CO2 Storage and Evaluation of Important Parameters Affecting the CO2 Plume Distribution: Simulation and Sensitivity Analysis

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Abstract: Carbon capture utilization and storage (CCUS) offers a potential solution to mitigate the effects of anthropogenic CO_2 and to reduce the direct CO_2 emissions from stationary sources into the atmosphere. The captured CO_2 is injected into deep saline-water saturated formations or in depleted oil and gas fields, or into the oil fields for storage and/or enhanced oil recovery (EOR). The primary objective of this study is to identify and analyze the critical parameters affecting CO_2 plume development in the reservoir. Understanding the subsurface dynamics of carbon sequestration will facilitate to plan the subsurface process better. The simulation models are developed using the commercial software Computer Modelling Group, CMG. The plume dynamics that include plume volume and plume geometry over 30 years of injection and 170 years of post-injection period is investigated. Additionally, the contribution of different trapping mechanisms over the time horizon in the storage process is assessed. Moreover, a sensitivity analysis is done for evaluating the impact of variables including porosity, permeability, injection rate, and injector bottom hole pressure. The simulation results show that CO_2 plume propagates at an increased rate during the injection period and continues to disperse at a comparatively reduced rate after the injection ends. The horizontal spread of plume is significantly greater than the vertical propagation when the horizontal permeability is larger than the vertical. Additionally, the plume volume shows a linear relationship with the injected CO_2 amount. In terms of storage efficiency, the most prevalent CO_2 is free phase super critical CO_2 that contributes around 80% of the stored CO_2 whereas the rest are structurally or residually trapped and dissolved CO_2. From the sensitivity analysis in a homogenous reservoir, it can be concluded that the horizontal permeability is impacting the most (42%) for structural and residual trapping of CO_2 whereas porosity impacts the most (38%) for dissolution of CO_2 contributing to solubility trapping mechanism.

Keywords: CCUS, Plume dynamics, CO_2 Storage, CO_2 trapping mechanism, Sensitivity

1. INTRODUCTION

Carbon dioxide (CO_2) reduction from the atmosphere has become a global attention from last decade which resulted in imposing several laws against emitting CO_2 in the atmosphere. However, CO_2 production is inevitable in lot of processes which compelled the industries and researchers to draw more attention in capturing the produced CO_2 and storing them to a safe place. In the storage purpose, depleted oil reservoirs or aquifers has a good potential to be used for storage of CO_2. According to a study, there is approximately 139 giga tones of CO_2 storage potential in worldwide oil reservoirs (Godec et al., 2011). Geological sequestration of CO_2 is presently the most viable, and probably the sole, short-to-medium term strategy for substantially increasing CO_2 sinks and thereby decreasing overall carbon emissions into the atmosphere (Bachu, 2008). So, CO_2 storage in oil reservoirs, coupled with enhanced oil recovery (EOR), has gained attention as a strategy for both mitigating climate change and improving oil recovery. Currently, CO_2 storage in geological formations such as oil and gas reservoirs and deep saline aquifers is not a new technology. The extensive history of natural gas storage in North America and Europe and CO_2-EOR practices primarily in the U.S (Moritis, 2006) provide some evidences of this fact.

Additionally, numerous commercial-scale projects worldwide engage in CO_2 injection for various purposes, ultimately contributing to the mitigation of greenhouse gas emissions, such as, in Canada, the Weyburn CO_2-EOR project uses CO_2 obtained from coal gasification (Whittaker et al., 2004). In the North Sea, the Sleipner project injects CO_2 stripped from natural gas into the Utsira formation (Torp & Gale, 2003). Over in Algeria, the In Salah project pumps CO_2 back into an aquifer underneath the gas field it came from (Riddiford et al., 2003) and some examples in Western Canada, show that CO_2 storage is often implemented for economic or regulatory reasons, not just for addressing climate change (Bachu, 2008) but resulted in the mitigation of diverse impact on climate change.

However, the success of CO_2 storage is highly dependent on the behavior of the CO_2 plume within the reservoir, which is influenced by reservoir characteristics (Birkholzer et al., 2015). The study by A. Luo et. al. (2022) suggests that studies on structural sequestration should take into account all relevant factors, and that the capacity of structural sequestration should be assessed in light of the characteristics of the caprock, the rate of CO_2 injection, and the saline aquifer actual geological conditions. Current research in the field of CO_2 plume evolution and the impact of reservoir parameters on storage efficiency emphasizes the complexity and variability of geological storage environments. Al-Khdheeawi et al. (2018) discusses the effects of heterogeneity, reservoir temperature, and wettability on CO_2 migration and trapping mechanisms. Myshakin et al. (2023) explores the impact of reservoir heterogeneity on fluid displacement and volumetric efficiency. But these studies underscore the critical role of physical reservoir characteristics in determining CO_2 storage efficiency. Moreover, Zapata et al. (2020) and Luo et al. (2022) contribute to this topic by investigating CO_2 plume dynamics over long-term injection periods and the effects of key parameters on gas recovery and storage efficiency, respectively. However, there remains a significant gap in comprehensive analyses integrating multiple reservoir parameters under varied operational conditions, particularly understanding the simultaneous effects of the reservoir parameters and dynamic injection scenarios on CO_2 storage efficiency.

The primary objective of this work is to observe plume evolution and analyze the reservoir parameters affecting CO_2 plume, and storage efficiency in the reservoir. These parameters include, reservoir permeability, porosity, pressure and temperature conditions, and fluid properties as well as the injection rate and injection bottom hole pressure. CO_2 storage model is developed in the commercial software Computer Modelling Group, CMG to investigate the CO_2 migration after a 30-year injection period and 170-year post-injection period. Sensitivity analysis is done among corresponding variables to understand the impact of different parameters on storage capacity. The simulation models are developed using CMG, by utilizing its five modules.

2. CO_2 STORAGE IN GEOLOGICAL MEDIA

Under normal atmospheric conditions, CO_2 exists as gas. However, when subjected to pressures exceeding 7.39 Mpa and temperatures above 31.1°C, reaching what is termed its critical point, it transitions into a supercritical fluid state (Zhi et al., 2019). In this form, CO_2 exhibits properties of both gases and liquids, making it ideal for underground storage. It becomes as dense as a liquid, which allows it to hold more CO_2 in the pore spaces of rock formations. At the same time, it maintains a gas-like viscosity, facilitating its movement through the rock layers. Reservoirs suitable for CO_2 storage are typically found deeper than 1 km, have a thickness of around 10500 m, and may extend for hundreds of kilometers across (Szulczewski, 2013). At these depths, CO_2 is kept in its supercritical condition, where it is somewhat lighter (~700 kg/m3) than the brine, oil, or any other existing fluids, leading it to migrate upwards due to buoyant forces (Verma et al., 2021). The upward movement of CO_2 ceases when it meets the caprock, effectively sealing it within the subsurface.

CO_2 has an influence on the relative permeability curve. CO_2 injection influences the wettability of the reservoir, causing the rock to become somewhat more water-wet, which promotes better oil displacement efficiency and optimizes the reservoir capacity to trap CO_2 effectively (Kułynycz, 2015). This process alters the endpoint relative permeabilities as well as modifying the shape of the corresponding relative permeability curves (Taghavi et al., 2023).

This indicates that CO_2 injection reduces the mobility ratio, M, between oil and water. Mobility, λ, is characterized as the ratio of the endpoint relative permeability, K_r, to dynamic viscosity, μ.

$$\lambda = \frac{K_r}{\mu} \tag{1}$$

As defined by Ahmed (2010), the mobility ratio is the ratio of the mobility of the fluid causing displacement, such as λ_w to the mobility of the fluid being displaced, such as λ_o where the subscripts denote the water for w and oil for o.

$$M = \frac{\lambda_w}{\lambda_o} = \frac{k_{rw}}{k_{ro}} \cdot \frac{\mu_o}{\mu_w} \tag{2}$$

Enhancing the water-wetness of the rock decreases the residual oil saturation while increasing the irreducible water saturation (Taghavi et al., 2023). Consequently, the oil relative permeability is increased. Moreover, there is a decrease in oil viscosity, collectively leading to a lower mobility ratio (Aakre et al., 2018).

2.1 Geological media

Potential CO_2 storage options include deep saline aquifers, operational or depleted oil and gas fields, unmineable deep coal beds, and mined salt caverns. According to Saeedi (2012), deep saline aquifers have the advantage of extensive capacity and wide availability but face the disadvantage of unproven storage reliability. Active or depleted oil and gas reservoirs offer demonstrated storage security, established infrastructure, and enhanced hydrocarbon recovery, yet they are not available in all regions and may not be available for immediate use (Saeedi, 2012). Unminable coal seams can potentially enhance methane recovery but are limited by uncertain storage capacity and regional availability. Basalt formations provide a permanent trapping mechanism for CO_2, although they are constrained by slow reaction rates and limited field experiences (Saeedi, 2012). CO_2 is stored safely without risking the contamination of underground resources. Historically, they have effectively contained oil and gas under high pressure and temperature, thereby reducing the likelihood of CO_2 leakage over extended periods. Furthermore, these abandoned hydrocarbon storage sites can maintain the necessary temperature and pressure for CO_2 to reach supercritical condition (Van Der Meer, 2005).

2.2 CO_2 Trapping Mechanism

At least six mechanisms exist that can secure CO_2 within a storage complex over extended duration. Among the most recognized are structural trapping, capillary trapping, solubility trapping, and mineral trapping. **Table 1** presents a comparative analysis of the trapping mechanisms.

Table 1. Comparison of different trapping mechanism (Ketzer et al., 2012; Raza et al., 2015)

Trapping Mechanism	Description	Advantages	Considerations
Structural and Stratigraphic Trapping	CO_2 is trapped beneath an impermeable cap rock, similar to how oil and gas are trapped in petroleum fields.	-Direct and immediate trapping - Utilizes existing geological structures	- Dependent on the integrity of the cap rock - Limited by the structure's capacity and closure.
Capillary Trapping	CO_2 becomes immobilized as a residual phase within the pore spaces of the storage medium.	- Rapid and efficient entrapment of CO_2 - Enhanced storage security through immobilization. - Higher capillary force than buoyant force, leading to pore-scale CO_2 bubbles	- Efficiency varies with rock properties and fluid characteristics - Requires sophisticated understanding of pore space interactions
Solubility Trapping	CO_2 dissolves in brine, and the denser CO_2-saturated brine sinks within the storage medium.	- Contributes to long-term storage stability - Reduces risk of leakage by dissolving CO_2	- Dependent on diffusion rates and storage medium properties - Slower process compared to capillary trapping
Mineral Trapping	Dissolved CO_2 reacts with minerals in the storage medium to form stable carbonate minerals.	- Provides the most permanent form of CO_2 storage. - Enhances storage security by chemically binding CO_2	- Slowest trapping mechanism. - Dependent on geochemical conditions and mineral availability

3. METHODOLOGY AND SIMULATION SETUP

CMG (*Computer Modelling Group Ltd.*, 2023) is used for this study. Among 13 of its products, GEM, Builder, cEdit, CMOST, and Results have been used to simulation setup, solving the system and analysis of result.

3.1 Structural and Petrophysical Modeling of Reservoir

Initially two reservoirs were modeled for the simulation. One is homogenous and the other is heterogenous. Both reservoirs are defined within a 3D Cartesian grid, delineating its structural and petrophysical attributes essential for CO_2 storage simulation. The model is structured into a 20×20×24 grid, translating into 9600 cells, with a uniform lateral cell dimension of 150 meters across both the X- and Y-axes which resulted in 3000 m × 3000 m reservoir dimensions. Vertically, each cell exhibits a consistent thickness of 8.8 m, summing up to a reservoir thickness of approximately 211 m. The reservoir top boundary is placed at a depth of 1200 m below the surface, establishing the initial conditions for simulation purposes. The other properties and initial conditions of the homogenous reservoir are shown in Table 2.

Table 2. Data used in the reservoir model

Property	Values
Porosity	12%
Permeability (Layers 1-3)	0 millidarcies (mD)
Permeability (Horizontal)	1000 millidarcies (mD)
Permeability (Vertical)	100 millidarcies (mD)
Initial Reservoir Pressure	11800 kpa
Initial Reservoir Temperature	70ºC
Compressibility Factor	5.5E-7 1/psi
Water saturation	25%
Reference depth	1200 m
Water-oil contact depth	1300 m

Porosity and permeability data of the grid cells in the heterogenous reservoir are shown in Fig. 1 which is the 3D grid view of a heterogenous reservoir.

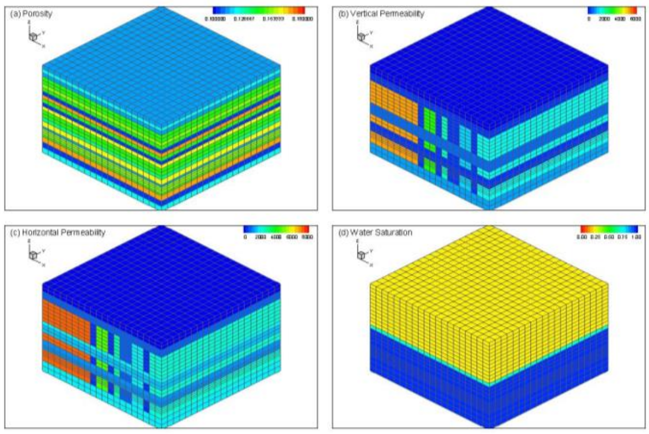

Figure 1. Heterogenous reservoir showing a) porosity b) vertical relativity c) horizontal permeability d) water saturation.

The relative permeability data used for the study is presented in Fig. 2.

3.2 Well (CO_2 Injector) Modeling

A well is characterized as an injection well, with the purpose of injecting a solvent composed entirely of pure CO_2. The operational parameters are governed by constraints implemented through a continuous repeat command to maintain stability and control over the injection process. These constraints are defined as follows: a maximum surface gas injection rate (STG) of 50,000 m^3/day, a maximum allowable bottom hole pressure (BHP) of 30,000 kPa, an injection period set to continue for 30 years, and a total simulation period of 200 years. Perforations have been done through three cells with coordinates (1,1,18), (1,1,19), and (1,1,20).

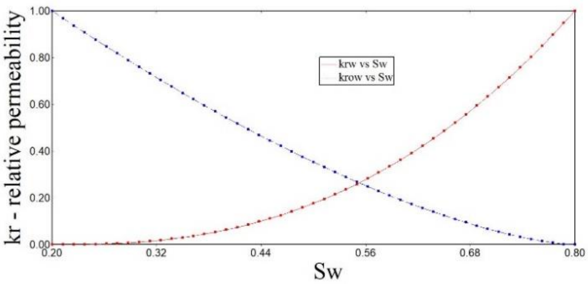

Figure 2. Water-oil relative permeability curve.

3.3 Simulation Cases

Two types of reservoirs, homogenous and heterogenous, were studied for achieving the objective of this study. Table 3 presents the parameters used in all case studies done in the homogenous reservoir. The other properties will follow the base case described until this chapter.

Table 3. Simulation cases for homogenous reservoir

Case No.	Injection rate m^3/d	Permeability X axis (mD)	Permeability Y axis (mD)	Permeability Z axis (mD)
5	50000	1000	1000	100
6	60000	1000	1000	100
7	70000	1000	1000	100
8	50000	1500	1500	50
9	50000	600	600	600
10	50000	100	100	100

In contrast, heterogenous reservoir have less freedom to change the parameters as the reservoir was considered as a predetermined property as it naturally is. This study, however, conducted some simulations by changing injection rate which are shown in Table 4.

Table 4. Simulation cases for heterogenous reservoir

Case No.	Injection rate (m^3/d)
1	50000
2	60000
3	70000
4	80000

Sensitivity analysis was done with CMOST which performs effect estimation by using Design of Experiments (DoE) to systematically vary input parameters and run multiple simulations. It constructs a response surface to model the relationship between inputs and outputs, and conducts sensitivity analysis to quantify the impact of each parameter on the results (Wang et al., 2023). The range of parameter values used in the CMOST sensitivity analysis for the homogenous reservoir are shown in Table 5. In total 36 experiments were selected by CMOST AI within these parameter ranges. The objective function taken in the CMOST study are as follows:

1) Trapped CO_2 (due to structural and residual trapping).
2) Dissolved CO_2 mol (solubility trapping).

Table 5. Range of parameter values for sensitivity analysis

Parameter Name	Lower Limit	Upper Limit
Injection Rate	50000 m^3/day	100000 m^3/day
Bottom Hole Pressure	25000 KPa	37500 KPa
Horizontal Permeability	300 mD	1500 mD
Vertical Permeability	100 mD	1000 mD
Porosity	9%	15%

4. RESULTS AND DISCUSSION

The primary objective of the study is to analyze the dynamics of CO_2 plume and to assess the roles played by various trapping mechanisms, along with investigating the influence of various reservoir characteristics on the plume development and storage efficiency. The primary objective is achieved through the following objectives: investigating the size of the CO_2 plume under different conditions, examining how the plume develops over time with continuous extended CO_2 injection, evaluating the effect of different CO_2 trapping methods in terms of storage, and conducting a sensitivity analysis to determine the impact of various reservoir parameters on the stored CO_2.

4.1 Plume Dynamics

An important element of CO_2 storage in an aquifer involves identifying the area of the aquifer surrounding the injection well that is affected by CO_2 injection. This affected region is referred to as the CO_2 plume. In this work, the criterion used to define the plume is based on the molality of CO_2 (Zapata et al., 2020). Because among all other criterion that generally used to define plume, CO_2 in aqueous phase spread across the aquifer region most, resulting in the maximum possible plume volume (Zapata et al., 2020). Cells exhibiting a CO_2 molality greater than the threshold of 0.4 are considered active within the plume.

In this study, plume volume is defined based on the pore volume of affected cells which are satisfying the threshold values of molality. So, the plume volume is not referring to pure CO_2 volume. Fig. 3 is a plot of plume volume with respect to the time for both heterogenous and homogenous reservoirs. In the heterogeneous reservoir, the plume volume initially increases rapidly, indicative of varied pathways that facilitate quicker CO_2 spread through regions of higher permeability. In contrast, the plume in the homogeneous reservoir expands more gradually and uniformly, reflecting the consistent geological properties that regulate a steadier CO_2 migration. Despite these initial differences in growth rates, both scenarios eventually start to stabilize after the injection period ends. Additionally, Fig. 4 is a graphical representation of the development of plume in a consistent CO_2 injection where the plume is defined based on the aqueous phase CO_2 as a function of total CO_2 injected with an injection rate of 50000 m^3/day in standard condition. In both cases it can be observed that the plume develops almost in a linear trend with the injected CO_2 and the development continues even after the injection stops. This continuation generally occurred by the buoyancy force or molecular diffusion. But these stabilized quickly after the injection period ended.

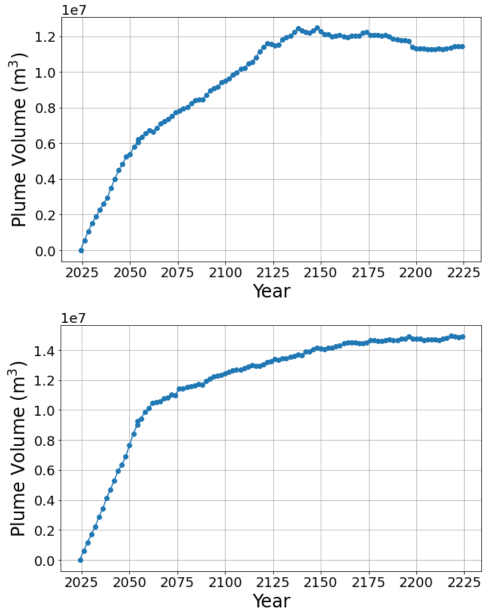

Figure 3. Plume volume with time (years) in (a) homogenous reservoir (b) heterogenous reservoir.

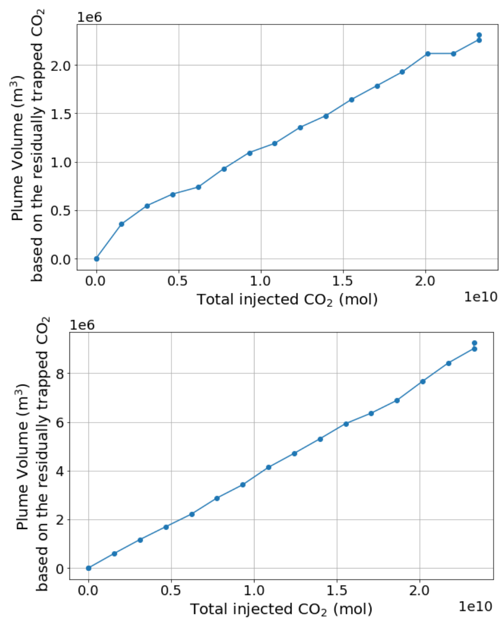

Figure 4. Volume of CO_2 plume with total CO_2 injected in (a) homogenous (b) heterogenous reservoir where plume is defined based on CO_2 in aqueous phase.

Studying plume geometry and its evolution is another objective in this study. Fig. 5 illustrates how the plume shape changes over time in different scenarios cases in a homogenous reservoir. The development of the plume is influenced by the structural and layered composition of the formation. The irregular plume shape of a heterogenous reservoir with various injection rates is shown in Fig. 6. It can be stated from the figures that in case 7 with high injection rate (70000 m^3/day), the plume spread cross vertical direction is larger than the other case. Additionally, in case 10, the case of low permeability (100 mD in each direction), shows almost a very small but dense CO_2 plume as gas cannot move freely due to very low permeability.

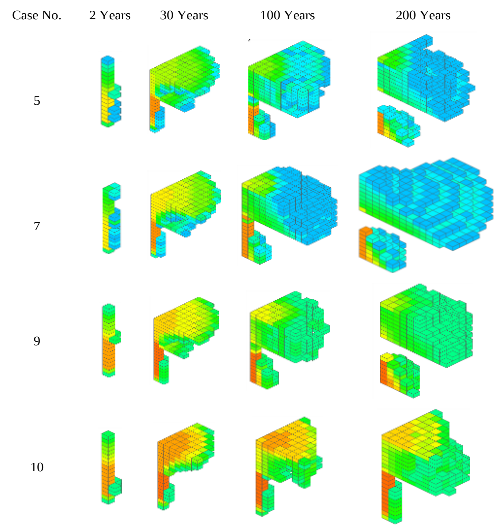

Figure 5. Plume evolution after different time for several cases in a homogenous reservoir.

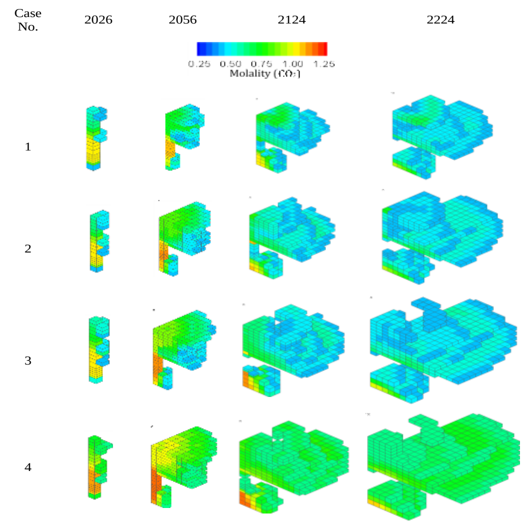

Figure 6. Plume evolution after different time for different cases in a heterogenous reservoir.

It can be implied that CO_2 plume is developing quickly in both vertical and horizontal direction during the injection period, then horizontal expansion rate becomes larger than the vertical. The permeability of the reservoir plays a critical role for the behavior of the plume evolution. At the very beginning of the injection period the injected CO_2 spreads vertically due to buoyancy-driven flow and initial pressure gradient with reservoir depth. Eventually, the horizontal propagation rate starts to increase as the horizontal permeability is 10 times larger than the vertical permeability. However, the propagation rate varies with the injection rate and permeability values. For example, plume evolution in case 10, with permeability value of 100 mD in each direction, has almost equal rate of propagation in both horizontal and vertical direction and the molality variation across the plume cells tends to be very low.

The heterogenous reservoir also shows a similar trend of plume propagation. As the reservoir has larger permeability value in horizontal direction, the plume propagates mostly horizontally. So, the radial expansion will prevail over the vertical expansion. As a result, a larger plume volume is generated after 200 years where the average CO_2 molality is reduced but the spreader plume volume results in a larger surface area of the CO_2-brine and interaction between CO_2 and rock.

4.2 *Storage Efficiency*

This chapter is focused on the impact of various trapping mechanisms in the geological storage of CO_2 in the aquifers. CO_2 is stored in two forms of super critical CO_2 and aqueous phase CO_2 due to solubility trapping mechanism. However, super critical CO_2 can be found in two different conditions of mobile free phase CO_2 and immobilized CO_2 by structural and residual trapping mechanism.

To compare the contributions of various trapping mechanisms over a period of 200 years, a metric known as the "storage ratio" has been established. The storage ratio is defined as the proportion of stored CO_2 (in moles) to the total injected CO_2 (in moles) expressed by: (Zapata et al., 2020).

$$Storage\ ratio = \frac{CO2\ stored\ due\ to\ that\ specific\ trapping\ mechanism\ (moles)}{Injected\ CO2\ (mol)} \tag{3}$$

The storage ratios for each mechanism across both type of reservoirs (case 1 and case 5) is presented in Fig. 7 At the initial stage, structural, residual, and solubility trapping shows a huge storage ratio which drastically falls as the injection of CO_2 continues and the system allows the CO_2 to move. On the other hand, mobile free phase CO_2 drastically increased and stabilized at the storage ratio around 0.9.

The scenario is elaborated in Fig. 8. It is visible that the amount of structurally and residually trapped CO_2 (red color) increases rapidly until the injection period ends, then it gets eclipsed by the solubility trapping (orange color). Because more CO_2 can move through the reservoir freely and get chance to be dissolved more in the aquifer. Moreover, some mobile free phase super critical CO_2 is also being dissolved over time which makes a negative slope in mobile free phase CO_2 curve too. As a result, even if the slope of solubility trapping curve is not too steep at the beginning but that positive slope holds with a close value throughout the long-term period.

The contribution of different trapping mechanisms in both homogenous and heterogenous reservoirs (case 1 and case 5) is shown in Fig. 9 as a stacked area diagram. It can be observed that the largest portion of CO_2 is retained as mobile CO_2 in the free phase. The ratio of mobile CO_2 rises rapidly throughout the injection phase; nonetheless, upon discontinuation of injection, the significance of alternative trapping mechanisms is amplified, leading to a decline in the mobile CO_2 fraction.

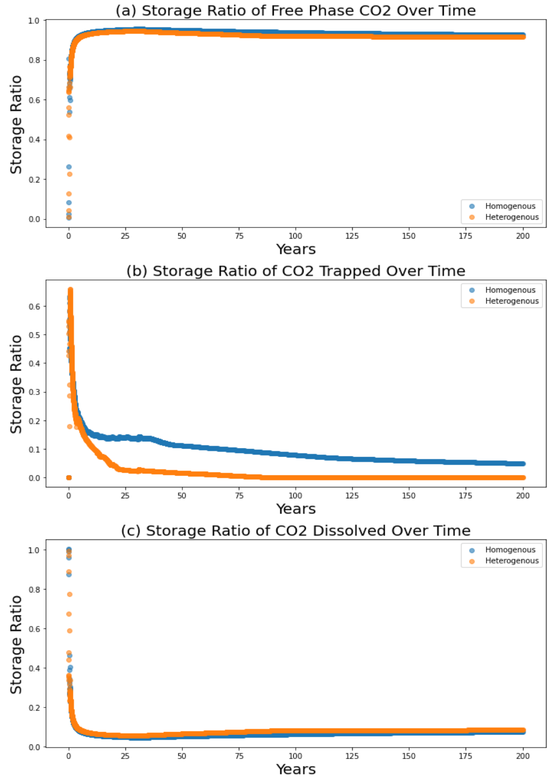

Figure 7. Contribution of (a) mobile free phase CO_2 (b) residual and structural trapping and (c) solubility trapping in a homogenous and heterogenous reservoir in terms of storage ratio with time

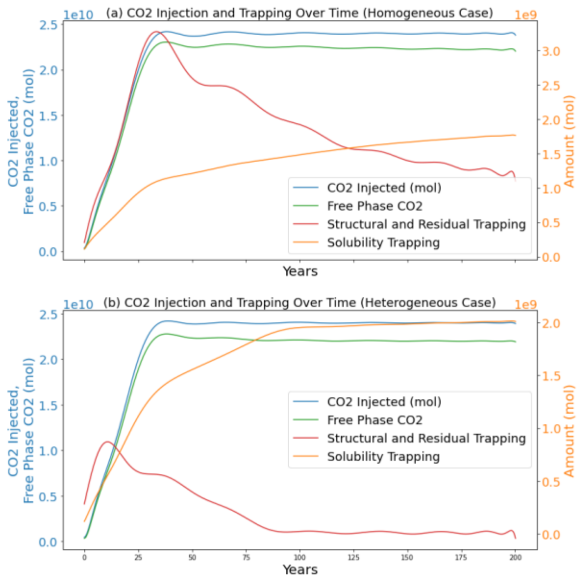

Figure 8. Injected and stored CO_2 amount (mol) in (a) homogenous and (b) heterogenous case.

4.3 *Sensitivity Analysis*

CMOST AI, an updated module was used in the sensitivity analysis. Response Surface Methodology (RSM) was employed to evaluate the effects of various operational parameters on the amount of trapped and dissolved CO_2. RSM comprises statistical and mathematical techniques for exploratory experiments aimed at developing, analyzing, and optimizing various processes (Bauer Jr. et al., 1999). RSM is particularly useful and efficient in performing sensitivity analyses for decision-making problems, offering a way to notably shorten the time required to conduct these analyses (Bauer Jr. et al., 1999). In this study, the parameters considered include bottom hole pressure (kPa), injection rate (m^3/day), horizontal permeability (mD), vertical permeability (mD), and porosity. The objective functions considered are trapped CO_2 and dissolved CO_2.

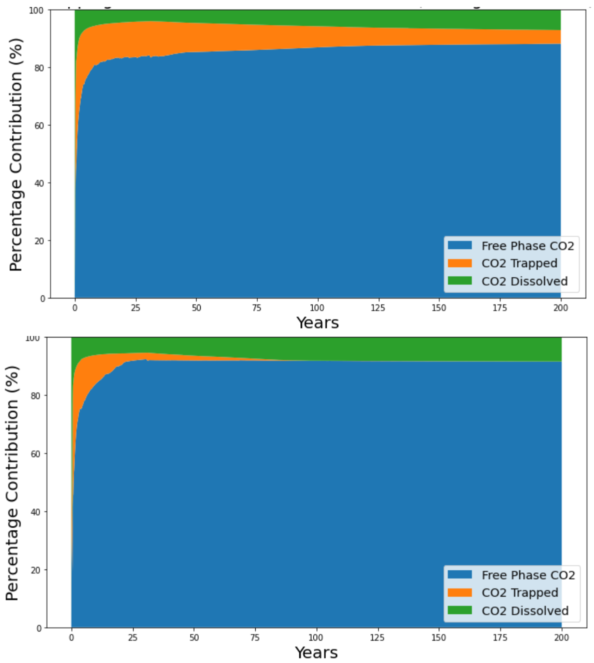

Figure 9. Contribution of different trapping mechanism in (a) homogenous reservoir (b) heterogenous reservoir

The charts displayed in Fig. 10 and Fig. 11 show the normalized impact of each parameter against the maximum effect value observed in our models.

From the analysis, it is evident that certain parameters are particularly influential, which are described in the following. The sensitivity analysis for trapped CO_2 reveals several key insights:

1) The horizontal permeability shows the most substantial positive quadratic effect, indicating that higher horizontal permeability increases CO_2 trapping significantly.
2) Although injection rate is positively impacting the trapped CO_2 amount, it has a negative quadratic impact which shows that after a certain level, the trapped CO_2 will decrease with the increase in injection rate.
3) The squared term of bottom hole pressure also positively affects CO_2 trapping.
4) Porosity and its squared value moderately influence CO_2 trapping, indicating that more porous formations tend to trap more CO_2.

The analysis of dissolved CO_2 shown in Fig. 11 indicates that porosity exhibits the strongest positive effect on the dissolution of CO_2 into the reservoir fluids. Higher porosity levels enhance the capacity for CO_2 dissolution, due to the increased fluid interactions within porous media. Then both injection rate and horizontal permeability positively impact CO_2 dissolution.

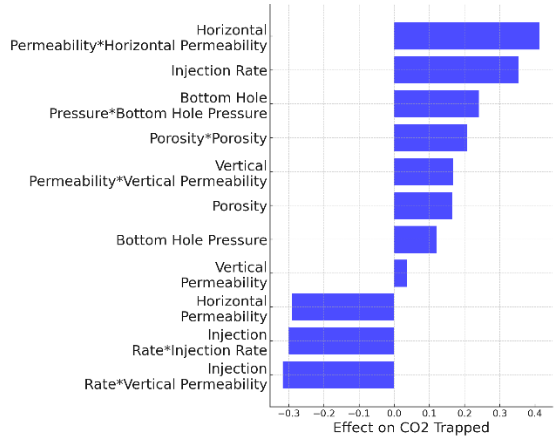

Figure 10. Relative impact of different parameters on structural and residually trapped CO_2.

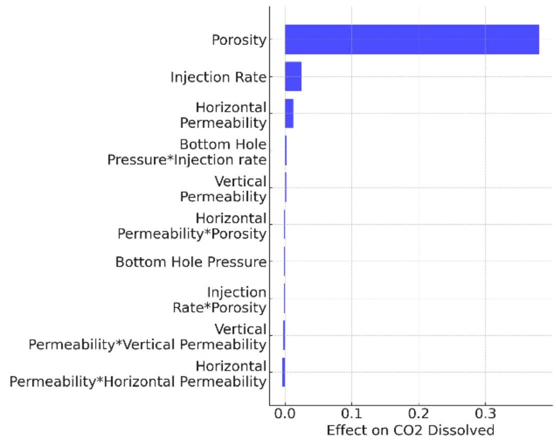

Figure 11. Relative impact of different parameters on dissolved CO_2 amount (moles).

5. CONCLUSIONS

CO_2 plume dynamics, storage capacity, and impact of different reservoir properties and parameters were explored in this study. The results show that horizontal plume spread exceeds vertical due to higher horizontal permeability. Case studies showed that permeability and injection rate significantly influence plume volume, with higher rates and permeabilities resulting in larger plumes. Additionally, the plume volume shows a linear relationship with the injected CO_2 amount. In terms of storage efficiency, the most prevalent CO_2 is free phase super critical CO_2 that contributes around 80% of the stored CO_2 whereas the rest are structurally or residually trapped and dissolved CO_2. Initially, trapped CO_2 contributed almost 15%. Over time, some of the trapped CO_2 dissolved into the reservoir or aquifer fluid. This led to a reduction in the percentage contribution to structural and residual trapping mechanisms, decreasing to 5% in homogeneous reservoirs and 0% in heterogeneous reservoirs. At the same time, the percentage contributed to solubility trapping increased to 15% in homogeneous reservoirs and 20% in heterogeneous reservoirs. Sensitivity analyses revealed that horizontal permeability and injection rate significantly affect trapped CO_2, while porosity impacts CO_2 dissolution. The Future research should incorporate more realistic reservoir models, explore mineral trapping, and conduct further sensitivity analyses.

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