the damage zone of sandstones are: joints, deformation bands (also called shear joints), slip surfaces, and the fault core. Joints are when normal stress has opened a fracture. Even a small fracture can have very high permeability, and Jourde et al. (2002) suggests \( \sim 10^6 \) md, which would change depending on the expected aperture size. If precipitates form in the fracture, the permeability will be significantly diminished.
Deformation bands are where the shear stress has compacted and crushed the grains and have a permeability of ~0.1 md (Jourde et al., 2002). This feature is pervasive in the damage zone of normal and strike-slip faults.

Slip surfaces are the border of the fault core and the damage zone. This is often a polished surface because it is where the slip actually occurs. Although the aperture can vary, Jourde et al. (2002) suggest a permeability of ~10^6 md. Again precipitate in the fracture would reduce the permeability. The fault core in this case is sandstone-derived gouge because the sand grains have been ground and crushed in the process called cataclasis.

The fault core could be shale-derived gouge from entrained shale layers. The permeability of the core can be seven orders of magnitude less than the host rock and have a porosity of less then 1% (Shipton et al., 2002). Jourde et al. (2002) assign ~0.1 md as a representative permeability.

Several strike-slip faults were mapped, and the process described in Fig 3.9 for assigning permeabilities was implemented on them (Jourde et al., 2002). The permeability predictions ranged from 1,000 to 1,500 md in the parallel to fault direction and 2 to 26 md in the across-fault direction for grid block approximately 4 to 6 m in size. These predictions capture the strong permeability anisotropy created by a fault.

**Core Samples and Borehole Measurements**

The case study reported by Shipton et al. (2002) agreed with the outcrop findings of Jourde et al. (2002). Boreholes were drilled to sample fault rock and make measurements of permeability on the borehole and the core. The boreholes were shallow going less than 70 m true vertical depth (Shipton et al., 2002). The 130+ m Navajo sandstone has a normal fault running through it with a varying slip of 3 to 8 m. (Slip is the distance the blocks have moved past one another.) The core is obviously sandstone-
derived gouge with a thickness varying between 6 to 33 cm, and the damage zone extended 12 to 27 m from the fault core.

Permeability measurements on the borehole were made by a probe permeameter. The results varied from less than 1 md near the fault core to ~2,000 md in the damage zone (Shipton et al., 2002). The triaxial permeability measurements on the whole core revealed the permeability anisotropy. The fault core permeability was ~1 md, and the host rock was ~500 md.

The findings and conclusions of this study are the permeability normal to the fault core was 2 to 10 times smaller than the permeability parallel to the fault core (Shipton et al., 2002). Because of the deformation bands, permeability is increased in the along-fault direction and decreased in the across-fault direction. These findings are in agreement with Jourde et al. (2002) with similar order magnitude permeabilities in the along- and across-fault directions.

**Damage Zone of Shales**

Overlying shale layers are generally considered impermeable barriers to vertical migration of the non-wetting phase such as hydrocarbons and CO₂. As discussed previously, overlying shale layers are breached by hydrocarbons, but the same entrained shale layers provide an across-fault barrier (see Brent province example in Fig 3.5; Yielding et al., 1997). The question more specifically becomes: where in the overlying shale does it fail thus allowing vertical hydraulic communication between two sandstone layers? Two reasons suggest failure of the shales occurs near the fault. First, the fault is often near the structural high where the pore pressures are the greatest. Second, the high stress concentrations and the resulting deformation occur near the fault possibly damaging the integrity of the shale layers. Possible fractures in the shale layer in the region of the fault (the damage zone of the shale) caused a seal failure.
As shown in Fig 3.10, purposeful study is needed to examine the properties of the shale in the damage zone. Are the properties similar to the host source shale, the shale in the fault core, or unique to the damage zone? What are the key features unique to this zone: fractures in the shale, slip surfaces, detachment, intrusion, or changed petrophysical properties? (Eichhubl et al. (2005) discusses some of these features.) As shown in the Brent province example (Fig. 3.5), the damage zone will be the petrophysical weakness over the fault core or the source shale. An understanding of the damage zone of shales is important to determine flow to the surface, attenuations in the reservoir layers, and sealing potential of faulted clastic sequences.

Figure 3.10: The arrows represent two important fault leakage paths. The deformed shales occur in the damage zone of shales and in the fault core. The across-fault fluid properties of the fault core have been studied for shale by Eichhubl et al. (2005), Yielding et al. (1997), and others. The fluid flow properties of the damage zone in shales have not been studied as extensively as sandstones perhaps because of lack of identification or methodology.
Fault Core

Previously, some studies of fault core for sandstone-derived gouge were shown (Shipton et al., 2002). The assumed fault core permeability was very low (~0.1 md; Jourde et al., 2002). The measured fault core permeabilities were low (1-2 md; Shipton et al., 2002). No mention was made in these studies of capillary pressure measurement.

Eichhubl et al. (2005) made both permeability and capillary pressure measurements on a fault with shale-derived gouge. The fault of interest for the study was in California in the Black Diamond mine. The fault is in a sandstone-shale formation and has slipped about 8 m. Measurements were made on the source shale layers and the gouge in the fault core derived from those layers. Capillary pressure and air permeability measurements made on samples from the fault core and source layers are shown as cumulative distribution functions (CDF’s) in Fig 3.11 and 3.12.

Figure 3.11: Eichhubl et al. (2005) measured this data and reported the deformed shales had an arithmetic average of 30% higher entry pressure than the undeformed shales. By creating this CDF, the distribution of values and the capillary weakness (lowest entry pressure) can be observed. The lowest entry pressure is in the source shale, not the fault core.
Figure 3.12: Air permeabilities from Eichhubl et al. (2005) are plotted as a CDF. Notice the permeability is plotted on a log scale. The source shale shows more variability than the fault core. The hydraulic weakness (highest permeability) is the undeformed source shale layer.

Eichhubl et al. (2005) reports that a good seal only requires a capillary entry pressure above 60 psi. All the entry pressures measured for the fault core are above 120 psi, and the capillary weakness in the system would be the source shale layers (Fig. 3.11).

The permeability samples were generally very low (< 1 md). The log normal average for the permeabilities (or P50 or Probability = 0 in Fig. 3.12) is similar for the source shale layers and the fault core, but the variability is different between the groups. Again, the weakness of the system is the source shale with the high measured permeability. Also reported by Eichhubl et al. (2005) were the porosities and pore aperture diameter. They reported that there was no significant between the porosities of the groups. Interpreted from the capillary pressure data, the modal pore aperture of the source shale layers was double that of the fault core.

In summary, the permeability in both shale- and sandstone-derived gouge is generally very low (< 1 md; Eichhubl et al., 2005; Shipton et al., 2002; Jourde et al.,
Capillary pressure measurements are important for shales as they provide the membrane seal to the non-wetting phase. No measurements of capillary pressure were found for sandstone-derived fault core. Studies like these are important to determine the permeability and capillary pressure trends of the fault core as they provide insight into hydraulic and membrane sealing capacity.

3.2.3 Reservoir Simulation Recommendations

Methods to upscale the small features and large heterogeneity in the region of a fault are important but not discussed here in much detail. Recommendations are available in Shipton et al. (2002), Jourde et al. (2002), and in the literature. Shipton et al. (2002) discusses averaging methods and correlations for permeability across the fault as a function of core thickness and the number of deformation bands for reservoir simulator grid blocks. Jourde et al. (2002) describes in more detail the procedure of mapping, making pixels of each feature, averaging, and upscaling as shown in Fig 3.9. The value of measurements-based studies is evident from Shipton et al. (2002) and Eichhubl et al. (2002).

Fault leakage models could possibly include stacked sand-shale sequences. Descriptions of stratigraphy and estimates of the petrophysical properties could reasonably be obtained along with the throw and dip of the fault. Phase behavior of CO$_2$-brine systems are available (Kumar, 2004) for use in commercial software CMG (Nghiem et al., 2006). One example of a homogeneous fault simulation is found in Pruess (2005). To obtain properties in the region of the fault, the studies and ideas presented here of the damage zones and the fault core could be used as a starting point for simulations.
3.3. SUMMARY

Vertical migration barriers will be more important in the CO₂ storage industry than in the petroleum industry. Different studies and approaches have been discussed and presented to determine the sealing characteristics of faults in clastic sequences. The discussion has centered on the two subjects of particular interest: indicators of leak or seal (also called fault seal analysis), and petrophysical properties in the region of a fault. Developed by Yielding et al. (1997) and implemented on a fault naturally leaking CO₂ by Dockrill (2005), the shale gouge ratio (SGR) is an approach to determining across-fault sealing potential. Similar observations as made to derive the SGR could be made of overlying shale to help determine trap development during CO₂ migration.

Petrophysical estimates and measurements have been made on the fault core through outcrop, core, and borehole studies (Jourde et al. 2002; Shipton et al., 2002; Eichhubl et al., 2005). To determine the permeability along or parallel to the fault, studies have been made of the sandstone damage zone but not for the shale damage zone. Jourde et al. (2002) identified key structural features and approximate petrophysical descriptions and correlations. The damage zone in shale layers is an important key in understanding how CO₂ will be trapped near a fault. The damage zone in shales should be the focus of future studies. Eichhubl et al. (2005) study is the closest starting point for the small scale feature of the shale damage zone, but, as well, identifying hydraulically communicating seals like in the Brent province should also provide some insight (Yielding et al., 1997). The currently available petrophysical data might be enough to enable estimates of the time scales and migration rates associated with leaking CO₂ from the reservoir to the surface.

Fault-fluid flow interaction is important to understand as faults are potential pathways for sequestered CO₂ back to the atmosphere and are pervasive in every basin.
As many billions of tonnes of carbon are sequestered, the probability of encountering faults will increase and being able to estimate leakage rates along these faults will become more important as a part of site selection and storage strategies. At this point, our level of understanding of faults needs to be improved.
CHAPTER 4: INJECTIVITY OF BULK PHASE CO₂

The standard approach to carbon storage in aquifers assumes injection of bulk phase CO₂ into the formation. A key limitation to this approach is the rate at which CO₂ can be injected without fracturing the formation. The purpose of this chapter is to investigate the effect of relative permeability and salt precipitation on bulk phase CO₂ injection into aquifers. The effects of multi-phase flow due to relative permeability between phases can vary between reservoirs and even within the same reservoir (Bennion and Bachu, 2005). It has also been shown that the injection of dry gas will evaporate water leaving salt precipitate in the pore space (Zuluaga, 2005). A simple model for injectivity using Darcy’s Law and modified Buckley-Leverett theory is used to investigate these mechanisms.

4.1. INTRODUCTION

The first order effect on injectivity is the product of formation permeability and formation thickness, \( k_h \) for vertical wells, or \( k_L \) for horizontal wells, \( L \) being the length of the horizontal section. Formations with large \( k_h \) will be preferred targets for storage, but \( k_h \) or \( k_L \) should not be the only criterion for site selection. Other factors will alter injectivity including the mutual solubility of CO₂ in the aqueous phase and H₂O in the CO₂-rich phase and the relative permeability to the brine and CO₂. Injectivity will vary with volume injected.

To understand injectivity of CO₂ in a brine aquifer, it is important to identify and understand regions of flow that will develop in the aquifer and then evaluate the mechanisms that control flow in those regions. The three regions that develop are dry CO₂ in the near-wellbore region, the Buckley-Leverett or two-phase region, and the brine region far from the well. The three regions are separated by two fronts that move at
characteristic speeds namely, the drying front and the Buckley-Leverett front (see Fig 4.1). Because of the mutual solubility of the phases, the situation differs from classical two-phase immiscible flow which has single front separating two regions.

![Figure 4.1: Three regions of flow develop during CO₂ injection and a pressure drop will result over each region. The fractional flow curve modified to account for multiphase transport of CO₂ (Noh et al., 2007) determines the speed of the fronts and the saturations in the two-phase Buckley-Leverett region.](image)

In this chapter, a simple 1-D radial model of injection will be developed for constant pressure outer boundary using Darcy’s Law and a modified form of Buckley-Leverett fractional flow theory which accounts for the mutual solubility. The front speeds and the region mobilities can be evaluated directly from the inputs of phase behavior, relative permeability curves, and viscosities. Using the model reservoir, sensitivity of injectivity to relative permeability, phase behavior, and salt precipitation can be studied.

### 4.2. Mathematical Modeling

#### 4.2.1 Basic Model

To describe CO₂ injection, the simplified 1-D model is a radial reservoir with a drainage radius of 10,000 ft and homogeneous properties. Constant pressure is assumed at the drainage radius, and the pressure gradients are computed from the flow rate at any instant as though the flow were at steady-state. The injection rate, $q$, will vary with time.
as the Buckley-Leverett and the drying front advance. Fractional flow theory can be applied to this situation of variable flow rate. The fluid properties such as the viscosity and density are assumed to be constant and independent of composition. Compressibility is ignored, and temperature is assumed constant. Chemical equilibrium is assumed wherever the CO2-rich and aqueous phases are in contact. No geochemical reactions (e.g. between the CO2-saturated brine and minerals comprising the formation) occur, but the precipitation of the dissolved solids is considered after the basic theory is developed.

**Phase Mobility and Relative Permeability**

The mobility $M$ of phase $j$ is given by

$$M_j = \frac{k_r j \mu_j}{\mu}$$

(4-1)

where $k_r$ is relative permeability and $\mu$ is viscosity. The fractional flow of phase $j$ is given by

$$f_j = \frac{M_j}{M_j + M_i}$$

(4-2)

where $i$ denotes the other phase.

Relative permeability is assumed to depend only upon phase saturation, so the fractional flow of a phase also depends only on saturation. Bennion and Bachu (2005) measured relative permeability curves on seven cores from deep formations in western Canada. The experiments were performed with CO2-saturated brine and brine-saturated CO2 to insure that drying fronts did not affect the measurements. Their reported data was fit to the following Corey-type equations (see fit parameters in Table 4-1):

$$k_{rw} = \left[1 - \left(\frac{S_g}{1 - S_{wr}}\right)^m\right]$$

(4-3)

and,
where \( w \) and \( g \) indicate aqueous and \( \text{CO}_2 \)-rich phases, respectively.

\[
k_{rg} = k_{rg}^0 \left[ \frac{S_g}{1 - S_{wr}} \right]^n
\]

(4-4)

Table 4-1—Corey-type Parameters for Alberta Basin Relative Permeability Curves

<table>
<thead>
<tr>
<th></th>
<th>( S_{wr} )</th>
<th>( k_{rg} )</th>
<th>( m )</th>
<th>( n )</th>
</tr>
</thead>
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<td>Viking</td>
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<td>0.3319</td>
<td>3.2</td>
<td>3</td>
</tr>
<tr>
<td>Basal Cambrian</td>
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<td>5</td>
</tr>
<tr>
<td>Cooking Lake</td>
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<td>0.0685</td>
<td>3.3</td>
<td>5</td>
</tr>
<tr>
<td>Ellerslie</td>
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<td>0.1156</td>
<td>2.05</td>
<td>2.3</td>
</tr>
<tr>
<td>Nisku</td>
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<td>0.1768</td>
<td>2.75</td>
<td>1.1</td>
</tr>
<tr>
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<td>0.1883</td>
<td>1.4</td>
<td>2.2</td>
</tr>
<tr>
<td>Wabamun Low</td>
<td>0.595</td>
<td>0.5289</td>
<td>1.42</td>
<td>5.5</td>
</tr>
</tbody>
</table>

**Pressure Drops in Three Regions of Flow**

Injecting anhydrous \( \text{CO}_2 \) into a deep saline aquifer produces three distinct regions of flow (Fig. 4.1). Farthest upstream (closest to injection well) is single-phase dry \( \text{CO}_2 \) flowing in dry rock. The drying front separates this region from the two-phase region, where the phase saturations vary continuously with position. The Buckley-Leverett front separates this region from the single-phase brine. The total pressure drop will be the sum of the pressure drops across these three regions.

**\( \text{CO}_2 \) Region**

The pressure drop across the single-phase \( \text{CO}_2 \) region is found using Darcy’s Law:

\[
\Delta p_{\text{dry}} = \int_{p_w}^{p_{\text{dry}}} \frac{d\phi}{2\pi kh} = \int_{r_w}^{r_{\text{dry}}} \frac{1}{r} dr = \frac{q\mu_g}{2\pi h d_{r_{\text{dry}}}} \ln \left( \frac{r_{\text{dry}}}{r_w} \right)
\]

(4-5)

where \( k_{r, S_g=1} \) is the permeability reduction due to salt precipitation.

70
The flow rate $q$ is a function of time, but for conciseness, this dependence is not written explicitly. The final expression on the right hand side has been modified to include the factor $k_{r,g=1}$. This factor satisfies the following bounds:

$$k_{r,g} \bigg|_{S_{g, dry}} < k_{r,g=1} < 1$$

(4-6)

The lower bound corresponds to the relative permeability of the CO$_2$-rich phase just downstream of the drying front (see Fig. 4.1). This bound arises because the precipitated salt cannot occupy more pore space than the water originally containing the salt. The upper bound corresponds to zero reduction in absolute permeability due to precipitation. Experiments (Zuluaga, 2005) suggest that typical values of $k_{r,g=1}$ are 0.7 to 0.85.

Permeability Reduction Model

To illustrate a simple estimate of $k_{r,g=1}$, it is assumed that the salt will be distributed evenly in the pore space. (In practice it is more likely to precipitate around the pore throat and at grain contacts (Motealleh and Bryant, 2007)). The salinity ($S_{ppm}$) expressed in parts per million (ppm) in solution can be converted to volume fraction ($V_{f,salt}$) if the density of the salt ($\rho_{salt}$) and the density of the solution ($\rho_{sol}$) are known.

$$V_{f,salt} = \frac{S_{ppm} \times \rho_{sol}}{10^6 \times \rho_{salt}}$$

(4-7)

The reduced porosity is found by subtracting the volume of salt in the remaining volume of water from the original volume:

$$\phi = \phi_0 - \phi_0 (1 - S_{g, dry}) V_{f,salt}$$

(4-8)

The permeability reduction as described by Kozeny-Carman is:

$$k_{r,g=1} = \frac{k}{k_0} = \left( \frac{\phi}{\phi_0} \right)^3 \left( \frac{1 - \phi_0}{1 - \phi} \right)^2$$

(4-9)
The permeability ratio in Eq. 4-9 is just the factor $k_{r,S_g=1}$.

**Two-phase Region**

The pressure drop across the two-phase Buckley-Leverett region can be approximated by:

$$
\Delta p_{BL} = \frac{q_{BL}}{2 \pi k \mu} \int_{r_{dry}}^{r_{BL}} \left( \frac{k_{rg}}{\mu_g} + \frac{k_{rw}}{\mu_w} \right)^{-1} \frac{1}{r} \, dr
$$

$$
= \frac{q_{BL}}{2 \pi k \mu} \ln \left( \frac{r_{BL}}{r_{dry}} \right) \left( \frac{k_{rg}}{\mu_g} + \frac{k_{rw}}{\mu_w} \right)^{-1} \left( S_{g,avg} \right)
$$

(4-10)

The final expression on the right hand side simplifies the analysis considerably.

The approximation consists of replacing the radial position-weighted mobility with the mobility at some average saturation within the two-phase region. This is reasonable if the range of saturations in the two-phase region is narrow. This is the case for the measured relative permeability curves used in this work. For this work, $S_{g,avg}$ is set by $(S_{g,dry} + S_{g,BL})/2$, where $S_{g,dry}$ is the CO$_2$ phase saturation in the two-phase region just downstream of the drying front, and $S_{g,BL}$ is the CO$_2$ phase saturation in the two-phase region just upstream of the Buckley-Leverett front.

**Brine Region**

The pressure drop across the single-phase brine region is:

$$
\Delta p_{BRINE} = \frac{q_{e}}{2 \pi k \mu} \int_{r_{BL}}^{r_{e}} \frac{1}{r} \, dr = \frac{q_{e} \mu_{w}}{2 \pi k \mu} \ln \left( \frac{r_{e}}{r_{BL}} \right)
$$

(4-11)

The sum of the pressure drops across each region yields the total pressure drop:

$$
\Delta p = \Delta p_{dry} + \Delta p_{BL} + \Delta p_{brine}
$$

$$
= \frac{q}{2 \pi k \mu} \left[ \frac{\mu_g}{k_{r,S_g=1}} \ln \left( \frac{r_{dry}}{r_{e}} \right) + \left( \frac{k_{rg}}{\mu_g} + \frac{k_{rw}}{\mu_w} \right)^{-1} \left( S_{g,avg} \right) \ln \left( \frac{r_{BL}}{r_{dry}} \right) + \mu_w \ln \left( \frac{r_{e}}{r_{BL}} \right) \right]
$$

(4-12)
Two situations can be computed from this equation. First, the instantaneous flow rate, $q$, can be prescribed and the corresponding pressure drop can be calculated through time. In this case, the pressure drop is an explicit function of flow rate. Second, the total pressure drop can be prescribed, the goal then being to find the instantaneous flow rate $q$. This is easily accomplished if the positions of the fronts $r_{\text{dry}}$ and $r_{\text{BL}}$ are known. The frontal positions are determined in the next section from the dimensionless cumulative injected volume ($t_D$) and the fractional flow curves. Thus Eq. 4-12 is an implicit equation for $q$.

**4.2.2 Modified Buckley-Leverett Theory**

The speed of the fronts and the phase saturations on either side of the fronts can be determined by using the fractional flow curve, constructing tangents to that curve which account for conservation of mass of CO$_2$ in the fluid phases (Noh et al., 2007). Buckley-Leverett theory for radial flow states:

$$\frac{r_D^2}{t_D} \frac{dS_g}{dS_g} = \frac{df_g}{dS_g} \bigg|_{S_g}$$  \hspace{1cm} (4-13)

It is applied to the breakthrough saturation, $S_{g,\text{dry}}$ or $S_{g,\text{BL}}$. The dimensionless cumulative injected volume, $t_D$, is defined as:

$$t_D = \int_0^t \frac{q(t)}{\pi r_g^2 h_d} dt$$  \hspace{1cm} (4-14)

The dimensionless radius, $r_D$ is defined as:

$$r_D = \frac{r}{r_g}$$  \hspace{1cm} (4-15)

An addition term called dimensionless velocity is also defined. This term is the velocity of the fronts in dimensionless time and radius as shown in Fig 4.2.
\[ v_D = \frac{r_D^2}{t_D} \]  

(4-16)

From Fig. 4.3, the dimensionless velocity of the drying front as defined by Noh et al. (2007) is:

\[ v_{D,\text{dry}} = \frac{f_{g,\text{dry}}}{S_{g,\text{dry}}} \quad (4-17) \]

Figure 4.2: A time-distance diagram showing the flow regions and fronts when CO\textsubscript{2} is injected into an aquifer. The slopes of the lines are the speeds of the corresponding fronts. The distance axis is plotted as \( r_D^2 \) because the flow is assumed radial. The schematic in Fig. 4.1 corresponds to a vertical cross-section of the time-distance diagram.
Figure 4.3: This fractional flow curve is evaluated by drawing tangent lines from the D-terms shown to account for the effects of dissolution of CO$_2$ into the water phase and water into the gas phase (modified from Noh et al. 2007). Notice the small window of saturations which will be realized in the ideal reservoir between $S_{g,BL}$ and $S_{g,dry}$. Recall, $S_{g,avg}$—used to evaluate Eq. 4-12—is $(S_{g,dry} + S_{g,BL})/2$ (Modified from Noh et al., 2007).

Also, the dimensionless velocity of the Buckley-Leverett front is:

$$v_{D, BL} = \frac{f_{g, BL} - D_{brine\rightarrow BL}}{S_{g, BL} - D_{brine\rightarrow BL}} = \left. \frac{df_{g}}{dS_{g}} \right|_{S_{g, BL}}$$

(4-18)

Similar to $S_{g,dry}$ and $S_{g,BL}$, $f_{g,dry}$ is the fractional flow just upstream of the drying front, and $f_{g, BL}$ is the fractional flow just downstream of the Buckley-Leverett front. $D_{BL\rightarrow dry}$ and $D_{brine\rightarrow BL}$ are defined by the phase concentrations in the different regions (Noh et al., 2007).

$$D_{brine\rightarrow BL} = \frac{c_{BL}}{c_{CO_2,a} - c_{CO_2,g}}$$

(4-19)

$$D_{BL\rightarrow dry} = \frac{c_{CO_2,g} - c_{BL}}{c_{CO_2,g} - c_{BL}}$$

(4-20)
The concentrations, $C$ (with units of mol/volume), have a superscript which defines the region and a subscript which defines the phase (i.e. CO$_2$,g is CO$_2$ in the gas phase and CO$_2$,a is CO$_2$ in the aqueous phase). Because $D_{BL \rightarrow dry}$ and $D_{brine \rightarrow BL}$ are functions of concentration and concentration is a function of phase behavior, $D_{BL \rightarrow dry}$ and $D_{brine \rightarrow BL}$ are functions of temperature, pressure, and salinity. PVTSim software (2004) is used for the concentration calculations. The software models the phase behavior with a Peng-Robinson equation of state. As pressure in the reservoir will change with time, some judgment was required for the determination of the concentrations. The pressure in the dry region was assumed to be the bottomhole injection pressure, and the pressure in the Buckley-Leverett region was assumed to be 200 psi above the drainage radius pressure (see footnote in Table 4-2). As will be shown later, changes to pressure, temperature, and salinity have only a relatively small influence on injectivity.

Now that the fractional flow curves can be evaluated in Fig. 4.3, how fronts will be realized in the reservoir can be observed (see Fig. 4.4). Also note, the speed of the fronts will remain constant with time. Since the speeds remain constant, their ratio, $v_{BL}/v_{dry}$, is also constant.

The radial positions needed for Eq. 4-12 can be solved for:

$$r_{dry} = r_e \sqrt{D^y \cdot D_{dry}}$$  \hspace{1cm} (4-21)

$$r_{BL} = r_e \sqrt{D^y \cdot D_{BL}}$$  \hspace{1cm} (4-22)

The ratio of the drying front position and the Buckley-Leverett position, $r_{BL}/r_{dry}$, is also independent of the time.

$$\frac{r_{BL}}{r_{dry}} = \frac{\sqrt{D_{BL}}}{\sqrt{D_{dry}}}$$  \hspace{1cm} (4-23)
Figure 4.4: Using a radial view of the reservoir, the three regions of flow can be visualized: dry CO₂, Buckley-Leverett or two-phase, and brine only. The saturations in the reservoir are $S_g = 0$ in the brine region, $S_g = 1$ in the dry CO₂ region, and between $S_{g,dry}$ and $S_{g,BL}$ in the two-phase region. The values are defined by the fractional flow curve in Fig. 4.3 (modified from Noh et al., 2007).

4.3. RESERVOIR APPLICATION

The Viking sandstone of Alberta, Canada, is used to demonstrate how to implement the modified Buckley-Leverett theory. Also, a discussion of mobility will provide some insight into injectivity. As well, the sensitivity of the theory is also evaluated with respect to changing the relative permeability curve and changing the D-terms—which is effectively changing the pressure, temperature, or salinity.

A CMG (Nghiem et al., 2006) radial model with 500 grid block was created to compare and validate to the semi-analytical solution. In that model, one well was placed at the center and one in the grid block at the drainage radius. Recommendations for solubility and viscosity behavior were based on Kumar et al. (2005). CMG uses a lookup table for the relative permeability. If relative permeability for aqueous saturations less
than the irreducible saturation, $S_{wr}$, are not given to the simulator, it will assume the endpoint relative permeability, $k^o_{rw}$, for all aqueous saturations below irreducible saturation.

4.3.1 Field Example

The reservoir properties used for the calculations of the Viking sandstone are found in Table 4-2. The relative permeability for the Viking sandstone as measured by Bennion and Bachu (2005) is shown in Fig. 4.5. Using this information, the fractional flow curves can be constructed and evaluated (see Fig. 4.6).
Table 4-2—Viking Sandstone Properties

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Permeability</td>
<td>30</td>
<td>md</td>
</tr>
<tr>
<td>Height</td>
<td>100</td>
<td>ft</td>
</tr>
<tr>
<td>Depth</td>
<td>4100</td>
<td>ft</td>
</tr>
<tr>
<td>Temperature</td>
<td>91</td>
<td>°F</td>
</tr>
<tr>
<td>Initial Pressure</td>
<td>1800</td>
<td>psi</td>
</tr>
<tr>
<td>Bottomhole Pres.</td>
<td>2800</td>
<td>psi</td>
</tr>
<tr>
<td>Salinity</td>
<td>30,000</td>
<td>ppm</td>
</tr>
<tr>
<td>Gas Visc., $\mu_{gas}$</td>
<td>0.17</td>
<td>cP</td>
</tr>
<tr>
<td>Brine Visc., $\mu_w$</td>
<td>0.7</td>
<td>cP</td>
</tr>
<tr>
<td>Porosity, $\phi$</td>
<td>13.5</td>
<td>%</td>
</tr>
<tr>
<td>Edge radius, $r_e$</td>
<td>10,000</td>
<td>ft</td>
</tr>
</tbody>
</table>

\[
D_{BLBrine} = 1.0469 \quad b
\]
\[
D_{dryBrine} = -0.0582 \quad b
\]

- Assumed hydrostatic pressure at depth.
- 2800 psia for dry CO₂ region and 2000 psia was used for brine and Buckley-Leverett region in the calculations of the D-terms

Figure 4.5: The relative permeability curves for the Viking sandstone as measured by Bennion and Bachu (2005).
Constant Flow Rate Case

Using the properties in Table 4-2 and the method described, the constant flow rate case can be determined. The flow rate on the first time step is solved for so that the pressure drop is 1,000 psi. The flow rate is then held constant for the next 10,000 days of injection. The flow rate and the pressure drop across each region are shown in Fig 4.7 and 4.8 respectively. No CMG simulation was run for this case.
Figure 4.7: The constant flow rate case for injection is shown. The flow rate was selected such that the initial pressure drop would be 1,000 psi.

Figure 4.8: The pressure drop for the constant flow rate case is shown. The total pressure drop decreases with time as the more mobile CO₂ advances into the reservoir. BL Δp is constant because the ratio of frontal speeds are constant. Dry Δp is increasing with time because the drying front is moving deeper in the formation while Brine Δp is decreasing due to the increasing Buckley-Leverett front.
**Constant Pressure Drop Case**

The more likely case is that the injection pressure will be held constant creating a constant pressure drop situation. Again, using the derived equations and the properties in Table 4-2, the injection rate for the reservoir and the pressure drop across each region as a function of time are predicted. A constant pressure drop of 1,000 psi is applied to the reservoir for the 10,000 days of injection. Eq. 4-12 is solved at each time step by varying the flow rate using a spreadsheet solver until convergence is reached. The process is then repeated for each additional time step. In Fig. 4.9, the flow rate is shown for our theory and from a CMG simulation of the same system. The pressure drop across each region is shown in Fig. 4.10. The largest pressure drop is across the Buckley-Leverett region after a short period of time. The curves differ by only 2%. Most importantly, the major trend is certainly captured by the simple theory.

**Figure 4.9:** During 10,000 days of injection of CO$_2$ at a constant 1,000 psi pressure differential, the injection rate increases steadily. The rate determined from our simplified theory compares well with a full-fledged reservoir simulation for the same system.
Figure 4.10: During 10,000 days of injection, the total pressure drop over the reservoir is 1,000 psi. As the dry CO\textsubscript{2} and Buckley-Leverett regions grow in influence, they contribute more to the total pressure drop. The Buckley-Leverett pressure drop (BL $\Delta p$) is the most influential region due to its low mobility (see Fig 4.12).

**Effect of Drying Front on Injectivity**

If mutual solubility between the CO\textsubscript{2} and brine were neglected, the drying front would not occur and injectivity would be determined by the mobility of the two-phase flow region, i.e. by a classical Buckley-Leverett solution. For the relative permeability curves of the Viking sandstone, the injection rate would decrease with time, the opposite of the trend when the drying front is accounted for (see Fig. 4.11). Injectivity predictions will be wrong if the drying front is neglected (Burton *et al.*, 2008). Clearly, the drying front is important for estimating the number of wells required for a target sequestration rate.
4.3.2 Mobility

The injectivity in the Viking example increases with time (several later examples will show the same) and injectivity increases more initially. The drying region is the difference between the two curves on Fig. 4.11, so it plays an important part in determining the trend. These observations help to frame the question: what specifically controls the injectivity? The most important mechanism controlling injectivity is the mobility in each of the three regions of flow (see Fig. 4.12).

Burton \textit{et al.} (2008) show that the injectivity will increase monotonically in time because the ratio of radius of the drying front to the radius of the Buckley-Leverett front is constant (see Appendix in Burton \textit{et al.}, 2008).
First, the mobility of the dry CO₂ region is much higher than the mobility of the other regions, and it is nearest the wellbore. It can be shown that if the mobility of the dry region is greater than mobility of the brine region, injectivity will be monotonically increasing (Burton et al., 2008). This is always the case unless mobility of the dry region is damaged significantly by salt precipitation.

In the Buckley-Leverett region, the full range of mobilities, although they exist in the reservoir, is not used for the calculations of injectivity. As shown in Fig. 4.12, the average mobility evaluated at the average saturation $S_{g,avg} = 0.34$ is 0.62 cp⁻¹. Notice the
full range of saturations is ~0.28 to 0.40 and the corresponding mobilities range from 0.42 to 0.92. The interfering gas and aqueous phases in the Buckley-Leverett region create a large low mobility region.

Looking at several relative permeability curves with different curvatures, endpoint permeabilities, and irreducible saturations, it would be unclear which curve would result in the best injectivity. Using the evaluations techniques presented here, they can now be compared directly using mobility. The higher the mobility of the Buckley-Leverett region is, the higher the flow rate will be all things being held equal (see Figs. 4.13, 4.14 and 4.15). In the Viking sandstone base case, the average mobility of the Buckley-Leverett region (evaluated at the average saturation, $S_{g,avg}$) is less than the brine mobility, but there could be instances where the average mobility is greater than the brine mobility.

Figure 4.13: The relative permeability has a strong impact on the injection rate. Seven different relative permeability curves were published by Bennion and Bachu (2005). Each of those curves was used in conjunction with the formation properties in Table 4-2 to obtain this plot. Different mobility in the Buckley-Leverett region (see Figs. 4.14) is responsible for the differences in injection rate. All cases were run at the same bottomhole injection pressure.
Figure 4.14: The mobility in the Buckley-Leverett region, evaluated at the average saturation $S_{g,avg}$, is primarily responsible for the differences in injection rate (Fig 4.13). The legend shows the formations in order of decreasing mobility in the Buckley-Leverett regions. The order is exactly the same as the arrangement of decreasing injection rate in Fig. 4.12.

Figure 4.15: Although not used in the calculations, the full range of mobilities that will be realized in the reservoir is shown. The different ranges of saturations and mobilities realized which vary with the shape of each set of relative permeability curves.
4.3.3 Sensitivity of Injectivity to Relative Permeability

Two studies are carried out to show the influence of the relative permeability on the mobility of the Buckley-Leverett region and, therefore, injectivity. The first uses the same Viking sandstone reservoir as described; the only difference is a completely different set of relative permeability curves. The second study is varying the curvature, end-point permeability, and end-point saturation parameters for the Viking sandstone set of relative permeability curves.

For the first study, each of the seven different relative permeability curves measured by Bennion and Bachu (2005) was applied to the Viking sandstone reservoir properties for the constant pressure case. The injectivity varied as shown in Fig 4.13 as previously discussed. The result of varying these curves is a four fold difference in injection rate between the “Cooking Lake carbonate” and the “Wabamun low permeability” cases. The actual formations have different absolute permeabilities and thicknesses as well as different relative permeabilities, so the actual variation in injectivity need not be the same as depicted in Fig. 4.13. The point of this comparison is that the difference in relative permeability from one formation to another will have a substantial effect on the injectivity.

For the second, each parameter of the Viking sandstone relative permeability curve was varied (i.e. m, n, k_r, S_w from Eqs. 4-3 and 4-4). Uncertainty in the relative permeability parameters results in variation in the injectivity (see Fig. 4.16). Therefore, the uncertainty in relative permeability can lead to uncertainty in flow rate and well count.
Figure 4.16: The parameters for the relative permeability equations (Eqs. 4-7 and 4-8) were varied by the amounts shown. The flow rate varies by as much as 20%. Small uncertainties in the relative permeability curve can lead to important uncertainties in the flow rate.

It is also important to point out that the $S_{g,\text{avg}}$ used in Eqs. 4-10 and 4-12 is only an approximation of the mobility of the Buckley-Leverett region. The studies here have shown strong sensitivity to the Buckley-Leverett region mobility which account for the four-fold difference in injectivity. The sensitivity to $S_{g,\text{avg}}$, which is used to determine the mobility of the Buckley-Leverett region, is very important. A perturbation of ±0.02 to $S_{g,\text{avg}}$ results in a ±10% change in flow rate. Future work could investigate how better to select $S_{g,\text{avg}}$ or more appropriately approximate the integrand of Eq. 4-12.

4.3.4 Sensitivity of Injectivity to Phase Behavior

The phase behavior in the theory has been grouped in two D-terms as shown in Eqs. 4-19 and 4-20 although the viscosity, density, and composition of the phases change as a function of pressure, temperature, and salinity. It is assumed that the density and viscosity do not change with pressure and that the composition remains fixed in each
region. Although the determination of the D-terms is not explored extensively, the sensitivity of flow rate to these terms is determined. Altering the D-terms in Eqs. 4-19 and 4-20 by ±0.02 will change the flow rate by less than 5%. Notice the injectivity is more sensitive the $D_{BL \rightarrow dry}$ because $D_{BL \rightarrow dry}$ controls the speed of the drying front in the near wellbore region. This suggests that the phase behavior uncertainty is less important than to the uncertainty of relative permeability and $S_{g,avg}$ uncertainty. More work could be done on how to more accurately determine the D-terms.

![Sensitivity to $D_{BL \rightarrow dry}$ and $D_{brin \rightarrow BL}$ on Flow Rate](image)

Figure 4.17: The injectivity is sensitive to temperature, pressure, and salinity because these parameters affect the D-terms in Eqs. 5-19 and 5-20. Altering the D-terms by ±0.02 changed the flow rate less than 5%.

4.3.5 Sensitivity of Injectivity to Permeability Reduction in the Dried Rock

The permeability reduction in the dry region is estimated for the Viking sandstone using Eqs. 4-7 through 4-9. The salinity of the formation is approximately 30,000 ppm (Bennion and Bachu, 2005) and $S_{g, dry}$ is 0.40. The density of the solution and of the salt deposit are 1.019 gm/cc and 2.16 gm/cc, respectively. The permeability reduction, $k_{r, S_g=1}$, is only 3% in the dry region and results in a injection rate reduction of 1%.
The work by Motealleh and Bryant (2007) and Zuluaga (2005) suggests that the permeability could be reduced much more than 3%. However, the permeability reduction in the dry CO$_2$ region should not be lower than the endpoint permeability at the residual water saturation, $S_{wr}$. This is because the volume of dissolved solids cannot exceed the volume of residual brine. If the permeability of the dry region were reduced to the endpoint saturation permeability for the Viking sandstone (i.e. set $k_{r,S_g=1}$=0.33 in the dry region), the flow rate would be reduced by 42%. A flow rate reduction between the 1% predicted by Kozeny-Carman and the 42% predicted at irreducible water saturation is expected due to permeability reduction in the dry CO$_2$ region. This range of permeability reduction for the Viking sandstone is shown in Fig. 4.18.

![Figure 4.18: The permeability reduction due to salt precipitation in the drying region will cause a reduction in flow rate. The two limiting cases are: Kozeny-Carman, which assumes salt precipitation will be distributed evenly in the pore space, and setting the permeability reduction to the measured gas phase permeability at the irreducible water saturation. The true permeability reduction is expected to lie somewhere in between.](image)

It is evident that a measurement of this permeability reduction could be incorporated into the measurement of the relative permeability curve. After measuring
permeability at residual water saturation, many pore volumes of dry CO\textsubscript{2} could be flooded through the core until all the water has been evaporated. If the salinity of brine used in the flood is similar to the in-situ salinity, the permeability reduction measurement in the dry CO\textsubscript{2} region could be made. This effect is obviously more important at high salinities and higher residual water saturations.

4.4. SUMMARY AND IMPLICATIONS

This simple model for determining the injectivity of CO\textsubscript{2} was based on Darcy’s Law and a modified form of Buckley-Leverett theory in a homogeneous brine reservoir. The theory draws attention to the three regions of flow and the phase mobilities in each region. The drying front develops because CO\textsubscript{2} and H\textsubscript{2}O are soluble in the aqueous and CO\textsubscript{2}-rich phases, respectively, and because the mobility of the dry CO\textsubscript{2} region is typically larger than the two-phase mobility. A classical Buckley-Leverett front also develops. Because the ratio of these two frontal locations is constant, injectivity will increase monotonically with time. The mobility of the Buckley-Leverett region is a controlling factor for injectivity. The trends of this simplified model agree well with simulations with full phase behavior.

The sensitivity of injectivity to relative permeability was tested with a set of measured curves for seven formations. The increase in injectivity occurs for all the relative permeability curves because of the large mobility of the dry region. But the curves strongly affect the absolute value of injectivity because they affect Buckley-Leverett region mobility. Varying only the relative permeability curves and keeping all other reservoir properties the same, injection rate can vary by a factor of four. By varying the parameters commonly used to characterize the relative permeability curve (\(m, n, k^{o}\tau_{g}\), and \(S_{w^*}\)), the flow rate varied by up to 20%. This research shows that quantifying the
relative permeability curve is very important in determining achievable injection rate and therefore the well count for CO₂ geologic sequestration projects.

The sensitivity to phase behavior, as summarized by two D-terms in modified Buckley-Leverett theory, appears to be less than the sensitivity shown for relative permeability.

Laboratory measurements of relative permeability should include measurements for a core dried by CO₂ injection from the state of residual saturation of the native brine. CO₂ will evaporate the brine and precipitate salts in the pore space. Salt precipitation in the dry region can reduce the injectivity especially in high salinity and high residual water saturation cases.

This model can be useful in determining the injection rate into a formation, for understanding the mechanisms that control injection, and for determining the radial extent of the fronts during injection. Relative permeability can restrict injectivity and create important uncertainty in forecasts of storage operations. Salt precipitation will also occur during bulk-phase injection. With a bulk phase CO₂ injection strategy, these phenomena are unpreventable and should be taken into consideration.
CHAPTER 5: SURFACE DISSOLUTION

In storing greenhouse gases, storage assurance and cost are both important objectives. Options like surface mineralization cost 3 to 10 times that of geologic storage (Lackner, 2003) but assurance that the carbon is completely stored is unarguable. Another clue to the importance of assurance is that geologic storage is focused on targets that are as deep as economically possible (Nicot et al., 2006). Human introduced uncertainty like high well densities in areas like the Gulf Coast pose important challenges to storage operations (Nicot et al., 2006). If deeper targets (~10,000 ft) are the preferred targets, higher risk aquifers at shallower depths should be available for alternative strategies.

As previously discussed in Chapter 3, natural geologic uncertainty poses important risk to buoyant mobile CO₂. As time progresses, more fault-prone sites are likely to be selected as the need for storage space increases. Two-phase injectivity is important and predictable as shown in Chapter 4, but it would be convenient to avoid this phenomenon all together.

Less risky strategies have been proposed. Alternatives like the “inject low and let rise” strategy maximize residual trapping and reduce risk (Bryant et al., 2006). Injection in the ocean sediments deep enough for the bulk phase CO₂ to be denser than brine is a strategy that would be more expensive and technically challenging but would add the benefits of safe and assured storage (House et al., 2006). Georgescu et al. (2006) suggested the co-injection of brine and CO₂ to improve the pore scale mixing and dissolution near the injection site as another example of risk mitigation.

With that background, the focus of this chapter is the surface dissolution process. This geologic storage strategy maximizes storage assurance by ensuring all the CO₂ sequestered is dissolved in brine. The risk of buoyancy-driven leakage through human
induced or geologic uncertainty is minimized. This alternative can be applied in deep aquifers, and it is feasible in shallow aquifers which are much less attractive targets for standard geologic storage strategies that inject bulk-phase CO₂. This strategy also reduces groundwater movement far from the well site. This study highlights the differences between surface dissolution and the standard approach to geologic sequestration. The means of comparison are costs, benefits, and the technical challenges of both.

5.1. Carbon Capture

The implementation of the standard approach to carbon capture and geologic sequestration (CCS) on existing power generation plants requires the capture of the CO₂ stream, compression, and injection into a brine-filled formation for storage (see Fig. 5.1).

---

Figure 5.1: This schematic of the standard approach for carbon capture and sequestration (CO₂ bulk phase injection) includes the captured stream which is compressed to an appropriate pressure and injected into a brine aquifer.
5.1.1 Capture Options

“Tail-end” capture technology separates the CO₂ from the flue gas. (Flue gas is the exhaust from typical coal (or fossil fuel) combustion). The concentration of CO₂ in the flue gas is 4-14% (Yamasaki, 2003). Fisher et al. (2005) suggest that the most likely capture process to be implemented that is currently available is absorption/stripping with monoethanolamine (MEA). These regenerative solvents absorb CO₂ from the flue gas at low pressures and release the CO₂ when the pressure and temperature conditions are changed. MEA scrubbing is already widely used in other applications. For instance, in the petroleum industry MEA is used to scrub CO₂ from produced natural gas. Absorption/stripping can recover 98% of the CO₂ (Yamasaki, 2003) but economically 90-95% recovery should be expected to be recovered (Fisher et al., 2005). The largest problem for CCS is the energy requirement to operate this process. In terms of energy, ~38% of the power plant energy may be required to run the capture and compression process (Fisher et al., 2005). The advantage of this technology is that it can be applied in the near term and into the future.

Future power generation may rely on advanced combustion schemes that eliminate the flue gas separation step (Yamasaki, 2003). The oxy-combustion process uses oxygen separated from ambient air to combust with hydrocarbons. The only end products are CO₂ and H₂O which can be easily separated. Pre-combustion processes react gasified coal and oxygen in a high temperature, carefully controlled environment. The end products of CO₂ and H₂ are separated. The hydrogen can then be used for combustion or in a fuel cell. Following either process, the CO₂ stream will be compressed and disposed to mitigate greenhouse gases. Full-scale projects are expected in the next few decades (Yamasaki, 2003). As tail-end technology could easily be implemented in the near term, estimates of the power and capital required for tail-end technology are used.
5.2. STANDARD APPROACH MODELING

5.2.1 Power Consumption

Based on modeling from Fisher *et al.* (2005), 90% CO₂ recovery is assumed for the base case (Case 1 in Fisher *et al.*). The flue gas is contacted in the absorber at near ambient pressure. After absorption, the CO₂ is stripped from the MEA and compressed from ambient pressure to pipeline pressure for transportation. Slightly more efficient configurations are reported (Cases 2 through 4 in Fisher *et al.*), but the base case is sufficient for this study. Emissions from a coal-fired power plant are approximately 4 million tonne of CO₂ annually for a 500 MW plant (Benson, 2005). Assuming 90% capture, that amounts to 20 tonne per day per MW of power plant, 200 rbbl/d per MW (using 40 lb/ft³ at reservoir conditions), or 400 mscf/d per MW (using 0.11 lb/ft³ at standard conditions).

Compression Consumption

CO₂ compression can be modeled as polytropic compression based on the recommendations by Fisher *et al.* (2005). The power consumption for polytropic compression as given by Boyce (2005) is:

\[
W_{CO₂} = \frac{SN_{CO₂}R T}{(n^*-1)} \left( \frac{p_x}{p_1} \right)^{n^*} \frac{1}{n^*-1} - 1
\]

(5-1)

where \(p_x\) is an intermediate stage pressure, and \(N_{CO₂}\) is the molar flow rate of CO₂. The other parameters used are in Table 5-1. The results of Eq. 5-1 and the parameters listed in Table 5-1 are shown in Fig. 5.2. Three points of interest are listed on the figure. The minimum pipeline pressure is set at 1250 psia in order to maintain the supercritical phase. The expected pipeline pressure, \(p_{LINE}\), of 2000 psia is the estimation from Fisher *et al.* (2005). For deep wells (> 8,000 ft), the high pipeline pressure will need to be
approximately 3,000 psia. Higher pipeline or wellhead pressures will require additional power consumption.

Table 5-1—Additional CO₂ Compression Properties and Relationships

<table>
<thead>
<tr>
<th>Property</th>
<th>Relationship or Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Intermediate Pressure ((p_i))</td>
<td>(p_i = P_f \left(\frac{P_{LINE}}{P_f}\right)^{\frac{1}{S}})</td>
</tr>
<tr>
<td>Polytropic Coefficient ((n^*))</td>
<td>(n^* = \frac{\eta \cdot k^<em>}{1 + \eta \cdot k^</em> - k^*})</td>
</tr>
<tr>
<td>CO₂ Compressor Polytropic Efficiency ((\eta_p))</td>
<td>79.6%</td>
</tr>
<tr>
<td>Number of Stages ((S))</td>
<td>4</td>
</tr>
<tr>
<td>Gas Constant ((R))</td>
<td>1.968 (\text{BTU lb-mole} \times R^\circ)</td>
</tr>
<tr>
<td>Ratio of Specific Heats ((k^*))</td>
<td>1.269</td>
</tr>
<tr>
<td>Inlet Temperature ((T_i))</td>
<td>104°F</td>
</tr>
<tr>
<td>Inlet Pressure ((P_i))</td>
<td>14.7psia</td>
</tr>
</tbody>
</table>

Figure 5.2: Compression of captured CO₂ from ambient pressure will consume more energy when a higher outlet pressure is required. Three outlet pressures and the power required for each (expressed as a percent of power plant output): minimum pipeline, expected pipeline, and high pipeline pressures.
Capture Consumption

Power consumption to run the capture process is 30% of the power plant output. Fisher et al. (2005) report 38% will be required for the capture and compression when the expected pipeline pressure is 2000psi. The 38% capture and compression less the 8% estimated by polytropic compression yields 30% for the capture process.

5.2.2 Capital Costs

Capture and Compression

Total capture capital requirements for Case 1 of Fisher et al. (2005) is $460,000 per MW of power plant. Of that, the overhead (land, royalty, etc.) amounts to $160,000 per MW of power plant, and capture and compression equipment amount to $300,000 per MW of power plant. Compression equipment is 22% of the capture and compression or $66,000 per MW of power plant. The capture is the other 78% or $234,000 per MW of power plant. Pipeline transportation costs are independent of the comparison being made and are site specific, so estimates are not made in this research.

Injection Wells

IEA GHG (2007) expects typical injection wells to cost $2 million per well for depths of 7,500 ft. The depths are typically deep to decrease the chance of interaction with abandoned wells as recommended by Nicot et al. (2006). Depths of ~10,000 ft are recommended in the Gulf Coast region (Nicot et al., 2006) which leaves considerable pore space at shallower depths.

Assuming a single well can dispose 40 mmscf/d (assuming 0.11 lb/ft³ at standard conditions) or 20,000 rbbl/d (assuming 40 lb/ft³ at reservoir conditions), one well will be needed for every 100 MW of power plant. The wellhead pressure can be calculated given general temperature and pressure profile information and an assumed 3 ¼” ID injection
well. Ignoring the acceleration term, the mechanical energy balance for pipe flow is written as follows (Economides et al., 1993) where \( z \) is depth and \( l_w \) is a section of pipe:

\[
\frac{dP}{\rho} + gdz + \frac{2f \mu^2 dl_w}{D_{\text{pipe}}} = 0
\]  

(5-2)

Assuming density and viscosity (in \( f \) or friction factor term) are functions of pressure, integrating Eq. 5-2 for a vertical well yields the following where \( u \) is the velocity, \( z \) is the depth, \( p \) is the pressure, and \( D \) is the pipe diameter:

\[
\Delta p = -\rho(p)g\Delta z - \frac{2\rho(p)f \mu^2 \Delta z}{D_{\text{pipe}}}
\]  

(5-3)

The code for the pipe flow and other details are shown in the Appendix. A lookup table was used to determine the viscosity and density based on expected pressure and temperature. The viscosity and density data were produced in PVTSim (2007).

Figure 5.3: The results from the created general CO\(_2\) wellbore flow model are shown (see code in the Appendix) and showed sensitivity to well depth (labeled curves) and bottomhole pressure differential (x-axis). Additional energy will be required above expected line pressure of 2000 psia to reach the wellhead pressures for injection.
A look at wellbore behavior revealed that wellhead pressure depends mainly on well depth and bottomhole pressure differential (see Fig. 5.3). (Bottomhole pressure differential is the bottomhole sandface pressure less the initial reservoir pressure.) The temperature profile, the surface temperature, bottomhole pressure differential, and well depth were all studied to observe their influence on wellhead pressure. The influence of temperature profile and surface temperature was weak. Only the relationships involving bottomhole pressure differential and well depth on wellhead pressure are shown.

Therefore, injection well operation will require additional compression at the wellhead as the depths and the bottomhole pressure differentials increase for nearly all depths over ~6,000 ft (see Fig. 5.3). An additional 1% of the power plant output will be needed to make the jump from expected line pressure to high pipeline or wellhead pressure (Fig. 5.2). $8,000 per MW is assumed as the cost of capital for additional compression at the injection wells and $20,000 per MW is the cost for the injection wells.

As deep, high pressure, high rate wells will be required for the injection of bulk phase CO₂, formations in the shallow subsurface are less attractive. But if such formations can be used for lower risk strategies, the overall storage capacity would be significantly larger.

**Additional Tangible and Intangible Costs**

Liability and ownership must ultimately be established for the sequestered CO₂ because buoyant CO₂ will migrate for hundreds of years after injection has stopped (Hesse *et al*., 2006; Ozah *et al*., 2005). Because of this, monitoring practices and remediation strategies are being developed (Benson, 2005; IEA GHG 2007). (Remediation is corrective action taken to fix a subsurface leak.) In the event CO₂ leaked along a fault, abandoned well, or through the intended seal, it could potentially migrate to some other subsurface asset like an oil field, a gas field, the groundwater, or the soil.
Migration to these subsurface assets could result in fiscal and physical corrective action. Migration back to the atmosphere should result in a loss of carbon credits (assuming a credit system is used) as the gas was not stored.

General estimates for insurance purposes were not found in the literature. Liability is approximately the cost of remediation times the probability of an event happening. Estimates for remediation costs addressing many of the mentioned issues have been published recently (IEA GHG, 2007). Probability estimates, however, are not available because the estimates are site specific and difficult to determine as shown in the fault discussion of Chapter 3.
### Monitoring and Remediation

**Table 5-2—Monitoring and Remediation for Standard Approach (IEA GHG, 2007)**

<table>
<thead>
<tr>
<th>Activity</th>
<th>Mid-Range Costs (millions)</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>A. Basic Costs</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1. Site Selection and Project Design</td>
<td>$18.0</td>
<td>Includes 6 observation wells plus other site selection costs</td>
</tr>
<tr>
<td>2. Monitoring and Leak Detection</td>
<td>$62.5</td>
<td>Includes the comprehensive seismic program otherwise included in site selection</td>
</tr>
<tr>
<td>3. Wellbore Integrity</td>
<td>$15.0</td>
<td>Includes multiple periodic ultrasonic cement bond logs and well integrity tests in 10 CO2 injection wells</td>
</tr>
<tr>
<td><strong>Sub-Total</strong></td>
<td>$95.5</td>
<td></td>
</tr>
<tr>
<td><strong>B. Remediation Costs (If Needed)</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1. Locating Sources of CO2 Leaks</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Old, Abandoned Wells</td>
<td>$1.0</td>
<td>Assumes 10 leaking, abandoned well surveys</td>
</tr>
<tr>
<td>• New CO2 Injection Wells</td>
<td>$3.0</td>
<td>Assumes 10 sets of diagnostic logs</td>
</tr>
<tr>
<td>• Caprock/Spill Point</td>
<td>$10.0</td>
<td>Includes seismic and 2 horizontal leak detection wells</td>
</tr>
<tr>
<td>2. Well Plugging</td>
<td>$1.0</td>
<td>Includes plugging of 20 old wells</td>
</tr>
<tr>
<td>3. Well Remediation</td>
<td>$3.5</td>
<td>Includes 10 well remediations and drilling one new CO2 Injection well</td>
</tr>
<tr>
<td>4. Caprock Leakage</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Pressure Boundary</td>
<td>$10.0</td>
<td>Includes two horizontal water injection wells plus a water plant</td>
</tr>
<tr>
<td>• Other Problems</td>
<td>Large</td>
<td>May need to abandon original storage site and build new site</td>
</tr>
<tr>
<td><strong>Sub-Total</strong></td>
<td>$28.5+</td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>$124.0+</td>
<td></td>
</tr>
</tbody>
</table>

The case examined by the IEA GHG (2007) is a 30 year injection site with 20 years of post injection monitoring for a 1,000 MW coal-fired power plant. Monitoring and remediation estimates are summarized in Table 5.2 along with brief explanations.

All the costs shown can vary significantly, for instance, remediation costs could potentially vary from nothing to hundreds of millions per site, but this estimate is $28.5 million per site. Other estimates in the IEA GHG (2007) report soil or groundwater contamination strategies and costs. No estimates were made for oil and gas asset damage even though there appears to be significant overlap between oil and gas assets and saline aquifers (see Fig. 1.1).
For 250 million tonne of CO₂ stored in the IEA GHG (2007) case, monitoring, prevention, and remediation are estimated to cost $124 million for a 30 year site or in terms of the plant $124,000 per MW of power plant. Even though these costs would spread out over the life of the site, they are reported in this research as capital costs.

Table 5-2 summarizes the remediation and basic site selection costs for the standard approach, but liability is not included in the estimate. If insuring against leakage risks becomes sufficiently expensive, alternatives with smaller risk of leakage but larger operating or capital costs may become more attractive. This is another basis for pursuing alternative approaches.

**Simple Reservoir Application**

The Mt. Simon formation of the Illinois Basin can be used as an example of a target saline aquifer (Katz and Lee, 1990; Finley et al., 2005).

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Injection Interval</td>
<td>1000 ft</td>
</tr>
<tr>
<td>Injection Depth</td>
<td>2500-3500 ft</td>
</tr>
<tr>
<td>Permeability</td>
<td>100 md</td>
</tr>
<tr>
<td>Porosity</td>
<td>12%</td>
</tr>
<tr>
<td>Salinity</td>
<td>20,000 ppm</td>
</tr>
<tr>
<td>Initial Temperature</td>
<td>91°F</td>
</tr>
<tr>
<td>Initial Pressure</td>
<td>1300 psig</td>
</tr>
<tr>
<td>Dip Angle</td>
<td>0°</td>
</tr>
</tbody>
</table>

The area of review recommended is 80 square miles by the IEA GHG (2007).

**Summary of Operational and Capital Costs: Standard Approach**

The operational and capital costs for the standard approach are summarized in Table 5-4. This summary is based on the estimates made in previous sections, applied to the Mt. Simon formation. The operational costs in terms of the power plant are 39% of
the power output, and the capital costs are approximately $600,000 per MW of power plant. For a 500 MW power plant, 195 MW would be used to run the capture and compression process, and $300 million would be needed for capital.

<table>
<thead>
<tr>
<th>Process</th>
<th>Operational</th>
<th>Capital</th>
</tr>
</thead>
<tbody>
<tr>
<td>Overhead</td>
<td>N/A</td>
<td>$160</td>
</tr>
<tr>
<td>Capture</td>
<td>30%</td>
<td>$234</td>
</tr>
<tr>
<td>CO₂ Compression</td>
<td>8%</td>
<td>$66</td>
</tr>
<tr>
<td>Transport</td>
<td>Site Specific</td>
<td>Site Specific</td>
</tr>
<tr>
<td>Well Site</td>
<td></td>
<td></td>
</tr>
<tr>
<td>- Wells</td>
<td>N/A</td>
<td>$20</td>
</tr>
<tr>
<td>- Compression</td>
<td>1%</td>
<td>$8</td>
</tr>
<tr>
<td>Liability</td>
<td>TBD</td>
<td>TBD</td>
</tr>
<tr>
<td>Monitoring</td>
<td>N/A</td>
<td>$95.5</td>
</tr>
<tr>
<td>Remediation</td>
<td>N/A</td>
<td>$28.5+</td>
</tr>
<tr>
<td>Totals</td>
<td>39%</td>
<td>~$600</td>
</tr>
</tbody>
</table>

a % of Total Power Plant Capacity  
b thousands per MW of Power Plant Capacity  
TBD = to be determined  
N/A = not applicable

5.3. SURFACE DISSOLUTION

Surface dissolution is an alternative to the standard approach of bulk phase CO₂ injection. Surface dissolution consists of dissolving the captured CO₂, then injecting CO₂-saturated brine into the subsurface formations. Because CO₂-saturated brine is denser than native brine, the risk of buoyancy-driven leakage is eliminated.

5.3.1 Basic Description

A schematic overview of how this process could be implemented is shown in Fig. 5.4.
Figure 5.4: Schematic of the brine dissolution strategy includes pumps for the brine extraction, brine injection, and compression of the captured CO₂ stream. Brine is lifted from the target aquifer and pumped to an adequate mixing pressure. The two fluids are mixed until the CO₂ dissolves, and then the saturated brine is re-injected.

Steps to accomplish this in most fields would be to lift brine from one region of the target formation through extraction wells. The CO₂ stream would be dissolved in the brine in a mixing tank near the injection site and would then be injected into a different region of the same target formation.

Dissolving the CO₂ in the brine at the surface changes the nature of the CO₂ movement in the subsurface. Only single phase flow occurs, eliminating complications associated with saturation fronts, mobility contrasts, fingering, and two-phase flow. CO₂-laden brine is slightly denser than the native brine eliminating gravity-driven segregation override of injected CO₂ or slumping of water. Because the density of an aqueous phase
is greater than of the CO₂ phase the wellhead injection pressure required for this alternative approach (300-1000 psi) is less than the standard approach (>2000 psi). On the other hand the fluid volumes to be handled are much greater (>15 times), and extraction wells are needed to supply the brine. The extraction offers a side benefit of “steering” the injected brine toward the extractors, controlling the brine displacement in a way that cannot be achieved with the standard approach.

The evaluation of these advantages and disadvantages along with the operating and capital costs are detailed in the following sections. Prior to those estimates, solubility of CO₂ in brine in solution is determined by an equation of state (EOS). Solubility estimates enable determination of required brine flow rates, power consumption, and capital costs in a similar fashion and format presented in the standard approach section.

5.3.2 Solubility Modeling

Solubility of CO₂ in brine is modeled as a function of three parameters: temperature, pressure, and salinity. In general, solubility of CO₂ in brine: decreases with increasing temperature, increases with increasing pressure, and decreases with increasing salinity (Finley et al., 2005). Although brines from different aquifers have different compositions, all were modeled as sodium chloride (NaCl) for simplicity. Monovalent salts like NaCl and KCl inhibit dissolution more than divalent salts CaCl₂ or MgCl₂ (Hangx, 2005). As well, NaCl inhibits more than KCl (Hangx, 2005). Therefore, modeling salinity as NaCl is conservative.

Peng-Robinson EOS

Fitting of the experimental solubility data for the Peng-Robinson EOS is reported in Kumar (2004). Data from two authors for CO₂ and pure water mixtures were used, and data from two authors were used for CO₂ and saline brines. These data covered different
ranges of pressures, temperatures, and salinities. No distinction was made for salt composition. The purpose of the fit was for use in CMG (Nghiem et al., 2006) for flash calculations to predict phase behavior.

**Duan EOS**

Fitting of the experimental solubility data for the Duan EOS is reported in Hangx (2005). Data from 6 authors for CO₂ and pure water, from 13 authors for CO₂ and saline brine, and from 2 authors for synthetic brines covering different ranges of pressures, temperatures, and salinities were used to tune the EOS. Average error for the Duan EOS was less than 7%.

Hangx (2005) also made measurements of solubility using what she claims to be a highly accurate way to measure the CO₂ concentration in the aqueous phase in real time. This allows an estimate of the dissolution rate which is necessary for the surface dissolution process. The instrument measures the wavelengths of light absorbed by the CO₂ dense brine. The cell has a closed volume containing pure CO₂ and water. The pressure is then perturbed and the instrument can measure the concentration of CO₂ in the aqueous solution in real time. The result for a pressure change from 333 psia to 580 psia is shown in Fig. 5.5. The implications are that dissolution can occur in a matter of minutes at conditions in a surface mixing tank.
Figure 5.5: Dissolution of CO₂ in brine is measured in absorbance by Hangx (2005). Absorbance is the ability of a solution to absorb radiation. The absorbance of a certain wavelength changes as CO₂ dissolves in solution. After 83 minutes, the reaction has come to general equilibrium. After 12 minutes, the dissolution has reached 90% of the equilibrium value for the pressure change from 333 psia to 580 psia.

Compared to the Peng-Robinson EOS, the Duan EOS predicted greater solubility by 15-21% for pressures between 500 and 3000 psia at 68°F for salinities of 0 ppm, 10,000 ppm, and 100,000 ppm NaCl brines. PVTSim (2007) was used for the Peng-Robinson EOS using the parameters fit by Kumar (2004).

The Duan EOS was used for the following calculations for several reasons. The equations provided by Hangx were easy to implement (see Appendix). Also, attention was given to different salts, and estimates were made of the error from the experimental data. Also, more data was used for the fit. Code was written to implement using the Hangx (2005) parameters and relationships. The relationships and the parameters for the Duan EOS fit by in Hangx (2005) are found in the Appendix.
Solubility in the Aquifer

No more CO₂ should be dissolved in the brine in the surface mixing tank than can remain in solution in the aquifer at aquifer conditions (aquifer temperature, pressure, and salinity). Although the pressure gradients and temperatures gradients can vary, a temperature gradient of 1°F/100 ft and a pressure gradient 0.44 psi/ft were assumed to learn about solubility trends in the aquifer. Different salinities are shown in Fig. 5.6 for the above mentioned temperature and pressure gradients. Surface temperature and pressure were assumed to be 61°F and 14.7 psia, respectively.

Figure 5.6: The solubility in mole percent predicted by the Duan EOS (Hangx, 2005) for a temperature and pressure gradient of 1°F/100 ft and 0.44 psi/ft. Surface temperature and pressure were assumed to be 61°F and 14.7 psia, respectively. Solubility increases with depth to ~2,000 ft then remains fairly constant. Brine salinity has a significant effect on the plateau solubility.

For constant salinity brine, the solubility remains fairly constant beyond depths of ~2,000 ft. Finley et al. (2005) state that salinity also tends to increase with depth with
gradients varying from 4 ppm/ft to 30 ppm/ft in the Illinois basin. Assuming the previous temperature and pressure gradients, a salinity gradient of 15 ppm/ft and a surface salinity of 0 ppm are implemented to produce the curve in Fig. 5.7.

Figure 5.7: In addition to the properties in Fig 5.6, a salinity gradient of 15 ppm/ft and 0 ppm at the surface were assumed to generate the curve shown. The optimum depth for the surface dissolution process is 2,000 ft. The loss of solubility at depths below 2,000 ft is not as rapid as the loss above 2,000 ft.

Understanding the tradeoffs between depths is important in the surface dissolution process. If salinity gradients are influential, targets near 2,000 ft are preferable. If salinity is fairly constant with depth, deeper targets are not restricted by reduced solubility.
Solubility in the Surface Mixing Tank

For the subsequent calculations, a salinity of 20,000 ppm NaCl was selected to investigate the operating conditions in the surface mixing tank. The operating conditions should be such that the CO₂ is dissolved in the mixing tank equal to a concentration corresponding to the aquifer condition solubility. The plateau value from Fig. 5.6 for 20,000 ppm of NaCL (or 2.1% mole of CO₂) is therefore the goal of the surface operation. The temperature in the mixing tank is uncertain, so several different temperatures are shown in Fig. 5.8.

Figure 5.8: Concentration of CO₂ in brine in the mixing tank depends on the pressure in the mixing tank and the temperature of the brine and CO₂ mixture. The “Aquifer Condition Solubility” line is the plateau value from Fig. 5.6 for 20,000 ppm salinity. Achieving this target concentration can be accomplished at different combinations of temperature and pressure.

The target concentration (Aquifer Condition Solubility line in Fig. 5.8) can be achieved at several combinations of temperature and pressure. Anything above that concentration will come out of solution in the aquifer. This will defeat the purpose of
eliminating a buoyant phase. The mixing tank can be run at lower pressures if the brine enters at cooler temperatures. Most likely, the pressure in the mixing tank will be adjusted to match the temperature of the brine entering the mixing tank. The mixing tank can be run at lower pressure if the brine enters at a cooler temperature. The choice of conditions entails a tradeoff (heat exchange vs. compression), the analysis of which is beyond the scope of this study.

**Solubility in the Wellbore**

Figure 5.9: The contour lines are concentrations of CO₂ in 20,000 ppm NaCl brine with units of mole fraction. The “Not Typically Possible” region is a region of pressures and temperatures not expected in the mixing tank or in the reservoir. Typical reservoir temperature and pressures are shown in the “Reservoir Conditions” region. The arrow is a typical path (mixing tank conditions at point A to reservoir conditions point B) which assumes perfect heat transfer and hydrostatic pressure increase. As long as the path never crosses a region with solubility smaller than the value at A, CO₂ will remain in solution. In this example, all solubilities along the path are similar.
It is important to ensure that the solubility path between the wellhead and the aquifer does not pass through a region of temperature and pressure where the CO\textsubscript{2} would come out of solution. The resultant multi-phase slug flow would complicate the simple modeling, invalidate some of the basic assumptions, and defeat the purpose of eliminating a buoyant phase. See recommendations in Fig. 5.9.

Figure 5.9 shows that the mixing tank CO\textsubscript{2} concentration will be less than the equilibrium concentration at aquifer conditions, and there should be no CO\textsubscript{2} coming out of solution between the mixing tank and the reservoir.

### 5.3.3 Brine Flow Rate

The flow rate of the captured CO\textsubscript{2} stream (\(N_{\text{CO}_2}\)) is about 500,000 lb-mol/d for a 500 MW of coal-fired power plant. From the definition of mole fraction, the rate at which brine must be supplied (\(q_{\text{brine}}\)) as solvent for captured CO\textsubscript{2} can be determined. Expressed in terms of rates, the mole fraction of dissolved CO\textsubscript{2} is,

\[
x_{\text{CO}_2} = \frac{\dot{N}_{\text{CO}_2}}{\dot{N}_{\text{CO}_2} + \dot{N}_{\text{H}_2\text{O}} + \dot{N}_\text{Na} + \dot{N}_\text{Cl}} \approx \frac{\dot{N}_{\text{CO}_2}}{\dot{N}_{\text{CO}_2} + \dot{N}_{\text{H}_2\text{O}}} \tag{5-4}
\]

where the molar flow rate of water can be approximated by,

\[
\dot{N}_{\text{H}_2\text{O}} \approx \frac{q_{\text{brine}} \rho_{\text{brine}}}{m_{\text{H}_2\text{O}}} \tag{5-5}
\]

Inserting Eq. 5-5 into Eq. 5-4 and solving for the brine flow rate (\(q_{\text{brine}}\)) yields the following relationship,

\[
q_{\text{brine}} = \frac{\dot{N}_{\text{CO}_2} m_{\text{H}_2\text{O}}}{\rho_{\text{brine}}} \left(\frac{1}{\eta_{\text{dissolve}}} - 1\right) \tag{5-6}
\]

where \(m_{\text{H}_2\text{O}}\) and \(\rho_{\text{brine}}\) are approximated by 18 lb/lb-mol and 62.4 lb/ft\textsuperscript{3} and \(\eta_{\text{dissolve}}\) is the efficiency of the dissolution process (see below).
Equation 5-6 relates the mole fraction and the molar rate of captured CO₂ to the flow rate of brine \( q_{\text{brine}} \), with conversion term, has units of bbl/d) needed for the dissolution process. Because of constraints on residence time, the dissolution reaction is not expected to reach the equilibrium solubility \( x_{\text{CO}_2} \) in the surface mixing facility. Therefore, \( \eta_{\text{dissolve}} = 90\% \) is taken as an estimate of what can be achieved.

Figure 5.10: For a 500 MW coal-fired power plant, the required flow rate of brine (units of millions of bbl/d) depends on the temperature and pressure at which the mixing tank operates which determine the CO₂ solubility by Eq. 5-6. The operating range is narrowed as low pressure operation requires high brine rates and as the high operation yields diminishing improvements. Operating range for the mixing tank should be i.e. 300 psia to 1000 psia. The flow rate should be set to achieve the equilibrium solubility at aquifer conditions.

Figure 5.10 shows the flow rate of brine predicted by Eq. 5-6 for the solubility curves in Fig. 5.8. The operating conditions in the mixing tank could be chosen to be 80°F and 900 psia when the target concentration corresponds to 90% \( (\eta_{\text{dissolve}}) \) of equilibrium solubility in 20,000 ppm salinity brine. The brine rate would then be about 2,700 bbl/d per MW of power plant capacity. For a 500 MW plant, the process would require extracting and re-injecting 1.35 million bbl/d of brine. Figure 5.10 also illustrates...
an important trend for the surface dissolution process; much less brine is required when the mixing tank operates at higher pressures and lower temperatures.

For an average coal-fired power plant (500 MW), a brine flow rate of 1 to 2 million bbl/d would be required, depending on brine salinity. Flow rates of this magnitude are large but not beyond current technology or experience. A large power plant using once-through cooling uses several million barrels of water a day (Feeley et al., 2005). This once-through cooling water is much lower salinity than brines sourced from deeper aquifers that would be employed in surface dissolution. Thus surface dissolution could be implemented at a plant even if it were presently constrained by availability of fresh water. As another point of reference, the municipal water requirements for a city of ¼ to ½ million inhabitants are comparable to these values (Nicot, 2004).

5.3.4 Power Consumption

![Diagram](image)

Figure 5.11: Points A-D in this simple schematic are used as references in Eqs. 5-7 through 5-11. The z-terms are depths.
Power must be supplied to three stations to estimate the power consumption for the surface dissolution process: submersible pumps to lift the brine, surface pumps which bring the brine to mixing pressure and/or injection pressure (since the mixing will occur close to the injection site), and compressors for the captured CO₂ near the capture facilities. In Fig. 5.11, the nomenclature for the subsequent calculations is outlined. Steady-state single phase flow is assumed in the aquifer.

First, the power required to lift the brine can be calculated by the mechanical energy equation,

\[
\dot{W}_{\text{extraction}} = \frac{\dot{m}_{\text{brine}}}{\eta_{\text{pump}}} \left( p_B - p_A + g(z_A - z_B) + \frac{\Delta p_{\text{friction}}}{\rho_{\text{brine}}} \right) \quad (5-7)
\]

Assuming \( z_B = 0 \) ft, the bottomhole pressure \( p_A \) can be expressed as \( p_A = p_B + \rho_{\text{brine}} g z_A - \Delta p_{\text{drawdown}} \). The \( \Delta p_{\text{drawdown}} \) is the extraction well bottomhole pressure differential relative to the initial (and far-field) aquifer pressure, \( p_{\text{aquifer}} - p_A \). Assuming the aquifer pressure is hydrostatic, Eq. 5-7 simplifies to,

\[
\dot{W}_{\text{extraction}} = q_{\text{brine, pump}} \left( \frac{\Delta p_{\text{drawdown}} + \Delta p_{\text{friction}}}{\eta_{\text{pump}}} \right) \quad (5-8)
\]

In the calculations below, a pump efficiency (\( \eta_{\text{pump}} \)) of 80% and friction loss (\( \Delta p_{\text{friction}} \)) of 85 psi in a 6 inch well are assumed.

The bottomhole pressure in the injection well can be expressed conveniently in terms of the hydrostatic head and the differential between wellbore and aquifer: \( p_D = \rho_{\text{brine}} g z_D + \Delta p_{\text{injection}} \). Friction losses in the injection well tubing are assumed to be the same as in the extraction well. Neglecting the small difference between the densities of CO₂-saturated brine and native brine and assuming for convenience that \( z_D = z_A \) and \( z_B = z_C \), the power for injection can be calculated,
Equation 5-9 includes the power needed to pump the brine from the extraction wellhead at pressure $p_B$ into the mixing tank at $p_{C,MIXING}$. Friction losses in the surface equipment are neglected, and the mixing tank pressure is thus the same as the injection wellhead pressure. Because $p_B$ is assumed to be one atmosphere, Eq. 5-9 simplifies to,

$$\dot{W}_{injection} = \frac{\dot{m}_{brine}}{\eta_{pump}} \left( \frac{P_B - P_D}{\rho_{brine}} + g(z_B - z_D) + \frac{\Delta p_{friction}}{\rho_{brine}} \right)$$  \hspace{1cm} 5-9$$

where the pump efficiency and friction losses are the same as stated for extraction.

It is instructive to express the power consumption in terms of the mixing tank pressure. The mechanical energy equation between $z_C$ and $z_D$ which reduces to

$$\left( \frac{P_D - P_{C,MIXING}}{\rho_{brine}} + g(z_B - z_D) + \frac{\Delta p_{friction}}{\rho_{brine}} \right) = 0$$  \hspace{1cm} 5-11$$

since no power is supplied between $z_C$ and $z_D$. Solving for $p_{C,MIXING}$ yields assuming $z_C = 0$ ft,

$$p_{C,MIXING} = \left( \Delta p_{injection} + \Delta p_{friction} \right)$$  \hspace{1cm} 5-12$$

This makes sense as the injection pressure ($p_{C,MIXING}$) is expected to be the pressure needed to overcome friction losses and to sustain continuous injection. Inserting Eq. 5-12 into Eq. 5-10 yields,

$$\dot{W}_{injection} = \frac{q_{brine,ppm} \times p_{C,MIXING}}{\eta_{pump}}$$  \hspace{1cm} 5-13$$

The subscript “ppm” indicates that the brine flow rate is a function of salinity which for the ensuing calculation is 20,000 ppm. As a check, Eq. 5-13 corresponds to the mechanical energy balance between points B and C, as it should.
If the aquifer’s petrophysical properties are the same at \( z_A \) and \( z_D \), the \( \Delta p_{\text{injection}} \) and \( \Delta p_{\text{drawdown}} \) should be the same. Hence, the power needed to move the brine through our process is,

\[
\dot{W}_{\text{brine, ppm}} = \dot{W}_{\text{injection}} + \dot{W}_{\text{extraction}} = 2\dot{W}_{\text{injection}} \tag{5-14}
\]

which is the brine pumping curve shown in Fig. 5.11 for the 20,000 ppm brine and an 85°F mixing tank temperature.

![Figure 5.12: Expressed as a percentage of power plant capacity, the brine pumping part of the surface dissolution process, Eqs. 5-13 and 5-14, will require 6% to 8% of the power plant output for the mixing pressure range of 300 to 1,000 psia.](image)

In order to mix CO₂ and brine, the CO₂ will be injected into the mixing tank. This should be done at the minimum necessary line pressure (see Fig. 5.2). Any additional pressure above the mixing pressure from the pipeline will be dissipated in the tank as long as the minimum line pressure is above the mixing pressure. From Fig. 5.2, the power required for polytropic compression to minimum line pressure is 7% of the power plant output. The power required to operate the surface dissolution process is 7% of the power output.
plant for the CO₂ compression (Fig. 5.2) and 6% to 8% to move the brine (Fig. 5.11). This result is shown in Fig. 5.13 again for the 20,000 ppm case.

Figure 5.13 Expressed as a percentage of power plant capacity, the surface dissolution process will require 7% for CO₂ compression and 6% to 8% for brine lifting and injection for a total of 13% to 15% of the total power plant capacity. Recall that the standard approach requires only 9%.

The power required for the dissolution process for the 20,000 ppm and 85°F case is 13%-15% of the power plant output which is greater than the 9% of power plant capacity required by the standard approach. Sensitivity to temperature, salinity, and other parameters will be discussed later.

5.3.5 Capital Costs

Additional major facilities required for the mixing process are pumps, injection wells, and mixing tanks. Additional pumping units were valued at $900,000/MW of power consumed similar to estimates of Fisher et al. (2005) for compressors. The “Pumps” curve in Fig. 5.14 follows the same trend of power consumption curves from Fig. 5.11.
Figure 5.14: As additional facilities will be required for the dissolution process, the capital for those facilities must be estimated. For the 20,000 ppm and 85°F case, we estimate capital costs for additional brine pumping units, additional wells, and mixing tanks to allow four minutes of residence time prior to injection. The injection wells are the largest part of the additional capital cost.

Injection or extraction wells are expected to handle 35,000 bbl/d based on largest submersible pumps available in artificial lift guide by Brown (1980). The maximum efficiency for these down-hole pumps is 80% at a rate of 35,000 bbl/d. The cost for the wells is estimated to be $1,000,000 each for the P50 case. The P10 and P90 cases are estimated at ±$500,000. The number of wells required is proportional to $q_{brine}$. In Fig. 5.14, the trend of the “Wells” capital costs curve mimics the brine flow rate curve from Fig. 5.10.

The mixing tank costs are related to the pressure of the tank, the flow rate of brine, and the residence time, which for purposes of illustration is assumed to be four minutes. Parameters and equations used to produce the mixing tank curves are found in Table 5-5. Summing the additional facility curves in Fig 5.14 yields the additional capital
for surface dissolution process in Fig. 5.15. Increasing the mixing pressure reduces the capital required. Additional capital costs, expressed as a function of mixing pressure in Fig. 5.15, exhibit a minimum in the range of 800 – 1000 psia. Higher pressures lead to higher pump and tank construction costs. At lower pressure, the required brine flow rate increases and, thus, the number of wells needed increases.

Table 5-5—Properties and Equations to Estimate Mixing Tank Costs

<table>
<thead>
<tr>
<th>Property</th>
<th>Relationship and/or Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hoop Stress</td>
<td>( \sigma_{\text{yield}} = \frac{p_{c,\text{MIXING}}rF_S}{T} = 30,000 \text{ psi} )</td>
</tr>
<tr>
<td>Volume of Tank</td>
<td>( \pi r^2 h = (q_{\text{brine}} + q_{\text{CO}_2})T )</td>
</tr>
<tr>
<td>Price of Tank</td>
<td>$0.60/lb \times 0.28 \text{ lb/in}^3 \times 2\pi r TL</td>
</tr>
<tr>
<td>Factor of Safety, ( F_S )</td>
<td>3.0</td>
</tr>
<tr>
<td>Tank Radius, ( r )</td>
<td>2 ft</td>
</tr>
<tr>
<td>Residence Time, ( t_r )</td>
<td>4 minutes</td>
</tr>
</tbody>
</table>

Figure 5.15: The capital costs for the surface dissolution strategy are the sum of the additional facilities curves from Fig. 5.14 for 20,000 ppm and 85°F. Increasing the mixing tank pressure reduces the well count but increases the pump and mixing tank costs. This tradeoff leads to the minimum at between 800-1000 psia.
Monitoring, Remediation, and Liability

Estimates for the standard approach from IEA GHG (2007) were used as starting point for very rough estimates of monitoring, remediation, and liability. Less monitoring and remediation practices will be required for the surface dissolution approach compared to the standard approach because of elimination of buoyant movement. Using Table 5-2 as a format, the comparison monitoring and remediation costs for surface dissolution were estimated (see Table 5-6).

<table>
<thead>
<tr>
<th>Activity</th>
<th>Mid-Range Costs (millions)</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>A. Basic Costs</td>
<td></td>
<td></td>
</tr>
<tr>
<td>1. Site Selection and Project Design</td>
<td>$6.0</td>
<td>Site selection costs and no monitoring wells necessary</td>
</tr>
<tr>
<td>2. Monitoring and Leak Detection</td>
<td>$12.5</td>
<td>For demonstration, assumed 20% of standard approach</td>
</tr>
<tr>
<td>3. Wellbore Integrity</td>
<td>$3.0</td>
<td>For demonstration, assumed 20% of standard approach</td>
</tr>
<tr>
<td><strong>Sub-Total</strong></td>
<td><strong>$21.5</strong></td>
<td></td>
</tr>
<tr>
<td>B. Remediation Costs (If Needed)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>1. Locating Sources of Leaks</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Old, Abandoned Wells</td>
<td>$1.0</td>
<td>Assumes 10 leaking, abandoned well surveys, same as standard</td>
</tr>
<tr>
<td>• New Injection Wells</td>
<td>$4.0</td>
<td>Assumes 4 new wells</td>
</tr>
<tr>
<td>• Caprock/Spill Point</td>
<td>$0.0</td>
<td>Not necessary</td>
</tr>
<tr>
<td>2. Well Plugging</td>
<td>$1.0</td>
<td>Includes plugging of 20 old wells, same as standard</td>
</tr>
<tr>
<td>3. Well Remediation</td>
<td>$3.5</td>
<td>Includes 10 well remediations</td>
</tr>
<tr>
<td>4. Caprock Leakage</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Pressure Boundary</td>
<td>$0.0</td>
<td>Not necessary</td>
</tr>
<tr>
<td>• Other Problems</td>
<td></td>
<td>Small</td>
</tr>
<tr>
<td><strong>Sub-Total</strong></td>
<td><strong>$8.5</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$30.0</strong></td>
<td></td>
</tr>
</tbody>
</table>

For the surface dissolution approach, basic monitoring activities like monitoring wells were eliminated. Other monitoring necessities were limited to 20% of the standard approach based on the assumption that monitoring costs would be dramatically reduced. The means for estimating monitoring and remediation more accurately for the surface
dissolution approach are beyond the scope of this study and would not change conclusions much.

Summary of Operational and Capital Costs: Surface Dissolution

The operational and capital costs for the surface dissolution approach to carbon sequestration in saline aquifers are summarized (see Table 5-7). If the liability costs are driven by buoyant leakage concerns, the liability costs would zero. The operational costs in terms of the power plant are 43-46% of the power output, and the capital costs are approximately $750,000-$900,000 per MW of power plant. For a 500 MW power plant, 215-230 MW would be used to run the capture and compression process, and $375-$450 million would be needed for capital.

<table>
<thead>
<tr>
<th>Process</th>
<th>Operational (%)</th>
<th>Capitalb (thousands per MW of Power Plant Capacity)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Overhead</td>
<td>N/A</td>
<td>$160</td>
</tr>
<tr>
<td>Capture</td>
<td>30%</td>
<td>$234</td>
</tr>
<tr>
<td>CO₂ Compression</td>
<td>7%</td>
<td>$60</td>
</tr>
<tr>
<td>Transport</td>
<td>Site Specific</td>
<td>Site Specific</td>
</tr>
<tr>
<td>Well Site</td>
<td>N/A</td>
<td>$150-$350</td>
</tr>
<tr>
<td>- Wells</td>
<td>N/A</td>
<td>$150-$350</td>
</tr>
<tr>
<td>- Water Pumping</td>
<td>6-9%</td>
<td>$50-$80</td>
</tr>
<tr>
<td>- Mixing Tank</td>
<td>N/A</td>
<td>$20-$30</td>
</tr>
<tr>
<td>Liability</td>
<td>$0</td>
<td>$0</td>
</tr>
<tr>
<td>Monitoring</td>
<td>N/A</td>
<td>$21.5</td>
</tr>
<tr>
<td>Remediation</td>
<td>N/A</td>
<td>$8</td>
</tr>
<tr>
<td><strong>Totals</strong></td>
<td>43-46%</td>
<td>~$750-$900</td>
</tr>
</tbody>
</table>

a % of Total Power Plant Capacity
b thousands per MW of Power Plant Capacity
TBD = to be determined
N/A = not applicable
5.4. SIMPLIFIED RESERVOIR MODEL

Derivations from streamline equations provide the basis for a method to establish geologic constraints for the surface dissolution approach. Large injection and extraction rates will require large intervals, high permeabilities, reasonable pressure drops ($\Delta p_{\text{drawdown}}$ or $\Delta p_{\text{injection}}$), or some combination of all three. If a line-drive configuration of Fig. 5.16 is assumed, well spacing is important. If the injection line is too close to the extraction line (referred to as injector/extractor spacing), early breakthrough will result, but injectivity will be high. If the injector/injector (or equivalently extractor/extractor) spacing is too close, the wells will interfere and lose injectivity. Also, the path swept between the injector and extractor will result in early breakthrough. For the purpose of balancing these criteria, the constraints for a homogeneous reservoir are developed.

5.4.1 Well Spacing

*Line Sink/Source Solution*

Ensuring that breakthrough is not too soon and that injectivity is met can be accomplished by strategically placing the wells. Starting with Darcy’s Law and the Laplace equation, the line sink/source solution can be derived. The Laplace equation in radial coordinates is:

$$\frac{\partial}{\partial r} \left( r \frac{\partial \Phi}{\partial r} \right) = 0$$  

(5-15)

where $r$ is radius and $\Phi$ is potential.

Assuming homogeneous medium, constant properties of the fluid and the rock, and steady-state flow, Eq. 5-15 can be integrated to yield,

$$\Phi = C_1 \ln r + C_2$$  

(5-16)

At two locations, Eq. 5-16 is:
\[ \Phi_1 = C_1 \ln r_1 + C_2 \quad (5-17) \]

\[ \Phi_2 = C_1 \ln r_2 + C_2 \quad (5-18) \]

Subtracting Eq. 5-18 from Eq. 5-17 and solving for \( C_1 \) yields:

\[ C_1 = \frac{\Phi_2 - \Phi_1}{\ln \frac{r_2}{r_1}} \quad (5-19) \]

Replacing it in Eq. 5-16:

\[ \Phi = \frac{\Phi_2 - \Phi_1}{\ln \frac{r_2}{r_1}} \ln r + C_2 \quad (5-20) \]

Assuming wells are at location 1 and 2, Darcy’s Law for radial flow between these two locations:

\[ q = \frac{-2\pi k h \Phi_2 - \Phi_1}{\mu} \ln \frac{r_2}{r_1} \quad (5-21) \]

Combining Eqs. 5-20 and 5-21 yields the line source and line sink equation for a single well:

\[ \Phi = \frac{-q \mu}{2\pi k h} \ln r + C_2 \quad (5-22) \]

Changing coordinate systems to Cartesian yields the following after pulling out a \( \frac{1}{2} \) inside the parentheses:

\[ \Phi = \frac{-q \mu}{4\pi k h} \ln \left( x^2 + y^2 \right) + C_2 \quad (5-23) \]

If the well is located at \((x_o, y_o)\), the equation becomes:

\[ \Phi = \frac{-q \mu}{4\pi k h} \ln \left( (x - x_o)^2 + (y - y_o)^2 \right) + C_2 \quad (5-24) \]

The velocity of a streamline can be obtained from Darcy’s Law in the x direction:
\[\nu_x = \frac{\mu_x}{\phi} = -\frac{k}{\mu} \frac{\partial \Phi}{\partial x}\]  
\hspace{2cm} (5-25)

Taking the derivative of Eq. 5-24:

\[\frac{\partial \Phi}{\partial x} = \frac{-q \mu}{4\pi kh} \frac{2(x - x_o)}{(x - x_o)^2 + (y - y_o)^2}\]  
\hspace{2cm} (5-26)

Combining Eqs. 5-24 and 5-25 gives the velocity in the x direction at any point:

\[\nu_x = \frac{q}{4\pi h \phi} \frac{2(x - x_o)}{(x - x_o)^2 + (y - y_o)^2}\]  
\hspace{2cm} (5-27)

Because the Laplace equation is a linear partial differential equation, the principle of superposition for wells at locations \((x_i, y_i)\) flowing at rate \(q_i\) applies to the solution:

\[\Phi = \frac{-\mu}{4\pi kh} \sum q_i \ln \left((x - x_i)^2 + (y - y_i)^2\right) + C_2\]  
\hspace{2cm} (5-28)

and the derivative of the solution:

\[\nu_x = \frac{1}{4\pi h \phi} \sum q_i \frac{2(x - x_i)}{(x - x_i)^2 + (y - y_i)^2}\]  
\hspace{2cm} (5-29)

**Line-Drive Configuration**

The simple situation envisioned for the injection is a line-drive as shown in Fig. 5.16. Because the flow rate \(q\) is the same for every well, the potential equation for our field will look as follows:

\[\Phi = \frac{-q \mu}{4\pi kh} \left[\ln \left(x^2 + y^2\right) - \ln \left((x - D)^2 + y^2\right)\right] + \sum_{i=1}^{n} \ln \left(x^2 + (y - iH)^2\right) - \sum_{i=1}^{n} \ln \left((x - D)^2 + (y - iH)^2\right) + C_2\]  
\hspace{2cm} (5-30)
where the top line is for the wells on the x-axis, and the middle line is for wells above the
x-axis, and the bottom line is for wells below the x-axis. The letter $n$ is related to the well
pairs by:

$$W_p = 2n + 1$$ \hspace{1cm} (5-31)

or the well count by:

$$W_c = 4n + 2$$ \hspace{1cm} (5-32)
Figure 5.16: The line-drive scenario has injectors on the left and extraction wells on the right. The distance between injector/injector or extractor/extractor is specified by variable $H$ and the distance between injector/extractor pairs is $D$. The well pairs do not go to infinity in both direction but are assume symmetric above and below the $x$-axis. In this case, the streamline that will break through first will be the streamline following the $x$-axis.
By taking the derivative, velocity can also be obtained:

\[ v_x = \frac{q}{4\pi h\phi} \left[ \frac{2x}{x^2 + y^2} - \frac{2(x - D)}{(x - D)^2 + y^2} + \sum_{i=1}^{n} \frac{2x}{x^2 + (y - iH)^2} - \sum_{i=1}^{n} \frac{2(x - D)}{(x - D)^2 + (y - iH)^2} \right] \]  \hspace{1cm} (5-33)

On the x-axis streamline, \( y = 0 \), and Eq. 5-33 simplifies to:

\[ v_x = \frac{q}{4\pi h\phi} \left[ \frac{2}{x} - \frac{2}{(x - D)} + \sum_{i=1}^{n} \frac{2x}{x^2 + (iH)^2} - \sum_{i=1}^{n} \frac{2(x - D)}{(x - D)^2 + (iH)^2} \right] \]  \hspace{1cm} (5-34)

To save space, the following is written,

\[ g(x, D, H) = \left[ \frac{2}{x} - \frac{2}{(x - D)} + \sum_{i=1}^{n} \frac{2x}{x^2 + (iH)^2} - \sum_{i=1}^{n} \frac{2(x - D)}{(x - D)^2 + (iH)^2} \right] \]  \hspace{1cm} (5-35)

Equation 5-34 can also be written as the derivative of position

\[ v_x = \frac{g(x, D, H)q}{4\pi h\phi} = \frac{dx}{dt} \]  \hspace{1cm} (5-36)

Separation and integration along the x-axis streamline can be performed from time zero to the breakthrough time, \( T \), and from the injector to extractor, zero to \( D \).

\[ T = \int_0^T dt = \frac{4\pi h\phi}{q} \int_0^p \frac{1}{g(x, D, H)} dx \]  \hspace{1cm} (5-37)
An analytical solution could not be found with $D$ in the function in the integral and as a limit to the integral. Because of this, a numerical method was employed to solve the integral. The solution for several formation thickness intervals ($h$) are shown in Fig 5.17.

**Figure 5.17:** Well spacing (in both acres and feet units) for different values of formation thickness. Each line is a solution to Eq. 5-37 when $T$ is 30 years for different $h$. The porosity is 13% and the flow rate is 35,000 bbl/d-well.
The original intent was to find the correct spacing so that breakthrough would occur at a specified breakthrough time. For example shown in Fig. 5.17, the breakthrough time is set as 30 years, the porosity as 13%, and the flow rate as 35,000 bbl/d per well. In our code (see Appendix), an $H$ is selected and then a $D$ is solved for. The code then moved to the next $H$ and solved for the next $D$. The curves of $D$ vs. $H$ were generated for different thickness intervals. 13 well pair (26 wells) were used, in other words, $n = 6$.

If there is no dip in the formation, the potential at a distance far from the well is the initial reservoir pressure, $p_i$, and all potential are now pressures:

$$\Phi_{x=\infty} = C_2 = p_i$$

(5-38)

The pressure at both wells on the x-axis are shown, the only difference is a sign change:

$$\Phi_{x=0} = \frac{-q \mu}{4\pi kh} \left[ -\ln(D^2) + \sum_{i=1}^{n} \ln((iH)^2) - \sum_{i=1}^{n} \ln\left(D^2 + (iH)^2\right) \right] + p_i$$

(5-39)

$$\Phi_{x=D} = \frac{-q \mu}{4\pi kh} \left[ \ln(D^2) + \sum_{i=1}^{n} \ln\left(D^2 + (iH)^2\right) - \sum_{i=1}^{n} \ln((iH)^2) \right] + p_i$$

(5-40)

So the pressure (or potential) at $x = 0$ on the x-axis is $\Delta p_{injection}$ and the pressure at $x = D$ is $\Delta p_{drawdown}$. $\Delta p_{injection}$ must be equal to $\Delta p_{drawdown}$ if the flow rate is to stay constant. Subtracting Eqs. 5-40 from 5-39 yields the following:

$$2\Delta p = \frac{-q \mu}{2\pi kh} \left[ -\ln(D^2) + \sum_{i=1}^{n} 2\ln((iH)^2) - \sum_{i=1}^{n} 2\ln\left(D^2 + (iH)^2\right) \right]$$

(5-41)
Solving for \( k \) yields,

\[
k = \frac{-q \mu}{4 \pi h \Delta \rho} \left[ -\ln\left( D^2 \right) + \sum_{i=1}^{n} 2 \ln\left( (iH)^2 \right) - \sum_{i=1}^{n} 2 \ln\left( D^2 + (iH)^2 \right) \right]
\]

(5-42)

For the 1,000 ft interval, \( \Delta \rho \) of 1,000 psi, \( \mu \) of 0.77 cp, 13% porosity, \( q \) of 35,000 bbl/d, and \( n \) equal to 6, the solution Eq. 5-42 is shown in Fig. 5.18.

Figure 5.18: The injector/injector spacing (or \( H \)) is shown on the x-axis. The injector/extractor spacing (or \( D \)) is shown on the y-axis. The contours are permeability in millidarcy (md). The curve labeled 1,000 ft is the solution to Eq. 5-37, also shown in Fig. 5.17, for a formation thickness of 1,000 ft. The intersection of the curve and the permeability contour determine the well spacing (\( D, H \)) for a period where 30 years are expected before breakthrough. The assumed values of the other parameters are for 1,000 psi (drawdown and injection), 35,000 bbl/d-well, and 13% porosity.

A CMG simulation of the same system was run to confirm well spacing calculations. The CMG simulations are not shown in detail here, but the code is provided for independent validation (see appendix). These simulations agree on the well spacing
curve Fig. 5.17, but not on the permeability. Fig 5.18 suggests that for 1,000 ft the permeability would have to be above 100md. The CMG simulation predicted the minimum permeability of about 20md. Based on a few simulations, Fig. 5.19 shows CMG prediction using the same plot style as Fig. 5.18 and the same trends as dictated by Eq. 5-42.

Figure 5.19: Similar to Fig 5.18, the injector/injector spacing (or $H$) is shown on the x-axis. The injector/extractor spacing (or $D$) is shown on the y-axis. The contours in the middle are permeability in millidarcy (md). The curve labeled 1,000 ft is the solution to Eq. 5-37, also shown in Fig. 5.17, for a formation thickness of 1,000 ft. The intersection of the curve and the permeability contour determine the well spacing ($D, H$) for a period where 30 years are expected before breakthrough. The same parameters from Fig. 5.18 are used. This plot is based on CMG simulation solutions to determine the values of permeability contours, while preserving the form obtained from Eq. 5-42.

5.4.2 Regional Groundwater Movement

One item of key concern is the movement of regional groundwater during bulk-phase CO$_2$ injection. Similar to Eq. 5-4 which defined the mole fraction, the mass fraction, $w_{CO_2}$, is defined as follows:
where $m_{w_{CO2}}$ is 44 lb/lbmol and $m_{w_{H2O}}$ is 18 lb/lbmol. The comparison for the mass and mole fraction is shown in Table 5-8. Notice that the mass fraction of CO$_2$ in solution is more than the mole fraction. Because injecting saturated brine means injecting more mass and because the density of brine saturated CO$_2$ is slightly more than the density of the native brine (Kumar, 2005), 3.7% to 5.4% more volume will be injected than was removed during the extraction for the surface dissolution process.

<table>
<thead>
<tr>
<th>Units</th>
<th>Fraction of CO$_2$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Moles ($x_{CO2}$)</td>
<td>0.015 to 0.022</td>
</tr>
<tr>
<td>Mass ($w_{CO2}$)</td>
<td>0.037 to 0.054</td>
</tr>
</tbody>
</table>

This is important when compared to the standard approach. The volume change in the subsurface during the surface dissolution process ($\Delta V_{SD}$) is the volume injected ($V_{inj}$) minus volume extracted ($V_{ext}$) or:

$$\Delta V_{SD} = V_{inj} - V_{ext} = \frac{m_{CO2}}{w_{CO2} \rho_{brine}} - \frac{m_{CO2}}{w_{CO2} \rho_{brine}} (1 - w_{CO2}) = \frac{m_{CO2}}{w_{brine} \rho_{brine}}$$

(5-44)

The volume change in the subsurface during the standard approach ($\Delta V_{SA}$) is just the volume of CO$_2$ injected at reservoir conditions:

$$\Delta V_{SA} = V_{inj} - V_{ext} = \frac{m_{CO2}}{\rho_{CO2, reservoir}}$$

(5-45)

Because the density of bulk phase CO$_2$ at reservoir conditions is less than the density of brine, the ratio of displaced volumes is therefore:

$$\frac{\Delta V_{SD}}{\Delta V_{SA}} = \frac{\rho_{CO2, reservoir}}{\rho_{brine}} \approx 0.7$$

(5-46)
Thus, the regional groundwater movement from the surface dissolution process is reduced by ~30% over the standard approach. The additional volume was not considered in the streamline calculations.

5.5. **TECHNICAL FEASIBILITY**

5.5.1 **Geologic Target Requirements**

The well spacing evaluated above was based upon the following assumptions and need to be verified for other properties than those shown: per well rate of 35,000 bbl/d per well, 13% porosity, 30 years of injection, 1,000 psi injection and drawdown. From Fig. 5.19, the minimum permeability for a 1,000 ft interval is approximately 20 md. The maximum permeability could be higher than the values shown if the injection and drawdown pressure were reduced. High permeability should not be a constraint but an advantage.

The minimum thickness was 200 ft. A minimum permeability for that thickness should be around 200-250 md, but as Fig 5.17 shows, the well spacing is much greater.

5.5.2 **Process Modeling and Optimization Challenges**

Several key aspects of the surface dissolution process can be quantified only roughly with available information. One of the most important challenges is to determine the time required to dissolve the CO₂. Because of the large flow rates, it is desirable to achieve dissolution in a few minutes or less. Otherwise, the volume of the mixing tank(s) would become very large. A four minute residence time implies a tank volume of 25,000 to 50,000 ft³ for a 500 MW coal-fired power plant. It is not known whether special mixing tank design would be required to provide the necessary mingling of the two phases. Measurements of a static CO₂/brine system (Hangx, 2005) suggest that 90% dissolution can occur in 12 minutes when the pressure is increased from 330 to 580 psia.
(see Fig. 5.5). This time could presumably be shortened by increasing the surface area between the two fluids. Measurements on a steady-state CO$_2$/brine mixing process at large flow rates were not found in the literature search.

Another important challenge is optimizing the operating temperature of the mixing tank. This has a strong effect on solubility and thus on brine requirements, as shown in Fig. 5.8 and 5.10. The mixing temperature is expected to be bounded by the initial aquifer temperature and the ambient temperature. Heat transfer for the brine and CO$_2$ depends on the pipeline and adjacent environment. The mixing process could be exothermic further adding to the temperature uncertainty. For the previous calculations, the mixing temperature was assumed to be 85°F, slightly lower than the expected aquifer temperature of 91°F.

5.5.3 Technical Challenges

**Sweep in the Reservoir**

In addition to the modeling uncertainty, challenges for surface dissolution are similar to those seen in the oilfield. First, the strategy for injecting such a large volume of water over such an extended period of time can be compared to waterflooding. Sweep efficiency, channeling, and early breakthrough are key concerns for waterflooding projects. When injecting CO$_2$-saturated brine, similar challenges are expected though without the complications that accompany multiphase flow. A line-drive well pattern allows some flexibility with injection/extraction rate adjustment to make the displacement as uniform as possible. As in some enhanced oil recovery processes, hydrodynamic dispersion will be an important property. The arrival of diluted injected brine at an extraction well marks the beginning of CO$_2$ recycling, which defeats the purpose of a storage process.
**Carbonic Acid**

When CO₂ is dissolved in water, carbonic acid is formed. Carbonic acid can be corrosive to piping, valves, seals, and O-rings, so design precautions for surface equipment and injection wells will be necessary. The cost of corrosion-resistant metallurgy was not included in the capital costs. Roughly it would double the injection well costs. Precipitation of minerals in high salinity solutions can occur due to the introduction of new ions and the effect of carbonic acid on the pH of the solution. Mineral precipitation in the mixing tanks, wellbore, or near-wellbore region of the formation might alter the injectivity.

**Sensitivity Studies**

Several key parameters were studied to determine the sensitivity of capital cost and power consumption to reasonable perturbations of these parameters (see Figs. 5.20 and 5.21). The parameters of interest are: temperature in the mixing tank, salinity of the brine, error in the EOS, well costs, and injection/extraction flow rate. The influence of each parameter on uncertainty will be discussed individually.

First, error in mixing tank temperature of ±10°F is reasonable. Changing the temperature changes the solubility and flow rate prediction. The flow rate prediction affects the energy consumption and capital costs.

Next for the EOS, the error reported by Hangx (2005) was on average 7% between the Duan EOS and the measured data. This changes the flow rate, power consumption, and capital costs.

For salinity uncertainty, error of ±20,000ppm is assumed to be reasonable. This change in salinity again changes the flow rate, the capital costs, and energy consumption.
Well design estimates for the injection and extraction wells for depths less than 4,000 ft came out to be $1,000,000 per well and ±$500,000 for the P10 and P90 cases. Error in well costs directly changes the capital costs.

Last, assuming injection rate uncertainty could be ±5,000 bbl/d-well. Changing the per well rate changes the well count which affects the capital costs.

Using the developed model, sensitivities were observed by perturbing each of the described parameters from the base values: 85°F in the mixing tank, 20,000 ppm salinity for the native brine, prediction of solubility using the Duan EOS, 35,000 bbl/d-well, and $1,000,000 per well. The results are shown in Figs. 5.20 and 5.21.

**Figure 5.20:** The range of operating costs for the base case is 43% to 46% (see Table 5-7) for the range of mixing pressures from 300 to 1,000 psi (see Fig. 5.11). Changes to salinity, temperature, and the EOS are less than 1% away from the base case. Therefore, the sensitivity of the power consumption to these changes is small.
Figure 5.21: The range of capital costs for the base case is $750,000 to $900,000 per MW of power plant (see Table 5-7) for the range of mixing pressures from 300 to 1,000psi (see Fig. 5.10). Adjusting one parameter from the base case changes the high and low case differently. Flow rate, temperature, salinity, and the EOS do not change the capital costs more the $50,000/MW on either end. The capital costs, however, show strong sensitivity to well costs.

5.6. FINANCIAL COMPARISON

Based on the estimates presented in Tables 5-4 and 5-7, surface dissolution has higher operating costs than the standard approach by 4-7 percentage points of power plant output or increase of 10% to 18% over the standard approach (see Table 5-9).

<table>
<thead>
<tr>
<th>Process</th>
<th>Standard Approach*</th>
<th>Surface Dissolution*</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capture</td>
<td>30%</td>
<td>30%</td>
</tr>
<tr>
<td>CO₂ Compression</td>
<td>8%</td>
<td>7%</td>
</tr>
<tr>
<td>Well Site (Compression and Pumping)</td>
<td>1%</td>
<td>6-9%</td>
</tr>
<tr>
<td>Totals</td>
<td>39%</td>
<td>43-46%</td>
</tr>
</tbody>
</table>

* % of Total Power Plant Capacity
Surface dissolution has higher capital costs than the standard approach by $150,000-$300,000 per MW of power plant or an additional 25% to 50% (from Tables 5-4 and 5-7 to create Table 5-10).

![Table 5-10— Comparison of Capital Costs of the Standard Approach vs. the Surface Dissolution Approach](image)

<table>
<thead>
<tr>
<th>Process</th>
<th>Standard Approach</th>
<th>Surface Dissolution</th>
</tr>
</thead>
<tbody>
<tr>
<td>Overhead</td>
<td>$160</td>
<td>$160</td>
</tr>
<tr>
<td>Capture</td>
<td>$234</td>
<td>$234</td>
</tr>
<tr>
<td>CO₂ Compression</td>
<td>$66</td>
<td>$60</td>
</tr>
<tr>
<td>Well Site</td>
<td>$28</td>
<td>$260-$425</td>
</tr>
<tr>
<td>Monitoring</td>
<td>$95.5</td>
<td>$21.5</td>
</tr>
<tr>
<td>Remediation and Liability</td>
<td>$28.5</td>
<td>$8</td>
</tr>
<tr>
<td><strong>Totals</strong></td>
<td>~$600</td>
<td>~$750-$900</td>
</tr>
</tbody>
</table>

b thousands per MW of Power Plant Capacity

5.6.1 Price per tonne CO₂ Comparison

Ultimately, greenhouse gas mitigation will require a market value for carbon, a price per tonne CO₂. The capital and operating cost should be converted to those units to compare CCS with market value. Two estimates of the cost per tonne CO₂ are presented. The first is based on estimates from Rochelle (2007). The second is based on what would be required only for financing (loans for the capital) and the cost to produce the electricity. An emission of 8,000 t-CO₂ per MW per year is assumed (term “Annual Emissions / MW” in Eqs. 5-47 and 5-48).

Estimates from Rochelle (2007) assume the lost power consumption will be valued at $100/MWh (term “$/MWh” in Eq. 5.47), and capital will be valued at $4/t-CO₂ for every $100,000/MW of power plant capital installed (term “$/t-CO₂ for $/MW capital” for Eq. 5.48).

For the second set of assumptions, according to Fisher et al. (2005) the cost to produce electricity from coal can vary, but $35/MWh (term “$/MWh” in Eq. 5.47) was used in his report as a typical estimate. The financing of the capital could be done on a
30-year loan with 8% interest rate. The yearly payback is $88/$1,000 borrowed for capture and sequestration capital (term “$/year for financing” in Eq. 5-48). That is the equivalent of $1.10/t-CO₂ for every $100,000/MW of power plant capital installed (term “$/t-CO₂ for $/MW capital” for Eq. 5.48.

The operation costs (OPEX) are found by:

$$\text{OPEX ($/t-CO₂)} = \frac{\text{(% of Power Plant Output) \times ($/MWh)}}{\text{Annual Emissions/MW}} \times 8760 \frac{\text{hr}}{\text{yr}}$$

5-47

The capital costs are found by:

$$\text{CAPEX ($/t-CO₂)} = \text{(Capital in $/MW of Power Plant) \times ($/t-CO₂ per $/MW-capital)}$$

5-48

The total costs are the addition of Eqs. 5-47 and 5-48:

$$\text{Total ($/t-CO₂)} = \text{CAPEX ($/t-CO₂)} + \text{OPEX ($/t-CO₂)}$$

5-49

The addition of the operational costs (OPEX) and the capital costs (CAPEX) equals the total cost (Total) for the standard approach (SA). For the surface dissolution approach (SD), the OPEX and CAPEX are evaluated at mixing pressures between 300 and 1000 psia and added together to get the total cost (Total). Fig. 5.22 is based on the assumptions of Rochelle (2007), and Fig. 5.23 is based on the second set of assumptions.
Figure 5.22: The costs shown are based upon Eqs. 5-47 through 5-49. For surface dissolution (SD), as the mixing pressure increases, the capital cost decreases and the energy costs increase for the surface dissolution process. The optimum for the surface dissolution process for assumptions of Rochelle (2007) is between 600-1,000 psi in the mixing tank. This optimum for the surface dissolution process is $79/t-CO₂ compared to $67/t-CO₂ for standard approach. This is an increase of 19% for surface dissolution.

Figure 5.23: The costs shown are based upon Eqs. 5-47 through 5-49. Again, as the mixing pressure increases, the capital cost decreases and the energy costs increase for the surface dissolution process. The optimum for the surface dissolution process assuming the $35/MWh of electricity and $1.10/t-CO₂ for $100,000/MW is between 600-1000 psi. The estimate of $25/t-CO₂ for surface dissolution compared to $22 for standard approach is an increase of 18% for surface dissolution for the second set of assumptions. The differences between this figure and Fig. 5.22 are the assumptions behind the operating and capital costs.
Based on the assumptions of Rochelle (2007), the cost per tonne of CO₂ for the standard approach is $67/t-CO₂ compared to $79/t-CO₂ for the surface dissolution approach between 600 and 1000 psia (see Fig. 5.22). Based on the second set of assumptions, the cost per tonne of CO₂ for the standard approach is $22/t-CO₂ compared to $25/t-CO₂ for the surface dissolution approach between 600 and 1000 psia (see Fig. 5.23).

Depending on the financial assumptions the surface dissolution approach will cost an additional 20% more in terms of $/t-CO₂. The estimates based on conversions from Rochelle (2007), which are probably better estimates, are $67/t-CO₂ for the standard approach and $79/t-CO₂ for the surface dissolution approach.

5.6.2 Summary Example Application

A 500 MW coal-fired power plant in the Mt. Simon formation of the Illinois Basin can be used to summarize the requirements for a surface dissolution capture and storage project. Using the properties from Table 5-3 and Fig. 5-18, the injector/injector spacing will be ~4,000 ft and the injector/extractor spacing will be ~5,000 ft to provide 30 years before breakthrough of the CO₂-saturated brine. The brine flow rate will be 1.35 million bbl/d, and the well count will be 76 (38 extractors and 38 injectors). The areal coverage would be approximately 50 square miles (which is the well count times the injector/injector spacing times injector/extractor spacing). At a 1000 psi injection pressure above hydrostatic (and similarly 1000 psi below hydrostatic for extraction pressure), the capital will be $375 million, and 46% of the power plant output will go to operate the surface dissolution process. Based on Rochelle (2007) estimates, the cost of CO₂ sequestered would be $79/t-CO₂.
5.7. CONCLUSION

The surface dissolution approach to geologic sequestration would appear to be feasible in brine aquifers at a wide range of depths. Estimates of costs per tonne of CO$_2$ sequestered showed that surface dissolution is $\sim$20% more costly than the standard approach, but far less than the 3 to 10 times cost for mineralization (Lackner, 2003). The surface dissolution strategy is safe and long-term, and as storage space in the subsurface becomes more marketable, it could be considered.

In considering the geologic targets, estimates of cost focused on aquifers $\sim$2,000 to 4,000 ft in depth. Because of high well densities in certain regions, standard approaches are expected to go as deep as economically feasible (Nicot et al., 2006). Faults and seal are not important concerns in long-term surface dissolution storage as buoyant migration has been eliminated. Surface dissolution ensures all subsurface flow is single phase, although the volume handling is considerably more than the standard approach. Surface dissolution is a strategy that maximizes safety by ensuring all CO$_2$ is dissolved in brine prior to injection thereby eliminating buoyant driven leakage risk. This eliminates risk to structural and human induced uncertainty in less attractive shallow aquifers.
CHAPTER 6: CONCLUSION AND FUTURE WORK

This research work was performed with the following objectives:

- review important topics and major issues related to climate change,
- address technical challenges of CO₂ bulk phase storage and injection,
- and introduce the surface dissolution approach to these challenges.

A comparison was made for the standard and surface dissolution approaches to saline aquifer sequestration using reasonable assumptions. Comparisons were made in monetary terms (operating costs, capital costs, and $/t-CO₂) and in technical and geologic feasibility terms. Surface dissolution eliminates the risk due to buoyant migration by ensuring all CO₂ sequestered is dissolved in the brine at surface facilities prior to injection. This alternative strategy is feasible in deep aquifers, like the standard approach, but is attractive in shallow aquifers (2,000 to 4,000 ft) which are less likely targets for the standard approach.

6.1. CONCLUSIONS

Several practical problems of carbon sequestration and related issues have been discussed. The following conclusions are made from this work:

Key Issues of Climate Change

1. Global warming is one of many critical elements in the debate for the future of energy and the environment. Surging energy demand and concerns about future energy supply are also important to this discussion because energy plays a central role in the quality of human life. The costs and benefits of mitigating carbon emissions, preventing climate changes, meeting energy demand and price
pressure, and human aspirations for quality of life must all be taken into account by individuals and organizations in the discussion of climate policies.

2. Analog situations like the Late Paleocene Thermal Maximum can be studied to better understand the timescale and amount of temperature increase associated with greenhouse gas increases.

3. Improvements to our understanding of the relationship between temperature and the drivers of the climate including the sun and human emissions should be studied and improved.

**Fault and Fluid Interaction**

1. Faults are an important challenge to bulk phase CO$_2$ storage as they could provide a highly permeable pathway to the surface. Currently, the tools do not exist to predict the sealing capability of a fault or a complete range of petrophysical properties in the fault region.

2. Seal or leak classification needs to include potential not only for across-fault flow but also for the breaching of overlying shales in clastic sequences. The shale gouge ratio is used in fault seal analysis to characterize across-fault sealing capacity and was applied by Dockrill (2005) to a leaking fault with reasonable results. This approach and tool is useful, and a similar approach might be used to determine the potential for overlying shales to breach.

3. Permeability parameters in the fault zone have been characterized and studied for the fault core in both shales and sandstones and for the damage zones of sandstones. The damage zones of shales are not well characterized nor were any studies found as to why they breach. Analysis of data from Eichhubl *et al.* (2005) revealed the capillary pressure and permeability weaknesses in the fault were in the host shale and not the shale smeared in the fault. These properties are needed
as they help answer the questions of how much buoyant CO₂ will leak and how long it will take buoyant CO₂ to reach the surface.

**Injectivity of Bulk Phase CO₂**

1. As multiphase flow is a challenge to bulk phase CO₂ injection, theory was developed to understand and describe the mechanisms and regions that will result in the aquifer. The theory was developed by using Darcy’s Law and a modified form of Buckley-Leverett theory and was applied on a homogeneous, 1D, radial brine reservoir with a constant pressure outer boundary.

2. Understanding the development of the drying front is a key to understanding injectivity. The drying front develops because CO₂ and H₂O are slightly soluble in the aqueous phase and CO₂-rich phase, respectively. This drying front occurs in addition to the classical Buckley-Leverett front. The ratio of the speeds of the two fronts is constant. As a consequence injectivity will increase monotonically with time. This trend agreed with reservoir simulations with full phase behavior.

3. Although the injectivity will increase with time independent of the relative permeability curves, the relative permeability curves strongly affect the absolute value of injectivity. The model was applied with relative permeability curves from seven formations from the Alberta Basin assuming that all the other parameters were the same. The differences due to relative permeability caused injection rate to vary by a factor of four. The parameters commonly used to characterize relative permeability curves (m, n, kᵣᵣ, and Sᵢₑ) were also varied, and the flow rate response varied by 20%. The conclusion reached is that quantifying the relative permeability curve is very important in determining achievable injection rate, and, therefore, the well count for CO₂ geologic sequestration projects
4. Salt precipitation can occur as the drying front passes during injection, and this can damage the permeability and, hence, the injectivity. Laboratory measurements of relative permeability could include measurements for a core dried by CO₂ injection from the state of residual saturation of the native brine to determine the effects of salt precipitation.

**Surface Dissolution**

1. The surface dissolution approach is presented because a tradeoff exists between security and cost. For example mineralization is substantially safer and significantly more expensive than the standard approach to geologic sequestration, and yet mineralization is considered as an option.

2. Surface dissolution is preferable at depths of 2,000 to 4,000 ft because of lower salinities and lower temperatures. This process is available at shallower than the 2,000 ft and deeper depths than the 4,000 ft, but the additional cost created in these situations was not explored in this research.

3. At both the aquifer and surface mixing tank conditions, a reasonable amount of CO₂ can be dissolved in brine: approximately 1.5 to 2.1% by mole or 3 to 5% by mass. Measurements have shown that dissolution can happen in a matter of minutes.

4. For surface dissolution, brine flow rates will be on the order of 2,000 to 4,000 bbl/d-MW of power plant which for a 500 MW coal-fired power plant is 1 million to 4 million bbl/d. For the sake of comparison, that amount of water is used by a large city (½ to 1 million people approximately), and is a fraction of the water used by a power plant for cooling. At 35,000 bbl/d each, 76 wells (injection and extraction) will circulate the 1.35 million barrels of brine for the 500 MW case of interest in Chapter 5.
5. More energy (~10-18%) will be required by surface dissolution approach over the standard approach. The energy requirements considered were capture (30%), CO₂ compression (7%), and brine extraction and injection (6-9%) all in terms of power plant output. Sensitivity of the operating energy to several variables was tested and none of them showed strong enough variation to change the conclusions significantly.

6. The capital costs of the surface dissolution approach are 25% to 50% greater than the standard approach. They amount to ~$750,000-$900,000 per MW of power plant for the capture and surface dissolution process. Thus for a 500 MW plant, $375-$450 million in capital will be needed. The reason for the increase in capital is primarily because of the additional wells that will be required, but also due to the additional pumps and mixing tank costs. The capital costs showed strong sensitivity to the well costs.

7. Expressed as per tonne of CO₂ sequestered, costs are approximately 20% more for the surface dissolution approach than the standard approach. Based on the estimates of Rochelle (2007), the cost of the surface dissolution process is $79/t-CO₂ which is greater than the $67/t-CO₂ for the standard approach.

8. The footprint of the project for 30 years of injection will cover ~45 square miles for a 1,000 ft injection interval. This is similar to the 80 square miles recommended for the area of review for the standard approach.

9. Regional groundwater movement is also reduced by approximately 30% in the surface dissolution process compared to the standard approach.

10. Geologic constraints for the surface dissolution process are also estimated. Larger intervals and higher permeabilities are obviously preferred. 200 ft intervals require a minimum of 200-250 md and 1,000 ft intervals require only 40 md
based on CMG simulations. Well spacing was predicted for a line-drive configuration and depends on permeability, per well rate, and years before breakthrough is expected.

11. CO₂ dissolution creates carbonic acid which could be corrosive. Changes in the pH could cause mineral precipitation in the mixing tank, wellbore, and in the near wellbore region depending on the rates of those reactions.

6.2. **Future Work**

There were several modeling issues that could be resolved or better predicted by further research:

**Faults**

1. Faults with hydrocarbon accumulations could be studied to learn more about the breaching of shale layers.

2. The petrophysical parameters of fault zones described in this research could provide a starting place for reservoir simulation and modeling.

**Injectivity**

1. Several properties during injection will change in time and space because of changes in composition and pressure, particularly the following: viscosity of the brine and CO₂, viscosity of the aqueous and gas phases in the two phase region, and the solubility between phases (i.e. D-terms). This research shows that the major trend in flow rate is certainly captured, but better predictions could be made to match the frontal velocities of the drying and Buckley-Leverett fronts in addition to matching the flow rate. The frontal velocities are controlled by the D-terms and viscosities, and additional research could be done to determine the more appropriate values.
2. Instead of assuming $S_{g,avg}$, numerical evaluation of the integral in Eq. 4-10 or 4-12 could be attempted. Alternatively, a more accurate average of the mobility of the Buckley-Leverett region could be studied.

3. Extending solution to 2-D so that the effects of gravity can be considered.

**Surface Dissolution**

1. The simple reservoir modeling could be extended to include properties of target formations like the Mt. Simon Formation in the Illinois Basin or the Frio Formation in the Texas Gulf Coast for both injectivity and surface dissolution models. Reservoir simulators could be used to investigate heterogeneity especially for surface dissolution process. Dispersive fronts could be studied to better predict breakthrough times.

2. The dissolution process could be measured and modeled to improve mixing time predictions and methods for best contacting CO$_2$ and brine. As proof of concept, steady-state mixing experiments of CO$_2$ and brine could be conducted at mixing pressures and temperatures.

3. In order to better determine the temperature in the mixing tank, heat transfer modeling could be done to include the heat transfer in the extraction well, across or under the ground, in the mixing tank, and down the injection wells. Cooling options could also be investigated.

Further research could be conducted to improve economic estimate of the following:

1. The cost effectiveness of desalination and cooling the brine could be explored.
2. Mixing tank designs, including inline mixing and residence tank, could be studied to determine the best ways to contact the fluids. Economic estimates of those designs would be insightful.

3. Well designs will need to consider the potential for carbonic acid corrosion and mineral precipitation. Additional costs for these preparations could be studied.

4. Efficiencies for both submersible pumps and surface pumps for where based on recommendations from the Brown (1980). It is likely that pump designs have improved since then. The cost of the pumps was based on the cost of CO$_2$ compressors from the estimates made by Fisher et al. (2005). Both pump efficiency and pump cost estimations could be improved.

5. The benefits of co-injection (Georgescu et al., 2006) could be explored.

6. Liability issues of surface dissolution including remediation and monitoring cost improved and studied in greater detail.
Nomenclature

\[ C = \text{concentration, mol/L, gmol/l} \]
\[ C_1 = \text{constant} \]
\[ C_2 = \text{constant} \]
\[ C_{BLCO_2,aq} = \text{concentration of CO}_2 \text{ in aqueous phase in Buckley-Leverett region, mol/L}^3, \text{ gmol/l} \]
\[ C_{\text{dry CO}_2,g} = \text{concentration of CO}_2 \text{ in gaseous phase in dry region, mol/L}^3, \text{ gmol/l} \]
\[ C_{BLCO_2,g} = \text{concentration of CO}_2 \text{ in gaseous phase in Buckley-Leverett region, mol/L}^3, \text{ gmol/l} \]
\[ D = \text{distance between injectors and producers (or extractor), L, ft} \]
\[ D_{\text{pipe}} = \text{pipe diameter, L} \]
\[ D_{BL-dry} = \text{retardation factor for drying front} \]
\[ D_{\text{brine-BL}} = \text{retardation factor for Buckley-Leverett front} \]
\[ f_f = \text{friction factor} \]
\[ f_j = \text{fractional flow of } j \text{ component} \]
\[ f_{BL-dry} = \text{fractional flow of gas in two phase region} \]
\[ f_{\text{dry}} = \text{fractional flow of gas in dry region} \]
\[ F_s = \text{factor of safety, mixing tank} \]
\[ g = \text{gravitational constant, L/t}^2, \text{ ft/s}^2 \]
\[ h = \text{formation thickness, L, ft} \]
\[ i = \text{integer} \]
\[ k* = \text{ratio of specific heat} \]
\[ k = \text{absolute permeability, L}^2, \text{ md} \]
\[ k_o = \text{original permeability, L}^2, \text{ md} \]
\[ k_r = \text{relative permeability} \]
\[ k_{rg} = \text{end point relative permeability to gas} \]
\[ k_{\text{dry}} = \text{relative permeability of gas in dry region} \]
\[ k_{\text{brine}} = \text{relative permeability of gaseous phase} \]
\[ l = \text{length of mixing tank, L, ft} \]
\[ l_w = \text{length of well, L, ft} \]
\[ L = \text{length of horizontal well, L, ft} \]
\[ m = \text{saturation exponent to brine} \]
\[ m_{CO_2} = \text{mass of CO}_2 \text{ injected into formation, m} \]
\[ m_{\text{brine}} = \text{mass flow rate of brine, m/t, tonne/d-MW of Power Plant} \]
\[ m_{wCO_2} = \text{molecular weight of carbon dioxide, m/n, lb/lb-mol} \]
\[ m_{wH_2O} = \text{molecular weight of water, m/n, lb/lb-mol} \]
\[ M_{BL} = \text{mobility Buckley-Leverett region, L/t/m, cp}^{-1} \]
\[ M_{\text{brine}} = \text{mobility of brine region, L/t/m, cp}^{-1} \]
\[ M_{\text{dry}} = \text{mobility of dry region, L/t/m, cp}^{-1} \]
\[ M_{\text{eff}} = \text{effective mobility of reservoir, L/t/m, cp}^{-1} \]
\[ M_i = \text{mobility in } i \text{ phase, L/t/m, cp}^{-1} \]
\[ M_j = \text{mobility in } j \text{ phase, L/t/m, cp}^{-1} \]
\[ n = \text{saturation exponent to brine} \]
\[ n* = \text{polytropic coefficient} \]
\[ N_{\text{brine}} = \text{mole flow rate of brine, n/t, lb-mole/d-MW of Power Plant} \]
\[ N_{CF} = \text{mole flow rate of C}^- \text{ ions, n/t, lb-mole/d-MW of Power Plant} \]
\( \dot{N}_{CO_2} \) = mole flow rate of CO\(_2\), \( n/t \), lb-mole/d-MW of Power Plant

\( \dot{N}_{H_2O} \) = mole flow rate of water, \( n/t \), lb-mole/d-MW of Power Plant

\( \dot{N}_{Na^+} \) = mole flow rate of Na\(^+\) ions, \( n/t \), lb-mole/d-MW of Power Plant

\( r \) = radius, L, ft

\( r_{BL} \) = radius of two-phase region, L, ft

\( r_D \) = dimensionless radius

\( r_{dry} \) = radius of dry region with injector at center, L, ft

\( r_w \) = wellbore radius, L, ft

\( r_e \) = drainage radius, L, ft

\( r_i \) = radius, L, ft

\( r_2 \) = radius, L, ft

\( p \) = pressure, m/Lt\(^2\), psi

\( p_i \) = inlet pressure, m/Lt\(^2\), psi

\( p_A \) = extraction bottomhole pressure, m/Lt\(^2\), psi

\( p_{aquifer} \) = initial aquifer pressure, m/Lt\(^2\), psi

\( p_B \) = extraction wellhead pressure, m/Lt\(^2\), psi

\( p_{BL} \) = pressure at Buckley-Leverett front, m/Lt\(^2\), psi

\( p_C \) = capillary entry pressure, m/Lt\(^2\), psi

\( p_{mixing} \) = inj. wellhead/mixing tank pressure, m/Lt\(^2\), psi

\( p_0 \) = injection bottomhole pressure, m/Lt\(^2\), psi

\( p_{dry} \) = pressure at dry front, m/Lt\(^2\), psi

\( p_e \) = bottomhole pressure at drainage radius, m/Lt\(^2\), psi

\( p_i \) = initial reservoir pressure, m/Lt\(^2\), psi

\( p_{LINE} \) = pipeline pressure, m/Lt\(^2\), psi

\( p_{surface} \) = hydrostatic pressure surface, m/Lt\(^2\), psi

\( p_w \) = bottomhole pressure, m/Lt\(^2\), psi

\( p_{intermediate} \) = intermediate pressure, m/Lt\(^2\), psi

\( q \) = total flow rate, L\(^3\)/t , bbl/d

\( q_{CO_2} \) = CO\(_2\) flow rate at mixing pressure, L\(^3\)/t, bbl/d-MW of Power Plant

\( q_{brine} \) = brine flow rate, bbl/d-MW, L\(^3\)/t, bbl/d-MW of Power Plant

\( r \) = radius, L, ft

\( R \) = gas constant, m\(^3\)/Lnt\(^3\), BTU/lb-mole-R

\( S \) = compressor stages

\( S_{avg} \) = average gas saturation

\( S_{BL} \) = gas saturation in Buckley-Leverett region

\( S_{dry} \) = gas saturation in the dry CO\(_2\) region

\( SGR \) = Shale gouge ratio

\( S_{ppm} \) = salinity of brine, ppm

\( S_{wr} \) = residual water saturation

\( t \) = time, t, d

\( T \) = mixing tank wall thickness, L, in

\( t_D \) = dimensionless time, cumulative volume injected

\( t_r \) = residence time, t, min

\( T \) = breakthrough time, t

\( T_{surface} \) = geothermal surface temperature, T, °F

\( T_i \) = inlet temperature, T, °F

\( u \) = average velocity, ft/s, L/t

\( u_x \) = velocity in x-direction, ft/s, L/t

\( v_D \) = dimensionless velocity

\( v_{D,dry} \) = dimensionless velocity of drying front

\( v_{D, BL} \) = dimensionless velocity of Buckley-Leverett front

\( V_{ext} \) = volume extracted from formation, L\(^3\)
\( V_{fsalt} \) = volume fraction of salt
\( V_{inj} \) = volume injected into formation, \( L^3 \)
\( V_{Si} \) = shale concentration in layer i
\( V_{S1} \) = shale concentration in layer 1
\( V_{S2} \) = shale concentration in layer 2
\( w_{CO2} \) = mass fraction of soluble CO2 in brine
\( W_c \) = well count
\( W_p \) = well pair
\( x_o \) = x-coordinate of well location, L, ft
\( x_{CO2} \) = mole fraction of soluble CO2 in brine
\( y_o \) = y-coordinate of well location, L, ft
\( z \) = depth, L, ft
\( z_A \) = average depth of extraction, L, ft
\( z_B \) = extraction wellhead depth, L, ft
\( z_C \) = injection wellhead depth, L, ft
\( z_D \) = average depth of injection, L, ft
\( z_i \) = thickness in layer i, L, ft
\( z_1 \) = thickness in layer 1, L, ft
\( z_2 \) = thickness in layer 2, L, ft
\( \Delta p_{BL} \) = pressure drop in two phase region, \( m/Lt^2 \), psi
\( \Delta p_{brine} \) = pressure drop in brine region, \( m/Lt^2 \), psi
\( \Delta p_{dry} \) = pressure drop in dry region, \( m/Lt^2 \), psi
\( \Delta p_{drawdown} \) = average aquifer pressure - \( p_A \), \( m/Lt^2 \), psi
\( \Delta p_{friction} \) = friction pressure loss, \( m/Lt^2 \), psi
\( \Delta p_{injection} \) = \( p_D \) - average aquifer pressure, \( m/Lt^2 \), psi
\( \Delta V_{SA} \) = change in reservoir volume for standard approach, \( L^3 \)
\( \Delta V_{SD} \) = change in reservoir volume for surface dissolution approach, \( L^3 \)
\( \phi \) = porosity
\( \phi_0 \) = original porosity
\( \Phi \) = potential, \( m/Lt^2 \), psi
\( \Phi_1 \) = potential at location 1, \( m/Lt^2 \), psi
\( \Phi_2 \) = potential at location 2, \( m/Lt^2 \), psi
\( \Phi_{x=0} \) = potential at x-axis injector, \( m/Lt^2 \), psi
\( \Phi_{x=D} \) = potential at x-axis extractor, \( m/Lt^2 \), psi
\( \mu \) = viscosity, \( m/Lt \), cp
\( \mu_g \) = gaseous phase viscosity, \( m/Lt \), cp
\( \mu_w \) = brine viscosity, \( m/Lt \), cp
\( \eta_{dissolve} \) = dissolution efficiency
\( \eta_p \) = polytropic efficiency
\( \eta_{pump} \) = mechanical efficiency of brine pump
\( \rho \) = density, \( m/L^3 \), lbm/ft^3
\( \rho_{brine} \) = density of brine, \( m/L^3 \), lbm/ft^3
\( \rho_{sol} \) = density of solution, \( m/L^3 \), lbm/ft^3
\( \rho_{salt} \) = density of salt, \( m/L^3 \), lbm/ft^3
\( \sigma_{yield} \) = yield stress of steel, \( m/Lt^2 \), ksi
Appendix

Pressure profile in CO₂ injection well

% This program calculates given certain initial pressures and
% flow rates the expected pressure profile.
% Names of programs called: well_model_CO2.m
% Compiler: Matlab
% Language: Matlab
%
% CO₂ Injection
% Mac Burton
% Mar. 5, 2006

clear all
clc

depth=4000;                %ft
 t_g=.86/100;              %°F/ft
 t_surCO2=100;             %°F
 t_bot=61+t_g*depth;       %°F of bottomhole
 del_p=1000;               %psi (BHP - Initial Pressure)
 n_wells=15;
 q=400;                    %mmscf from 1GW power plant

%Basic conversions
ft2m=.3048;                %ft to meters
 psi2Pa=101325/14.7;       %psia to Pa
 lbf2kgm=16.018463;        %lb/ft^3 to kg/m^3
 in2m=0.0254;              %in to m

%Well Properties
 leng = depth*ft2m;        %m middle of target formation
 d=(3+1/4)*in2m;           %meters diameter of inner
 eps = .0003;              %relative roughness

%Fluid Properties
 g = 9.81;                 %m/s^2 gravitational constant
 den_sc = 1.8404682;       %kg/m^3 at standard conditions

%Reservoir Properties
 P_grad=62.4/144;
 P_stand=P_grad*leng*ft2m+del_p;  %psi reservoir pressure + injection pressure

%Flowrate
 q = 0.3277*q/n_wells;     %m^3/s from mmscf/d
 g = 9.81;                 %m/s^2 gravitational constant

%Basic Calculations
 a = 3.1415*d^2/4;         %m^2 cross sectional area
 u_sc = q/a;               %m/s velocity at sc

%Numerical Properties
n_max=200; %number of steps
dz=leng/n_max; %length of each step
z_long=dz*(0:n_max);
z_mid=dz*(1:n_max)-dz;

%Temperature Profile
t_surface=(t_surCO2-32)/1.8; %F to C
t_bottom=(t_bot-32)/1.8; %F to C
dt=(t_bottom-t_surface)/n_max;
t=t_bottom-dt*(1:n_max)+dt/2;

%Initializing arrays
%First Elements in Array
P_SI=P_stand*psi2Pa; %wellhead pressure in psi
u_stand=0;
u=0;
P_grav=0; %gravity term of pressure
P_fric=0; %friction term of pressure

%Loops
for n=1:n_max %midpoint iteration scheme
for m=1:2
if m==1
Pavg=P_SI(n);
else
Pavg=(P_SI(n)+P_SI(n+1))/2;
end
den(n)=co2_den_lkp(Pavg,t(n)); %lookup density and viscosity
visc(n)=co2_visc_lkp(Pavg,t(n));
u(n)=u_sc*den_sc/den(n); %assume constant flow rate
Re(n)=d*u(n)*den(n)/visc(n); %Reynolds # and friction factor
if Re(n) < 2100
    f_f=16/Re(n);
else
    f_f=(1/(-4*log10((eps/3.7065)-(5.0452/Re(n))*log10((eps^1.1098/2.8257)+(7.149/Re(n))^0.8981))))^2;
end;
% We need P2 to find u2, so I estimate u2 as u1 to find P2
% and then iterate a few times to ensure convergence
u_temp=u(n);
convergence(n+1)=1;
while convergence(n+1) > .001
    u_av(n)=(u_temp+u(n))/2;
P_grav(n+1)=-den(n)*g*dz;
P_fric(n+1)=2*den(n)*f_f*u_av(n)^2*dz/d;
P_SI(n+1) = P_SI(n)+P_grav(n+1)+P_fric(n+1);
u(n+1) = u_sc*den_sc/co2_den_lkp(P_SI(n+1),t(n));
    convergence(n+1)=abs(u_temp-u(n+1));
    u_temp=u(n+1);
end
end
P_stand=P_SI/psi2Pa; %wellhead pressure in psi
p_sur_CO2=P_stand(n+1);

Subroutines
%lookup table for the total density of CO2
%lookup values obtained from PVTSim by Calsep
function den_SI=co2_den_lkp(p,t)    %return SI units kg/m^3
%Conversion from SI to standard
psi2Pa=101325/14.7; %psi to Pascals
lbf2kgm=16.018463;  %lb/ft^3 to kg/m^3
p=p/psi2Pa; %change to Pa to Psia
t=t*9/5+32; %change to Fahrenheit
% Tables in the following units
%temperature in Fahrenheit
%Pressures in psia
%densities in lb/ft^3
p_min=100;
p_max=7000;
t_min=0;
t_max=150;

den_co2=[0.9478 0.9403 0.9329 0.9257 0.9186 0.9116 0.9048 0.8980.8914 0.8849 0.8784 0.8721 0.8659 0.8598 0.8538 0.8478 0.842 0.8362 0.8306 0.825 0.8195 0.8141 0.8087 0.8035 0.7983 0.7931 0.7881 0.7831 0.7782 0.7734 0.7686 0.7639 0.7592 0.7546 0.7501 0.7456 0.7412 0.7368 0.7325 0.7283 0.7241 0.7199 0.7158 0.7118 0.7078 0.7038 0.6999 0.6961 0.6923 0.6885 0.685 2.5368 2.5094 2.4828 2.457 2.4318 2.4074 2.3835 2.3603 2.3377 2.3156 2.294 2.273 2.254 2.232 2.212 2.193 2.1743 2.1563 2.1383 2.1207 2.1034 2.0865 2.0699 2.0536 2.038 2.024 2.0107 1.9961 1.9815 1.9662 1.9417 1.9181 1.8956 1.8731 1.8516 1.8301 1.8096 1.7891 1.7686 1.7481 1.7276 1.7071 1.6866 1.6661 1.6456 1.6251 1.6046 1.5841 1.5636 1.5431 1.5226 1.5021 1.4816 1.4611 1.4406 1.4201 1.3996 1.3791 1.3586 1.3381 1.3176 1.2971 1.2766 1.2561 1.2356 1.2151 1.1946 1.1741 1.1536 1.1331 1.1126 1.0921 1.0716 1.0511 1.0306 1.0101 0.9896 0.9691 0.9486 0.9281 0.9076 0.8871 0.8666 0.8461 0.8256 0.8051 0.7846 0.7641 0.7436 0.7231 0.7026 0.6821 0.6615 0.6410 0.6205 0.6000 0.5795 0.5590 0.5385 0.5180 0.4975 0.4770 0.4565 0.4360 0.4155 0.3950 0.3745 0.3540 0.3335 0.3130 0.2925 0.2720 0.2515 0.2310 0.2105 0.1900 0.1695 0.1490 0.1285 0.1080 0.0875 0.0670 0.0465 0.0260 0.0055].
den=interp2(den_co2,(t-t_min)/(t_max-t_min)*49+1,(p-p_min)/(p_max-p_min)*49+1);
den_SI=den*lbf2kgm;

%lookup table for the total viscosity of CO2
%lookup values obtained from PVTSim by Calsep

function visc_SI=co2_visc_lkp(p,t)    %return SI units kg/m^3

%Conversion from SI to standard
psi2Pa=101325/14.7; %psi to Pascals
cp2pa_s=0.001;      %cp to Pa-s
p=p/psi2Pa; %change to Pa to Psi
t=t*9/5+32; %change to Fahrenheit

%densities in following units
%temperature in Fahrenheit
%Pressures in psia
%viscosities in cP
p_min=100;
p_max=7000;
t_min=0;
t_max=150;

56.6063];

163
visc=interp2(visc_co2,(t-t_min)/(t_max-t_min)*49+1,(p-p_min)/(p_max-p_min)*49+1);
visc_SI=visc*cp2pa_s;
**Duan EOS Code**

% This program accepts inputs of T, P and S
% and returns the solubility in mole fraction.
% Names of programs called: DuanEOS.m
% Compiler: Matlab
% Language: Matlab
% CO2 Injection
% Mac Burton
% Mar. 10, 2007

function mf=DuanEOS(ppm, p_psi, t_far)

% Duan EOS developed with units S = molality, T = Kelvin, and P = bar
mNa=-1.711083544/100000*ppm;    %molality or mol/liter
mCl=mNa;                        %molality or mol/liter
p=(t_far-32)*5/9+273.15;        %F to K
p=p_psi/14.504;                 %psi to bars

%Coefficients of EOS
fug=fug_func(p,t);
yco2=(p-ph2o_func(t))/p;
gamma=gamma_func(p,t);
zeta=zeta_func(p,t);
mew_rt=mew_rt_func(p,t);
mco2=exp(log(yco2*fug*p)-mew_rt+2*gamma*mNa-zeta*mCl*mNa);

mf=(1/(0.0180153*mco2)+1)^-1;

Subfunction of DuanEOS.m

function fug_new=fug_func(p,t);

if t<573 & t>273 & p>=.999999 & p<75+(t-305)*1.25

b1= 1.0;
b2= 4.7586835e-3;
b3= -3.3569963e-6;
b4= 0.0;
b5= -1.3179396;
b6= -3.838910e-6;
b8= 2.2815104e-3;

fug_new= b1 + (b2+b3*t+b4/t+b5/(t-150))*p + (b6+b8/t)*p^2;

elseif t<340 & t>273 & p<1000 & p>75+(t-305)*1.25

b1= -7.1734882e-1;
b2= 1.5985379e-4;
b3= -4.9286471e-7;
b6= -2.7855285e-7;
b7= 1.1877015e-9;
b12= -96.539512;
b13= 4.4774938e-1;
b14= 101.81078;
b15= 5.3783879e-6;

fug_new=b1+(b2+b3*t)*p + (b6+b7*t)*p^2 + (b12+b13*t)/p + b14/t + b15*t^2;
else
    error=99999999 % prints error to screen
end;

function ph2o_new=ph2o_func(t);
ph2o = 220.59;  %bar
T=t;
t=(T-tch2o)/tch2o;
ph2o_new = (pch2o*T/tch2o)*(1-38.640844*(-t)^1.9...
    +5.89488420*t+59.876516*t^2+26.65627*t^3+10.637097*t^4);
function gamma_new=gamma_func(p,t);

c1= -0.411370585;
c2= 6.07632013e-4;
c3= 97.5347708;
c8= -0.023762269;
c9= 0.0170656236;
c11= 1.41335834e-5;

gamma_new=c1+c2*t+c3/t+c8*p/t+c9*p/(630-t)+c11*t*log(p);

function zeta_new=zeta_func(p,t);

c1 = 3.6389723e-4;
c2 = -1.9829898e-5;
c8 = 2.122208300e-3;
c9 = -5.248733030e-3;
zeta_new=c1+c2*t+c8*p/t+c9*p/(630-t);

function mew_rt_new=mew_rt_func(p,t);

c1 = 28.9447706;
c2 = -0.0354581768;
c3 = -4770.67077;
c4 = 1.02782768e-5;
c5 = 33.8126098;
c6 = 9.04037140e-3;
c7 = -1.14934031e-3;
c8 = -0.30745726;
c9 = -0.0907301486;
c10 = 9.32713393e-4;
mew_rt_new= c1 +c2*t+c3/t+c4*t^2+c5/(630-t)+c6*p+c7*p*log(t)...
    +c8*p/t+c9*p/(630-t)+c10*p^2/(630-t)^2;

Well Spacing Code

% This program determines the need spacing between injectors and
% injectors in a line drive configuration.
% Names of programs called: well_spacing.m
% Compiler: Matlab
% Language: Matlab
%
% Brine Injection Well Spacing
% Mac Burton
% Feb. 20, 2008
clc
clear all

q=35000*5.615;  %bbl/d to ft^3/d
T=30*365;       %years to days
h=600;          %ft
p=.13;          %porosity
pi=4*atan(1);
H=500.;
num=40;

% D is the distance between inject/extract wells
% H is the distance between inject/inject wells
for j=1:num
  i=1;
  T_2(i,j)=-1000;
  D=1000;
  while T_2(i,j)<-2
    x=0.25:0.1:D-.25;
    Q = trapz(x,g_x(x,D,H(j)));
    T_2(i,j)=4*pi*h*p/q*Q-T;
    if T_2(i,j)<-5000
      D=D+1000;
    elseif T_2(i,j)<-1000
      D=D+200;
    elseif T_2(i,j)<-100
      D=D+30;
    else
      D=D+10;
    end
    if D>50000
      break
    end
    T_2(i+1,j)=T_2(i,j);
    i=i+1;
  end
  D_final(j)=D;
  if j~=num
    H(j+1)=H(j)+500;
  end
end

Subroutine for Well Spacing

function y = g_x(x,D,H)

k = 2./x - 2./(x-D)...
+ 4.*x./(x.^2+1^2*H^2) - 4.*(x-D)./(x-D).^2+1^2*H^2)...
+ 4.*x./(x.^2+2^2*H^2) - 4.*(x-D)./(x-D).^2+2^2*H^2)...
+ 4.*x./(x.^2+3^2*H^2) - 4.*(x-D)./(x-D).^2+3^2*H^2)...
+ 4.*x./(x.^2+4^2*H^2) - 4.*(x-D)./(x-D).^2+4^2*H^2)...
+ 4.*x./(x.^2+5^2*H^2) - 4.*(x-D)./(x-D).^2+5^2*H^2)...
+ 4.*x./(x.^2+6^2*H^2) - 4.*(x-D)./(x-D).^2+6^2*H^2);

y = 1./(k);
CMG Simulation of Brine Injection/Extraction

**Simulation of CO2-saturated brine injection and native brine extraction with 2 constant pressure boundaries and 2 no-flow boundaries**

RESULTS SIMULATOR GEM
RESULTS SECTION INOUT
** Brine Injection
** 3 D Simulation--80*11*5
** with VSP and BIC changed based upon Garcia's Correlation and Exp Data respectively.

*INUNIT *FIELD

**OUTPRN *GRID *ALL
**OUTPRN *RES *ALL
**OUTSRF *GRID *ALL
*INTERRUPT *INTERACTIVE
*RANGECHECK *ON
*XDR *ON
*MAXERROR 20
*WPRN *WELL *TIME
*WPRN *GRID *TIME
*WPRN *ITER *NONE
*WSRF *WELL 10
*WSRF *GRID 10
*DIARY *CHANGES
*OUTPRN *WELL *ALL
*OUTPRN *GRID DENG RHOG MWG FRG KRG SG VISG K 'CO2' Z 'CO2' SIG W 'CO2'
   Y 'CO2' X 'CO2' W 'H2O' Y 'H2O' X 'H2O' DENO RHOO
MWO KRO SO
   VISO DROP PRES SATP DENW KRW SW K 'H2O' Z 'H2O'

VELOCRC

*OUTPRN *RES *ALL
*OUTSRF *WELL *PSPLIT
*OUTSRF *GRID DENG RHOG MWG FRG SG Z 'CO2' Z 'H2O' W 'CO2' Y 'CO2' X 'CO2'
   W 'H2O' Y 'H2O' X 'H2O' DENO RHOO SO DENW SW KRG
VISG K 'CO2'
   K 'H2O' MWO KRO VISO PRES KRW VELOCRC

*OUTSRF *RES *ALL

RESULTS XOFFSET 0.
RESULTS YOFFSET 0.
RESULTS ROTATION 0.
RESULTS AXES-DIRECTIONS 1. 1. 1.

GRID CART 80 11 10
KDIR DOWN
DIP 0 0
DI CON 185.
DJ CON 409.
DK CON 100.

DEPHTOP 1 1 1 2500.
**$ RESULTS PROP NULL Units: Dimensionless
**$ RESULTS PROP Minimum Value: 1 Maximum Value: 1
**$ 0 = NULL block, 1 = Active block
NULL CON 1.

**$ RESULTS PROP PINCHOUTARRAY Units: Dimensionless
**$ RESULTS PROP Minimum Value: 1 Maximum Value: 1
**$ 0 = PINCHED block, 1 = Active block
PINCHOUTARRAY CON 1.

RESULTS SECTION GRID
RESULTS SECTION NETPAY
RESULTS SECTION NETGROSS
RESULTS SECTION POR

RESULTS SPEC 'Porosity'
RESULTS SPEC SPECNOTCALCVAL 0
RESULTS SPEC REGION 'All Layers (Whole Grid)'
RESULTS SPEC REGIONTYPE 0
RESULTS SPEC LAYERNUMB 0
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 0.25
RESULTS SPEC STOP

**$ RESULTS PROP POR Units: Dimensionless
**$ RESULTS PROP Minimum Value: 0.12 Maximum Value: 0.2
POR CON 0.13

RESULTS SECTION PERMS

**$ RESULTS PROP PERMI Units: md
**$ RESULTS PROP Minimum Value: 5 Maximum Value: 2000
*PERMI *KVAR 10*.35.

**$ RESULTS PROP PERMJ Units: md
**$ RESULTS PROP Minimum Value: 5 Maximum Value: 2000
*PERMJ *EQUALSI

**$ RESULTS PROP PERMK Units: md
**$ RESULTS PROP Minimum Value: 5 Maximum Value: 2000
*PERMK *EQUALSI * 0.01

RESULTS SECTION TRANS
RESULTS SECTION FRACS
RESULTS SECTION GRIDNONARRAYS
CPOR MATRIX 0
PRPOR MATRIX 14.7

RESULTS SECTION VOLMOD
RESULTS SECTION SECTORLEASE

RESULTS SECTION ROCKCOMPACATION
RESULTS SECTION GRIDOTHER
RESULTS SECTION MODEL
*MODEL
  *PR
  *NC 2 2
  *COMPNAME 'CO2' 'H2O'
  *HCFLAG 0 0
  *VISCOR  *PEDERSEN
  *VISCOEFF 0.291
  1.4
  0.0005747
4.265
1.0579
*MIXVC 1
*TRES 91.
*PCRIT 72.809000 217.754600
*TCRIT 304.127800 647.094400
*AC 0.223940 0.344000
*VCRIT 0.094000 0.056000
*MW 44.010000 18.015000
*PCHOR 78.000000 52.000000
*SG 0.818000 1.000000
*TB -109.210000 212.000000
*ZCRIT 0.274139 0.229409
*VISVC 0.094000 0.056000
*VSHIFT 0.024668 0.184084
*OMEGA .457235530 .457235530
*OMEGB .077796074 .077796074
*BIN -0.099737
*PHASEID *DEN

RESULTS SECTION MODELARRAYS
RESULTS SECTION ROCKFLUID

*ROCKFLUID

*RPT 1
*SWT
0 0 1 0
0.2 0.2 0.8 0
0.4 0.4 0.6 0
0.6 0.6 0.4 0
0.8 0.8 0.2 0
1 1 0 0

*SLT
0 1 0 0
0.2 0.8 0.2 0
0.4 0.6 0.4 0
0.6 0.4 0.6 0
0.8 0.2 0.8 0
1 0 1 0

*MODBUILDER
TYPE:1_KRWRO_KROCW_KROCG_SWCON_SGCON_SWCR_SGCR_SORW_SORG_SOIRW_SOIRG_NW_NG_NOG 1_.21_.334_1_.334_0_.25_0_.25_.25_.25_.25_.25_.25_2.7_2.5_2.7 **$
ModelBuilder passed through this Keyword

*KRGAS *KRG
*KROIL *STONE2 *SWSG

RESULTS SECTION ROCKARRAYS
RESULTS SECTION INIT

174
*INITIAL
*USER_INPUT
*NREGIONS 1

RESULTS SECTION INITARRAYS

**$ RESULTS PROP SW Units: Dimensionless
**$ RESULTS PROP Minimum Value: 0 Maximum Value: 1
SW CON 1

**$ RESULTS PROP PRES Units: psi
**$ RESULTS PROP Minimum Value: 1000 Maximum Value: 3000
PRES *KVAR 1110.3125 1153.854167 1197.395833 1240.9375 1284.479167
               1328.020833 1371.5625 1415.104167 1458.645833 1502.1875

**$ RESULTS PROP ZGLOBALC 'CO2' Units: Dimensionless
**$ RESULTS PROP Minimum Value: 0 Maximum Value: 0
ZGLOBALC 'CO2' CON 0

**$ RESULTS PROP ZGLOBALC 'H2O' Units: Dimensionless
**$ RESULTS PROP Minimum Value: 1 Maximum Value: 1
ZGLOBALC 'H2O' CON 1.

RESULTS SECTION NUMERICAL
*NUMERICAL
*DTMAX 1.
*DTMIN 1.E-06
*NORM *PRESS 2000.
*MAXCHANGE *GMOLAR 0.95
*MAXCHANGE *SATUR 0.95
*CONVERGE *PRESS 0.514884

RESULTS SECTION NUMARRAYS
RESULTS SECTION GBKEYWORDS
RUN

DATE 2000 08 01
WELL 1 'NewWell'
INJECTOR 'NewWell'
INCOMP SOLVENT .014 .986
OPERATE MAX BHP 2110. CONT

GEOMETRY K 0.7 0.35 1. 0.
PERF GEO 'NewWell'
  27 6 1. OPEN
  27 6 2. OPEN
  27 6 3. OPEN
  27 6 4. OPEN
  27 6 5. OPEN
  27 6 6. OPEN
  27 6 7. OPEN
  27 6 8. OPEN
  27 6 9. OPEN
  27 6 10. OPEN

WELL 2 'NewWell2'
PRODUCER 'NewWell2'
OPERATE MIN BHP  110. CONT

GEOMETRY K 0.7 0.35 1. 0.
PERF GEO 'NewWell2'
   54 6 1 1. OPEN
   54 6 2 1. OPEN
   54 6 3 1. OPEN
   54 6 4 1. OPEN
   54 6 5 1. OPEN
   54 6 6 1. OPEN
   54 6 7 1. OPEN
   54 6 8 1. OPEN
   54 6 9 1. OPEN
   54 6 10 1. OPEN

WELL  3 'NewWell3'
PRODUCER 'NewWell3'
OPERATE MIN BHP  1132.083 CONT

GEOMETRY K 0.5 0.35 1. 0.
PERF GEO 'NewWell3'
   1 1 1 1. OPEN
   1 1 2 1. OPEN
   1 1 3 1. OPEN
   1 1 4 1. OPEN
   1 1 5 1. OPEN
   1 1 6 1. OPEN
   1 1 7 1. OPEN
   1 1 8 1. OPEN
   1 1 9 1. OPEN
   1 1 10 1. OPEN

WELL  4 'NewWell4'
PRODUCER 'NewWell4'
OPERATE MIN BHP  1132.083 CONT

GEOMETRY K 0.5 0.35 1. 0.
PERF GEO 'NewWell4'
   1 2 1 1. OPEN
   1 2 2 1. OPEN
   1 2 3 1. OPEN
   1 2 4 1. OPEN
   1 2 5 1. OPEN
   1 1 6 1. OPEN
   1 1 7 1. OPEN
   1 1 8 1. OPEN
   1 1 9 1. OPEN
   1 1 10 1. OPEN

WELL  5 'NewWell5'
PRODUCER 'NewWell5'
OPERATE MIN BHP  1132.083 CONT

GEOMETRY K 0.5 0.35 1. 0.
PERF GEO 'NewWell5'
   1 3 1 1. OPEN
   1 3 2 1. OPEN
WELL 6 'NewWell6'
PRODUCER 'NewWell6'
OPERATE MIN BHP  1132.083 CONT

GEOMETRY K 0.5 0.35 1. 0.
PERF GEO  'NewWell6'
  1 4 1 1. OPEN
  1 4 2 1. OPEN
  1 4 3 1. OPEN
  1 4 4 1. OPEN
  1 4 5 1. OPEN
  1 4 6 1. OPEN
  1 4 7 1. OPEN
  1 4 8 1. OPEN
  1 4 9 1. OPEN
  1 4 10 1. OPEN

WELL 7 'NewWell7'
PRODUCER 'NewWell7'
OPERATE MIN BHP  1132.083 CONT

GEOMETRY K 0.5 0.35 1. 0.
PERF GEO  'NewWell7'
  1 5 1 1. OPEN
  1 5 2 1. OPEN
  1 5 3 1. OPEN
  1 5 4 1. OPEN
  1 5 5 1. OPEN
  1 5 6 1. OPEN
  1 5 7 1. OPEN
  1 5 8 1. OPEN
  1 5 9 1. OPEN
  1 5 10 1. OPEN

WELL 8 'NewWell8'
PRODUCER 'NewWell8'
OPERATE MIN BHP  1132.083 CONT

GEOMETRY K 0.5 0.35 1. 0.
PERF GEO  'NewWell8'
  1 6 1 1. OPEN
  1 6 2 1. OPEN
  1 6 3 1. OPEN
  1 6 4 1. OPEN
  1 6 5 1. OPEN
  1 6 6 1. OPEN
  1 6 7 1. OPEN
  1 6 8 1. OPEN
  1 6 9 1. OPEN
  1 6 10 1. OPEN
WELL 9 'NewWell9'
PRODUCER 'NewWell9'
OPERATE MIN BHP 1132.083 CONT

GEOMETRY K 0.5 0.35 1. 0.
PERF GEO 'NewWell9'
 1 7 1 1. OPEN
 1 7 2 1. OPEN
 1 7 3 1. OPEN
 1 7 4 1. OPEN
 1 7 5 1. OPEN
 1 7 6 1. OPEN
 1 7 7 1. OPEN
 1 7 8 1. OPEN
 1 7 9 1. OPEN
 1 7 10 1. OPEN

WELL 10 'NewWell10'
PRODUCER 'NewWell10'
OPERATE MIN BHP 1132.083 CONT

GEOMETRY K 0.5 0.35 1. 0.
PERF GEO 'NewWell10'
 1 8 1 1. OPEN
 1 8 2 1. OPEN
 1 8 3 1. OPEN
 1 8 4 1. OPEN
 1 8 5 1. OPEN
 1 8 6 1. OPEN
 1 8 7 1. OPEN
 1 8 8 1. OPEN
 1 8 9 1. OPEN
 1 8 10 1. OPEN

WELL 11 'NewWell11'
PRODUCER 'NewWell11'
OPERATE MIN BHP 1132.083 CONT

GEOMETRY K 0.5 0.35 1. 0.
PERF GEO 'NewWell11'
 1 9 1 1. OPEN
 1 9 2 1. OPEN
 1 9 3 1. OPEN
 1 9 4 1. OPEN
 1 9 5 1. OPEN
 1 9 6 1. OPEN
 1 9 7 1. OPEN
 1 9 8 1. OPEN
 1 9 9 1. OPEN
 1 9 10 1. OPEN

WELL 12 'NewWell12'
PRODUCER 'NewWell12'
OPERATE MIN BHP 1132.083 CONT

GEOMETRY K 0.5 0.35 1. 0.
PERF GEO 'NewWell12'
 1 10 1 1. OPEN
<table>
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<tr>
<th>WELL 13 'NewWell13'</th>
<th>PRODUCER 'NewWell13'</th>
<th>OPERATE MIN BHP 1132.083 CONT</th>
</tr>
</thead>
<tbody>
<tr>
<td>GEOMETRY K 0.5 0.35 1. 0.</td>
<td>PERF GEO 'NewWell13'</td>
<td></td>
</tr>
<tr>
<td>1 10 2 1. OPEN</td>
<td>1 10 3 1. OPEN</td>
<td>1 10 4 1. OPEN</td>
</tr>
<tr>
<td>1 10 5 1. OPEN</td>
<td>1 10 6 1. OPEN</td>
<td>1 10 7 1. OPEN</td>
</tr>
<tr>
<td>1 10 8 1. OPEN</td>
<td>1 10 9 1. OPEN</td>
<td>1 10 10 1. OPEN</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>WELL 14 'NewWell14'</th>
<th>INJECTOR 'NewWell14'</th>
<th>INCOMP WATER</th>
</tr>
</thead>
<tbody>
<tr>
<td>OPERATE MAX BHP 1132.083 CONT</td>
<td>GEOMETRY K 0.5 0.35 1. 0.</td>
<td>PERF GEO 'NewWell14'</td>
</tr>
<tr>
<td>80 1 1 1. OPEN</td>
<td>80 1 2 1. OPEN</td>
<td>80 1 3 1. OPEN</td>
</tr>
<tr>
<td>80 1 4 1. OPEN</td>
<td>80 1 5 1. OPEN</td>
<td>80 1 6 1. OPEN</td>
</tr>
<tr>
<td>80 1 7 1. OPEN</td>
<td>80 1 8 1. OPEN</td>
<td>80 1 9 1. OPEN</td>
</tr>
<tr>
<td>80 1 10 1. OPEN</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>WELL 15 'NewWell15'</th>
<th>INJECTOR 'NewWell15'</th>
<th>INCOMP WATER</th>
</tr>
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<tbody>
<tr>
<td>OPERATE MAX BHP 1132.083 CONT</td>
<td>GEOMETRY K 0.5 0.35 1. 0.</td>
<td>PERF GEO 'NewWell15'</td>
</tr>
<tr>
<td>80 2 1 1. OPEN</td>
<td>80 2 2 1. OPEN</td>
<td>80 2 3 1. OPEN</td>
</tr>
<tr>
<td>80 2 4 1. OPEN</td>
<td>80 2 5 1. OPEN</td>
<td>80 2 6 1. OPEN</td>
</tr>
<tr>
<td>80 2 7 1. OPEN</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
WELL 16 'NewWell16'
INJECTOR 'NewWell16'
INCOMP WATER
OPERATE MAX BHP 1132.083 CONT
GEOMETRY K 0.5 0.35 1. 0.
PERF GEO   'NewWell16'
  80 3 1 1. OPEN
  80 3 2 1. OPEN
  80 3 3 1. OPEN
  80 3 4 1. OPEN
  80 3 5 1. OPEN
  80 3 6 1. OPEN
  80 3 7 1. OPEN
  80 3 8 1. OPEN
  80 3 9 1. OPEN
  80 3 10 1. OPEN

WELL 17 'NewWell17'
INJECTOR 'NewWell17'
INCOMP WATER
OPERATE MAX BHP 1132.083 CONT
GEOMETRY K 0.5 0.35 1. 0.
PERF GEO   'NewWell17'
  80 4 1 1. OPEN
  80 4 2 1. OPEN
  80 4 3 1. OPEN
  80 4 4 1. OPEN
  80 4 5 1. OPEN
  80 4 6 1. OPEN
  80 4 7 1. OPEN
  80 4 8 1. OPEN
  80 4 9 1. OPEN
  80 4 10 1. OPEN

WELL 18 'NewWell18'
INJECTOR 'NewWell18'
INCOMP WATER
OPERATE MAX BHP 1132.083 CONT
GEOMETRY K 0.5 0.35 1. 0.
PERF GEO   'NewWell18'
  80 5 1 1. OPEN
  80 5 2 1. OPEN
  80 5 3 1. OPEN
  80 5 4 1. OPEN
  80 5 5 1. OPEN
  80 5 6 1. OPEN
  80 5 7 1. OPEN
  80 5 8 1. OPEN
  80 5 9 1. OPEN
  80 5 10 1. OPEN

180
WELL 19 'NewWell19'
INJECTOR 'NewWell19'
INCOMP WATER
OPERATE MAX BHP 1132.083 CONT
GEOMETRY K 0.5 0.35 1. 0.
PERF GEO   'NewWell19'
  80 6 1 1. OPEN
  80 6 2 1. OPEN
  80 6 3 1. OPEN
  80 6 4 1. OPEN
  80 6 5 1. OPEN
  80 6 6 1. OPEN
  80 6 7 1. OPEN
  80 6 8 1. OPEN
  80 6 9 1. OPEN
  80 6 10 1. OPEN

WELL 20 'NewWell20'
INJECTOR 'NewWell20'
INCOMP WATER
OPERATE MAX BHP 1132.083 CONT
GEOMETRY K 0.5 0.35 1. 0.
PERF GEO   'NewWell20'
  80 7 1 1. OPEN
  80 7 2 1. OPEN
  80 7 3 1. OPEN
  80 7 4 1. OPEN
  80 7 5 1. OPEN
  80 7 6 1. OPEN
  80 7 7 1. OPEN
  80 7 8 1. OPEN
  80 7 9 1. OPEN
  80 7 10 1. OPEN

WELL 21 'NewWell21'
INJECTOR 'NewWell21'
INCOMP WATER
OPERATE MAX BHP 1132.083 CONT
GEOMETRY K 0.5 0.35 1. 0.
PERF GEO   'NewWell21'
  80 8 1 1. OPEN
  80 8 2 1. OPEN
  80 8 3 1. OPEN
  80 8 4 1. OPEN
  80 8 5 1. OPEN
  80 8 6 1. OPEN
  80 8 7 1. OPEN
  80 8 8 1. OPEN
  80 8 9 1. OPEN
  80 8 10 1. OPEN

WELL 22 'NewWell22'
INJECTOR 'NewWell22'
INCOMP WATER
OPERATE MAX BHP 1132.083 CONT
GEOMETRY K 0.5 0.35 1. 0.
PERF GEO 'NewWell22'
 80 9 1 1. OPEN
 80 9 2 1. OPEN
 80 9 3 1. OPEN
 80 9 4 1. OPEN
 80 9 5 1. OPEN
 80 9 6 1. OPEN
 80 9 7 1. OPEN
 80 9 8 1. OPEN
 80 9 9 1. OPEN
 80 9 10 1. OPEN

WELL 23 'NewWell23'
INJECTOR 'NewWell23'
INCOMP WATER
OPERATE MAX BHP 1132.083 CONT

GEOMETRY K 0.5 0.35 1. 0.
PERF GEO 'NewWell23'
 80 10 1 1. OPEN
 80 10 2 1. OPEN
 80 10 3 1. OPEN
 80 10 4 1. OPEN
 80 10 5 1. OPEN
 80 10 6 1. OPEN
 80 10 7 1. OPEN
 80 10 8 1. OPEN
 80 10 9 1. OPEN
 80 10 10 1. OPEN

WELL 24 'NewWell24'
INJECTOR 'NewWell24'
INCOMP WATER
OPERATE MAX BHP 1132.083 CONT

GEOMETRY K 0.5 0.35 1. 0.
PERF GEO 'NewWell24'
 80 11 1 1. OPEN
 80 11 2 1. OPEN
 80 11 3 1. OPEN
 80 11 4 1. OPEN
 80 11 5 1. OPEN
 80 11 6 1. OPEN
 80 11 7 1. OPEN
 80 11 8 1. OPEN
 80 11 9 1. OPEN
 80 11 10 1. OPEN

TIME 10
*DTMAX 25.
TIME 30
TIME 50
TIME 80
TIME 100
TIME 150
TIME 200
TIME 250
TIME 300
TIME 350
TIME 400
TIME 450
TIME 500
TIME 550
TIME 600
TIME 650
TIME 700
TIME 800
TIME 900
TIME 1000
TIME 1100
TIME 1200
TIME 1300
TIME 1400
TIME 1500
TIME 1600
TIME 1700
TIME 1800
TIME 1825
TIME 2500
TIME 3650
TIME 5000
TIME 7500
183
TIME 10950
SHUTIN 'NewWell'
SHUTIN 'NewWell2'
TIME 11500
STOP

****************** TERMINATE SIMULATION******************

RESULTS SECTION WELLDATA
RESULTS SECTION PERFS
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