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Effect of Salinity on Effectiveness of CO_2 Injection in the CO_2 Storage Project in Bunter Field

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ABSTRACT

The increase in CO_2 concentration in the atmosphere has contributed to global warming. Reducing CO_2 emissions can be achieved through Carbon Capture Storage (CCS) projects, optimized by selecting appropriate formation water salinity for CO_2 injection. High salinity can impede CO_2 movement and cause mineral deposits, potentially clogging rock pores and reducing CO_2 solubility. This paper aims to analyze the impact of salt concentration in brine on CO_2 solubility and storage capacity in saline aquifers. In this study, a sensitivity simulation was conducted on an existing saline aquifer dataset to analyze the effects of varying formation water salinity using a CO_2 sequestration method with a reservoir simulator. Simulation results showed that different salinity levels in formation water yield varying CO_2 solubility rates; for instance, in a formation with water salinity of 1000 ppm, CO_2 solubility increased with a storage capacity of 910.283 MMscf, whereas at 100.000 ppm salinity, CO_2 solubility decreased, and the CO_2 storage capacity was slightly lower at 652.440 MMscf. Formations with lower salinity are considered more ideal for CCS projects as they can maintain higher CO_2 storage capacity and long-term stability. This study is expected to provide additional insights into enhancing the CO_2 solubility mechanism in saline aquifers.

Keywords: Carbon Capture Storage; salinity; CO_2 solubility; CO_2 storage capacity.

I. INTRODUCTION

Carbon dioxide (CO_2) emissions from fossil fuel use have the potential to increase greenhouse gas concentrations in the atmosphere, becoming a primary driver of global warming. Efforts to reduce CO_2 emissions are being undertaken through the Carbon Capture and Storage (CCS) program. The UK government has highlighted CCS as a key initiative to achieve carbon neutrality by 2050. CCS consists of three main stages: capture, transportation, and storage. Injected CO_2 is compressed into a supercritical form, moving through the rock pore space where it then dissolves in water, forming carbonic acid (H_2CO_3).

The development plan involves deviated well injection across five injection wells, with four wells (INJ1, INJ4, INJ5, and INJ6) designated for regular injection and a fifth well reserved as a backup in case of unexpected well issues. The success of the CCS project is also influenced by formation conditions, including water salinity. High salinity can lead to mineral deposits that clog rock pores and reduce the efficiency of CO_2 trapping.

1.1. CO_2 Storage in Saline Aquifer

A saline aquifer is a geological formation located deep below the Earth's surface, containing water with a very high salt concentration dominated by carbonates, primarily calcite ($CaCO_3$) and dolomite ($MgCa(CO_3)_2$). Saline aquifers have a vast and widespread storage capacity, making them an effective option for long-term CO_2 storage (Bentham, 2017).

1.2. Trapping Mechanism

1.2.1. Hydrodinamic Trapping

CO2 will rise until it encounters a cap rock layer with capillary pressure greater than the buoyancy or hydrodynamic forces, accumulating in structural or stratigraphic features with vertical and lateral orientations. These traps generally include anticlinal folds or fault blocks (Bachu et al., 1996).

1.2.2. Residual Trapping

The CO_2 injected into the reservoir displaces the brine in the same flow pattern. However, when injection stops, due to the density difference between CO_2 and brine, the fluids flow in opposite directions, causing CO_2 to move upward while brine flows downward. As a result, the wetter phase (brine) enters the rock pores left by the less wetting phase (CO_2). This process causes the CO_2 to become trapped as it saturates in small pores (Suekane et al., 2008).

1.2.3. Solubility Trapping

This trapping method occurs when CO_2 dissolves in the formation fluid. After injection, CO_2 will move upward toward the boundary between the reservoir and cap rock, then spread laterally beneath the cap rock as a separate phase. When CO_2 encounters formation water and hydrocarbons, mass transfer occurs, and CO_2 dissolves in the water until equilibrium is reached. During the dissolution process, the density of the saline formation water slightly increases due to the dissolved CO_2. This results in the heavier saline water at the top of the aquifer flowing downward due to gravity, enhancing CO_2 and brine mixing and promoting the diffusion process. CO_2 solubility in formation water tends to decrease with increasing salinity (Lindeberg, 1997).

1.2.3. Mineral Trapping

Mineral trapping is a process in which CO_2 is trapped in a stable mineral phase through interaction with minerals and other organic materials in the formation. CO_2 in the aqueous phase forms a weak acid that reacts with rock minerals to produce bicarbonate ions along with various cations, depending on the mineralogy of the formation. This trapping process is highly influenced by the minerals in the rock, gas pressure, temperature, and rock porosity. Significant variations in rock permeability and porosity may occur (Bachu et al., 1996).

1.3. The Effect of Formation Water Salinity on CO_2 Solubility and Storage Capacity

Generally, the higher the salinity of the water, the more salt ions are present in the solution, which can reduce the solubility of CO_2 due to the salting-out effect. Ions such as sodium (Na^+) and chloride (Cl^-) compete with CO_2 molecules for interaction with water molecules, thereby decreasing the amount of CO_2 that can dissolve. According to Bachu et al. (2007), the solubility of CO_2 in water decreases significantly with increasing salinity because the salt ions reduce the interactions between water molecules and CO_2. The increase in salinity not only lowers the solubility of CO_2 but also affects the dynamics of CO_2 migration within the aquifer (Kharaka et al., 2010).

The solubility of CO_2 increases with increasing pressure. Figure 1.1 shows that at the same pressure point, solutions with higher salinity have a lower ability to dissolve CO_2 compared to those with lower salinity. Under isothermal conditions, the temperature remains constant, so changes in solubility are only due to changes in pressure and formation water salinity (Nghiem et al., 2004).

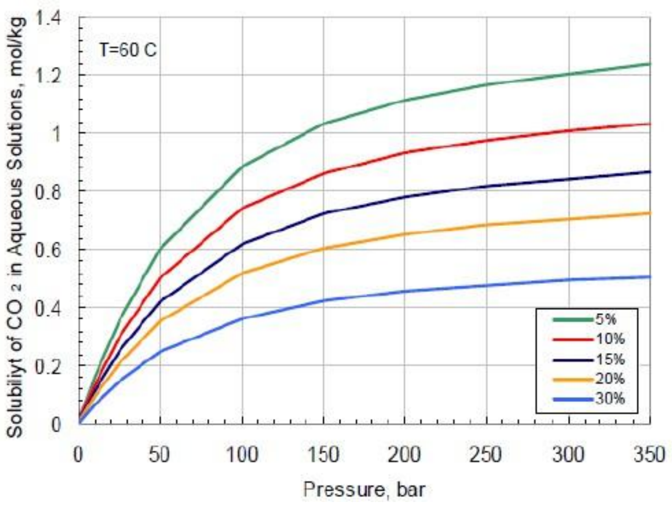


Figure 1. CO_2 solubility in saline water (NaCl) with variations in total salinity under isothermal conditions (Setiawan, 2022)

Best et al. (2011) state that high salinity reduces CO_2 storage capacity due to lower CO_2 solubility, indicating that formations with high salinity tend to have lower storage capacities. This occurs when salinity increases and salt ions in the solution compete with CO_2 molecules for interaction with water molecules, thereby reducing the amount of CO_2 that can dissolve. Furthermore, Nghiem et al. (2004) also demonstrate that at high pressures, the solution's ability to dissolve CO_2 does indeed increase; however, solutions with higher salinity still have a lower capacity compared to those with lower salinity. This is due to the salting-out reaction, where the presence of salt ions reduces the solution's ability to dissolve CO_2, even at high pressures (Nghiem et al., 2004).

II. METHODS

Based on the workflow in Figure 2, the research method begins with a literature review on Carbon Capture and Storage (CCS), as well as the impact of water salinity on CO_2 solubility and CO_2 storage capacity. Next, data collection is conducted as outlined in the workflow, with the required data including reservoir data ($\emptyset$, K, Swi, Pr, Tr), CO_2 injection data (injection rate and duration), and operational data (injection schedule). The model is initialized using the CO_2SOL model. Then, simulations are run to evaluate the impact of variations in formation water salinity on CO_2 solubility and storage capacity for each scenario, with salinity variations from 1000 ppm to 100000 ppm. This research method is also complemented by an analysis of the impact of formation water salinity on CO_2 solubility and storage capacity, as well as a comparison of results across scenarios with different salinities.

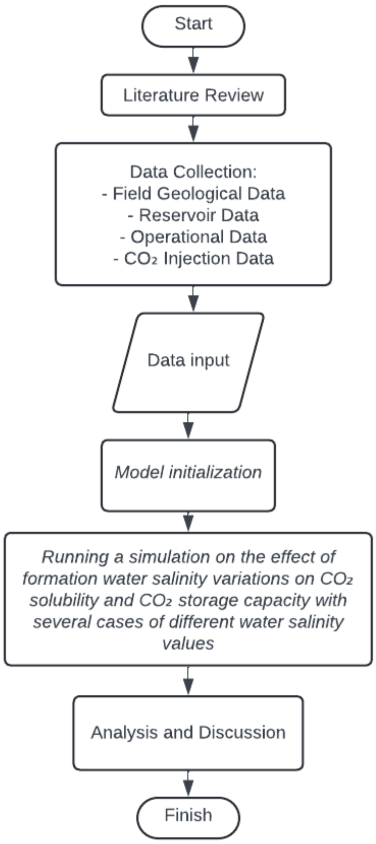


Figure 2. Research Flowchart

III. RESULTS AND DISCUSSION

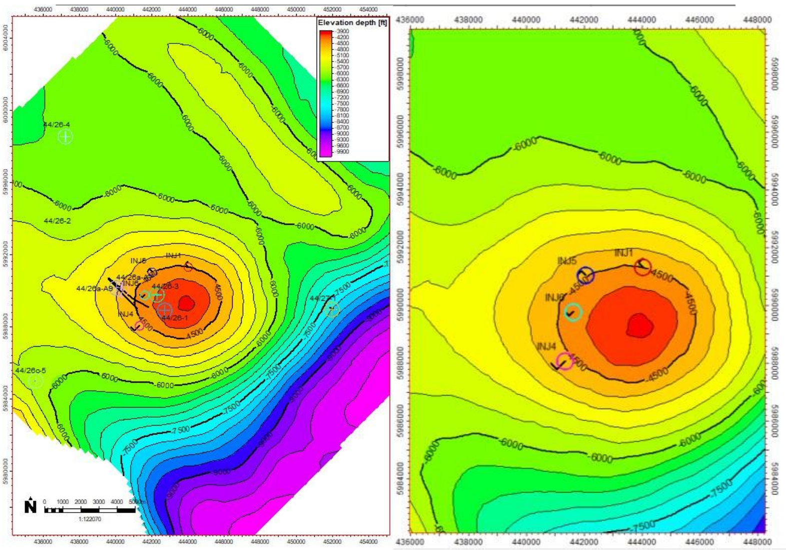
3.1. Bunter Field Case Study

The primary storage used as a storage location is a water-bearing sandstone layer formed during the Triassic period. Drilling of wells in this area has not resulted in any hydrocarbon accumulation. Limitations in data collection leads to a high level of uncertainty in understanding the reservoir characteristics in the Bunter Field. A summary of the basic property model for the Bunter Field are as follows:

Table 1. Summary of the model properties

Parameter	Value	Unit
Type	Saline Aquifer	
Grid Size	200x200	
Avg NTG	0,85	fraction
Avg Porosity	22	%
Avg Permeability	210	mD
Storage	391	Mt
Initial Reservoir Pressure	124.4	barg

Initial Reservoir Temperature	45	°C
Depth	1170	mTVD-SS
Injector	4	
Tcr	30,98	
Pcr	73,77	
Vcr	0,0939	
MW	44,01	
SG	1,53	



(a) (b)

Figure 3. Injection Well Location Map of Bunter Field
(a) Overall Contour Map of Existing Wells
(b) Contour Map of the Four CO_2 Injection Well Locations

Based on the location map in Figure 3, Bunter Field has several existing wells that were previously drilled and once operated. Among these existing wells, four wells were selected with available conventional core data. This core data was analyzed to determine the physical and chemical characteristics of the rock, such as porosity and permeability.

A range of salinity values used in this analysis represents an assumption from minimum to maximum values, with a wide spread chosen according to the water types categorized in Table 1. The simulation includes timesteps up to 500 years, from 2027 to 2527, to examine the long-term effects of CO_2 injection under varying formation water salinity levels. The extended simulation period captures dynamic changes in the reservoir system throughout the CO_2 injection period.

Table 1. Formation Water Types Categorized by Salinity in PPM

Type of water	Salinity values of water
Fresh	0 – 2000 ppm

Brackish	2000 – 10.000 ppm
Saline	10.000 – 30.000 ppm
Hyper Saline	30.000 – 100.000 ppm
Brine	≥ 100.000 ppm

3.2 Effect of Formation Water Salinity on CO_2 Solubility

Variations in formation water salinity significantly impact CO_2 solubility in the Bunter Field, which has a sandstone formation with high porosity and permeability. At low salinity levels, CO_2 solubility is higher due to the lower concentration of ions like sodium (Na^+) and chloride (Cl^-), allowing the water more capacity to dissolve CO_2. Dissolved CO_2 forms carbonic acid (H_2CO_3), which can increase the density of formation water. Conversely, at high salinity, CO_2 solubility decreases because more dissolved ions reduce the solution space and increase the risk of solid deposit formation (salting out), potentially reducing the rock's pore space. This analysis highlights the relationship between salinity and formation water density in influencing CO_2 storage capacity.

Effect on Formation Water Density

High-salinity water has greater density due to the presence of more dissolved ions like Na^+ and Cl^-, which add mass per volume without a proportional volume increase. In the context of Carbon Capture and Storage (CCS), when CO_2 is injected into a saline reservoir, solubility trapping occurs, where CO_2 dissolves and reacts with water to form ions like HCO_3^- and CO_3^{2-}, increasing water density. However, at very high salinity, the "salting-out" effect reduces CO_2 solubility, limiting the increase in water density. Thus, at lower salinity levels, water density can be higher due to the additional volume of dissolved CO_2 in brine.

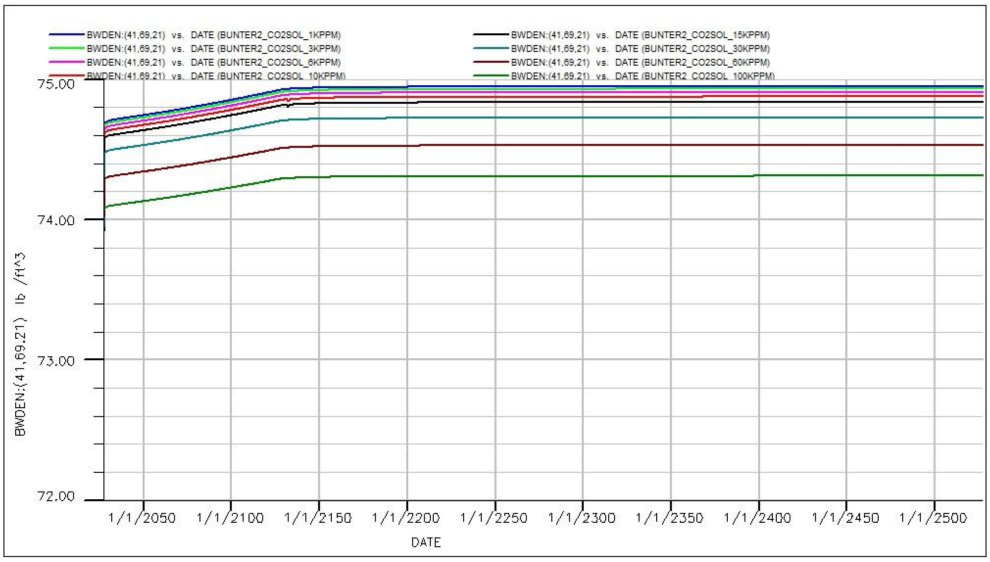


Figure 4. Formation Water Density in the Bunter Field Based on the Influence of Formation Water Salinity Variations

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Table 2. Simulation Results of the Effect of Formation Water Salinity Variation on Formation Water Density in the Bunter Field

Salinity (ppm)	Formation water density after CO_2 injection (lb/ft³)	Initial formation water density (lb/ft³)	Δdensity (final density – initial density) (lb/ft³)
1000	74,95	72,41	2,54
3000	74,93		2,52
6000	74,91		2,5
10000	74,88		2,47
15000	74,84		2,43
30000	74,73		2,32
60000	74,53		2,12
100000	74,31		1,9

Figure 4 shows that formation water with higher density, which generally has lower salinity, demonstrates a greater ability to dissolve CO_2 because water molecules are more closely packed. Based on the simulation results in Table 2, at low salinity (e.g., 1,000 ppm), the formation water density reaches 74.95 lb/ft³, providing a higher CO_2 solubility capacity compared to higher salinity, such as 100,000 ppm, where density decreases to 74.31 lb/ft³. This density reduction is due to the salting-out effect, where dissolved ions at high salinity occupy pore space, reducing water's capacity to dissolve CO_2. The ΔDensity, or change in density, in Table 2 also indicates this relationship: at low salinity, the increase in density after CO_2 injection is greater (e.g., 2.54 lb/ft³ at 1,000 ppm) compared to high salinity (1.9 lb/ft³ at 100,000 ppm), indicating lower CO_2 solubility at high salinity.

3.3 Effect of Formation Water Salinity on CO_2 Storage Capacity

CO_2 storage capacity is measured by the cumulative volume of CO_2 that can be stored in the formation. Water salinity affects the distribution of CO_2 within the reservoir, thus influencing the amount of CO_2 that can be stored. The reservoir in Bunter Field has a storage capacity of 391 Mt. The effect of salinity on CO_2 storage is shown in Figure 5 and Table 3 below.

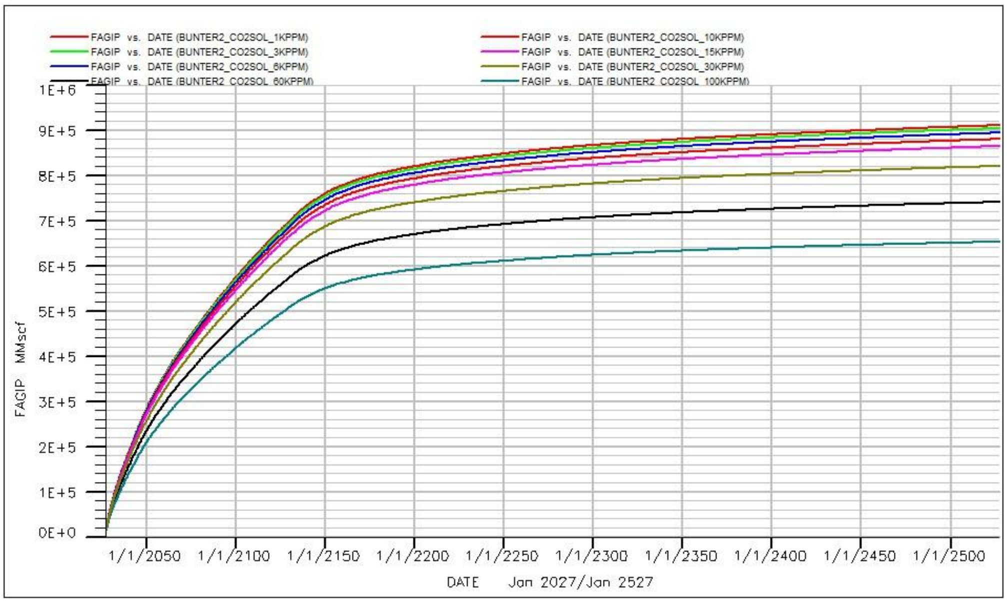

Figure 5. Gas In Place of Bunter Field Based on the Influence of Formation Water Salinity Variations

Table 3. Simulation Results of the Influence of Formation Water Salinity Variations on CO_2 Storage Capacity in Bunter Field

Salinitas (ppm)	**Gas In Place after CO_2 injection (MMscf)**
1.000	910.283
3.000	903.653
6.000	893.776
10.000	879.772
15.000	864.048
30.000	819.902
60.000	740.435
100.000	652.440

In this simulation, Table 3 shows that the CO_2 storage capacity in the low-salinity formation (1,000 ppm) reaches 910,283 MMscf, the highest capacity among the tested salinity variations. As salinity increases, CO_2 storage capacity continues to decrease, with only 652,440 MMscf at a salinity of 100,000 ppm. This capacity reduction aligns with the 'salting-out' phenomenon, which causes solid deposits to form in rock pores and reduces CO_2 storage space. Low-salinity formations have a lower risk of clogging, making them more suitable for long-term CO_2 storage and able to maintain higher storage capacity without significant reduction due to deposits.

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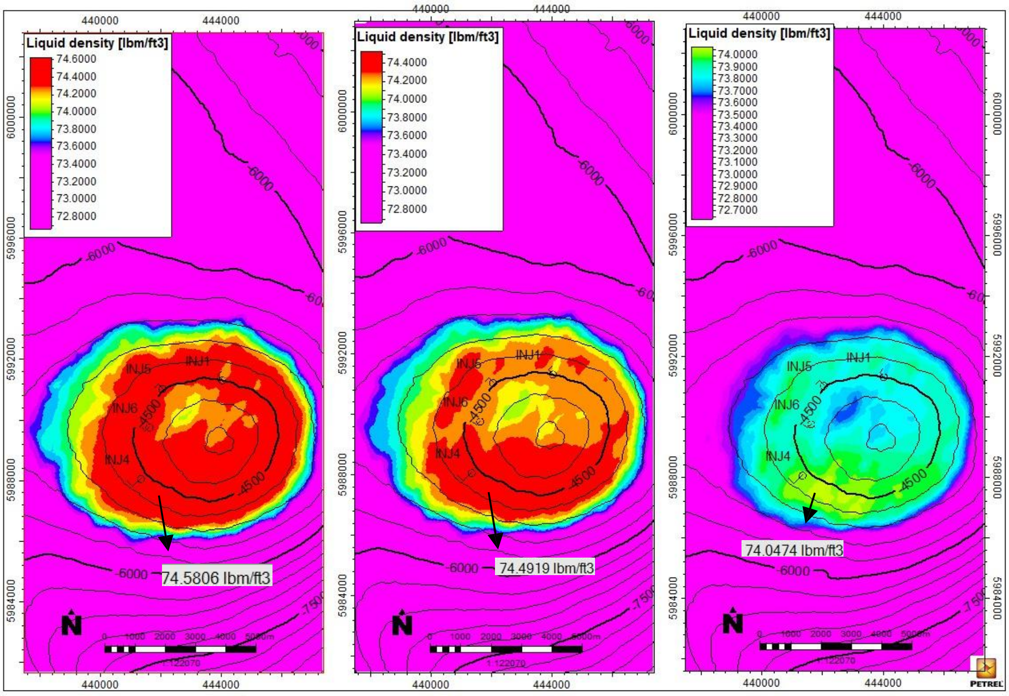
Effect on Formation Water Density

The variation in formation water salinity significantly impacts CO_2 storage capacity, as seen in the change in formation water density on the Water Density Map (Figure 6). Higher salinity tends to decrease formation water density due to the salting-out effect, which reduces the formation water's ability to dissolve CO_2 optimally.



(a) (b) (c)

Figure 6. Water Density Map after CO_2 Injection under three conditions:

(a) 1,000 ppm (fresh water),

(b) 15,000 ppm (saline water),

(c) 100,000 ppm (brine).

Table 4. Formation Water Density Values after CO_2 Injection based on the Water Density Map.

Salinity	Formation water density after CO_2 injection
1.000 ppm	74,58 lbm/ft^3
15.000 ppm	74, 49lbm/ft^3
100.000 ppm	74,05 lbm/ft^3

Table 4 shows that at low salinity conditions (1,000 ppm), the formation water density is higher (74.58 lbm/ft^3), which allows for better dissolution of CO_2 and increases storage efficiency. However, at high salinity (100,000 ppm), the density decreases (74.05 lbm/ft^3), indicating lower CO_2 solubility and a significant amount of CO_2 remains in the gas or supercritical phase, requiring larger pore space. These results indicate that CO_2 storage is more efficient in formations with low salinity because more CO_2 can be stored in the dissolved phase, while high salinity limits CO_2 solubility and reduces storage efficiency.

Effect on Plume Diameter

The plume diameter reflects the extent of CO_2 spread in the reservoir during and after the injection process, where a larger diameter indicates a wider distribution of CO_2 and higher storage capacity.

Table 5. Difference in Plume Diameter after CO_2 injection based on Map Water Density.

Salinitas	dPlume water density after CO_2 injection (m)
1.000 ppm	9689,11
15.000 ppm	9463,15
100.000 ppm	8140,45

Table 5 shows that at low salinity (1,000 ppm), the plume diameter reaches 9,689.11 meters, indicating optimal and efficient CO_2 distribution. However, at higher salinities (15,000 ppm and 100,000 ppm), the plume diameter decreases to 9,463.15 meters and 8,140.45 meters, respectively. These results indicate that high salinity limits the spread of CO_2, thereby reducing the effective storage capacity within the reservoir. Low salinity proves to enhance CO_2 storage efficiency by expanding the area of CO_2 distribution.

IV. CONCLUSION

Based on the analysis discussed above, the following are the conclusions of this research.

1. At low formation water salinity (1,000 ppm), CO_2 solubility is higher (formation water density reaches 74.95 lb/ft³) because the solubility of dissolved ions is lower, providing more space to dissolve CO_2. In contrast, at high salinity (100,000 ppm), CO_2 solubility decreases (formation water density is lower at 74.31 lb/ft³) due to the dominant salting-out effect.
2. At low formation water salinity (1,000 ppm), CO_2 storage capacity is greater (910,283 MMscf) because the concentration of dissolved ions is lower. However, at high salinity (100,000 ppm), CO_2 storage capacity decreases (652,440 MMscf) due to the salting-out reaction, where the ions in saline water react with the CO_2 injected into the formation, resulting in solid precipitates that form in the rock pores, thereby reducing the available space in the pores for CO_2 storage.

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