Investigation of Multiple Well Injections for Carbon Dioxide Sequestration in Aquifers

by

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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 CO_2 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 CO_2. 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 CO_2 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 CO_2 sequestration in a reservoir. This study can help in the CO_2 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 (CO_2 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.

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Chapter 1
Introduction

1.1 Need for CO_2 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 facilitates the growth of fast modes of transport, which in turn has transformed the world into a global village. Technological changes has 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 2010and will reach nearly 9 billion by 2040(The Outlook of Energy, 2040). The increase in population will be followed by 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 depend 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 CO_2 in the atmosphere. CO_2 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 effect. In-order to continue using fossil fuels without increasing the concentration of CO_2 in the air below 450ppm (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 same time decrease carbon footprint is to use **Carbon Capture and Sequestration (CCS)** technique which can provide up to 20 percent of the CO_2 emission reductions. CCS is Capture, Transportation and Sequestration of CO_2 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.

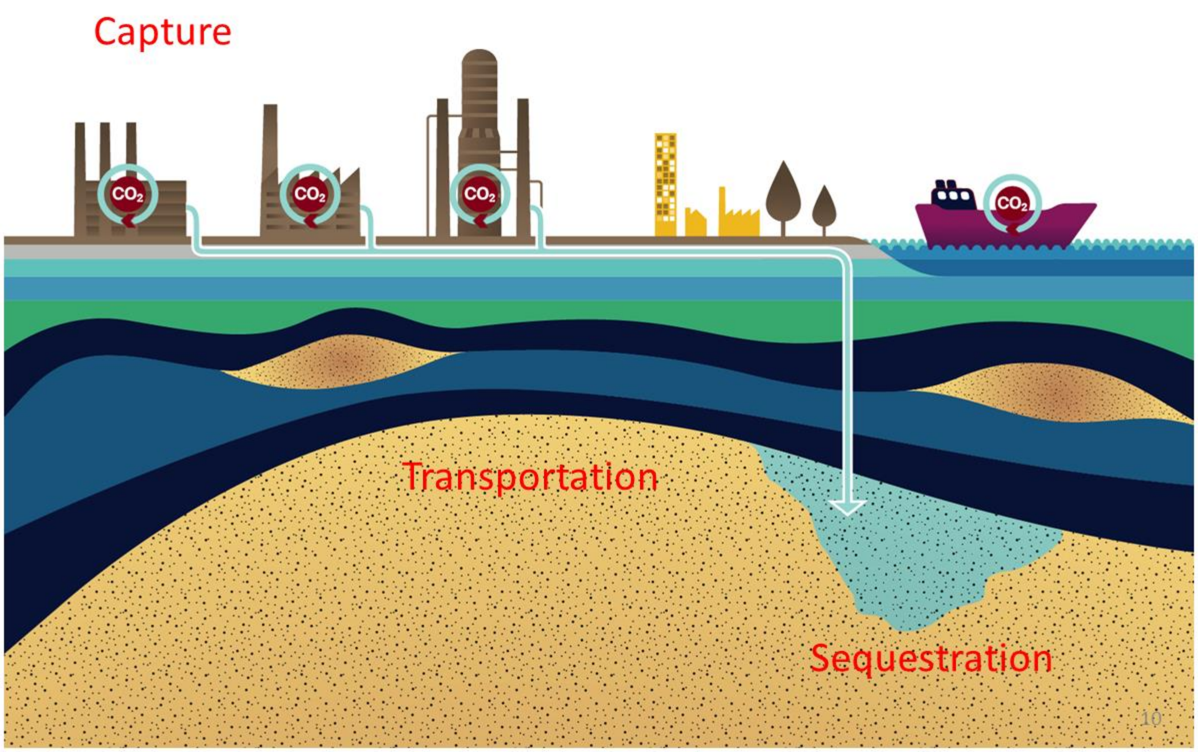


Figure 1: CCS Overview (courtesy of IPCC; reported in IPCC 2005, after Bradshaw and Dance, 2004)

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).

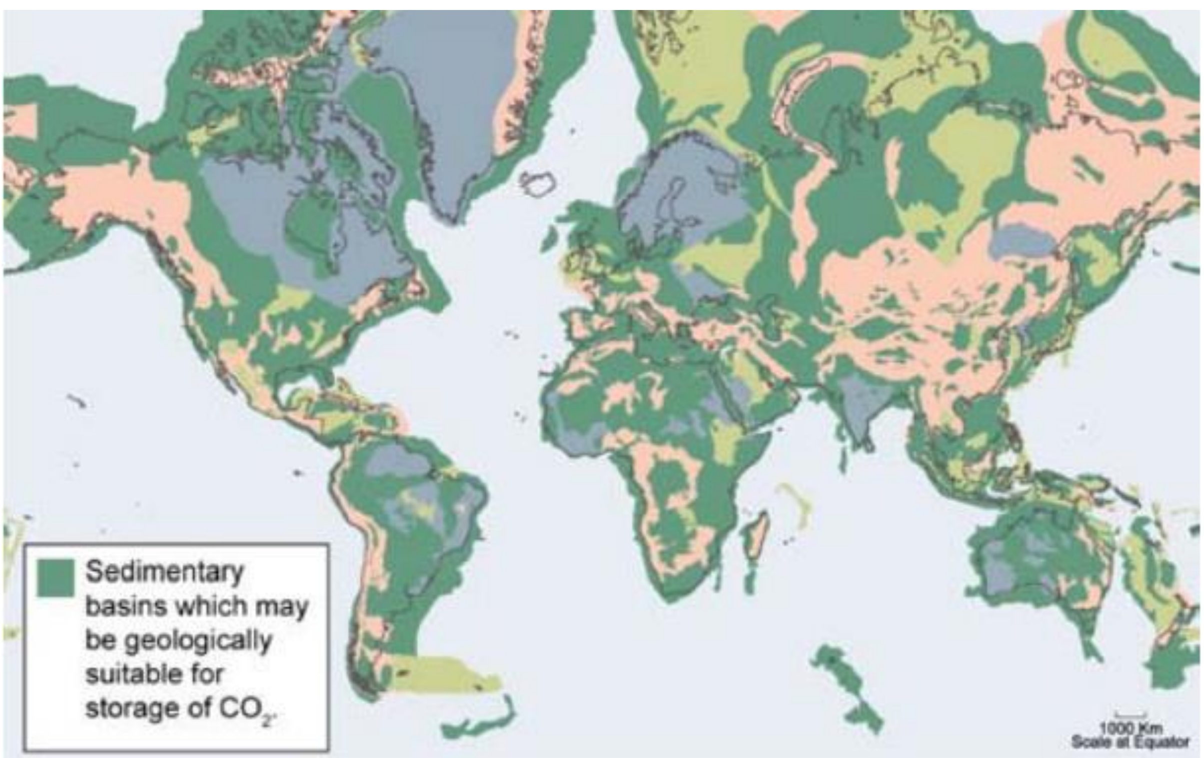


Figure 2: Worldwide regions that may be suitable for geological CO_2 storage (courtesy of IPCC; reported in IPCC 2005, after Bradshaw and Dance, 2004)

Geological CO_2 storage involves injecting large volumes of the captured CO_2 into the pore space of rock formations typically more than 900 m below the earth's surface. At such depths, the CO_2 is in a supercritical state and denser than a gas and occupies less pore space for the same amount (mass) of CO_2.

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 CO_2, 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 CO_2 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 CO_2 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 micro-pores in coal (Benson et al., 2011).

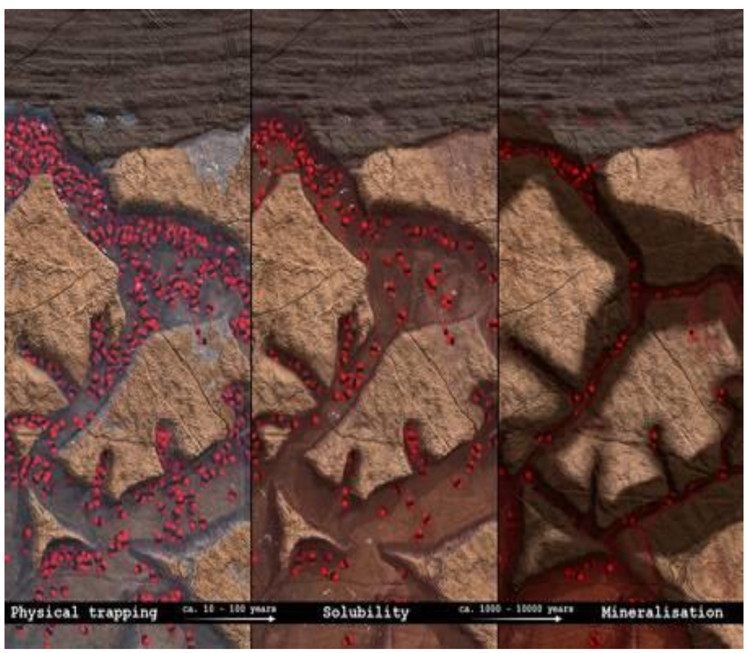


Figure 3: CO_2 Sequestered into a Porous Rock formation is permanently locked (CCSeducation)

There are various types of CO_2 storage mechanisms operating in reservoir rocks generally in combinations. These are:

Stratigraphic and Structural Trapping: It happens due to physical trapping of CO_2 in the porous rock below caprocks. Here the migration of CO_2 is prevented by low permeability barriers such as layers of mudstone or halite.

Residual saturation trapping: The injected CO_2 is immobilized by getting adsorption onto the surfaces of mineral grains within the rock matrix due to capillary forces. The CO_2 is thus trapped along its migration path.

Dissolution trapping: The injected CO_2 reacts or it dissolves into surrounding salt water in the reservoir and gets permanently trapped.

Hydrodynamic trapping: The CO_2 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 CO_2 saturation. This is known as hydrodynamic trapping.

Geochemical trapping: In this the CO_2 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 CO_2 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.

$$CO_2\,(g) + H_2O \;\text{<-->}\; H_2CO_3 \;\text{<-->}\; HCO_3^{-} + H^{+} \;\text{<-->}\; CO_3^{2-} + 2H^{+}$$

Different mechanisms mentioned above operate at various different timescales and is important in assessing a CO_2 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 CO_2 injection and storage. Injection is most likely to take place over the next century or so, when the need to store CO_2 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 CO_2 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 CO_2 storage requirements. Thus making saline aquifers, potential and viable sites for CO_2 storage.

2.3 Site Selection

It is important that while selecting a site for CO_2 storage both volumetric capacity and practical injection rate of CO_2 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 CO_2 storage site.

Properties	Suitable Values
Reservoir Depth	> 1000 m < 2500 m
Reservoir Thickness	> 50 m
Reservoir Porosity	> 20%
Reservoir Permeability	> 300 mD
Reservoir Salinity	> 100 g/l

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 CO_2 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 CO_2 source, so as to make the transportation of CO_2 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 CO_2 is pumped deep underground into one of two types of CO_2 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 CO_2 storage capacity as they are abundant and are present throughout the world and most existing large CO_2 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 CO_2. (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 CO_2 saturation in traps and the saline pore fluids, local or regional pressurization to get the maximum CO_2 injection storage capacity and the number of realistic wells needed to get access to all the traps and fluid in the reservoir.

The CO_2 injected into the reservoir acts in different ways in different geological formations. In saline formations and oil reservoirs, the buoyant plume of injected CO_2 migrates upwards due to buoyant forces, but not evenly. This is because a lower permeability layer acts as a barrier and causes the CO_2 to migrate laterally, filling any stratigraphic or structural trap on its migration pattern. The shape of the CO_2 plume rising inside a reservoir is strongly affected by formation heterogeneity and may cause viscous fingering. The demerits of storage of CO_2 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 CO_2 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 CO_2, H_2CO_3, H_2S, amines, H_2SO_4 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 CO_2 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 CO_2 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 CO_2 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 CO_2 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 CO_2 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 CO_2 along with enhanced oil recovery (EOR) in 2000. During 2000 to 2004, more than seven million tons of CO_2 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 CO_2 and provides rapid minimization and provide high storage capacity.

- Salah (Algeria). Sonatrach: BP and Statoil began capturing CO_2 from natural gas production in 2004 and started storing it in depleted gas reservoirs, as world's first full scale CO_2 capture and storage project at a gas field. The target capacity is one million tons of CO_2 to be stored per year.

- Otway (Australia): CO2CRC is injecting CO_2 from natural gas wells in hydrocarbon reserves, and the target sequestration amount is 0.1 million tons of CO_2. The objective is to provide technical information on CO_2 storage and monitoring and verification.

2.7 CO_2 Storage Capacity

It is important to carefully access the capacity of a CO_2 storage site. CO_2 storage capacity depends not only on the properties of the reservoir rock itself but also on the nature of its boundaries. Very little CO_2 can be injected into the water filled small reservoir having perfectly sealed non-elastic boundaries. This is because the injected CO_2 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 CO_2, 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 CO_2 that can be stored in a reservoir formation.

Geological CO_2 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 CO_2 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 CO_2 and brine, buoyant action caused due to the density differences between CO_2 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 CO_2 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 CO_2 is injected into a gas reservoir, a single miscible fluid phase consisting of natural gas and CO_2 is formed locally. This is because both natural gas and CO_2 combine to form a miscible single phase fluids as both are organics. But this is not true when CO_2 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 CO_2 and other reservoir formation fluids are immiscible in water. CO_2 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 CO_2 injection in a gas reservoir. Equation (1) was used to calculate the well-pore pressure based on the reservoir properties like initial pressure (P_i), permeability (k), porosity (ϕ), reservoir thickness (h) and depth, rock compressibility (c_t) and reservoir fluid properties like viscosity (μ_o), density, temperature, formation factor (b_0) etc. In this equation, we consider constantly radially flowing fluid (Q_0) 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 CO_2(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.

$$P(r,t) = P_i + \left[\frac{70.6 Q_0 \mu_0 b_0}{kh}\right] E_i \left[\frac{-948 \Phi \mu_0 c_t r^2}{kt}\right] \tag{1}$$

3.3 Two Phase Model

In reality CO_2 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 CO_2 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 CO_2 at a constant rate namely the CO_2 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 CO_2–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 CO_2. 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 CO_2 migrates as they move at characteristic speeds (Burton et al., 2008).

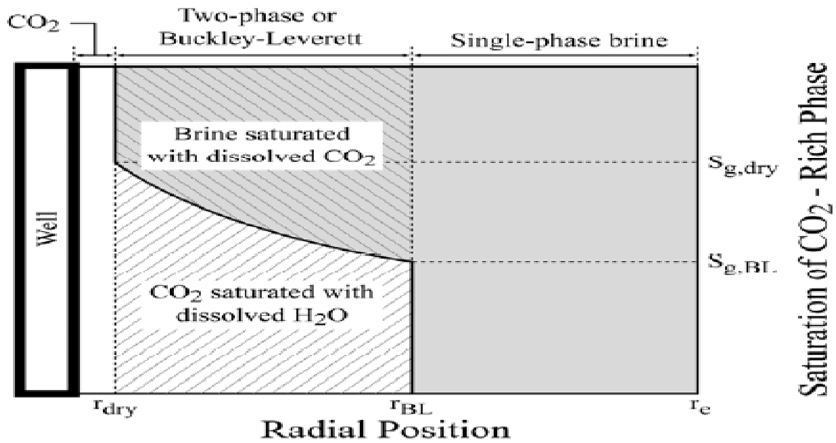


Figure 4: Shows three regions of flow developed during CO_2 injection (Burton et al., 2009)

3.3.1 Modified Buckley-Leverett Model

In order to model the flow of CO_2 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_{Ddry}) and two-phase fronts (r_{BL}). The dimensionless positions of the drying and BL fronts (r_{Ddry} and r_{DBL}) can be predicted independently of all other parameters, for a specified set of relative permeability curves by using Equation (2) (Azizi and Cinar, 2013).

$$
\begin{aligned}
&\frac{1}{r_D}\frac{\partial}{\partial r_D}\left(r_D\frac{\partial P_{D1}}{\partial r_D}\right)=\frac{\partial P_{D1}}{\partial t_D}, 0<r_D<r_{D\mathrm{dry}}\\
&\frac{1}{r_D}\frac{\partial}{\partial r_D}\left(r_D\frac{\partial P_{D2}}{\partial r_D}\right)=\frac{1}{F_{\lambda g}\eta_{D2}}\frac{\partial P_{D2}}{\partial t_D}, r_{D\mathrm{dry}}<r_D<r_{DBL}\\
&\frac{1}{r_D}\frac{\partial}{\partial r_D}\left(r_D\frac{\partial P_{D3}}{\partial r_D}\right)=\frac{1}{\eta_{D3}}\frac{\partial P_{D3}}{\partial t_D}, r_{DBL}<r_D<\infty
\end{aligned}
\tag{2}
$$

To solve for pressure gradient in the reservoir, we use dimensionless technique using dimensionless parameters such as P_D, t_D, ε and r_D which are the dimensionless pressure, time, rate and radius respectively. Here, r_D is the dimensionless radial distance from injector, ε is the dimensionless injection rate and t_D is the dimensionless time or equivalently the number of pore volumes of CO_2 injected into a reservoir. All of them are defined as follows:

$$r_D=\frac{\mathrm{r}}{\mathrm{r_w}} \tag{3}$$

$$t_D = \frac{k\bar{k}_{rg}\mathrm{t}}{\mu_g \mathrm{r_w^2}\,\Phi\,\mathrm{c_{tg}}} \tag{4}$$

$$\varepsilon = \frac{\mathrm{qB_g}(\mathrm{c_g}+\mathrm{c_r})\mu_g}{4\Pi hk\bar{k}_{rg}} \tag{5}$$

In the above equations, r is the radial distance from the well, r_w is the well radius, k is the formation permeability, $\bar{k}_{rg}$ is the gas relative permeability in the drying-out zone ($\bar{k}_{rg} = \bar{k}_{rg}|_{Sg=1}$), t is the time, μ_g is the CO_2 viscosity, ϕ is the porosity, c_{tg} 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 ($D_{brine—BL}$ and $D_{BL—dry}$) 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 η_{D2}, η_{D3} and $F_{\lambda g}$ which are diffusivity ratios and dimensionless total mobility as defined below:

$$\eta_{D2} = \frac{c_{tg}}{c_t}\bigg|_{S_{g,\mathrm{ave}}} \tag{6}$$

$$\eta_{D3} = \frac{c_{tg}}{c_{tw}}\frac{\overline{\lambda_w}}{\lambda_g} \tag{7}$$

$$F_{\lambda g} = \frac{\lambda_g + \lambda_w}{\overline{\lambda_g}}\bigg|_{S_{g,\mathrm{ave}}} \tag{8}$$

λ_w and λ_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 $S_{g,avg} = (S_{gdry} + S_{gBL})/\,2$, where S_{gdry} is the gas saturation at the dry region front and S_{gBL} 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 ξ_{DBL} and ξ_{Ddry} corresponding to two saturation fronts.

$$\xi_{DBL} = \frac{1}{4}\varepsilon \left.\frac{df_g}{dS_g}\right|_{S_{gBL}} \tag{9}$$

$$\xi_{Ddry} = \frac{1}{4}\varepsilon \left.\frac{df_g}{dS_g}\right|_{S_{gdry}} \tag{10}$$

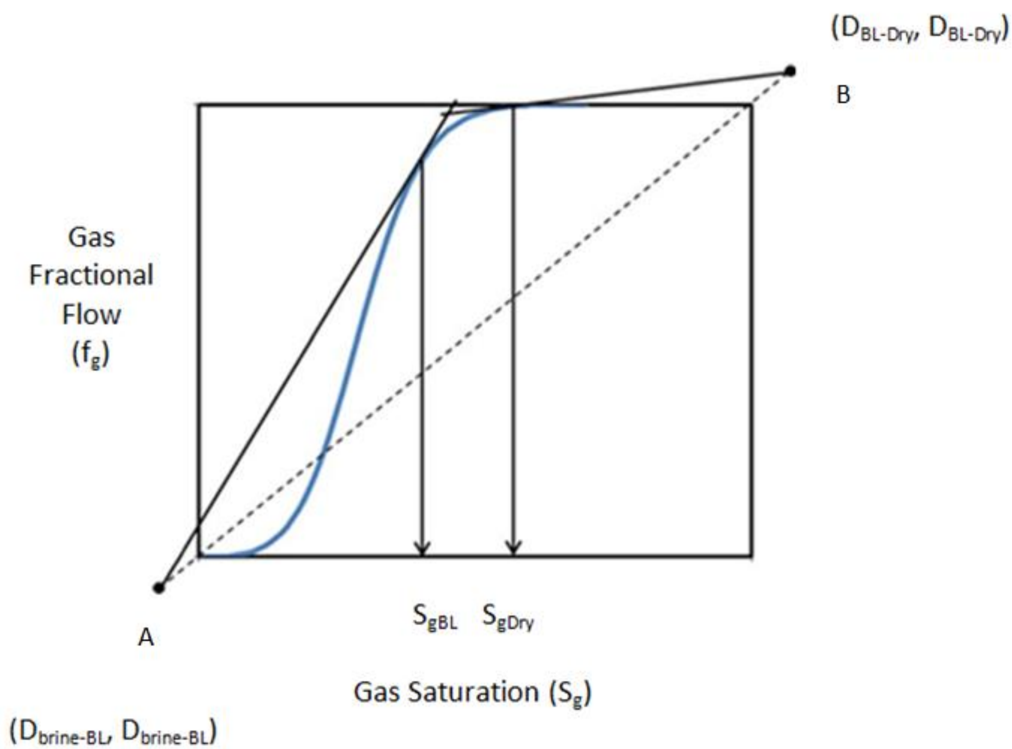


Figure 5: Fractional-flow curve showing gas saturation corresponding to the two front r_{Ddry} and r_{BL}, based on Azizi and Cinar, 2013

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)):

$$P_{D1} = -\frac{1}{2} E_i(\frac{-r_D^2}{4t_D}) + \frac{1}{2} E_i(-\xi_{Dry}) - \frac{1}{2F_{\lambda g}} E_i\left(\frac{-\xi_{Dry}}{F_{\lambda g}\eta_{D2}}\right) + \frac{1}{2F_{\lambda g}} E_i\left(\frac{-\xi_{DBL}}{F_{\lambda g}\eta_{D2}}\right) - \frac{\overline{\lambda}_g}{2\lambda_w} E_i\left(\frac{-\xi_{DBL}}{F_{\lambda g}\eta_{D3}}\right)$$

$$\text{For } t_D \geq \frac{r_D^2}{4\xi_{Ddry}} \tag{11}$$

$$P_{D2} = -\frac{1}{2F_{\lambda g}} E_i(\frac{-r_D^2}{4F_{\lambda g}\eta_{D2}t_D}) - \frac{1}{2F_{\lambda g}} E_i\left(\frac{-\xi_{DBL}}{F_{\lambda g}\eta_{D2}}\right) + -\frac{\overline{\lambda}_g}{2\lambda_w} E_i\left(\frac{-\xi_{DBL}}{F_{\lambda g}\eta_{D3}}\right)$$

$$\text{For } \frac{r_D^2}{4\xi_{DBL}} \leq t_D \leq \frac{r_D^2}{4\xi_{Ddry}} \tag{12}$$

$$P_{D3} = -\frac{\overline{\lambda}_g}{2\lambda_w} E_i(\frac{-r_D^2}{4F_{\lambda g}\eta_{D3}t_D}) \quad \text{For } t_D \leq \frac{r_D^2}{4\xi_{DBL}} \tag{13}$$

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).

$$\Delta p_{total} = \Delta p_{dry} + \Delta p_{BL} + \Delta p_{brine} \tag{14}$$

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

$$P_{final}(r,t) = P_i + P_d(r,t)\left[\frac{q\mu_g b_g}{2\Pi \overline{k}_{rg} kh}\right] \tag{15}$$

3.4 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).

$$P_{final} = Pi + \sum_{n=1}^{n} \Delta P_n \qquad (16)$$

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_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_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_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 λ and was varied between 6 to 10 kms.

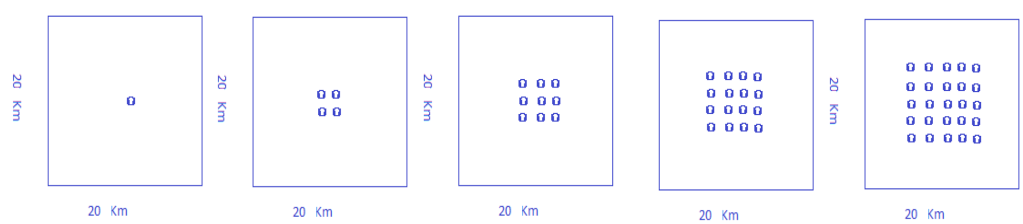


Figure 6: Symmetrical well placement (Ghaderi et al., 2009)

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_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}*16 for 50 years.

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)

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

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 CO_2 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 CO_2 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 CO_2 on being injected in a saline aquifer follows a two phase model.

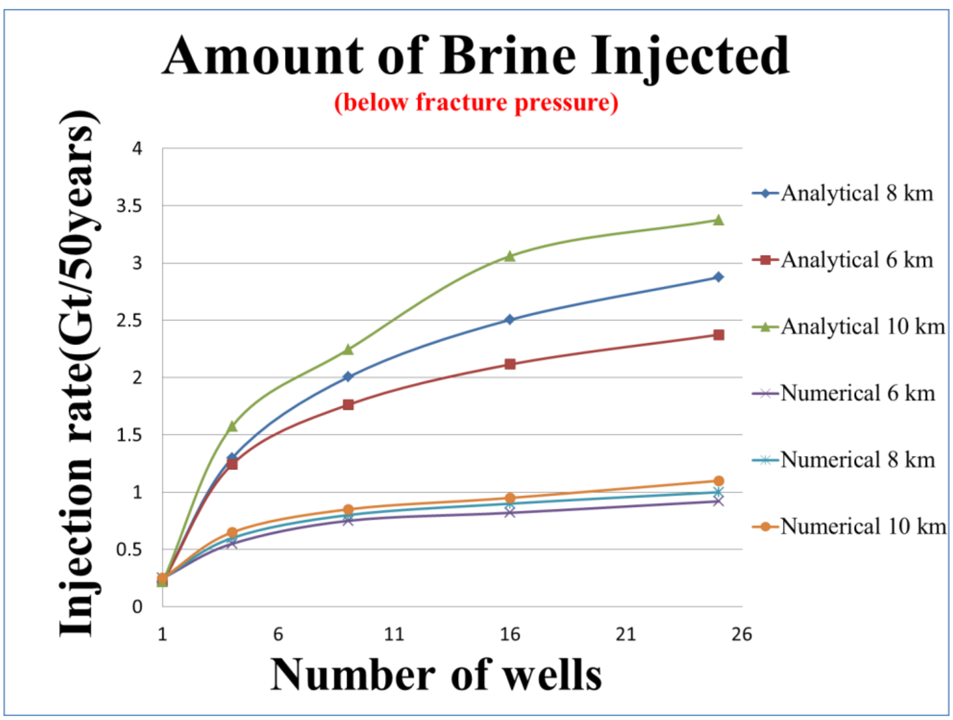


Figure 7: Plot showing the amount of CO_2 injected into the reservoir for a period of 50 years of various number of wells

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.

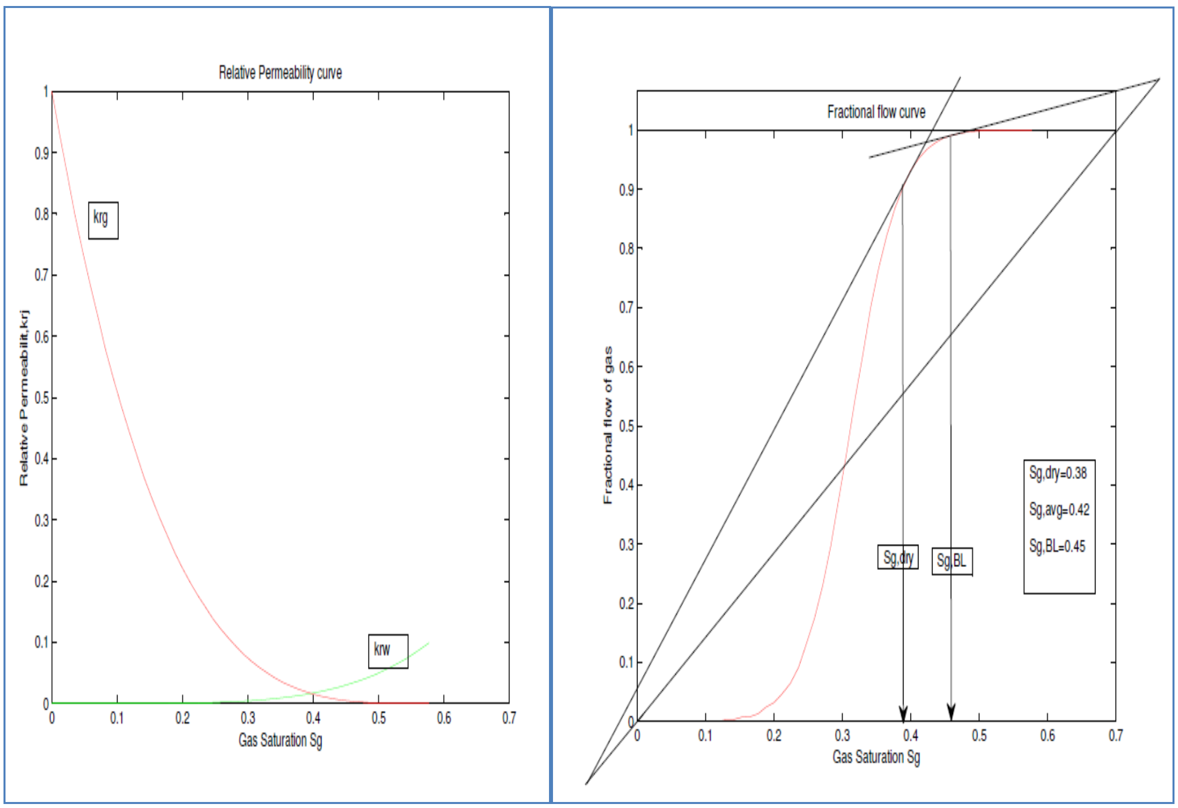


Figure 8: Graph showing the plotted (a) Relative Permeability Curve (b) Fractional Flow Curve for the nisku aquifer based on the data provided.

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_{Ddry} and r_{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.

Parameters	**Value**	**Units**
Porosity(Φ)	0.064	
Permeability(k)	46	mD
Thickness(h)	102	m
Brine Viscosity(μw)	0.84	cP
Gas Viscosity(μg)	0.062	cP
Rock Compressibility(cr)	$1.45*10^{-10}$	1/Pa
Brine Compressibility(cw)	10^{-9}	1/Pa
Gas formation Volume Factor(Bg)	0.003	
Injection Rate(Q)	17 .01	m^3 /s
Initial Pressure(Pi)	$1.6*10^7$	Pa
Fracture Pressure(Pf)	$3.1*10^7$	Pa

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 (ξ_{DBL} and ξ_{Ddry}) and to get endpoint saturations (S_{gdry} and S_{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 ξ_{DBL} and ξ_{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_{gdry}) 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 $1.47*10^6$ 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

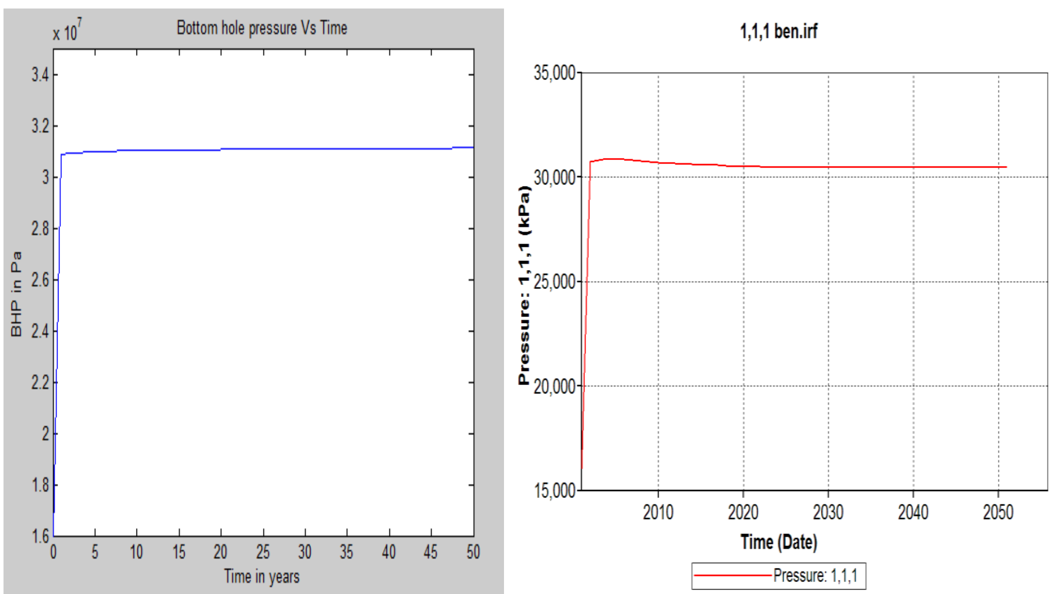


Figure 9 (a) BHP vs. time for 50 years (b) BHP vs. time by analytical BL- Two Phase Model

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

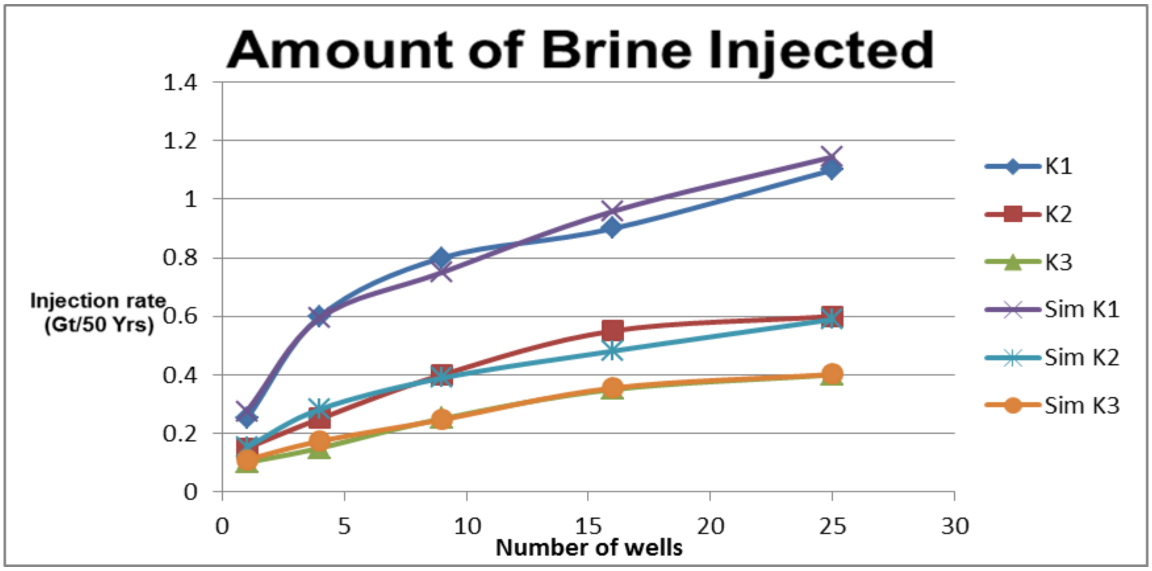
As the bottom-hole pressure is one of the most important factors that come into play when determining the storage capacity of CO_2 storage sites, it is important to realize what parameters are affected by it. Sensitivity test was carried out based on important parameters like reservoir thickness (50-100 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.

Parameters	**Source**	**Effect**
Permeability	A	Highly Significant
Thickness	B	Very Significant
Rock Compressibility	C	Significant
Porosity	D	Less Significant

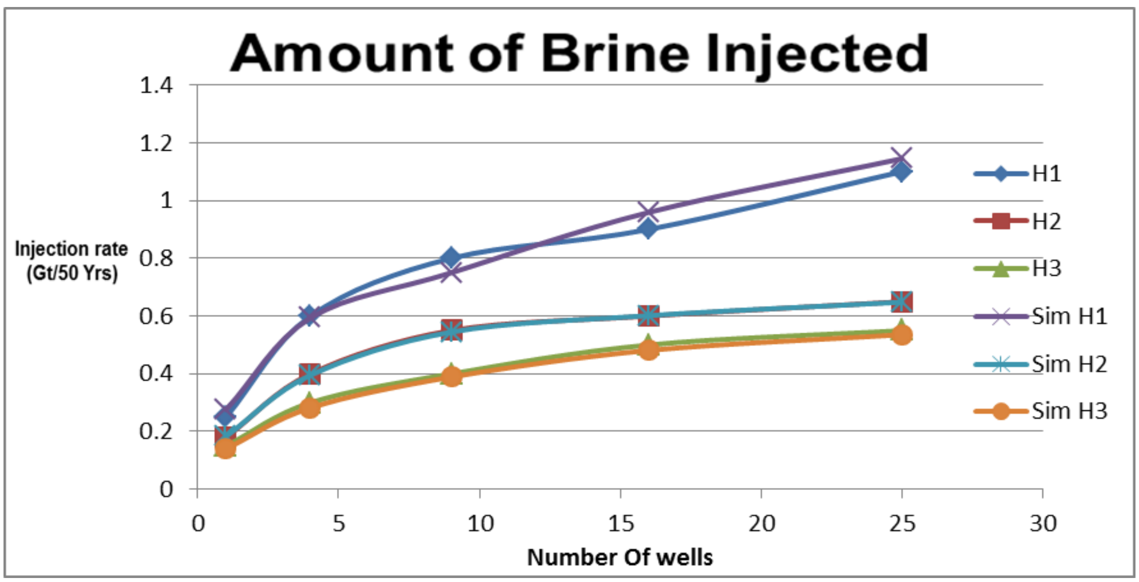
Table 4: Shows the effect of the different parameters on the well-bore pressure based on the ANOVA table

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 CO_2 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 CO_2 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)
1.4
1.2
1
0.8
0.6
0.4
0.2
0
0
5
10
15
20
25
30
Number of wells
K1
K2
K3
Sim K1
Sim K2
Sim K3



Amount of Brine Injected
Injection rate (Gt/50 Yrs)
1.4
1.2
1
0.8
0.6
0.4
0.2
0
0
5
10
15
20
25
30
Number Of wells
H1
H2
H3
Sim H1
Sim H2
Sim H3

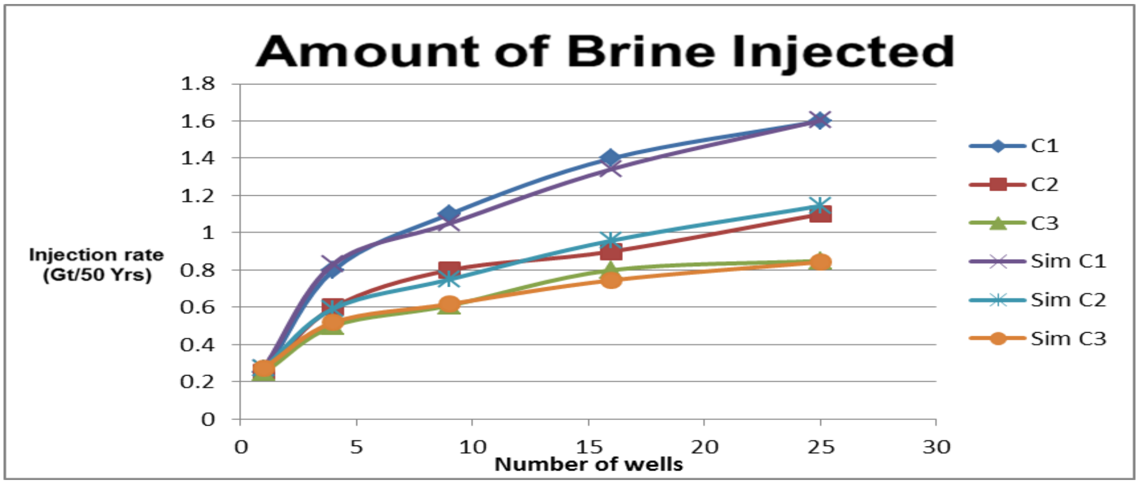


Figure 10: Effect of sensitive parameters on storage capacity, a) effect of permeability, b) effect of aquifer thickness, c) effect of compressibility. Also further comparison is made with the data obtained from the CMG simulation model and analytical BL- two phase model. Both showing similar results 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 CO_2 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

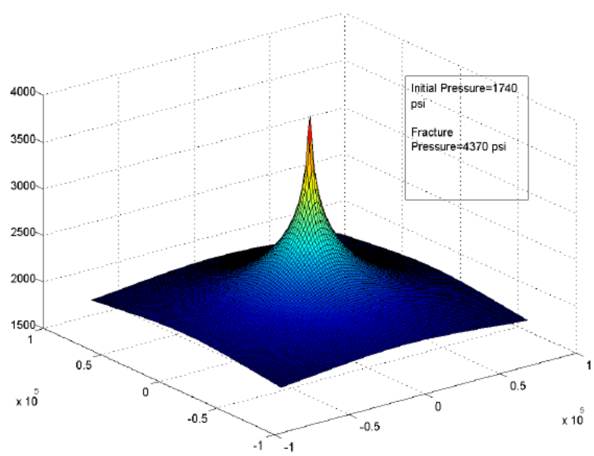
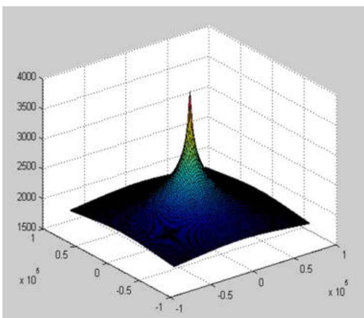


Figure 11: 3D Plot for BHP vs. Time for 50 years at Initial pressure (P_i)=1740 psi and Fracture pressure(P_f)=4370 psi.

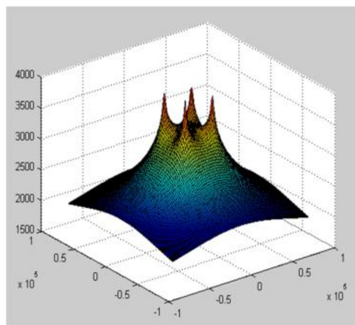
In general, it is required to inject the maximum amount of CO_2 within a relatively small area of injection and short period of time. But, by injecting larger amount of CO_2 into the reservoir there will be increase in reservoir pressure. So it is important to maintain low injection rates, which increases 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

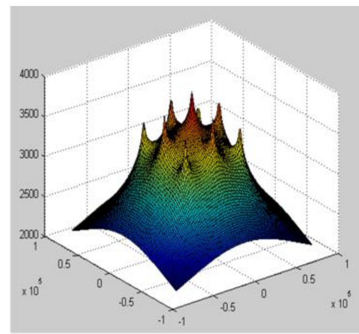
One of the ways to increase the injection capacity of an ideal reservoir is to drill many injection wells so as to cover the maximum available pore space possible within a short while. In the study, we try injecting CO_2 for different well scenarios with the constraint of maintaining the reservoir pressure under 90 percent of the facture 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.



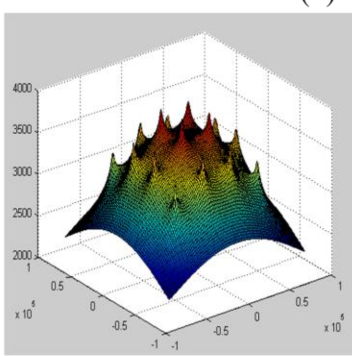
(a) 1 well



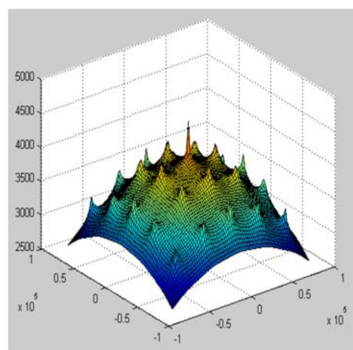
(b) 4 wells



(c) 9 wells



(d) 16 wells



(e) 25 wells

Figure 12: Pressure profile for multiple

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 CO_2. 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.

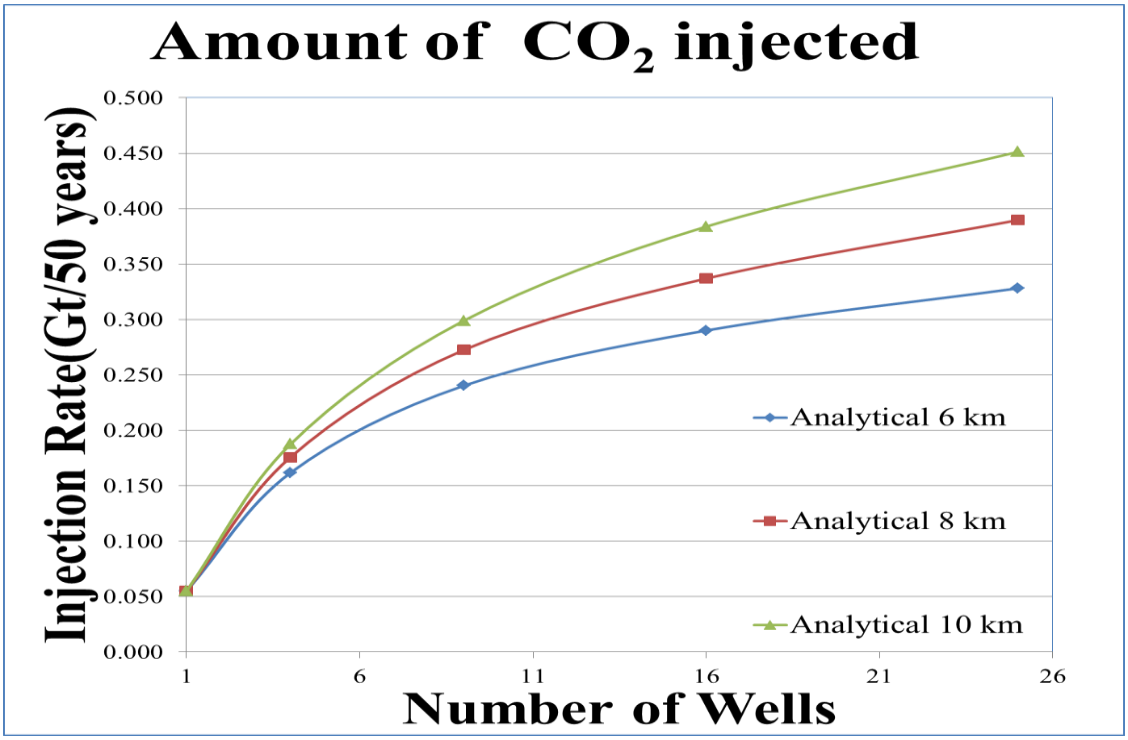


Figure 13: Analytical two phase model for amount of CO_2 injected for symmetrically spaced wells (i.e. 6km, 8km, and 10km) for 50 years

5.2 Varying Well Placement within a Confined Area

As we increase the number of wells we get higher CO_2 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.

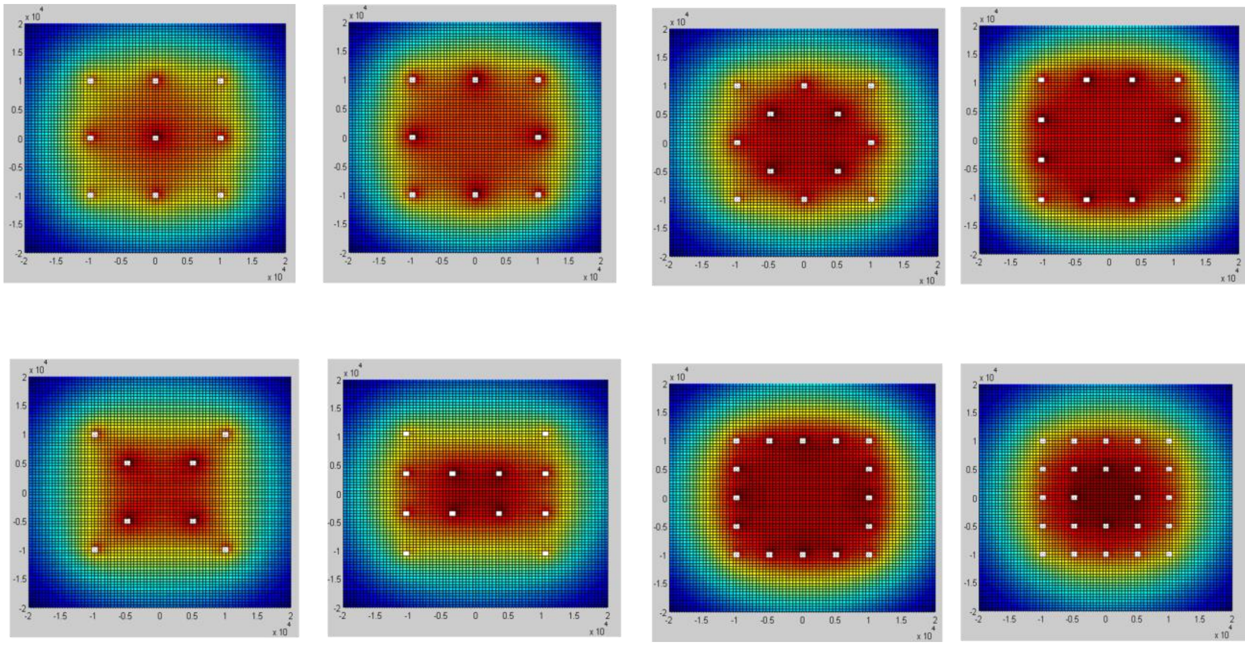


Figure 14: Different well placement (a) 9 wells (b) 8 (exterior) (c) 8 (interior) (d) 12 (interior) (e) 12 (circle) (f) 12 (exterior) (g) 16 wells (h) 24 wells.

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 increses, 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_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 well 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 well 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.

No of Wells	**Amount of CO_2 injected in Gt for 50 years**			
	6km	**8km**	**10km**	**Boundary**
1	0.05	0.05	0.05	0.05
4	0.20217	0.21975	0.2344	0.38676
9	0.24026	0.27249	0.29886	0.4395
16	0.29007	0.33695	0.38383	0.50103
25	0.32816	0.38969	0.45122	0.45122

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(exterior)	32
12(interior) Vs 12(exterior)	9.944751381
12(interior) Vs 9	6.832298137
16(interior) Vs 12(interior)	6.432748538
16(exterior) Vs 12(exterior)	3.723404255
16(exterior) Vs 16(interior)	9.042553191
24 Vs 25	6.666666667
12(interior) Vs 12(circle)	1.226993865

Table 6: Showing the increase in amount CO_2 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 $Q_{12}/12$). 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 CO_2 at the boundary and less at the center.

For analysis two flow rates were considered Q_1 and Q_2 ($Q_1 < Q_2$). Q_2 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 Q_1. On doing so it was found that from CO_2 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.

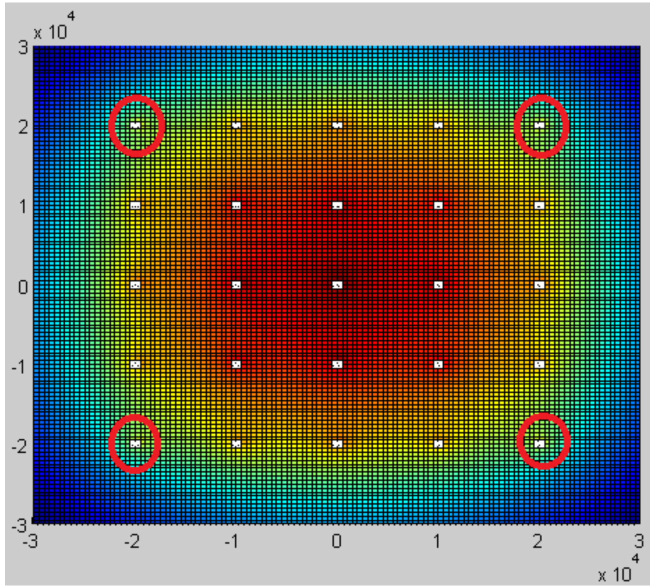


Figure 15: Wells shown by red circles indicates wells with higher flow rates

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 see in the Table 7 there is not a significant increase in the injection capacity of the reservoir, when we have more than 12 wells.

Wells	Amount of CO_2 injected in Gt for 50 years		
	Constant Flow rate	**Variable Flow rate**	**% Increase**
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

Table 7: Showing the amount of CO_2 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 counterfeit 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 CO_2 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 CO_2 sequestration site. Using the analytical BL- Two Phase Model developed during the study we are able to predict the CO_2 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 CO_2 that can be injected based on number of wells and the cost associated with each well.

The study concluded that CO_2 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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