

Article

Optimizing Oil Recovery: A Sector Model Study of CO₂-Water-Alternating-Gas and Continuous Injection Technologies

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Abstract: Optimizing oil recovery from mature reservoirs remains a key challenge in the petroleum industry. This study evaluates the efficiency of CO₂-WAG injection compared to continuous CO₂ and water flooding using a sector model of the *X Oil Field*. A compositional reservoir simulator was employed to analyze oil recovery under water-wet and mixed-wet conditions, incorporating three-phase relative permeability and wettability effects. The results show that continuous CO₂ flooding yields the highest oil recovery, with water-wet systems outperforming mixed-wet reservoirs. CO₂-WAG injection provides a balanced approach, enhancing recovery while enabling CO₂ sequestration, but remains less effective than continuous CO₂ flooding. Water flooding, though the least efficient in terms of oil recovery, demonstrates long-term production stability. The gas–oil ratio (GOR) is notably higher in CO₂-WAG, indicating gas breakthrough challenges. These findings emphasize the significant role of wettability in enhanced oil recovery (EOR) and suggest that continuous CO₂ flooding is the most effective technique for maximizing production in heterogeneous reservoirs. This study contributes valuable insights for optimizing injection strategies, improving hydrocarbon recovery, and supporting sustainable reservoir management.

Keywords: CO₂-WAG; EOR; CO₂ injection; relative permeability

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1. Introduction

Enhanced oil recovery (EOR) techniques play a pivotal role in maximizing hydrocarbon extraction from mature and heterogeneous reservoirs, where conventional methods often fail to achieve economic recovery targets. Among CO₂-based EOR strategies, Water-Alternating-Gas (CO₂-WAG) injection and continuous CO₂ flooding have emerged as leading approaches due to their potential to improve sweep efficiency and mitigate challenges such as gas channeling and gravity override. Numerous studies have demonstrated that these technologies can enhance the EOR by 5–17% compared to traditional methods [1–3]. While WAG injection has historically been favored for its ability to balance fluid mobility and delay gas breakthrough, recent advancements have underscored a growing debate over the efficacy of continuous CO₂ flooding in heterogeneous reservoirs, particularly under specific operational and geological conditions [4–8].

A wealth of studies have demonstrated the advantages of WAG injection in heterogeneous systems. For instance, Al-Obaidi, Galkin and Smirnov [4] reported a 12% increase in oil recovery in water-wet carbonate reservoirs through improved mobility control. Recent findings have further reinforced these observations, with chemical-assisted

WAG (e.g., surfactant- or foam-enhanced injection) achieving up to 5% higher recovery rates in fractured reservoirs compared to traditional methods [9]. However, emerging evidence has challenged this consensus. For example, a field study of a highly heterogeneous sandstone reservoir revealed that optimized continuous CO₂ flooding outperformed WAG by 14% over a 15-year period, achieving 97 MMSTB recovery through high-pressure (2700 psi) miscible displacement [10]. Similarly, advanced numerical simulations have highlighted that continuous CO₂ injection in reservoirs with staggered well patterns yield 3.1% higher recovery in high-permeability zones, emphasizing the role of operational design in EOR success [11,12].

The conflicting findings stem from unresolved complexities in heterogeneous reservoirs, including wettability dynamics and fluid–rock interactions. In water-wet systems, WAG's alternating phases enhance macroscopic sweep by suppressing CO₂'s low viscosity, but mixed-wet conditions introduce uncertainties. A simulation study demonstrated that continuous CO₂ flooding can bypass wettability-driven trapping in mixed-wet reservoirs, outperforming WAG by 8% when capillary forces dominate [10]. Furthermore, operational parameters such as injection pressure, well spacing, and CO₂ recycling efficiency (e.g., 40% in continuous vs. 25% in WAG) critically influence outcomes, as highlighted in recent economic analyses. Despite these insights, gaps persist in understanding how three-phase flow hysteresis, permeability anisotropy, and economic constraints interact to determine optimal EOR strategies.

This study addresses these gaps by conducting a comparative numerical analysis of CO₂-WAG and continuous flooding in the X Oil Field's heterogeneous sector model. Leveraging current advancements in compositional simulation frameworks (e.g., GEM and Eclipse), the work incorporates three-phase relative permeability hysteresis models and wettability variations to evaluate the sweep efficiency under realistic reservoir conditions.

By bridging theoretical insights with practical operational constraints, this study aims to resolve the ongoing debate over EOR optimization in heterogeneous reservoirs. The findings will provide actionable guidelines for selecting CO₂-WAG and continuous injection methods, tailored to reservoir architecture, wettability profiles, and infrastructure readiness.

2. Materials and Methods

2.1. Properties of the Sector Model

A compositional simulation software was used for the numerical simulation of this study. Figure 1 demonstrates a 3D view of a seven-point CO₂-WAG sector model. There are 32 layers in the model, and each layer has its own characteristics. The porosity and permeability distribution in some of the layers are shown in the figures below.

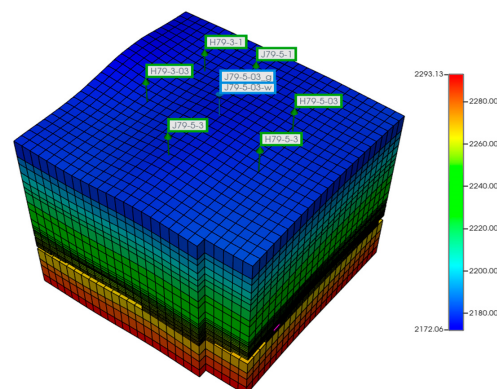


Figure 1. Three-dimensional view of CO₂-WAG sector model.

2.2. Reservoir Porosity

In this reservoir, the porosity ranges from 0.070 to 0.091. Most of the layers have the same porosity; however, the highest porosity value of 0.091 was found in layer 20. Figure 2 portrays the porosity distributions in layers 17 and 18.

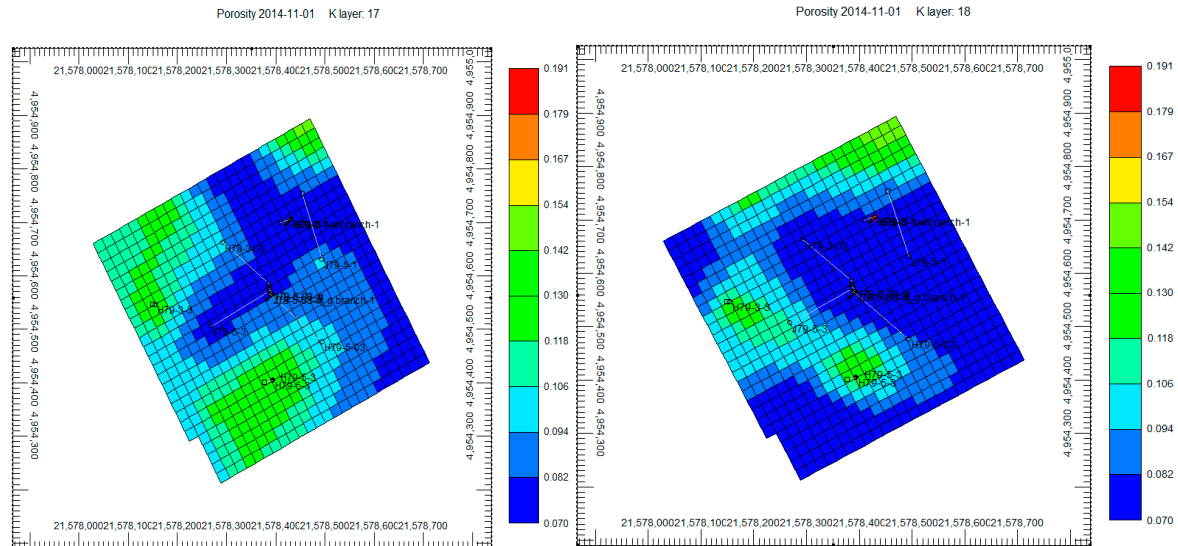


Figure 2. Porosity distribution in layer 17 (left) and in layer 18 (right).

2.3. Reservoir Permeability

The study reservoir is heterogeneous. The permeability variation is high, with permeability ranging from 1 to 70 md. Most of the layers have the same permeability. The highest permeability was found in layers 20 and 22 (see Figure 3). In reservoirs with high permeability contrast, CO₂ migration, and trapping efficiency are affected by the variability in flow paths. High-permeability layers, such as layers 20 and 22, act as conduits, enabling faster CO₂ migration. Low-permeability layers may impede vertical migration and provide additional trapping mechanisms.

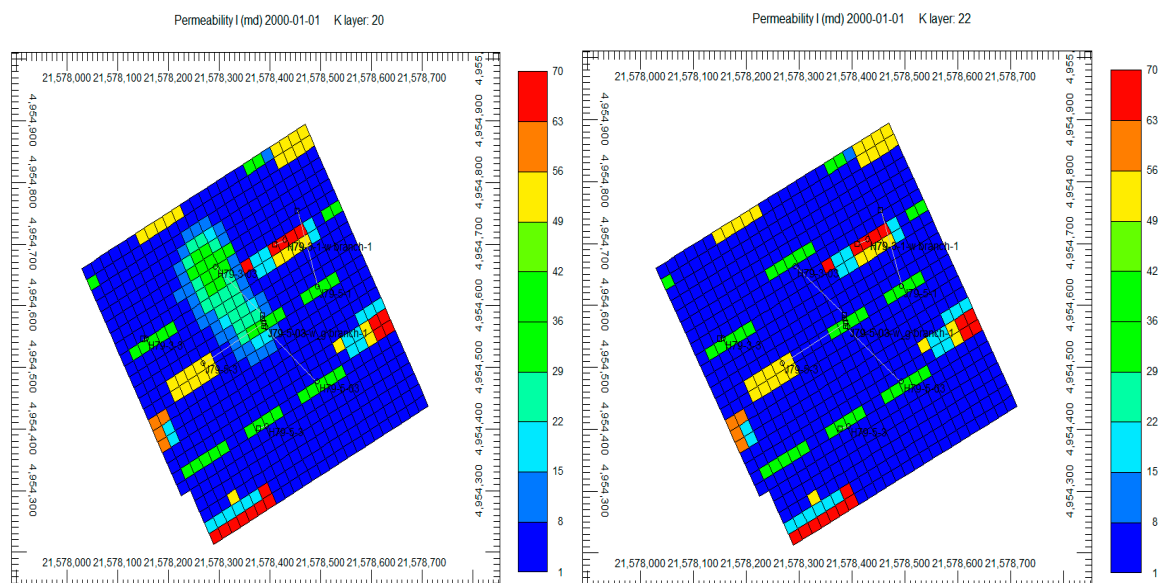


Figure 3. Permeability distribution in layer 20 (left) and in layer 22 (right).

2.4. Reservoir Porosity, Permeability, and Thickness Statistical Analysis

Data portrayed in Figures 4–10 have been measured.

Measurement Procedure:

- **Porosity:** Measured using helium porosimetry and log-derived porosity data. The porosity values in the sector model range from 0.070 to 0.091, with the highest porosity (0.091) recorded in layer 20.
- **Permeability:** Determined from core flooding experiments and well-test data. The permeability values range from 1 mD to 70 mD, with variations corresponding to different geological layers. Layers 20 and 22 exhibit the highest permeability.
- **Relative Permeability and Capillary Pressure (Figures 6–10):** These were obtained through laboratory special core analysis (SCAL) tests on representative core samples from the field. The curves were incorporated into the compositional reservoir simulator to model fluid flow accurately.

Figure 4 depicts a full examination of a water-wet reservoir, with histograms and box plots for porosity, permeability, and thickness. The porosity values vary from 0.0155 to 0.0178. The most common porosity readings appear to be around 0.017, indicating that the reservoir has low but rather uniform porosity. The fluid storage capacity is limited because of the poor porosity. A bimodal distribution may indicate varied rock kinds or compaction levels within the reservoir.

Permeability ranges from 10 to 50 mD, which is suitable for reservoirs with moderate to low permeability. The distribution seems bimodal, with peaks at 30 and 40 mD. This suggests two main river regimes or depositional differences. Heterogeneous permeability can result in uneven fluid flow, lowering manufacturing efficiency. To optimize output, this reservoir may require zonal completion or selective perforation.

The thickness measurements range from 12 m to 24 m, with most values being between 17 and 19 m. The histogram displays a bell-shaped (normal) distribution, indicating a well-defined depositional environment. Thickness influences the volume of hydrocarbons in place. The normal distribution implies a generally uniform reservoir thickness across the field. Overall, porosity is low, which means that fluid storage capacity is limited. Secondary recovery treatments might be required. Permeability is quite varied, with a bimodal distribution that suggests potential flow obstacles or high-permeability streaks. The thickness is generally distributed, indicating constant reservoir layers with few dramatic variances. Targeting high-permeability zones requires selective perforation. Improved recovery strategies are required for increased connectivity.

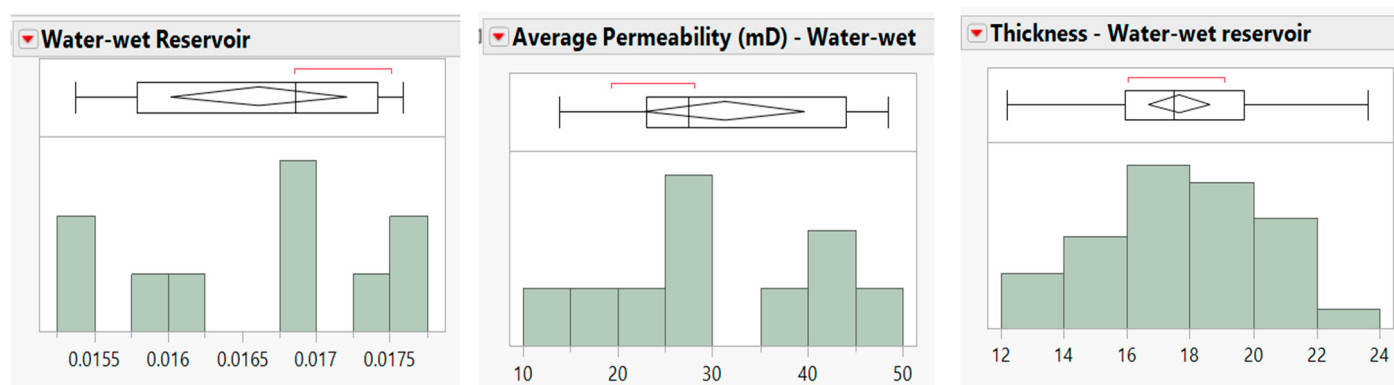


Figure 4. Porosity, permeability, and thickness histograms (water-wet conditions).

The graphs below in Figure 5 show histograms and box plots of permeability, thickness, and porosity for a mixed-wet reservoir, which has distinct flow characteristics from

water-wet reservoirs. Porosity values vary from 0.0715 to 0.0745. Unlike the water-wet reservoir, the porosity is higher but has a narrow range, resulting in less variance. The distribution seems bimodal, with maximums at 0.072 and 0.074. Higher porosity results in increased storage capacity, although flow efficiency is dependent on permeability. Because permeability varies, pore throat distribution influences fluid flow.

Permeability readings vary from 10 mD to 50 mD, with a somewhat left-skewed distribution, indicating that the majority of values are on the lower end (10–30 mD). This permeability distribution is more spread out than in the water-wet reservoir, showing higher variability. Mixed-wet reservoirs frequently show larger capillary pressure differences, indicating that fluid movement is less uniform. To minimize early oil bypass, recovery solutions should focus on balanced depletion.

Thickness values range from 12 to 24 m, with the majority falling between 16 and 20 m. Consistent thickness ensures accurate hydrocarbon volume estimation. If high-permeability zones coincide with thicker reservoir portions, oil recovery will be more effective. Layered heterogeneity may still exist, necessitating zonal characterization.

Due to its mixed-wettability and heterogeneous permeability, this reservoir has more production issues than the water-wet scenario. However, the increased porosity and consistent thickness indicate that if well location and completions are performed correctly, oil-in-place volumes should be adequate.

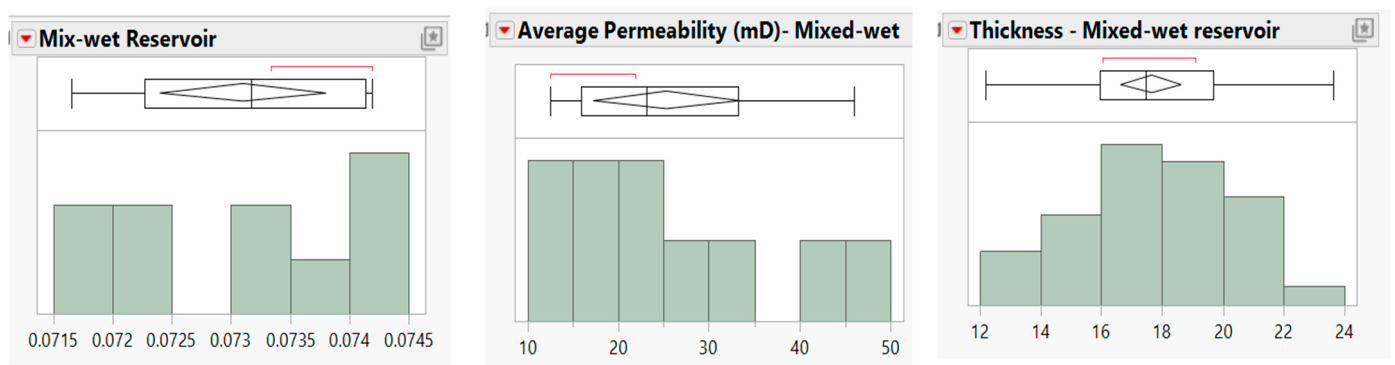


Figure 5. Porosity, permeability, and thickness histograms (mixed-wet conditions).

2.5. Relative Permeability Curves

Figures 6 and 7 depict the relative permeability data for two rock types (Type 1 and Type 2). Both formations are water-wet (S_{ux} values when k_{rw}/k_{ro} vs. S_w intersect are larger than 0.5).

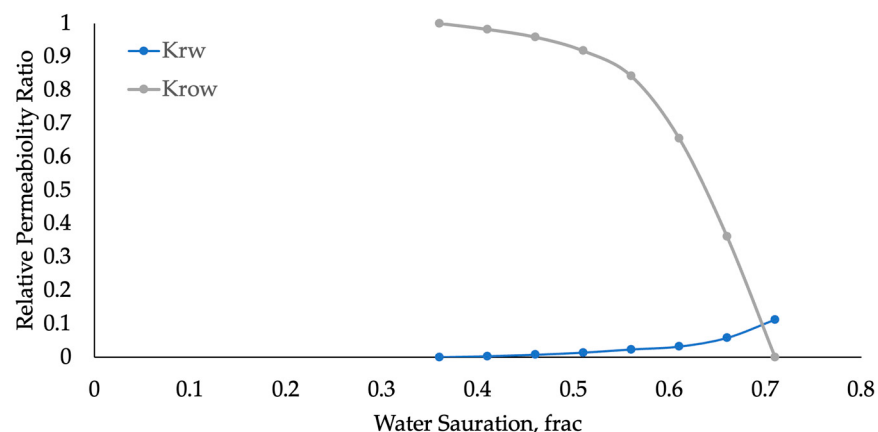


Figure 6. Relative permeability curves (rock type 1).

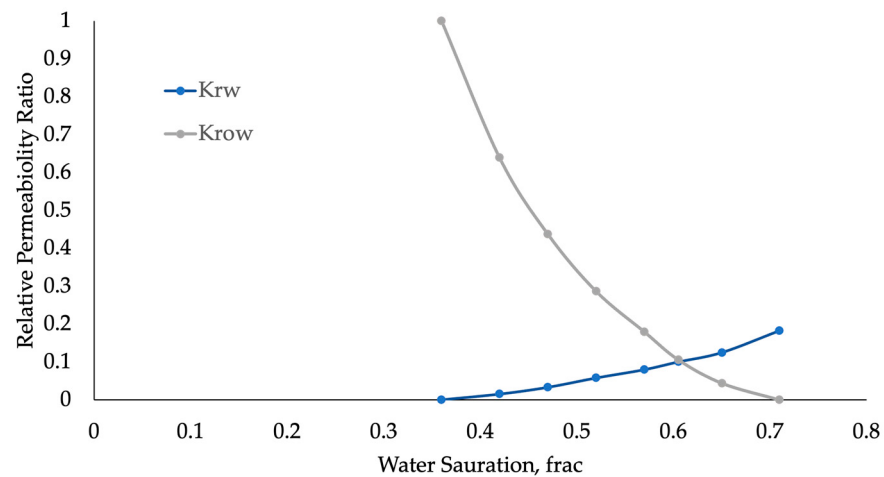


Figure 7. Relative permeability curves (rock type 2).

In water-wet rocks, despite the enhanced trapping, an early gas breakthrough may occur in high-permeability zones, requiring careful control of injection rates and cycle timing. In addition, high water retention in smaller pores can lead to water blockage in low-permeability zones, reducing oil recovery efficiency. However, the addition of CO₂ will potentially alter rock wettability over time (e.g., shifting to intermediate-wet conditions), affecting long-term WAG performance.

Figure 8 illustrates the relative permeability data of a mixed-wet system (S_{wx} values when k_{rw}/k_{ro} vs. S_w intersect are at 0.5)

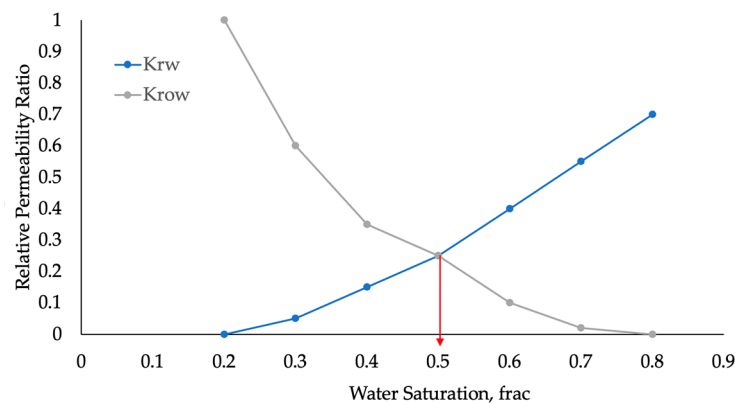


Figure 8. Relative permeability curves with water saturation (mixed-wet conditions).

2.6. Capillary Pressure Curves

Figures 9 and 10 illustrate the capillary pressure during injection under mixed-wet and water-wet conditions, respectively. The trend observed in the graphs indicates that water-wet conditions consistently resulted in better performance compared to mixed-wet conditions. In both cases, the plotted parameter exhibits a sharp initial decline, followed by a more gradual decrease as the x -axis variable increases. However, the water-wet system shows a less pronounced decline, suggesting more effective oil recovery.

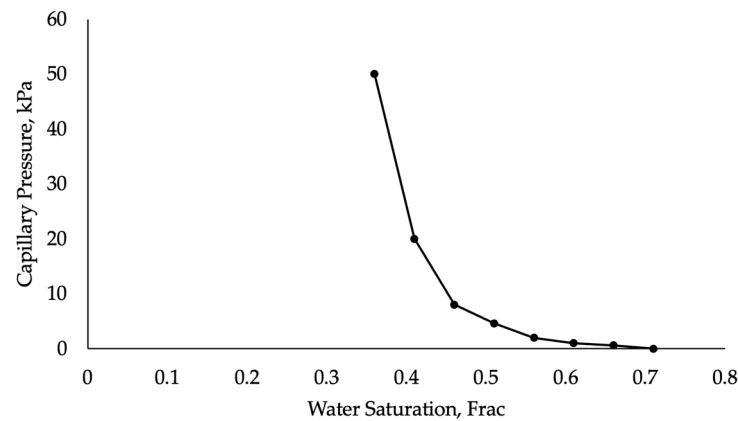


Figure 9. Capillary pressure curve (mixed-wet conditions).

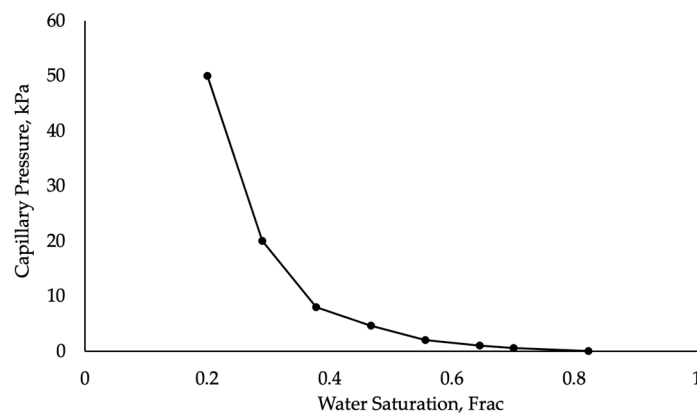


Figure 10. Capillary pressure curve (water-wet conditions).

3. Results and Discussion

3.1. CO₂-WAG Recovery Technique

Following primary depletion, a secondary recovery technique—waterflooding—was implemented to restore declining formation pressure by injecting water into the reservoir. While this method led to some oil recovery, a substantial amount of oil remained trapped. To enhance recovery, a tertiary method, CO₂-WAG injection, was introduced to extract the residual oil. Once CO₂ was introduced in alternating slugs with water, a clear increase in oil production was observed across most of the wells, underscoring the effectiveness of WAG in mobilizing the remaining oil. This pattern is consistent with field observations by Christensen et al. and Al-Obaidi et al. [1,4], who noticed that WAG can enhance the sweep efficiency by periodically lowering the CO₂ mobility in heterogeneous formations. This approach proved effective, leading to significant additional oil recovery.

In this study, a sector model incorporating the real history of CO₂-WAG implementation was used to assess its potential for oil production. Water injection commenced in 2002, with two wells, H79-3-03 and H79-5-3, showing an increase in the oil recovery factor. Approximately a year later, well H79-5-3 experienced a production surge, recovering around 25,000 m³ of oil. Production then stabilized until the transition to the tertiary CO₂-WAG method. Additionally, another well, H79-3-1, achieved substantial oil recovery over time solely through water flooding.

Mechanistically, CO₂ dissolution and miscibility with the reservoir oil reduce the oil viscosity, facilitating displacement from smaller pore spaces. Simultaneously, the injection of water slugs helps maintain a lower gas–oil ratio (GOR) at early stages by providing partial mobility control. However, as discussed later (Sections 3.2 and 3.3), if the reser-

voir heterogeneity is high, CO₂ can eventually channel through preferential flow paths, diminishing the long-term incremental oil recovery. Despite these limitations, Figure 11 demonstrates that CO₂-WAG outperforms waterflooding alone for tertiary recovery, confirming its merit in improving the overall production from mature reservoirs [13].

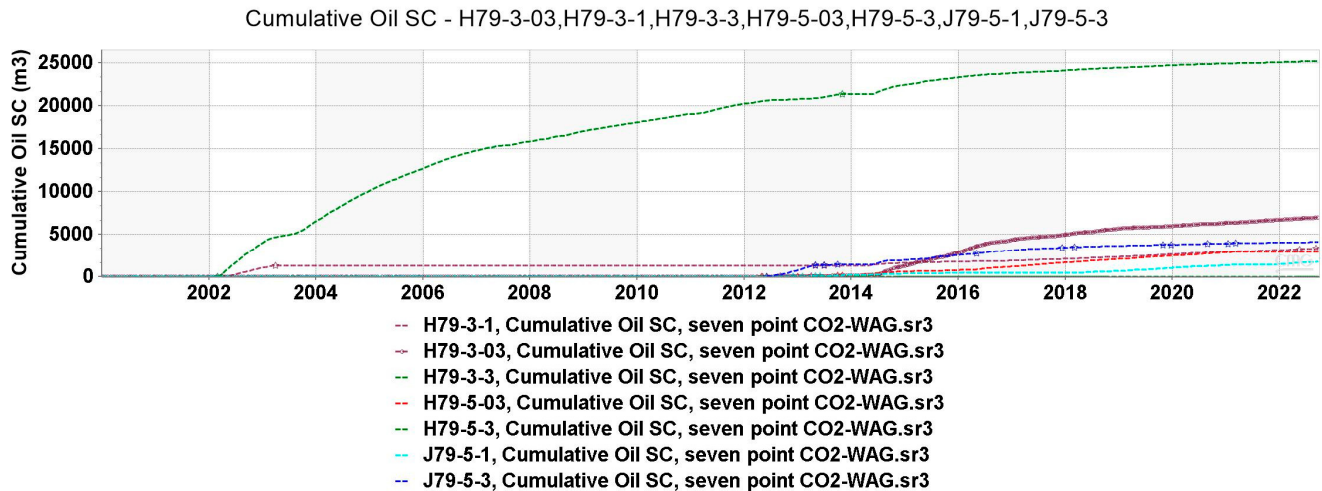


Figure 11. Oil production by CO₂-WAG injection process.

3.2. WAG Performance in Comparison with Waterflood and CO₂ Flood in the Water-Wet System

This research is based on a sector model consisting of two rock types and ten wells. Among them, seven are producer wells (H79-3-1, H79-3-03, H79-3-3, H79-5-03, H79-5-3, J79-5-1, and J79-5-3), while the remaining three serve as injector wells (H79-3-1-w, J79-5-03-w, and J79-5-3-g). For this investigation, the following three scenarios were evaluated in the first stage:

(1) Continually flooding with water; (2) CO₂ flooding; (3) CO₂-WAG injection.

The fundamental multiphase characteristics of the rock, such as capillary pressure and relative permeability curves, are influenced by its wettability, which directly affects fluid distribution and movement within the pores. While reservoirs can be water-wet, oil-wet, or mixed-wet, this study focuses solely on oil production in water-wet and mixed-wet systems. To ensure a fair comparison among the three injection methods, additional models will be developed for both water-wet and mixed-wet conditions.

A comparison of the simulation results for CO₂ injection and CO₂-WAG shows that both techniques involved injecting the same amount of CO₂ into the reservoir, as illustrated in Figure 12.

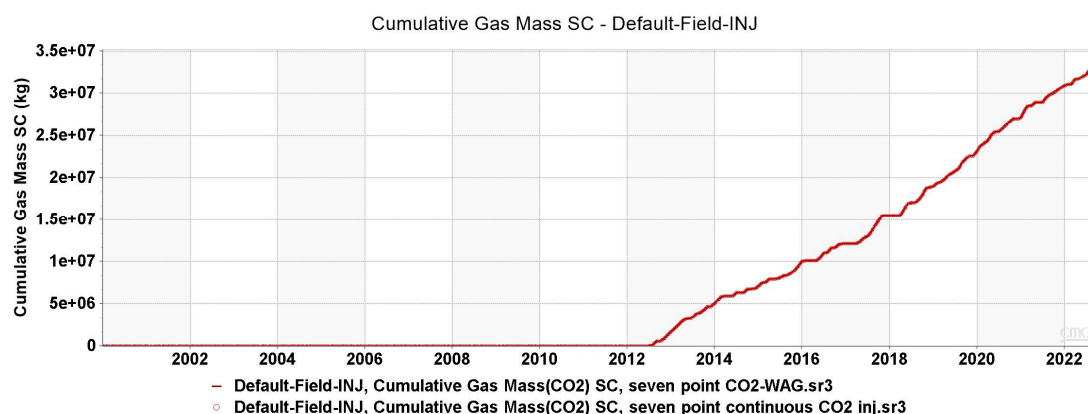


Figure 12. Cumulative CO₂ injection during continuous CO₂ flooding and CO₂-WAG.

To ensure a fair comparison, the constraints for CO₂ injection and water injection were set identical to those in the WAG injection sector model. For the water injection wells (H79-3-1-w, J79-5-03-w), the surface water rate (STW) was limited to 78.7 m³/day and 20.0 m³/day, respectively, while the bottom hole pressure (BHP) was capped at 30,000 MPa and 1,000,000 kPa. Similarly, for the gas injection well, the surface gas rate (STG) was restricted to 22,983.4 m³/day, with a maximum bottom hole pressure (BHP) of 1,000,000 kPa.

The volume of water injected into the two injection wells was kept consistent for both WAG and water injection operations, as illustrated in Figure 13. In both methods, more than 40,000 m³ of water was injected.

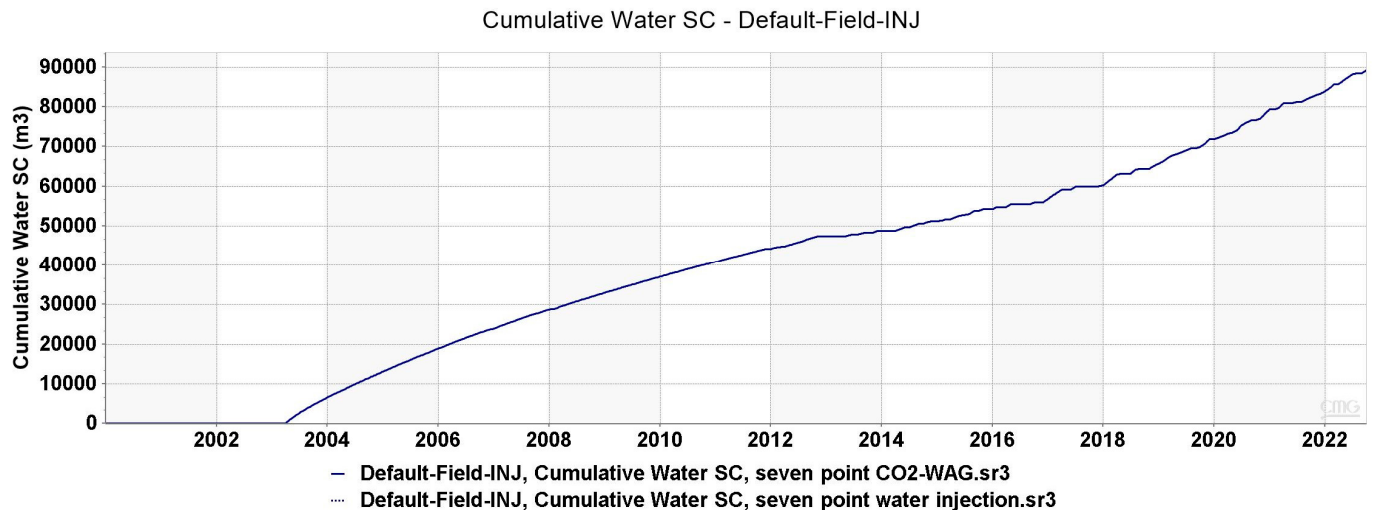


Figure 13. Cumulative water injection during continuous water flooding and CO₂-WAG.

Figures 12 and 13 confirmed that both CO₂ and water volumes were similarly constrained for continuous flood vs. WAG. Such an approach allows a direct comparison of how injecting CO₂ alone vs. alternating CO₂ and water affects recovery.

A detailed analysis of the three injection methods revealed that CO₂ injection initially achieved the highest oil production rate from 2015 to 2020. However, production declined in the later stages due to the CO₂ breakthrough. Similarly, CO₂-WAG injection demonstrated strong initial performance, though its oil production rate remained lower than that of continuous CO₂ flooding. In contrast, water injection yielded the lowest oil production rate in the early stages but unexpectedly outperformed the other two methods in the later stages. The oil production trends for all three injection methods are illustrated in Figure 14.

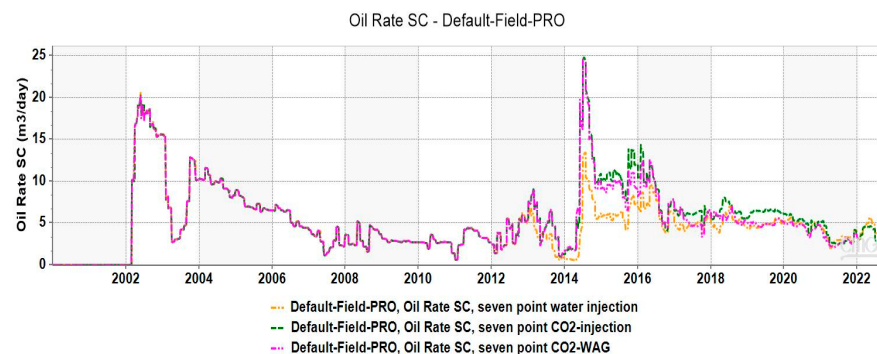


Figure 14. Oil production rate during continuous CO₂ flooding, CO₂-WAG, and water flooding techniques (water-wet conditions).

Figure 15 illustrates the total oil production from all three injection methods. Overall, the simulation results indicate a dramatic increase in cumulative oil production for each

method from 2014 to 2022. Water injection had the lowest production, accounting for 40,000 m³ by the end of the period. The WAG method produced more oil than water injection alone, but still less than continuous CO₂ injection, with a cumulative production of around 45,000 m³. In contrast, the continuous CO₂ flooding technique achieved the highest cumulative oil production, reaching approximately 48,000 m³ by the end of the period. In conclusion, it was analyzed that continuous CO₂ yields the highest total recovery (~48,000 m³), surpassing CO₂-WAG (~45,000 m³) and waterflood (~40,000 m³). Similar trends have been reported by Bui et al. [10] where continuous CO₂ injection achieved 14% higher oil recovery than WAG in certain high-permeability reservoirs.

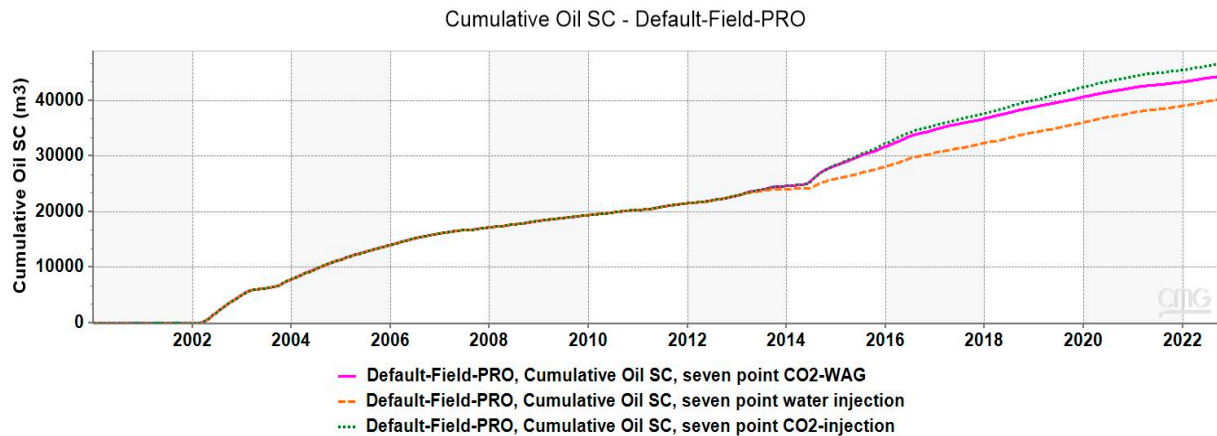


Figure 15. Cumulative oil production through continuous CO₂ flooding, CO₂-WAG, and water flooding techniques (water-wet conditions).

Figure 16 demonstrates that CO₂-WAG not only results in lower oil production compared to continuous CO₂ flooding but also exhibits a higher gas-oil ratio (GOR). This presents a significant drawback of the CO₂-WAG injection method. In contrast, the GOR for continuous CO₂ injection was initially higher but gradually decreased over time relative to CO₂-WAG. The GOR for CO₂-WAG peaked at around 32,000 m³/m³, marking the highest ratio throughout the period. This observation matches Adullah et al. [14] and Ding et al. [5] who found that sustained CO₂ injection can develop stable miscible fronts in some formations despite early breakthrough risks.

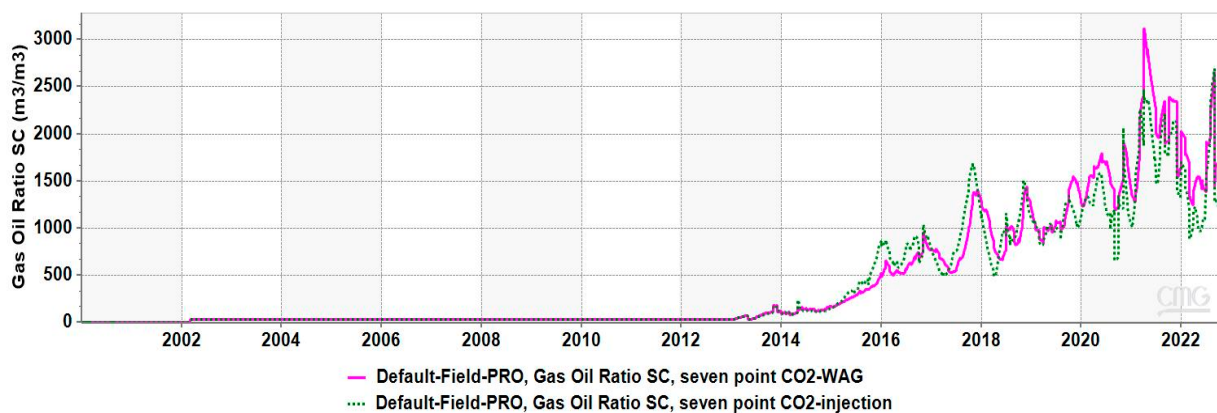


Figure 16. Gas oil ratio during continuous CO₂ flooding and CO₂-WAG flooding techniques (water-wet conditions).

Figure 17 shows that the water cut was quite similar during water injection and CO₂-WAG. Although the water cut for CO₂-WAG started lower than that of water flooding in the early stages, it gradually increased from 2015 until the end of the period. This result

clearly indicates that the CO₂-WAG process is not superior to water flooding in terms of water cut performance. The results highlight that in water-wet conditions, water cut is an important factor shaping the long-term economics and recovery efficiency, echoing earlier studies that emphasize the interplay of wettability, relative permeabilities, and fluid viscosities [15].

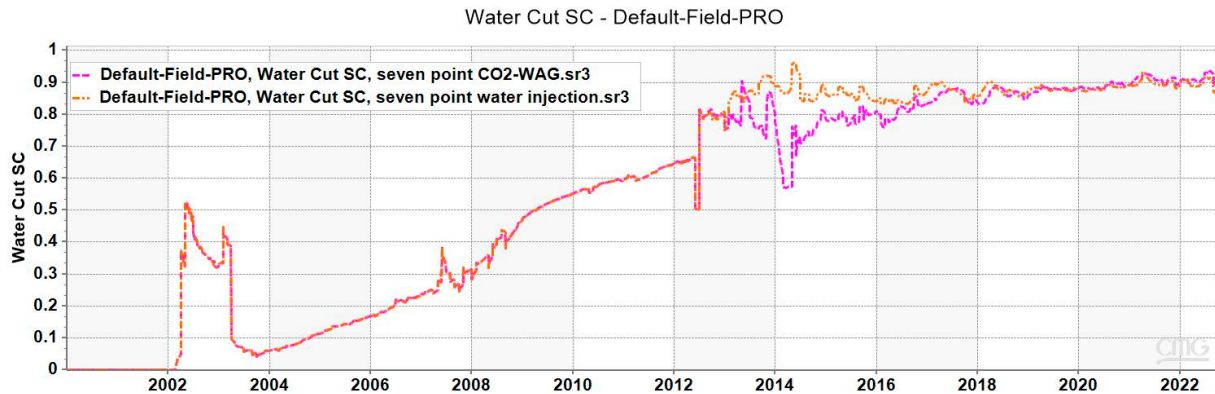


Figure 17. Water cut during continuous CO₂ flooding and CO₂-WAG flooding techniques (water-wet conditions).

Overall, water-wet reservoirs exhibit higher overall recovery factors, as the wetting phase distribution favors water in smaller pores, enabling CO₂ to displace oil more effectively in the larger pore channels. This aligns with the findings of Li et al. [7] who noted that strongly water-wet systems generally respond more predictably to gas-based EOR methods.

3.3. WAG Performance in Comparison with Waterflood and CO₂ Flood in Mixed-Wet System

The simulation results for the mixed-wet system were comparable to those for the water-wet system, providing a foundation for the comparative study of oil rates. Throughout most of the period, the oil rate for CO₂ flooding was consistently higher; however, by the end of the period, the oil rate for water injection surpassed that of CO₂ flooding. The oil rate for CO₂-WAG was nearly identical to that of continuous CO₂ flooding initially but declined later on. In contrast, the oil rate for water flooding was lower in the early stages but increased by the end of the period. Figure 18 illustrates the oil rate in all three injection methods for mixed-wet reservoirs.

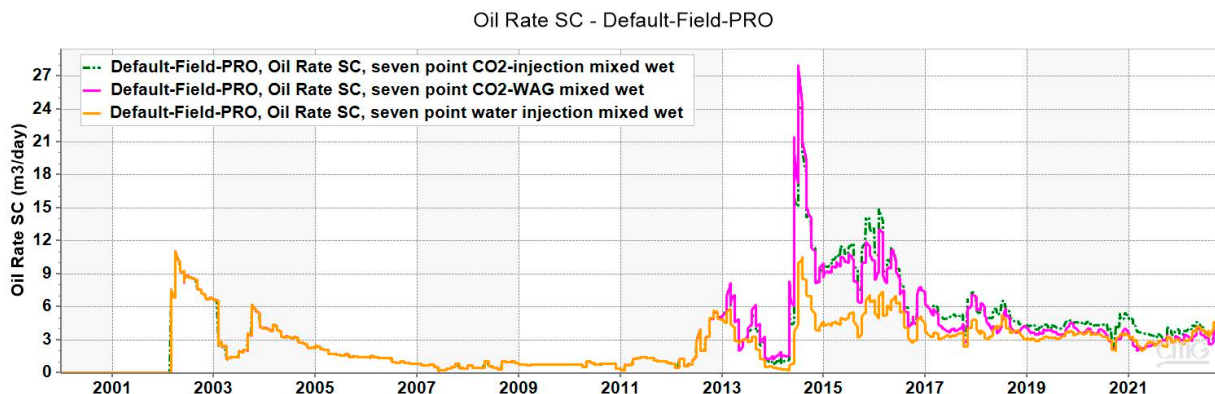


Figure 18. Oil production rate during continuous CO₂ flooding, CO₂-WAG, and water flooding techniques (mixed-wet conditions).

Figure 19 displays the cumulative oil production for all three injection methods in the mixed-wet system. Overall, the simulation results indicated an increase in oil production

for each injection method from 2014 to 2022, similar to the trends observed in the water-wet system. However, the cumulative oil production for each method was notably lower compared to that of the water-wet reservoir. CO₂ injection achieved a cumulative oil production of around 30,000 m³, remaining the highest among the flooding processes. In contrast, the cumulative oil production for CO₂-WAG and water injection was approximately 28,000 m³ and 21,000 m³, respectively. The more complex capillary pressure profile in mixed-wet rocks (shown in Figures 9 and 10) contributes to uneven displacement fronts, leading to additional oil bypass. Mixed-wettability can create regions of partial oil-wet conditions, reducing the sweep efficiency and hindering CO₂ from contacting bypassed oil [16].

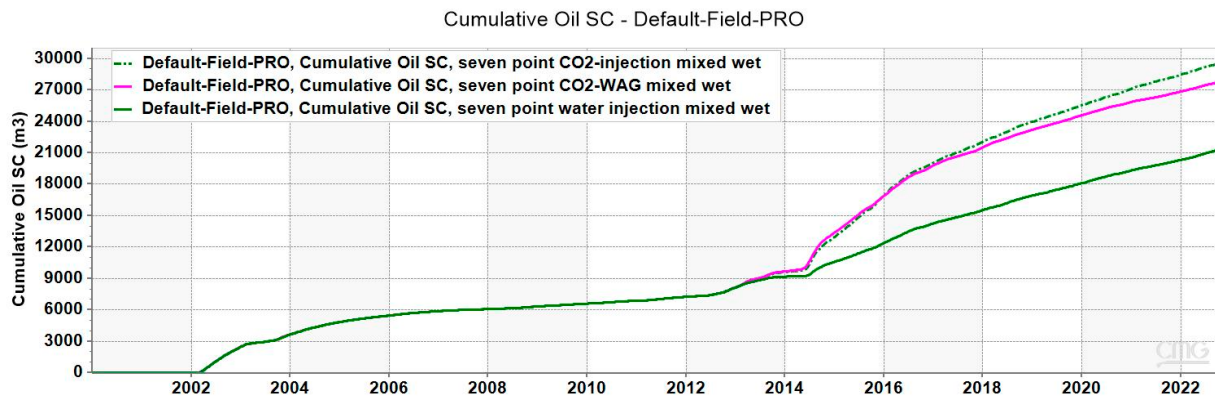


Figure 19. Cumulative oil production through continuous CO₂ flooding, CO₂-WAG, and water flooding techniques (mixed-wet conditions).

The gas–oil ratio (GOR) in the mixed-wet model is nearly identical to that in the water-wet model. Overall, the GOR data exhibit fluctuations. Initially, the GOR for CO₂-WAG was lower compared to that for CO₂ injection; however, it increased later on. Significant variations occurred after 2016 for both CO₂-WAG and continuous CO₂ GOR, likely due to modifications in well completion and gas meter maintenance issues. Figure 20 provides a comprehensive illustration of the GOR for the mixed-wet system.

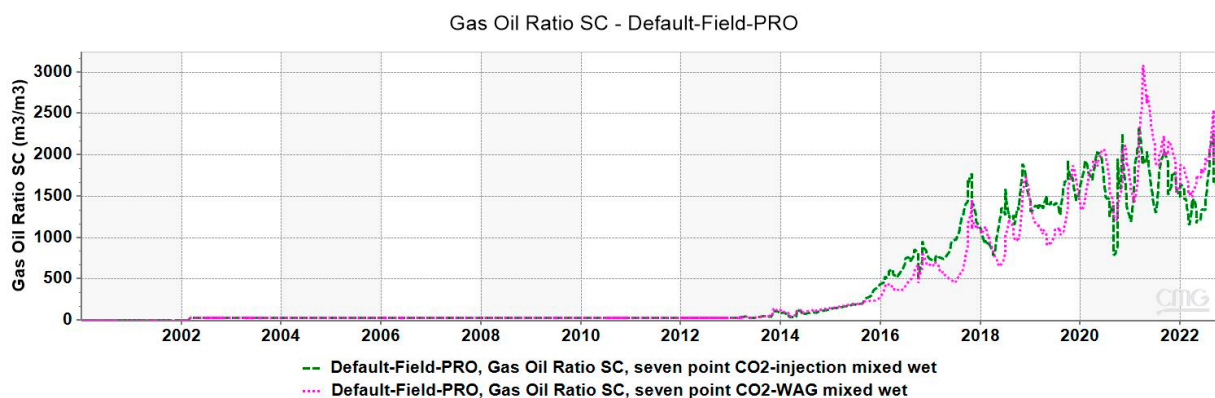


Figure 20. Gas–oil ratio during continuous CO₂ flooding and CO₂-WAG flooding techniques (mixed-wet conditions).

Water cut is another important parameter to consider for optimizing the oil recovery factor. In this study, the water cut for both the CO₂-WAG and water flooding techniques in mixed-wet systems was analyzed. The results were similar to those observed in the water-wet system, indicating that the water cut for CO₂-WAG was lower in the initial stages compared to water flooding. However, over time, the water cut for CO₂-WAG increased and eventually matched that of water flooding. These variations are illustrated in Figure 21.

Water cut trends highlight that once waterflood or WAG fails to efficiently stabilize the gas front, both the oil rate and sweep efficiency drop significantly [12].

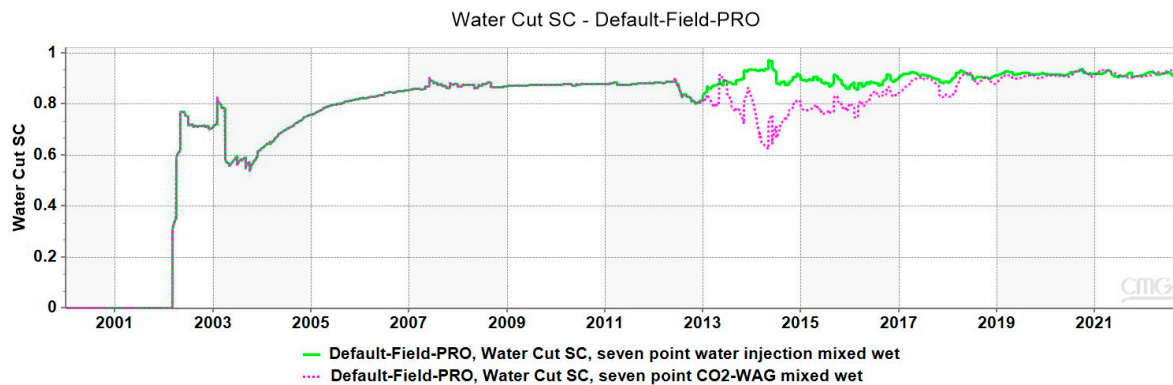


Figure 21. Water cut during continuous CO₂ flooding and CO₂-WAG flooding techniques (mixed-wet conditions).

The standard deviation analysis reveals that the mixed-wet system has greater variability in cumulative oil production. This variability suggests an inconsistent performance due to the complex interactions between wettability effects, capillary forces, and injection fluid behavior. Water-wet systems, in contrast, exhibit more predictable recovery trends, contributing to a smoother performance across different injection strategies, as shown in Figure 22. This variability—observed in the standard deviation plots—mirrors insights from Fang et al. [12], who emphasize that even minor changes in injection scheduling or slug sizes can produce disproportionately large swings in mixed-wet fields.

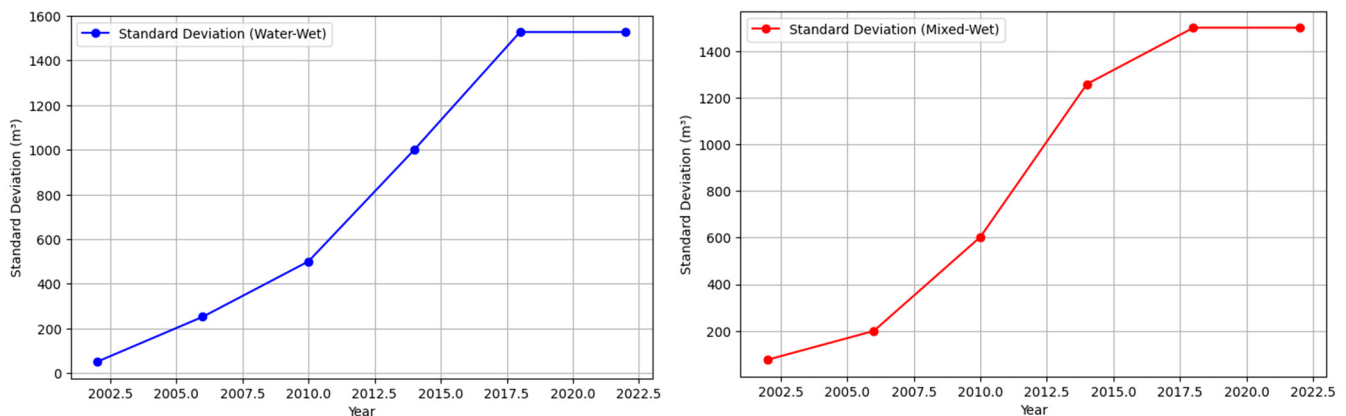


Figure 22. Standard deviation analysis for water-wet and mixed-wet conditions.

In summary, the oil recovery factors from the simulation findings for the water-wet and mixed-wet systems were markedly different. In the water-wet model, the recovery factor for CO₂ flooding was 27.2%, while the recovery factors for CO₂-WAG and water flooding were 26% and 23.6%, respectively. In the mixed-wet model, continuous CO₂ flooding also demonstrated a higher recovery efficiency than the other two injection techniques. As shown in Table 1, the recovery factors for CO₂-WAG, water injection, and continuous CO₂ injection were 16.2%, 12.4%, and 17.2%, respectively.

Table 1. Oil recovery factors for water-wet and mixed-wet systems.

Injection Methods	Water-Wet System	Mixed-Wet System
CO ₂ -WAG	26	16.1
CO ₂ flooding	27.2	17.2
Water flooding	23.6	12.4

In the water-wet model, the total oil production from CO₂ injection was 48,000 m³, slightly higher than the 45,000 m³ produced by CO₂-WAG. In the mixed-wet model, although the overall results were lower compared to the water-wet model, oil production from continuous CO₂ flooding remained higher than that of the other two injection methods within the same wettability system. Specifically, CO₂-WAG produced a total of 174,328.3 barrels per day, while continuous CO₂ injection produced 185,584 barrels per day, and continuous water flooding yielded 133,881.7 barrels per day.

Overall, these findings from results confirm that in both the water-wet and mixed-wet environments, continuous CO₂ flooding typically leads to higher ultimate recovery. CO₂-WAG remains an attractive alternative when balancing CO₂ utilization, mobility control, and sequestration goals, but may require additional techniques (e.g., foam or polymer slugs) to outperform continuous CO₂ in heterogeneous or mixed-wet settings [1,4,12].

4. Conclusions

This study evaluates the efficiency of CO₂-WAG injection compared to continuous CO₂ and water flooding in water-wet and mixed-wet reservoirs. The key results of this study are as follows:

- Continuous CO₂ injection achieves the highest oil recovery, particularly in water-wet systems.
- CO₂-WAG injection provides a balance between oil recovery and CO₂ sequestration but remains less efficient than continuous CO₂ flooding in terms of the overall oil recovery.
- Water flooding, while the least effective for oil recovery, offers long-term production stability and pressure maintenance.

These findings highlight the importance of reservoir wettability in enhanced oil recovery (EOR) and confirm continuous CO₂ injection as the most effective strategy for maximizing oil recovery in heterogeneous reservoirs.

However, this study has certain methodological limitations that should be considered:

- The sector model used may not fully capture large-scale reservoir heterogeneities.
- Assumptions made in relative permeability modeling could influence the accuracy of the results.

To address these limitations, future research should focus on the following:

- Refining three-phase relative permeability models to improve the prediction accuracy.
- Optimizing CO₂ sequestration techniques for better long-term efficiency.
- Conducting field-scale validations to ensure applicability to real-world reservoirs.

By addressing these aspects, future studies can enhance long-term sustainability and improve model reliability in CO₂-based EOR strategies.

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Abbreviations

The following abbreviations are used in this manuscript:

CO ₂ -WAG	Carbon dioxide-water-alternating-gas
EOR	Enhanced oil recovery
IPCC	Intergovernmental Panel on Climate Change
GOR	Gas–oil ratio
GEM	Generalized equation-of-state model
BHP	Bottom hole pressure
STW	Surface water rate
STG	Surface gas rate

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