



ARTICLE

Alternating Slug Injection for Enhanced Oil Recovery in Strongly Heterogeneous Reservoirs

Lianfeng Zhang^{1,2}, Hong He^{3,*} and Yifei Zang³

¹Research Institute of Exploration and Development, Sinopec Henan Oilfield Company, Nanyang, China

²Henan Provincial Key Laboratory of Enhanced Oil Recovery, Nanyang, China

³College of Petroleum Engineering, Yangtze University, Wuhan, China

*Corresponding Author: Hong He. Email: hehong1103@163.com

Received: 17 July 2026; Accepted: 22 September 2026; Published: 19 October 2026

ABSTRACT: This study investigates and optimizes alternating slug injection strategies for heterogeneous phase combination flooding in strongly heterogeneous, ultra-high-water-cut reservoirs. Integrated parallel core-flooding and three-dimensional physical simulation experiments were performed to evaluate three injection strategies at a total slug volume of 0.6 PV: conventional heterogeneous phase combination flooding, alternating injection of heterogeneous phase combination system/polymer slugs, and alternating injection of heterogeneous phase combination system/heterogeneous system slugs. The core-flooding results demonstrate a clear advantage of alternating injection, with incremental recovery factors of 27.4%, 30.8%, and 34.4% for the three strategies, respectively. Alternating injection also produced a pronounced reduction in water cut following chemical flooding, with the heterogeneous phase combination system/heterogeneous system strategy delivering the most effective water control. Three-dimensional physical simulations further revealed that alternating injection promotes redistribution of the injected fluids, improves sweep efficiency, and increases the incremental recovery factor by 5.0 percentage points relative to conventional flooding. Overall, the results demonstrate that appropriate sequencing of heterogeneous and polymer-based slugs can substantially improve profile control, expand sweep coverage, and mobilize otherwise inaccessible remaining oil in strongly heterogeneous, ultra-high-water-cut reservoirs.

KEYWORDS: Heterogeneous phase combination flooding; alternating injection; injection mode; enhanced oil recovery; core flooding; heterogeneous reservoir; polymer/surfactant/gel slug; water cuts

1 Introduction

Improving sweep efficiency and recovering remaining oil remain major challenges in mature reservoirs after prolonged waterflooding and subsequent polymer flooding, particularly as production reaches ultra-high water cuts [1,2]. Although polymer flooding can improve the water–oil mobility ratio and enhance sweep efficiency, its performance depends on reservoir heterogeneity, crossflow conditions, and polymer bank design. *In-situ* rheology and injectivity also influence polymer flow behavior in porous media and must be considered when designing effective displacement strategies [3]. In strongly heterogeneous reservoirs at ultra-high water cuts, injected fluids preferentially flow through high-permeability pathways, leaving remaining oil unevenly distributed in poorly swept regions and making further recovery difficult [4]. These limitations have motivated investigations into alternating polymer injection and heterogeneous phase composite flooding after polymer flooding [5,6]. However, visualization experiments have shown that preferential flow through established high-permeability channels can still constrain sweep expansion in strongly

heterogeneous systems. Shuanghe Oilfield provides a representative example of this broader development challenge, with previous studies documenting high-temperature polymer flooding and the subsequent development of heterogeneous combination flooding systems for post-polymer-flooding reservoirs [7,8]. Further optimization of injection strategies is therefore needed to improve fluid redistribution, expand sweep coverage, and mobilize remaining oil in strongly heterogeneous reservoirs at ultra-high water cuts.

To further improve oil recovery after polymer flooding, a variety of profile control and chemical flooding technologies have been developed in recent years, including gel flooding, polymer/surfactant flooding, and heterogeneous phase combination flooding [9–12]. Among them, heterogeneous phase combination flooding has attracted increasing attention because it integrates the synergistic effects of polymer, surfactant, and preformed particle gel (PPG), which can simultaneously improve sweep and displacement efficiencies [13–15]. Polymer improves the mobility ratio between the injected fluid and crude oil, thereby enhancing macroscopic sweep efficiency. PPG particles selectively enter and partially plug high-permeability channels, improving profile control and promoting fluid diversion toward unswept low-permeability regions. Unlike polymer and PPG, which mainly contribute to mobility control and profile modification, the surfactant primarily improves microscopic displacement efficiency by reducing the oil–water interfacial tension and facilitating the mobilization of trapped oil [16–18]. Therefore, polymer, surfactant, and PPG perform complementary functions at different scales, and their synergistic combination enables heterogeneous phase combination flooding to simultaneously improve sweep efficiency and displacement efficiency, thereby enhancing overall oil recovery [19–21]. Although polymer and PPG can effectively improve mobility control and profile conformance, they have limited ability to mobilize capillary-trapped residual oil. After long-term water flooding and polymer flooding, a considerable amount of remaining oil is retained by capillary forces in unswept and poorly swept regions. Therefore, surfactant is introduced to reduce the oil–water interfacial tension (IFT), thereby lowering capillary forces and improving microscopic displacement efficiency. Consequently, the incorporation of surfactant complements the mobility-control functions of polymer and PPG rather than duplicating them.

Previous studies have demonstrated that heterogeneous phase-flooding systems exhibit good adaptability in heterogeneous reservoirs following polymer flooding. By integrating the synergistic effects of polymer, surfactant, and preformed particle gel (PPG), these systems can improve mobility control, reduce preferential channeling, and enhance oil recovery in low-permeability regions [22–24]. However, most existing studies have focused on the performance evaluation of heterogeneous-phase flooding systems or conventional sequential multi-slug injection strategies. For ultra-high water-cut reservoirs with severe heterogeneity, the effectiveness of heterogeneous phase flooding remains limited by uncertainty in slug combination and injection sequence design. In particular, the interaction between slug structure, fluid redistribution, and remaining oil mobilization under strong reservoir heterogeneity has not been sufficiently understood [25–27]. Recent studies have further demonstrated that the performance of chemical enhanced oil recovery systems is strongly influenced by chemical formulation, injection strategy, and reservoir conditions. Optimizing slug size, chemical composition, and injection sequence is crucial for improving displacement efficiency under heterogeneous reservoir conditions. For example, chemically enhanced water-alternating-gas and compositionally tuned slug injection strategies have shown that optimized injection sequences can enhance fluid redistribution and oil recovery performance [28–30]. Surfactant-polymer flooding has been widely investigated for its ability to combine mobility control and interfacial tension reduction, while optimizing slug design remains essential for improving recovery efficiency [31]. In addition, recent investigations have emphasized the importance of chemical stability under harsh reservoir conditions, including high salinity and temperature, which directly affect the long-term effectiveness of chemical flooding processes [32–34].

Although alternating injection has shown potential advantages in improving sweep efficiency and profile control performance, systematic optimization of alternating slug injection strategies under strongly heterogeneous reservoir conditions remains limited. Therefore, this study aims to optimize alternating slug injection strategies for heterogeneous phase combination flooding in ultra-high water-cut reservoirs. Different injection modes were systematically evaluated using parallel core-flooding experiments and three-dimensional physical simulations. The effects of injection strategies on fluid distribution, profile control performance, sweep efficiency, and remaining oil mobilization were investigated. By integrating microscopic flow-regulation analysis from core experiments with macroscopic displacement behavior from three-dimensional models, this work provides new insights into optimizing alternating injection strategies and offers experimental guidance for improving oil recovery in strongly heterogeneous reservoirs.

2 Experimental Section

2.1 Experimental Materials and Instruments

Experimental materials: Experimental polymer with a molecular weight of 20 million (In this study, polymer was not investigated as an independent EOR method but served as a mobility-control component in the heterogeneous phase combination flooding system.), produced by SNF (China); Experimental oil provided by Shuanghe Oilfield (the viscosity of dehydrated crude oil under 70°C reservoir conditions is mPa·s); Surfactant with an effective content of 50.8%, produced by Shandong DESHI; PPG with a solid content of 86.6%, produced by Shandong JUXING Petroleum Technology Co., Ltd; Experimental core, dual-tube sand-filling core model ($\Phi 2.5\text{ cm} \times 50\text{ cm}$), three-dimensional inter-layer heterogeneity physical simulation model ($40\text{ cm} \times 40\text{ cm} \times 4\text{ cm}$), which is water-wet, ratio of 3:1 ($1.5\text{ }\mu\text{m}^2:0.5\text{ }\mu\text{m}^2$); Experimental quartz sand, 100–120 mesh, 80–100 mesh, 40–60 mesh; Experimental water was the produced water from Shuanghe Oilfield, with a salinity of 5002 mg/L.

Experimental equipment: Brookfield DV2T viscosimeter, multi-functional core displacement device, oven, ISCO constant-speed constant-pressure pump, magnetic stirrer, lifting platform, mixing intermediate container, mechanical pressure gauge, temperature-resistant and pressure-resistant pipelines, constant-temperature water bath pot, six-way valve, several graduated cylinders.

2.2 Experimental Method

2.2.1 Parallel Core Oil Recovery Experiment

The experiment simulated the reservoir conditions of the Shuanghe Oilfield. The experiment was carried out at 70°C and atmospheric pressure. The flowchart of the experiment is shown in Fig. 1. The specific experimental steps are as follows:

- (1) The sand-packed tubes with a permeability of $1.5\text{ }\mu\text{m}^2$ were wet-packed with 80–100 mesh quartz sand, and the sand-filled pipes were filled with 100–120 mesh quartz sand with a permeability of $0.5\text{ }\mu\text{m}^2$. Seal both ends with 40–60 mesh coarse sand. The amount of formation water used during packing corresponded to the pore volume.
- (2) Simulated formation water was injected at a rate of $1.0\text{ mL}\cdot\text{min}^{-1}$ to measure the permeability of sand-packed cores. After stable water production at the outlet and stable pressure, permeability was calculated based on pressure readings.
- (3) The prepared sand-packed models were placed in an oven at 70°C. Experimental oil was injected at $0.1\text{ mL}\cdot\text{min}^{-1}$ to saturate the sand packs. After oil appeared at the outlet, the injection was continued at $0.2\text{ mL}\cdot\text{min}^{-1}$ for another 1 h to achieve oversaturation. The volume of water produced during oil

saturation was equal to the oil saturation volume. After oil saturation, the models were aged in the oven for 2 days.

- (4) Water flooding was conducted at $0.5 \text{ mL} \cdot \text{min}^{-1}$ until the water cut of the produced fluid reached 98%. Chemical flooding was then conducted according to the injection schemes listed in Table 1. The heterogeneous phase combination system consisted of 1500 mg/L polymer, 2000 mg/L surfactant, and 1000 mg/L PPG, while the polymer solution contained 1500 mg/L polymer and the heterogeneous system consisted of 1500 mg/L polymer and 1000 mg/L PPG. For Scheme 1, 0.6 PV of the heterogeneous phase combination system was injected. For Scheme 2, 0.3 PV of the heterogeneous phase combination system was followed by 0.3 PV of the polymer solution. For Scheme 3, 0.3 PV of the heterogeneous phase combination system was followed by 0.3 PV of the heterogeneous system. Thus, the total chemical-slug volume was 0.6 PV for all three schemes. Subsequently, water flooding was resumed until the produced-fluid water cut reached 98%. During the displacement process, injection pressure, water cut, and recovery factor were continuously monitored and recorded.

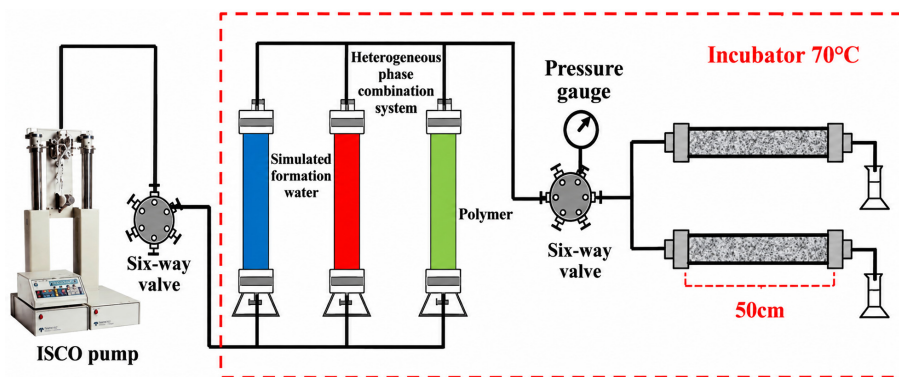


Figure 1: Flow chart of parallel sand-packed tube displacement experiment.

Using parallel cores, experimental studies were conducted on conventional injection, alternating injection of a heterogeneous phase combination system and polymer, and alternating injection of a heterogeneous phase combination system and a heterogeneous system to optimize the injection mode of heterogeneous phase combination flooding. The specific experimental schemes are shown in Table 1.

Table 1: Scheme design of different multi-slug combination injection modes.

No.	Injection Mode	Injection Slug and Slug Size
1	Conventional injection of heterogeneous phase combination system	Slug combination ①: 1500 mg/L polymer + 1000 mg/L PPG + 2000 mg/L surfactant; total injection volume 0.6 PV
2	Alternating injection of heterogeneous phase combination system and polymer	Slug combination ①: 0.3 PV; Slug combination ②: 1500 mg/L polymer; 0.3 PV; Total injection volume: 0.6 PV
3	Alternating injection of heterogeneous phase combination system and heterogeneous system	Slug combination ①: 0.3 PV; Slug combination ③: 1500 mg/L polymer + 1000 mg/L PPG; 0.3 PV; Total injection volume: 0.6 PV

Note: For the alternating-injection schemes, one alternating cycle consisted of two consecutive 0.3-PV slugs, giving a total chemical injection volume of 0.6 PV.

2.2.2 Three-Dimensional Physical Simulation Displacement Experiments

Three-dimensional areal heterogeneous physical simulation models ($40\text{ cm} \times 40\text{ cm} \times 4\text{ cm}$) were designed to test the variation patterns of oil saturation in high- and low-permeability layers and the oil recovery enhancement capability under conventional and alternating injection of different heterogeneous phase combination flooding systems. The specific experimental procedures were as follows:

- (1) Saturated water. One end of the plate model was connected to a circulating-water multi-purpose vacuum pump and evacuated for 10–12 h to achieve a vacuum. Simulated formation water was injected into the vacuumed core using a pump. As water has a higher density, water was injected from bottom to top during saturation. The saturated water volume was measured to determine the core's pore volume.
- (2) Saturated oil. Simulated oil was prepared by mixing crude oil with kerosene in the specified ratio and was traced with Sudan III red biological dye. An ISCO pump was then used to displace water with oil at different rates ($0.5\text{ mL}\cdot\text{min}^{-1}$, $1.0\text{ mL}\cdot\text{min}^{-1}$, $1.5\text{ mL}\cdot\text{min}^{-1}$) until the produced fluid contained 100% oil. During oil saturation, taking advantage of gravity, the plate model was rotated 90° to an upright position. Since oil density is lower than water density, simulated oil was injected from the top, and formation water was discharged from the bottom to ensure full saturation of the plate model with simulated oil. The volume of discharged formation water represented the oil saturation volume.
- (3) Water flooding. The experimental apparatus was connected as shown in Fig. 2. Simulated formation water was injected into the model at a constant total rate of $4\text{ mL}\cdot\text{min}^{-1}$, and the produced fluid at the outlet was collected. Resistance values were measured and recorded. The experiment was stopped when the water cut of the produced fluid reached 98%.
- (4) Injection of heterogeneous phase combination flooding system and subsequent water flooding. According to the experimental scheme design, conventional injection of a heterogeneous phase combination flooding system and alternating injection of a heterogeneous phase combination system and a heterogeneous system were conducted, respectively. Based on saturation field changes during the experiment, the variation patterns of the remaining oil saturation field under different injection modes and the degree of recovery enhancement were compared and analyzed until the produced fluid water cut reached 98%.

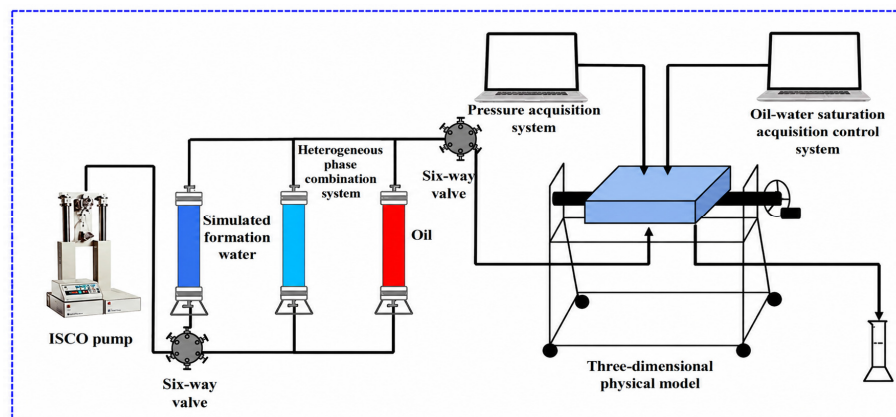


Figure 2: Experimental setup for three-dimensional inter-layer heterogeneous model displacement.

The specific schemes are shown in Table 2. In the table, the heterogeneous phase combination flooding system: 1500 mg/L polymer + 1000 mg/L PPG + 2000 mg/L surfactant; the heterogeneous flooding system: 1500 mg/L polymer + 1000 mg/L PPG.

Table 2: Experimental schemes for a three-dimensional heterogeneous model.

No.	Porosity/%	Core Permeability/ μm^2	Injected Heterogeneous Phase Combination Flooding System	Injection Slug/PV
1	30	0.5:1.5	Conventional injection of heterogeneous phase combination flooding system	0.6
2	30	0.5:1.5	Alternating injection of heterogeneous phase combination system and heterogeneous system	0.6

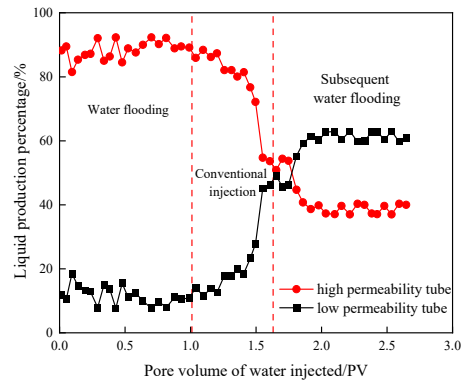
Note: For the alternating-injection schemes, one alternating cycle consisted of two consecutive 0.3-PV slugs, giving a total chemical injection volume of 0.6 PV.

3 Experimental Results and Discussion

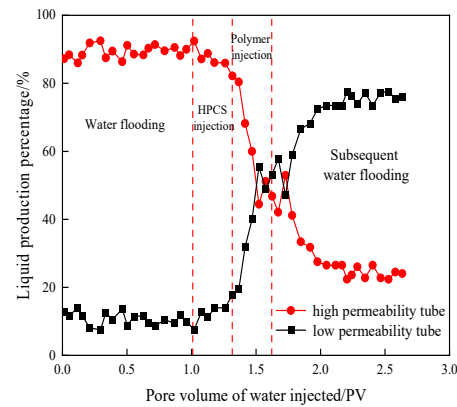
3.1 Optimization of Heterogeneous Phase Combination Flooding Injection Mode

3.1.1 Analysis of Fluid Distribution under Different Heterogeneous Phase Combination Flooding Injection Modes

According to the displacement experimental procedures and scheme design, the fluid distribution curves for conventional injection of a heterogeneous phase combination system, alternating injection of a heterogeneous phase combination system, and alternating injection of a heterogeneous phase combination system and a heterogeneous system were plotted (Fig. 3).

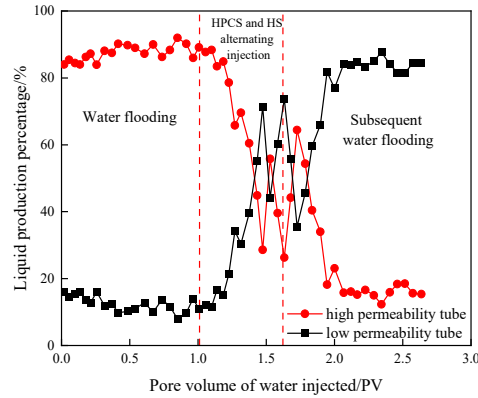


(a)



(b)

Figure 3: *Cont.*



(c)

Figure 3: Fluid distribution curves under different injection modes of a heterogeneous phase combination system. (a) Fluid distribution of conventional injection of heterogeneous phase combination system; (b) Fluid distribution during alternating injection of the heterogeneous phase combination system and polymer; (c) Fluid distribution of alternating injection of heterogeneous phase combination system and heterogeneous system. Note: (b) HPCS-Heterogeneous phase combination system; (c) HS-Heterogeneous system.

During the initial water flooding stage, flow was almost entirely dominated by the high-permeability tube, reflecting severe channeling and low sweep efficiency in the low-permeability zone. Conventional single-slug injection only partially improved the split ratio, which changed from 90:10 to 36:64, with the low-permeability tube's contribution limited to 64%, indicating incomplete plugging and residual channeling. Alternating injection with a pure polymer slug achieved a more stable improvement, as the polymer slug further enhanced flow resistance in the high-permeability zone, promoting more effective fluid diversion. Alternating injection with two heterogeneous slugs yielded the best performance, with the split ratio improving to 16:84 and the low-permeability tube's liquid production percentage reaching 84%. The repeated plugging-diversion cycles continuously built resistance in high-permeability channels, improving sweep efficiency in the low-permeability zone.

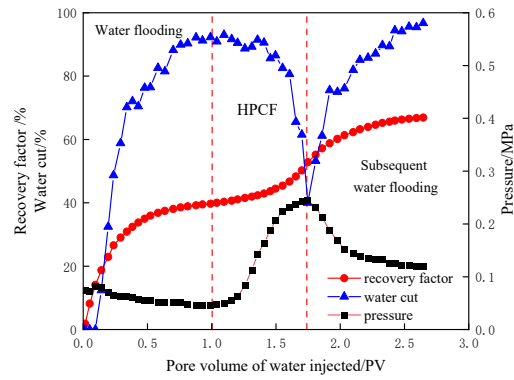
Overall, alternating injection outperformed conventional single-slug injection, and the heterogeneous-heterogeneous alternating mode delivered the strongest profile improvement. Thus, this mode is recommended for field application.

3.1.2 Analysis of Displacement Curves

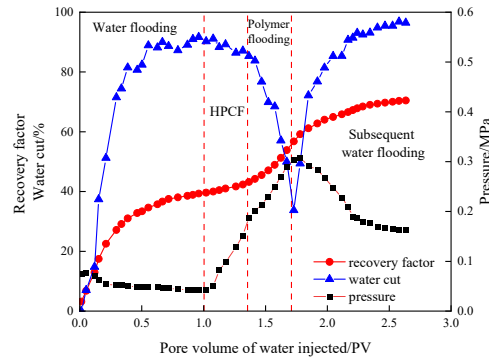
The variation curves of water cut, pressure, and recovery factor with injected pore volume multiples were plotted, yielding the displacement curves for conventional injection of a heterogeneous phase combination system, alternating injection of a heterogeneous phase combination system and polymer, and alternating injection of a heterogeneous phase combination system and a heterogeneous system (Fig. 4).

During the water flooding stage, the water cut rapidly increased to 80% after the water-free oil production period, then slowly increased to 90%. After switching to heterogeneous phase combination system injection, pressure continued to rise, and water cut began to decrease significantly. The alternating injection of a heterogeneous phase combination system and a heterogeneous system yielded the highest pressure and the largest reduction in water cut. During subsequent water injection, pressure decreased and then stabilized.

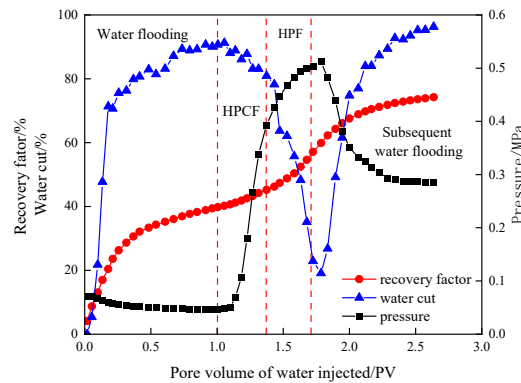
The increase in injection pressure after chemical flooding indicates increased flow resistance in preferential channels, suggesting that the injected system partially restricted the flow capacity of high-permeability pathways and promoted subsequent fluid diversion toward low-permeability regions.



(a)



(b)

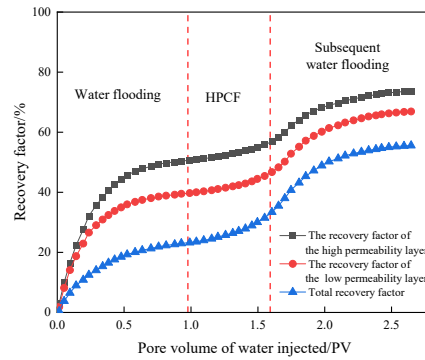


(c)

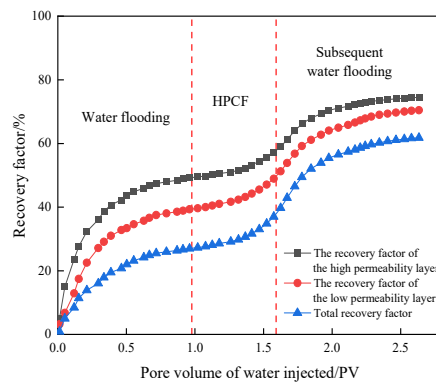
Figure 4: Displacement curves under different injection modes in heterogeneous phase-combination flooding. (a) Displacement curve of conventional injection of heterogeneous phase combination system; (b) Displacement curve of alternating injection of heterogeneous phase combination system and polymer; (c) Displacement curve of alternating injection of heterogeneous phase combination system and heterogeneous system. Note: (a) HPCF—heterogeneous phase-combination flooding; (c) HPF—Heterogeneous phase flooding.

3.1.3 Recovery Factor Analysis

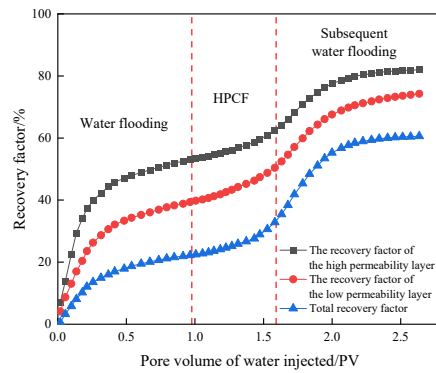
Comprehensive analysis yielded the recovery factor curves for conventional injection of a heterogeneous phase combination system, alternating injection of a heterogeneous phase combination system and polymer, and alternating injection of a heterogeneous phase combination system and a heterogeneous system (Fig. 5).



(a)



(b)



(c)

Figure 5: Recovery factor curves for different injection modes in heterogeneous phase-combination flooding. (a) Conventional injection recovery factor curve of heterogeneous phase combination system; (b) Alternating injection recovery factor curve of heterogeneous phase combination system and polymer; (c) Alternating injection recovery factor curve of heterogeneous phase combination system and heterogeneous system.

In terms of oil displacement effect, the incremental recovery factor for conventional injection of heterogeneous phase combination system was 27.4%; for alternating injection of heterogeneous phase combination system and polymer, it was 30.8%; and for alternating injection of heterogeneous phase combination system and heterogeneous system, the oil recovery enhancement effect was the best, with an incremental recovery factor of 34.4%, significantly higher than other injection modes. Therefore, the recommended injection mode for field application is alternating injection of a heterogeneous phase combination system and a heterogeneous system.

3.1.4 Comparison of Displacement Effects under Different Multi-Slug Combination Modes

To further analyze the displacement effects of different injection schemes, the profile improvement effects and oil displacement effects of various injection modes were comprehensively compared to select the optimal multi-slug combination injection mode.

As shown in Table 3, alternating injection exhibited better profile improvement and oil displacement performance than conventional injection. The fluid distribution ratio between high- and low-permeability tubes changed from 90:10 during water flooding to 16:84 after alternating injection, indicating improved fluid diversion capacity. In terms of oil displacement performance, the incremental recovery factors were 27.4%, 30.8%, and 34.4% for conventional injection, alternating injection of a heterogeneous phase combination system and polymer, and alternating injection of a heterogeneous phase combination system and a heterogeneous system, respectively. Although the differences among the schemes were relatively limited, repeated experiments confirmed the reproducibility of the results. Compared with conventional injection, the alternating injection of a heterogeneous phase combination system and a heterogeneous system increased the incremental recovery factor by 7.0 percentage points. This improvement was mainly attributed to the complementary functions of the three components. Polymer improved mobility control, PPG selectively plugged high-permeability channels and promoted fluid diversion, whereas the surfactant reduced the oil–water interfacial tension and facilitated the mobilization of capillary-trapped residual oil. The synergistic interaction of these mechanisms enhanced both macroscopic sweep efficiency and microscopic displacement efficiency. Subsequently, the injected heterogeneous system was diverted toward relatively unswept, low-permeability regions, thereby improving reservoir space utilization and mobilizing remaining oil. Compared with alternating injection of the heterogeneous phase combination system and polymer, the heterogeneous-heterogeneous alternating mode provided a stronger and more persistent profile control effect because both injected slugs contributed to channel regulation and mobility control. Therefore, this injection mode was considered the optimal strategy among the tested schemes.

Table 3: Comparison of displacement effects under different multi-slug combination injection modes.

Injection Mode	Fluid Distribution Ratio between High and Low Permeability Tubes (High-Permeability: Low-Permeability)	Incremental Recovery Factor/%
Conventional injection of heterogeneous phase combination system	36:64	27.4
Alternating injection of heterogeneous phase combination system and polymer	24:76	30.8

3.2 Three-Dimensional Physical Model Displacement Experiments under Different Heterogeneous Phase Combination System Injection Modes

3.2.1 Analysis of Oil Saturation at Different Stages

Through the oil saturation monitoring system, real-time monitoring was conducted throughout the experimental process to obtain corresponding data. Using plotting software, oil saturation distribution maps after subsequent water flooding under conventional and alternating injection modes were generated (Fig. 6).

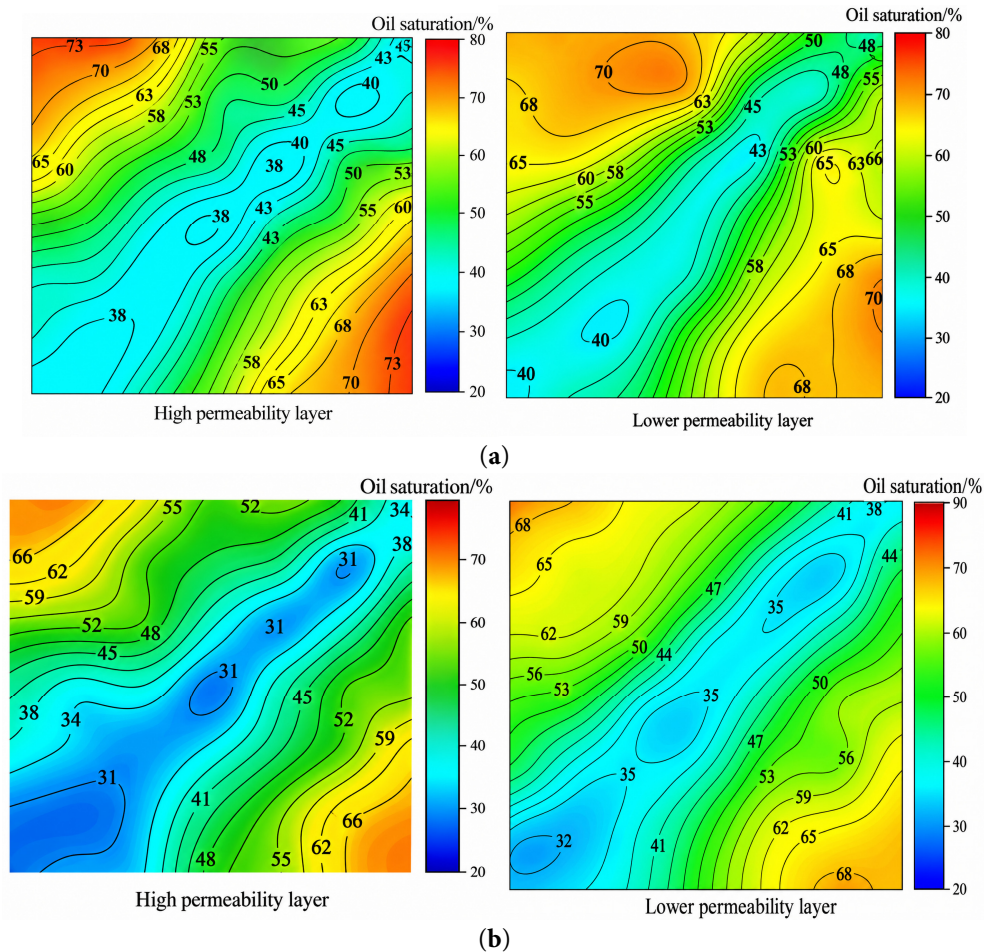


Figure 6: Oil saturation contour map in high- and low-permeability layers after subsequent water flooding. (a) Conventional injection; (b) Alternating injection.

From the perspective of oil saturation changes, alternating injection improved sweep efficiency by enhancing fluid diversion between high- and low-permeability regions, thereby enabling better mobilization of remaining oil in both layers. The oil saturation in the mainstream channels of both layers was lower, and the swept area was wider. Under alternating injection, oil saturation in high-permeability layer mainstream channels decreased from 44%–47% to 31%–34%, while in low-permeability layers it decreased from 50%–58% to 32%–38%. In terms of incremental recovery factor, alternating injection achieved a 5 percentage point higher value than conventional injection, demonstrating greater oil recovery enhancement.

3.2.2 Recovery Factor Analysis

Through experiments, the variation curves of recovery factor, water cut, and injection pressure with respect to injected pore volume multiples during conventional and alternating injection in a heterogeneous phase-combination flooding system were obtained (Fig. 7).

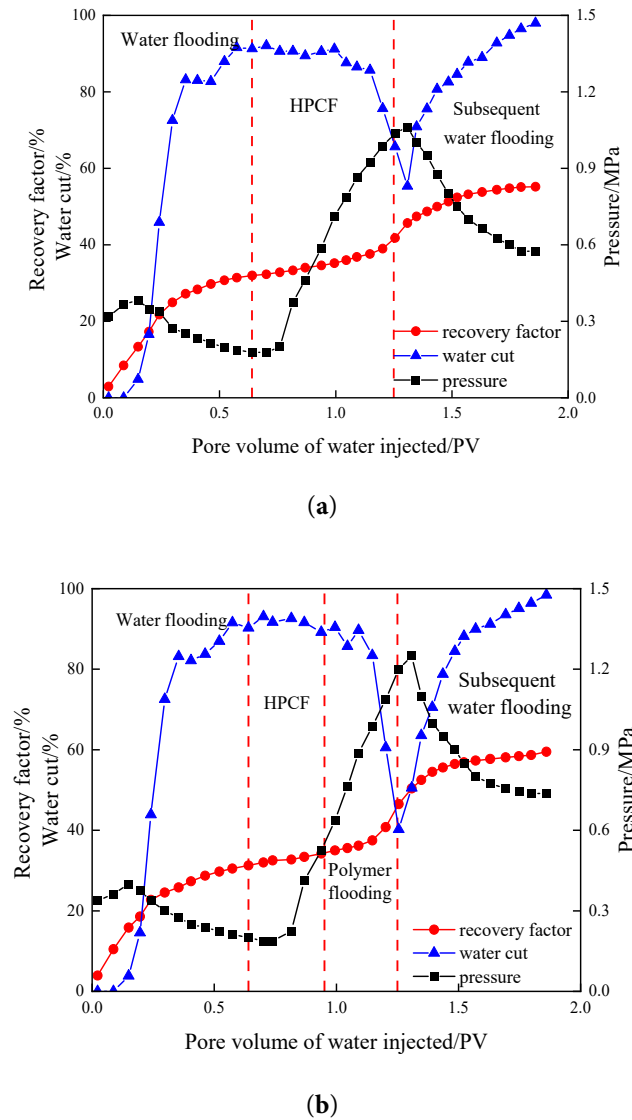


Figure 7: Displacement curves under different injection modes. (a) Conventional injection; (b) Alternating injection.

In Table 4, the incremental recovery factor for conventional injection was 23.2%, while that for alternating injection was 28.2%. Alternating injection achieved a 5 percentage point higher incremental recovery factor than conventional injection, indicating that it has better sweep-volume expansion effects, can better mobilize remaining oil after the high water-cut stage, and demonstrates superior oil recovery enhancement capability.

Table 4: Recovery factors at different stages under different injection modes in large plate displacement experiments.

Permeability Ratio	Injection Mode	Water Flooding Recovery Factor/%	Subsequent Water Flooding Recovery Factor/%	Incremental Recovery Factor/%
3:1	Conventional injection	32	55.2	23.2
3:1	Alternating injection	31.3	59.5	28.2

4 Conclusions

- (1) Alternating injection significantly improved fluid redistribution and profile control compared with conventional single-slug injection. For the optimal alternating mode, the fluid distribution ratio between the high- and low-permeability tubes changed from 90:10 before profile modification to 16:84 after treatment, indicating effective suppression of preferential flow through the high-permeability channels and enhanced fluid diversion toward low-permeability regions.
- (2) Among the investigated injection strategies, alternating injection of the heterogeneous phase combination system and heterogeneous system exhibited the best overall displacement performance, with an incremental recovery factor of 34.4%, which was 7.0 percentage points higher than that of conventional injection. This improvement was mainly attributed to the synergistic effects of selective plugging, mobility control, and repeated fluid redistribution, which enhanced sweep efficiency and mobilization of remaining oil under strongly heterogeneous conditions.
- (3) The three-dimensional physical simulation further confirmed the effectiveness of the alternating injection strategy. Compared with conventional injection, alternating injection increased the incremental recovery factor by 5.0 percentage points and promoted the redistribution of injected fluids toward previously less-swept regions. These results demonstrate that optimization of slug sequence and injection mode has practical significance for improving the development performance of ultra-high water-cut heterogeneous reservoirs.
- (4) Nevertheless, the present study was conducted using laboratory-scale sand-pack and three-dimensional physical models, which cannot fully reproduce the geological complexity, spatial scale, and long-term transport behavior of field reservoirs. Therefore, the experimental results should primarily be regarded as mechanistic evidence and relative performance evaluation. Future studies may further assess the applicability of the optimized strategy through reservoir-scale numerical simulation and, where appropriate, pilot-scale or field validation.

Acknowledgement: The Henan Provincial Key Laboratory of Enhanced Oil Recovery for providing laboratory facilities and technical support.

Funding Statement: The authors received no specific funding for this study.

Author Contributions: Conceptualization, Lianfeng Zhang and Hong He; methodology, Lianfeng Zhang; validation, Lianfeng Zhang and Hong He; formal analysis, Hong He; investigation, Hong He; resources, Lianfeng Zhang; writing—original draft preparation, Lianfeng Zhang; writing—review and editing, Lianfeng Zhang, Hong He and Yifei Zang; visualization, Yifei Zang. All authors reviewed and approved the final version of the manuscript.

Availability of Data and Materials: The original contributions presented in this study are included in the article. Further inquiries can be directed to the corresponding author.

Ethics Approval: Not applicable. This study did not involve human participants, human data, human tissues, animals, or animal-derived materials.

Conflicts of Interest: Author Lianfeng Zhang was employed by the Sinopec Henan Oilfield Company. The remaining authors declare that the research was conducted in the absence of any commercial or financial relationships that could be construed as a potential conflict of interest.

References

1. Terry RE. Enhanced oil recovery. In: Meyers RA, editor. Encyclopedia of physical science and technology. 3rd ed. New York, NY, USA: Academic Press; 2001. p. 503–18. [\[CrossRef\]](#).
2. Seright RS, Wang D. Polymer flooding: Current status and future directions. *Petrol Sci.* 2023;20(2):910–21. [\[CrossRef\]](#).
3. Skauge A, Zamani N, Gausdal Jacobsen J, Shaker Shiran B, Al-Shakry B, Skauge T. Polymer flow in porous media: Relevance to enhanced oil recovery. *Colloids Interfaces.* 2018;2(3):27. [\[CrossRef\]](#).
4. Yu H, Wang Y, Zhang L, Zhang Q, Guo Z, Wang B, et al. Remaining oil distribution characteristics in an oil reservoir with ultra-high water-cut. *Energy Geosci.* 2024;5(1):100116. [\[CrossRef\]](#).
5. Han P, Liu H, Han X, Cao R, Zhang Y, Liu X. Alternative injection and its seepage mechanism of polymer flooding in heterogeneous reservoirs. In: Proceedings of the SPE Asia Pacific Enhanced Oil Recovery Conference; 2015 Aug 11–13; Kuala Lumpur, Malaysia. Richardson, TX, USA: Society of Petroleum Engineers; 2015. p. SPE 174586–MS. [\[CrossRef\]](#).
6. Zhang X, Zhang Y, Liu H, Li S, Liu L. Dynamic sweep experiments on a heterogeneous phase composite system based on branched-preformed particle gel in high water-cut reservoirs after polymer flooding. *Gels.* 2023;9(5):364. [\[CrossRef\]](#).
7. He J, Song Z, Qiu L, Xie F, Tan Z, Yue Q, et al. High temperature polymer flooding in thick reservoir in Shuanghe Oilfield. In: Proceedings of the SPE International Oil and Gas Conference and Exhibition in China; 1998 Nov 2–6; Beijing, China. Richardson, TX, USA: Society of Petroleum Engineers; 1998. p. SPE 50933–MS. [\[CrossRef\]](#).
8. Wang Z, Zhang L, Yang L, Liu Y, Lu J, Zhang Z. Heterogeneous combination flooding system for post-polymer-flooding reservoirs in Shuanghe Oilfield. *Reserv Eval Dev.* 2020;10(6):78–84. (In Chinese). [\[CrossRef\]](#).
9. Liu W, He H, Yuan F, Liu H, Zhao F, Liu H, et al. Influence of the injection scheme on the enhanced oil recovery ability of heterogeneous phase combination flooding in mature waterflooded reservoirs. *ACS Omega.* 2022;7(27):23511–20. [\[CrossRef\]](#).
10. Xue L, Liu P, Zhang Y. Status and prospect of improved oil recovery technology of high water cut reservoirs. *Water.* 2023;15(7):1342. [\[CrossRef\]](#).
11. Li H, Wang K, Han X, Zheng J. Research on heterogeneous compound flooding system based on dispersed particle gel. *Adv Geo Energy Res.* 2019;3(2):156–64. [\[CrossRef\]](#).
12. Lu X, Cao B, Xie K, Cao W, Liu Y, Zhang Y, et al. Enhanced oil recovery mechanisms of polymer flooding in a heterogeneous oil reservoir. *Pet Explor Dev.* 2021;48(1):169–78. [\[CrossRef\]](#).
13. Wu D, Zhou K, Hou J, An Z, Zhai M, Liu W. Experimental study on combining heterogeneous phase composite flooding and streamline adjustment to improve oil recovery in heterogeneous reservoirs. *J Pet Sci Eng.* 2020;194:107478. [\[CrossRef\]](#).
14. Seidy Esfahlan M, Khodapanah E, Tabatabaei-Nezhad SA. Comprehensive review on the research and field application of preformed particle gel conformance control technology. *J Pet Sci Eng.* 2021;202:108440. [\[CrossRef\]](#).
15. Wang L, Xia H, Han P, Cao R, Xu T, Li W, et al. Synthesis of new PPG and study of heterogeneous combination flooding systems. *J Dispers Sci Technol.* 2022;43(2):164–77. [\[CrossRef\]](#).
16. Rong G, Liu Y, Xie W, Chen X. Oil displacement mechanism of a novel surfactant. *Chem Technol Fuels Oils.* 2024;60(4):1048–59. [\[CrossRef\]](#).
17. Seright RS. Conformance improvement using gels. Washington, DC, USA: New Mexico Institute of Mining and Technology; 2002. Report No.: FC26-01BC15316. [\[CrossRef\]](#).
18. Bai B, Liu Y, Coste JP, Li L. Preformed particle gel for conformance control: Transport mechanism through porous media. *SPE Reserv Eval Eng.* 2007;10(2):176–84. [\[CrossRef\]](#).
19. Sheng JJ. Modern chemical enhanced oil recovery: Theory and practice. Houston, TX, USA: Gulf Professional Publishing; 2011.
20. Lake LW. Enhanced oil recovery. Englewood Cliffs, NJ, USA: Prentice-Hall; 1989.

21. Pope GA. Recent developments and remaining challenges of enhanced oil recovery. *J Petrol Technol.* 2011;63(7):65–8. [[CrossRef](#)].
22. Du QJ, Pan GM, Hou J, Guo LL, Wang RR, Xia ZZ, et al. Study of the mechanisms of streamline-adjustment-assisted heterogeneous combination flooding for enhanced oil recovery for post-polymer-flooded reservoirs. *Pet Sci.* 2019;16(3):606–18. [[CrossRef](#)].
23. Pi Y, Su Z, Cao R, Li B, Liu J, Fan X, et al. Experimental study on enhanced oil recovery of PPG/ASP heterogeneous system after polymer flooding. *Gels.* 2023;9(5):427. [[CrossRef](#)].
24. An ZB, Zhou K, Wu DJ, Hou J. Production characteristics and displacement mechanisms of infilling polymer-surfactant-preformed particle gel flooding in post-polymer flooding reservoirs: A review of practice in Ng3 block of Gudao Oilfield. *Pet Sci.* 2023;20(4):2354–71. [[CrossRef](#)].
25. Zhang L, Liang L, Xue G, Long W, Shen N, Zhang Y, et al. Well-pattern adjustment for heterogeneous combination flooding in the IV1-3 reservoir of Shuanghe Oilfield. *Pet Reserv Eval Dev.* 2020;10(6):85–9. (In Chinese). [[CrossRef](#)].
26. Luo C. Channeling-control technology for binary combination flooding: A case study of the 438 I and II1-2 reservoirs in Shuanghe Oilfield. *Pet Geol Eng.* 2016;30(4):96–8. (In Chinese).
27. Hu J, Li A, Memon A. Experimental investigation of polymer enhanced oil recovery under different injection modes. *ACS Omega.* 2020;5(48):31069–75. [[CrossRef](#)].
28. Majidaie S, Onur M, Tan IM. An experimental and numerical study of chemically enhanced water alternating gas injection. *Pet Sci.* 2015;12(3):470–82. [[CrossRef](#)].
29. He H, Fu J, Hou B, Yuan F, Guo L, Li Z, et al. Investigation of injection strategy of branched-preformed particle gel/polymer/surfactant for enhanced oil recovery after polymer flooding in heterogeneous reservoirs. *Energies.* 2018;11(8):1950. [[CrossRef](#)].
30. Santoso R, Torrealba V, Hoteit H. Investigation of an improved polymer flooding scheme by compositionally-tuned slugs. *Processes.* 2020;8(2):197. [[CrossRef](#)].
31. Ahmed ME, Sultan AS, Al-Sofi A, Al-Hashim HS. Optimization of surfactant-polymer flooding for enhanced oil recovery. *J Pet Explor Prod Technol.* 2023;13(10):2109–23. [[CrossRef](#)].
32. Panthi K, Mohanty KK. Surfactant-polymer flood with seawater for a high temperature carbonate reservoir. *Colloids Surf A Physicochem Eng Asp.* 2024;688:133615. [[CrossRef](#)].
33. Al-Azani K, Abu-Khamsin S, Elsayed M, Patil S, Shakil Hussain SM, Al Shalabi E, et al. Chemical enhanced oil recovery under Harsh conditions: Investigation of rock permeability and insights from NMR measurements. *Geoenergy Sci Eng.* 2024;236:212764. [[CrossRef](#)].
34. Soleimani M, Abdaliousan A, Manshad AK, Ahmad Sajadiyan V. Advanced polymer-based surfactant for improved heat and salinity stability in enhanced oil recovery processes. *J Surfactants Deterg.* 2024;27(3):421–32. [[CrossRef](#)].