

Article

Water Influx Behavior and CO₂ Injection for Water Control and Production Enhancement in Vertically Heterogeneous Gas Reservoirs

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Abstract

In heterogeneous edge-water carbonate gas reservoirs during the middle-to-late development stage, edge-water invasion and pressure depletion significantly compromise production stability and gas recovery. To investigate water invasion behavior under permeability heterogeneity and evaluate the effectiveness of CO₂ injection for water control and enhanced gas recovery, a series of long-core depletion experiments and three-dimensional vertically heterogeneous physical-model experiments were conducted based on representative reservoir conditions. The results show that permeability contrast plays a key role in governing water breakthrough timing and gas production performance. High-permeability cores experience earlier water breakthrough but contribute higher overall recovery, whereas low-permeability cores exhibit delayed depletion and pronounced production decline after breakthrough due to large pressure differentials. In multilayer commingled production, interlayer pressure imbalance drives fluid crossflow from low- and medium-permeability zones toward high-permeability zones, leading to premature water breakthrough, delayed layer activation, and the development of water-blocked gas zones, thereby intensifying interlayer heterogeneity. After depletion, CO₂ injection effectively modifies fluid flow pathways and improves reservoir connectivity. Through gravity-assisted displacement and energy replenishment, CO₂ mitigates water invasion, reconnects previously isolated gas zones, and enhances overall reservoir utilization. The findings demonstrate that CO₂ injection provides a dual benefit in both water control and production enhancement, offering valuable insights for improving recovery strategies in heterogeneous edge-water gas reservoirs.



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Keywords: Puguang Gas Field; edge-water carbonate gas reservoir; water influx; CO₂ injection; enhanced gas recovery (EGR)

1. Introduction

Carbonate gas reservoirs constitute a major component of China's natural gas resources and are widely distributed in the Anyue [1], Puguang [2], Yuanba [3], and other regions. However, the development of these reservoirs is commonly affected by edge-

and bottom-water influx [4,5]. Strong reservoir heterogeneity further complicates gas–water flow paths [6]. Edge and bottom water preferentially invade along dominant flow channels and high-permeability streaks, advancing gas–well water breakthrough. After breakthrough, well productivity decreases sharply and water cut increases rapidly [7–10]. Ultimately, a large volume of gas in the reservoir may be isolated and trapped by the water phase, forming water-sealed gas [11–14], which substantially reduces the producing degree of reserves and poses severe challenges to reservoir pressure maintenance and stable production.

Therefore, clarifying the production mechanisms of gas reservoirs with edge and bottom water and revealing the governing laws of water influx are essential for development plan adjustment in the middle and late development stages and for enhanced gas recovery [15–18]. Based on geological conditions and production performance, Li Tao [19] predicted the direction and intensity of water influx in both vertical and horizontal directions and analyzed the influence of water-sealed gas on recoverable reserves. Li Yudan et al. [20] used field-scale numerical simulation and showed that a high production rate, a large water body, and strong interlayer connectivity further accelerate water influx. Based on visual microscopic experiments, Fang Feifei et al. [21] found that water preferentially breaks through along fractures and vugs, then enters matrix pores through imbibition and traps gas, thereby substantially reducing gas recovery. Zhang et al. [22] verified, through pore-scale experiments and numerical simulation, that the capillary number significantly affects gas–water distribution and that complex pore structures aggravate the water-sealed gas phenomenon. By summarizing multiscale research findings, Yang Dongsheng et al. [23] concluded that flow-around trapping, spontaneous imbibition-induced water blocking, and interface snap-off jointly contribute to water-sealed gas formation, with producibility controlled by capillary force, interfacial tension, and other factors.

In recent years, CO₂ injection has become a research focus because it can simultaneously inhibit water influx, replenish formation energy, and enhance gas recovery [24]. Guo Xiao et al. [25] indicated that CO₂ injection can form a gas cushion at the gas–water interface, hinder edge-water influx, and improve gas reservoir recovery. Liu Shuyang et al. [26] conducted macroscopic mechanism-based numerical simulations and demonstrated that CO₂ migration and methane production are jointly controlled by gravity effects and reservoir pressure. CO₂ injection at low pressure can effectively enhance recovery, whereas CO₂ injected under high pressure tends to sink and undergo premature breakthrough, thereby weakening the stimulation effect. Zeng Daqian et al. [27] verified, through nuclear magnetic resonance (NMR)-based series and parallel core experiments, that CO₂ preferentially migrates deep into high-permeability water-flooded zones, displaces invaded water backward in large pores, and effectively connects and produces water-trapped gas in water-invaded areas. On this basis, Song Zhaojie et al. [28] carried out series-parallel core-scale numerical simulations and further confirmed that CO₂ injection after water flooding can effectively delay edge-water influx, prolong the gas production period of production wells, and promote more balanced gas production from high- and low-permeability zones in heterogeneous reservoirs. Additionally, recent studies have emphasized that fluid migration and recovery performance in underground reservoirs are strongly affected by reservoir heterogeneity and coupled physical processes. Li et al. [29] reviewed thermo-mechanical mechanisms and fracture evolution during thermal stimulation in deep reservoirs, indicating that temperature- and stress-induced changes in fracture networks and permeability can significantly influence reservoir flow capacity. For gas reservoirs, Dai et al. [30] proposed an integrated calculation method for current recovery and limited recovery in tight sandstone gas reservoirs and indicated that gas recovery should be evaluated based on recoverable reserves and original gas in place, with key parameters including effective porosity, initial

gas saturation, and gas formation volume. These studies suggest that reliable physical simulation and recovery-factor evaluation require not only representative permeability contrasts and temperature-pressure conditions, but also clear definitions of pore volume, initial gas saturation, and recovery-factor calculation methods.

Depleted carbonate gas reservoirs have been increasingly recognized as promising targets for integrated CO₂ geological storage and enhanced gas recovery. Tang et al. [31] re-evaluated the CO₂ storage capacity of depleted fractured-vuggy carbonate reservoirs and indicated that complex pore-fracture structures and multiscale heterogeneity strongly affect CO₂ migration and trapping behavior. Hu et al. [32] investigated CO₂ storage with enhanced gas recovery in depleted, highly heterogeneous carbonate gas reservoirs and showed that reservoir type, interlayer communication, and permeability heterogeneity play important roles in CO₂ breakthrough, CH₄ recovery, and storage performance. These findings indicate that CO₂ injection in heterogeneous carbonate gas reservoirs is controlled not only by density difference and displacement capacity, but also by reservoir architecture and gas–water flow redistribution, further highlighting the necessity of physical simulation studies on CO₂-assisted water control and production enhancement in vertically heterogeneous edge-water gas reservoirs. In addition, three-dimensional flow in porous media is strongly affected by permeability distribution and pore-structure heterogeneity. Latif et al. [33,34] investigated three-dimensional convective flow in porous media with periodic permeability and showed that spatial variations in permeability can significantly influence flow-field redistribution and transport behavior. Although these studies mainly focus on theoretical porous-media flow and heat-transfer processes, they indicate that three-dimensional flow behavior is highly sensitive to permeability- and porosity-related heterogeneity. This further supports the use of three-dimensional physical models to investigate water influx, interlayer crossflow, and gas–water redistribution in vertically heterogeneous gas reservoirs.

Current studies of gas reservoir water influx and CO₂ injection are mostly limited to small-scale core experiments or field-scale numerical simulations. The production performance and water influx characteristics of vertically heterogeneous multilayer reservoirs under commingled production, as well as the mechanisms by which CO₂ injection controls water and enhances recovery, remain insufficiently understood. Although previous studies have clarified pore-scale water blocking, single-core water-influx behavior, and field-scale CO₂-EGR performance, two key issues remain unresolved. First, the mechanism by which vertical permeability contrast redistributes pressure, invading water, and remaining gas during multilayer commingled production has not been quantified sufficiently at the physical-model scale. Second, the way in which post-depletion CO₂ injection reconnects water-sealed gas zones and changes the interlayer production contribution is still unclear. To address these issues, this study systematically investigates water influx behavior and CO₂-based water control mechanisms in vertically heterogeneous edge-water gas reservoirs. Long-core depletion and water-influx experiments were conducted using representative core samples from the Puguang Gas Field to quantify the influence of permeability heterogeneity on water breakthrough behavior, pressure-depletion lag, and recovery performance. In addition, three-dimensional large-scale physical models with different vertical permeability contrasts were constructed to simulate multilayer commingled production under realistic reservoir conditions, enabling the identification of water invasion stages and interlayer crossflow mechanisms. Post-depletion CO₂ injection experiments were further performed to evaluate its effectiveness in redistributing gas–water phases, mitigating water encroachment, and enhancing recovery. This study is based on the hypothesis that an increase in vertical permeability contrast promotes preferential flow toward high-permeability layers, intensifies interlayer crossflow, and traps significant amounts

of gas in low- and medium-permeability zones, whereas CO₂ injection can partially reverse this unfavorable distribution through gravity segregation and viscous displacement, thereby reconnecting water-blocked gas zones and improving overall reservoir utilization. Through real-time monitoring of pressure evolution and saturation distribution, the study clarifies the mechanisms of interlayer interference during depletion and CO₂ injection processes, providing theoretical support for optimizing production strategies, improving water control, and enhancing gas recovery in mature edge-water gas reservoirs.

2. Experimental Design

2.1. Long-Core Depletion and Edge-Water Influx Experiments

Based on the petrophysical properties of different reservoir types in the Puguang Gas Field, four representative natural cylindrical core plugs (30 cm long and 2.5 cm in diameter) were selected. Their gas permeabilities were 0.64, 5.94, 442, and 1923 mD, corresponding to reservoir types ranging from ultra-low-permeability matrix to high-permeability matrix. The petrophysical properties of the cores are listed in Table 1. Depletion gas-production experiments were conducted under reservoir conditions (123 °C and 56 MPa). A constant-pressure edge-water simulation system was established, and production was controlled at a constant rate using a back-pressure regulator and a flow meter. Gas production rate and pressure data were measured to characterize pressure evolution and differences in recovery factor among cores with different permeabilities during edge-water influx.

Table 1. Petrophysical properties of the experimental cores.

Core Number	Permeability Class	Gas Permeability	Porosity	Irreducible Water Saturation
1	High-permeability matrix	1923 mD	18.19%	24.26%
2	Medium-permeability matrix	442 mD	15.19%	24.1%
3	Low-permeability matrix	5.94 mD	13.06%	22.93%
4	Ultra-low-permeability matrix	0.64 mD	8.34%	21.59%

The experimental gas was N₂ with a purity of 99%, and the edge water was CaCl₂-type synthetic formation water. N₂ was selected as the initial gas phase because it is chemically stable, safe under high-temperature and high-pressure laboratory conditions, and can be clearly distinguished from injected CO₂ during subsequent gas-composition analysis. The purpose of the experiments was to reproduce gas–water flow and pressure redistribution rather than hydrocarbon phase behavior; therefore, the use of N₂ provides a conservative and repeatable substitute for dry reservoir gas in the physical simulation.

The edge-water system was operated in constant-pressure mode at the initial reservoir pressure, so the instantaneous water-influx rate was controlled by the pressure gradient and core permeability rather than by a preset fixed water rate. The experimental apparatus mainly included a high-precision constant-flow/constant-pressure pump for controlling water-end pressure; a high-pressure core holder equipped with multiple pressure measurement points, pressure sensors, and a data acquisition system; and a gas booster and gas flow meter for maintaining and monitoring gas pressure and flow rate. The schematic configuration is shown in Figure 1.

The experimental procedures were as follows:

- (1) Core Sample Preparation: The core samples were dried, and their permeability and porosity were measured.
- (2) Establishment of Initial Water Saturation: The core samples were placed in a reactor, evacuated at −0.1 MPa for one day, and then saturated with formation water at 25 MPa for three days. Subsequently, each long core was removed and placed in a core holder.

Gas displacement of water was performed at the experimental temperature of 123 °C to establish the initial reservoir water saturation (Table 1).

(3) Core Pressurization: The gas boosting device and inlet valve were opened. The core sample was charged with gas at a constant pressure of 56 MPa for more than 3 h until the pressures at the inlet, outlet, and intermediate measurement points remained stable. The gas source and inlet valve were then closed.

(4) Gas Production Stage: The outlet valve of the core holder was opened to start gas production. Meanwhile, the edge water injection valve was opened at the inlet end, and the water-end pressure was maintained at 56 MPa via the constant-pressure pump to simulate an active edge water body. No fixed water injection rate was set, and the actual water influx occurred naturally under the combined effect of the defined pressure boundary and production pressure drop. A back-pressure regulator and flow meter at the outlet were used to achieve gas production at a constant rate. The gas production rates for cores with different permeability were scaled based on flow capacity, which were consistent with the layer flow rate design adopted in the 3D model experiments. During the test, the gas flow meter at the outlet was used to record gas production volume, and the pressure at each measuring point along the core was monitored in real time. The experiment was terminated when the pressure dropped to the abandonment pressure of 17 MPa. This value serves as the lower pressure limit for laboratory depletion comparison, and it is also the critical pressure at which stable gas production becomes difficult for the water-invaded gas reservoirs investigated in this study.

(5) Equipment Cleaning: After the experiment, the pressure was released, the pipelines were drained, and the experimental equipment was cleaned. Steps (1)–(4) were repeated to complete the depletion and water-influx experiments on long cores with different permeabilities.

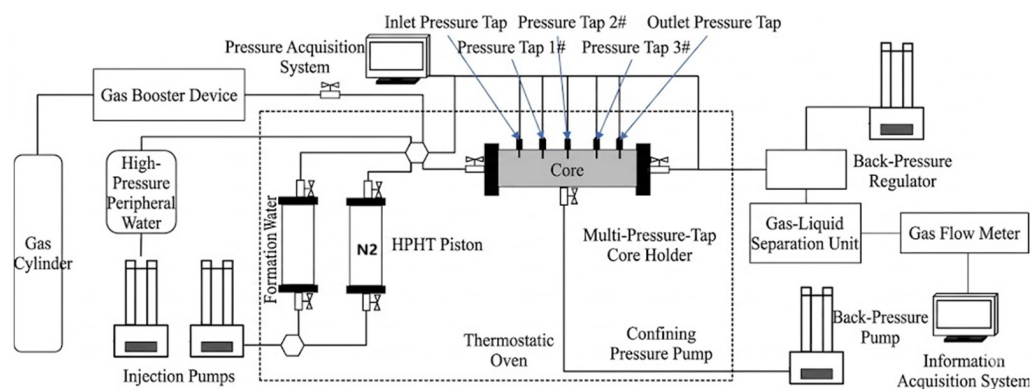


Figure 1. Schematic diagram of the long-core depletion and edge-water influx apparatus.

2.2. Simulation Experiments of Depletion-Driven Water Influx and CO₂ Injection Water Control in Porous 3D Large-Scale Physical Models

2.2.1. Fabrication of the 3D Large-Scale Physical Model

A porous rectangular core block measuring 300 mm × 100 mm × 100 mm was fabricated for each layer. Each block represented one vertical reservoir interval with a length of 300 mm, a layer height of 100 mm, and a model thickness of 100 mm. Three blocks were stacked from top to bottom and sealed along the interfaces to form a three-layer model with overall dimensions of 300 mm × 300 mm × 100 mm (30 cm × 30 cm × 10 cm). In the manuscript, “upper”, “middle”, and “lower” describe the vertical position of a layer, whereas “low-permeability”, “medium-permeability”, and “high-permeability” describe its flow capacity. Two large-scale models with different permeability combinations (0.64 mD–1923 mD–442 mD and 5.94 mD–1923 mD–53.2 mD from top to bottom) were

designed to simulate vertical reservoir heterogeneity under different permeability contrasts. In Model No. 2, the 53.2 mD lower layer is therefore referred to as the lower medium-permeability layer relative to the 5.94 mD upper low-permeability layer. Gas permeability was measured using N_2 under the experimental confining-pressure condition, and porosity was determined from the saturated-water volume and the geometric volume of each core block. The pore volume of each layer was then calculated based on the measured porosity and the bulk volume of the corresponding rectangular core block. These calibrated parameters were used to verify that the designed permeability contrast and storage capacity of each layer were consistent with the target reservoir conditions.

The experimental gas was N_2 with a purity of 99%, which was used as the initial gas phase in both the long-core experiments and the 3D physical model experiments, whereas CO_2 was introduced only during the post-depletion injection stage. Therefore, the produced-gas composition during CO_2 injection reflects the displacement relationship between the original N_2 phase and the injected CO_2 phase. The edge water was $CaCl_2$ -type synthetic formation water. A computer-controlled electro-hydraulic servo pressure testing machine and a core-cutting machine were used to fabricate and cut the square cores. Nine pressure sensors were embedded in each square core and connected to a data acquisition system. During the experiment, the large-scale physical model was placed in a high-temperature and high-pressure 3D experimental chamber. A high-precision constant-flow/constant-pressure pump was used to inject water and simulate water encroachment. In addition, high-pressure metering instruments, including a gas flow meter and an automatic liquid/gas production measurement device, were used to accurately measure production rate. Photographs of the 3D large-scale physical model and the experimental setup are shown in Figure 2.

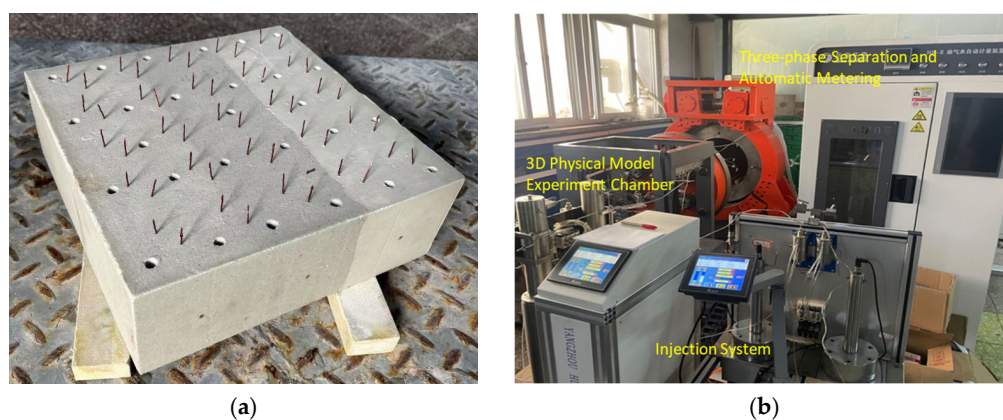


Figure 2. Photograph of the 3D large-scale physical model (a) and the large-scale physical simulation cell with supporting equipment (b).

2.2.2. Methods and Procedures for Depletion-Water Influx Experiments

Depletion production experiments were conducted on the prepared 3D large-scale models using a high-temperature and high-pressure 3D physical simulation platform. Through real-time monitoring of water saturation, pressure, and gas production rate, water-intrusion behavior, pressure evolution, and gas-production characteristics were determined for reservoirs with different permeabilities. The overall and layer-specific recovery factors during depletion were then summarized.

(1) Rock Sample Preparation: The rock sample was compacted, cut, cleaned, and dried. The 3D large-scale model was then installed in the chamber, and water was injected to establish a confining pressure of 56 MPa.

(2) Establishment of Initial Water Saturation: The model was evacuated at -0.1 MPa for one day and then saturated with formation water at 25 MPa for three days. At an experimental temperature of 123 °C, the initial water saturation of each layer was established by gas-driven water displacement (Table 2).

(3) Model Pressurization: The gas pressurization unit and chamber inlet valve were opened. Gas was charged into the 3D large-scale model at a constant pressure of 56 MPa until all pressure monitoring points stabilized. The gas source and inlet valve were then closed.

(4) Experimental Stage: The outlet valve was opened to initiate commingled gas production through a single production outlet. Simultaneously, the edge-water supply valve was opened, and the constant-pressure pump maintained the edge-water boundary at 56 MPa. Therefore, the water influx rate was not prescribed as a constant value, but varied dynamically with pressure depletion, permeability contrast, and water-front migration. During the experiment, gas production, water production, and pressure data for the entire 3D large-scale model and each individual layer were continuously recorded. The experiment was terminated when the model pressure declined to 17 MPa. This abandonment pressure was selected to represent a sufficiently depleted late-stage reservoir condition (approximately 30% of the initial pressure of 56 MPa), while ensuring reliable observation of water breakthrough behavior and avoiding unrealistic near-zero pressure conditions in the laboratory system.

(5) Experimental steps (1)–(4) were repeated for 3D large-scale Model No. 2, and the water-intrusion behavior and production characteristics of vertically heterogeneous reservoirs with different permeability contrasts were compared.

Table 2. Layer design and physical properties of the vertically heterogeneous large-scale physical model.

Model No.	Horizon	K_g	S_{wi}	q_g
1	Upper	0.64 mD	26.56%	313 mL/min
	Middle	1923 mD	22.54%	1300 mL/min
	Lower	442 mD	23.73%	630 mL/min
2	Upper	5.94 mD	25.88%	406 mL/min
	Middle	1923 mD	24.69%	1300 mL/min
	Lower	53.2 mD	26.82%	522 mL/min

Note: K_g represents gas permeability; S_{wi} represents irreducible water saturation; q_g represents the designed equivalent gas-production capacity of each layer under the model flow-capacity design.

The q_g values were used to characterize the designed equivalent gas-production capacity of each layer based on its permeability and flow capacity. During the commingled-production experiment, the model produced gas through a single outlet, and the layer-specific production contribution was evaluated from the measured production response, pressure evolution, and saturation-field variation rather than by independently controlling each layer flow rate.

2.2.3. Methods and Procedures for CO₂ Injection After Depletion and Water Influx

Using the large-scale 3D models after depletion production under edge-water intrusion, CO₂ injection experiments for energy replenishment and enhanced gas recovery (EGR) were conducted. Based on gas-composition sampling, pressure measurements, and saturation-field variations, the water-control effect of CO₂ injection and production data for each layer were analyzed. The suppression of edge-water front advancement was determined, and changes in produced-fluid components and gas–water ratio were evaluated (Figure 3).

(1) Top CO₂ Injection Experiment: The production rate at the outlet was consistent with that adopted in the depletion production test. CO₂ was injected at a constant flow rate into the center of the upper square core of the physical model with an injection–production ratio set to 1.2 to conduct the water control experiment of CO₂ injection after gas depletion. This injection–production ratio was determined with reference to field development experience of edge-water gas reservoirs and previous studies on CO₂-enhanced gas recovery (CO₂-EGR), which can moderately maintain reservoir pressure and prevent premature gas breakthrough. CO₂ injection at the center of the upper square core of the model adopts a quasi-top injection layout. This design can reproduce the actual working conditions of injection at structural highs in field formations and eliminate the interference of boundary-dominated flow in laboratory models. It enables CO₂ to accumulate at the top of the core and form gravity-stable gas–water segregation similar to actual reservoir conditions.

(2) Monitoring of Produced Components During Production: The produced gas–liquid mixture was metered by an intermediate vessel installed at the outlet and equipped with a sampling port, enabling gas composition sampling and analysis at different stages. Because N₂ was used as the initial gas phase and CO₂ was used as the injected gas, variations in the produced N₂ proportion were used to characterize the recovery of the original gas phase and to identify CO₂ breakthrough during injection. The experiment was completed when the model continuously produced to the abandonment pressure of 17 MPa.

(3) Steps (1)–(2) were repeated for the 3D large-scale Model No. 2, and the water-control effect of CO₂ injection after water invasion and the production behavior of vertically heterogeneous reservoirs with different permeability contrasts were compared.

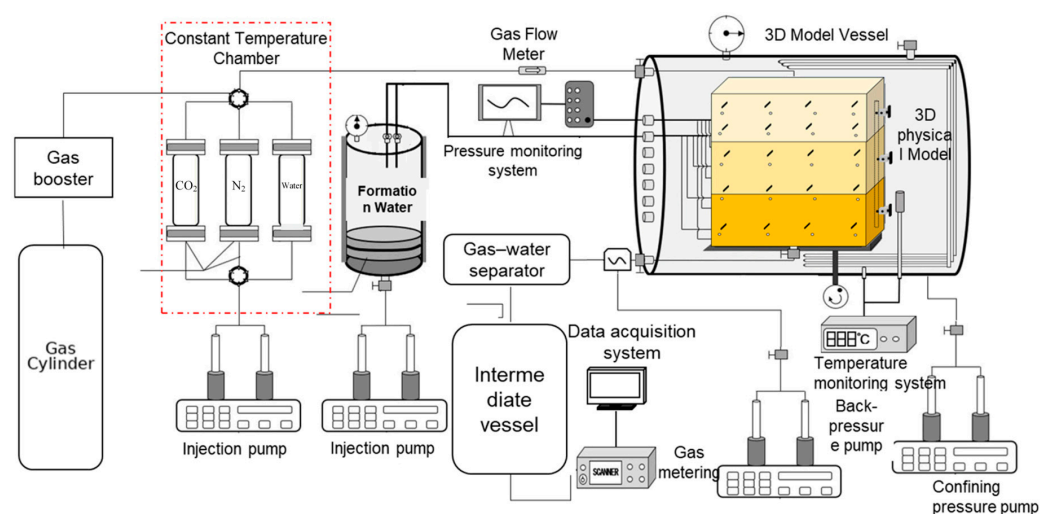


Figure 3. Schematic diagram of the post-depletion CO₂ injection apparatus for the large 3D model.

3. Experimental Results and Discussion

3.1. Effects of Reservoir Physical Properties on Water Influx Behavior and Depletion Production Characteristics

Four long cores with substantial permeability contrast were used for depletion gas–production and edge-water encroachment simulation experiments to analyze the influence of permeability on production characteristics. The experimental results are shown in Figure 4. The depletion production characteristics of all cores were generally similar. Before water breakthrough at the production end, gas production rate was relatively high and recovery factor increased rapidly. However, water breakthrough time and post-breakthrough gas production rate were strongly affected by permeability. Overall, lower core permeability delayed water breakthrough but caused a greater decline in gas production rate after breakthrough. As core permeability decreased from 1923 mD to 0.64 mD, water break-

through was delayed from approximately 10% to 31.7% of the production period, where the production period was normalized by the total experimental production time from the start of gas production to the abandonment pressure of 17 MPa. Therefore, the value of 31.7% refers to the proportion of elapsed production time before water breakthrough, rather than the recovery factor or cumulative gas production, whereas the ultimate recovery factor decreased from 66.61% to 52.32%.

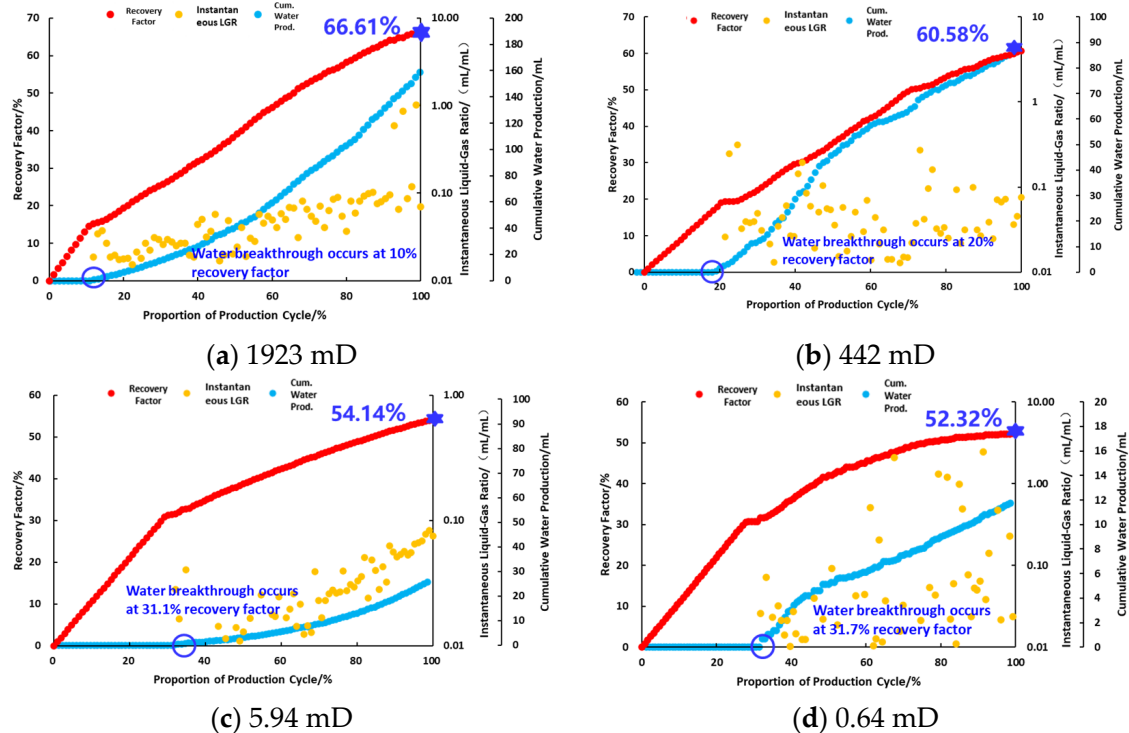


Figure 4. Comparison of production characteristics for cores with different permeabilities.

High-permeability cores (1923 mD and 442 mD) exhibited relatively stable production rates throughout the production period, indicating that edge-water energy supply played a significant role in maintaining productivity. Even during the transition from water-free recovery to gas–water co-production, the production rate was only slightly affected by edge-water influx and remained relatively high [35]. Specifically, compared with the 1923 mD core, the production rate during the gas–water co-production period decreased by only 10.2%. In contrast, because of their high internal flow resistance, low-permeability cores (5.94 mD and 0.64 mD) had a substantially prolonged water-free gas production period, exceeding 30% of the total production period, owing to edge-water replenishment during depletion. However, the contribution of the gas–water co-production period to overall production was much smaller than that of the water-free gas-production period. After water breakthrough, the production rate decreased rapidly, resulting in a relatively low overall recovery factor. Therefore, in the trade-off between reservoir physical properties and water influx, the production gain associated with the high flow capacity of high-permeability cores outweighed the production loss caused by water influx. For low-permeability cores, the production loss induced by water influx became dominant (Figure 5).

In the early production stage, edge-water influx primarily has a positive effect by supplementing formation energy. In high-permeability reservoirs, low fluid-flow resistance enables rapid pressure transmission and effectively mitigates pressure depletion. Moreover, because of the strong overall flow capacity, gas maintains good mobility even after water breakthrough, leading to a relatively gradual decline in production rate. Pressure decreases slowly and uniformly along the core (Figure 6a,b), and the water-blocking effect remains

weak. In contrast, low-permeability cores exhibit markedly different pressure evolution characteristics (Figure 6c,d). Extremely high flow resistance slows pressure transmission and causes significant pressure-depletion lag. Rapid gas production at the outlet causes a sharp local pressure drop, whereas the inlet pressure responds slowly, generating a substantial pressure differential across the core [36]. For example, during depletion of the 0.64 mD core, the pressure differential increased continuously and reached 39 MPa by the end of depletion (Figure 6d). This relatively high pressure gradient is mainly caused by the extremely low permeability and the long-core experimental configuration under constant-rate production, which leads to strong flow resistance and significant pressure-depletion lag. In field-scale reservoirs, such a magnitude of pressure drop would be distributed over much larger spatial scales; however, similar localized high-pressure gradients may still occur in tight or strongly heterogeneous zones (Table 3). Therefore, the observed value should be interpreted in terms of flow resistance and pressure communication efficiency rather than as a direct field-equivalent pressure drop.

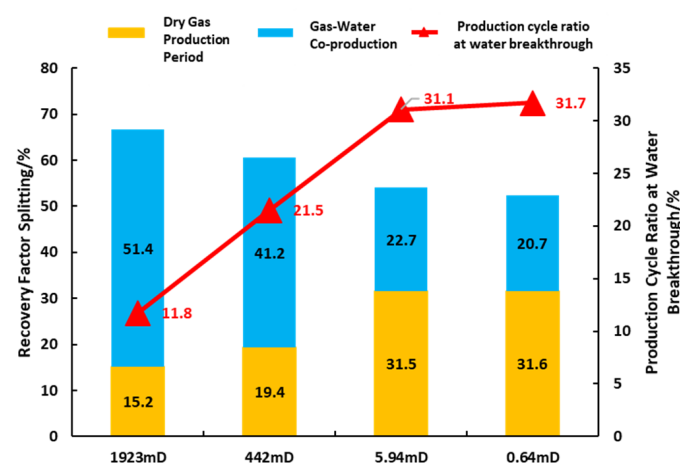


Figure 5. Comparison of staged recovery classification for cores with different permeabilities.

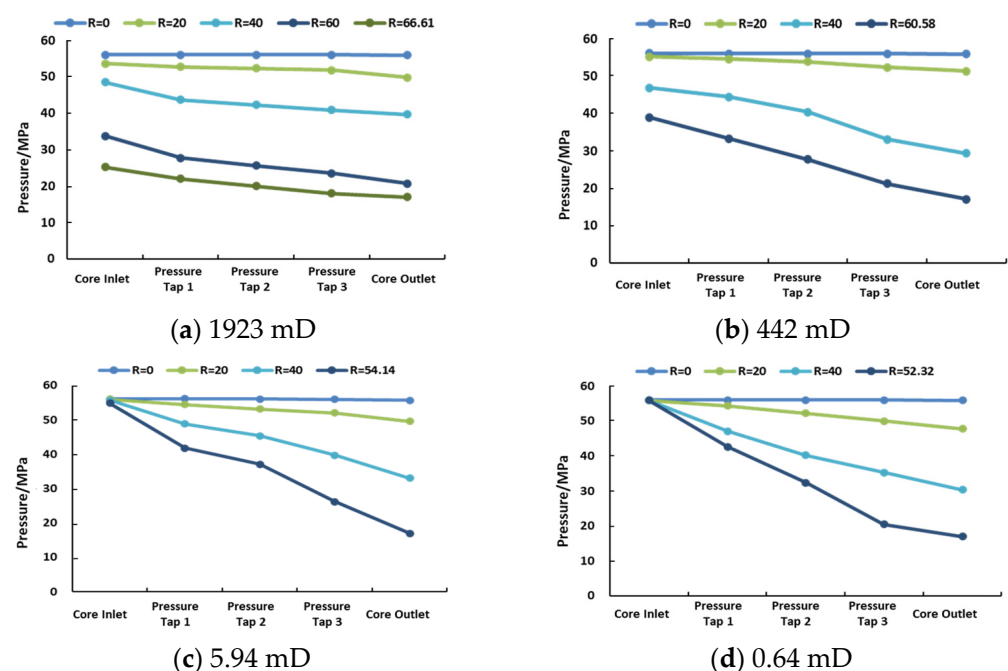


Figure 6. Temporal variation in axial pressure for cores with different permeabilities.

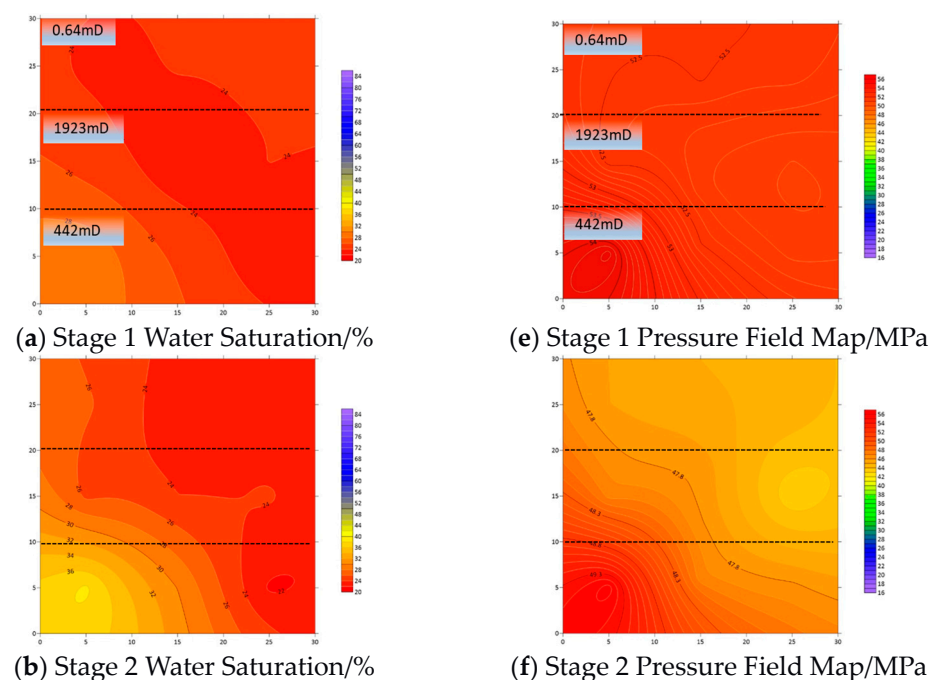
Table 3. Final recovery factors of long-core depletion experiments under different permeability condition.

Permeability (mD)	Final Recovery Factor (%)
1923	66.61
442	60.58
5.94	54.14
0.64	52.32

3.2. Water Influx Behavior and Production Characteristics During Depletion in Vertically Heterogeneous Reservoirs

To further investigate water influx under multilayer interactions in vertically heterogeneous reservoirs, a large-scale 3D heterogeneous physical model approximating actual reservoir conditions was used to analyze interlayer interference and uneven production caused by interlayer contradictions during depletion, and to compare production characteristics under different permeability ratios.

Under multilayer commingled production in Model No. 1 (0.64 mD–1923 mD–442 mD), the saturation and pressure monitoring results in Figure 7 show that, during the early production stage, the gas–water interface migrated from the lower-left corner of the model toward the center of the bottom medium-permeability layer. Because the edge-water influx rate was considerably lower than the gas production rate at the outlet, pressure depletion at the outlet gradually increased. As depletion degree and interlayer pressure differences further intensified, the migration direction of the gas–water interface changed, inducing fluid crossflow from the higher-pressure medium- and low-permeability layers to the lower-pressure high-permeability layer, i.e., interlayer crossflow. This resulted in water-blocked gas on the right side of the bottom medium-permeability layer (Figure 7d). Subsequently, as encroached water in the high-permeability layer further migrated to the upper low-permeability layer through imbibition and other mechanisms, the low-permeability layer began to produce, and the abrupt rise in edge water induced gas–water co-production in this layer.

**Figure 7.** Cont.

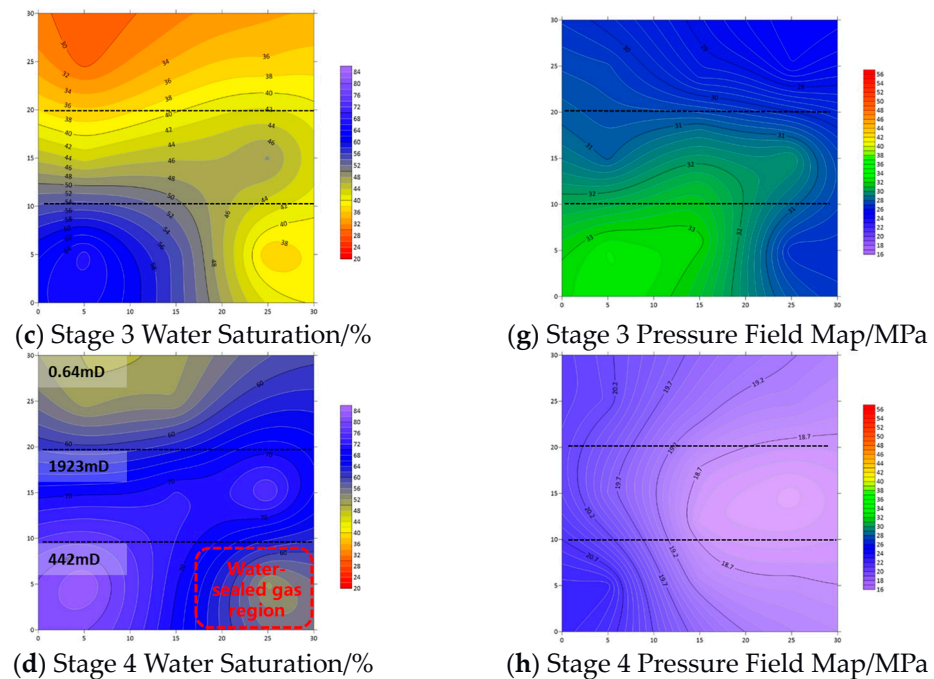


Figure 7. Water saturation and pressure distribution fields at different depletion-development stages for 3D Model No. 1.

The overall recovery factor of Model No. 1 during depletion was 58.58%. Specifically, the middle high-permeability layer (1923 mD) produced 136,716 mL of gas, corresponding to a recovery factor of 96.29%; the bottom medium-permeability layer (442 mD) produced 36,378 mL of gas, with a recovery factor of 31.32%; and the top low-permeability layer (0.64 mD) produced 13,669 mL of gas, achieving a recovery factor of 22.53% (Figure 7). Based on the production characteristics of each layer, the depletion development and water-influx process can be divided into four stages (Figure 8):

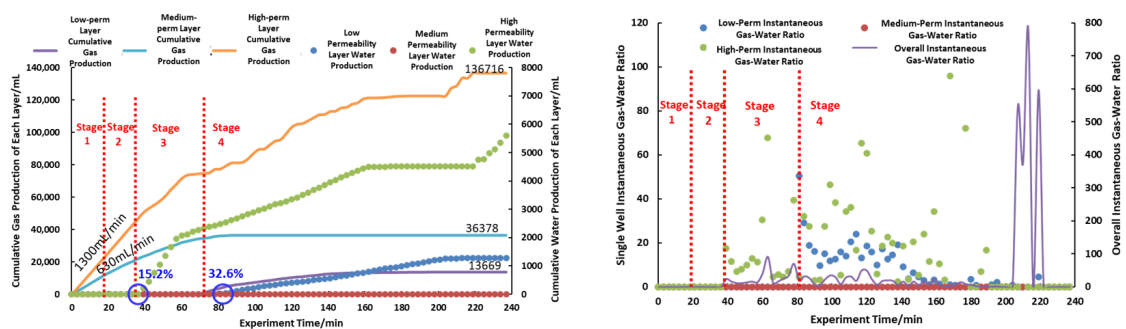


Figure 8. Comparison of layer-by-layer production and instantaneous gas–water ratio for Model No. 1 during depletion development.

Stage 1 (initial production): The medium- and high-permeability layers produce gas steadily, while the low-permeability layer remains inactive.

Stage 2 (edge-water influx into the medium-permeability layer): Edge water gradually invades the bottom medium-permeability layer and affects its gas production, whereas the high-permeability layer remains unaffected by water influx and maintains a stable gas production rate.

Stage 3 (edge-water influx into the high-permeability layer): Edge water further invades upward into the middle high-permeability layer. Water breakthrough rapidly occurs at the production end, the gas-water ratio increases, and the medium-permeability layer gradually ceases gas production.

Stage 4 (low-permeability-layer production and co-production): System pressure continues to decline, the low-permeability layer is mobilized, and water continues to invade upward. Eventually, gas from the low-permeability layer and water near the production end of the high-permeability layer are produced together.

The saturation and pressure-field evolution characteristics of Model No. 2, with a permeability combination of 5.94 mD–1923 mD–53.2 mD, are shown in Figure 9. Because the permeability contrast between the bottom medium-permeability layer and the middle high-permeability layer is relatively greater, interlayer crossflow occurs in Model No. 2 even at the early production stage. Edge water directly bypasses toward the high-permeability layer with lower flow resistance, migrating rapidly upward from the bottom medium-permeability layer to the left end of the high-permeability layer. This produces a larger area of water-blocked gas in the central and right portions of the medium-permeability layer (Figure 9d). As production proceeds, rapid energy depletion occurs in the middle high-permeability layer, and fluids are produced through the water-channeling path in this layer, resulting in earlier water breakthrough. Similar to Model No. 1, the low-permeability layer becomes mobilized after water breakthrough in the high-permeability layer, after which water and gas are produced together.

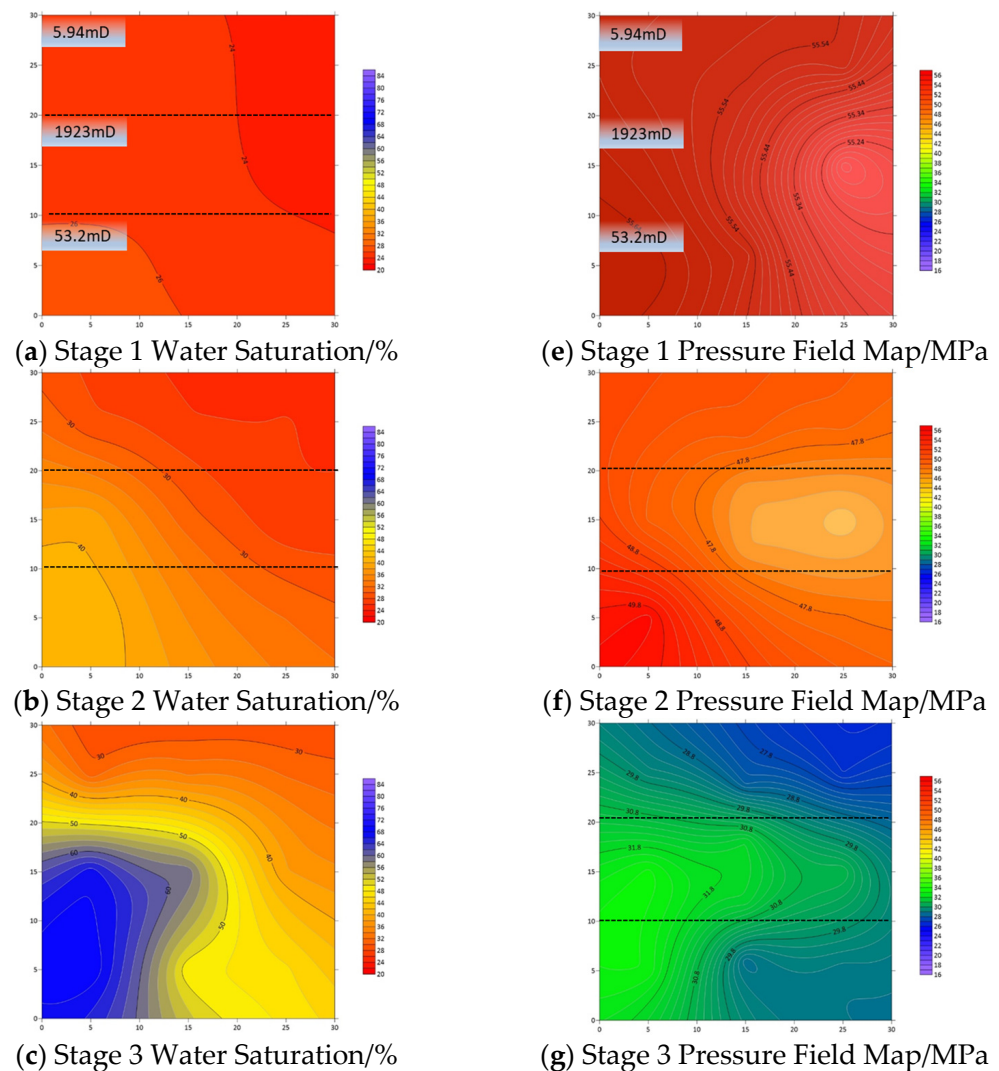


Figure 9. Cont.

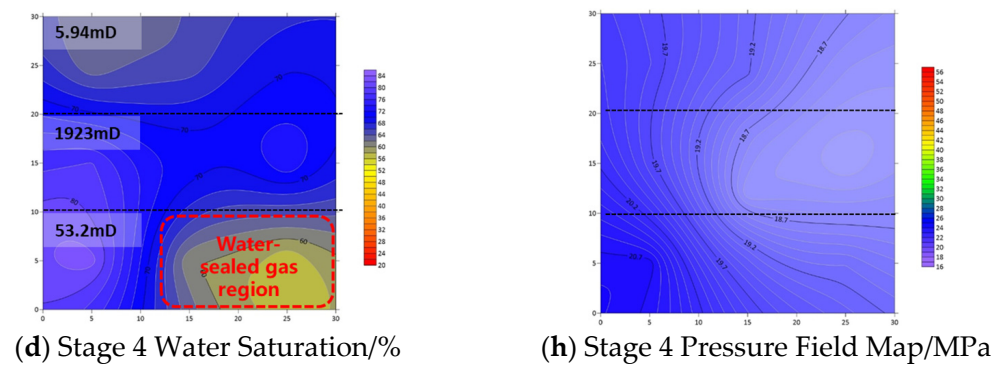


Figure 9. Water saturation and pressure distribution fields at different depletion-development stages for 3D Model No. 2.

The overall recovery factor of Model No. 2 during depletion was 52.55%. Specifically, the high-permeability layer (1923 mD) produced 131,733 mL of gas, corresponding to a recovery factor of 96.97%; the low-permeability layer (5.94 mD) produced 19,520 mL of gas, with a recovery factor of 20.51%; and the medium-permeability layer (53.2 mD) produced 22,912 mL of gas, achieving a recovery factor of 22.83%. Following the same four-stage production trend as Model No. 1, Model No. 2 exhibits stable gas production from the medium- and high-permeability layers during the early stage, while the low-permeability layer remains inactive. Subsequently, edge water invades the medium-permeability layer and simultaneously bypasses into the high-permeability layer, impairing gas production from the medium-permeability layer. As a large volume of invading water enters the high-permeability layer, rapid water breakthrough occurs at the production end, and production from the medium-permeability layer ceases. With further pressure decline, the low-permeability layer is mobilized, and gas from this layer carries the water phase near the production end of the high-permeability layer out of the model.

To further quantify interlayer crossflow behavior, pressure measurements from the embedded sensors in each layer were analyzed. The results indicate that a clear and sustained pressure gradient exists between layers during depletion, with the high-permeability layer exhibiting a significantly faster pressure decline compared to the low- and medium-permeability layers (Figure 10). This interlayer pressure differential provides the primary driving force for crossflow from the higher-pressure low- and medium-permeability layers toward the lower-pressure high-permeability pathway, thereby confirming the occurrence of interlayer fluid communication observed in the saturation evolution profiles. Meanwhile, the permeability contrast further strengthens this preferential flow behavior, while the stronger capillary resistance and weaker pressure transmission in the lower-permeability layers delay gas mobilization. In this study, severe water flooding of the high-permeability layer was identified by continuous water breakthrough, high-water-saturation distribution along the main flow pathway, and rapid decline in gas production capacity, whereas poor mobilization of the low-permeability layer was evaluated by pressure-depletion lag, delayed gas production response, and relatively low layer-specific recovery factor.

Compared with the long-core depletion and water-encroachment experiment, inter-layer bypassing in the three-layer heterogeneous large-scale physical model results in more complex depletion-production behavior. Although bypassing effectively replenishes energy in the high-permeability layer, it weakens the production capacity and mobilization potential of the medium- and low-permeability layers [37]. The results show that the high-permeability layer contributes most of the gas production. Compared with the 1923 mD single-layer long-core experiment, which had a recovery factor of 66.61%, the apparent recovery factors of the high-permeability layer in the 3D models increased to 96.29% and 96.97%, corresponding to an increase of approximately 30 percentage points. This apparent

increase is mainly attributed to the dominant drainage role of the high-permeability layer during commingled production, where part of the gas from adjacent medium- and low-permeability layers may migrate toward and be produced through the high-permeability pathway. In contrast, because of slow pressure transmission and high flow resistance, the low- and medium-permeability layers are difficult to fully mobilize even in the late depletion stage, resulting in recovery-factor reductions of 29–36% (Figure 11a) and thus exacerbating interlayer heterogeneity. Furthermore, the permeability contrast causes edge water to bypass the bottom medium-permeability layer and invade upward, reducing the energy supply to the medium-permeability layer and eventually causing cessation of gas–water production from this layer. Consequently, water breakthrough in the middle high-permeability layer is delayed by 5–13% compared with single-layer depletion (Figure 11b). Overall, the upward advancement rate of edge water is primarily governed by interlayer permeability contrast. A greater permeability difference between the medium- and high-permeability layers causes earlier edge-water bypassing and, accordingly, earlier water breakthrough in the high-permeability layer.

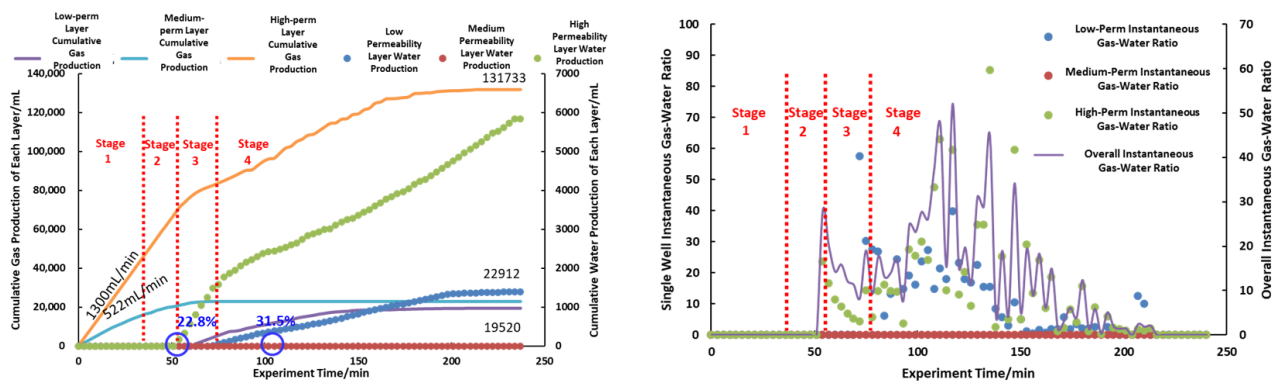


Figure 10. Comparison of layer-by-layer production and instantaneous gas–water ratio for Model No. 2 during depletion development.

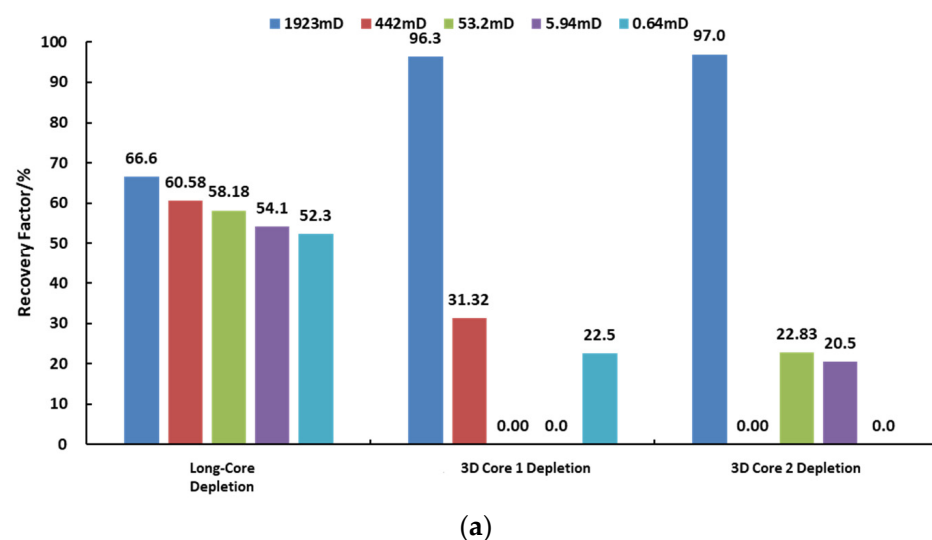


Figure 11. Cont.

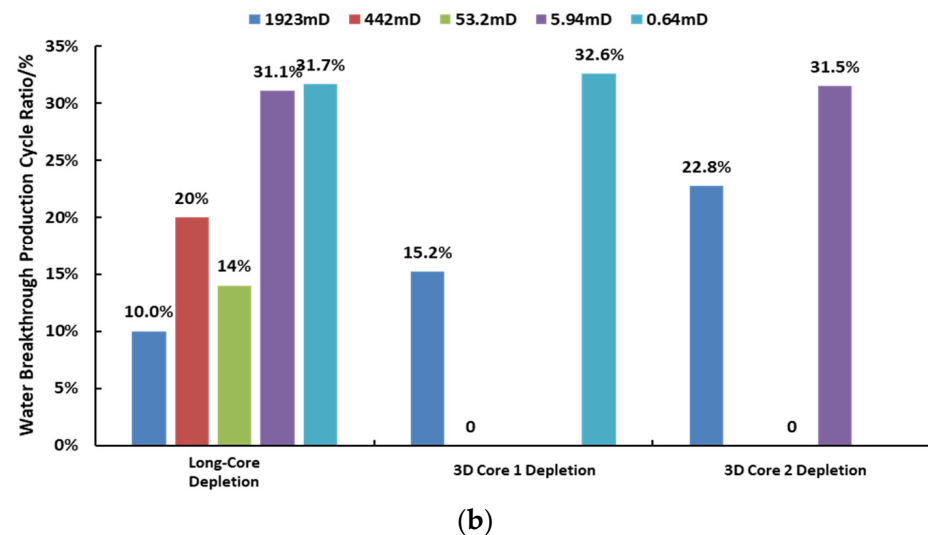


Figure 11. Comparison of recovery factors between long cores and large 3D models during depletion development. (a) Comparison of depletion recovery factor between long core and 3D core. (b) Comparison of water breakthrough time in each layer during depletion development of long core and 3D core.

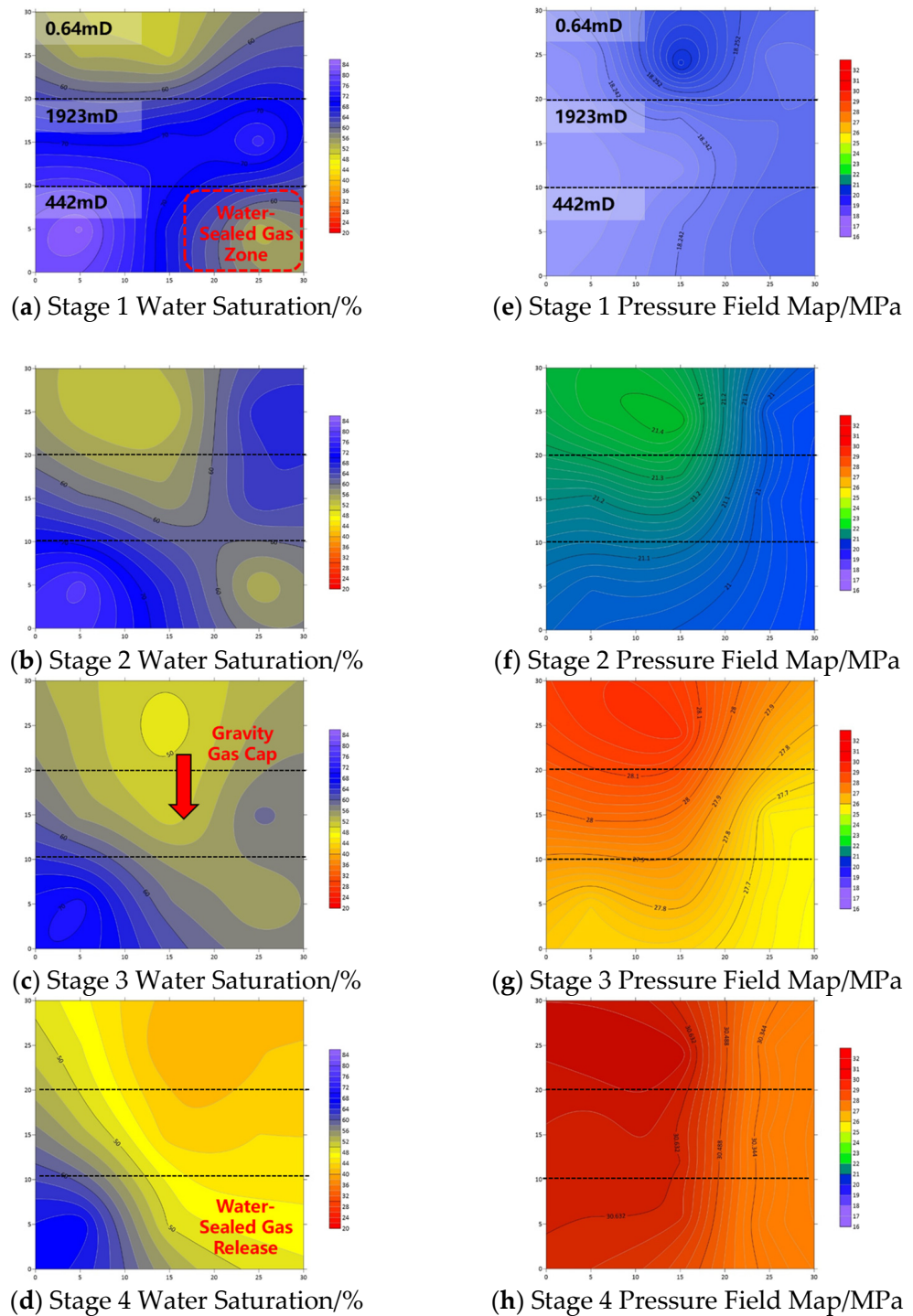
3.3. Water Control and Production Enhancement by CO₂ Injection in Vertically Heterogeneous Reservoirs

After depletion-driven multilayer commingled production and edge-water influx in a heterogeneous reservoir, residual gas content and water-influx intensity differ markedly among layers with different permeabilities. To further recover residual gas, push back the invading edge water, and restore reservoir productivity, a top CO₂ injection strategy was designed using the heterogeneous 3D models after depletion and water influx. The evolution of gas composition, pressure, and saturation fields was monitored to analyze the effects of CO₂ injection on energy maintenance and water control, as well as the production performance of each layer.

Taking Model No. 1 with a permeability combination of 0.64 mD–1923 mD–442 mD as an example, CO₂ accumulated at the top of the model during the early injection stage and formed a gas cap. As the injection volume increased, the accumulated gas cap induced gravity drainage and pushed water downward [38], resulting in steady downward advancement of the gas–water interface (Figure 12a,b). This promoted gas production and water drainage from each layer, reduced the overall average water saturation, and gradually diminished interlayer differences in water saturation. When CO₂ swept downward to the bottom medium-permeability layer, it effectively connected the capillary resistance zones that could not be bypassed during depletion (Figure 12c,d), alleviating water-blocked gas and expanding the sweep area; consequently, water saturation decreased from 57% after depletion to 48%. Eventually, the average model pressure recovered from 17.85 MPa to 30.53 MPa, and the pressure-deficit and pressure-distribution differences caused by different production rates were effectively improved.

Following CO₂ injection, the gas–water interface was driven downward while CO₂ simultaneously flowed toward the low-pressure outlet, carrying dispersed residual gas out of the model through viscous displacement. The gas phase progressively broke through the water barrier, mitigating water-blocked gas and the Jamin effect and thereby enhancing residual gas recovery. After the CO₂ injection water-control stage, the overall recovery factor of the 0.64 mD–1923 mD–442 mD model increased from 58.58% at the end of depletion to 67.79%, corresponding to an incremental recovery factor of 9.21 percentage points. The layer-specific incremental recovery factors were 4.41 percentage points for the 0.64 mD

layer, 8.34 percentage points for the 1923 mD layer, and 12.79 percentage points for the 442 mD layer. Cumulative gas production from the three layers increased by 29,368 mL. Notably, the medium-permeability layer, which ceased production early during depletion because of severe water-blocked gas, was reactivated when injected CO_2 reconnected the water-blocked gas zone, contributing 51% of the total incremental gas production (Figure 13).



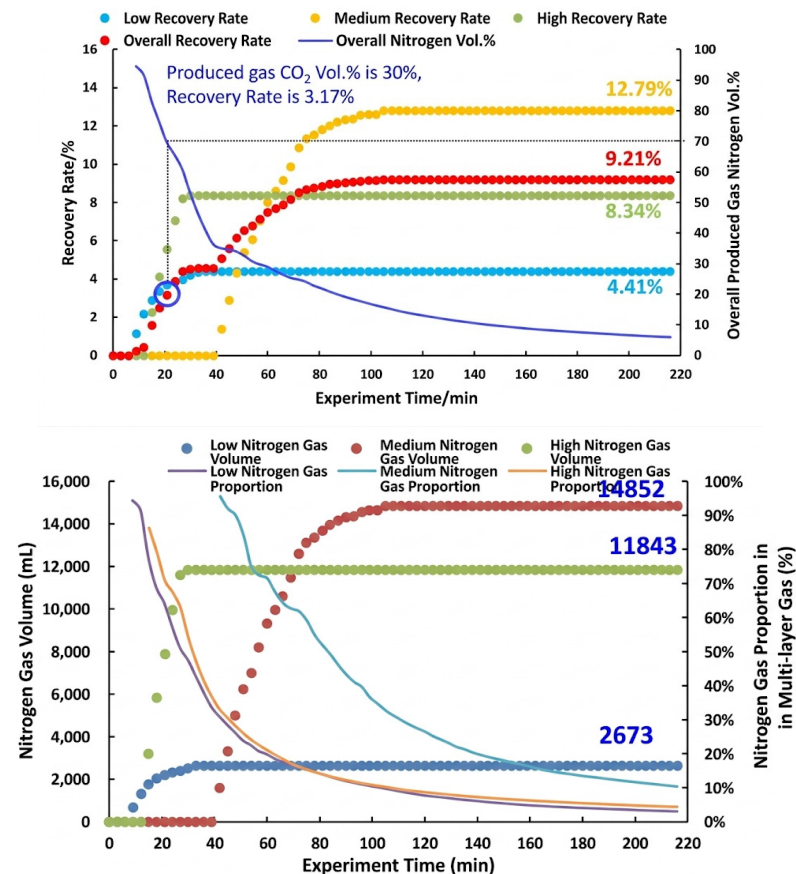


Figure 13. Gas production characteristics of each layer and nitrogen proportion in produced gas for Model No. 1 under CO₂ injection.

For Model No. 2, with a permeability combination of 5.94 mD–1923 mD–53.2 mD, the relatively high permeability of the upper low-permeability layer allowed injected CO₂ to accumulate rapidly at the top and form a larger gas cap. As a result, gravity drainage that pushed water downward occurred earlier, and the overall water cut of the model decreased rapidly (Figure 14a,b). Under gravity differentiation, the gas–water interface advanced downward over a large area, effectively alleviating water blockage in the central and right portions of the medium-permeability layer and reducing the average water saturation of the water-blocked gas zone from 59% to 39%. Ultimately, after energy replenishment by CO₂ injection, the overall water saturation of Model No. 2 decreased from 71% to 46%, demonstrating significant water drainage, while the average pressure recovered from 18.06 MPa to 28.22 MPa.

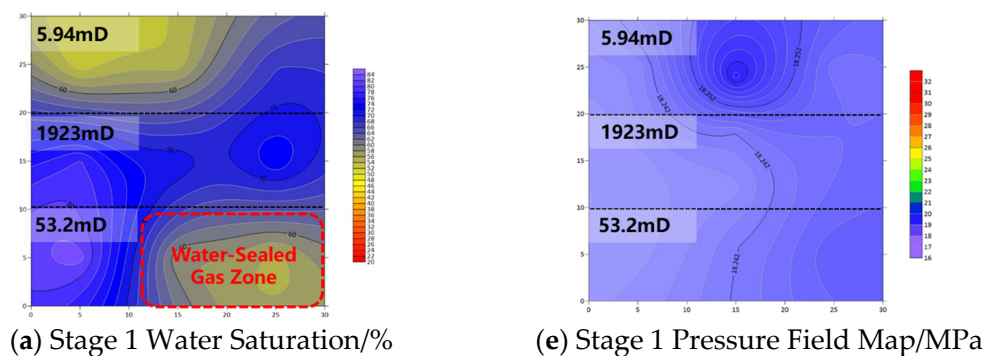


Figure 14. Cont.

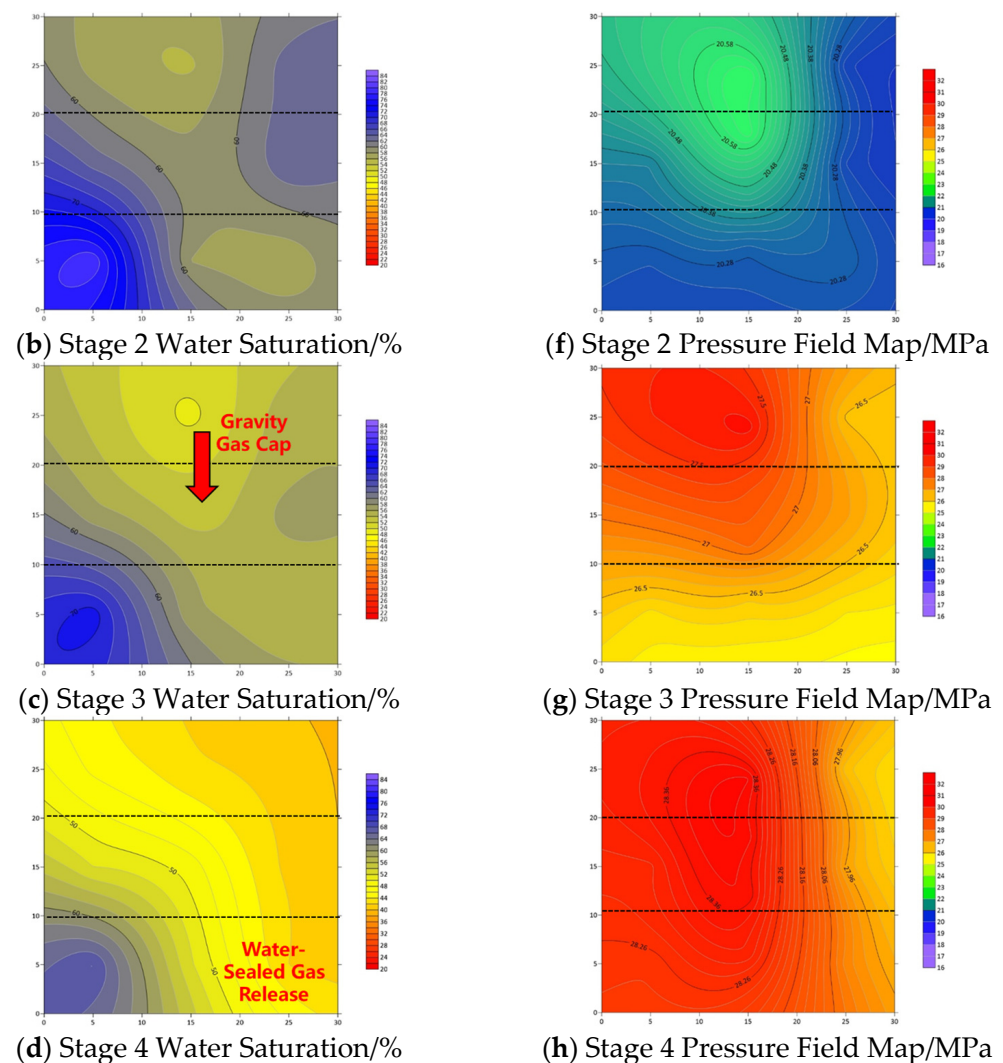


Figure 14. Water saturation and pressure distribution fields at different CO₂ injection stages for Model No. 2.

After the CO₂ injection water-control stage, the overall recovery factor of the 5.94 mD–1923 mD–53.2 mD composite model increased by 12.81%, and cumulative gas production from the three layers increased by 42,439 mL. The recovery factor increased by 4.36% in the low-permeability layer (5.94 mD), 9.59% in the high-permeability layer (1923 mD), and 25.17% in the medium-permeability layer (53.2 mD). Compared with Model No. 1, Model No. 2 has a greater permeability contrast between the medium- and high-permeability layers, leading to earlier water bypassing at a more advanced position. Consequently, the medium-permeability layer in Model No. 2 contains a larger water-blocked gas area and thus greater enhanced-recovery potential (Figure 15). After reactivation by CO₂ injection, this layer contributed 74% of the incremental production.

Overall, CO₂ injection significantly alters reservoir fluid-flow paths and redistributes gas–water two-phase flow. It pushes back encroached water and delays water influx while simultaneously mobilizing residual gas previously isolated by water through viscous displacement. The response to CO₂ injection varies with permeability. The low-permeability layer contains substantial non-mobile gas, and the medium-permeability layer retains substantial water-blocked gas; both show notable production enhancement after CO₂ injection. In contrast, the high-permeability layer, which had already produced a large volume of gas during depletion, shows a relatively modest incremental gain; in this layer, CO₂ injection mainly pushes back encroached water. The production characteristics of the two

permeability-ratio models are shown in Figure 16. At the end of depletion, Models No. 1 and No. 2 achieved recovery factors of 58.58% and 52.55%, respectively. After CO₂ injection, the recovery factors increased by 9.21% and 12.81%, average water saturation decreased by 23.22% and 25.28%, and average pressure increased by 12.68 MPa and 10.16 MPa, respectively. These results demonstrate clear synergistic effects of production enhancement, water control, and pressure maintenance, effectively improving production potential during subsequent depletion.

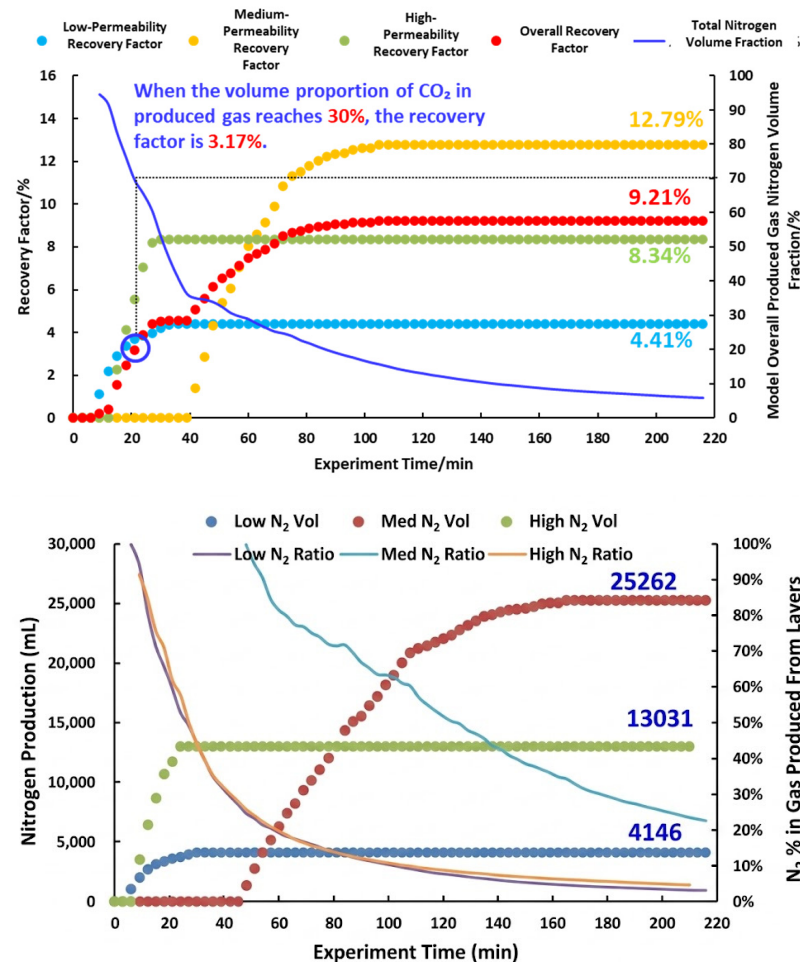
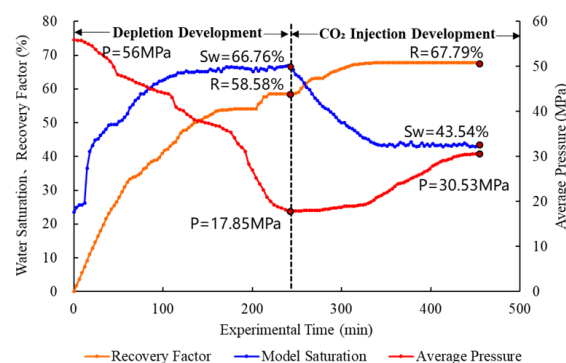


Figure 15. Gas production characteristics of each layer and nitrogen proportion in produced gas for Model No. 2 under CO₂ injection.



(a)

Figure 16. Cont.

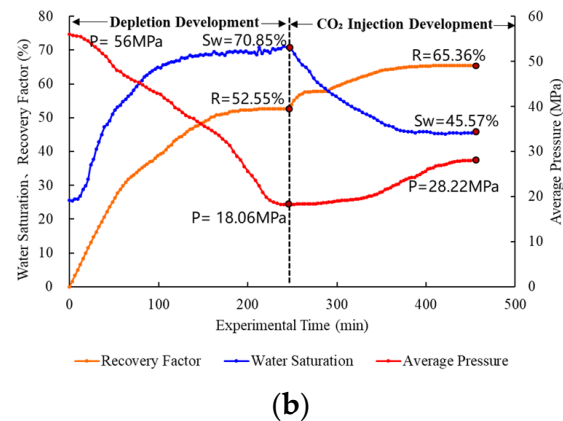


Figure 16. Parameter variation characteristics during depletion development and CO₂ injection stages for Model No. 1 (a) and Model No. 2 (b).

4. Conclusions

(1) Reservoir permeability controls water-influx behavior and production characteristics during depletion by regulating pressure communication, water-breakthrough timing, and post-breakthrough gas production capacity. As core permeability decreases, water breakthrough is delayed and the water-free gas production period becomes longer; however, the increasing mismatch between edge-water encroachment at the inlet and gas production at the outlet intensifies pressure-depletion lag. Consequently, low-permeability cores develop larger pressure differentials, sharper gas-rate decline after water breakthrough, and lower recovery factors. This indicates that recovery from edge-water gas reservoirs is governed not only by water breakthrough timing, but also by the matching relationship between reservoir flow capacity and edge-water energy supply.

(2) A conceptual model of multilayer commingled production in vertically heterogeneous edge-water gas reservoirs is proposed. The process can be generalized into four stages: preferential gas production from medium- and high-permeability layers, pressure-imbalance-driven water influx into the medium-permeability layer, edge-water bypassing and breakthrough along the high-permeability pathway, and delayed mobilization of the low-permeability layer. Under this mechanism, the high-permeability layer acts as the dominant flow pathway, while the medium- and low-permeability layers are insufficiently mobilized and prone to water-blocked gas formation. Compared with single-layer depletion, multilayer water bypassing leads to an apparent increase of approximately 30 percentage points in the recovery of the high-permeability layer, while reducing recovery from the medium- and low-permeability layers, thereby intensifying interlayer production disparity.

(3) Post-depletion top CO₂ injection can partially reverse the unfavorable gas–water distribution formed during depletion. Injected CO₂ accumulates in the upper part of the model and forms a gas cap, which drives the gas–water interface downward through gravity differentiation and viscous displacement. This process reconnects water-blocked gas zones, drives back encroached water, replenishes formation energy, and improves gas-phase connectivity. The CO₂ injection stage provides an incremental recovery factor of approximately 9–13 percentage points in the tested models, while also reducing average water saturation and restoring pressure support. These findings demonstrate that CO₂ injection provides a practical strategy for water control, trapped-gas mobilization, and production enhancement in mature vertically heterogeneous edge-water gas reservoirs.

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