Halite precipitation during CO2 injection: insights from microfluidics and cores

Yan, L.; Voskov, D.; Farajzadeh, R.

DOI
10.3997/2214-4609.202522049

Publication date
2025

Document Version
Final published version

Citation (APA)
Yan, L., Voskov, D., & Farajzadeh, R. (2025). *Halite precipitation during CO2 injection: insights from microfluidics and cores*. Paper presented at World Carbon Capture, Utilisation and Storage Conference 2025, Bergen, Norway. https://doi.org/10.3997/2214-4609.202522049

49

Halite precipitation during CO2 injection: insights from microfluidics and cores

L. Yan[1], D. Voskov[1,2], R. Farajzadeh[1,3]

[1] Delft University Of Technology; [2] Stanford University; [3] Shell Global Solutions International B.V.

Summary

Halite precipitation during CO_2 injection can significantly reduce injectivity and impact long-term storage in saline aquifers and depleted reservoirs. However, the impact of geological porous media on salt precipitation and brine movement is not fully undersood. This study explores salt precipitation dynamics from the pore to core scale using microfluidic experiments and core-flooding tests. Microfluidic results reveal three distinct phases of salt deposition: slow evaporation, rapid evaporation, and complete dry-out. Heterogeneous pore structures retain more initial water, leading to localized salt accumulation due to capillary effects. Core-scale experiments show that permeability strongly influences salt penetration and porosity reduction. In high-permeability cores, salt fronts extend deeper into the rock, causing up to 70% porosity reduction. In contrast, heterogeneous cores experience limited salt penetration but increased surface accumulation, suggesting that capillary pressure and brine redistribution control final deposition patterns. These findings highlight the complex interactions between fluid flow, rock properties, and salt crystallization, which provides valuable insights for predicting injectivity loss and optimizing CO_2 storage strategies. Understanding these mechanisms is essential for improving reservoir management and ensuring the long-term stability of geological CO_2 sequestration projects.

Halite precipitation during CO2 injection: insights from microfluidics and cores

Introduction

CO2 storage is widely considered in geological formations such as depleted hydrocarbon reservoirs, coal seams, igneous rocks, and saline aquifers (Luo et al., 2022). Among these, depleted reservoirs and deep saline aquifers are the most viable candidates due to their large storage capacities and established trapping mechanisms. However, during CO2 injection, complex geochemical and physical interactions occur, including water vaporization-induced salt precipitation, which may reduce injectivity and impact long-term storage efficiency.

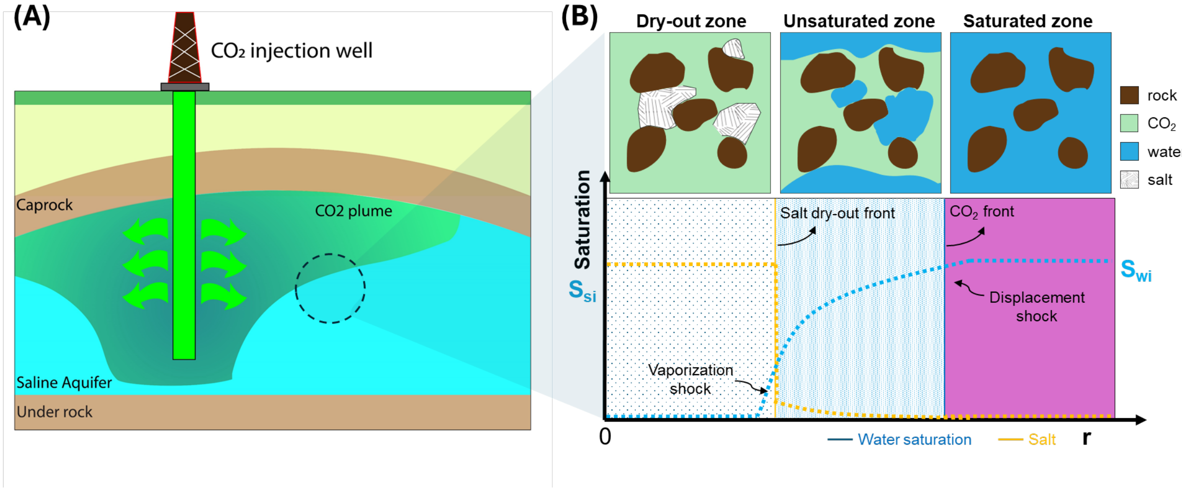

__Figure 1__ Schematic of CO2 injection into a reservoir. (A) shows the CO2 plume and transport into a saline aquifer. (B) represents a pore-scale salt and water distribution in three zones: dry-out zone, unsaturated zone and saturated zone. The other chemical reactions due to CO2 injection is not considered here, e.g. hydrate formation and mineral dissolution.

Salt precipitation, particularly halite crystallization, is a leading cause of injectivity impairment. As dry CO2 displaces formation brine, water evaporates into the CO2 phase causing localized salinity increases and subsequent salt crystallization within pore spaces. Figure 1 illustrates the process of CO2 injection into a saline aquifer and the associated pore-scale distribution of water and salt. In the reservoir-scale schematic (Figure 1A), dry CO2 is injected into the aquifer formation, resulting in a plume that displaces brine and migrates radially. When CO2 enters the pore space and displaces high-salinity brine, the reservoir presents three zones: dry-out zone, unsaturated zone and saturated zone (Figure 1B). The dry-out zone appears from the water evaporation and salt accumulation until the salt dry-out front. The water saturation is zero with the neglectable water inside salt crystals. In the unsaturated zone where residual brine and CO2 co-exist together, CO2 dissolution and water evaporation occur simultaneously. Before brine salinity reaches supersaturation point of salt, dry-out front has a sharp shock of salt saturation. There is no continuous salt precipitation in this zone. With the movement of dry-out front, the salt crystal aggregation occupies the pore space and throat, which gives chance to reduce the rock permeability. This process is particularly severe near the injection point, where the CO2 flow rate is highest and humidity is lowest, leading to rapid water loss and salt supersaturation.

Laboratory experiments and field studies have provided evidence for salt precipitation-induced permeability reduction. Smith et al. (2022) reported significant injectivity reduction of a well located in the Quest CCS field in Canada due to the halite precipitation. Peysson et al. (2014) conducted CO2 flooding experiments in sandstone cores under 50 bar confining pressure and high-temperature conditions (90~120 °C). The results demonstrated a 70% permeability reduction within 46 hours, which gains severe pore clogging near the injection zone. At the pore scale, Ott et al. (2015) used X-ray microtomography to visualize salt growth patterns within sandstone cores, showing that crystallization along gas-brine interfaces disrupts pore connectivity and enhances capillary trapping effects. Additionally, Miri et al. (2015) highlighted the role of capillary backflow and brine redistribution, which further intensifies localized salt deposition. However, there is a lack of comprehensive description on the impacts of rock surface property on the kinetic of salt precipitation and pore plugging from pore-to-core scale, especially on the pore structure, wettability and rock heterogeneity (Dashtian et al., 2018; Yan et al., 2025). Therefore, understanding these processes at the pore scale and their impact on the porous reservoir is essential. The relevant research questions include: what is the impact on the rock permeability? And how do the pore structure and size give influence on salt kinetics? These questions need to be investigated further at multiple scales.

This work aims to investigate the influence of local heterogeneity on the kinetics of salt precipitation in a confined porous area. Using glass-based microfluidics, we provide direct observations of salt precipitation at the pore scale and an influence of capillary backflow to the process. Using core-flood setup, we are able to investigate the salt behaviour in the real 3D porous media and the impact of capillary-driven water backflow on salt precipitation. The combine approaches enhance our understanding in three areas: 1) the impact of pore structure on salt distribution and patterns; 2) impact of rock heterogeneity on salt precipitation; 3) mechanism of salt aggregation and blockage in pore space at pore-scale and the corresponding response in pressure at core-scale due to the capillary-driven water backflow.

Method and/or Theory

We have developed a well-controlled setup for the microfluidic and micro-CT experiments, as shown in Figure 2. The micro-chips are fabricated through an acid chemical etching method, resulting in isotropic etching features. Each chip encompasses a porous media domain measuring 20 mm (length) × 10 mm (width). One type of microfluidic chip features a uniform (homogeneous) pore network characterized by a pore diameter of 90 µm and a throat width of 50 µm. The other microfluidic chip is designed with rock-shaped (heterogeneous) structures to emulate the natural formations of rocks, which has a pore size range of 75~675 µm and a median value of 275 µm, as shown in the figure.

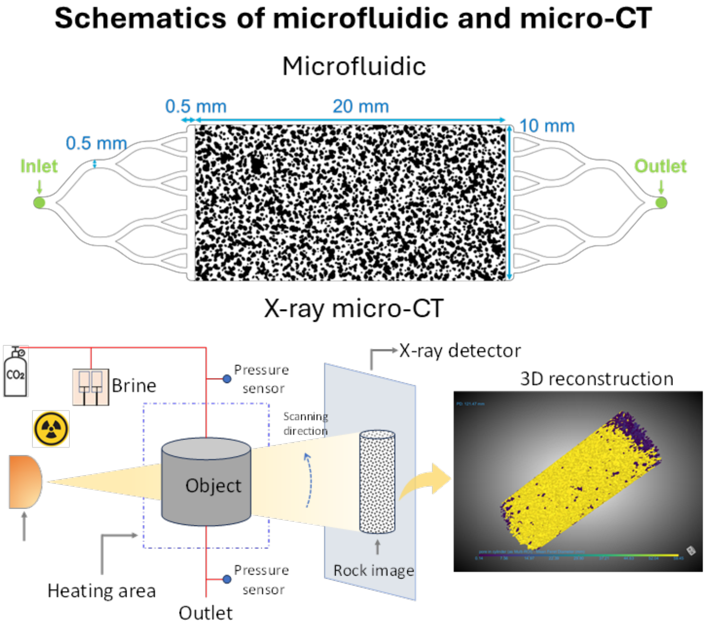

Figure 2 Schematic of microfluidic setup and X-ray CT setup.

The experimental setup in a CT room designed to investigate the salt dry-out process during CO2 injection in porous media. The system integrates a high-pressure CO_2 injection apparatus, a X-ray CT scanner, and a rock sample placed inside a core holder for dynamic imaging and pressure monitoring. The scanner has a resolution of 5.12 pixels/µm and a voxel size of 0.023 mm^3, which enables real-time 3D imaging of fluid distribution and salt deposition.

Result and discussion

In the microfluidic experiment, the dynamic salt crystallization and overall salt distribution in the whole micro-chips are observed, as shown in the Figure 3.

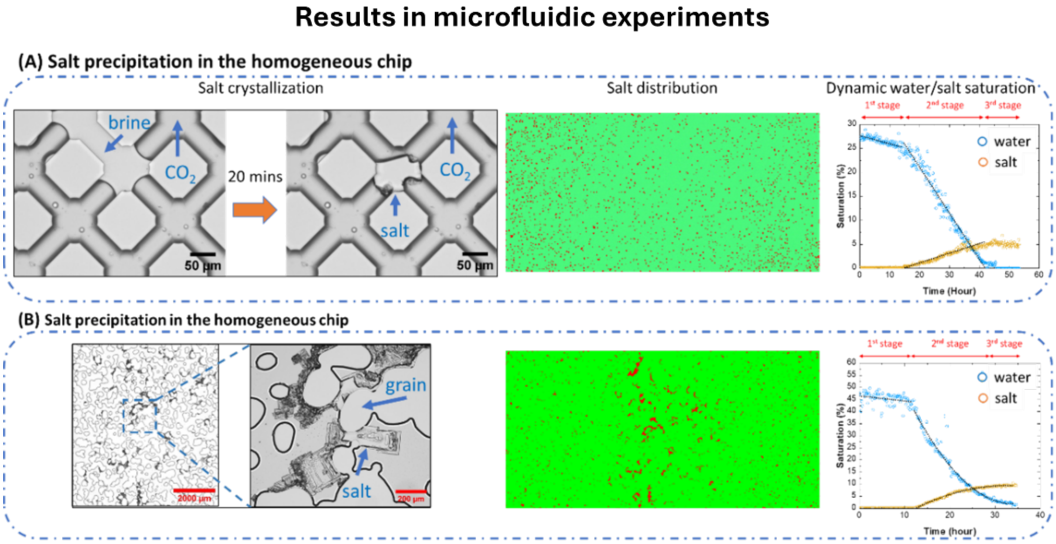

Figure 3 *The results of salt crystallization, salt distribution and the dynamic salt and water saturation for the two whole chips. In the middle pictures, salt is in red and green is the grain+water+*CO_2*.*

This figure illustrates how water and salt saturation change over time during the experiment and can be used to deduce the parameters of salt precipitation kinetics for homogeneous porous media. In the heterogeneous pore structure, the initial water saturation is approximately 45%, significantly higher than in homogeneous chips (both water-wet and intermediate-wet). The heterogeneous structure can retain more water due to varying local capillary pressures. The chip exhibits three stages of water and salt saturation, similar to homogeneous chips. Notably, during the second stage, the changes in water and salt saturation are nonlinear. The final salt saturation reaches approximately 9.5%, about 1.9 times higher than in uniform chips.

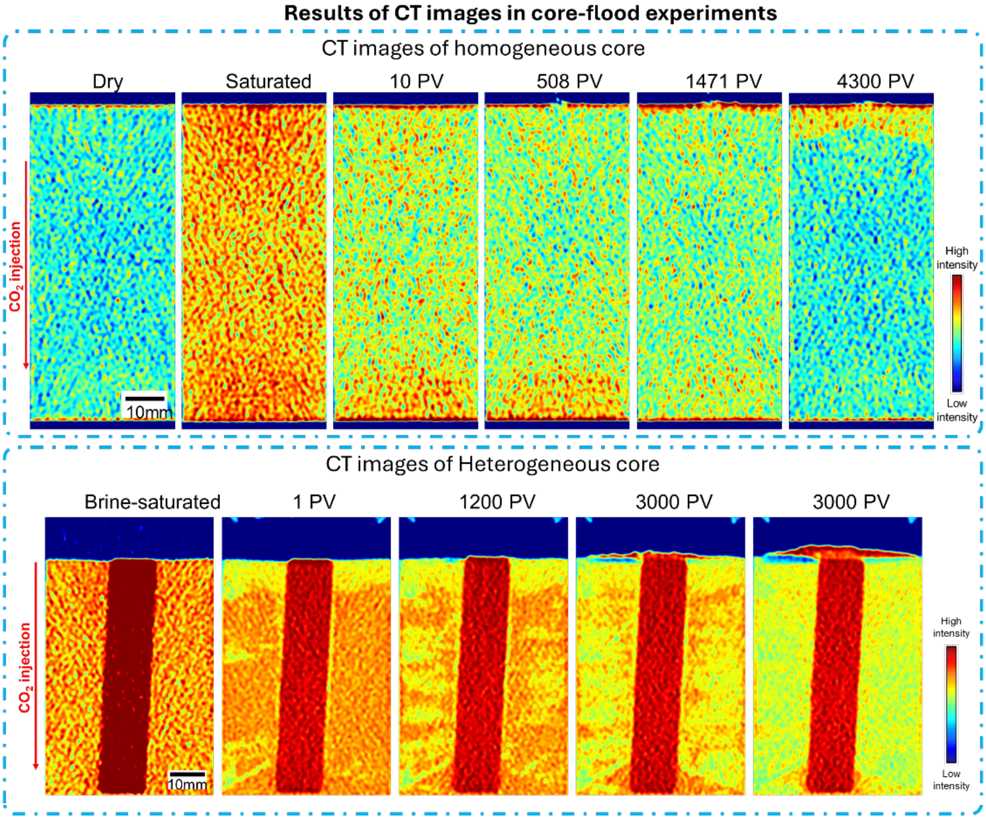

***Figure 4** The results of CT scanning images for the homogeneous (A) and heterogeneous cores (B). The colour represents the intensity of material in the cores.*

In the core-flood experiment, we used two cores: homogeneous and heterogeneous cores, as shown in Figure 4. Three homogeneous cores from outcrop were used with various permeability from 160 to 1700 mD. Another synthetic core with a low-permeable rock inside and a high-permeable sand packed outside was fabricated for the experiment. The results show that homogeneous core had apparent salt penetration depending on the permeability. The dynamic salt dry-out front was observed. Higher permeable rock contains deeper salt front, while lower permeable rock presents the reverse phenomenon. The porosity reduction in the highest-permeable core had about 70% porosity drop. Furthermore, we noticed that the heterogeneous core had less salt penetration and more salt accumulation at the surface. This demonstrated the strong capillary pressure plays an important role on dominating the brine position in the core and the final salt locations.

Conclusions

In our work, we developed the microfluidic and CT setup for investigating salt precipitation from pore-to-core scale. The set of studies have been performed with continuous injection of CO_2 into the porous media and subsequent formation of salts in real-time. Three main conclusions are drawn from the results of experiments: 1) the process of salt deposition can be divided into three stages: slow water evaporation, rapid water evaporation, and water drying out; 2) local heterogeneity in pore structure significantly influences the initial water saturation and the final distribution morphology of precipitated salt; 3) insights into impact of rock heterogeneity on brine backflow and salt locations at core scale are gained.

Acknowledgements

Authors thank Shell Global Solutions International for granting permission to publish this work.

References

Dashtian, H., Shokri, N., & Sahimi, M. (2018). Pore-network model of evaporation-induced salt precipitation in porous media: The effect of correlations and heterogeneity. *Advances in Water Resources*, **112**, 59-71.

Luo, A., Li, Y., Chen, X., Zhu, Z., & Peng, Y. (2022). Review of CO2 sequestration mechanism in saline aquifers. *Natural Gas Industry B*, **9**(4), 383-393.

Miri, R., van Noort, R., Aagaard, P., & Hellevang, H. (2015). New insights on the physics of salt precipitation during injection of CO2 into saline aquifers. *International Journal of Greenhouse Gas Control*, **43**, 10-21.

Ott, H., Roels, S., & De Kloe, K. (2015). Salt precipitation due to supercritical gas injection: I. Capillary-driven flow in unimodal sandstone. *International Journal of Greenhouse Gas Control*, **43**, 247-255.

Peysson, Y., André, L., & Azaroual, M. (2014). Well injectivity during CO_2 storage operations in deep saline aquifers-Part 1: Experimental investigation of drying effects, salt precipitation and capillary forces. *International Journal of Greenhouse Gas Control*, **22**, 291-300.

Smith, N., Boone, P., Oguntimehin, A., van Essen, G., Guo, R., Reynolds, M. A., Friesen, L., Cano, M.-C., & O'Brien, S. (2022). Quest CCS facility: Halite damage and injectivity remediation in CO2 injection wells. *International Journal of Greenhouse Gas Control*, **119**, 103718.

Yan, L., Niftaliyev, R., Voskov, D., & Farajzadeh, R. (2025). Dynamics of salt precipitation at pore scale during CO2 subsurface storage in saline aquifer. *Journal of Colloid and Interface Science*, **678**, 419-430.