Malaysian Journal of Chemistry, 2026, Vol. 28(2), 291-298
(Special Issue: *1st International Conference on Chemical and Energy Engineering 2025, ICChEE2025*)

Evaluating Tween-80 Pre-treatment for Mitigating Salt Precipitation and CO_2 Injectivity Loss in High Salinity Aquifers

Baafi, F.[1]*, Md Yusof, M. A.[1]*, Md Akhir, N. A.[1], Turkson, J. N.[2], Darkwah-Owusu, V.[1], Sokama-Neuyam, Y. A.[3], Fjelde, I.[4], Radzali, I. B.[5] and Yusof, S. R. B. M.[6]
[1]Petroleum Engineering Department, Universiti Teknologi PETRONAS, 32610, Bandar Seri Iskandar, Malaysia
[2]Department of Chemical Engineering, University of Virginia, Charlottesville, VA 22903, USA
[3]Department of Petroleum Engineering, Kwame Nkrumah University of Science and Technology, Kumasi, Ghana
[4]NORCE Research, Stavanger, Norway
[5]Laboratory Management Department, Universiti Teknologi PETRONAS, 32610, Bandar Seri Iskandar, Malaysia
[6]Department of Petroleum Engineering, Universiti Teknologi Malaysia, 81310, Skudai, Malaysia.
*Corresponding author (e-mail: franklin_24004865@utp.edu.my; aslam.myusof@utp.edu.my)

Salt precipitation in saline aquifers adversely affects carbon dioxide (CO_2) injectivity, posing significant operational challenges for geological carbon storage projects. This study investigates the potential of Tween-80 as a chemical pre-treatment to mitigate salt precipitation during supercritical CO_2 ($scCO_2$) injection into sandstone saturated with 200000 parts per million (ppm) sodium chloride brine. Before the core flooding experiments, the turbidity and critical micelle concentration (CMC) of Tween-80 in the high-salinity brine were measured as 0.56 nephelometric turbidity unit (NTU) and 12.6 ppm, respectively. Core flood tests on a Berea sandstone core with an initial brine permeability of 311 millidarcy (mD), porosity 23.57% were run at 1650 psi and 50°C, after Tween-80 was pre-injected at 0.5 ml/min. The pre-injection of surfactant produced a clear short-term improvement where permeability rose to 393 mD, indicating improved flow capacity during treatment. However, the final brine permeability reduced to 136 mD after CO_2 injection, and salt precipitation was observed, indicating that the single high-concentration pre-flush was insufficient to prevent CO_2-driven salt precipitation under the experimental sequence and condition. These findings demonstrate that Tween-80 can transiently enhance injectivity, but effective mitigation of salt plugging in extreme-salinity conditions will likely require optimized dosing strategies or alternative treatment approaches.

Keywords: Saline aquifers, salt precipitation, CO_2 injectivity, nonionic surfactants, chemical pre-treatment

Received: July 2025; Accepted: January 2026

Storing CO_2 in geological formations, particularly in deep saline aquifers, has been shown to be an effective way to lower greenhouse gas emissions caused by human activities [1]. However, their high salinity levels pose significant challenges during CO_2 injection. One of the most critical challenges during CO_2 injection is the precipitation of salts [2]. This effect often occurs near the wellbore, where the hygroscopic nature of injected CO_2 causes localized water loss through evaporation. The salts accumulate and restrict fluid flow by reducing both porosity and permeability, ultimately leading to a decline in injectivity and compromising the performance of CO_2 storage operations [3]. This challenge has been observed in several real-world carbon capture and storage (CCS) projects, such as the Snøhvit field [4], the Aquistore Project, and the recently opened QUEST CCS site [5], where salt precipitation near the injection zone has led to significant reductions in permeability and injectivity. Furthermore, several core flooding experiments have shown that even small changes in porosity from halite precipitation can lead to significant permeability declines. In Berea sandstones, for example, permeability reductions of roughly 60 % [2], 30-86 % [3], 75 % [6], and about 50 % [7] have all been reported from their laboratory experiments.

Addressing salt precipitation is therefore essential for ensuring the long-term effectiveness and reliability of CO_2 storage in saline aquifers. Conventional approaches, such as freshwater injections and low salinity water injections, tend to offer only short-term relief, as injectivity typically decreases once CO_2 injection resumes [5, 8]. Also, acidizing with acetic and hydrochloric acid has been investigated with improvements ranging from 162% to 275% depending on the initial salt concentration [9, 10]. However, reprecipitation of salt was observed upon the reintroduction of $scCO_2$, and it is highly corrosive to materials,

---

†Paper presented at the 1st International Conference on Chemical and Energy Engineering 2025 (ICChEE2025)

which initiate complex geochemical reactions that affect the geomechanical stability of the reservoir formation, leading to further risks to long-term storage integrity [11, 12].

Due to the reprecipitation of salts upon the reintroduction of $scCO_2$ in the above methods, attention is increasingly shifting toward pretreatment approaches, which would stop salt from forming in the first place. He, et al. [13] demonstrated at the pore scale that salt precipitation during CO_2 injection is strongly controlled by local water availability and thermal conditions. In 2D micromodel experiments with 20 wt% NaCl brine, freshwater pre-flushing improved injectivity only when boundary brine was negligible, with an injectivity ratio (IR) of 1.5, while trapped or continuously supplied brine promoted wet salt barrier formation and severe injectivity loss (IR = 0.03). Humidified CO_2 injection showed similar sensitivity: low-temperature saturated CO_2 entering a hotter system accelerated salt blockage, whereas high-temperature saturated CO_2 that cooled upon injection condensed water, dissolved incipient salts, and preserved injectivity (IR = 0.86–0.94). Although mechanistically insightful, these findings are limited by short-term, 2D, atmospheric-pressure conditions and simplified NaCl brine. Similarly, Papi, Jahanbakhsh and Maroto-Valer [14] used 2D compositional simulations to show that dry CO_2 injection drives intense near-wellbore evaporation, causing porosity losses of up to 4% and permeability reductions of 14%, while mineral reactions are negligible. Injecting CO_2 with dissolved water (0.2–0.63 mol%) markedly reduced or nearly eliminated salt precipitation, confirming that CO_2 humidification can suppress evaporation-driven salt clogging. However, the benefit diminishes at typical pipeline water contents, and the purely numerical, homogeneous modeling framework highlights the need for experimental and field-scale validation. Although both methods demonstrated potential in delaying or minimizing salt crystallization, their effectiveness was largely influenced by reservoir-specific parameters. These approaches tend to be temporary and can cause corrosion, fines migration, clay swelling, hydrate formation, and increased costs.

While pre-injection conditioning and control of reservoir conditions have been tried, chemical pretreatment strategies to prevent salt formation during CO_2 injection remain underexplored. Nonionic surfactants represent a promising class of additives for this purpose. Their amphiphilic nature enables strong adsorption on rock surfaces, potential wettability modification, and reduced brine evaporation, which could collectively mitigate halite formation. Despite their extensive use in enhanced oil recovery, their application in CO_2 storage environments has received limited attention [15-17]. This study, therefore, investigated the pretreatment of Tween 80 in inhibiting salt precipitation under high-salinity and reservoir-representative conditions. Through core flooding experiments combined with physicochemical and mineralogical analyses, we assessed how surfactant treatment influences permeability preservation and pore-scale processes during CO_2 injection. By addressing this gap, the present work contributes to developing practical reduction strategies for enhancing CO_2 injectivity in saline aquifers.

METHODOLOGY

Materials

Berea sandstone core with a diameter of 3.812 cm and length of 7.445 cm, with a mass of 175.331 g, was used in the experiments with gas permeability and porosity of 418.872 mD and 23.57%, respectively. Sodium chloride (NaCl) brine of 200,000 ppm was prepared to represent very high-salinity formation water, where NaCl was purchased from Chemiz with a molecular weight of 58.44 g/mol with CAS No. 7647-14-5. Similarly, Tween 80 was purchased from R&M Chemicals with CAS No.9005-65-6 and hydrophilic–lipophilic balance (HLB) of 15, served as the nonionic surfactant additive, chosen for its ability to promote passivation at the CO_2-saline aquifer interface and to adsorb onto mineral and crystal surfaces, thereby reducing nucleation sites and limiting fines migration. Experiments used commercial CO_2 (≈99.5% purity). For supercritical CO_2 flooding, injections were performed at 1,650 psi and 50°C; these conditions were held constant across all core-flood experiments.

Methods

The CMC of the nonionic surfactant was initially determined by surface tension measurement using a drop shape analyzer. After surfactant stability was assessed using a static bottle test in which Tween 80 of 1500 ppm was dissolved in 200,000 ppm NaCl brine and held at 50 °C for 24 h, while the solutions were observed for turbidity and precipitation using a turbidimeter. After the surfactant was found to be stable at the specified concentration, core-flooding experiments were conducted on a Formation Damage System (FDS), clearly depicted in Figure 1; Hastelloy tubing and core holders were used to provide resistance to CO_2-induced corrosion. Inlet, outlet, and confining pressures were recorded with individual pressure transducers, and produced fluids were collected for subsequent effluent analysis. The general experimental flowchart is clearly shown in Figure 2.

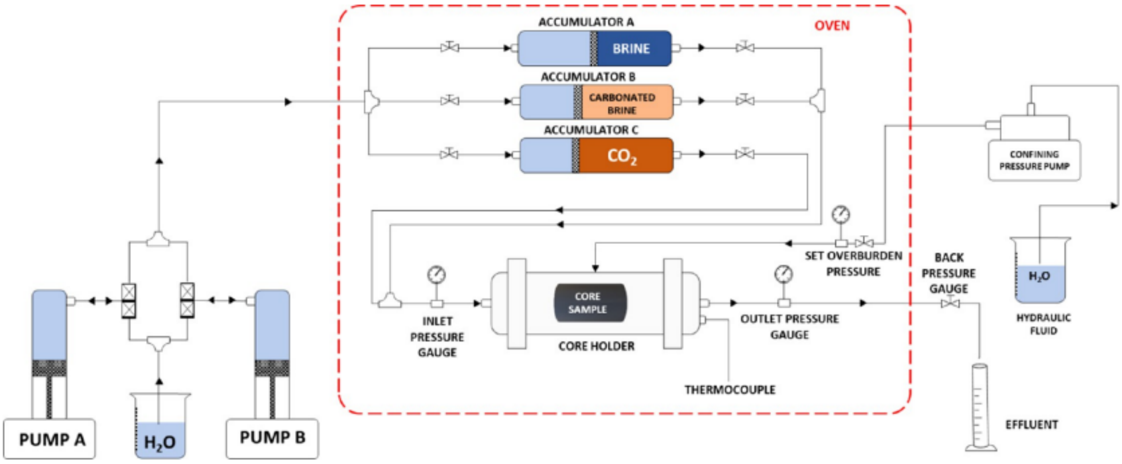

Figure 1. Schematic drawing of the core flooding apparatus[18].

Before testing, cleaned core samples were vacuum-saturated with 200,000 ppm NaCl brine by placing them in a vacuum desiccator at 800 psi for approximately 4 hours and then allowing them to soak overnight to ensure full saturation. Each core was mounted in the core holder and was subjected to a confining pressure of 2,500 psi with a backpressure of 1,650 psi maintained throughout the experimental runs.

The experimental sequence was carried out as follows:

- A 200,000 ppm NaCl brine was prepared, and the initial brine permeability was measured by injecting brine for approximately 3 hours at 0.5 ml/min; permeability was calculated using Darcy’s law.
- Tween 80 was injected at 1,500 ppm and 0.5 ml/min for 24 hours.
- About 3-5 PV of carbonated brine (brine: CO_2, 80:20 v/v) was injected at 0.5 ml/min to simulate convective mixing between CO_2 and brine.
- The saturated core was flooded with supercritical CO_2 at 2 ml/min to displace the aqueous phase, and differential pressure across the core was continuously recorded.
- Final permeability and injectivity were reassessed by injecting brine; stabilization was defined as a steady pressure drop.

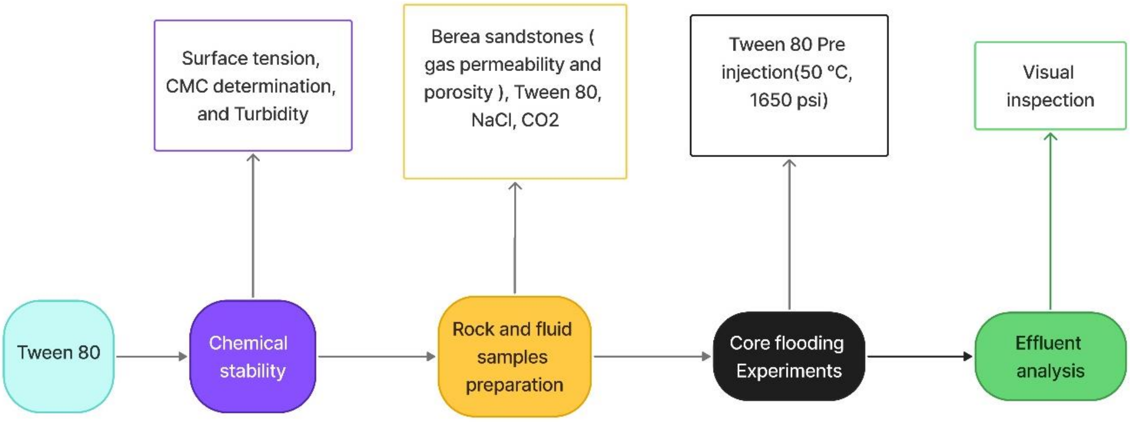

Figure 2. Flowchart of the experiment method.

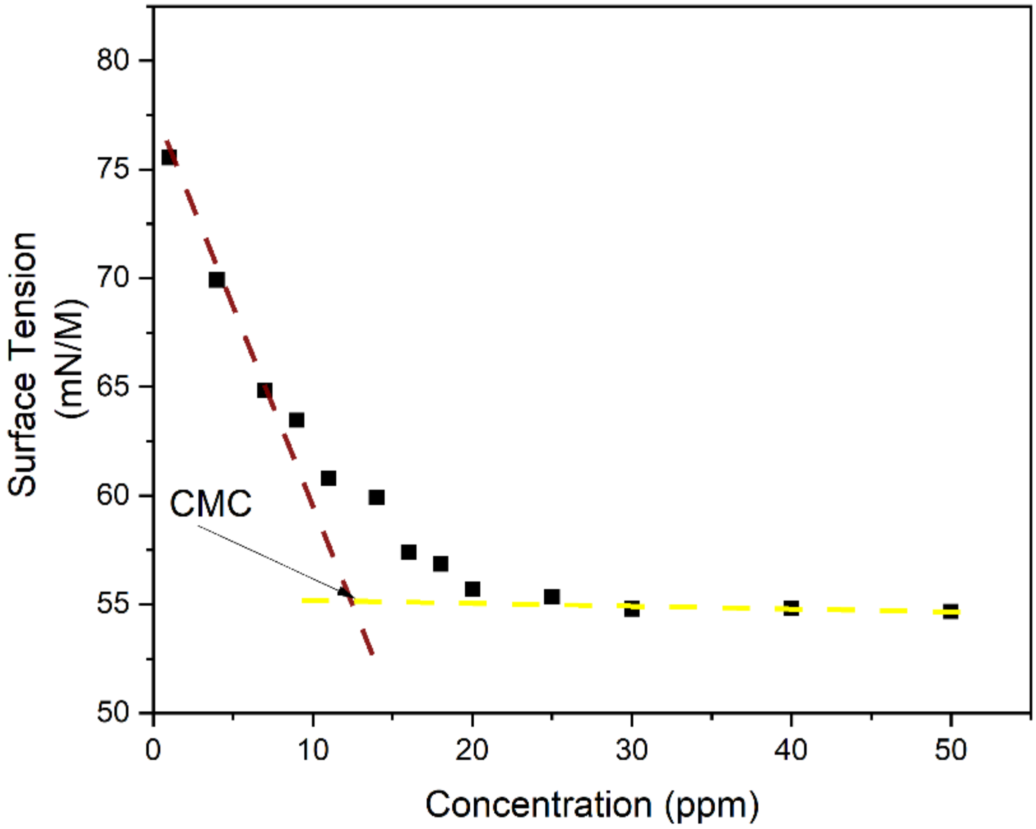

Figure 3. Surface tension profile of Tween as a function of concentration in 200,000 ppm NaCl, showing a distinct breakpoint around 12.6 ppm corresponding to the CMC**.**

RESULTS AND DISCUSSION

Surfactant Stability and CMC in 200,000 ppm Brine

The CMC of Tween-80 in 200,000 ppm NaCl brine was obtained from the surface tension-concentration curve using a two-segment linear regression breakpoint method and was determined as approximately 12.6 ppm at a surface tension of 55.3 mN/m which is clearly shown in Figure 3. Above this concentration, the surface tension decrease became markedly less sensitive to concentration, indicating micelle formation and near-saturation of the interface. This value was found to be generally below the CMC of Tween 80 found in literature when CMC is determined by distilled water [19, 20]. This reduction is attributed to the salting-out effect, where strong ion-water interaction at high ionic strength reduces surfactant solubility and promotes earlier micellization. Thus, the elevated salinity favors micelle formation at much lower surfactant concentrations, consistent with reported trends for nonionic surfactants under high-salinity conditions [21]. The surfactant concentration at 1500 ppm is well above the measured CMC, and Tween-80 is expected to be present predominantly as micelles in bulk solution while still adsorbing at the rock surface to form an interfacial film.

Consequently, turbidity measurements performed at 24 h showed that Tween-80 at 1500 ppm remained optically clear in the 200,000 ppm NaCl brine, with a turbidity value of 0.56 NTU, clearly shown in Figure 4. The absence of cloudiness over the test interval indicates colloidal stability and no macroscopic phase separation or precipitation of the surfactant under the chosen conditions.

Figure 4. Turbidity observation of Tween 80(1500 ppm) in 200000 ppm brine after 24h, showing no visible precipitation or cloudiness, confirming surfactant stability.

Core Flood Sequence, Permeability, and Differential Pressure Response

The influence of salt precipitation inhibition was investigated in one Berea sandstone core sample, with permeability and differential pressure clearly shown in Table. The core sample was initially saturated with 200000 ppm brine by pretreatment with Tween-80 after initial permeability measurement by brine flooding with a value of 311 mD. During the Tween-80 flood the differential pressure reduced, and the inferred permeability rose to 393 mD (+26% of the initial permeability), by producing an interfacial film that (a) increases surface hydrophilicity, (b) provides steric hindrance to particle adhesion, and (c) can reduce capillary resistance together these effects explain the observed increase in permeability immediately after surfactant flooding [22, 23]. After the carbonated water and $scCO_2$ injection, the final brine injection increased the dP and the final permeability dropped to 135.464 mD (44% of the initial permeability), the $scCO_2$ exposure created conditions that promote salt precipitation (local evaporation/film thinning, CO_2-induced vaporization of water in mesoscopic films, and local supersaturation), and the magnitude of salt crystallization overwhelmed the protective film, producing dense halite deposition that reduced permeability to roughly half the original [24]. It is also possible that surfactant action mobilized fines or redistributed salts transiently; these mobilized materials may have re-deposited during CO_2 exposure in locations that caused more effective blockage than before treatment. Thus, the surfactant provided a transient benefit but did not prevent the long-term, CO_2-driven precipitation process under the extreme salinity and experimental sequence used in Figure 5.

Table 1. Differential pressure(dP) and permeability after brine and surfactant injection.

	Initial brine	Nonionic surfactant	Final brine	Permeability/dP reduction
dP	0.231	0.183	0.532	56%
Permeability (mD)	311 ± 10	393 ± 10	136 ± 5	

Figure 5. Inlet section views comparing the core after(left) and before(right) flooding.

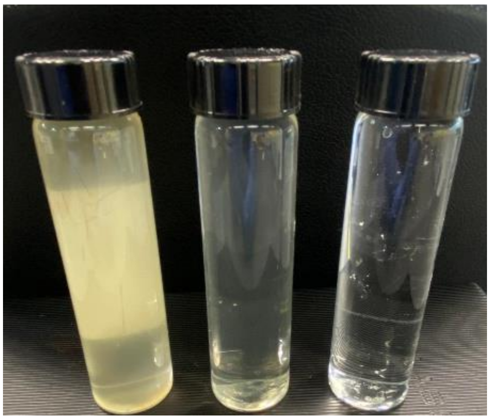

Figure 6. Effluent appearance during the core-flood sequence: initial brine (right), Tween-80 stage (middle), and final brine after $scCO_2$ (left).

Effluent Analysis

During the experiment, the effluent changed colour through the injection sequence: clear during the initial 200,000 ppm brine injection, slightly cloudy during the Tween-80 stage, and cloudier in the final effluent after the final brine injection, as shown in Figure 6. These visual changes indicate evolving chemistry in the pore fluid rather than simple turbidity. Several processes can explain the progression. First, the Tween-80 solution itself and its micelles can impart a pale tint when present in the effluent, especially at high concentrations used: partial desorption and carry-over of surfactant from the core will therefore shift effluent colour from clear to faint yellow [25, 26]. Second, CO_2 interactions lower pH in the aqueous phase and can mobilize rock-bound minerals and fines. Acidified porewater and the changing redox conditions favour the release of iron and other transition metals or of soluble organic fragments from the rock matrix, leading to yellowing of the effluent [27, 28]. Finally, the deeper yellow observed in the final stage is consistent with increased ionic and dissolved species in the effluent following dissolution-reprecipitation cycles [29].

CONCLUSION

Tween-80 was stable at 200000 ppm NaCl, and its CMC in the brine was about 12.6 ppm. The pre-injection of the surfactant allowed for adsorption and micelle formation. The surfactant flood produced a clear short-term benefit, where permeability rose by 26% which shows improved flow capacity during treatment. However, after carbonated water/$scCO_2$ flooding, the core was plugged by salt precipitation, and the final permeability declined to 136 mD, indicating that the pre-injection did not prevent $scCO_2$-driven salt precipitation. The evolution of the effluent color from clear to deep yellow was consistent with surfactant carry-over followed by increased dissolved/colloidal load after $scCO_2$ introduction. These results suggest that while high-concentration Tween-80 can boost early injectivity, it is insufficient by itself to eliminate CO_2-induced salt clogging in very high systems.

ACKNOWLEDGEMENTS

The authors would like to thank Universiti Teknologi PETRONAS (through YUTP-FRG-015LC0-572) for providing support and assistance. The authors state that there is no conflict of interest. The funders had no role in the design of the study, in the collection, analysis, or interpretation of data; in the writing of the manuscript, or in the decision to publish the manuscript.

REFERENCES

1. Tomić, L., Karović-Maričić, V., Danilović, D. and Crnogorac, M. (2018) Criteria for CO2 storage in geological formations, 61–74.

2. Muller, N., Qi, R., Mackie, E., Pruess, K. and Blunt, M. J. (2009) CO2 injection impairment due to halite precipitation. *Energy Procedia*, **1(1)**, 3507–3514.

3. Bacci, G., Korre, A. and Durucan, S. (2011) Experimental investigation into salt precipitation during CO2 injection in saline aquifers. *Energy Procedia*, **4**, 4450–4456.

4. Grude, S., Landrø, M. and Dvorkin, J. (2014) Pressure effects caused by CO2 injection in the Tubåen Fm., the Snøhvit field. *International Journal of Greenhouse Gas Control*, **27**, 178–187.

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

6. Ott, H., de Kloe, K., Marcelis, F. and Makurat, A. (2011) Injection of supercritical CO2 in brine saturated sandstone: Pattern formation during salt precipitation. *Energy Procedia*, **4**, 4425–4432.

7. Peysson, Y., André, L. and Azaroual, M. (2014) Well injectivity during CO2 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.

8. Sokama-Neuyam, Y. A. and Ursin, J. R. (2016) Experimental and theoretical investigations of CO2 injectivity, AGH Drilling, Oil, Gas, **33(2)**, 2299–3017.

9. Darkwah-Owusu, V., Yusof, M. A. M., Sokama-Neuyam, Y. A., Tackie-Otoo, B. N., Turkson, J. N., Radzali, I. B., Yusof, S. R. B. M. and Fjelde, I. (2024) Experimental Investigation of the Impact of Low Salinity Water and Hydrochloric Acid Solutions as Halite Precipitation Reduction Agents for Enhancing CO2 Injectivity in Deep Saline Aquifers. In *Offshore Technology Conference Asia*, 34798.

10. Darkwah-Owusu, V., Md Yusof, M. A., Sokama-Neuyam, Y. A., Tackie-Otoo, B. N., Turkson, J. N., Kwon, S., Hyun, L. J. and Fjelde, I. (2024) Investigating the Extent of the Impact of Acetic Acid as Halite Precipitation Reduction Agent for Enhancing CO2 Injectivity in Deep Saline Aquifers. In *SPE International Conference and Exhibition on Formation Damage Control*, 217884.

11. Md Yusof, M. A., Mohamed, M. A., Md Akhir, N. A., Ibrahim, M. A. and Mardhatillah, M. K. (2021) Combined Impact of Salt Precipitation and Fines Migration on CO2 Injectivity Impairment. *International Journal of Greenhouse Gas Control*, **110**, 103422.

12. Miri, R. (2015) Effects of CO2-Brine-Rock Interactions on CO2 Injectivity–Implications for CCS, University of Oslo.

13. He, D., Zhang, M., Wang, Z., Chen, S. and Yuan, H. (2025) Strategies for Preventing Salt Precipitation and Blockage Risks in CO2 Injection Wells: Pore-Scale Experimental Insights. *Energy & Fuels*, **39(6)**, 3176–3187.

14. Papi, A., Jahanbakhsh, A. and Maroto-Valer, M. M. (2025) Preventing Salt Precipitation in CO2 Storage Processes in Saline Aquifers: Dissolved-Water CO2 Injection Method. *Energy & Fuels*, **39(8)**, 3926–3941.

15. Sagir, M., Mushtaq, M., Tahir, M. S., Tahir, M. B. and Shaik, A. R. (2020) Surfactants for enhanced oil recovery applications. *Springer*.

16. Al-Qasim, A., Al-Anazi, A., Omar, A. B. and Ghamdi, M. (2018) Asphaltene Precipitation: A Review on Remediation Techniques and Prevention Strategies. In *Abu Dhabi International Petroleum Exhibition & Conference*, 192784.

17. Subramanian, D. and Firoozabadi, A. (2015) Effect of Surfactants and Water on Inhibition of Asphaltene Precipitation and Deposition. In *Abu Dhabi International Petroleum Exhibition and Conference*, 177669.

18. Darkwah-Owusu, V., Md Yusof, M. A., Sokama-Neuyam, Y. A., Turkson, J. N. and Fjelde, I. (2024) Assessment of Advanced Remediation Techniques for Enhanced CO2 Injectivity: Laboratory Investigations and Implications for Improved

CO2 Flow in Saline Aquifers. *Energy & Fuels*, **38(10)**, 8895–8908.

19. Ramly, N. H., Zakaria, R. and Naim, M. N. (2017) Surfactant-assisted aqueous extraction of palm-pressed mesocarp fiber residual oil with Tween 80 solution. *Separation Science and Technology*, **52(11)**, 1796–1805.

20. Tiwari, S., Mall, C. and Solanki, P. P. (2020) CMC studies of CTAB, SLS & tween 80 by spectral and conductivity methodology to explore its potential in photogalvanic cell. *Surfaces and Interfaces*, **18**, 100427.

21. Hartyányi, M., Nagy, R., Bejczi, R., Bartha, L. and Puskás, S. (2025) The Impact of Salt Concentration on the Screening of Surfactant Packages for EOR Applications. *Energy Science & Engineering*, **13(6)**, 3296–3306.

22. Lin, S., Yuanyuan, T. and Wanfen, P. (2013) Study on the influence factors of surfactant flooding in high-temperature low-permeability reservoir. *Oilfield Chemistry*, **30(2)**, 216–220.

23. Zhang, W., Hou, J., Liu, Y., Cao, W., Zhou, K. and Du, Q. (2022) Effect of interfacial tension on relative permeability curves obtained by considering surfactant adsorption and diffusion. *Journal of Energy Resources Technology*, **144(12)**, 123006.

24. Miri, R., van Noort, R., Aagaard, P. and 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.

25. Knoch, H., Ulbrich, M. H., Mittag, J. J., Buske, J., Garidel, P., and Heerklotz, H. (2021) Complex Micellization Behavior of the Polysorbates Tween 20 and Tween 80. *Molecular Pharmaceutics*, **18(8)**, 3147–3157.

26. Azeez, M. A., Ali, I. H. and Kareem, S. H. (2022) Study of Micellar Behavior of a Tween 80 Surfactant in Aqueous Media Containing Diphenhydramine Hydrochloride. *Iraqi Journal of Science*, 3276–3282.

27. Sokama-Neuyam, Y. A., Forsetløkken, S. L., Lien, J. -E. and Ursin, J. R. (2017) The Coupled Effect of Fines Mobilization and Salt Precipitation on CO2 Injectivity. *Energies*, **10(8)**, 1996–1073.

28. Xie, Q., Saeedi, A., Delle Piane, C., Esteban, L. and Brady, P. V. (2017) Fines migration during CO2 injection: Experimental results interpreted using surface forces. *International Journal of Greenhouse Gas Control*, **65**, 32–39.

29. Fuchs, S. J., Espinoza, D. N., Lopano, C. L., Akono, A. -T. and Werth, C. J. (2019) Geochemical and geomechanical alteration of siliciclastic reservoir rock by supercritical CO2-saturated brine formed during geological carbon sequestration. *International Journal of Greenhouse Gas Control*, **88**, 251–260.