Capillarity

Vol. 19, No. 3, p. 71-74, 2026

Perspective

Capillary management: A framework for improving CO_2 geological storage efficiency

Suparit Tangparitkul[1,2]*

[1] *Department of Mining and Petroleum Engineering, Chiang Mai University, Chiang Mai 50200, Thailand*

[2] *Chiang Mai Research Center for Carbon Capture and Storage (Chiang Mai CCS), Chiang Mai University, Chiang Mai 50200, Thailand*

Keywords:
CO_2 geological storage
carbon capture and storage
storage efficiency
capillarity
relative permeability

Cited as:
Tangparitkul, S. Capillary management: A framework for improving CO_2 geological storage efficiency. Capillarity, 2026, 19(3): 71-74.
https://doi.org/10.46690/capi.2026.06.01

Abstract:
CO_2 geological storage in saline formations faces a persistent challenge of low storage efficiency (typically ∼3%–10%), limiting effective pore space utilization. This limitation mainly arises from capillary-controlled multiphase flow, where pore-scale processes govern plume distribution and trapping. However, capillarity is commonly treated as an intrinsic rock–fluid property rather than a controllable parameter. This perspective introduces a capillary management framework that enables process-dependent control of interfacial tension and wettability to optimize both drainage and imbibition. By engineering capillary conditions, the framework enhances pore accessibility during injection and promotes residual trapping during fluid redistribution. Recent laboratory studies, together with analytical evaluation, indicate that modifying relative permeability through capillary control could potentially improve storage efficiency from ∼5% to ∼7%-8% under representative conditions. Analytical evaluation further indicates that these improvements result from reduced mobility ratio and enhanced saturation states. Capillary management therefore provides a new pathway for actively controlling subsurface multiphase flow and improving the performance of geological CO_2 storage.

1. Introduction

Globally, the deployment of carbon dioxide (CO_2) geological storage remains significantly below projected targets, with many planned projects not reaching implementation due to economic and techno-operational constraints (Zhang et al., 2024). For storage in saline formations, storage efficiency (ε), defined as the fraction of pore space effectively occupied by CO_2, is typically on the order of a few percent (∼3%–10%) (Okwen et al., 2010). As a key controlling parameter, improving storage efficiency directly increases the usable storage capacity of a formation and potentially reduces the cost per unit of CO_2 stored (Tangparitkul et al., 2025).

Storage efficiency is governed by the CO_2 plume dynamics within the reservoir, controlled by the interplay of viscous, gravitational, and capillary forces (Nordbotten et al., 2005). Near the injection well, flow is primarily viscous-dominated due to imposed injection rates (Q), while gravitational segregation becomes more pronounced with increasing distance, influencing vertical plume migration. Plume behavior is therefore commonly managed through injection strategies that promote viscous forces and improve sweep efficiency near the wellbore. However, away from the injection region, flow behavior becomes increasingly governed by capillary heterogeneity and pore-scale interactions, which control fluid distribution and trapping mechanisms, particularly residual and solubility trappings (Akamine et al., 2024; Ramadhan et al., 2024; Thanasaksukthawee et al., 2025b; Han et al., 2026).

Yandy Scientific Press

*Corresponding author.
E-mail address: suparit.t@cmu.ac.th (S. Tangparitkul).

Received April 26, 2026; revised May 17, 2026; accepted May 29, 2026; available online June 1, 2026.

Despite these challenges, capillarity is typically treated as an intrinsic rock–fluid property rather than a controllable design parameter, limiting the achievable storage efficiency under conventional approaches. In the current perspective, capillary management is introduced as a framework to actively engineer pore-scale capillary systems, particularly in the capillary-dominated regime. By enabling process-dependent modification of capillary behavior, this approach provides a pathway to enhance storage efficiency in geological formations.

2. Capillary control of storage efficiency

Mechanistically, storage efficiency is controlled at both reservoir and pore scales, with capillarity linking the two. At the reservoir scale, the efficiency is governed by the spatial distribution of the CO_2 plume, which determines the extent of pore space effectively utilized during injection and trapping as discussed above. This distribution is controlled by (i) the ratio of gravity to viscous forces and (ii) the mobility ratio. The former can be expressed as $\Gamma = 2\pi \Delta\rho K K_{rw} B^2/(\mu_w Q)$, where $\Delta\rho$ is the density difference between CO_2 and brine, K is the absolute permeability, k_{rw} is the brine relative permeability, B is the reservoir thickness, and μ_w is the brine viscosity (Nordbotten et al., 2005; Okwen et al., 2010). The mobility ratio is given by $\lambda = k_{rg}\mu_w/(k_{rw}\mu_g)$, where k_{rg} and μ_g are the relative permeability and viscosity of CO_2, respectively. Among these parameters, the k_r governs both plume spreading and fluid mobility, thus controls vertical segregation and sweep efficiency. More importantly, k_r is not an independent parameter, but emerges from pore-scale displacement processes governed by capillary forces.

At the pore scale, fluid displacement and the evolution of fluid saturation govern storage efficiency, characterized by the maximum CO_2 saturation established during injection ($S_{\max}$) and the residual CO_2 saturation retained after imbibition (S_t). During drainage, CO_2 displaces brine and establishes $S_{\max}$, governed by capillary entry conditions and fluid connectivity within the pore network, which determine the extent of pore space accessed during invasion. During imbibition, brine reenters the pore space and redistributes the previously trapped CO_2, resulting in residual trapping (S_t) through capillary instabilities such as snap-off (Singh et al., 2017). These two consecutive processes govern the fragmentation and immobilization of the CO_2 phase, thereby defining the saturation states that control storage efficiency: $S_{\max}$ determines the extent of pore-space utilization established during drainage, while S_t determines the fraction retained as immobilized CO_2 after imbibition, so that ε is directly governed by both.

These two displacement processes impose inherently *conflicting* capillary requirements. Conditions that favor efficient drainage promote invasion into smaller pores and higher $S_{\max}$ (Seok et al., 2023), thereby improving pore accessibility during injection, but may suppress capillary trapping during imbibition. Conversely, conditions that enhance residual trapping could increase CO_2 immobilization and S_t, but limit the extent of pore space accessed during drainage. This ‘asymmetry’ indicates that a single and/or static capillary condition cannot simultaneously optimize both displacement processes, thereby constraining storage efficiency and highlighting the need for a **“capillary management approach”**.

3. Capillary management framework

A capillary management framework is proposed to regulate CO_2 distribution and trapping through process-dependent control of capillary forces. Rather than treating capillary conditions as fixed properties of the rock–fluid system, the framework enables their adjustment in accordance with the displacement regime. This approach recognizes that storage efficiency can be improved by actively controlling capillary behavior, allowing the system to *transition* between conditions that favor pore accessibility and those that enhance trapping. Within this framework, capillarity is treated as a ‘controllable’ parameter governing both the extent of pore utilization and the efficiency of CO_2 immobilization.

Capillary management can be implemented by controlling key parameters that govern capillary forces, primarily the CO_2-brine interfacial tension (σ) and wettability (represented by the three-phase contact angle: θ), which determine capillary pressure and fluid connectivity at the pore scale. During drainage, reducing σ lowers capillary resistance and facilitates CO_2 invasion into smaller pores, enhancing pore accessibility and increasing $S_{\max}$. In contrast, during imbibition, conditions that increase effective capillary forces, through higher σ or less CO_2-wet behavior, promote capillary instabilities such as snap-off, leading to increased residual trapping and S_t. By adjusting these parameters in a process-dependent manner, capillary conditions can be tuned to meet the distinct requirements of each displacement regime. This establishes σ and θ as practical control variables for engineering capillary behavior, enabling storage efficiency to be improved beyond the constraints of fixed rock–fluid properties.

Some previous research has explored the role of σ on capillary behavior using both numerical and experimental approaches. Pore-scale simulations examined two-phase flow through sequential drainage and imbibition processes, demonstrating that σ governs the morphology and stability of residual CO_2 clusters formed during imbibition (Jiang et al., 2015). Higher values promote snap-off and increase S_t, while lower values favor more continuous phase distribution and reduced residual trapping. These results indicate that capillary-controlled trapping behavior can, in principle, be tuned through interfacial conditions. Experimental investigations by Kim and co-workers further confirm that reducing σ using surfactants enhances CO_2 invasion and improves injectivity by increasing fluid connectivity and accessibility to smaller pores (Seok et al., 2023; Kim et al., 2025). However, these studies focus primarily on improving $S_{\max}$ during drainage, without addressing the corresponding impact on residual trapping (S_t) during imbibition.

More recent work demonstrates that the trade-off between improving $S_{\max}$ during drainage and enhancing residual trapping (S_t) during imbibition can be overcome through process-dependent control of σ (Thanasaksukthawee et al., 2025a). Experimental studies using switchable surfactant systems show

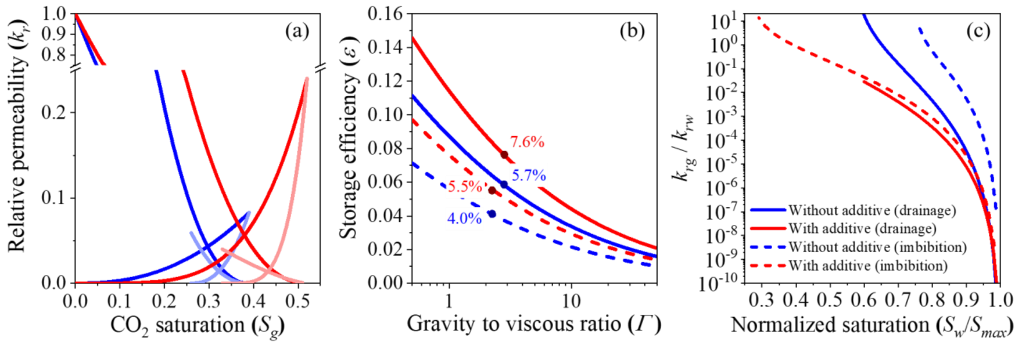

Fig. 1. Analytical demonstration of storage efficiency enhancement through capillary management across scales. (a) Relative permeability (k_r) curves for CO_2–brine systems without (blue) and with (red) surfactant additive during drainage (solid lines) and imbibition (faded lines), adapted from Thanasaksukthawee et al. (2025a). (b) Corresponding storage efficiency (ε) calculated using the analytical model of Okwen et al. (2010) based on the modified k_r relationships. (c) Influence of k_r on mobility ratio, expressed as k_{rg}/k_{rw} as a function of normalized saturation ($S_w/S_{\max}$).

that interfacial conditions can be altered between displacement processes, enabling low σ during drainage to enhance CO_2 invasion and higher σ during imbibition to promote residual trapping. Core-scale measurements indicate that such control leads to simultaneous increases in both $S_{\max}$ and S_t, with corresponding improvements in k_r relative to non-switchable systems. This behavior represents a reversal of capillary conditions between displacement processes, providing experimental support for the capillary management framework at the laboratory scale and demonstrating that the conflict between drainage efficiency and trapping effectiveness can be resolved through controlled capillary manipulation.

Wettability alteration could also provide a pathway for capillary management. Experimental studies using nanoparticle-based treatments have shown evidence that shifting rock surfaces toward more water-wet conditions could enhance both CO_2 invasion and residual trapping, with a pronounced increase in $S_{\max}$ but a slight increase in S_t (Jha et al., 2023). The magnitude and direction of such effects depend on the underlying wetting regime, ranging from strongly water-wet to CO_2-wet conditions (Iglauer et al., 2015). Such improvements are likely attributed to enhanced fluid connectivity and capillary instabilities associated with the wettability change. However, the study considered only a single wettability state throughout the displacement regimes, without process-dependent control between drainage and imbibition. Further work should explore dynamic control of wettability to achieve greater storage efficiency.

To demonstrate the capillary management framework, an analytical study was conducted by integrating pore-scale k_r data with a reservoir-scale storage efficiency model. Relative permeability curves for drainage and imbibition obtained from Thanasaksukthawee et al. (2025a) (Fig. 1(a)) were used as input to the analytical solution of Okwen et al. (2010), in which storage efficiency is governed primarily by λ and S_t. The results (Fig. 1(b)) show that capillary modification leads to consistent improvements in storage efficiency during both displacement processes, increasing from 5.7% to 7.6% during drainage and from 4.0% to 5.5% following imbibition under representative conditions. Assuming a constant μ_w/μ_g, the reduction in λ is primarily attributed to a decrease in the relative permeability ratio (k_{rg}/k_{rw}), see Fig. 1(c). Notably, this reduction is more pronounced at lower saturations, where mobility contrast strongly governs plume spreading. These results demonstrate that capillary management could enhance storage efficiency by simultaneously improving saturation states and reducing λ, thereby providing a direct mechanistic link between pore-scale control and reservoir-scale performance.

Extending this pore-scale link to reservoir-scale performance, however, involves uncertainty that should be acknowledged. The analytical estimates above assume a homogeneous formation, whereas real saline aquifers exhibit pronounced sub-meter to inter-bed heterogeneity from depositional fabric, mineralogy variation, and diagenesis. Such heterogeneity can either promote or impede capillary trapping: small-scale capillary barriers may divert the CO_2 plume into preferential flow paths and reduce effective sweep, while heterogeneity-induced trapping at facies boundaries can enhance the immobilized CO_2 fraction beyond homogeneous-model predictions (Saadatpoor et al., 2010; Krevor et al., 2015; Kim et al., 2021; Han et al., 2026). Combined with gravity segregation (discussed in **Section 1**), these formation-scale effects mean that reservoir-scale numerical simulation under representative geological inputs is required to fully quantify the gains from capillary management.

4. Outlook and future directions

Translating capillary management into field-scale application likely depends on developing chemical systems capable of controlling CO_2–brine–rock interfacial properties to be *preferentially functional*. Key challenges include stability at elevated temperature and pressure, and compatibility with formation fluids and minerals. Current approaches have progressed toward static or partially reversible capillary modification but do not yet provide reliable process-dependent control between drainage and imbibition. In addition to the limited availability of suitable chemical systems, experimental investigation is also constrained by time-intensive experimentation, highlighting the need for pore network modeling to explore capillary-controlled displacement and guide the design of functional chemicals for managing capillary systems.

Capillary management should be considered within an integrated subsurface framework, where interfacial properties evolve with reactive transport and geomechanical processes. By influencing mobility, plume stability, and trapping, capillary control can impact reservoir-scale performance beyond pore-scale displacement. The concept is broadly applicable to systems involving multiphase flow and fluid trapping, not limited to CO_2 storage, but also including CO_2-enhanced oil recovery and underground hydrogen storage. Ultimately, engineering capillarity shifts subsurface storage from passive characterization to active control, providing a new dimension for optimizing storage efficiency and enabling control of the *'hard-to-control'*, or even the *'uncontrollable'*.

Acknowledgements

The author gratefully acknowledges postgraduate researchers for their fruitful discussions that contributed to the development of this work over the years, especially Vorasate Thanasaksukthawee, Pirada Madla, Radamanee Rattanakom, and Thanandorn Patthanaporn. Thanawat Leotphiphatthanakit, an undergraduate student, is also acknowledged for his assistance in preparing the plot of Fig. 1(c). Appreciation is further extended to his peers in the capstone project class of 2025 for their collective support.

Financial support is greatly acknowledged with contributions from (i) Chiang Mai University through the Chiang Mai Research Center for Carbon Capture and Storage (Chiang Mai CCS); and (ii) the National Science, Research and Innovation Fund (NSRF) via the Program Management Unit for Frontier Brainpower and Future Industries, Research and Innovation Acceleration Agency for Competitiveness and Area Development (Public Organization) (No. B49G680118).

Conflicts of interest

The author declares no competing interest.

References

Akamine, T., Tosuai, T., Ramadhan, R., et al. Visualizing oil displacement by nanofluids at pore scale: A concentration-dependent nanofluid spreading induced by structural disjoining pressure. Capillarity, 2024, 12(1): 17-26.

Han, G., Kim, K.-Y., Kim, C. H., et al. Dynamic CO_2 trapping mechanisms driven by pore-scale capillary heterogeneity. Geoenergy Science and Engineering, 2026, 262: 214457.

Iglauer, S., Al-Yaseri, A. Z., Rezaee, R., et al. CO_2 wettability of caprocks: Implications for structural storage capacity and containment security. Geophysical Research Letters, 2015, 42(21): 9279-9284.

Jha, N. K., Kitagawa, H., Abe, M., et al. Chemically enhanced carbon dioxide geosequestration using nanofluids. Paper SPE 215252 Presented at SPE/IATMI Asia Pacific Oil & Gas Conference and Exhibition, Jakarta, Indonesia, 10-12 October, 2023.

Jiang, F., Tsuji, T. Impact of interfacial tension on residual CO_2 clusters in porous sandstone. Water Resources Research, 2015, 51(3): 1710-1722.

Kim, C. H., Kim, K.-Y., Han, G., et al. Enhancement of storage efficiency during carbon dioxide sequestration in depleted reservoirs. Environmental Science & Technology Letters, 2025, 12(3): 269-275.

Kim, K.-Y., Kim, M., Oh, J. Core-scale investigation of the effect of heterogeneity on the dynamics of residual and dissolution trapping of carbon dioxide. Journal of Hydrology, 2021, 596: 126109.

Krevor, S., Blunt, M. J., Benson, S. M., et al. Capillary trapping for geologic carbon dioxide storage – From pore scale physics to field scale implications. International Journal of Greenhouse Gas Control, 2015, 40: 221-237.

Nordbotten, J. M., Celia, M. A., Bachu, S. Injection and storage of CO_2 in deep saline aquifers: Analytical solution for CO_2 plume evolution during injection. Transport in Porous Media, 2005, 58(3): 339-360.

Okwen, R. T., Stewart, M. T., Cunningham, J. A. Analytical solution for estimating storage efficiency of geologic sequestration of CO_2. International Journal of Greenhouse Gas Control, 2010, 4(1): 102-107.

Ramadhan, R., Promneewat, K., Thanasaksukthawee, V., et al. Geomechanics contribution to CO_2 storage containment and trapping mechanisms in tight sandstone complexes: A case study on Mae Moh Basin. Science of the Total Environment, 2024, 928: 172326.

Saadatpoor, E., Bryant, S. L., Sepehrnoori, K. New trapping mechanism in carbon sequestration. Transport in Porous Media, 2010, 82(1): 3-17.

Seok, G.-B., Park, Y.-C., Lee, J. Y., et al. Impact of surfactants on CO_2-brine relative permeability under reservoir conditions. Energy Reports, 2023, 9: 3755-3770.

Singh, K., Menke, H., Andrew, M., et al. Dynamics of snap-off and pore-filling events during two-phase fluid flow in permeable media. Scientific Reports, 2017, 7(1): 5192.

Tangparitkul, S., Akamine, T., Ramadhan, R., et al. CO_2 storage infrastructure and cost estimation for bioenergy with carbon capture and storage in Northern Thailand. Carbon Capture Science & Technology, 2025, 15: 100425.

Thanasaksukthawee, V., Madla, P., Patthanaporn, T., et al. CO_2 storage efficiency improvement using interfacially switchable surfactant: A two-stage capillary flip for greater residual trapping. Paper SPE 225813 Presented at SPE Asia Pacific CCUS Conference, Kuala Lumpur, Malaysia, 26-27 August, 2025.

Thanasaksukthawee, V., Patthanaporn, T., Bangpa, N., et al. Assessing the geological storage capacity of CO_2 in Khorat Sandstone: Geochemistry and fluid flow examinations. International Journal of Greenhouse Gas Control, 2025, 141: 104322.

Zhang, Y., Jackson, C., Krevor, S. The feasibility of reaching gigatonne scale CO_2 storage by mid-century. Nature Communications, 2024, 15(1): 6913.