2010

The impact of formation characteristics on CO₂ sequestration into an aquifer

Nagi A. Lam
West Virginia University

Follow this and additional works at: <https://researchrepository.wvu.edu/etd>

Recommended Citation

Lam, Nagi A., "The impact of formation characteristics on CO₂ sequestration into an aquifer" (2010).
Graduate Theses, Dissertations, and Problem Reports. 4622.
<https://researchrepository.wvu.edu/etd/4622>

This Thesis is protected by copyright and/or related rights. It has been brought to you by the The Research Repository @ WVU with permission from the rights-holder(s). You are free to use this Thesis in any way that is permitted by the copyright and related rights legislation that applies to your use. For other uses you must obtain permission from the rights-holder(s) directly, unless additional rights are indicated by a Creative Commons license in the record and/ or on the work itself. This Thesis has been accepted for inclusion in WVU Graduate Theses, Dissertations, and Problem Reports collection by an authorized administrator of The Research Repository @ WVU. For more information, please contact researchrepository@mail.wvu.edu.

THE IMPACT OF FORMATION CHARACTERISTICS ON CO₂ SEQUESTRATION INTO AN AQUIFER

Nagi A. Lam

Thesis submitted to the
College of Engineering and Mineral Resources
at West Virginia University
in Partial fulfillment of the requirements
for the degree of

Master of Science

in

Petroleum and Natural Gas Engineering

Kashy Aminian, Ph.D., Chair
Sam Ameri, M.S.
Kenneth Means, Ph.D.

Department of Petroleum and Natural Gas Engineering

Morgantown, West Virginia
2010

Keywords: CMG GEM Simulator, Geologic Storage, CO₂ Trapping Mechanisms,
Saline Aquifer, Two-phase flow modeling, Plume Stabilization

ABSTRACT

THE IMPACT OF FORMATION CHARACTERISTICS ON CO₂ SEQUESTRATION INTO AN AQUIFER

Nagi Lam

With the increasing trends in global temperature and CO₂ emissions, there is expanding interest in geological storing as potential sites for the safe and fast disposal of CO₂. This expanding interest necessitates the need of studying the effects of geological parameters on CO₂ sequestration. The processes that occur in CO₂ sequestration are complex with many different parameters influencing the behavior of the injected CO₂ and therefore numerical simulations are required.

The objective of this research is to study the impact of the aquifer properties and operational parameters to understand the CO₂ plume behavior and their contribution to various trapping mechanisms. Such study will help minimize uncertainty in estimates of the capacity and injectivity of CO₂.

In order to accomplish these objectives, selection of a set of representative characteristics for an aquifer as 'base case' was first modeled. Next variation of injection schemes and rates were modeled to evaluate CO₂ plume behavior and the potential of CO₂ storage volume. In addition this study demonstrates how different trapping mechanisms are influenced by variation of reservoir properties and dip angle.

These studies show that bottom injection of CO₂ at high rates for a slight dipping aquifer has a significant impact on the total amount of CO₂ injected, dissolved and trapped in the aquifer. Bottom completion and high rate injection allow more CO₂ to be injected and the plume to come into contact with larger amount of brine due to buoyancy effect and larger distribution of the plume, which will enhance solubility and residual trapping mechanisms. Temperature and pressure have a slight impact on the solubility of CO₂. The results also show that reservoir permeability has a large impact on the dissolved and trapped CO₂, as it facilitates the lateral migration of CO₂ enhancing dissolution into the brine.

ACKNOWLEDGEMENTS

I would like to extend my sincere to my academic advisor Dr. Kashy Aminian for all his help and support. I want to thank him for his valuable support and guidance, and for having been a constant source of inspiration for this work. I would like to extend my heartfelt thanks to Dr. Sam Ameri for assistance and continuous encouragement and support during my studies at West Virginia University. I also would like to thank Dr. Kenneth Means for his participation in my committee. Special thanks to all the faculty of the Petroleum and Natural Gas Engineering Department.

Special thanks to Baker Hughes Drilling Fluids employees. I would like to thank Ron Bland, PDM Process Owner, who had given me unconditional technical support for the training I had at BHDF facilities. I am thankful to Jim Miller, Sr. Training Specialist, John Pierce, Technical Training Manager, and all Class083H members for their sustenance and unconditional supervision during my training program.

Finally, I dedicate my work to my parents, and family members. Thank you very much for all your guidance, support, encouragement, and most importantly, the love that you always have given me. I would like to express special thanks to my friends: Fahad Almutairi, Abbas Belyadi, Abdullah Almansour and Tariq Ali for the moments I have spent in their company and for the inspirations I have drawn from them.

TABLE OF CONTENTS

ABSTRACT.....	ii
ACKNOWLEDGEMENTS.....	iii
TABLE OF CONTENTS.....	iv
LIST OF FIGURES	v
LIST OF TABLES.....	vi
NOMENCLATURE	vii
CHAPTER 1	1
INTRODUCTION	1
1.1 A Technology Approach to Reduce GHG Emissions.....	2
1.2 What is Carbon Sequestration?	4
1.3 Saline Formation CO ₂ Storage Resource Estimating.....	5
1.4 Carbon Dioxide Sources and Current Work	6
CHAPTER 2	8
LITERATURE REVIEW	8
2.1 Properties of the Porous Medium.....	8
2.2 Processes in Porous Media.....	9
2.3 Modeling of Flow in Porous Media	11
2.4 Criteria for Storage Reservoirs and Trapping Mechanisms	13
2.5 Previous Work.....	14
CHAPTER 3	17
OBJECTIVE AND METHODOLOGY	17
3.1 Objective of this study.....	17
3.2 Simulator Description	18
3.3 Aquifer Model Description	25
3.4 Case Studies	28
CHAPTER 4	30
RESULTS AND DISCUSSIONS.....	30
4.1 Injection Scheme Case Study.....	30
4.2 Injection Rate Case Study	32
4.3 Temperature Case Study	34
4.4 Pressure Case Study	36
4.5 Horizontal Permeability Case Study	38
4.6 Vertical Permeability Case Study	40
4.7 Porosity Case Study	42
4.8 Aquifer Dip Case Study	43
CHAPTER 5	46
CONCLUSIONS AND RECOMMENDATIONS	46
REFERENCES.....	48
APPENDIX.....	50

LIST OF FIGURES

Figure 1: U.S. Electric Power Generation by Fuel Type (USDOE, 2008)	2
Figure 2: U.S. Projected Carbon Dioxide (CO ₂) Emissions (USDOE, 2008)	3
Figure 3: Various Types of Geologic Carbon Sequestration (USDOE, 2008)	4
Figure 4: North American Saline Formations (USDOE, 2008).....	5
Figure 5: CO ₂ Stationary Source Emissions by Category (USDOE, 2008)	6
Figure 6: Advection in Multi-phase Flow. Advection is caused by Pressure Gradients ..	10
Figure 7: Buoyancy in Multi-phase Flow. Density Differences cause Buoyancy Flow...	10
Figure 8: Relevant Transport Processes of CO ₂	11
Figure 9: Solubility of CO ₂ in the Water Phase in Correlation to Pressure, including several Isotherms. (Bielinski, 2007)	12
Figure 10: CMG's Suite of Integrated Modelling Tools	18
Figure 11: Basel Cambrian Sandstone. Alberta Basin in Canada (Bennion, 2005)	26
Figure 12: Various Injection Schemes for Base Case.....	30
Figure 13: Percentage of CO ₂ Phases at Various Times for Base Case.....	32
Figure 14: Injection Period for Case 1	33
Figure 15: Percentage of CO ₂ Phases at Various Times for Case 1	34
Figure 16: Percentage of CO ₂ Dissolved Over Time for Different Temperatures	35
Figure 17: Percentage of CO ₂ Phases at Various Times for Temperature Effects Case...	36
Figure 18: CO ₂ Plume Distribution after 25 years of Injection at 2 Different Pressures ..	36
Figure 19: Percentage of CO ₂ Dissolved (top), CO ₂ Residual (center) and CO ₂ Mobile (bottom) over Time for Different Pressures in the Aquifer	38
Figure 20: CO ₂ Plume Distribution 325 years after the Injection Period showing the Effects of Horizontal Permeability	38
Figure 21: Percentage of CO ₂ Dissolved (top), CO ₂ Residual (center) and CO ₂ Mobile over Time for Different Horizontal Permeabilities.....	40
Figure 22: CO ₂ Plume Distribution 325 years after the Injection Period showing the Effects of Vertical Permeability.....	40
Figure 23: Percentage of CO ₂ Phases at Various Times for Vertical Permeability Effects Case.....	41
Figure 24: CO ₂ Plume Distribution 650 years after the Injection Period showing the Effects of Reservoir Porosity	42
Figure 25: Percentage of CO ₂ Phases at Various Times for Porosity Effects Case	43
Figure 26: Percentage of CO ₂ Phases at Various Times for Aquifer Dip Effects Case....	44
Figure 27: Percentage of CO ₂ Dissolved (top), CO ₂ Residual (center) and CO ₂ Mobile over Time for Different Aquifer Dips.....	45

LIST OF TABLES

Table 1: Simulation Input for Base Case	27
Table 2: Summary of Simulation Runs for Sensitivity Analysis	29
Table 3: Amount of CO ₂ injected and Gas Injection Rate and Period for Base Case	31
Table 4: Amount of CO ₂ injected and Gas Injection Rate and Period for Case 1	33

NOMENCLATURE

L_{res}	Reservoir Length, ft
W_{res}	Reservoir Width, ft
H_{res}	Reservoir Height, ft
Φ	Porosity, %
K_H	Horizontal Permeability, md
K_V	Vertical Permeability, md
K_H/K_V	Ratio of Vertical Permeability to Horizontal Permeability, dimensionless
T_{res}	Reservoir Temperature, °F
P_{res}	Reservoir Pressure, psi
P_{int}	Reservoir Initial Pressure, psi
D_{res}	Reservoir Depth, ft
D_{WGC}	Water Gas Contact, ft
Q	Injection Rate, ft ³ /day
P_{BH}	Bottom Hole Pressure, psi
t	time, yrs
A	Area, ft ²
r_w	Wellbore radius, ft
deg	Reservoir Dip Angle, ° degree

CHAPTER 1

INTRODUCTION

Climate change is a topic that has received a lot of exposure during the last years amongst other things as a consequence of Intergovernmental Panel on Climate Change (IPCC). The general public is increasingly aware of the effects of greenhouse gas emissions and many governments and organizations have become involved in finding solutions. The most important contributor to the enhanced global warming is carbon dioxide (CO_2) produced by burning of fossil fuels. One of the possibilities considered in order to reduce emission of greenhouse gases enough is the capturing and geological storing of CO_2 . This is not a method that can be applied to the transportation sector with its many small sources, but rather at large stationary sources of CO_2 such as fossil-fueled power plants. The CO_2 can there be separated and injected into deep geological formations such as saline aquifers, depleted oil and gas fields and coal seams.

In the subsurface, CO_2 exists as an immiscible free phase and as a solute in the aqueous phase. The present study does not consider pressure/temperature conditions below the critical point of CO_2 (1,070 psi, 87.77°F), so CO_2 never exists as a free phase in liquid or gaseous form. Supercritical CO_2 is lighter and much less viscous than the native aquifer; hence, in a two-phase flow context, it is referred to as gas, whereas the aqueous phase is referred to as liquid.

Trapping CO_2 is a significant challenge because the low density of free-phase CO_2 compared to native aquifer makes it strongly buoyant. Immobilizing CO_2 for long-term geologic storage can be accomplished by four primary mechanisms. (1) Stratigraphic or structural trapping: buoyant free-phase CO_2 is trapped beneath low-permeability layers or faults. (2) Residual CO_2 trapping (also known as capillary trapping): multiphase flow processes immobilize free-phase CO_2 . (3) Dissolution trapping (also known as solubility trapping): the CO_2 that dissolves in aquifer is no longer buoyant so there is no driving force toward the surface. (4) Mineral trapping: CO_2 reacts with rock minerals to form

carbonate compounds, typically over very long time scales. The first three mechanisms referred to as hydrodynamic trapping by Bachu et al. (1994), dominate plume behavior over the hundred-year time scale and are the focus of the present research.

1.1 A Technology Approach to Reduce GHG Emissions

Figure 1 the “U.S. Electric Power Generation by Fuel Type,” shown below, displays the *Annual Energy Outlook’s* 2008 predictions of growth in energy generation by different fuel types (USDOE, 2008). Coal is predicted to continue to dominate power generation for the next 20 years. Power generation from coal is one major source of CO₂ emissions, which makes it a critical goal for the Research and Development team to reduce these emissions.

Figure 1: U.S. Electric Power Generation by Fuel Type (USDOE, 2008)

The Energy Information Administration's graph shown at the bottom, **Figure 2**, explains the projected increase in CO₂ emissions over the next 20 years. The U.S. will emit approximately 6,850 million metric tons (7,550 million tons) of CO₂ by 2030, increasing 2005 emission levels by more than 14%. The U.S. can work toward reducing GHG emissions with the development and implementation of appropriate Carbon Capture and Storage (CCS) technologies (USDOE, 2008).

Figure 2: U.S. Projected Carbon Dioxide (CO₂) Emissions (USDOE, 2008)

1.2 What is Carbon Sequestration?

Carbon sequestration is the processes of capturing and storing CO₂. The separation and capture of CO₂ at the point of emissions followed by storage in deep underground geologic formations is known as *Geologic carbon sequestration*.

Geologic carbon sequestration is the placement of CO₂ into a subsurface formation in a way that it will remain permanently stored. There are three types of underground formations for geologic carbon sequestration as shown in **Figure 3**, each with different challenges and opportunities: (1) oil and natural gas reservoirs, (2) deep coal seams, and (3) deep saline formations.

Figure 3: Various Types of Geologic Carbon Sequestration (USDOE, 2008)

1.3 Saline Formation CO₂ Storage Resource Estimating

Saline formations are made of porous rock saturated with brine and covered by impermeable rock formations enabling the trapping of CO₂ that is injected into it. The amount determined of CO₂ into a saline formation is defined as a porous and permeable body of rock containing water, which can store large volumes of CO₂. Saline formations are widespread throughout the United States and Canada as shown in **Figure 4** with the red circles; and therefore have the largest CO₂ storage resource potential

Figure 4: North American Saline Formations (USDOE, 2008)

1.4 Carbon Dioxide Sources and Current Work

There are two types of CO₂ emission sources: stationary sources and non-stationary sources. Stationary source emissions come from a particular source, such as a power plant. CO₂ from stationary sources can be separated from plant emissions and transported to a geologic storage injection site. Non-stationary source emissions include CO₂ emissions from the transportation area (vehicles, railroads, airplanes, etc.).

According to the Environmental Protection Agency (EPA) in 2006, total U.S. GHG emissions were estimated at 7,100 million metric tons (7,800 million tons) CO₂ equivalent. This estimation included CO₂ emissions as well as methane (CH₄), nitrous oxide (N₂O), and hydrofluorocarbons (HFCs). Approximately CO₂ emissions were estimated at 5,600 million metric tons (6,200 million tons) with 3,800 million metric tons (4,200 million tons) from stationary sources (USDOE, 2008).

Figure 5: CO₂ Stationary Source Emissions by Category (USDOE, 2008)

The chart above, *Figure 5*, contains value showing that CO₂ stationary source emissions result largely from electric power generation, energy use, and industrial processes. Although not all GHG sources have been tested, the Department of Energy has reported total annual emissions of over 3,200 million metric tons (3,600 million tons) of CO₂.

Currently, there are several projects running in the field of carbon dioxide sequestration. In 1996, the Sleipner project in Norway was started. There are approximately one million tons of CO_2 per year pumped into a huge saline sandstone aquifer called Utsira formation, which is situated under the North Sea in a depth of 1,000 meters. The CO_2 was separated from the extraction and purification process of natural gas from the offshore gas field called Sleipner in North Sea. Up to now, the results indicate that safe storage of CO_2 under a suitable cap rock is possible. The injected carbon dioxide was monitored successfully by seismic surveying in a related project called SACS, which aims at finding suitable monitoring methods.

Another important project is currently performed near the town Ketzin west of Berlin, where CO_2 is injected into a deep saline formation. It is the first European on-shore CO_2 sequestration project. This showcase shall help to get a better understanding of the sequestration and monitoring processes.

The processes that occur in CO_2 sequestration are very complex with many different parameters influencing the behavior of the injected CO_2 . Moreover, field experiments are very expensive and include certain risks. The processes of CO_2 storage can be described by different highly non-linear equations and complex partial differential equations. For those, the analytical solution of such problems is often difficult or impossible to obtain. To get, despite this, an impression what is going on in such a process, the help of numerical simulations is required.

CHAPTER 2

LITERATURE REVIEW

2.1 *Properties of the Porous Medium*

In this section, the properties of the porous medium needed for the description of multi-phase flow in the subsurface are explained.

2.1.1 Porosity

The porosity “ ϕ ” is a measure of the pore volume in a porous medium. It is defined by the ratio between the volume of the pores and the total volume:

$$\phi = \frac{V_{\text{pores}}}{V_{\text{total}}}.$$

In some cases, it is necessary to distinguish between porosity and effective porosity, i.e. the pore volume that is accessible for fluid flow.

2.1.2 Saturation

In the case of several phases flowing in a porous medium, it is necessary to have a measure of the fraction of the pores filled with a fluid phase. This is given by the saturation “ S ” that is defined as the ratio between the volume of the pores filled with phase α and the total pore volume:

$$S_{\alpha} = \frac{V_{\alpha}}{V_{\text{pores}}}.$$

Following this definition, it is clear that the phase saturations have to sum up to unity:

$$\sum_{\alpha} S_{\alpha} = 1.$$

2.1.3 Permeability

The absolute permeability “K” is a measure of the resistance of a particular porous medium towards flow of a fluid in its pores. It is a material property of the porous medium and assumed to be independent of the fluid. The absolute permeability is linked to the hydraulic conductivity “K_f” by taking into account the viscosity “μ” and density “ρ” of the fluid:

$$K = K_f \frac{\mu}{\rho \cdot g}$$

where “g” is the gravitational constant. In most cases, the K_f-values refer to pure water as the pore-filling fluid.

Permeability is dependent on the porosity and the grain-size distribution of the porous medium. However, large porosities do not necessarily mean high permeabilities, e.g. clays have high porosities but very low permeabilities. The unit for permeability used in reservoir engineering is Darcy “D” (or Millidarcy “mD”).

2.2 Processes in Porous Media

This section gives an overview of the various processes that can take place when fluid flow in porous media is investigated.

2.2.1 Advection

Advection is the fluid movement due to pressure gradients. **Figure 6** illustrates the advection process for an immiscible two-phase system. Fluid ‘A’ flows from left to right, because its pressure decreases in the same direction, $p_1 > p_2$. At the same time fluid ‘B’ is displaced towards the right.

Figure 6: Advection in Multi-phase Flow. Advection is caused by Pressure Gradients

As pressure may have gradients in all various directions, advective flow can go into all directions as well. For example, when fluid ‘A’ is injected into a porous medium fully saturated with fluid ‘B’, the additional external pressure required will cause fluid ‘A’ to flow in all directions, away from the injection point.

2.2.2 Buoyancy

Buoyancy flow is caused by density differences within a phase (e.g. salt-/freshwater) or between two phases (e.g. CO₂ and water). Both processes are described for one-phase water flow in porous media by Darcy’s Law and for multi-phase flow by the extended Darcy’s Law.

Figure 7 described the process of buoyancy in a two-phase system. Initially, fluid ‘B’ forms a layer on top of fluid ‘A’. As fluid ‘A’ is of lower density than fluid ‘B’, buoyancy causes fluid ‘A’ to rise to the top. At the same time, fluid ‘B’ has to migrate downwards for continuity reasons in a closed system.

Figure 7: Buoyancy in Multi-phase Flow. Density Differences cause Buoyancy Flow

2.2.3 Diffusion

Molecular Diffusion is the movement due to concentration gradients and is caused by the motion of the molecules. It is a process that equals out concentration differences as shown in **Figure 8**. In contrast to advection and buoyancy, diffusion is independent of orientation, i.e. it behaves the same in all directions.

Figure 8: Relevant Transport Processes of CO₂

2.3 Modeling of Flow in Porous Media

To understand the behavior of carbon dioxide that is injected into the subsurface, one has to know the different processes that may occur. At the injection well, CO₂ enters the aquifer with a certain density difference to the brine depending on the pressure at the respective aquifer depth and the applied pressure at the injection. The forming plume will spread, mainly driven by pressure differences that are induced by the injection well. As it flows further away from the injection point, the influence of buoyancy, diffusion and advection driven by the density difference between CO₂ and brine. Consequently, the CO₂ dissolves more and more in the formation brine. In a long-lasting process, the CO₂ may react with minerals of the formation rock. These different processes are explained in the following section.

2.3.1 Solubility of the Fluids

The solubility of carbon dioxide is of interest in the field of CO₂ sequestration, since it represents an important storage mechanism. Solubility of CO₂ in brine is higher when salinity is lower. The dissolution of CO₂ in brine is taken into account by an attempt of Duan and Sun, who present a thermodynamic formula to calculate the maximum solvable CO₂ concentration. The behavior of the CO₂ solubility is shown in **Figure 9**. As can be seen, the solubility of CO₂ in brine becomes higher with higher pressures and lower with higher temperatures.

Figure 9: Solubility of CO₂ in the Water Phase in Correlation to Pressure, including several Isotherms. (Bielinski, 2007)

2.3.2 Capillary Pressure

Capillary pressure at the pore scale describes the effect, that the pressures at the interface of two non-miscible fluids have a jump. The non-wetting phase (CO₂ phase) has a higher pressure than the wetting phase (the aqueous one). This difference is called capillary pressure and can be calculated on the micro scale using the equation below. It is proportional to the surface tension and to the contact angle, which the fluids describe at the interface. Smaller pores lead to higher capillary pressures.

$$P_c = \frac{4\sigma \cdot \cos(\alpha)}{d}$$

2.3.3 Relative Permeability

This is a rock-fluid property, which expresses the influence of the fluids on each other and the influence of the rock matrix on the flow behavior. Relative permeabilities have values between zero and one.

2.4 Criteria for Storage Reservoirs and Trapping Mechanisms

In order to understand CO₂ storage in aquifers, the different mechanisms, which prevent the CO₂ from escaping the storage site and that increase storage security should be known. They are listed and explained in the following.

2.4.1 Stratigraphic and Structural Trapping

Usually, CO₂ is injected into an aquifer which is situated under a geologic formation with a lower permeability. This uses the mechanism, that the low permeable layer forms a barrier for the CO₂ plume and prevents it from moving upwards e.g. due to buoyancy forces. This low permeable layer is called *cap rock*, and has ideally an intrinsic permeability, which is several orders lower than the permeability of the storage aquifer. The injected plume migrates upwards and becomes trapped there.

2.4.2 Residual Trapping

The residual saturation describes a part of a fluid in the pores of a volume which is not drainable by advective forces. Residual trapping occurs when the saturation drops, e.g. due to dissolution processes or buoyancy effects. The saturation usually does not drop to zero. A certain part is kept back in small pores, which cannot move anymore and is trapped there by capillary forces.

2.4.3 Solubility Trapping

Carbone dioxide, which is injected into an aquifer, dissolves to a certain amount in the aquifer brine. This is an ongoing process which takes relatively long and is influenced by

temperature and pressure and the salt content of the brine. The brine density is increasing, when CO₂ is dissolved. This enforces a downwards movement of the brine with the higher density and increases storage safety. Moreover, since it is not a separate phase anymore, there are no buoyancy effects acting, that drive the CO₂ upwards.

2.4.4 Mineral Trapping

This is a process that takes very long. It describes the effect, that CO₂ reacts with soil minerals and is then securely stored as chemical compound. This mechanism is not taken into account in this thesis.

Potential target reservoirs should meet several criteria in order to provide a high storage security and enable an economic sequestration. A confining layer on top the storage aquifer, which has a considerable lower permeability, is usually required. It has to prevent the CO₂ from rising upwards and to form a geological barrier for the gas. Enough storage space is required. Therefore the aquifer porosity should be high. Moreover, it should be possible to reach high injection rates into the reservoir with a technically feasible injection pressure. Therefore, the permeability of the storage reservoir should be high enough.

2.5 *Previous Work*

Numerical simulation of CO₂ geologic sequestration remains in the developmental stage, with a few studies, which are summarized below. Even fewer studies have employed reactive transport simulators, and much of these studies are in developmental stages. A brief overview of published previous work in CO₂ sequestration modeling is provided in this section.

Non-reactive transport modeling began in the early 90s when Van der Meer (Meer, 1993) simulated CO₂ sequestration in a circular anticlinal stratigraphic trap. A subsequent study by Holt et al. (Holt, 1995) modified ECLIPSE 100, a black oil simulator, to include the

solubility of CO₂ in H₂O and incorporated empirical relative permeability relations between liquid and gas phases, both previously not considered by Van der Meer (Meer, 1993). Their findings indicated that injection rate and absolute permeability were the dominant factors of migration of injected CO₂. Another study by Van der Meer (Meer, 1995) addressed CO₂ injection into a two dimensional, quasi-infinite aquifer and concluded that it was possible to sequester significant amounts of CO₂ in the subsurface but added that capturing the combined effects of viscous fingering and gravity segregation would require three dimensional modeling. Linderburg (Linderburg, 1995) described simulations of CO₂ injection at 8000 meters depth in a horizontally finite aquifer. He concluded that CO₂ storage was feasible beneath horizontal seals, provided that injection locations were sufficiently deep.

Law and Bachu (H.S. Law, 1966) conducted a study incorporating the STARS model to simulate multidimensional, multi-component flow and transport of CO₂ injected into a sedimentary basin for 30 years. The STARS model allows phase partitioning between separate and dissolved phase CO₂. They concluded that the most important factors affecting CO₂ storage potential include permeability and injection pressure, while the unit thickness is moderately important. Variable porosity produced minimal effects on the results. Weir et al (Weir, 1996) used the multiphase, multi-component TOUGH2 model to simulate CO₂ injection in geologic media. They concluded that the most significant factor affecting volumetric CO₂ storage potential is permeability.

Patterned after the work of Weir et al. (Weir, 1996) and Cole (Cole, 1999) developed a CO₂ equation of state for use with the TOUGH2 simulator that incorporated the effect of capillary pressure phenomena. In addition, he changed the previously employed variable switching technique used in TOUGH2 to a persistent set of primary variables applicable in both saturated and unsaturated conditions. His analyses indicated that, in agreement with previous studies, absolute permeability was the dominant mechanism controlling CO₂ migration. However the injection rate and injection depth were also of significant importance. None of the above studies considered chemical reactions between media, formation fluid, and injected CO₂.

Johnson et al. (Jonhson, 2000) used the simulator package NUFT (Nitao, 1998) to model CO₂ sequestration in geologic media. The NUFT simulator models the reactive transport of CO₂ injected into geologic media. Simulations were patterned after field scale CO₂ injections that are taking place at Statoil's North-Sea Sleipner facility. Their findings indicated that intra-aquifer structures have the most control of separate phase CO₂ migration paths and solubility within the aquifer unit, but that a capping layer of at least 25 meters thickness is required to prevent CO₂ of eventually escaping into the atmosphere.

In summary, previous work indicates it is possible to sequester CO₂ in the subsurface for long periods under ideal conditions. Previous studies also suggest that absolute permeability of both the aquifer and capping layer are the dominant geologic controls on CO₂ migration.

CHAPTER 3

OBJECTIVE AND METHODOLOGY

3.1 Objective of this study

The primary objective of this research is to study the impact of an aquifer properties and operational parameters to understand the CO₂ plume behavior and their contribution to each trapping mechanisms. The plume behavior of CO₂ injected into the aquifer formation is investigated, focusing on trapping mechanisms that lead to CO₂ plume stabilization. Since this is a generic study of CO₂ storage into an aquifer rather than a specific aquifer, the goal was to select representative characteristics for the aquifer as a 'base case'. This setting provides an ideal situation for investigating the interplay of CO₂ dissolution, buoyancy flow, capillary forces and geologic characteristics in regulating the behavior of the injected CO₂ plume. In addition, only one set of relative permeability curve is used in this study for a specific aquifer rock type. Therefore, the results can alter with a different rock type.

An understanding of the impact of the parameters in the process of storing CO₂ and their contribution to each trapping mechanism will help us to minimize uncertainty in estimates of the capacity and injectivity of CO₂. This study focuses on the different trapping mechanisms and how to maximize these forms of sequestration so that very large volumes of CO₂ can be permanently stored.

In order to accomplish these objectives the follow procedures were followed:

- Select representative characteristics for aquifer as 'base case'.
- Various injection schemes were modeled to evaluate CO₂ plume behavior.
- Vary the injection rate to evaluate the potential of CO₂ storage volume.
- Vary the reservoir properties and dip to evaluate the governing trapping mechanisms.

3.2 Simulator Description

GEM (*Generalized Equation-of-State Model Reservoir Simulator*) is a full “*Equation of State*” compositional reservoir simulator with advanced features for modelling the fluid composition effects. GEM also models Asphaltenes, Coal Bed Methane and the Geochemistry of the sequestration of various gases including Acid Gases and CO₂.

GEM is CMG's general equation-of-state (EOS) based compositional reservoir simulator for modelling the flow of three-phase, multi-component fluids. GEM is a robust, fully compositional simulator used to model any type of reservoir where the importance of the fluid composition and their interactions are essential.

Figure 10: CMG's Suite of Integrated Modelling Tools

GEM simulates a variety of structurally complex and varying fluid combinations beyond the conventional black oil simulators. Whether you are dealing with laboratory scale projects, pilot areas, elements of symmetry, or full-scale field studies, GEM will effectively model:

- Single and multi-component CBM recovery.
- Gas condensate recovery.
- Volatile oil reservoirs.
- CO₂ and hydrocarbon injection.
- Gas cycling and re-cycling.
- Water Alternating Gas (WAG) processes.
- Numerous other reservoir management processes

GEM is an essential engineering tool for modelling very complex reservoirs with complicated phase behavior interactions. This engineering tool includes all the features you would expect from a full-field compositional simulator. CMG's GEM simulator is practical, comprehensive, and effective.

3.2.1 Theoretical Outline

This section describes the equations and variables used in GEM and the approach for solving these equations. The flow equations are discretized using the adaptive-implicit method (Collins, Nghiem and Li, 1986; Thomas and Thurnau, 1983) because it encompasses both the explicit-transmissibility method and the fully-implicit method as particular cases.

The equations, variables and solution method presented in the following are variations of the approach of Collins, Nghiem and Li (1986).

Flow Equations

The material-balance finite-difference equations for the components in the oil and gas phases, and for the water component are:

$$\begin{aligned} \psi_i &\equiv \Delta T_o^m y_{io}^m (\Delta p^{n+1} - \gamma_o^m \Delta D) + \Delta T_g^m y_{ig}^m (\Delta p^{n+1} + \Delta P_{cog}^m - \gamma_g^m \Delta D) \\ &+ q_i^m - \frac{V}{\Delta t} [N_i^{n+1} - N_i^n] = 0 \quad i = 1, \dots, n_c \\ \psi_{n_c+1} &\equiv T_w^m (\Delta p^{n+1} - \Delta P_{cwo}^m - \gamma_w^m \Delta D) + q_{n_c+1}^m - \frac{V}{\Delta t} [N_{n_c+1}^{n+1} - N_{n_c+1}^n] = 0 \end{aligned}$$

where

N_i ($i=1, \dots, n_c$) denote the moles of Component ‘i’ per unit of grid block volume, and where N_{n_c+1} denotes the moles of water per unit of grid block volume. All other symbols are defined in the nomenclature. It is assumed that no mass transfer exists between the hydrocarbon and water phases. The superscripts ‘n’ and ‘n+1’ denote respectively the old and current time level. The superscript ‘m’ refers to ‘n’ for explicit grid blocks and ‘n+1’ for fully-implicit grid blocks. In GEM, the term explicit refers to grid blocks with explicit transmissibilities where only pressure is treated implicitly.

The N_i 's are related to porosities phase molar densities, saturations and compositions as follows:

$$\begin{aligned} N_i &= \phi (\rho_o S_o y_{io} + \rho_g S_g y_{ig}) \quad i = 1, \dots, n_c \\ N_{n_c+1} &= \phi \rho_w S_w \end{aligned}$$

Phase-Equilibrium Equations

If the hydrocarbon system is in the two phase region at a given p , T and N_i ($i=1,...,n_c$), the phase compositions and splits can be obtained by solving the thermodynamic-equilibrium equation

$$g_i \equiv \ln f_{ig} - \ln f_{io} = 0 \quad i=1,...,n_c$$

for N_{ig} , the moles of Component 'i' in the gas phase. The moles of Component 'i' in the oil phase, N_{io} , can be obtained from

$$N_{io} = N_i - N_{ig} \quad i=1,...,n_c$$

Saturation Equation

The saturations are related to N_i and ρ_m ($m = o, g, w$) through the following equation

$$S_w = N_{n_c+1} / (\phi \rho_w)$$

$$S_o = (1 - S_w) \frac{N_o / \rho_o}{N_o / \rho_o + N_g / \rho_g}$$

$$S_g = (1 - S_w) \frac{N_g / \rho_g}{N_o / \rho_o + N_g / \rho_g} = 1 - S_w - S_o$$

where

D	depth
f_{ij}	fugacity of component 'i' in phase j
F	function
g	phase-equilibrium function
n_b	number of grid blocks
n_c	number of components
N_i	moles of component 'i' per unit block volume

p	pressure
P_{cog}	oil-gas capillary pressure
P_{cwo}	water-oil capillary pressure
q	injection/production rate
t	time
T_j	transmissibility of phase j
V	grid block volume
y_{ij}	mole fraction of component i in phase j
γ	specific gravity or gravity term in flow equation
Δt	time step
ρ_m	molar density of phase m
ϕ	Porosity
ψ	Function

3.2.2 Well Model

Injector

The injection well model correlates the reservoir flow rate of phase j ($j = g, w$) to the wellbore pressure, p_{bh} and the pressure at grid point via the relationship:

$$Q_j = \sum_1 W I_1 \lambda_{Tj} (p_{bh} - p_{o,i}) \quad j = g, w$$

$$W I = 2 \pi f f k h \frac{w_{\text{frac}}}{\ln(r_e / r_w) + S} \quad j = g, w$$

with $p_{bh} > p_{o,i}$

where

Q_j = flow rate of phase j ($j = g, w$) at reservoir conditions (m^3/day | ft^3/day)

p_{bh} = bottom hole pressure (kPa | psia)

$p_{o,i}$ = pressure of i -th grid block containing the well (kPa | psia)

$WI_{j,l}$ = well injectivity index for phase j ($j = g, w$) to layer l

wfrac = well fraction, governed by areal geometry

k = effective permeability in the plane perpendicular to the well direction

h = grid block thickness in well direction (m | ft)

$$\lambda_T = \sum_j \frac{k_{rj}}{\mu_j} \quad j=g, w$$

is the total mobility of the fluid in the well block. The relative permeabilities are calculated using the grid block saturation

r_w = wellbore radius (m | ft)

A_i = area of i -th grid block perpendicular to well direction (m^2 | ft^2)

CC = geometric factor

S = skin factor (dimensionless)

ff = fraction of completion of the well in the grid block

The well model is a generalization of the well model proposed by Peaceman (1987, 1982) for square and non-square grid blocks. The mobility treatment follows the suggestion of Chappelle and Williamson (1979). In addition, the geometric factor allows the determination of the equivalent radius from both the geometry of the grid block and the location of the well in the grid block.

3.2.3 Wellbore Model

Pressure Loss Equation

The equation governing the change in pressure in the direction of flow used for the wellbore model is

$$\Delta p = \Delta p_H - \Delta p_{KE} - \Delta p_F$$

where

$$\Delta p_H = \rho g \Delta z \quad (\text{Hydrostatic head over the length } \Delta z)$$

$$\Delta p_F = \frac{2fv^2\rho}{D} \Delta z \quad (\text{Friction gain over a length } \Delta z)$$

$$\Delta p_{KE} = -\rho v^2 \ln\left(\frac{p_2}{p_1}\right) \quad (\text{Kinetic energy gain})$$

Here

ρ = density of the flowing "in situ" mixture

g = acceleration due to gravity

f = fanning friction factor

v = average velocity of mixture

D = inside pipe diameter

$\Delta p = p_2 - p_1$ = pressure drop over the length Δz

The wellbore model is a modification of the method of Aziz et al (1972). The modifications involve the use of an EOS to calculate the phase behavior and fluid properties of the flowing fluid. Further details may be found in Agarwal and Li (1988).

3.3 Aquifer Model Description

The Computer Modeling Group's GEM simulator was used in this study. Base case simulations were conducted for aquifer storage times of 1,000 years. Because this is a generic study of CO₂ storage in an aquifer rather than the study of a specific aquifer, the goal was to select representative characteristics for the aquifer as a “*base case*” for a systematic parameter study. This provides insight into the potential for CO₂ storage and to understand the sensitivity behavior of aquifer characteristics.

The input parameters for the base case simulation are summarized in **Table 1**. The simulated aquifer is 14,144 ft long, 14,144 ft wide and 960 ft thick, while the injector is in the center of the aquifer. The relative permeability curves are shown in **Figure 11**.

Pure supercritical CO₂ is injected into the aquifer for 25 years. The injector is then shut in, and the simulation continues with only density differences driving the flow. Having established the base case, we conducted several simulations to study the effect of the parameters influencing the distribution of CO₂ in the aquifer. These parameters include horizontal permeability, the ratio of vertical to horizontal permeability, porosity, and aquifer temperature, pressure and dip angle. These runs did not include geochemical reactions.

Assumptions used in the simulation are as follows:

- No conductive faults and no leaky wellbores in the aquifer.
- A single porosity medium is considered and is independent from capillary pressure effects.
- There is two-phase flow in the porous medium (liquid & gas).
- Rock type is the “*Basel Cambrian Sandstone*” in the Wabamun Lake area in the Alberta basin, Canada.
- No mineral trapping is considered in this study.

a) Basal Cambrian Sandstone

CO2 Saturation Fraction	Krg	Krw
0.000	0.0000	1.0000
0.035	0.0003	0.9105
0.071	0.0005	0.8248
0.106	0.0008	0.7430
0.141	0.0012	0.6650
0.177	0.0019	0.5911
0.212	0.0029	0.5211
0.247	0.0047	0.4552
0.282	0.0076	0.3933
0.318	0.0123	0.3356
0.353	0.0194	0.2821
0.388	0.0299	0.2328
0.424	0.0449	0.1879
0.459	0.0657	0.1474
0.494	0.0940	0.1114
0.529	0.1315	0.0800
0.565	0.1805	0.0535
0.600	0.2433	0.0318
0.635	0.3228	0.0154
0.671	0.4221	0.0045
0.706	0.5446	0.0000

Figure 11: Basel Cambrian Sandstone. Alberta Basin in Canada (Bennion, 2005)

Reservoir Data			
• Grid			
Type	Cartesian	64x64x24	
Size, ft	D "I"	221	
	D "J"	221	
	D "K"	40	
• Aquifer Properties			
Length, ft		14,144	
Width, ft		14,144	
Thickness, ft		960	
Depth, ft	Top	7,425	
	Bottom	8,385	
Porosity, %	Type	Single	
	Constant	13	
Vertical to horizontal permeability ratio		0.1	
Horizontal permeabilities of each layer, md	Layer 1-24	100	
Rock Fluid Data			
• Rock Compressibility, 1/psi		4.00E-06	
• Ref. Pressure for calculating rock compressibility, psi		3,550	
Fluid Component Data			
• Model		Ping- Robinson	
• Description of Components			
CO2	Critical pressure, psi	1,070.00	
	Critical temperature, °F	87.77	
	Critical volume, cu ft/lb-mole	1.5076	
	Molecular weight, lb/lb-mole	44.01	
	Acentric factor, dimensionless	0.22394	
	Parachor, dimensionless	78	
• Reservoir Temperature, °F		200	
Initial Condition			
• Reference Pressure, psi		3,550	
• Reference Depth, ft		7,500	
• Dip, degree		0	
Well Data			
Well # 1			
• Type		INJ	
• Constraints			
	• Maximum injection pressure, psi		
	"Bottom Hole Pressure"	5,000	
	• Maximum injection rate, ft3/day		
	"Surface Gas Rate"	5,000,000	
• Injection Fluid		CO2	
• User Block Address		32 32 20:24	
• Operating Status			
	Starting Date	Jan-00	
	Shutin Date	Jan-25	

Table 1: Simulation Input for Base Case

3.4 Case Studies

Studying of the impact of the parameters in the process of storing CO₂ and their impact on each trapping mechanism will help reduce uncertainty in estimates of the capacity and injectivity of CO₂. By trapping mechanisms, refers to any chemical or physical process through which CO₂ can be stored and retained in a geological environment.

The efficiency of long-term storage in aquifers will be directly related to the efficiency of each of the trapping mechanisms involved. In the context of CO₂ storage particularly in aquifers, four major trapping mechanisms are:

- Hydrodynamic (structural or stratigraphic) trapping, where cap rock prevents mobile CO₂ from flowing back to the surface.
- Residual or capillary trapping, where capillary forces and relative permeability effects will contribute to converting the CO₂ injected into an immobile phase.
- Solubility trapping, where CO₂ dissolves in the aqueous phase.
- Mineral trapping, where chemical reactions between CO₂ and rock minerals forms a solid carbonate.

During the injection phase, structural or stratigraphic trapping is the main contributor preventing CO₂ from escaping to the surface. Mineral trapping the safest long-term way to trap CO₂, as it transforms it into an immobile solid; however, this process can be very slow and not included in this study.

In this paper, we will focus on the first three trapping mechanisms that are likely to be effective on an intermediate time-scale. We perform a sensitivity analysis on the parameters listed in *Table 2*.

Table 2: Summary of Simulation Runs for Sensitivity Analysis

Case Studies	Parameter Varied	Modified Inputs	Comments
Base Case *	Bottom Injection *	bottom perforation	Various Injection Schemes were modeled to better understand the behavior of CO ₂ plume
Run 1	Top Injection	top perforation	
Run 2	All Layers Injection	all layers perforations	
Case 1 *	Q _{rate} = 5 MMCFD *	N/A	Increasing Injection Rate to evaluate the potential for CO ₂ storage volume
Run 1	Q _{rate} = 7 MMCFD	N/A	
Run 2	Q _{rate} = 10 MMCFD	N/A	
Run 3	Q _{rate} = 20 MMCFD	N/A	
Case 2	Temperature _{reservoir} = 100 °F	Pressure _{reservoir} = 3,500 psi	Increasing Reservoir Temperature and Pressure to determine the effect of both temperature and pressure mainly on Solubility Trapping Mechanism
Run 1	Temperature _{reservoir} = 135 °F	Pressure _{reservoir} = 3,500 psi	
Run 2 *	Temperature _{reservoir} = 200 °F *	Pressure _{reservoir} = 3,550 psi	
Run 3	Temperature _{reservoir} = 265 °F	Pressure _{reservoir} = 3,550 psi	
Case 3	Pressure _{reservoir} = 3,250 psi	Temp _{reservoir} = 190 °F	
Run 1	Pressure _{reservoir} = 3,400 psi	Temp _{reservoir} = 190 °F	
Run 2 *	Pressure _{reservoir} = 3,550 psi *	Temp _{reservoir} = 200 °F	
Run 3	Pressure _{reservoir} = 3,700 psi	Temp _{reservoir} = 200 °F	
Case 4 *	Permeability _{horizontal} = 100 md *	Porosity = 13 %	
Run 1	Permeability _{horizontal} = 200 md	Porosity = 13 %	
Run 2	Permeability _{horizontal} = 500 md	Porosity = 15 %	
Run 3	Permeability _{horizontal} = 800 md	Porosity = 15 %	
Case 5	Permeability _{vertical} = 0.1 md	N/A	Modifying the reservoir properties " Horizontal Permeability, Vertical Permeability and Porosity " to evaluate the governing trapping mechanisms
Run 1	Permeability _{vertical} = 1 md	N/A	
Run 2	Permeability _{vertical} = 5 md	N/A	
Run 3 *	Permeability _{vertical} = 10 md *	N/A	
Case 6	Porosity = 8 %	Perm _{horizontal} = 95 md	
Run 1	Porosity = 10 %	Perm _{horizontal} = 95 md	
Run 2 *	Porosity = 13 % *	Perm _{horizontal} = 100 md	
Run 3	Porosity = 20 %	Perm _{horizontal} = 100 md	
Case 7 *	Aquifer _{dip angle} = 0 °*	N/A	Increasing Aquifer Dip Angle in order to maximize the trapping mechanisms so that large volumes of CO ₂ can be permanently stored in the aquifer
Run 1	Aquifer _{dip angle} = 10 °	N/A	
Run 2	Aquifer _{dip angle} = 15 °	N/A	
Run 4	Aquifer _{dip angle} = 25 °	N/A	

*Base Case

CHAPTER 4

RESULTS AND DISCUSSIONS

The aquifer model was initially fully saturated with brine; CO₂ was then injected over 25 years. In almost all the simulation runs, one vertical well is used to inject CO₂, which is located at the center of the model and, in the case of the “*Dipped Aquifer*” model; the CO₂ injection well is located near the edge of the reservoir. In most runs, an injection rate of ‘5 MMSCF/D’ is used.

To understand the impact of each parameter independently, a few values per parameter were selected to identify their contribution to the different trapping mechanisms. The parameters in the analysis were horizontal permeability, vertical permeability, porosity, temperature and pressure. In addition, the effects of injection strategies (i.e. various injection schemes), different injection rates, well location and aquifer dip angle are included as part of the analysis.

4.1 Injection Scheme Case Study

A vertical well was selected with 3 different locations of perforation for this case study. The following case study were modeled in order to better understand the plume behavior of CO₂ and to assess the impact of well perforation location. **Figure 12** shows the different injection schemes that were modeled.

Figure 12: Various Injection Schemes for Base Case

In **Table 3**, we observe that the amount of CO₂ that has been injected is the same for both the ‘base case’ (bottom perforation) and ‘run 01’ (top perforation). However, for ‘run 02’ the amount of CO₂ injected is higher since it is injected with 10 MMSCFD.

CASE	KEY FEATURES	CUMULATIVE GAS INJECTION, ft ³	GAS INJECTION RATE, ft ³ /day	GAS INJECTION PERIOD, years
Base Case	Bottom Injection	4.56E+10	5.00E+06	25
Run 01	Top Injection	4.56E+10	5.00E+06	25
Run 02	All Layers Injection	9.13E+10	1.00E+07	25

Table 3: Amount of CO₂ injected and Gas Injection Rate and Period for Base Case

In **Figure 13**, we observe that amount of CO₂ dissolved is higher in ‘bottom perforation’ than both ‘top and all layers perforation’ throughout the simulation period. Bottom completion allows the CO₂ plume to come into contact with larger amount of brine, which will enhance the solubility trapping mechanism as it moves upward due to buoyancy effect. In addition, the larger distribution of the plume will benefit the CO₂ residual, **Figure 13**, the well with ‘bottom and all layers completion’ gave us more CO₂ trapped than the ‘top completion well’. Also, as time passes the super-critical CO₂ will decreases because it will either goes to get trapped or goes into solution and dissolved. The deeper and larger the well completion, the longer the path for the CO₂ plume to reach the top of the structure, and in consequence large volumes of water and a larger distribution benefits both trapping mechanisms.

Figure 13: Percentage of CO₂ Phases at Various Times for Base Case

In addition, diagrams for CO₂ plume behavior and its different phases for this case are presented in Appendix ‘A’ section of the following paper. In all these runs, solubility trapping is an ongoing process, brine density increases when CO₂ is dissolved and enforces a downward movement of the brine as shown in the Appendix which will increase storage safety.

4.2 Injection Rate Case Study

Four injection rates were used in this case study to evaluate the potential for CO₂ storage volume. In case 1, CO₂ was injected at a rate of 5 MMSCF/D, while Run 1, 2 and 3 the injection rates were 7 MMSCF/D, 10 MMSCF/D and 20 MMSCF/D respectively. All

injections were carried out for 25 years, except for Run 2 and 3 since it reaches its maximum injection pressure before 25 years. This is shown in the following **Table 4**.

CASE	KEY FEATURES	CUMULATIVE GAS INJECTION, ft ³	GAS INJECTION RATE, ft ³ /day	GAS INJECTION PERIOD, years
Case 1	$Q_{rate} = 5$ MMSCF/D	4.56E+10	5.00E+06	25
Run 01	$Q_{rate} = 7$ MMSCF/D	6.39E+10	7.00E+06	25
Run 02	$Q_{rate} = 10$ MMSCF/D	8.77E+10	1.00E+07	23
Run 03	$Q_{rate} = 20$ MMSCF/D	8.90E+10	2.00E+07	12

Table 4: Amount of CO₂ injected and Gas Injection Rate and Period for Case 1

In order to increase the trapping mechanisms efficiency, all the wells are completed from the middle of the aquifer to the bottom as we concluded in the previous case. With injection rates increasing, the cumulative gas injected into the aquifer also increases. However, the higher the injection rates, the shorter the injection period will be due to the constraints of the injection pressure. This is shown in the following **Figure 14**.

Figure 14: Injection Period for Case 1

Figure 15: Percentage of CO₂ Phases at Various Times for Case 1

In *Figure 15*, the amount of CO₂ trapped is highest when injected at high rate throughout the simulation period. Injection at high rates allows the CO₂ plume to spread out horizontally, mainly caused by advection processes. This allows more CO₂ to come in contact with more brine and residual trapping occurs when CO₂ saturation drops due to dissolution and buoyancy effects. Super-critical CO₂ slowly decreases allowing more CO₂ to go into solution which increases the solubility trapping mechanism. Diagrams of CO₂ plume behavior for this case are shown in Appendix 'B' section of this report.

4.3 Temperature Case Study

An increase in temperature increases the mobility contrast between the brine and CO₂, which allows the CO₂ plume to disperse faster. Then, as the plume travels faster, it will be in contact with larger amounts of fresh brine causing more CO₂ to be dissolved, as

shown in **Figure 16** and **Figure 17**. This effect is seen even though the solubility of CO₂ in brine decreases slightly with temperature—it is the overall movement of the free-phase CO₂ that dominates the behavior.

Figure 16: Percentage of CO₂ Dissolved Over Time for Different Temperatures

Temperature also has an impact on capillary trapping mechanism, though over time the amount of residual CO₂ is slightly less at higher temperatures, since more CO₂ is now dissolved as seen in **Figure 17**. Overall though, temperature has slight impact on the amount of CO₂ that is trapped. The CO₂ plume behavior is illustrated in the Figures given in the Appendix ‘C’.

Figure 17: Percentage of CO₂ Phases at Various Times for Temperature Effects Case

4.4 Pressure Case Study

Figure 18 compares the CO₂ phase distributions for the highest pressure with the lowest pressure case: the extent of CO₂ migration reduces as the pressure increases. As pressure increases, the CO₂ becomes denser and more viscous, which lowers the volume (a fixed mass is injected) and mobility of the CO₂ plume and in consequence reduces its spread.

Figure 18: CO₂ Plume Distribution after 25 years of Injection at 2 Different Pressures

In **Figure 19** (on the top), we can observe that higher pressures very slightly increase the amount of dissolved CO_2 . Again, as we saw for temperature, the amount of dissolution in both cases is dominated by the extent of the plume. In contrast, we observe that higher pressures increases slightly the amount of CO_2 residual (**Figure 19**, center), since the CO_2 is less mobile, which makes the residual trapping mechanism more effective at late times, when the CO_2 saturation becomes lower.

Both mechanisms act counter to an increase in pressure, and in **Figure 19** (bottom) we observe that both contributions cancel each other out approximately and the amount of free CO_2 does not change significantly with a change in pressure.

Figure 19: Percentage of CO₂ Dissolved (top), CO₂ Residual (center) and CO₂ Mobile (bottom) over Time for Different Pressures in the Aquifer

4.5 Horizontal Permeability Case Study

Figure 21 shows that the amount of CO₂ dissolved increases as the average permeability increases. This is due to the lateral spreading of the CO₂ plume over a larger volume which is directly controlled by the horizontal permeability (**Figure 20**). In addition, as a consequence of the greater spreading of the CO₂ plume, it leaves behind a bigger residual trail, further increasing the total amount of CO₂ trapped. For the highest permeability studied (800 md), 975 years after injection, less than 20% of the CO₂ injected remains as free gas, compared with 55% for the case with 100 md.

Figure 20: CO₂ Plume Distribution 325 years after the Injection Period showing the Effects of Horizontal Permeability

The results of this study case show that horizontal permeability has a large impact on the migration of a CO₂ plume. High overall permeability increases the overall distance that a plume may migrate. Low permeability impedes CO₂ movement away from the injector post injection. These processes help more CO₂ to go into solution and cause no buoyancy effects. Diagrams of CO₂ plume behavior for this case study are presented in Appendix 'E' section with a chart of various CO₂ phases during and after injection.

Figure 21: Percentage of CO₂ Dissolved (top), CO₂ Residual (center) and CO₂ Mobile over Time for Different Horizontal Permeabilities

4.6 Vertical Permeability Case Study

Vertical permeability has a significant impact on long term migration to the seal of the model. Generally low vertical permeability reduced the volume of CO₂ reaching the top of the model by impeding vertical flow as shown in *Figure 22*.

Figure 22: CO₂ Plume Distribution 325 years after the Injection Period showing the Effects of Vertical Permeability

Figure 23 shows that the amount of CO₂ dissolved increases as the vertical permeability increases over the simulation period. This is due to the upward movement of the CO₂ plume caused by mainly buoyancy which is directly controlled by the vertical permeability (**Figure 22**) allowing more CO₂ to come in contact with more brine.

However, for the trapped CO₂ phase, at first we noticed that it is increasing over time, but overall the trapped CO₂ decreases as we increase the vertical permeability. This happens because with low vertical permeability CO₂ gets trapped and slowly reaches the top of the aquifer. For the highest permeability studied (10 md), 975 years after injection, 15% of the CO₂ injected remains as trapped gas, compared with 40% for the case with 1 md.

Figure 23: Percentage of CO₂ Phases at Various Times for Vertical Permeability Effects Case

Chart and diagrams for CO₂ plume over time for this case is shown in Appendix ‘F’ section.

4.7 Porosity Case Study

Porosity has a minimum effect on dissolved CO_2 over time. As the reservoir porosity increases as seen in **Figure 25** dissolved CO_2 decreases at very minimum rates. On the other hand, residual trapping increases over time due to more porosity in the rock which allows the CO_2 free gas to get trapped in a larger pore volume. With a higher porosity reservoir, more free gas CO_2 get trapped and allowing less buoyancy and advection effect to occur. This allows less CO_2 to come in contact with the aquifer and therefore less CO_2 goes into solution as shown in the **Figure 24**.

Figure 24: CO₂ Plume Distribution 650 years after the Injection Period showing the Effects of Reservoir Porosity

Figure 25: Percentage of CO₂ Phases at Various Times for Porosity Effects Case

The results of this study case show that porosity has a large impact on the amount of free gas trapped CO₂. Diagrams of CO₂ plume behavior for this case study are presented in Appendix ‘G’ section with a chart of various CO₂ phases during and after injection.

4.8 Aquifer Dip Case Study

We next analyze the effects of having a reservoir structure with a certain slope. **Figure 27** (top) shows that even a small dip causes the same benefit as a more clearly dipping aquifer in terms of the amount of CO₂ dissolved. The dipping and the buoyancy of the CO₂ make the plume migrate upwards rapidly and come into contact with larger volumes of fresh brine. This enhances the solubility process and in addition, the larger the

spreading area of the CO₂, the larger the residual trail left behind as the plume travels upwards, enhancing the residual trapping mechanism.

Figure 26: Percentage of CO₂ Phases at Various Times for Aquifer Dip Effects Case

After 350 years the amount of CO₂ mobile for the flat case is 65% of the CO₂ injected, while in the case of an aquifer with a slope of 10 degrees, this amount is reduced to 48%. Thus, even a small dip in the aquifer is beneficial for incrementing the total amount of CO₂ trapped. In our particular case and conditions, we observe that the effectiveness on reducing CO₂ mobile gives the best performance with a dip of 10 degrees. If we continue increasing the dip, the benefit is reduced and larger amounts of CO₂ remain free. This behavior occurs because a strongly dipping reservoir causes the CO₂ plume to migrate so fast that it reaches the top of the structure without much dissolution.

Figure 27: Percentage of CO₂ Dissolved (top), CO₂ Residual (center) and CO₂ Mobile over Time for Different Aquifer Dips

CHAPTER 5

CONCLUSIONS AND RECOMMENDATIONS

The concerns about CO₂ escape pathways from aquifers used for storage can be considerably mitigated if all or almost all of the CO₂ were stored in the immobile forms of residual gas, dense brine and minerals. Mineralization trapping mechanism (conversion of dissolved CO₂ into carbonate minerals) is a very long process and was not considered in this study; therefore it is important to study this mechanism. CO₂ injection in a saline aquifer was simulated with emphasis on dissolution and residual trapping mechanisms that would immobilize (store) the CO₂. Based on the results, the following conclusions were made:

- The most significant conclusion from this scoping study is that the effect of residual gas on CO₂ storage can be significant. Potentially all of the CO₂ can be stored in an immobile form if one can take advantage of capillary trapping. Therefore, the magnitude and variation of residual gas saturation as a petrophysical property demand further study.
- Both aquifer dip and permeability have a significant impact on gas migration, which in turn affects CO₂ dissolution in brine and capillary trapping. The time scale for reduction of mobile gas to insignificant values strongly depends on the petrophysical parameters of the aquifer. Over the range of parameters investigated in this scoping study, less than half of the mobile gas remained in the aquifer after a few hundred years.
- Operational parameters, such as well placement, well completion and injection strategies, are very important contributors to both trapping mechanisms. Wells completed over a longer period and located at greater depths will contribute to an increase in the total amount of CO₂ trapped.
- In addition, the method of water alternating gas (WAG) was not included in this study. However, the use of such technique enhances the residual trapping mechanism because of a forced imbibition process or the injection of mixtures of CO₂ and brine that reduces the mobility ratio of the CO₂ enhancing the spread of

the plume. Thus, the use of a WAG injection scheme is strongly recommended as this can lead to the trapping of more CO₂ injected during a few years following the injection period.

Potential target reservoirs should meet several criteria in order to provide a high storage security and enable an economic sequestration. A confining layer on top the storage aquifer, which has a considerable lower permeability, is usually required. It has to prevent the CO₂ from rising upwards and to form a geological barrier for the gas. Enough storage space is required. Therefore the aquifer porosity should be high. Moreover, it should be possible to reach high injection rates into the reservoir with a technically feasible injection pressure. Therefore, the permeability of the storage reservoir should be high enough.

REFERENCES

- Bennion, S. B. (2005). Relative Permeability Characteristics for Supercritical CO₂ Displacing Water in a Variety of Potential Sequestration Zones in the Western Canada Sedimentary Basin.
- Bielinski, A. (2007). *Numerical Simulation of CO₂ Sequestration in Geological Formations*. Institut für Wasserbau, University of Stuttgart.
- Cole. (1999). *An Equation of State for Multiphase CO₂ and Water*. New Mexico Institute of Mining and Technology.
- D.O.E. (2008). Carbon Sequestration Atlas of the United States and Canada. *Second Edition*.
- Doughty, C. (2009). *Investigation of CO₂ Plume Behavior for a Large-Scale Pilot Test of Geologic Carbon Storage in a Saline Formation*. Springerlink.com.
- H.S. Law, S. B. (1966). Hydrological and Numerical Analysis of CO₂ disposal in deep aquifer systems in the Alberta sedimentary basin. 37.
- Holt, e. a. (1995). Underground Storage of CO₂ in Aquifers and Oil Reservoirs. 36.
- Jan Nordbotten, M. C. (2004). Injection and Storage of CO₂ in Deep Saline Aquifers: Analytical Solution for CO₂ Plume Evolution During Injection.
- Jonhson, J. (2000). Reactive Transport Modeling of Subsurface CO₂ Sequestration: Identification of Optimal Target Reservoirs and Evaluation of Performance Based on Geochemical, Hydrologic, and Stractural Constraints.
- L. Nghiem, P. S. (2004). Modeling CO₂ Storage in Aquifers with a Fully-Coupled Geochemical EOS Compositional Simulator. *SPE/DOE Fourteenth Symposium of Improved Oil Recovery*. Tulsa, Oklahoma: SPE 89474.
- L. Nghiem, V. S. (2009). Simulation of Trapping Processes for CO₂ Storage in Saline Aquifers. Calgary, Alberta, Canada: Canadian International Petroleum Conference.
- Linderburg, E. (1995). Escape of CO₂ from Large Horizontal Aquifers Confined Only by a Cap Seal. *Greenhouse Gases: Mitigation Options*.
- Meer, V. D. (1995). The CO₂ Storage Efficiency of Aquifers. 36.
- Meer, V. D. (1993). The Conditions Limiting CO₂ Storage in Aquifers. 34.

Metz, B. (2005). *Special Report on Carbon Dioxide Capture and Storage*. Retrieved from http://www.ipcc-wg3.de/pages_media/SRCCS-final/ccsspm.pdf

Nghiem, L. (n.d.). *Compositional Simulator for Carbon Dioxide Sequestration. (Computer Modeling Group Ltd) . 2002.*

Nitao, J. (1998). Reference Manual for the NUFT Flow and Transport Code. *UCRL-ML-130651 , version 2.0 . Lawrence Livermore National Laboratory.*

S. Bachu, W. G. (1994). Aquifer Disposal of CO₂: Hydrodynamic and Mineral Trapping. 35 (pp 269-279).

Weir, G. (1996). Reservoir Storage and Contaminant of Greenhouse Gases. 23.

APPENDIX

‘A’

Various Injection Strategies Case Study:

- Bottom Injection

- Top Injection

- All Layers Injection

‘B’ Various Injection Rates Case Study:

- Injection rate 5 MMSCF/D

- Injection rate 7 MMSCF/D

- Injection rate 10 MMSCF/D

- Injection rate 20 MMSCF/D

‘C’

Temperature Effects Case Study:

- Reservoir Temperature 100 °F

- Reservoir Temperature 135 °F

- Reservoir Temperature 200 °F

- Reservoir Temperature 265 °F

'D'

Pressure Effects Case Study:

- Reservoir Pressure 3,250 psi

- Reservoir Pressure 3,400 psi

- Reservoir Pressure 3,550 psi

- Reservoir Pressure 3,700 psi

‘E’ Horizontal Permeability Effects Case Study:

- Horizontal Permeability 100 md

- Horizontal Permeability 200 md

Horizontal Permeability 500 md

- Horizontal Permeability 800 md

'F'

Vertical Permeability Effects Case Study:

- Vertical Permeability 0.1 md

- Vertical Permeability 1 md

- **Vertical Permeability 5 md**

- **Vertical Permeability 10 md**

‘G’

Porosity Effects Case Study:

- Reservoir Porosity 8 %

- Reservoir Porosity 10 %

- Reservoir Porosity 13 %

- Reservoir Porosity 20 %

‘H’

Aquifer Dip Effects Case Study:

- Reservoir Dip 0 degree

- Reservoir Dip 10 degree

- Reservoir Dip 15 degree

- Reservoir Dip 25 degree