

Article

Nano-Water-Alternating-Gas Simulation Study Considering Rock–Fluid Interaction in Heterogeneous Carbonate Reservoirs [†]

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Abstract: In carbonate reservoirs, nanoparticles can adhere to rock surfaces, potentially altering the rock wettability and modifying the absolute permeability. In the water-alternating-gas (WAG) process, the introduction of nanoparticles into the water phase, termed nano-water-alternating gas (NWAG), is a promising approach for enhancing oil recovery and CO₂ storage. The NWAG process can alter rock wettability and absolute permeability through the adsorption of nanoparticles on the rock surface. This study investigated the efficiency of the NWAG method, which utilizes nanofluids in CO₂-enhanced oil recovery (EOR) processes to simultaneously recover oil and store CO₂ using 1D core and 3D heterogeneous reservoir models. The simulation results of the 1D core model showed that applying the NWAG method enhanced both oil recovery and CO₂ storage efficiency by increasing to 3%. In a 3D reservoir model, a Dykstra–Parsons coefficient of 0.4 was selected to represent reservoir heterogeneity. Additionally, the capillary trapping of CO₂ during WAG injection was computed using Larsen and Skauge’s three-phase relative permeability hysteresis model. A sensitivity analysis was performed using the NWAG ratio, slug size, injection period, injection cycle, and nanofluid concentration. The results confirmed an increase of 0.8% in oil recovery and 15.2% in CO₂ storage compared with the conventional WAG process. This mechanism suggests that nanofluids can enhance oil recovery and expand CO₂ storage, improving the efficiency of both the oil production rate and CO₂ storage compared to conventional WAG methods.

Keywords: NWAG; rock–fluid interaction; carbonate reservoirs; SiO₂ nanoparticles



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1. Introduction

To effectively implement the water-alternating-gas (WAG) method, various factors such as the volume of water and gas injected, timing of injections, and well management must be carefully considered [1,2]. Effective parameters play a crucial role in influencing oil recovery such as decreased miscibility pressure. Although CO₂ injection causes gas segregation and viscous fingering, increasing the dissolved CO₂ content in water can enhance CO₂ storage capabilities. The injected CO₂ tends to accumulate near the top of the reservoir, whereas water and oil predominantly flow near the bottom, particularly in larger reservoirs with significant vertical heterogeneity. Differences in density between gas and water/oil, influenced by reservoir conditions such as temperature, pressure, and gas type, exacerbate gas segregation, potentially impacting CO₂ storage outcomes. CO₂-WAG is a method for enhanced oil recovery (EOR), designed to capture and store CO₂ generated from industrial processes or produced underground. This technique involves alternately

injecting water and CO₂, which improves solubility, residual oil recovery, and CO₂ storage efficiency [3,4].

Research aimed to optimize the efficiency of CO₂-WAG has led to the development of nano-water-alternating gas (NWAG), representing a considerable advancement. Jia et al. [5] reported that NWAG, which uses nanofluids, enhances oil recovery efficiency by addressing the viscosity concerns typical of conventional CO₂-WAG methods. Nanoparticles incorporated into the fluids modify the interfacial tension with oil, alter the contact angles with rock surfaces, shift endpoint saturations in relative permeability, and enhance oil recovery [6]. Furthermore, nanoparticles contribute to the management of CO₂ solubility, control of its flow dynamics, and optimization of its structural integrity, thereby enhancing the initial CO₂ injection and storage capacities. Typically, carbonate reservoirs exhibit characteristics such as heterogeneous rock properties and oil-wet conditions due to their geological features. Figure 1 shows the change in oil recovery due to wettability alteration. A nanofluid injected into an oil-wet reservoir creates a disjoining pressure through spreading forces and interfacial tension reduction that cause wettability alteration [7,8]. Consequently, the critical water saturation increases and the residual oil saturation decreases. Thus, wettability alteration increases the oil recovery. These effects were efficient on a carbonate reservoir, because it has a characteristic oil-wet rock surface. Therefore, the NWAG process is expected to increase oil recovery when applied to carbonate reservoirs.

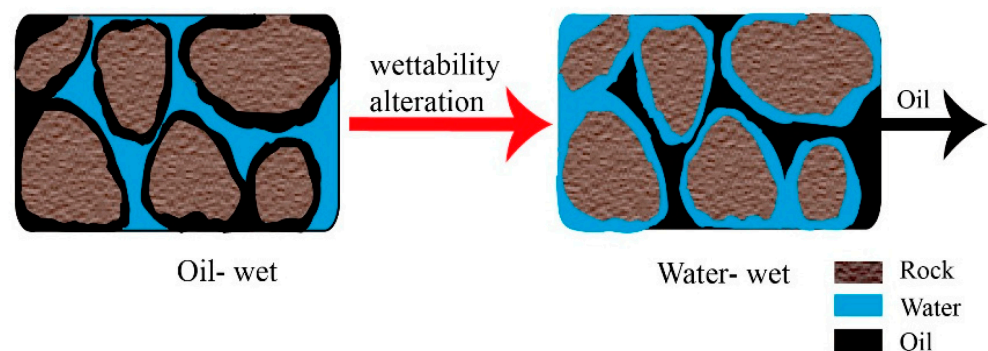


Figure 1. Effect of wettability alteration on oil recovery [7].

The WAG method has been widely implemented across different fields, including in Wasson in the USA, Rumaith in the UAE, and Weyburn in Canada [9]. When a simulation study of the WAG method is conducted, types of reservoirs rock should be considered. Modeling for a carbonate reservoir typically formed oil-wet rock surface and heterogeneous characteristics such as variable permeability and porosity, unlike clastic rock reservoirs. The optimum conditions for achieving the highest oil recovery in sandstone reservoirs involve a WAG ratio of 2:1, as determined through reservoir simulations [10]. Abdurrahman et al. [11] conducted reservoir simulations of the CO₂-WAG process in the Sumatera oil field in Indonesia and found that the effectiveness of the CO₂-WAG process depended significantly on the chosen WAG ratio, as shown in Figure 2. Lower-viscosity oil can improve the oil production rate but reduces CO₂ storage. In summary, although WAG has demonstrated success in enhancing oil recovery and CO₂ storage efficiency in various reservoir types, its application must consider specific reservoir conditions and challenges, such as rock wettability and crude oil properties.

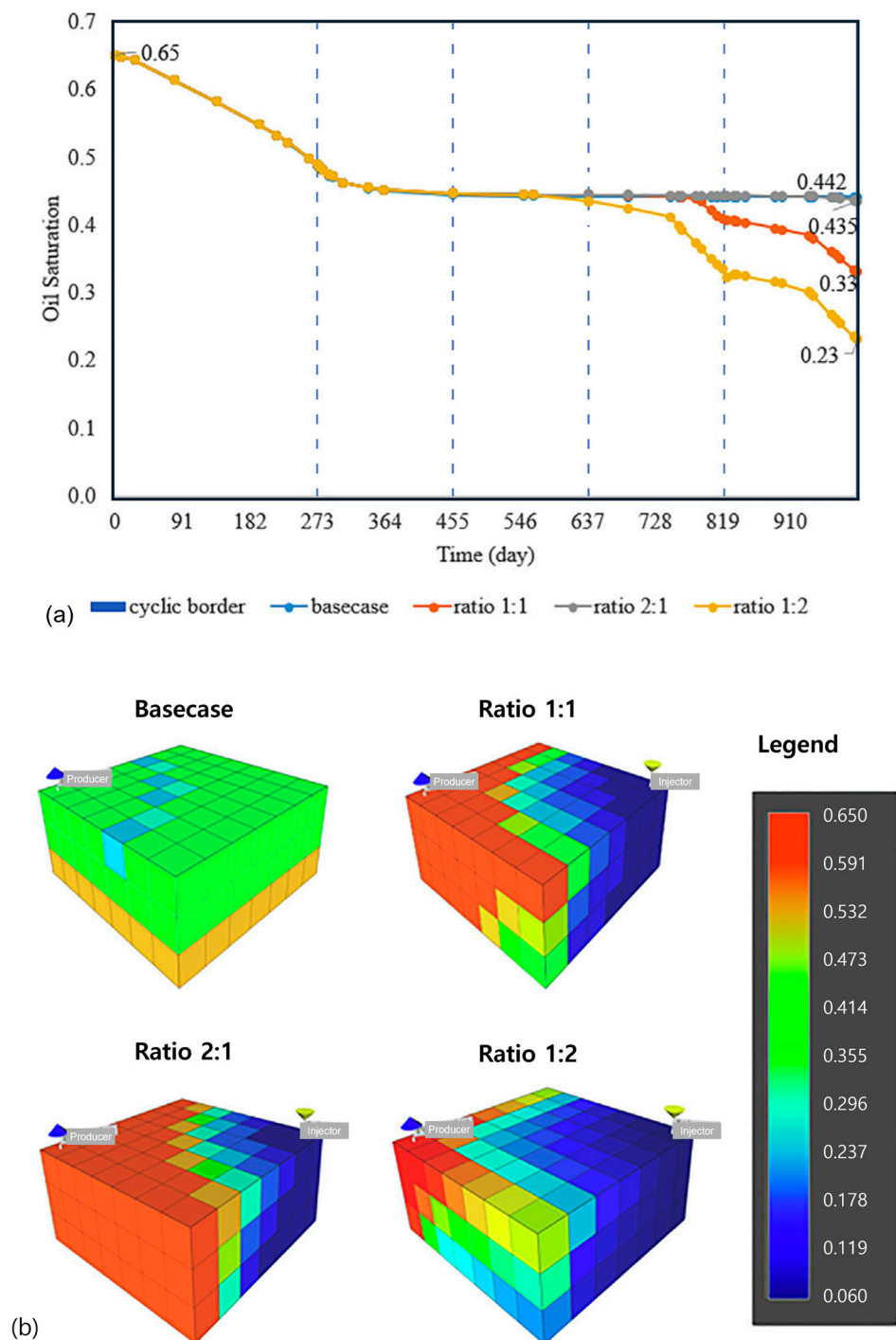


Figure 2. Effects of oil saturation by WAG ratio: (a) comparison of oil saturation by WAG ratio in the graph, (b) comparison of oil saturation by WAG ratio using 3-D models [12], Materials Today: Proceedings; published by Elsevier in 2021.

Matroushi et al. [12] conducted a simulation to compare the WAG and NWAG methods. The NWAG involved a ratio of 2:1 and injection of a nanofluid containing a 0.63% hydrocarbon pore volume (HCPV) and 0.32% HCPV CO₂ over a six-month cycle. The results indicated that the NWAG method maintains higher oil production levels than the WAG method, as shown in Figure 3. Øyvind Eide et al. investigated the stability of nanoparticles in CO₂-EOR with nanoparticles under challenging reservoir conditions, in that the stability of nanoparticles considering chemical reactions and pH changes under high-temperature and high-salinity conditions of carbonate reservoirs. They also reported

that nanoparticles affected the viscosity of the injected fluid and oil recovery [13]. Additionally, Cao et al. [14] experimentally compared the oil recovery between waterflooding and nanofluid flooding and demonstrated that nanofluid flooding achieved higher oil recovery rates and accelerated recovery than waterflooding.

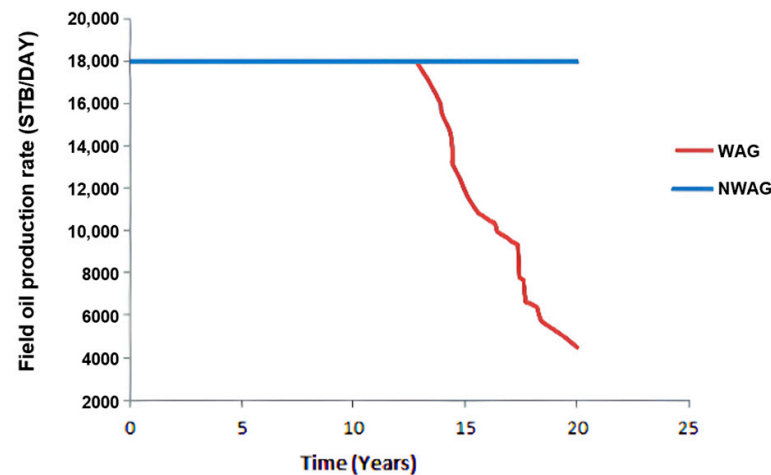


Figure 3. Comparison of oil production rate for WAG and NWAG methods [12], Abu Dhabi International Petroleum Exhibition and Conference; published by Society of Petroleum.

This study proposes a method to simultaneously enhance oil recovery and CO₂ storage using the NWAG technique. By utilizing the NWAG method, the wettability of the rock can be improved, and the solubility between fluids can be enhanced, maximizing both oil recovery and CO₂ storage. The 1D and 3D models were constructed using CMG's commercial simulator to compare and analyze the efficiency of the CO₂-WAG and NWAG methods. In a 1D core model, the applicability of the NWAG method in both oil recovery and CO₂ storage was studied. In the case of a 3D reservoir model, various scenarios of NWAG were compared and analyzed for oil recovery and CO₂ storage by setting the NWAG ratio, slug size, and nanoparticle concentration. Additionally, to more accurately understand the changes occurring during the actual operation process, a model reflecting heterogeneity and hysteresis was constructed. From the constructed model, operational parameters for maximizing the efficiency of the NWAG method were derived, and the oil recovery and CO₂ storage efficiency were compared and analyzed.

2. Simulation Model

2.1. Fluid Modeling

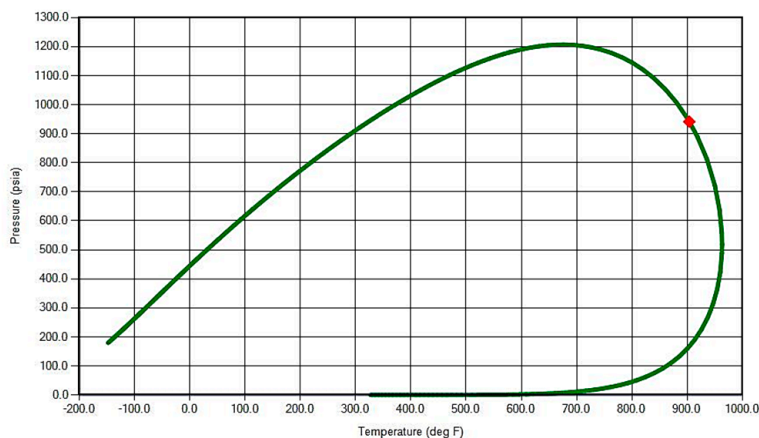
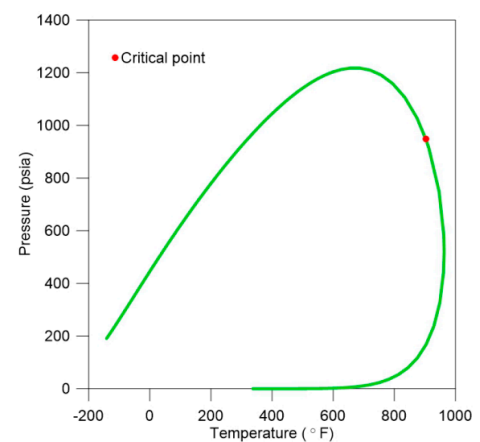
The fluid properties were modeled using W3 oil from the Weyburn oil field located in Saskatchewan in Canada, by applying waterflooding production and CO₂-WAG processes. For the EOR, CO₂ was purchased from the North Dakota Gasification Plant and transported by a gas pipeline [15]. Table 1 lists the fluid model using the Peng–Robinson equation of state (PR-EOS) to calculate the Weyburn W3 components and compositions. The PR-EOS was used to calculate the critical pressure and temperature of the oil. The fluid model was examined in a comparison between the fluid model and Weyburn W3 parameters including the American Petroleum Institute (API) and saturation pressure in Table 2. The phase behavior was compared with that reported in a previous study, as shown in Figure 4. Based on these results, the fluid model generated in this study is similar to that of Weyburn W3 [16,17].

Table 1. Components and composition of Weyburn W3 fluid [16].

Component	Mole Fraction	Molecular Weight	Critical Pressure (Atm)	Critical Temperature (K)	Parachor	Acentric Factor
N ₂	2.07	28.01	33.5	126.2	41	0.040
CO ₂	0.74	44.01	72.8	304.2	78	0.225
H ₂ S	0.12	34.08	88.2	373.2	80	0.100
CH ₄	7.49	16.04	45.4	190.6	77	0.008
C ₂ H ₆	4.22	30.07	48.2	305.4	108	0.098
C ₃ H ₈	7.85	44.10	41.9	369.8	150	0.152
NC ₄	6.55	58.12	37.5	425.2	186	0.193
NC ₅	4.59	72.15	33.3	469.6	228	0.251
C ₆₋₉	21.55	102.50	29.8	556.4	297	0.331
C ₁₀₋₁₇	22.02	184.00	19.9	692.3	508	0.584

Table 2. The comparison of the data for Weyburn fluid and the fluid model.

Parameters	W3	Fluid Model in This Study
API (°)	31	29.3
Saturation pressure (psi)	714	700
Oil density at P _c (kg/m ³)	806.4	816

**(a)****(b)****Figure 4.** Comparison of PVT graph of fluid model and that reported in previous study: (a) fluid model in this study and (b) Weyburn field model [17].

2.2. Description of a 1D Core Model

A 1D core simulation model incorporating nanoparticle flow was constructed with dimensions of $50 \times 1 \times 1$, a horizontal length of approximately 10 cm, porosity of 18%, and permeability of 50.0 md, as listed in Table 3. Simulations were conducted using CMG-GEM and CMOST. While CMG-GEM did not include nanoparticle adsorption, variations in oil recovery were observed for different WAG ratios and slug sizes. The CMOST module was used to consider rock–fluid interactions by nanoparticle adsorption, resulting in oil residual saturation shifting in relative permeability curves and permeability reduction by pore plugging. Optimizing the nanoparticle adsorption process was performed by randomly setting the nanofluid concentration in 20 cases from 0 to 1 wt.% and adjusting wettability changes with nanoparticle input, thereby influencing the endpoint of relative permeability and absolute permeability.

Table 3. The description of the 1D core model.

Parameters	Values
Number of grid blocks	50(I) × 1(J) × 1(K)
Length	10 cm
Diameter	3.14 cm
Porosity	0.18
Permeability	50.0 md
Rock compressibility	5.8×10^{-7} 1/kPa
Pressure	17,340 kPa
Temperature	85.6 °C
Bulk volume	77.3 cm ³
Pore volume	13.9 cm ³
Initial oil saturation	0.7
Original oil in place (OOIP)	6.13×10^{-5} bbl

2.3. Description of a 3D Core Model

In the results from the 1D core model, improved oil recovery and CO₂ storage were observed using both the WAG and NWAG methods. However, hysteresis effects were not considered, and CMG-GEM was used without incorporating nanoparticle adsorption. CMG-STARs was used to simulate a 3D reservoir model that included nanoparticle adsorption. This model incorporates the hysteresis effects of relative permeability and was designed to consider oil-wet conditions and heterogeneity specific to carbonate reservoirs. The 3D model was based on the properties of the Weyburn Reservoir, where the CO₂-WAG operations are ongoing, as detailed in Table 4. The simulation scenario included pre-waterflooding for one year, followed by five years of NWAG, and concluded with one year of post-waterflooding. The CO₂ dissolution changed by nanoparticle injection was not included in the model, as the monitoring period of six years was relatively short for solubility trapping to occur. In this study, to determine the optimal operating conditions for NWAG, the effective parameters selected were the WAG ratio, slug size, and nanoparticle concentration.

Table 4. The description of the 3D reservoir model.

Parameters	Values
Number of grids	21(I) × 21(J) × 5(K)
Thickness	50 m
WOC depth	1050 m
Reference pressure	15,000 kPa
Grid top	1000 m
Porosity	21.9–28%
Permeability	31–75 md
Pressure	15 MPa
Temperature	37 °C
Initial oil saturation	0.8

The NWAG simulation is a complex system, because it comprises incompressible and three phase fluids consisting of oil, water, and CO₂. The governing equations used the mass/molar balance and Darcy's equations. Neglecting the dispersion between the phase and gravity effects and applying Darcy's equation, the following can be obtained:

$$\nabla \cdot \left(\frac{\rho_o K k_{ro}}{\mu_o} \frac{\partial p_o}{\partial x} \right) + q_o = \frac{\partial}{\partial t} (\phi \rho_o s_o) \quad (1)$$

$$\nabla \cdot \left(\frac{\rho_g K k_{rg}}{\mu_g} \frac{\partial p_g}{\partial x} \right) + q_g = \frac{\partial}{\partial t} (\phi \rho_g s_g) \quad (2)$$

$$\nabla \cdot \left(\frac{\rho_w K k_{rw}}{\mu_w} \frac{\partial p_w}{\partial x} \right) + q_w = \frac{\partial}{\partial t} (\phi \rho_w s_w) \quad (3)$$

where the subscripts o , g , and w denote the oil, gas, and water phases, respectively; ρ is the density; K and k_r are absolute permeability and relative permeability, respectively; and μ is the fluid viscosity. q is the production or injection rate; t is the injection period; and x is the spatial location. ϕ and s are the rock porosity and saturation, respectively [18].

To account for the heterogeneity commonly observed in carbonate reservoirs, we targeted a Dykstra–Parsons coefficient of 0.4, based on well data. The porosity was randomly generated using a Gaussian geological simulation. The permeability, which was calculated using porosity of each grid block, ranged from 31 to 75 md, effectively capturing the heterogeneity of the carbonate rock, as illustrated in Figure 5. Because the WAG method involves the alternating injection of water and CO₂, considering the behavior of the relative permeability is crucial. During the drainage and imbibition processes, the fluid often does not reach complete residual conditions, necessitating a correction for relative fluid permeability using residual gas saturation. To address this issue, we applied the Carlson method, based on Land's theory [19]. The critical gas saturation was set to 0.3.

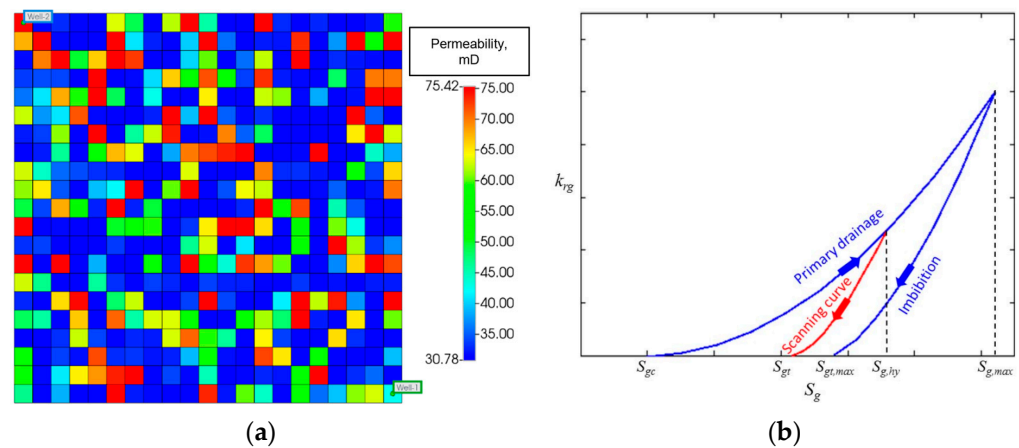


Figure 5. Three-dimensional reservoir model and Larsen and Skauge's three-phase relative permeability hysteresis model: (a) heterogeneity of permeability and (b) hysteresis effect of relative permeability [20].

To incorporate the adsorption phenomenon of the nanoparticles, we employed the Langmuir adsorption isotherm to determine the adsorption amount based on the derived mole fraction. The maximum adsorption capacity was set at 2.5 gmol/m³, with a residual adsorption value of 1 gmol/m³. Furthermore, as the wettability of the rock changed from an initial state of no adsorption to maximum adsorption, a relative permeability model adjusted for nanoparticle adsorption was designed, as shown in Figure 6. To implement the NWAG method effectively, we selected the NWAG ratio, slug size, and nanoparticle concentration based on the parameters listed in Table 5. The method was then performed accordingly. Additionally, we analyzed the efficiency of the NWAG method by focusing on the oil recovery rates and subsurface storage capacity of CO₂.

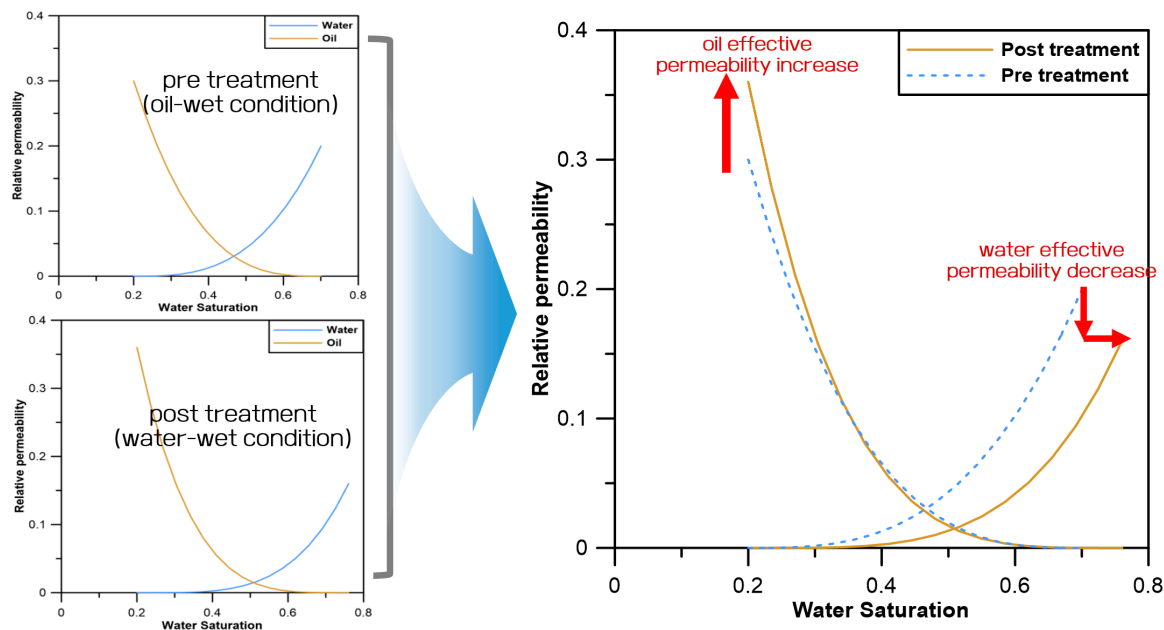


Figure 6. Shifting of oil–water relative permeability owing to nanoparticle adsorption.

Table 5. NWAG design for sensitivity analysis of oil recovery and CO₂ storage.

NWAG Ratio	Slug Size	Nanoparticle Conc. (wt.%)
1:3	0.1 HCPV	0.001
1:2		0.005
1:1	0.2 HCPV	0.01
2:1		0.02
3:1	0.3 HCPV	0.03

3. Results and Discussion

3.1. Results of 1D Simulations

From Figure 7, it is evident that nanofluids can enhance oil recovery and increase CO₂ storage, leading to an improvement of over 5% in both oil production and CO₂ storage compared to that in the conventional WAG process. The lowest oil recovery was achieved at a WAG ratio of 3:1, whereas the highest (81.86%) was observed at a WAG ratio of 1:1. An oil recovery of 84.23% was noted for a slug size of 0.02 PV in the 1:1 WAG ratio simulation.

CMOST was used to simulate the impact of the nanoparticle concentration on oil recovery. The effect of the wettability alteration by the implemented nanoparticle concentration shifted the critical gas saturation. As a result, oil-wet reservoirs were altered to water-wet reservoirs by applying a nanofluid, resulting in a 5% improvement in oil recovery at the nanofluid concentration of 0.85 wt.% compared with that in conventional WAG. These

results confirm that a nanoparticle concentration increase results in a change in the relative permeability endpoint, thus improving oil recovery.

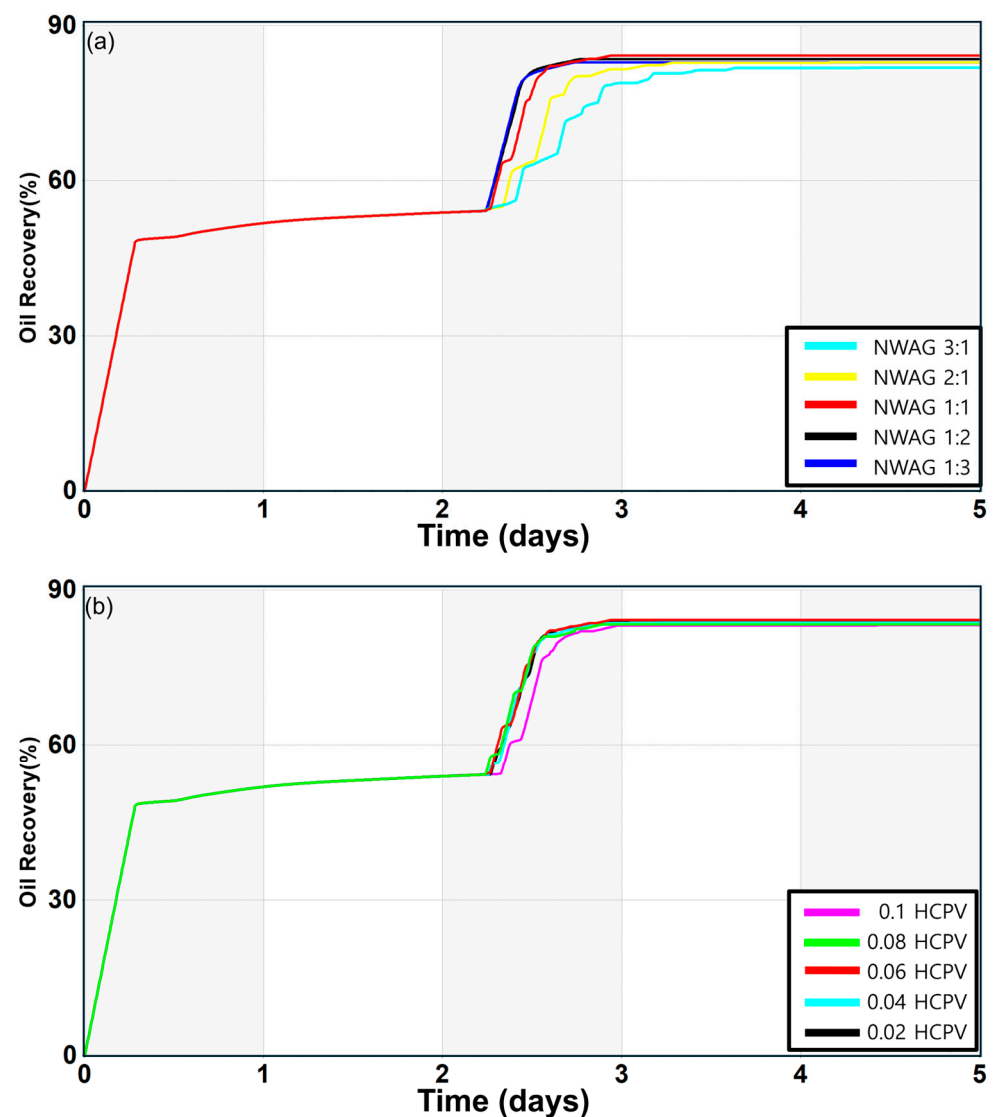


Figure 7. Comparison of oil recovery factor of 1D core model with NWAG method: (a) WAG ratio; (b) slug size.

This study confirmed that controlling the WAG ratio, slug size, and nanoparticle concentration influences oil recovery. However, the simulation was conducted on a 1D core model that did not consider the inherent heterogeneity and hysteresis effects of carbonate rocks or nanoparticle adsorption on reservoir particles. Therefore, subsequent simulations were performed on a 3D model incorporating the unique heterogeneity and hysteresis effects of carbonate rocks.

3.2. Results of 3D Simulations

Figure 8 illustrates the relative gas permeability and gas saturation in the central grid block at (11, 11, 3) during NWAG. These parameters remained unchanged during the water-flooding. However, during NWAG, the maximum points alter relative gas permeability and gas saturation. Consequently, these variations result in subtle changes in the relative fluid permeability of the gas. In addition, the hysteresis effects impact the residual saturation of CO₂, indicating that maximum points may affect the subsurface storage capacity of CO₂ in the context of the NWAG method.

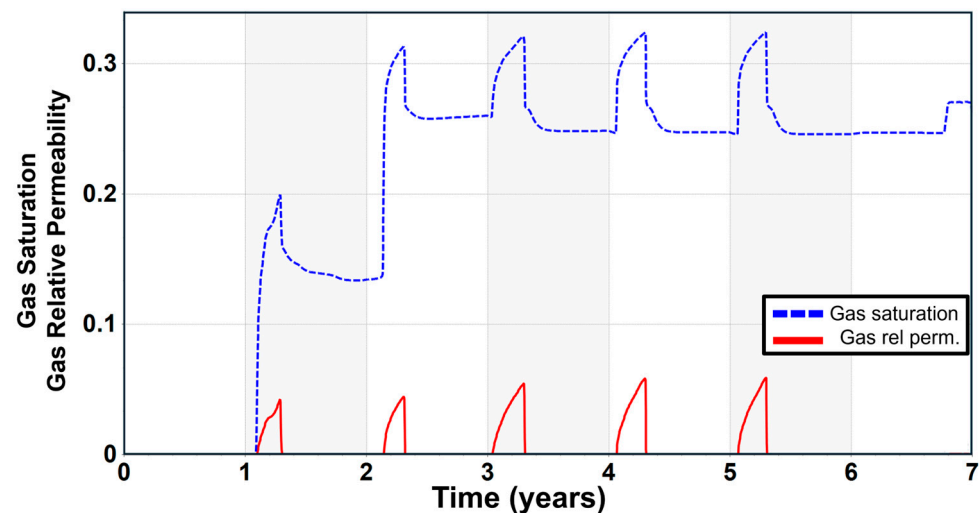


Figure 8. Mole fraction of CO₂, gas relative permeability, and gas saturation in (11, 11, 3) grid block (center point of 3D reservoir model).

Figure 9 shows the adsorption capacity of SiO₂ nanoparticles within the reservoir. Figure 9a illustrates the distribution of SiO₂ injection, highlighting the high levels of nanoparticle adsorption concentrated around the injection well. Figure 9b displays the adsorption capacity of SiO₂ nanoparticles following waterflooding, showing residual adsorption across most grid blocks. Based on the adsorption data, changes in the wettability were observed, which led to potential shifts in the relative fluid permeability. These shifts contribute to reduce the residual oil saturation, thereby enhancing additional oil recovery. Furthermore, the results indicate an increase in the saturation of water and gas, while excluding oil, thereby supporting the increase in the CO₂ storage capacity, as previously discussed.

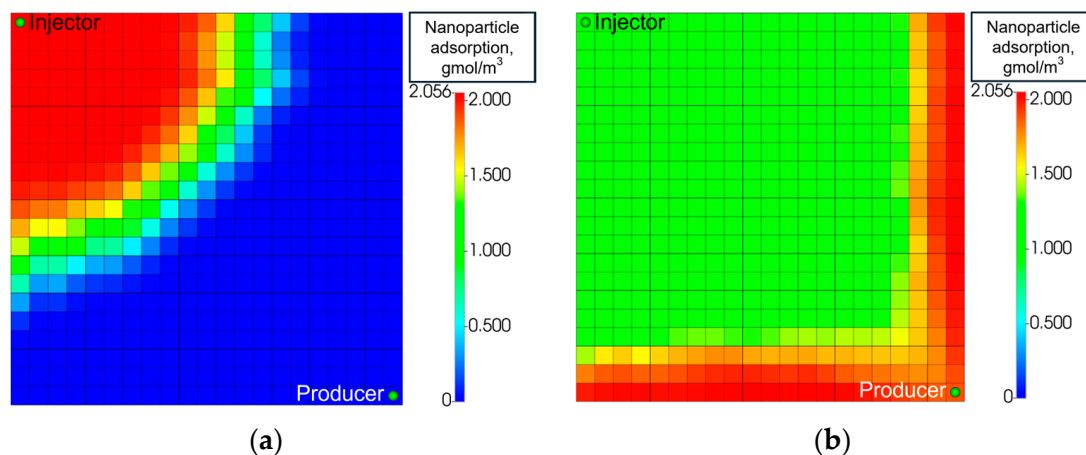


Figure 9. Amount of nanoparticle adsorption on rock surface: (a) during SiO₂-waterflooding period; (b) after post-waterflooding period.

3.2.1. Results of Oil Recovery by NWAG

In the NWAG simulation, the effect of the WAG ratio, slug size, and nanoparticle concentration were examined sequentially. The WAG ratio had the greatest impact on oil recovery compared to the other factors, followed by slug size and nanoparticle concentration, based on previous studies [10–12]. These were adjusted in a specified order, and the scenario producing the best outcome was selected as the base case for a further analysis. Figure 10 shows the oil production and recovery rates relative to the NWAG ratio. The findings show the alternating injection of CO₂ and nanofluids after one year of water

injection, followed by post-waterflooding once the cycle was completed. Initially, a high production rate was sustained; however, it decreased after the water injection stopped. Subsequently, the NWAG implementation resulted in increased oil production, leading to a higher cumulative oil yield. The timing of SiO₂ injection, based on the NWAG ratio, influences the point at which oil production increases, and this timing difference affects the final recovery rate. At an NWAG ratio of 3:1, the oil recovery rate peaked at 71.53%, which is approximately five percentage points higher than the lowest value of 66.7% at a ratio of 1:2. These results demonstrated the effect of the NWAG ratio on oil recovery.

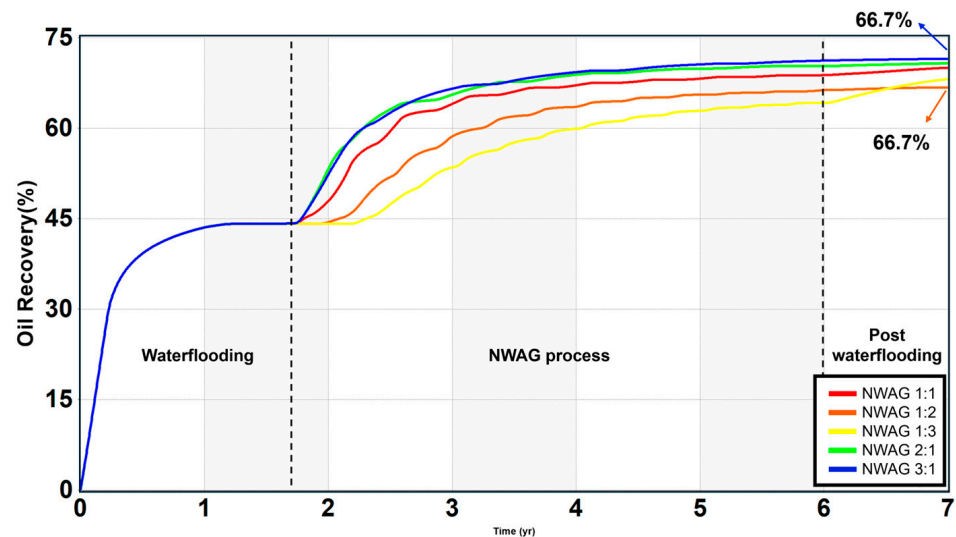


Figure 10. Production performance during the NWAG processes with different WAG ratios.

Simulations were conducted using an NWAG ratio of 3:1, and the size of the slug was varied; results are illustrated in Figure 11. Different outcomes were explored by varying the CO₂ ratio from 0.1 to 0.3 HCPV. After the injection phase, the oil recovery rate reached its peak at 71.85% with a slug size of 0.2 HCPV. However, a slug size of 0.1 HCPV was selected based on the superior initial production rate, resulting in the recovery rate of 71.53%. This suggests that, regardless of the CO₂ injection volume, a higher SiO₂ fluid injection effectively enhances the oil recovery rates. This can be attributed to the improvements in rock wettability and fluid mobility resulting from nanofluid injection properties.

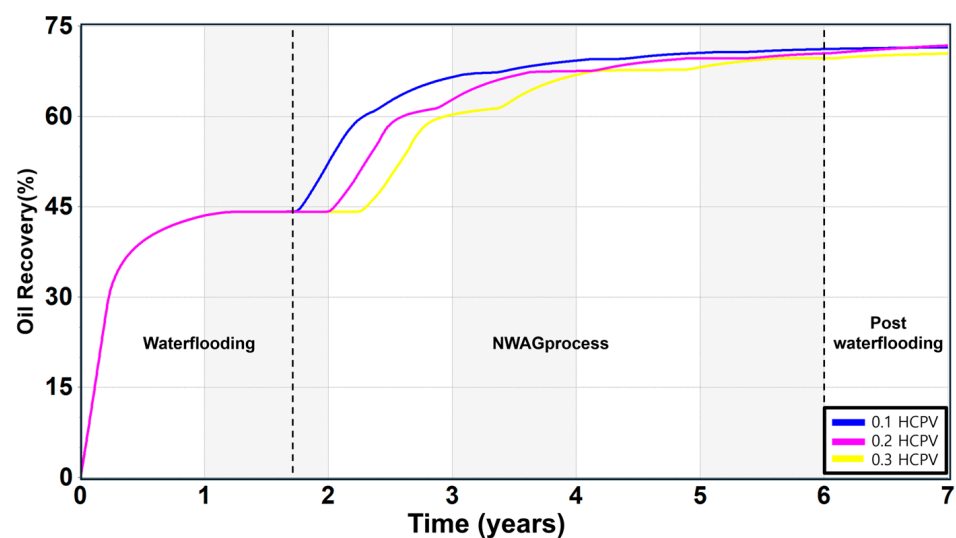


Figure 11. Production performance during the NWAG process with different slug sizes.

Figure 12 shows the simulations conducted with an NWAG ratio of 3:1, utilizing a constant slug size of 0.1 and varying nanoparticle concentrations. The greatest increase in the initial production occurred at a nanoparticle concentration of 0.03 wt.%. In the early stage of simulation, higher nanoparticle concentrations cause increased oil production rates because the effect of nanoparticle adsorption on rock surfaces is more active than lower nanoparticle concentration. Over time, similar or comparable recovery rates were consistently observed. Because during the NWAG processes, nanoparticle adsorption attained maximum capacity, oil recovery at the end of simulation is therefore similar in each simulation. Therefore, in the later stages of the process, marginally better oil recovery was observed at lower nanoparticle concentrations. Despite the slower onset of oil recovery effects at lower concentrations owing to adsorption dynamics, these concentrations, which are characterized by a relatively low density, suggest an expanded adsorption area within the reservoir. Even in scenarios where the initial oil recovery rates are favorable, assessing the economic implications of increasing nanoparticle concentrations is crucial. Therefore, further economic evaluations are necessary to facilitate informed decisions regarding factors such as nanoparticle concentration.

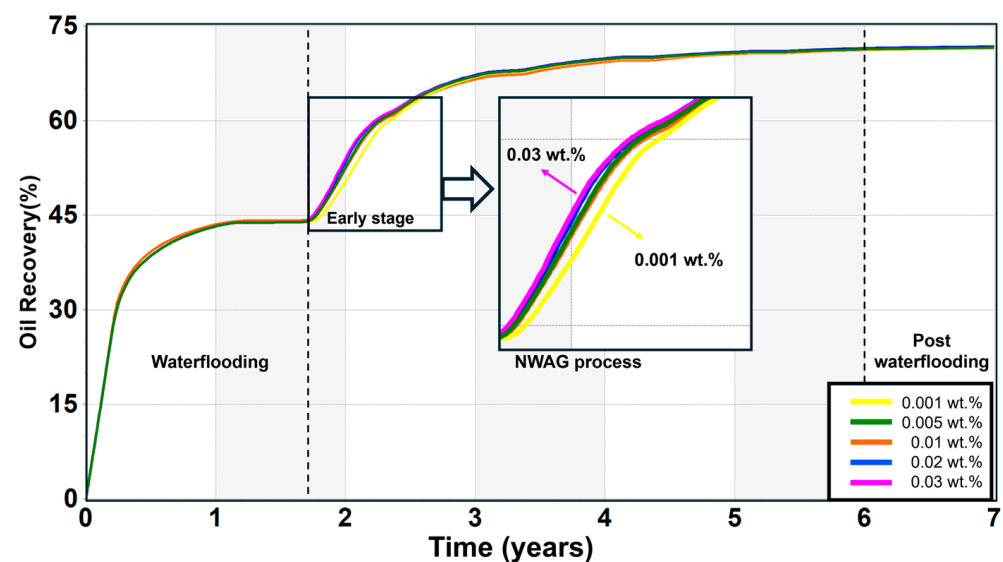


Figure 12. Production performance during the NWAG process with different nanoparticle concentrations.

3.2.2. Results of CO₂ Storage by NWAG

The simulation model categorized CO₂ storage into three primary mechanisms, structural, residual, and solution forms, with a focus on structural and residual storage. The solution-phase changes in CO₂ were not included in the analysis. The total amount of stored CO₂ was calculated by subtracting the produced CO₂ from the injected amount, and the stored quantity was evaluated based on the specific parameters applied in each method. Figure 13 illustrates the cumulative injected CO₂ amount based on various WAG ratios, highlighting the variability in the total CO₂ injection and its impact on the storage capacity. The WAG ratio significantly influenced CO₂ storage, with a peak observed at a specific ratio. Notably, the 1:2 WAG ratio resulted in a higher amount of injected CO₂ than the nanofluid. A slug size of 0.1 HCPV exhibited the highest storage capacity at 11,318 tons.

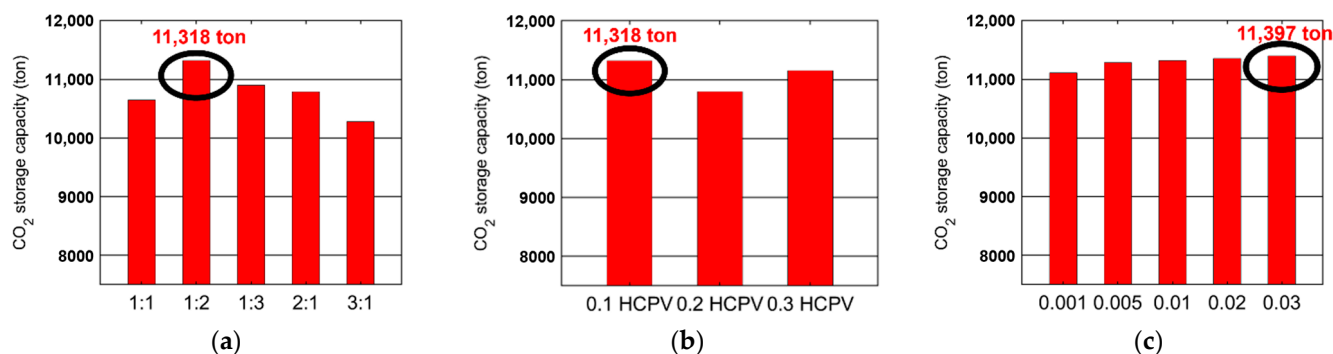


Figure 13. CO₂ storage capacity in NWAG method. Effect of (a) WAG ratio; (b) slug size; (c) nanoparticle concentration.

Alternate injection cycles enhanced CO₂ storage, indicating increased residual CO₂ saturation and water volume, suggesting the possibility of a soluble CO₂ phase. Nanoparticle concentration also affected the CO₂ storage capacity, which increased at higher concentrations. The reservoir pressure increased due to the high-density fluid injection. Nanoparticles adsorb onto the rock surface through mass transfer; however, once the rock surface reaches its maximum adsorption capacity, the remaining nanoparticles contribute to an increase in reservoir pressure. Therefore, with the same volume of CO₂ injected into the reservoir, higher pressure allows for more CO₂ to be trapped. And SiO₂ nanoparticle adsorption changed the contact angle of the rock surface, which altered wettability and relative fluid permeability. It was attributed to the critical gas saturation influence [21,22]. The critical gas saturation increased as the concentration of the injected outgassing particles increased owing to a change in the wetting phase. Moreover, nanoparticles reduce CO₂–oil minimum miscibility pressure (MMP) [23]. An increased nanoparticle concentration caused more CO₂ dissolution in the oil. The mechanism of CO₂ dissolving in oil is similar to that of solubility trapping in carbon capture and storage.

In conclusion, optimal conditions for expanding CO₂ storage were observed at a WAG ratio of 1:2, a slug size of 0.1 HCPV, and higher nanoparticle concentrations at 11,397 tons, as shown in Figure 13. These findings highlight the influence of the hysteresis effect, such as critical saturation changes that significantly impact the CO₂ storage capacity, and underscore the role of nanoparticle concentration in enhancing residual CO₂ retention. Rahmatmand et al. [24] confirmed the adsorption of CO₂ onto nanoparticles when injecting SiO₂ nanoparticles. It is expected that the difference in CO₂ storage due to the increase in nanoparticle concentration will be even greater if future studies consider the adsorption of CO₂ onto SiO₂.

4. Conclusions

In this study, the efficiency of the NWAG method, which utilizes nanofluids in CO₂–EOR processes to recover oil and store CO₂ simultaneously, was investigated. Various influencing factors were identified and used to establish the injection scenarios for the comparison and analysis. The objective was to determine the optimal conditions for maximizing oil recovery rates and CO₂ storage capacity. The following conclusions were drawn:

1. The 1D core models based in CMG-GEM were simulated to evaluate the applicability of the NWAG method, and 1D core models based on CMG-GEM were simulated. Sensitivity analyses were conducted on the factors influencing WAG, followed by the incorporation of the effects of nanoparticles on wettability improvement and absolute permeability reduction using CMOST. The results confirmed that applying the NWAG method enhanced both oil recovery and CO₂ storage efficiency.
2. To construct a 3D reservoir model, a Dykstra–Parsons coefficient of 0.4 was set for heterogeneity, and Carlson’s relative permeability curve with a gas saturation threshold of 0.3 was applied to incorporate history matching. Applying the NWAG method to

- the 3D model considering heterogeneity and history matching yielded results for oil recovery and CO₂ storage capacity based on each influencing factor.
3. The optimal conditions for oil recovery were determined to be an NWAG ratio of 3:1, slug size of 0.1 HCPV, and SiO₂ mole fraction of 0.001, achieving approximately 71.8% oil recovery. Optimal CO₂ storage conditions were found with an NWAG ratio of 1:2, slug size of 0.1 HCPV, and SiO₂ mole fraction of 0.03, resulting in 11,397 tons of CO₂ storage.
 4. Increasing the SiO₂ concentration rapidly increased oil recovery in the initial stages. Therefore, using a higher concentration of nanofluids can initially lead to quick oil recovery, whereas a lower concentration of nanofluids expands the adsorption area, resulting in long-term effectiveness. CO₂ storage tended to plateau after reaching a certain range. Additionally, higher nanoparticle concentrations were found to increase the reservoir pressure and alter the wettability, thereby enhancing the CO₂ storage effectiveness.

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Abbreviations

API	American Petroleum Institute
CMG	Computer modeling group
EOR	Enhanced oil recovery
HCPV	Hydrocarbon pore volume
NWAG	Nano-water-alternating gas
OOIP	Original oil in place
PR-EOS	Peng–Robinson equation of state
WAG	Water-alternating gas
WOC	Water oil contact
SNP	Silica nanoparticle

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