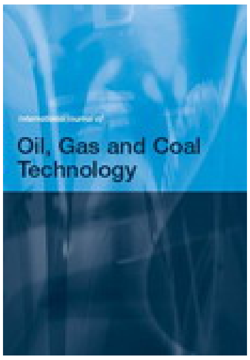

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Influence of relative permeability, capillary pressure, and well orientation in the geological carbon sequestration in a saline aquifer

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Influence of relative permeability, capillary pressure, and well orientation in the geological carbon sequestration in a saline aquifer

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Abstract: In carbon capture and sequestration (CCS), geological sequestration of carbon dioxide (CO_2) in deep saline aquifers with porous and permeable rocks is one of the most feasible among various solutions to sequester CO_2. Here, the TOUGH2 numerical simulator was validated with the analytical model developed predicting the CO_2 behaviour in confined saline aquifers. The sensitivity of the numerical model was examined by changing the model of fluid relative permeability (RP) and capillary pressure (CP) functions. Corey's RP functions and Van Genuchten's CP function is most effective to capture the gas saturation (SG) well. The effect of CO_2 injection, well orientation, and its length in a simplified saline aquifer model are also demonstrated. This study reveals that the horizontal well configuration is most acceptable. For the same injection well length (at 100 m), 22% drop in the pressure rise is computed in horizontal well as compared to its vertical counterpart. [Received: October 9, 2021; Accepted: February 7, 2022]

Keywords: carbon capture and sequestration; CCS; CO_2 geological sequestration; saline aquifers; relative permeability; capillary pressure; well orientation.

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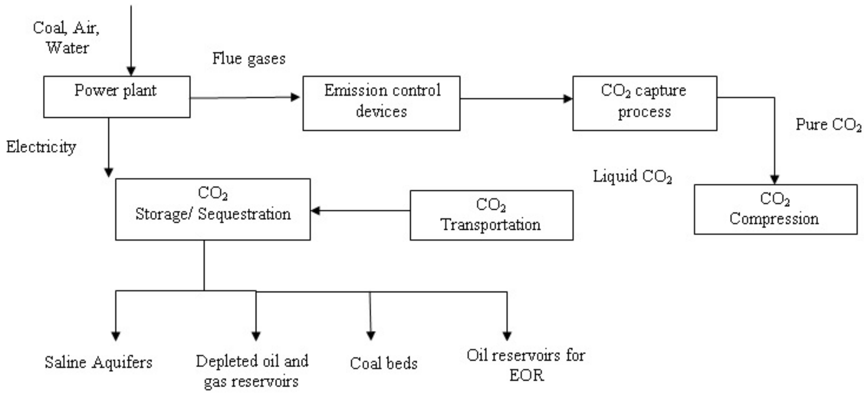
1 Introduction

The primary reason for current global warming and subsequent climate change issues is the large increase of anthropogenic CO_2 concentration in the environment compared to the pre-industrial era (IPCC, 2005). The structures that involve the burning of fossil fuels are power plants to generate electricity and industrial operation such as refining oil or generating iron, steel, cement, and ammonia; all transmit vast amounts of CO_2. The significant industrial zone contributes one-fifth of the world's emissions (Donald et al., 2015). Considering the contemporary trend in the world's monetary and population growth, the concentration of CO_2 can nevertheless rise (IPCC, 2005). IPCC in 2018 published a report titled 'Global Warming of 1.5°C' which states, "At the current rate of emissions, the world will reach 1.5°C warming by 2030 and 2052 and is on track for more than 3°C to 4°C warming by 2100". It also set the goal of 1.5°C of global temperature increase up to 2100. In order to achieve this target, global CO_2 emissions require to be brought down by 45% by 2030 from 2010 levels and then zeroed out entirely by the year 2050. Large-scale emissions-intensive commercial and power generation processes must significantly be decarbonised to meet this target (IPCC, 2018; Fragkos, 2020).

Carbon dioxide capture, sequestration, and utilisation (CCUS or CCS) are among the potential clean technologies to mitigate CO_2 that can have a substantial optimistic impact on reducing global climate change. The IPCC report concluded that realising a 2°C limit might be higher than twice as expensive without CCUS, equating to an incremental 3% of the cumulative global GDP through to 2100. Failure to put into effect CCUS broadly throughout all industries worldwide might make realising a 2°C outcome unlikely. To satisfy the targets set in the Paris Agreement, the implementation of the CCUS project ought to increase swiftly alongside commercial deployment of other clean energy technologies.

Geological carbon dioxide sequestration is one of the leading clean technologies available to lessen CO_2 emissions. CCS stands out because of its massive potential in terms of CO_2 volumes that may be stored in geological media for thousands of years. CO_2 capture and geological storage include four primary stages: Firstly, CO_2 capture and separation from different flue gases from the stationary emitting source. Secondly, CO_2 transportation from emitting source to the storage location via pipelines, trucks, or tankers; thirdly, CO_2 storage in distinctive geological formations, each with specific advantages and disadvantages, and the last and the most crucial, CO_2 measurement, monitoring, and verification throughout and after injection phase right into a geological formation. The relevant geological options that can adequately store vast quantities of CO_2 and hold it from reaching the atmosphere are gas and oil fields, deep saline aquifers, basalt rocks, and deep coal seams (Kuk et al., 2021). As a result, Hasan et al. (2015) proposed an approach to CCUS technology optimal design that incorporates multiple dimensions. The goal was to keep costs down and CO_2 emissions down in the USA. Figure 1 show various processes involved in the CCS system for the coal-fired powerplant.

Figure 1 Schematic diagram of CCS for a coal-fired powerplant



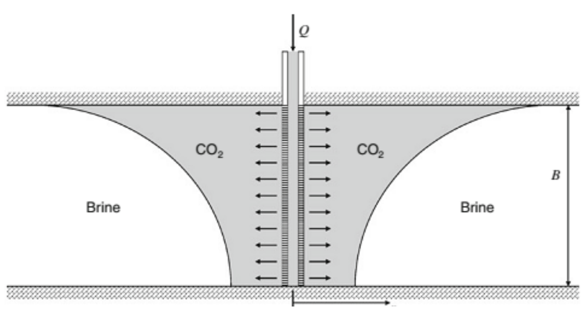
Specifically, deep saline aquifers, described as permeable and porous reservoir rocks that contain brine, placed between 800 to 2,000 metres underneath the sea level, are widely available for sequestration of CO_2. These saline aquifers are more prevailing than gas and oilfields and coal mines and have a massive prospective for sequestration in storage capacity, which is the largest (Rosa and Adisa, 2015; Gupta and Paul, 2019). The physical characteristics of CO_2 are significant for its underground storage (Bachu, 2008). Four mechanisms can be recognised to store CO_2 geologically in saline aquifers. These are structural and stratigraphic trapping, residual gas trapping, solubility trapping, and mineral trapping. All have different time scale contributions to CO_2 sequestration (Bachu and Adams, 2003). Physical or stratigraphic trapping of fluids (CO_2 in dense phase) within the sub-surface is achieved by a structural or stratigraphic caprock. Capillary forces and dissolution of CO_2 in brine cause this trapping, which controls the aquifer's capacity for CO_2 storage (Kumar et al., 2005; Martinez and Hesse, 2016; Bo and Hoonyoung, 2018). Physical trapping is crucial throughout the injection period of CO_2 sequestration. Residual trapping can be described as residual saturations of CO_2 trapped as gas bubbles or supercritical fluid bounded by brine in the formation rocks. From the top of the injection well (IW) to the reservoir, CO_2 is affected by numerous physical effects that contribute to the pressure and temperature profile alongside the well (Amin et al., 2019). In the ionic or solubility trapping mechanism, CO_2 dissolved within the aqueous phase of the geologic formation is retained as dissolved carbonate and bicarbonate species. Solubility trapping may be crucial as it lessens buoyancy effects and leaves CO_2 accessible for geochemical reactions with species in brine (IPCC, 2005). Mineral trapping entails absorption of CO_2 into solid-state, this occurs when the dissolved CO_2 reacts with selected cations (such as Ca_2^{+}or Mg_2^{+}), present within the aqueous phase or originated from mineral dissolution. Once in a solid phase, CO_2 will probably stay immobilised for millions of years and therefore is considered the most secure trapping mechanism. A reservoir is deemed appropriate to sequestration of CO_2 if it has adequate capacity to store a massive amount of CO_2 for an adequately significant time.

Generally, reservoirs at depths below 800 m are preferred because the thermophysical properties at these depths are higher than the supercritical pressure, the temperature of CO_2, i.e., 73.8 bar and 31.1ºC, respectively (Bachu, 2008). Before injection, precise geological site data and reservoir simulation are essential to interpret the storage volume and estimate safe and balanced long-lasting containment. Wan et al. (2016) introduced an algebraic targeting method to select a CO_2 storage site to utilise the largest amount of CO_2 possible while storing the least amount of CO_2 in geological storage. This technique was termed total site CO_2 integration (TSCI).

Many researchers (Nordbotten et al., 2005; Dentz and Tartakovsky, 2009; Mathias et al., 2009, 2011) have developed analytical solutions to estimate pressure buildup and CO_2 plume migration in saline aquifers. Analytical solutions depict the impact of specific characteristics of physics on the supercritical CO_2 injection by eliminating the impact of other parameters. These analytical models were developed by taking the assumption of confined and homogeneous reservoirs with isothermal conditions. Various commercial and academic numerical simulators like GEM, CSIRO, TOUGH2, FLOTRAN, and Eclipse300 have been developed to study the CO_2 plume behavior in confined geologic reservoirs (Pruess et al., 2004, 1999; Schlumberger, 2002; Oladyshkin et al., 2011). The outcomes from these simulators encompass the counts of crucial constants, which could be utilised to weigh the appropriateness of geologic formations (Pruess et al., 2004).

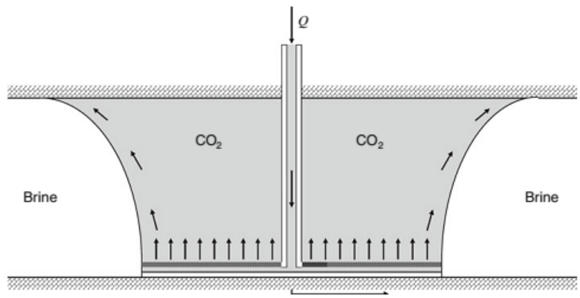
Supercritical CO_2 injection right into saline aquifers will bring on temperature and pressure changes in the formation that will induce some geo-mechanical changes within and on surrounding of the reservoir, mainly near the area of IW (Rutqvist, 2012; Rathnaweera et al., 2018; Nguyen et al., 2017). Also, the basin and caprock's hydro-mechanical feedback is firmly associated with fluid pressure growth and is restrained by the direction from which CO_2 is injected, i.e., vertical or horizontal. A study shows that CO_2 sequestration by a horizontal well allows a higher CO_2 injection rate and more exceptional CO_2 storage ability than a vertical well. Also, for constant CO_2 injection pressure, the feasible CO_2 injection rate rises with the horizontal right length (Jikich et al., 2003). Another study reported that the adoption of horizontal wells could be of little benefit in CO_2 injection in the aquifer, with curtailing CO_2 rising the top seal of the basin, possibly decreasing the rescue of the CO_2 which was injected (Ozah et al., 2005).

Figure 2 Schematic representation of CO_2 injection into the saline aquifer by a vertical IW



Nordbotten et al. (2005) assumed gravity to govern rather than viscous effects in modelling supercritical CO_2 injection in confined saline aquifers. They injected supercritical CO_2 with a vertical well into the reservoir of an infinite radial extent (Figure 1). They ignored the effects of capillary pressure (CP) and considered incompressible CO_2 and brine and immiscible with each other. When supercritical CO_2 is injected, it moves brine far-off from the IW because of viscous force and moves upwards because of buoyancy. The reason behind this is CO_2 is less viscous and less dense than brine reservoir conditions (Bachu and Adams, 2003; Nordbotten et al., 2005). They also carried out the injection of supercritical CO_2 via a horizontal well. Figures 2 and 3 illustrate the injection of CO_2 into saline aquifers by a vertical and a horizontal well as presented by Nordbotten et al. (2005).

Figure 3 Schematic representation of CO_2 injection into the saline aquifer by a horizontal IW



Horizontal IW is one strategy for increasing the injectivity and capacity of aquifers because this configuration builds up lesse pressure spikes around the IW and evenly distributes pressure throughout the flow domain. A minimum horizontal well length must be determined to use this method, which is based on the effective radius of pressure disturbance surrounding the vertical IW (Khudaida and Das, 2020). The maximum dynamic capacity of the reservoir is also a function of the configuration of the IW. The effect of horizontal well in increasing the rate of CO_2 injection and sequestration adaptability is still inadequately evaluated and not well understood in the literature. Also, more study is required to optimise the length of the horizontal well and the injection procedures including injection of chase brine along with CO_2. The present study is therefore, an extended version of the simplified analytical model of Nordbotten et al. (2005). It also interprets the sensitivity of the numerical model by changing the model of fluid relative permeability (RP) and CP functions from linear to nonlinear as developed by Corey (1954) and Van Genuchten (1980). Furthermore, the orientation of the IW and the extent of the IW were also analysed to demonstrate the effect in fluid pressure and CO_2 plume migration on the viability of CO_2 sequestration.

2 Numerical modelling

2.1 Governing equations

The study of the flow of two immiscible fluids (supercritical CO_2 and resident brine), with different viscosities and densities, has been done in a homogeneous isotropic porous medium. The supercritical CO_2 is injected into the reservoir, bounded by an impermeable layer of cap rock at the top and bottom boundaries. In the reservoir, the entire porous medium is saturated with brine and both fluid phases (supercritical CO_2 and brine) have their separate flow channels. The continuity equation for the multiphase flow of the system can be written as:

$$\frac{\partial(\rho_\alpha \phi S_\alpha)}{\partial t} + \nabla.(\rho_\alpha V_\alpha) = 0 \tag{1}$$

$$\sum S_\alpha = 1 \tag{2}$$

where ρ the fluid density; ϕ is the reservoir porosity, S represents fluid saturation, t is the injection period, and V represents Darcy velocity. The subscript α classifies each fluid, with $\alpha = c$ is for CO_2 and $\alpha = w$ is for brine.

Momentum conservation equation can be written by Darcy's law as given:

$$q_\alpha = \frac{kk_{r\alpha}}{\mu_\alpha}(\nabla P_\alpha + \rho_\alpha g \nabla z), \alpha = c, w \tag{3}$$

where as k represents intrinsic permeability, $k_{r\alpha}$ represents RP of α phase, μ_α is viscosity of α phase P_α is fluid pressure of α phase, g is gravity and z denotes the vertical distance (Bear, 1972).

The reservoir boundary has an impermeable layer of caprock at the upper and lower part. These are considered as no-flow boundaries as CO_2 or brine could not permeate through the layers. At the lateral extent, we have assumed the aquifer to be of infinite extent, enabling constant pressure boundary conditions at the outer layer. The boundary of the IW is considered as the source or inner boundary. These boundary conditions can be expressed as:

$$\begin{cases} \left.\dfrac{\partial P}{\partial n}\right|_{\text{Upper and lower boundaries}} = 0 \\ P_{R_0} = P_0 \end{cases} \tag{4}$$

$$P(r, t = 0) = P_0 \tag{5}$$

where P denotes the vertically averaged fluid pressure in the reservoir; n denotes the normal direction for upper and lower boundaries; P_{R_0} is the vertically averaged fluid pressure at the outer extent, and P_0 denotes the initial formation pressure.

As the CO_2 injection is started, this supercritical CO_2 penetrates along the top layers of the aquifer initially due to low pressure in the aquifer. As injection advances, the pressure of the aquifer builds up, resulting in CO_2 flowing up to the depth where the pressure of both fluids can equilibrate. This results in CO_2 migration laterally as well as vertically downwards. Pressures of both fluids can be related by CP at the interface of a porous medium.

$$P_c(r_1, z) = P_w(r_1, z) + P_{cc} \tag{6}$$

where P_{cc} denotes capillary entry pressure and r_1 is the radial position of the interface at depth z.

2.2 Structure and details of TOUGH2 code

Numerical simulations have been performed using the TOUGH2 code, developed by Pruess et al. (1999). The TOUGH2 code, a short form of transport of unsaturated groundwater and heat, is used for non-isothermal flows of multiple fluids with multiple components in a porous medium. It is a general-purpose program written in the FORTRAN language, used in the applications of reservoir engineering, environmental remediation, nuclear waste disposal, oil and natural gas production, and carbon sequestration.

TOUGH2 solves general mass and energy balance equations by the integral finite difference method, which applies to one-dimensional, two-dimensional, and three-dimensional regular or irregular grid geometries. TOUGH2 solves the following general form of mass and energy balance equations:

$$\frac{d}{dt}\int M^K dV_n = \int_{\Gamma_n} F^K \bullet n d\Gamma_n + \int_{V_n} q^K dV_n \tag{7}$$

Here, V_n represents a random sub-domain of the flow system, bound by a closed surface Γ_n where n is a normal vector on the surface element $d\Gamma_n$ pointing inward to V_n. M corresponds to mass or energy per volume, with K labelling the mass or heat components. F stands for mass or heat flux, and q denotes sinks and sources (Pruess et al., 1999).

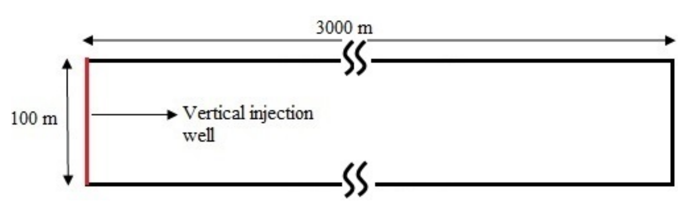
An EOS module (equation of state), ECO2N has been employed with TOUGH2 simulator (Pruess and Spycher, 2006) to combine the brine-CO_2 system to the code TOUGH2. It was mainly developed to cope with issues related to CO_2 geological sequestration in saline aquifers. ECO2N is written in Fortran 77 and is 'plug-compatible' with TOUGH2. It describes thermodynamic and thermophysical properties of water-saline-CO_2 systems that reproduce fluid properties primarily within experimental error for the temperature, pressure, and salinity conditions, i.e., 10°C < T < 300°C, P < 600 bar, and salinity up to halite saturation respectively. TOUGH2 with ECO2N can model a single phase and multiphase flow, inclusive of RP and CP effects. The EOS does not consist of molecular diffusion equations.

3 Computational methodology

3.1 Computational domain and mesh generation

During the study, some assumptions were made, such as homogeneous, isotropic, and brine saturated porous medium. As compared to its thickness, a large radial extent has been taken of the aquifer. The CO_2 IW has been perforated along with the whole depth of the aquifer, with CO_2 injection at a constant volumetric rate.

Figure 4 Computational domain for vertical CO_2 injection (see online version for colours)



As used by Zhang and Agarwal (2012a), a standard aquifer model is employed. A radial axis-symmetric model of 3,000 m and 100 m depth, shown in Figure 4, is made to simulate the aquifer. Supercritical CO_2 has been injected with a 1 kg/s injection rate (nearly 31 Mt/yr) in the brine saturated aquifer. The simulations have been performed in isothermal conditions.

For well orientation analysis, the vertical well is placed at the side of the domain. The horizontal well is located along the radial direction, at the bottom of the domain, as the injection scenario is taken as axis-symmetrical as shown in Figure 5. Hydro-geological properties used are given in Table 1 (Zhang and Agarwal, 2012a). During CO_2 injection by horizontal well, we presumed that the horizontal portion of the well (not the vertical wellbore) is puncture for CO_2 injection solely. Thus the vertical wellbore does not influence the numerical simulation and its results.

Figure 5 Computational domain for horizontal CO_2 injection (see online version for colours)

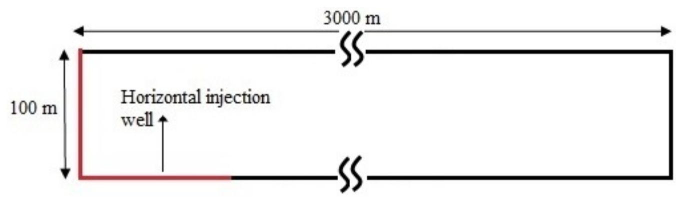


Table 1 Boundary conditions and hydro-geological properties of the model

Parameter	*Value*
Depth of the reservoir	1,200 m
Size of the domain	3,000 m ×100 m
Pressure	6.4 MPa
Permeability	100 mDarcy
Porosity	0.3
Salinity	0.3
Relative permeability	Linear
Temperature	20ºC
CO_2 injection rate	1 kg/s
Injection time	10 years
Capillary pressure	None
CO_2 density	789.96 kg/m^3
CO_2 viscosity	7.12905×10^{-5} Pa.s
Brine density	1029.69 kg/m^3
Brine viscosity	1.488427×10^{-5} Pa.s

A grid with simple 300 radial cells with 20 layers in the vertical direction has been considered. A grid independence study has been done regarding the size and number of cells in a similar geometry. Cell conditions adjacent to the IW have been kept constant during the grid independence study to maintain uniformity with the injection amount.

3.2 Boundary conditions

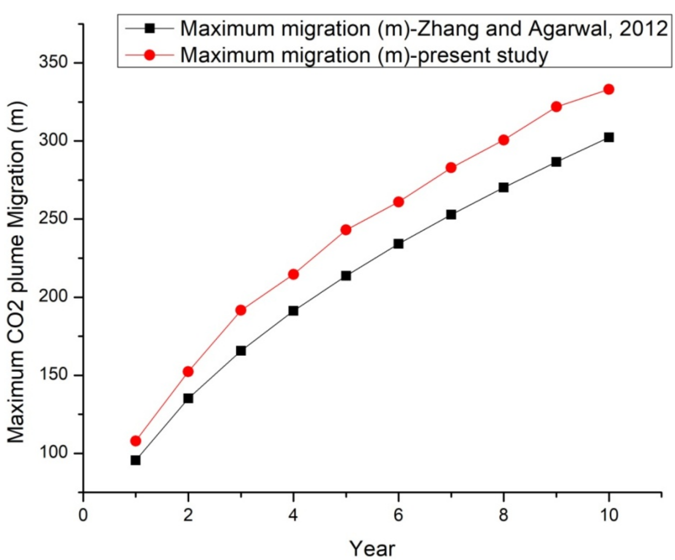
The initial boundary conditions and hydro-geological properties are reviewed in Table 1. Initially, hydrostatic pressure is distributed in the model, which is fully saturated with brine. Flow is restricted from the top and bottom layers of the aquifer. At the radially outer end, hydrostatic pressure is taken as constant to represent an infinite length aquifer. The total simulation period is taken as ten years, the same as the CO_2 injection time. In the TOUGH2 model, the relative error criterion has been set at 1×10^{-5}.

4 Results and discussion

4.1 Verification of the model

The numerical model was verified by comparing the maximum CO_2 plume migration data given by Zhang and Agarwal (2012a) and is shown in Figure 1. The CO_2 plume migration indicates dispersing volume of dissolved CO_2 into greater depths in the geological saline aquifer with increasing flow path distance. For the first year of CO_2 injection, the dissolved migrates up to 100 m into the aquifer. As the time and injection proceeds, the CO_2 migrates further into the aquifer and flows up to caprock where it gets blocked due to low permeable caprocks. After ten years of CO_2 injection, the CO_2 plume migrates up to 340 m from the IW. The maximum difference for verification has come around 15%.

Figure 6 Verification study for maximum CO_2 plume migration (see online version for colours)



4.2 Sensitivity analysis: effects of RP and CP

The RP describes the phase flow in two or multiphase flows. It is the ratio of the permeability of a particular phase within a porous medium to the absolute permeability of the medium. It is proportional to the phase saturation. The RP is equal to one for a single-phase flow. The CP is the phase pressure difference between two phases in contact with each other. It is related to the interfacial tension between the phases (Wang et al., 2015).

It is crucial to estimate RP and CP of CO_2-brine-rock systems to model the injection of supercritical CO_2 right into the saline aquifer (Cinar et al., 2009; Jing et al., 2019; Li et al., 2018). These are executed by changing the CP and fluid RP model from linear to the nonlinear relationship between the RP of brine and CO_2, as formulated by Van Genuchten (1980) and Corey (1954). The equations of RP and CP function for both the models are furnished below:

- RP functions:
- Corey's model:

$$k_{rl} = \hat{S}^4 \tag{8}$$

$$k_{rl} = \left(1-\hat{S}\right)^2\left(1-\hat{S}^2\right) \tag{9}$$

where $\hat{S} = (S_l - S_{lr})/(1 - S_{lr} - S_{gr})$

with $S_{lr} = RP(1)$; $S_{gr} = RP(2)$

and restrictions: $RP(1) + RP(2) < 1$

- Van Genuchten-Mualem model:

$$k_{rl} = \begin{cases} \sqrt{S^*}\left\{1-\left(1-[S^*]^{1/\lambda}\right)^{\lambda}\right\}^2 & \text{if } S_1 < S_{ls} \\ 1 & \text{if } S_1 \geq S_{ls} \end{cases} \tag{10}$$

The RP of gas may be selected as any one of the two relations. Corey (1954) used the second one.

$$k_{rg} = \begin{cases} 1-k_{rl} & \text{if } S_{gr} = 0 \\ \left(1-\hat{S}\right)^2\left(1-\hat{S}^2\right) & \text{if } S_{gr} > 0 \end{cases} \tag{11}$$

Restriction $0 \leq k_{rl}, k_{rg} \leq 1$

Here, $S^* = (S_1 - S_{lr})/(S_{ls} - S_{lr})$, $\hat{S} = (S_1 - S_{lr})/(1 - S_{ls} - S_{gr})$

- Parameters:

$RP(1) = \lambda$
$RP(2) = S_{lr}$
$RP(3) = S_{ls}$
$RP(4) = S_{gr}$

λ is m in Van Genuchten's notation, with $m = 1 - 1/n$

n is frequently written as β.

- CP functions:
- Linear model:

$$P_{cap} = \begin{cases} -CP(1) & \text{for } S_1 \le CP(2) \\ 0 & \text{for } S_1 \ge CP(3) \\ -CP(1)\dfrac{CP(3)-S_1}{CP(3)-CP(2)} & \text{for } CP(2) < S_1 < CP(3) \end{cases} \quad (12)$$

Restriction $CP(3) > CP(2)$.

- Van Genuchten's model:

$$P_{cap} = -P_0\left([S^*]^{-1/\lambda} - 1\right)^{1/\lambda} \quad (13)$$

Restriction $-P_{\max} \le P_{cap} < 0$

Here, $S^* = (S_l - S_{lr})/(S_{ls} - S_{lr})$

Parameters: $CP(1) = \lambda = 1 - 1/n$

$CP(2) = S_{lr}$

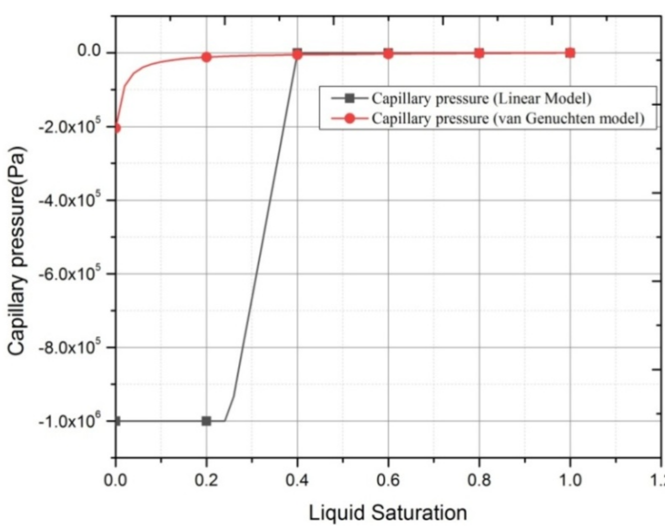
$CP(3) = 1/P_0 = \alpha/\rho wg$

$CP(4) = P_{\max}$

$CP(5) = S_{ls}$

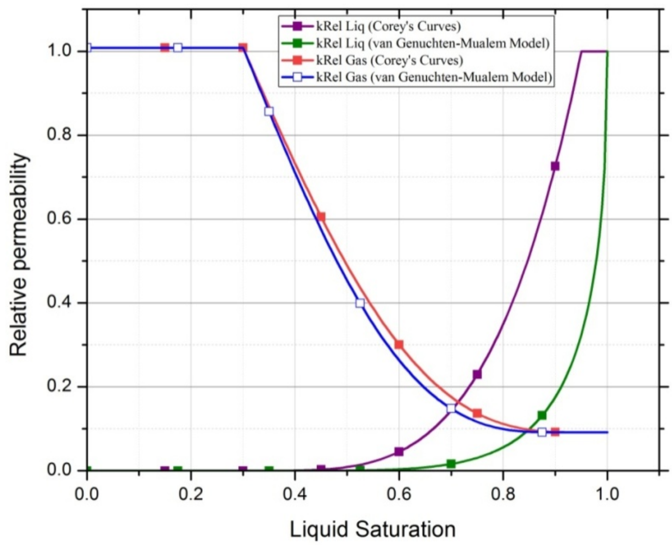
The RP and CP variation graphs used for the model are furnished in Figures 7(a) and 7(b).

Figure 7 (a) CP variation and (b) RP variation (see online version for colours)



(a)

Figure 7 (a) CP variation and (b) RP variation (continued) (see online version for colours)



(b)

A total of five cases are considered in the present study with different RP and CP models for sensitivity analysis in the numerical runs, as shown in Table 2.

Table 2 Cases for sensitivity analysis

Variables	*Verified model*	*Case-1*	*Case-2*	*Case-3*	*Case-4*	*Case-5*
RP function	Linear	Corey	Van Genuchten	Corey	Corey	Van Genuchten
CP function	None	None	None	Linear	Van Genuchten	Van Genuchten

Simulations are performed for basic verification cases as well as for five other cases of sensitivity analysis. Five cases with varying RP and CP models have been compared in Figure 8 with gas saturation (SG) on the aquifer top together with the radial direction from the CO_2 well. It is easily described from Figure 8 that Corey's RP functions and Van Genuchten's CP function captured the gas saturation well.

4.3 Effects of well orientation

Corey's RP functions and Van Genuchten's CP function are selected for the present study. The length of the vertical well has been taken as 100 m as the thickness of the reservoir, whereas, the horizontal well's length has been assumed as 100 m, 500 m, 1,000 m, and 2,000 m.

Table 3 represents that after ten years of CO_2 injection, the peak rise in pressure is experienced along the well of injection. A higher value of pressure in the formation favours the chance of whooping the caprock encouraging CO_2 to flow up to the ground level. Figure 9 shows the maximum CO_2 plume migration in all the cases which is represented as gas saturation (SG). It shows that for the case of vertical IW, the CO_2 migrates up to 340 m from the well however, for the case of horizontal injection well, it migrates up to 390 m. It was also found that with the increasing length of the IW, the CO_2 front advances to the radial direction and becomes more exposed to the reservoir. Over 10 years, as the CO_2 injection is carried out in the aquifer, a pressure rise is anticipated to be extreme at the IW. However, horizontal IW causes less pressure rise in the aquifer as compared to vertical IW. It is evident from Table 3 that for the same IW length (at 100 m), 22% drops in the pressure rise is computed in the horizontal well as compared to the vertical well configuration.

Figure 8 Plume of CO_2 migrated at the aquifer top (see online version for colours)

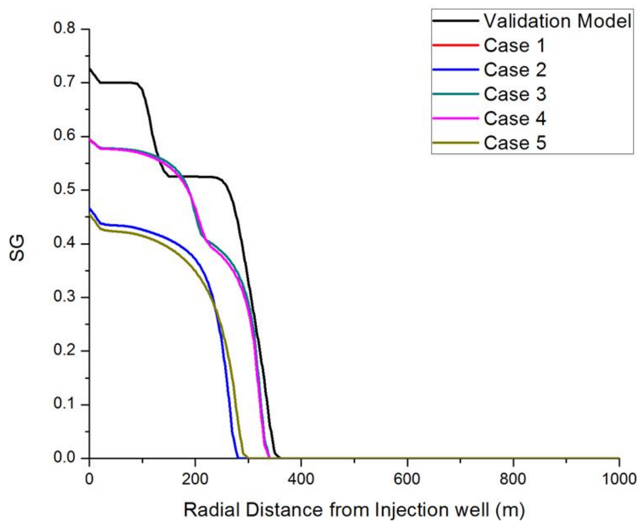
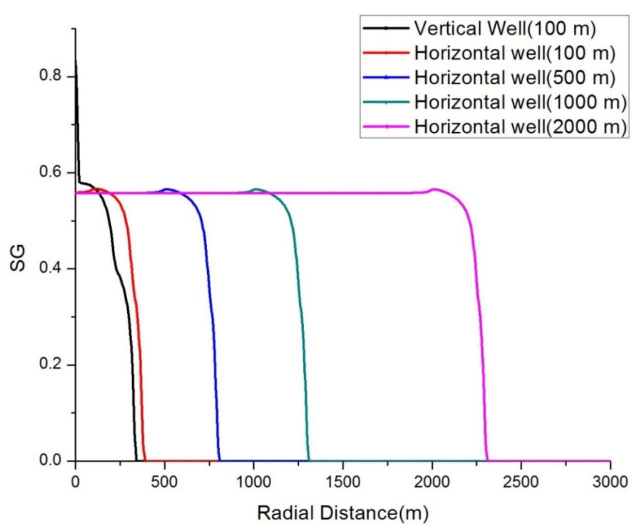


Figure 9 Plume of CO_2 migrated at the aquifer top after ten years of CO_2 injection (see online version for colours)



The horizontal well's length was varied up to 2 km, which lies inside the scope of nearly all horizontal wells. The longest horizontal well, which has been drilled, is 11 km long, so the drilling technology is viable for long horizontal IW (Denney, 2009). The over-pressure induced by a vertical IW can be obtained in the horizontal well if the length of the well is 8 km. However, one should consider drilling costs to efficiency trade-off while considering long horizontal well. The results demonstrated the superiority of horizontal well configuration over vertical well because of its ability to inject a large volume of CO_2 at a shorter period with less pressure increase, and hence cost-effectiveness is achieved. This also corroborated with the findings by Zhang and Agarwal (2012b).

Table 3 Comparison of pressure rise along the IW

Case	*IW length*	*Pressure rise (bar)*
Vertical well	100 m	10.474
Horizontal well	100 m	8.156
Horizontal well	500 m	7.575
Horizontal well	1000 m	7.573
Horizontal well	2000 m	7.572

5 Conclusions

The present work aimed to compute the effect on reservoir conditions due to well orientation and extent of well on CO_2 sequestration in the saline aquifers. The major findings of the study are summarised in the following points:

- The TOUGH2 code employed in the present study captures the formation pressure profiles and CO_2 saturation profiles in the same way as the analytical model. However, the prediction capability of the model used in the study was limited due to the assumption that the CO_2 and brine are immiscible.
- The equal length of the IW does not present a symbolic disparity between the horizontal and vertical wells in terms of CO_2 plume migration. However, it impacts the rise in pressure in the aquifer because of the CO_2 injection. For the same IW length (at 100 m), 22% drop in the pressure rise is evident in horizontal well as compared to the vertical configuration.
- The use of horizontal CO_2 injection maintains a compelling advantage over vertical injection under pressure-limited conditions. Increasing the IW length, the aquifer can take a symbolically higher CO_2 injection rate without crossing allowable pressure. The longer horizontal well can indeed administer a fair usage of applicable aquifer volume. Horizontal CO_2 injection is cost-effective, especially when an enormous amount of CO_2 is to be injected and that too, for a short period in subsurface conditions.
- The additional cost of horizontal IW can be justified by greater storage efficiency and more CO_2 to be dissolved in the brine.

In this study, a basic model of the saline aquifer has been modelled for CO_2 sequestration. For further study, three-dimensional geological reservoirs can be simulated. Also, fully coupled hydro-mechanical analysis can be done to analyse CO_2 injection and caprock mechanical stability. This study performs CO_2 injection with only a single IW. A further study can involve multiple wells and their optimum locations to each other. Various CO_2 injection techniques such as constant pressure and constant mass injection of CO_2 can be applied to get the optimum efficiency of storage. A study with mineralisation trapping can be done, which will investigate injected CO_2 reaction with rock types. Also, for the Indian scenario, this model can be applied in a suitable geological reservoir, which will solve India's CO_2 emission problem. Further, a study of assessment of the life cycle of this technique can be done to improve it.

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