Investigation of Multiple Well Injections for Carbon Dioxide Sequestration in Aquifers

by

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A thesis presented to the University of Waterloo in fulfillment of the thesis requirement for the degree of Master of Applied Science in Chemical Engineering

Waterloo, Ontario, Canada, 2014

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Author’s Declaration

I hereby declare that I am the sole author of this thesis. This is a true copy of the thesis, including any required final revisions, as accepted by my examiners.

I understand that my thesis may be made electronically available to the public.

Abhishek Joshi
Abstract

As the amount of CO₂ present in the atmospheres is increasing due to combustion emission, it is becoming more and more important to find ways to reduce greenhouse gas emissions. One of the ways to do that is through carbon sequestration. Saline formations (aquifers) provide viable destination for carbon sequestration. The storage potential in these reservoirs is estimated at several thousands of Giga Tonnes (Gt) of CO₂. Even though the capacity is substantial, the process of filling this capacity has a lot of challenges. Injection of large volumes within short period of time increases the formation pressure (which should be below fracture pressure) very fast. For each particular reservoir, injection capacity should be identified based on which CO₂ can be injected within a particular injection area and time. In order to achieve this, an in-depth sensitivity study needs to be done on the various reservoir parameters such as thickness, rock compressibility, permeability, porosity, reservoir temperature and pressure, aquifer fracture pressure, number and placement of injection’s wells. The objective of my Master's thesis work is finding ways to increase the storage injection capacity based on reservoir parameters and optimizing the well placement by identifying and developing analytical and numerical tools to do so. The research also focuses on conducting a sensitivity analysis on these parameters in order to find out the optimal injection scenario to obtain the amount of maximum CO₂ sequestration in a reservoir. This study can help in the CO₂ sequestration capacity predictions and screening suitable reservoir based on technical and economic criteria.

In order to derive the injection capacity of the reservoir based on the reservoir parameters, two analytical models of multiple well injections were studied: i) Single-phase (Brine injection in a brine reservoir and ii) Two phase model (CO₂ injection in a brine reservoir). In both cases, the aim is to analyse the pressure build-up and the results are discussed in terms of comparison with numerical simulations. Although analytical modeling is less accurate (compare to numerical) and restricted to vertical well injection it allows large number of realizations for sensitivity analysis to find significant patterns of the process and reduces the number of numerical simulations needed at final stages of optimization. Analysis is done by considering infinite acting, homogenous, isotropic and isothermal reservoir condition. The Ei-function approximation method was used to simulate results on pressure profile across the reservoir.
Once we have a validated model, we look into increasing the CO$_2$ injection capacity of saline aquifers by applying the multiple wells injection strategy. This was done by looking at the well interferences based on superposition principle and mapping the pressure build-up profile in the reservoir. Various approaches were used to get maximum injection capacity.
Acknowledgements

Foremost, I would like to express my sincere gratitude to Professor Yuri Leonenko for the continuous support for my MASc research, for his motivation, patience and immense knowledge. His guidance helped me in all the time of research and writing of this thesis. I am extremely grateful for having better advisor and mentor for my study at Waterloo.

Besides my advisor, I would like to thank the rest of my thesis committee: Professor Ali Elkamel and Professor Carolyn Renor for their encouragement and insightful comments.

I am grateful to my grandmother Late Sarla Joshi, who has always had a very strong influence in my life; my parents and guardians Dinesh Joshi, Mukesh Joshi and Mamta Joshi for always supporting me and providing me with all the amenities to achieve my dreams; my brothers and sisters, Binita, Anita, Ashish and Aditya for loving me unconditionally always and having faith in me when I doubted myself.

Very special thanks goes out to my colleague and my dear friend, Swati for the immense discussions about well placements, for the sleepless nights we were working together before deadlines, attending conferences, attending most of the courses together and for all the fun we had in the last two years. I would also like to thank my friends Ankita and Bhushan for our philosophical debates and venting of frustration during my graduate studies at Williams, which helped enrich the experience. I would like to be grateful to my friends Manoj, Sami, Jill, Aravind, Ushnik, Hussain and Samudra for always being there to brighten my spirits up.

I would like to thank my extended family in Canada which includes Chakravarti uncle, aunty, Bhargavi my loving understanding Anand bhaiya and Bhabhi for always being there whenever I felt homesick and needed a time off from work.

Lastly I would like to pay my gratitude to god for his blessings and guidance.
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Chapter 1
Introduction

1.1 Need for CO₂ Capture

Our world runs on energy – it’s fundamental to our way of life and growing our economy. Energy is essential for everything from fueling our cars to heating our homes to powering the appliances we depend on daily. But the world is changing. The discovery and development of a large number of powerful energy sources—coal, petroleum, electricity, etc.—have enabled humanity to conquer the barriers of nature. All this has facilitated the growth of fast modes of transport, which in turn has transformed the world into a global village. Technological changes have led to drastic changes in various aspects of human life from life expectancy, education levels, material standards of living, and the nature of work, and the effects of human activities on the natural environment. This has led to a rapid increase in population across the globe. It is estimated that the world’s population will rise by more than 25 percent from 2010 and will reach nearly 9 billion by 2040 (The Outlook of Energy, 2040). The increase in population will be followed by an increase in energy consumption. Global energy demand will grow by 35 percent compared to 2010, with energy demand in developing countries rising to about 65 percent from 2010 to 2040 (The Outlook of Energy, 2040). In order to meet the energy demand, our dependency on fossil fuels will further increase. It is estimated that by 2040 about 80% of energy needs will be met by Fossil Fuels like Oil, Gas, and Coal. Non-Renewable Source of Energy won’t be enough to meet the growing energy demands and fossil fuels (including oil and natural gas) will be an important source of energy till 2040.

As the demand for Fossil Fuels increases, so will the amount of CO₂ in the atmosphere. CO₂ is one of the most prominent greenhouse gases leading to global warming. It is predicted that the global surface temperature may rise by 1.1°C to 6.4°C depending upon the emissions scenario which will have devastating effects. In order to continue using fossil fuels without increasing the concentration of CO₂ in the air below 450 ppm (2.0 – 2.4°C temperature rise) is to look into innovative ways to decrease our carbon footprint.

1.2 CCS (Carbon Capture and Sequestration)

One of the ways to increase our energy source and simultaneously decrease carbon footprint is to use Carbon Capture and Sequestration (CCS) technique which can provide up to 20 percent of the CO₂ emission reductions. CCS is Capture, Transportation and Sequestration of CO₂ safely and
permanently into geological formations. Carbon dioxide capture and storage (CCS) is being actively pursued by many countries as one of the key options for reducing atmospheric carbon dioxide (CO$_2$) emissions. The overall technology involves firstly an industrial process that separates and captures CO$_2$ (from other emissions) before it is released to the atmosphere. It is projected that by 2050, CCS could reduce annual carbon dioxide emissions by 9 to 16 billion tonnes worldwide.

Figure 1: CCS Overview (courtesy of IPCC; reported in IPCC 2005, after Bradshaw and Dance, 2004)

1.3 CCS Feasibility

A CCS technology has the capacity to reduce emissions from fossil fuel power plants by 85-90% but it is very expensive as it increases the overall cost of an industrial process. It is estimated that incorporating CCS results in increases in operational costs (due to increase in energy requirement) by about 10 to 40 percent and capital costs by about 30 to 60 percent.

Carbon Capture and Storage is an expensive process and is economically feasible only if we have stringent public policies and high carbon taxes (about 25-30$ per tonne).
The International Energy Agency has estimated that by 2050, the cost of tackling climate change without CCS could be 70 percent higher than with CCS. Similarly EU also estimated that the cost of tackling climate change would be 40 percent higher without CCS by 2030. So we have to start incorporating CCS projects into our current industrial plans in order to decrease our carbon footprint. Also by finding additional uses of captured CO\(_2\) either for Enhanced Oil/Gas Recovery (EOR) or for using in urea plant, polymer processing, chemical manufacturing etc., we can promote this technology.

### 1.4 Objective

The worldwide emissions from fossil fuels reached an all-time high of 9.7 billion tons of carbon in 2012 (Olivier et al., 2012). Typical present benchmark rate (in academic studies and field projects) of CO\(_2\) injection is 1 Mt/year. In-order to manage global CO\(_2\) emissions by CCS, we have to consider much higher injection rates. But injection of large volumes within short period of time increases formation pressure (which should be below fracture pressure) very fast which may lead to loss in integrity of the reservoir leading to leakage. The objective of the research is to identify and develop approaches to model the pressure behavior inside a reservoir during CO\(_2\) injection. By performing modeling on injection of large volume of CO\(_2\) for various different reservoir parameters we will be able to predict the reservoir CO\(_2\) storage capacity. This will help in screening of suitable reservoir based on technical and economical criteria’s.

Also the study was conducted to look at ways to increase the injection capacity of the screened and selected reservoir without over pressurizing the system by looking at places of maximum pressure buildup and mitigating theses spots by varying either the wells placement or by varying the injection flow rates.
Chapter 2
Carbon Storage/Sequestration

2.1 Overview

Sequestration is the process of isolating CO$_2$ from the environment. It involves the capture and disposal of anthropogenic CO$_2$ in geologic sites. A suitable CO$_2$ storage reservoir needs a layer of porous rock, at the correct depth to hold the CO$_2$, sufficient capacity and an impermeable layer of “cap” rock to seal the porous layer underneath.

CO$_2$ can be stored successfully deep underground as many natural accumulations of CO$_2$ exist throughout the world without any evidence of leakage. The widespread distribution of natural CO$_2$–rich fields within large sedimentary basins in geologically stable regions provides numerous potential CO$_2$ storage sites (Stenhouse, 2009).

Figure 2: Worldwide regions that may be suitable for geological CO$_2$ storage (courtesy of IPCC; reported in IPCC 2005, after Bradshaw and Dance, 2004)
Geological CO₂ storage involves injecting large volumes of the captured CO₂ into the pore space of rock formations typically more than 900 m below the earth’s surface. At such depths, the CO₂ is in a supercritical state and denser than a gas and occupies less pore space for the same amount (mass) of CO₂.

Various geologic sites identified so far includes producing or abandoned oil and natural gas reservoirs, un-mineable coal seams, deep saline aquifers (which contain undrinkable salt water), deep ocean injection. During the storage of the CO₂, the gas stream is compressed to its critical condition so that the maximum amount of gas can be injected in the geologic sites.

### 2.2 CO₂ Storage Mechanism

The effectiveness of geological storage depends on a combination of physical and geochemical trapping mechanisms. The most effective storage sites are those where CO₂ is immobile as it is trapped permanently under a thick, low-permeability cap rock or is mineralized or is adsorbed due to combination of physical and chemical trapping mechanisms on the surfaces of subsurface micropores in coal (Benson et al., 2011).

![Figure 3: CO₂ Sequestered into a Porous Rock formation is permanently locked (CCSeducation)](image)
There are various types of CO₂ storage mechanisms operating in reservoir rocks generally in combinations. These are:

**Stratigraphic and Structural Trapping:** It happens due to physical trapping of CO₂ in the porous rock below caprocks. Here the migration of CO₂ is prevented by low permeability barriers such as layers of mudstone or halite.

**Residual saturation trapping:** The injected CO₂ is immobilized by getting adsorption onto the surfaces of mineral grains within the rock matrix due to capillary forces. The CO₂ is thus trapped along its migration path.

**Dissolution trapping:** The injected CO₂ reacts or it dissolves into surrounding salt water in the reservoir and gets permanently trapped.

**Hydrodynamic trapping:** The CO₂ injected migrates buoyantly upwards very slowly over long distances either due to pressure imbalance or because it is less dense than the water and displaces saline formation water. When it reaches the top of the formation, it continues to migrate as a separate phase until it is trapped as residual CO₂ saturation. This is known as hydrodynamic trapping.

**Geochemical trapping:** In this the CO₂ reacts with the native pore fluid and the minerals present in the rock matrix of the reservoir and produces a solid carbonate minerals and aqueous complexes. Also the CO₂ rich-water which is heavier than the surrounding liquids migrates downwards and it may also react to form minerals such as those found in limestone. This is also known as ionic trapping due to the reaction taking place in the presence of bicarbonate anions dissolved in the formation water.

\[
\text{CO}_2 (g) + \text{H}_2\text{O} \rightarrow \text{H}_2\text{CO}_3^{-} \rightarrow \text{HCO}_3^{-} + \text{H}^+ \rightarrow \text{CO}_3^{2-} + 2\text{H}^+
\]

Different mechanisms mentioned above operate at various different timescales and is important in assessing a CO₂ storage site capacity. Storage by mineral reactions that happen due to carbonate precipitation are very slow and so will play little part in creating additional space during CO₂ injection and storage. Injection is most likely to take place over the next century or so, when the need to store CO₂ is likely to be greatest, whereas the kinetics of mineral trapping are so slow that they will only have a significant effect over hundreds to thousands of years. In practice, mineral trapping commonly can be ignored as a significant storage mechanism on a hundred-year timescale. Any analysis of the CO₂ storage capacity of formations needs to take account of the remaining storage mechanisms and the boundary constraints. Availability of storage sites also needs to be considered. Oil and gas fields will not become available until the economic circumstances are right, which may
not match CO₂ storage requirements. Thus making saline aquifers, potential and viable sites for CO₂ storage.

2.3 Site Selection

It is important that while selecting a site for CO₂ storage both volumetric capacity and practical injection rate of CO₂ is considered. Various important reservoir parameters to be considered should be considered like aquifer fracture pressure, reservoir thickness, rock compressibility, reservoir permeability, porosity, reservoir temperature and pressure, number and placement of injection’s wells, etc. Table 1 mention some of the criteria are considered for selection of a CO₂ storage site.

<table>
<thead>
<tr>
<th>Properties</th>
<th>Suitable Values</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reservoir Depth</td>
<td>&gt; 1000 m &lt; 2500 m</td>
</tr>
<tr>
<td>Reservoir Thickness</td>
<td>&gt; 50 m</td>
</tr>
<tr>
<td>Reservoir Porosity</td>
<td>&gt; 20%</td>
</tr>
<tr>
<td>Reservoir Permeability</td>
<td>&gt; 300 mD</td>
</tr>
<tr>
<td>Reservoir Salinity</td>
<td>&gt; 100 g/l</td>
</tr>
</tbody>
</table>

Table 1: Some geological indicators for storage site Selection (CO2STORE_BPM_final)

When CO₂ captured is first compressed and then injected into the reservoir. On injecting CO₂ condenses and rises up due to the buoyant action. This condensed gas increases the pressure of the formation within time. Rock can bear pressure until a point, after which fracturing occurs. This needs to be avoided to maintain the integrity of the reservoir. Therefore, the formation fracture pressure needs to be found and the pressure shouldn’t exceed fracture pressure as serves as one very parameter to be considered for site selection. Also it is important to select the storage site close to the CO₂ source, so as to make the transportation of CO₂ easier.

2.4 Deep saline aquifer

Saline formations are deep sedimentary rocks saturated with formation waters or brines containing high concentrations of dissolved salts. The liquid CO₂ is pumped deep underground into one of two types of CO₂ storage reservoir (porous rock). These are deep saline aquifers, which contain undrinkable salt water, and depleted oil and gas fields. Deep saline aquifer represents the largest CO₂ storage capacity as they are abundant and are present throughout the world and most existing
large CO₂ point sources are nearby saline formation injection point, therefore making them practically feasible for countries and industries to use it to attain near-zero carbon emissions via making economically possible retrofits. The global storage capacity of saline aquifers could be more than 1 trillion metric tons of CO₂. (IPCC 2007)

The volumes that can be stored in aquifers depend on various parameters of the reservoir and the caprock like the pore volume in structural or stratigraphic traps, integrality of reservoirs, the amount of achievable CO₂ saturation in traps and the saline pore fluids, local or regional pressurization to get the maximum CO₂ injection storage capacity and the number of realistic wells needed to get access to all the traps and fluid in the reservoir.

The CO₂ injected into the reservoir acts in different ways in different geological formations. In saline formations and oil reservoirs, the buoyant plume of injected CO₂ migrates upwards due to buoyant forces, but not evenly. This is because a lower permeability layer acts as a barrier and causes the CO₂ to migrate laterally, filling any stratigraphic or structural trap on its migration pattern. The shape of the CO₂ plume rising inside a reservoir is strongly affected by formation heterogeneity and may cause viscous fingering. The demerits of storage of CO₂ in deep saline formations is that it does not produce value-added by-products like in case of oil and gas reservoirs and coal bed methane and also compared to other CO₂ geo-sequestration methods, very little is known about them, especially under high pressure and temperature conditions.

### 2.5 Safety & Concerns

Potential Environmental impacts of CCS include mini-earthquakes, ground water contamination and leakage of harmful off gases and chemicals like CO₂, H₂CO₃, H₂S, amines, H₂SO₄ into the environment. The greatest concern surrounding carbon dioxide storage is the potential for it to leak of harmful off gases and chemicals into the environment. The determination that CO₂ will not escape from formations and either migrate up to the earth's surface or contaminate drinking water supplies is a very important for making carbon storage an viable option for managing the greenhouse gas control. To ensure that a CO₂ storage site functions as it should, a rigorous monitoring process should be done not only on the reservoir but also on pipelines and other storage equipment. Monitoring should be continued even after a CO₂ injection well is closed. It is important to have a risk assessment of the selected storage site and have mitigation strategies developed to be implemented in case a problem arises.
2.6 CCS Projects

In the middle of the 1990’s, the world’s first commercial-scale GCS project, the Sleipner West GCS project, was commissioned in the North Sea, Norway. As a successful demonstration project to show the feasibility of commercial GCS, the Sleipner West GCS project has inspired dozens of other GCS projects worldwide (Zhang, 2013). Some representative pilot and demonstration GCS projects are listed below.

- Sleipner West (Norway): The carbon dioxide injection at the Sleipner field in the North Sea, operated by Statoil and the Sleipner partners, is the world’s first industrial scale CO₂ injection project designed specifically as a greenhouse gas mitigation measure. By 2009, 11 million tonnes of carbon dioxide were separated and injection into saltwater aquifers 1000 meters below the seafloor by the Sleipner project off the Norwegian coast. No significant pressurization or leakage has been reported during the past 16 years of injection.

- Fenn Big Valley (Canada): The Alberta Research Council began injecting CO₂ into deep coal beds for enhanced coal bed methane in 1999. So far, all testing has been successful. Currently the economics of the project is being accessed.

- Weyburn CO₂ Flood Project (Canada): EnCana and IEA began storing CO₂ along with enhanced oil recovery (EOR) in 2000. During 2000 to 2004, more than seven million tons of CO₂ was stored; the geology has been found to be suitable for long-term storage. The site will be maintained to study long-term sequestration. The second phase (2004 and after) includes site characterization, leakage risks, monitoring and verification, and a performance assessment. These formations also contain enormous quantities of water, which reacts with CO₂ and provides rapid minimization and provide high storage capacity.

- Salah (Algeria). Sonatrach: BP and Statoil began capturing CO₂ from natural gas production in 2004 and started storing it in depleted gas reservoirs, as world’s first full scale CO₂ capture and storage project at a gas field. The target capacity is one million tons of CO₂ to be stored per year.

- Otway (Australia): CO2CRC is injecting CO₂ from natural gas wells in hydrocarbon reserves, and the target sequestration amount is 0.1 million tons of CO₂. The objective is to provide technical information on CO₂ storage and monitoring and verification.
2.7 CO₂ Storage Capacity

It is important to carefully access the capacity of a CO₂ storage site. CO₂ storage capacity depends not only on the properties of the reservoir rock itself but also on the nature of its boundaries. Very little CO₂ can be injected into the water filled small reservoir having perfectly sealed non-elastic boundaries. This is because the injected CO₂ can only be able to occupy those sites created by the compression of the water and rock. In-order to store a significantly large amount of CO₂, it is necessary for a significant proportion of the native pore fluid to be displaced from the reservoir over the injection period. This may occur either by anthropogenic production of fluids generally brine in case of saline aquifers, and/or by migration of groundwater into adjacent formations and/or to the ground surface or seabed. Internal barriers within the reservoir, such as faults, also need to be considered as these may divide it into separate, unconnected or poorly connected compartments.

Also sometime it is not possible to achieve theoretical maximum storage capacity due to some complications like unacceptable rise in reservoir pressure which may compromise the integrity of the reservoir or unexplainable mitigation of fluids into the surrounding, contaminating the biosphere around, thereby limiting the amount of CO₂ that can be stored in a reservoir formation.

Geological CO₂ storage needs to carefully select so as to minimize chances of leakage. It is important to maintain bottom-hole pressure always below the fracturing pressure to prevent leakage.
Chapter 3
Mathematical Formulation

3.1 Fluid Flow

The CO₂ injected into the saline aquifer, migrates and is transported to different realms of the rock matrix by different processes and mechanisms. They are influenced by forces like diffusion and dispersion caused due to mobility contrast between CO₂ and brine, buoyant action caused due to the density differences between CO₂ and the formation fluids mainly brine, pressure gradients created by the injection, fluid flow due to natural hydraulic gradients, fingering caused by formation heterogeneities, mineralization of rocks and adsorption of CO₂ onto pore space present in the organic materials of the reservoir.

The rate of fluid flow depends on the number and properties of the fluid phases present in the formation. When two or more fluids mix in any proportion, they are referred to as miscible fluids. If they do not mix, they are referred to as immiscible. The presence of several different phases may decrease the permeability and slow the rate of migration. If CO₂ is injected into a gas reservoir, a single miscible fluid phase consisting of natural gas and CO₂ is formed locally. This is because both natural gas and CO₂ combine to form a miscible single phase fluids as both are organics. But this is not true when CO₂ is injected into a deep saline formation either in a liquid form or in a liquid-like supercritical dense phase. We get two or more phase as the CO₂ and other reservoir formation fluids are immiscible in water. CO₂ rich phase labelled as gas phase while the water rich phase is labelled as brine phase (liquid phase).

3.2 Single Phase Model

We started this study with a very simplified single phase modeling allowing analytical solutions for pressure distribution during multiwall injection scenario. It allowed fast sensitivity analysis and qualitative understanding of the processes followed by more accurate approaches. In the model we assume either brine injection in a brine reservoir or CO₂ injection in a gas reservoir. Equation (1) was used to calculate the well-pore pressure based on the reservoir properties like initial pressure (Pᵢ), permeability (k), porosity (ϕ), reservoir thickness (h) and depth, rock compressibility (cᵣ) and reservoir fluid properties like viscosity (μₒ), density, temperature, formation factor (bₒ) etc. In this equation, we consider constantly radially flowing fluid (Qₒ) toward a well in a circular reservoir.
Combining the law of conservation of mass and Darcy’s law for the isothermal flow of fluids of small and constant compressibility gives us the radial diffusivity equation which helps us to calculate the bottom hole pressure of the reservoir on injecting CO₂ (Ahmed, 2006). The $E_i$ function is the exponential integral function and is assumed to be valid during the simulation time period and condition. An ideal reservoir model is based on the assumptions like compressibility of the total system is small and independent of pressure, permeability is constant and isotropic, viscosity is independent of pressure, porosity is constant, and heterogeneity effects are negligible.

$$P(r,t) = P_i + \left[ \frac{70.6Qot \mu_o b_o}{kh} \right] E_i \left[ \frac{-9480 \Phi \mu_o c_o r^2}{kt} \right]$$ (1)

### 3.3 Two Phase Model

In reality CO₂ when injected into a reservoir does not behave like a single phase as it forms immiscible fluid with the brine solution present in the reservoir. For more accurate modeling two phase modeling should be considered. Based on the recent work by (Burton et al., 2008) it was found that the CO₂ being injected into saline aquifers will form three main regions of flow due to the effects of relative permeability and mobility of the reservoir fluids. On assuming that the well runs through the entire thickness of the formation, we get three main regions on injecting CO₂ at a constant rate namely the CO₂ rich gas phase region around the well, preceded by two-phase commonly called Buckley-Leverett (BL) region followed by the single-phase brine region.

In Region 1, drying-out occurs because of brine evaporating into the CO₂-rich gas phase. In Region 2, we have formation of two regions, based on the density differences between both brine and water when saturated with CO₂. Due to the difference in mobility of the two phases and mutual solubility we have two fronts in between the three regions. These fronts are very important and decide the rate at which the injected CO₂ migrates as they move at characteristic speeds (Burton et al., 2008).
3.3.1 Modified Buckley-Leverett Model

In order to model the flow of CO₂ and brine in the reservoir, it is important to know the pressure and saturation of the reservoir using which we can calculate the speed of the two saturation fronts namely, the dry gas ($r_{D_{dry}}$) and two-phase fronts ($r_{BL}$). The dimensionless positions of the drying and BL fronts ($r_{D_{dry}}$ and $r_{D_{BL}}$) can be predicted independently of all other parameters, for a specified set of relative permeability curves by using Equation (2) (Azizi and Cinar, 2013).

\[
\begin{align*}
\frac{1}{r_D} \frac{\partial}{\partial r_D} \left( r_D \frac{\partial P_{D1}}{\partial r_D} \right) &= \frac{\partial P_{D1}}{\partial t_D}, 0 < r_D < r_{D_{dry}} \\
\frac{1}{r_D} \frac{\partial}{\partial r_D} \left( r_D \frac{\partial P_{D2}}{\partial r_D} \right) &= \frac{1}{F_k \epsilon \eta D2} \frac{\partial P_{D2}}{\partial t_D}, r_{D_{dry}} < r_D < r_{BL} \\
\frac{1}{r_D} \frac{\partial}{\partial r_D} \left( r_D \frac{\partial P_{D3}}{\partial r_D} \right) &= \frac{1}{\eta D3} \frac{\partial P_{D3}}{\partial t_D}, r_{D_{BL}} < r_D < \infty
\end{align*}
\]

(2)

To solve for pressure gradient in the reservoir, we use dimensionless technique using dimensionless parameters such as $P_D$, $t_D$, $\epsilon$ and $r_D$ which are the dimensionless pressure, time, rate and radius respectively. Here, $r_D$ is the dimensionless radial distance from injector, $\epsilon$ is the dimensionless injection rate and $t_D$ is the dimensionless time or equivalently the number of pore volumes of CO₂ injected into a reservoir. All of them are defined as follows:

\[
r_D = \frac{r}{r_w}
\]

(3)
\[ t_D = \frac{k\bar{k}_r \一代}{\mu_g \一代^2 \Phi c_g} \quad (4) \]

\[ \varepsilon = \frac{qB_g(c_g + c_r)\mu_g}{4\Pi hk\bar{k}_r} \quad (5) \]

In the above equations, \( r \) is the radial distance from the well, \( r_w \) is the well radius, \( k \) is the formation permeability, \( \bar{k}_r \) is the gas relative permeability in the drying-out zone (\( \bar{k}_r = \bar{k}_r \mid S_g = 1 \)), \( t \) is the time, \( \mu_g \) is the CO\(_2\) viscosity, \( \phi \) is the porosity, \( c_g \) is the total compressibility of the gas region given by summation of reservoir and gas compressibility \((c_g + c_r)\), \( q \) is the total injection rate at surface conditions, \( B_g \) is the gas formation volume factor, \( h \) is the reservoir thickness, \( f_g \) are the gas fractional flow and \( S_g \) is the gas saturation.

It is important to calculate the speed of the movement of the two fronts which are a function of various fluid parameters like viscosity and permeability at different saturation corresponding to the fronts. In both the regions, CO\(_2\) concentration (\( D_{\text{brine-}BL} \) and \( D_{BL-\text{dry}} \)) is a function of phase behavior which in turn is a function of pressure, temperature, and salinity.

As mentioned in the Azizi and Cinar, 2013, we select parameters like \( D_{D2} \), \( D_{D3} \) and \( F_{\lambda g} \) which are diffusivity ratios and dimensionless total mobility as defined below:

\[ \eta_{D2} = \frac{c_g}{c_t} \mid_{S_{g,av}} \quad (6) \]

\[ \eta_{D3} = \frac{c_g}{c_{w}} \mid_{\lambda_{w}} \quad (7) \]

\[ F_{\lambda g} = \frac{\lambda_g + \lambda_w}{\lambda_g} \mid_{S_{g,av}} \quad (8) \]

\( \lambda_w \) and \( \lambda_g \) are the mobility’s of brine and CO\(_2\) respectively, while \( \bar{\lambda}_w \) and \( \bar{\lambda}_g \) are the end-point mobility, \( c_t \) is the compressibility of the two-phase region which is a function of CO\(_2\) saturation and the average saturation is assumed to be \( S_{g,av} = (S_{g,\text{dry}} + S_{g,BL}) / 2 \), where \( S_{g,\text{dry}} \) is the gas saturation at the dry region front and \( S_{g,BL} \) is the saturation at the two-phase front. The pressure and flux are equal at either side of the fronts. Mobility ratio determines if the displacement of the reservoir fluid is stable or not and also determines the speed of buoyancy-driven CO\(_2\) migration.
Now to find the velocity of the fronts, we need to draw tangents to fractional flow curves as given by Noh et al., 2007. From these we can get two fluid properties constants namely $\xi_{DBL}$ and $\xi_{Ddry}$ corresponding to two saturation fronts.

\[
\xi_{DBL} = \left. \frac{1}{4} \epsilon \frac{df}{dS} \right|_{S_{gBL}}
\]

\[
\xi_{Ddry} = \left. \frac{1}{4} \epsilon \frac{df}{dS} \right|_{S_{gDry}}
\]

**Figure 5:** Fractional-flow curve showing gas saturation corresponding to the two front $r_{Ddry}$ and $r_{BL}$, based on Azizi and Cinar, 2013
Based on the works of Azizi and Cinar, 2013, the equations can be transformed using Laplace transformation to be dependent upon dimensionless time. Using equations below, we can calculate the pressure rise in all the three regions (CO$_2$ region (11), two phase region (12) and brine region (13)):

\[ P_{D1} = \frac{1}{2} \left(\frac{-r_D^2}{4t_D}\right) + \frac{1}{2} E_i\left(-\xi_{Dry}\right) - \frac{1}{2F_{Ag}} E_i\left(-\xi_{Dry}\right) + \frac{1}{2F_{Ag}} E_i\left(-\xi_{Dry}\right) - \frac{1}{2F_{Ag}} E_i\left(-\xi_{Dry}\right) - \frac{1}{2\lambda_w} F_i\left(-\xi_{Dry}\right) \]

For \( r_D^2 \geq \frac{\xi_{Dry}}{4\xi_{Dry}} \)

\[ P_{D2} = \frac{1}{2} \left(\frac{-r_D^2}{4t_D}\right) - \frac{1}{2F_{Ag}} E_i\left(-\xi_{Dry}\right) + \frac{1}{2F_{Ag}} E_i\left(-\xi_{Dry}\right) + \frac{1}{2\lambda_w} F_i\left(-\xi_{Dry}\right) \]

For \( 0 \leq r_D^2 \leq \frac{\xi_{Dry}}{4\xi_{Dry}} \)

\[ P_{D3} = -\frac{1}{2\lambda_w} F_i\left(-\xi_{Dry}\right) \]

For \( r_D^2 \leq \frac{\xi_{Dry}}{4\xi_{Dry}} \)

The total pressure in the reservoir is the summation of the initial pressure in addition to pressure due to all the three regions (Burton et al., 2008).

\[ \Delta p_{total} = \Delta p_{Dry} + \Delta p_{BL} + \Delta p_{brine} \]

The bottom hole pressure at particular time and position is given by the equation below:

\[ P_{final}(r,t) = P_i + P_d(r,t) \left[ \frac{q \mu \beta g}{2 \pi k_r g k_h} \right] \]

\[ 3.4 \text{ Superposition} \]

In order to understand the effect of multiple well injection of CO$_2$ on pressure buildup in the reservoir, the principle of superposition was used. It indicates that the total pressure at any point in a reservoir is the sum of the pressure drops at that point caused by flow in each of the wells in the reservoir.
So, as we increase the number of wells in the reservoir simulation, the total pressure build up in the reservoir will be the summation of pressure build up due to each individual well as seen in the Equation (16) (Ahmed, 2006).

\[
P_{final} = P_i + \sum_{n=1}^{n} \Delta P_n
\]  

(16)
Chapter 4
Model Selection

4.1 Modeling

In order to verify and calibrate the model, calculations were conducted and compared to the investigations done by Ghaderi et al., 2009. Calculations were first carried out for a single well and calibrated using CMG reservoir simulation software (Computer Modelling Group) results which is used for modeling of CO\textsubscript{2} storage in saline aquifers. In this case, modeling was done based on the Nisku aquifer located in Wabamun Lake Area, Alberta, under Wabamun Area CO\textsubscript{2} Sequestration Project (WASP).

Numerical simulations are done considering an injection area square of size 200 km × 200 km so that the aquifer behaves as though it is infinite acting reservoir for the injection of the target volume of CO\textsubscript{2}. Also we assume a homogenous, isotropic and isothermal reservoir for simulating pressure profile across the reservoir.

The next step was to study multiwell case. In order to replicate the results of Ghaderi et al., 2009 and validate the model, multiple well scenarios were used. During the investigation, different numbers of vertical injector wells were used varying from 1 to 25 and were used based on symmetry. The distance between the wells in both the \( x \) and \( y \) directions are the same and equal to \( \lambda \) and was varied between 6 to 10 kms.

Constant flow rate is maintained throughout the 50 year time period and all the well flow rates are maintained equal. The total cumulative amounts of CO\textsubscript{2} injected are calculated in Gt for 50 years by combining the flows in all the injectors and taking a summation for a period of 50 years. For example in the case of 16 wells, the total flow rate for all the wells is \( Q_{16} \times 16 \) for 50 years.

![Figure 6: Symmetrical well placement (Ghaderi et al., 2009)](image)
4.2 Model Development and Validation

The first goal of the study was to identify the analytical approaches for modeling of multiple well injection of CO$_2$ in aquifers. The major part of the investigation is focused on the description of two main models:

- Single Phase Model
- Two Phase Model

Modeling was done based on both single phase and two phase assumptions and the results were compared.

4.3 Single Phase (Model Calibration)

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Value</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Porosity(Φ)</td>
<td>0.12</td>
<td></td>
</tr>
<tr>
<td>Permeability(k)</td>
<td>100</td>
<td>mD</td>
</tr>
<tr>
<td>Thickness(h)</td>
<td>100</td>
<td>m</td>
</tr>
<tr>
<td>Viscosity(µ)</td>
<td>0.25</td>
<td>cP</td>
</tr>
<tr>
<td>Rock Compressibility(cr)</td>
<td>3.3*10^{-6}</td>
<td>1/psi</td>
</tr>
<tr>
<td>Gas formation Volume Factor(Bg)</td>
<td>1.075</td>
<td>rB/SCF</td>
</tr>
<tr>
<td>Injection Rate(Q)</td>
<td>0.2</td>
<td>Gt/50 years</td>
</tr>
<tr>
<td>Radius of well</td>
<td>0.076</td>
<td>m</td>
</tr>
<tr>
<td>Initial Pressure(Pi)</td>
<td>1740</td>
<td>psi</td>
</tr>
<tr>
<td>Fracture Pressure(Pf)</td>
<td>4370</td>
<td>psi</td>
</tr>
</tbody>
</table>

Table 2: Parameters used for Single Phase Model Simulation (Ghaderi et al., 2009)
Analysis is done considering a square (200 km × 200 km) infinite acting, homogenous, isotropic and isothermal reservoir condition and using the Ei-function approximation to simulate results on pressure profile across the reservoir. Equation (1) was used to calculate the well-pore pressure based on the reservoir properties mentioned in the Table 2. As the fracture pressure of the aquifer is the limiting factor for CO₂ sequestration the bottom-hole pressure (BHP) was monitored, so that it is less than 32MPa for a period of 50 years i.e. 90% of the fracture pressure during the injection period.

4.3.2 Comparison with Simulation result for Single Phase Model

On comparing the results between from the one obtained from CMG simulator, IMEX (Ghaderi et al., 2009) with the one based on single phase analytical model, it was found that the results greatly varied. The trend was same i.e. as we increase the number of wells, the amount of CO₂ injection capacity of the reservoir increases but the values did not match the one mentioned in the paper. The reason for such results was because CO₂ on being injected in a saline aquifer follows a two phase model.

![Figure 7](image.jpg)

**Figure 7:** Plot showing the amount of CO₂ injected into the reservoir for a period of 50 years of various number of wells
Injection capacity increases with the number of wells as the injection area increases. But the effect is not significant on increasing the number of wells after 10 wells.

### 4.4 Two Phase (Model Calibration)

In order to use the modified Buckley-Leverett two phase model, we had to calculate a number of important reservoir parameters such as porosity, thickness, relative permeability values, fracture pressure etc. The fractional flow curve is constructed from the relative permeability curves. The relative permeability curves are also used to simplify the calculation of effective mobility (Burton et al., 2009). These can be obtained for different aquifers from Bennion and Bachu, 2005 work on various CO$_2$ and brine sandstones and carbonates formation.

![Graph showing the plotted (a) Relative Permeability Curve (b) Fractional Flow Curve for the nisku aquifer based on the data provided.](image)

**Figure 8:** Graph showing the plotted (a) Relative Permeability Curve (b) Fractional Flow Curve for the nisku aquifer based on the data provided.

It is important to note that if we change the reservoir conditions, the model properties will change resulting in calculating the values of the parameters again. Thus the model is very sensitive to the nature of the reservoir.
The radial position of the fonts i.e. $r_{\text{Ddry}}$ and $r_{\text{BL}}$ is based on the fractional flow curve. Fractional flow curve is mainly dependent upon viscosity and mobility of gas and brine respectively. For getting the model parameters based on single well injection, we need to draw tangents to fractional flow curves as given by Noh et al., 2007.

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Value</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Porosity ($\Phi$)</td>
<td>0.064</td>
<td></td>
</tr>
<tr>
<td>Permeability (k)</td>
<td>46</td>
<td>mD</td>
</tr>
<tr>
<td>Thickness (h)</td>
<td>102</td>
<td>m</td>
</tr>
<tr>
<td>Brine Viscosity ($\mu_w$)</td>
<td>0.84</td>
<td>cP</td>
</tr>
<tr>
<td>Gas Viscosity ($\mu_g$)</td>
<td>0.062</td>
<td>cP</td>
</tr>
<tr>
<td>Rock Compressibility (cr)</td>
<td>$1.45 \times 10^{-10}$</td>
<td>1/Pa</td>
</tr>
<tr>
<td>Brine Compressibility (cw)</td>
<td>$10^{-9}$</td>
<td>1/Pa</td>
</tr>
<tr>
<td>Gas formation Volume Factor (Bg)</td>
<td>0.003</td>
<td></td>
</tr>
<tr>
<td>Injection Rate (Q)</td>
<td>17.01</td>
<td>m$^3$/s</td>
</tr>
<tr>
<td>Initial Pressure (Pi)</td>
<td>$1.6 \times 10^{7}$</td>
<td>Pa</td>
</tr>
<tr>
<td>Fracture Pressure (Pf)</td>
<td>$3.1 \times 10^{7}$</td>
<td>Pa</td>
</tr>
</tbody>
</table>

**Table 3**: Parameters used for Single Phase Model Simulation (based on TransAlta data for Nisku aquifer)

We started with saturation profile as shown in figure 8. Once we have the saturation profile, we can plot fractional flow curve as mentioned in the Azizi and Cinar, 2013. By trial and error approach, the slope of the tangent is varied to get the values of fluid constants ($\xi_{\text{DBL}}$ and $\xi_{\text{Ddry}}$) and to get endpoint saturations ($S_{\text{gdry}}$ and $S_{\text{gBL}}$) corresponding to both the fronts respectively. These parameters are fitted
into the model for single well injection and checked for validation. Once validated, we use the model parameters for multiple well scenarios.

In multiple well scenario, these values act as input to the model like other parameters mentioned in the Table 2 which then calculates the pressure build up in the reservoir on injecting CO$_2$. For the given nisku aquifer, the gas saturation occurring in the BL two-phase region lies between 0.38 and 0.45 giving us the average gas saturation ($S_{g,avg}$) of 0.42. For our case, the values of fluid properties constants namely $\xi_{DBL}$ and $\xi_{Ddry}$ corresponding to two saturation fronts were found to be 1.9 and 0.01 respectively. Also, the fractional flow of gas in two phase region ($f_{g, dry}$) and fractional flow of gas in dry region ($f_{g, BL}$) was found to be 0.82 and 0.89 respectively.

Using this data and other parameters like diffusivity ratios and dimensionless total mobility, we plot the bottom-hole pressure on injecting $1.47 \times 10^6$ m$^3$/day of CO$_2$ for 50 years by a single well.

4.4.2 Comparison with Simulation result for Modified BL- Two Phase Model

![Figure 9](image)

**Figure 9** (a) BHP vs. time for 50 years (b) BHP vs. time by analytical BL- Two Phase Model

On comparing the results with the CMG commercial simulator, we almost get identical results implying that the analytical BL- Two Phase Model is valid and can be used to estimate the storage capacity for potential CO$_2$ storage sites. This model can further be used for multiple well injections.
4.5 Sensitivity Test

As the bottom-hole pressure is one of the most important factors that come into play when determining the storage capacity of CO₂ storage sites, it is important to realize what parameters are affected by it. Sensitivity test was carried out based on important parameters like reservoir thickness (50-100 m), permeability (25-100 mD), rock compressibility (from 9*10⁻¹⁰ to 2*10⁻⁹ (1/Pa)) and porosity (0.12 to 0.20) based on the multiple regression model by conducting additional analytical simulation. The values of the parameters were varied between the upper limit and lower limit values of the properties of a potentially likely saline aquifer.

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Source</th>
<th>Effect</th>
</tr>
</thead>
<tbody>
<tr>
<td>Permeability</td>
<td>A</td>
<td>Highly Significant</td>
</tr>
<tr>
<td>Thickness</td>
<td>B</td>
<td>Very Significant</td>
</tr>
<tr>
<td>Rock Compressibility</td>
<td>C</td>
<td>Significant</td>
</tr>
<tr>
<td>Porosity</td>
<td>D</td>
<td>Less Significant</td>
</tr>
</tbody>
</table>

Table 4: Shows the effect of the different parameters on the well-bore pressure based on the ANOVA table

It was found that permeability & thickness of the formation are one of the most important parameters to be considered while selecting a storage site for CO₂ sequestration.

The permeability of the formation is important because it controls both the pressure distribution over the system volume and the propagation velocity of the pressure pulse away from the injection site. Using the analytical model, permeability was varied between 100 mD, 50 mD and 25 mD values. As per the diffusivity equation, pressure will diffuse faster in formations with higher permeability which is verified in the figure 10 (a). It was noted that by reducing the permeability by half, the amount of CO₂ stored into the reservoir decreases nearly by half. Also it is observed that for a low permeability reservoir increasing the number of wells does not contribute significantly to increase the capacity of the reservoir.
Amount of Brine Injected

Injection rate (Gt/50 Yrs)

Number of wells

Amount of Brine Injected

Injection rate (Gt/50 Yrs)

Number of wells
Figure 10: Effect of sensitive parameters on storage capacity, a) effect of permeability, b) effect of aquifer thickness, c) effect of compressibility. Also further comparison is made with the data obtained from the CMG simulation model and analytical BL- two phase model. Both showing similar results further validating the analytical BL- two phase model. (Ghaderi et al., 2009)

The second most important parameter is the thickness of the formation. As the value of the reservoir thickness was reduced (100 > 75 > 50 m), the amount of CO₂ stored into the reservoir decreases nearly by 50 percent as seen in the Figure 10 (b). This is because as the reservoir gets thinner the amount of void pore spaces decreases thereby decreasing the volume capacity of the site. Also, it was seen that by increasing the number of wells we can increase the capacity of the reservoir.

Lastly, the compressibility of the reservoirs was varied from 2.25*10⁻⁹ 1/Pa to 9*10⁻¹¹ 1/Pa. We note that rocks with low compressibility will have higher storage capacity as seen in Figure 10 (c). Also, by increasing the number of wells for a high compressibility reservoir, we can increase the capacity of the reservoir.
Chapter 5
Results & Discussions

In order to store large volumes of CO$_2$ into an aquifer, we need to have a very sufficiently large aquifer with high reservoir thickness and permeability but lower reservoir compressibility as seen by the sensitivity analysis as mentioned in section (4.5) to have a lower pressure build up in the reservoir. Once the BL- two phase models has been validated, the next objective of the study was to optimize the well placement in order to achieve maximum carbon dioxide sequestration. This was done by considering various approaches as follows:

- Increasing number of wells
- Varying well placement with in a confined area
- Having different flow rates with in various well placed

![Figure 1: 3D Plot for BHP vs. Time for 50 years at Initial pressure (P$_{i}$)=1740 psi and Fracture pressure(P$_{f}$)=4370 psi.](image)

In general, it is required to inject the maximum amount of CO$_2$ within a relatively small area of injection and short period of time. But, by injecting larger amount of CO$_2$ into the reservoir there will be increase in reservoir pressure. So it is important to maintain low injection rates, which increases the injection period. One way to do so is by using multiple wells injection strategy. By using multiple wells, the injection rate per well can be maintained low as the injection amount $q$ is split equally between the various injectors.
5.1 Increasing Number of Wells

One of the ways to increase the injection capacity of an ideal reservoir is to drill many injection wells so as to cover the maximum available pore space possible within a short while. In the study, we try injecting CO$_2$ for different well scenarios with the constraint of maintaining the reservoir pressure under 90 percent of the fracture pressure during the injection period. A symmetrical approach for the placement of well was carried out keeping the distance between the well constant as seen in the work of Ghaderi et al., 2009. Pressure builds up as the injection time period increase reaching the maximum of 32 MPa by the end of 50 year injection period.

![Pressure profile for multiple wells](image)

(a) 1 well  (b) 4 wells  (c) 9 wells
(d) 16 wells  (e) 25 wells

**Figure 12:** Pressure profile for multiple wells

It was observed that as we increase the number of wells, the amount of CO$_2$ injection capacity of the reservoir increases. It was also noted that slope of the curve decreases after a certain number of wells hinting that there is only limited benefit to increasing the number of wells after 10 wells.
Also, it was pointed out that on increasing the distance (λ) between the wells we are able to sequester more amount of CO₂. This is because as λ increases from 6 to 10 kms, so does the injection area, which results in more pore volume which leads to higher sequestration.

![Amount of CO₂ injected](image)

**Figure 13**: Analytical two phase model for amount of CO₂ injected for symmetrically spaced wells (i.e. 6km, 8km, and 10km) for 50 years

### 5.2 Varying Well Placement within a Confined Area

As we increase the number of wells we get higher CO₂ injection capacity for the selected site. But increasing the number of wells may not be economically feasible always as each well is around a million dollars. In order to optimize the number of wells, we look at variable scenarios of well placement. This was done by trial and error approach at first and then was perfected using the optimizing tool such as genetic algorithm.

On trying to optimizing the placement of wells randomly results into a pattern. It is found that symmetrical placed wells are one which gives better result considering the isotopic, infinite acting and homogenous nature of the reservoir.
Figure 14: Different well placement (a) 9 wells (b) 8 (exterior) (c) 8 (interior) (d) 12 (interior) (e) 12 (circle) (f) 12 (exterior) (g) 16 wells (h) 24 wells.

Also it was noted that if the injection area was maintained constant, then the injection capacity of the reservoir increases as the number of well increases at first but then it tapers down. This is because as the number of wells increases, we are able to access more and more available pore volume until there are no more extra pore spaces. Using more wells after this point, it becomes pointless.

The other major observation made here was that the maximum pressure build up occurs in the center of the reservoir. This happens due to the super-imposition principle, which occurs due to the fact that in case of ideal reservoir conditions a group of wells when looked upon from a distance will act in a similar way to one large well placed at the center of the wells.

Next way to optimize the well placement was to lower the pressure build up in the reservoir by removing the well in the middle. So, well were optimized from 9 to 8 wells and from 25 to 24 wells. It was seen that on doing so the amount of CO\textsubscript{2} injected increased from 0.451 Gt/50 yrs for 25 wells to 0.483 Gt/50 yrs for 25 and similarly from 0.4395 Gt/50 yrs for 9 wells to 0.480 Gt/50 yrs for 8 wells. Thus, by decreasing the number of well we are able to increase the injection capacity of the reservoir.
Then we tried optimizing by keeping the same number of wells but changing the well positions. On doing so it was observed that to increase the amount of CO$_2$ injection, it was important to keep the wells as far as possible to prevent pressure build up. This can be achieved by placing the well on the boundary of the reservoir. Thus on placing the same number of wells on the boundary like in case of 12 exterior wells, we found that we are able to sequester 0.5303 Gt/50 yrs compared to 0.4775 Gt/50 yrs for 12 interior wells. Likewise, by placing the 8, 9, 16 or 25 wells at the boundary we get higher sequestration.

<table>
<thead>
<tr>
<th>No of Wells</th>
<th>Amount of CO$_2$ injected in Gt for 50 years</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>6km</td>
</tr>
<tr>
<td>1</td>
<td>0.05</td>
</tr>
<tr>
<td>4</td>
<td>0.20217</td>
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<td>9</td>
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<tr>
<td>16</td>
<td>0.29007</td>
</tr>
<tr>
<td>25</td>
<td>0.32816</td>
</tr>
</tbody>
</table>

**Table 5:** Showing the amount of CO$_2$ injected for symmetrically spaced wells (i.e. 6km, 8km, and 10km) for 50 years (Ghaderi et al., 2009)

One important point that was observed was that if we place the same number of wells in different pattern but at different positions there isn’t much difference in the amount of CO$_2$ that can be stored as in the case of 12 interior wells compared to 12 circularly placed wells both showing a storage capacity of 0.477 Gt/50 yrs and 0.471 Gt/50 yrs respectively.

Various other comparisons were done as seen in Table 6, to get the optimized wells and it was noted that using 12 wells will give good results on considering the economic benefits with maximum amount of CO$_2$ sequestered.
Wells | % Increase in Injection Capacity (50 Years)
--- | ---
4 Vs 25 | 14.28571429
8(interior) Vs 9 | 9.090909091
9(10 Kms) Vs 9(external) | 32
12(interior) Vs 12(external) | 9.944751381
12(interior) Vs 9 | 6.83298137
16(interior) Vs 12(interior) | 6.432748538
16(external) Vs 12(external) | 3.72304255
16(external) Vs 16(interior) | 9.042553191
24 Vs 25 | 6.666666667
12(interior) Vs 12(circle) | 1.22693865

**Table 6**: Showing the increase in amount CO₂ injected for different types of well arrangement.

### 5.3 Different Flow-rate within Various Wells Placed

Until now simulations were carried out using injection flow rate in each well constant (for example for 12 wells individual flow rates will be Q₁₂/12). Now, we try changing the flow rates in different wells. Based on the above result it was found that maximum pressure build up happens at the center, considering that we try simulating injecting more amounts CO₂ at the boundary and less at the center.

For analysis two flow rates were considered Q₁ and Q₂ (Q₁ < Q₂). Q₂ was injected at the boundary wells (highlighted in red) as seen in the Figure 15 and the other wells were injected with the flow rate Q₁. On doing so it was found that from CO₂ injection capacity of the reservoir increased. This observation can be explained on ideal infinite acting reservoir theory. As the reservoir is ideal and homogenous, so the pressure build up at the boundary is symmetrical and is distributed evenly across the reservoir without building too much pressure at the center, keeping the reservoir integrity intact.
It was also noted that the effect of varying the flow rate on the injection capacity of the reservoir is not very significant for higher number of wells. As seen in the Table 7 there is not a significant increase in the injection capacity of the reservoir, when we have more than 12 wells.

\[
\begin{array}{|c|c|c|c|}
\hline
\text{Wells} & \text{Constant Flow rate} & \text{Variable Flow rate} & \% \text{ Increase} \\
\hline
9 & 0.4395 & 0.49517 & 12.667 \\
12 & 0.47173 & 0.50396 & 6.832 \\
16 & 0.50103 & 0.51568 & 2.924 \\
25 & 0.45122 & 0.46294 & 2.597 \\
\hline
\end{array}
\]

\textbf{Table 7:} Showing the amount of CO}_2\text{ injected for different numbers of wells based on flow rates

This is because as the number of wells increases, the entire available pores are occupied. So there are no significant numbers of void pores available to increase the injection capacity of a reservoir. Thus
changing the flow rates among the injection well is not that economical as maintaining different flow rates for the entire injection wells which are not easy in practical scenarios.
Chapter 6
Conclusion

An expanding population, economic growth, new technology development and changes in the nature and scope of regulations are all transforming the energy landscape. We are becoming more energy-efficient and moving to cleaner fuels. But still we have a long way to go before we are able to reach to a point of zero carbon footprints as we will be relying on fossil fuels for a while. We have to use all the available technologies including CSS technology to counterfeet the effect of use of fossil fuels.

In order to make CCS a viable option to reduce carbon footprint we have to look at ways increase the select by screening potential reservoir sites based upon its injection capacity for CO₂ sequestration and having favorable properties.

All the presently available software tools currently present like CMG’s commercial “black oil” simulator, IMEX are very expensive and take a lot of time and data to predict the injection capacity for CO₂ sequestration site. Using the analytical BL- Two Phase Model developed during the study we are able to predict the CO₂ sequestration capacity of a potential site and thus can help in screening of suitable reservoir based on technical and economic criteria. It should be noted that the developed approach is not aiming to replace numerical simulation but rather to be used for fast preliminary estimates, to carry fast sensitivity analysis, to optimize the process and to reduce the number of expensive numerical simulations needed at the final stages of design.

The analytical BL- Two Phase Model has been simulated with a wide range of parameters and has been compared with numerical simulations to get good agreement in pressure behavior inside the reservoir. This model allow for fast optimization of well placement to increase injection capacity of aquifer. It also helps to predict the maximum amount of CO₂ that can be injected based on number of wells and the cost associated with each well.

The study concluded that CO₂ injection capacity can be increased significant not only by increasing the number of wells, which increases the cost but also by optimizing well placement and flow rates.
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