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CO₂-Assisted Mitigation of Coupled Water Blocking and Retrograde Condensation Damage in Condensate Gas Reservoirs

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ABSTRACT: This study elucidates the coupled damage mechanisms induced by retrograde condensation and water blocking in low-permeability edge-bottom water condensate gas reservoirs and develops an optimized CO₂ injection strategy for simultaneously enhancing hydrocarbon recovery and geological carbon storage. Using the K condensate gas reservoir in the Junggar Basin as a case study, nuclear magnetic resonance (NMR) measurements and long-core displacement experiments are integrated to characterize the evolution of water-lock and retrograde-condensation damage across pore and core scales and to unravel the mechanisms governing its mitigation by CO₂ injection. The results reveal a pronounced synergistic interaction between the two damage mechanisms, with their combined impact on gas-phase permeability substantially exceeding that of either mechanism acting independently. CO₂ injection effectively alleviates the coupled damage through the combined effects of miscible displacement, interfacial-tension reduction, and condensate vaporization. Building on these experimental insights, a high-fidelity three-dimensional compositional reservoir model is established to optimize an integrated CO₂ injection-production strategy. The resulting scheme comprises two cycles of CO₂ huff and puff, with an injection volume of 4000 t per cycle, followed by continuous CO₂ displacement at 240 t/d and an injection pressure of at least 24 MPa. Numerical predictions indicate that this strategy can sustain stable production for 15 years, achieving cumulative recoveries of 6.2×10^8 m³ of natural gas and 3.5×10^4 m³ of condensate oil, while simultaneously sequestering 1.125×10^6 t of CO₂. These findings demonstrate that CO₂ injection can effectively overcome the coupled flow impairment associated with water blocking and retrograde condensation while providing a pathway toward the integrated recovery of condensate gas and geological CO₂ storage.

KEYWORDS: CCUS; condensate gas reservoir; retrograde condensation; water invasion; CO₂ injection; enhanced gas recovery (EGR)

1 Introduction

The Chinese government explicitly put forward the emission reduction goals of “achieving carbon peak before 2030” and “achieving carbon neutrality before 2060” in September 2020, fully demonstrating its determination to deeply participate in global climate governance and promote the transformation of the energy structure [1,2]. The in-depth transformation of the global energy structure and the proposal of the carbon neutrality goal have driven a surge in demand for clean energy such as natural gas [3–5], while the high-value condensate oil from condensate gas reservoirs has further improved the development economy

and attracted extensive attention from the industry [6–8]. The efficient development of condensate gas reservoirs is of great practical significance for ensuring national oil and gas supply security and realizing the “dual carbon” strategic goals [9,10].

However, condensate gas reservoirs generally have the characteristics of complex phase behavior, deep burial, high temperature and pressure conditions, and active edge and bottom water. During the depletion development process, dual damage from retrograde condensation and water lock is extremely prone to occur, leading to rapid decline of gas well productivity and difficulty in improving recovery efficiency [11]. When the formation pressure drops below the dew point pressure, the retrograde condensate oil precipitated in the near-wellbore zone will occupy the effective seepage channels, triggering a severe retrograde condensation effect and causing a significant decrease in gas phase permeability [12,13]. At the same time, edge and bottom water advances non-uniformly along high-permeability streaks driven by the production pressure difference, which is easy to induce strong water lock damage in the near-wellbore zone [14–16]. For condensate gas reservoirs with edge and bottom water, the dual damage formed by the superposition of retrograde condensation and water lock is the core bottleneck restricting the efficient development of gas reservoirs, and also a key technical problem to be solved urgently in the current field of oil and gas field development [17,18].

Extensive systematic studies on the reservoir damage mechanism of condensate gas reservoirs have been reported in the literature [19–22]. Zhao et al. [23] confirmed that the inhibitory effect of retrograde condensation on gas phase flow capacity is more significant under low-permeability conditions by coupling the multiphase flow model and the retrograde condensation damage calculation model.

CO₂ injection flooding technology has become the core technical means to remove reservoir damage in condensate gas reservoirs due to its dual advantages of enhancing oil and gas recovery and CO₂ geological storage [24–27]. Su et al. [28] constructed a core-flooding numerical model using the GEM numerical simulator and conducted a series of experimental investigations on water flooding and CO₂ flooding. The results demonstrate that CO₂ treatment can enhance gas productivity by a factor of approximately 1.39 compared with the water flooding mode. Meng et al. [29] constructed a theoretical field-scale simulation model and analyzed the effects of injection pressure, injection duration and soaking time on the efficiency of CO₂ huff-n-puff. The experimental results demonstrate that the condensate oil recovery factor increases by 30.36% after five cycles of CO₂ huff-n-puff. Furthermore, the simulation results indicate that the injection cycle and injection pressure should be optimized to ensure that the pressure in the main condensate zone always remains above the dew point pressure. Wang et al. [30] investigated the effects of CO₂ injection pressure and injection rate on the reservoir performance of condensate gas reservoirs using a numerical model. The results showed that injecting CO₂ at a rate of 5×10^4 m³/d restored the formation pressure to 22.5 MPa. This scheme increased the condensate oil recovery factor by 18.7 percentage points and reduced the rising rate of water cut by approximately 34%. Although rich research progress has been made in CO₂ injection-enhanced recovery technology, existing studies mostly focus on the evaluation of macroscopic flooding effects. Under dual damage conditions, the microscopic action mechanism of CO₂ injection for damage removal and the fluid production behavior in pores of different scales remain unclear. Meanwhile, for condensate gas reservoirs with edge and bottom water, there is also a relative lack of targeted research and field practice guidance for optimizing differentiated CO₂ injection development schemes in zones with different damage types.

In view of this, this paper takes the K low porosity and low permeability condensate gas reservoir with edge and bottom water in the Junggar Basin, Xinjiang as the research object, and adopts a method combining nuclear magnetic resonance (NMR) experiments and long core flooding experiments to reveal the formation mechanism of water lock-retrograde condensation dual damage and the CO₂ injection removal mechanism

from both microscopic and macroscopic scales. While revealing the damage mechanism, the laboratory experiments also provide key inputs—such as miscibility pressure, relative permeability curves, and fluid phase behavior—for the numerical model; on this basis, a high-precision three-dimensional compositional numerical model of the gas reservoir is established to optimize the field-scale key gas-injection parameters of CO₂ huff and puff and continuous flooding, and ultimately to form an implementable integrated injection-production scheme. The research results can provide theoretical support and technical reference for the efficient development of similar condensate gas reservoirs with edge and bottom water.

2 Overview of the Study Area

The K Gas Reservoir is located in the Junggar Basin, Xinjiang, and is a typical low-porosity and low-permeability edge-bottom water condensate gas reservoir. The reservoir lithology is mainly sandstone. The porosity of the main pay zone is mainly distributed between 8% and 16%, and the permeability is mainly between 0.01 mD and 156.30 mD, with an average permeability of 5.8 mD, belonging to a low-porosity and low-permeability reservoir. The original formation pressure of the gas reservoir is 41.20 MPa, the dew point pressure is 40.58 MPa, the formation-dew point pressure difference is small, retrograde condensation is very easy to occur during development, and the maximum retrograde condensate liquid content is 7.4%. The edge and bottom water of the gas reservoir are active, the average salinity of the water body is 17,644.5 mg/L, and the water type is calcium chloride type. Controlled by reservoir heterogeneity and high-permeability streaks, the water invasion of the gas reservoir shows significant planar heterogeneity, which is generally characterized by “strong water flooding in the southwest, moderate water flooding in the east, and weak water flooding in the north”.

The gas reservoir was put into development in June 2003, adopting depletion production. Up to now, 15 production wells have been put into operation, with a cumulative gas production of $37.51 \times 10^8 \text{ m}^3$, a cumulative condensate production of $56.08 \times 10^4 \text{ t}$, and a recovery degree of only 36.77%. The development of the gas reservoir has gone through six stages: production ramp-up, stable production, production decline, low production, pressurized stable production, and low pressure and low production. At present, it has entered the low pressure and low production stage, with only 2 wells maintaining production, the daily gas production is about $5.0 \times 10^4 \text{ m}^3$, and the gas production rate is only 0.24%. The overall productivity retention degree of the gas reservoir is poor and the planar difference is large. The dual damage formed by retrograde condensation and water invasion is the core factor restricting gas well productivity: after the pressure drops below the dew point pressure, the precipitation of retrograde condensate oil leads to a 60%~80% decrease in gas phase permeability; the non-uniform advancement of edge and bottom water causes bottom hole liquid loading, which changes the seepage pattern from plane radial flow to composite radial flow, and the flow resistance increases significantly.

3 Experimental Study on Removal of Water Lock-Retrograde Condensate Dual Damage

3.1 Study on the Mechanism of Dual Damage Removal

3.1.1 Experimental Materials and Procedures

(1) Experimental Instruments

This experiment adopts the MacroMR series large-bore nuclear magnetic resonance imaging analyzer with a magnetic field strength of 0.5 T and a main frequency of 15 MHz, equipped with high-temperature and high-pressure core holders, confining pressure control systems, displacement pumps, back pressure valves, oil-gas separators and other equipment, which can realize real-time testing of T₂ spectrum, T₁-T₂

two-dimensional spectrum and nuclear magnetic resonance imaging (MRI) during core displacement. The core parameters of the experimental pulse sequence are shown in Table 1.

Table 1: Core parameters of nuclear magnetic resonance experimental pulse sequence.

Parameter Name	Test Sequence	Sampling Bandwidth (KHz)	Number of Sampling Points	Waiting Time TW (ms)	Number of Accumulations	Echo Time TE (ms)	Number of Echoes
T ₂ Spectrum	CPMG	200	320,024	2000	16	0.2	8000
T ₁ -T ₂ Spectrum	IR-CPMG	250	217,552	1500	4	0.15	50,000

(2) Experimental Samples and Fluids

The experimental core is taken from the main pay zone of the K low-porosity and low-permeability edge-bottom water condensate gas reservoir in the Junggar Basin, Xinjiang. It is a standard plunger core with a diameter of 24.65 mm and a length of 49.97 mm. The core porosity is 16% and the gas permeability is 35.6 mD, which is consistent with the reservoir physical properties of the target block.

The experimental fluids include: (1) Simulated formation water prepared according to the formation water test results of K Gas Reservoir, with a salinity of 17,644.5 mg/L and a water type of calcium chloride, as shown in Table 2; (2) Manganese chloride aqueous solution with a mass fraction of 5%, used to shield the nuclear magnetic signals of the rock matrix and aqueous phase and eliminate the interference of aqueous phase on hydrocarbon signals; (3) Reconstituted condensate gas sample according to the well stream composition of K Gas Reservoir, as shown in Table 3, with a gas-oil ratio of 3800 m³/m³ and a dew point pressure of 40.58 MPa under the conditions of formation temperature 102.5°C and pressure 45 MPa; (4) CO₂ gas with a purity of 99.99%, used as the displacement medium; (5) High-purity nitrogen, used for core pretreatment and establishment of irreducible water.

Table 2: Formation water test results.

Chloride Ion	Calcium Ion	Sodium-Potassium Ion	Water Type	Salinity
10,358	292.58	6561.7	CaCl ₂	17,644.5

Table 3: Well stream composition.

Component	Well Stream/mol%	Flashed Gas/mol%	Flashed Oil/mol%
CO ₂	0.37	0.38	–
N ₂	2.01	2.06	–
C ₁	85.29	87.37	–
C ₂	5.54	5.67	0.01
C ₃	1.92	1.97	0.07
iC ₄	0.55	0.56	0.14
nC ₄	0.74	0.75	0.40
iC ₅	0.28	0.27	0.71
nC ₅	0.35	0.33	1.34
C ₆	0.51	0.37	6.15
C ₇	0.41	0.15	11.12
C ₈	0.51	0.12	16.51
C ₉	0.32	–	13.46
C ₁₀	0.26	–	10.85
C ₁₁ +	0.95	–	39.25

(3) Experimental Procedures

1. The experiment is conducted throughout at the formation temperature of 102.5°C. Vacuum-saturate the core with manganese chloride aqueous solution for 48 h, perform constant-speed nitrogen displacement until no more water is produced at the outlet end, establish the irreducible water state of the core, and complete the aqueous phase signal shielding. Load the treated core into a high-temperature and high-pressure holder, continuously inject the reconstituted condensate gas under 45 MPa (above the dew point pressure of 40.58 MPa) until the fluid composition at the inlet and outlet is consistent and the core pressure is stable (saturation-completion criterion), complete the condensate gas saturation, and scan to obtain the T₂ spectrum, T₁-T₂ two-dimensional spectrum and MRI of the core in the initial saturation state.
2. Simulate the formation depletion process by gradually reducing the back pressure, with each stage proceeding only after the pressure stabilizes, until the core pressure drops to 15 MPa (the current formation pressure of the target block). Inject 0.25 PV of simulated formation water into the core, close the inlet and outlet and let it stand for aging for 12 h to allow the formation water to fully invade the pore network under capillary force, and scan to obtain the NMR data under the dual damage state.
3. Inject CO₂ into the core at a constant rate of 0.1 mL/min until the core pressure rises to 25 MPa (above the minimum miscibility pressure of 24.6 MPa), close the inlet and outlet for well soaking for 12 h, and scan to obtain the NMR data after miscible well soaking.
4. Maintain the back pressure at 28 MPa, inject CO₂ at the same constant rate for displacement until no oil-phase production is observed at the outlet for at least 30 consecutive minutes and the produced-fluid composition is stable as verified by online chromatography (end-of-displacement criterion), and scan to obtain the NMR data of the core after displacement.

3.1.2 Experimental Results and Analysis

Based on the nuclear magnetic resonance relaxation characteristics and combined with the pore structure characteristics of the target block reservoir, the core pores are divided into four grades: $T_2 < 1$ ms are micropores, $1 \text{ ms} \leq T_2 < 10$ ms are small pores, $10 \text{ ms} \leq T_2 < 100$ ms are mesopores, and $T_2 \geq 100$ ms are macropores. Through the quantitative changes in the T₂ spectrum peak shape, peak value and peak area, combined with the T₁-T₂ two-dimensional spectrum and MRI imaging results, the microscopic formation mechanism of dual damage and the CO₂ injection removal mechanism are systematically analyzed.

(1) Microscopic Superposition Mechanism of Water Lock-Retrograde Condensate Dual Damage

Figs. 1–3 show the core T₂ spectrum, T₁-T₂ two-dimensional spectrum and MRI imaging results at different displacement stages, and Table 4 shows the characteristics of the main and secondary peaks of pores during gas injection displacement (Note: The peak-area proportion is normalized by the total peak area of the T₂ spectrum in the initial saturation state (unit: %); the peak value is the original signal amplitude of the T₂ spectrum (unit: a.u., arbitrary unit). All peak values and peak areas at each stage are acquired under the same NMR sampling parameters (see Table 1) and are thus comparable). Under the initial saturation state, the T₂ spectrum of the core shows a typical bimodal characteristic: the main peak is located in the small pore interval with $T_2 = 2.3$ ms, accounting for 61.2% of the peak area, corresponding to the capillary-bound fluid in the pores; the secondary peak is located in the macropore interval with $T_2 = 114$ ms, accounting for 32.5% of the peak area, corresponding to the free condensate oil and gas, which is the core channel for gas phase seepage. Two independent strong signal clusters of free oil and gas

and irreducible water appear in the T_1 - T_2 two-dimensional spectrum, and the MRI image shows uniform red-yellow highlights across the entire core profile, indicating that the condensate oil and gas fully fill the entire pore network.

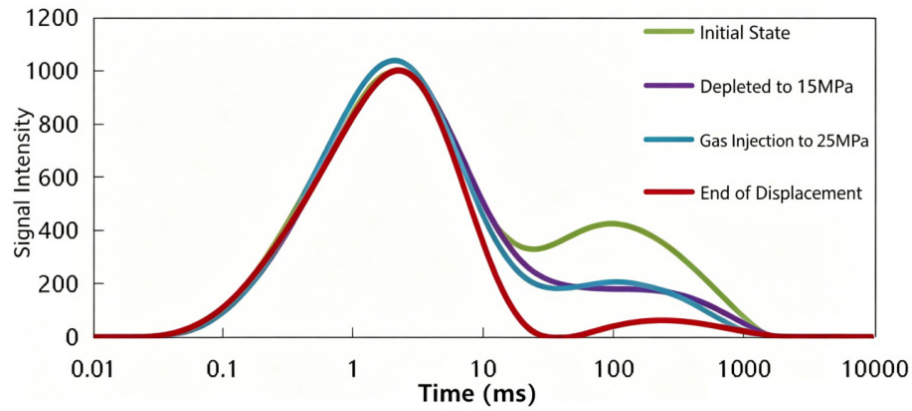


Figure 1: Nuclear magnetic resonance time spectrum at different stages of gas injection displacement.

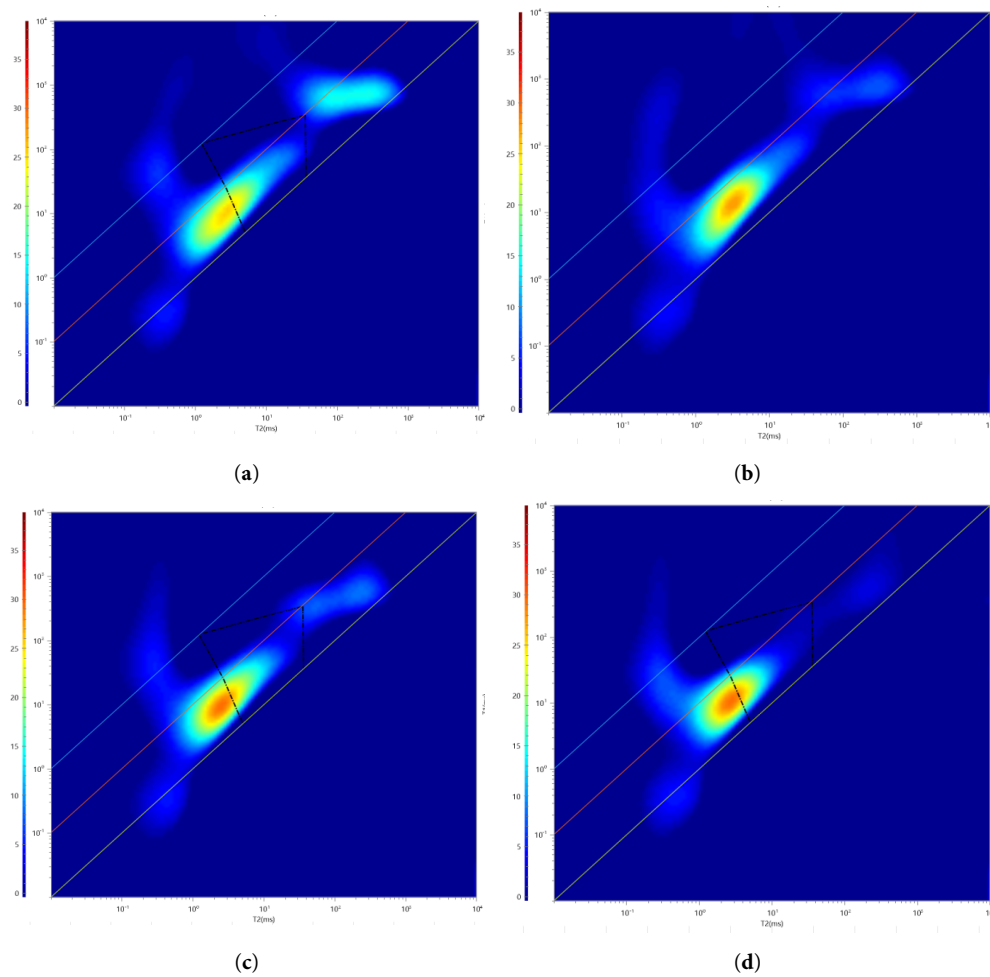


Figure 2: Nuclear magnetic resonance T_1 - T_2 spectrum test results at different stages: (a) initial state; (b) depletion to 15 MPa; (c) gas injection to 25 MPa; (d) end of displacement.

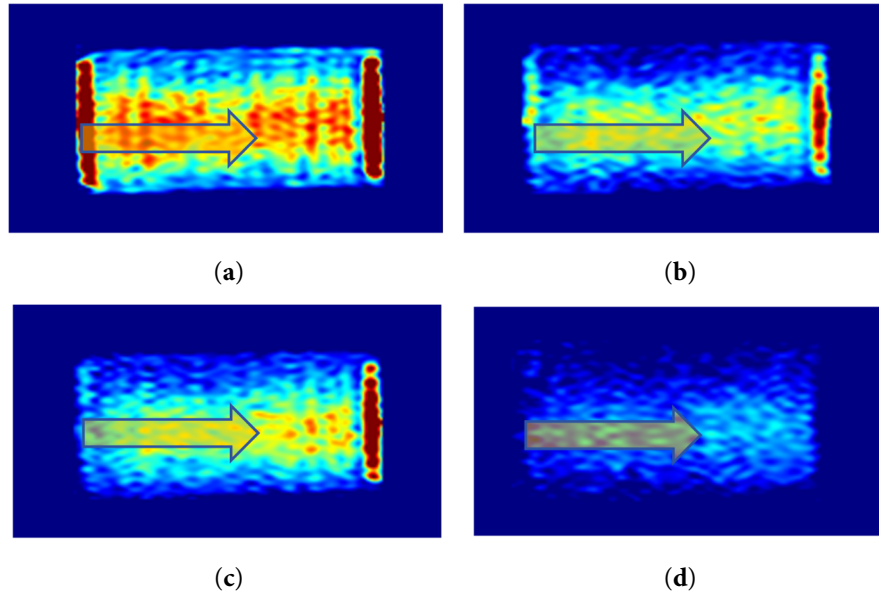


Figure 3: Nuclear magnetic resonance imaging test results at different stages: (a) initial state; (b) depletion to 15 MPa; (c) gas injection to 25 MPa; (d) end of displacement.

Table 4: Characteristics of main and secondary peaks of pores during gas injection displacement.

Experimental Stage	Micropore-Small Pore Main Peak			Mesopore-Macropore Secondary Peak		
	Main Peak Position	Peak Signal Quantity	Peak Area Proportion	Secondary Peak Position	Peak Signal Quantity	Peak Area Proportion
Initial State	2.3	1005	61.2%	114	412	32.5%
Depletion to 15 MPa	2.3	1012	73.6%	187	205	21.9%
Gas Injection to 25 MPa	1.7	1040	70.8%	146	218	24.3%
End of Displacement	2.3	1008	88.7%	231	47	6.8%

After the establishment of water lock-retrograde condensate dual damage, the nuclear magnetic characteristics of the core undergo fundamental changes: the secondary peak value in the macropore interval of the T_2 spectrum decreases by 50.2% compared with the initial state, and the peak area proportion decreases by 32.6%; the main peak area proportion in the small pore interval increases from 61.2% to 73.6%, with no obvious shift in the main peak position and only a slight increase in the peak value. In the T_1 - T_2 two-dimensional spectrum, the free oil and gas signal in the high relaxation region is significantly attenuated, and the aqueous phase signal is significantly enhanced and highly bonded with the oil and gas signal cluster; in the MRI image, the overall signal of the core is significantly attenuated, the main area turns to a blue-green tone, and only the small pore development area at the end of the core retains local oil-rich and water-rich highlight bands.

The nuclear magnetic experimental results reveal the superposition mechanism of water lock-retrograde condensate damage from the pore scale: retrograde condensation has meso-/macropore selectivity, blocking

the main gas-seepage channels, while water lock has micro-/small-pore selectivity, with an irreducible water film narrowing the bypass throats. Because the two act on complementary, non-overlapping pore systems, gas can still maintain partial connectivity through the bypass throats or the macropore main channels under a single damage, whereas their coexistence blocks the main channels and bypass throats simultaneously and collapses the seepage network, so the gas-phase permeability loss is “compounded” rather than “linearly added.” A quantitative comparison of the three cases shows 60%–80% for retrograde condensation alone, while in the combined state the macropore secondary-peak value decreases by 50.2% and its peak-area proportion by 32.6%; the combined damage rate clearly exceeds the sum of the two single damages, indicating a genuine synergistic damage rather than a simple superposition, which is also the fundamental microscopic reason for the irreversible productivity decline of field gas wells after water invasion.

(2) Microscopic Mechanism of CO₂ Miscible Flooding for Removing Dual Damage

After injecting CO₂ to the miscible pressure of 25 MPa and soaking the well for 12 h, the peak value and peak area proportion of the secondary peak in mesopores and macropores in the core T₂ spectrum show a significant rebound, the oil and gas signal in the T₁-T₂ two-dimensional spectrum is significantly recovered, the range of the aqueous phase signal cluster is significantly shrunk, the overall signal intensity of the core in the MRI image is slightly increased, and the range of the fluid enrichment zone at the end is expanded. This result indicates that during the well soaking process, CO₂ fully contacts the retained condensate oil in the pores through molecular diffusion, reduces the viscosity of condensate oil through the swelling effect, re-vaporizes the adsorbed condensate oil on the pore wall through reverse evaporation, and displaces part of the free water in the pores at the same time, initially alleviating the blockage of seepage channels caused by dual damage.

After the displacement experiment, the characteristics of the core T₂ spectrum change significantly: the final attenuation amplitude of the secondary peak value in the macropore interval reaches 88.6% compared with the initial state, and the peak area proportion decreases from 32.5% to 6.8%; the position and peak value of the main peak in the small pore interval remain stable all the time, and only the peak area proportion continues to rise to 88.7%. The free oil and gas signal in the T₁-T₂ two-dimensional spectrum almost completely disappears, and only an extremely weak bound fluid signal remains in the low relaxation region; in the MRI image, the entire core area basically turns dark blue, and only sporadic weak signal fluctuations exist in the matrix micropore region.

The experimental results clarify the microscopic mechanism of CO₂ miscible flooding for removing dual damage: after CO₂ and condensate oil reach the miscible state, the interfacial tension between them drops to an extremely low level, and the movable condensate oil and free water in mesopores and macropores can be efficiently produced through diffusion-displacement, finally achieving a fluid production degree of 88.6% in mesopores and macropores, indicating that the condensate oil and free water retained in mesopores and macropores are substantially mobilized and the mobility of the pore fluids is markedly improved. Limited by the extremely strong capillary resistance of reservoir micropores, the residual bound fluid in the micropore network is always difficult to completely produce and remove. Overall, CO₂ miscible flooding can act on both retrograde condensate retained oil and water invasion retained water simultaneously, which is an efficient means to remove reservoir damage in edge-bottom water condensate gas reservoirs.

3.2 Experimental Study on CO₂ Flooding Long Core Displacement

3.2.1 Experimental Materials and Apparatus

(1) Experimental Cores

The harmonic average method (Huppler criterion) is used to arrange and combine multiple short cores. First, calculate the harmonic average permeability value of all cores, compare this value with the measured permeability of each core, and select the core closest to the calculated value as the first core at the outlet end. Then remove this core, recalculate the harmonic average permeability of the remaining cores, compare it with the permeability of each core again, and select the core closest to this value to place in the second position. Gradually calculate and screen the remaining cores in the same way until all cores are sorted. Finally, load the short cores into the long core holder in the obtained order, and connect adjacent cores with filter paper to reduce the influence of end effect on the experimental results.

$$\frac{L}{\bar{K}} = \frac{L_1}{K_1} + \frac{L_2}{K_2} + \cdots + \frac{L_i}{K_i} + \cdots + \frac{L_n}{K_n} = \sum_{i=1}^n \frac{L_i}{K_i} \quad (1)$$

where L is the total length of the core, cm; $\bar{K}$ is the harmonic average permeability of the core, $10^{-3} \mu\text{m}^2$; L_i is the length of the i -th core, cm; K_i is the permeability of the i -th core, $10^{-3} \mu\text{m}^2$.

To account for reservoir heterogeneity and areal water-drive differences, the experimental cores were taken from two different zones of the K Gas Reservoir—the west-central area (Wells X11 and X13) and the northern area (Wells X9 and X18)—covering a permeability range of 2.57–23.08 mD and corresponding to different present-day formation pressures and water-drive intensities (the west-central cores depleted to 16 MPa with simulated water invasion, and the northern cores to 10 MPa); multiple short cores were combined using the harmonic-average (Huppler) criterion to represent vertical heterogeneity, so as to reflect the reservoir's variability as far as possible at the experimental scale. The harmonic average permeability is 5.80 mD, the average porosity is 13.18%, and the total length is 30.16 cm (Table 5); the permeability of the northern well cores ranges from 2.06 mD to 21.54 mD, the harmonic average permeability is 5.86 mD, the average porosity is 11.81%, and the total length is 30.34 cm (Table 6). The cores are sorted in turn according to the similarity between the permeability and the harmonic average value of the cores. The core selection results are shown in Tables 5 and 6.

(2) Experimental Fluids

The simulated formation water, reconstituted condensate gas sample, CO_2 and nitrogen used in the experiment are consistent with those in the nuclear magnetic resonance experiment in Section 3.1 to ensure the comparability and consistency of the experimental results. The dew point pressure of the condensate gas sample is 40.58 MPa, and the minimum miscible pressure at the formation temperature of 102.5°C is 24.6 MPa, which provides a basis for the pressure setting of immiscible and miscible displacement experiments.

(3) Experimental Apparatus

The experimental apparatus consists of four parts: injection system, high-temperature and high-pressure long core holder system, production system and data acquisition system, as shown in Fig. 4, with a maximum working pressure of 70 MPa and a maximum working temperature of 150°C, which can accurately simulate the high-temperature and high-pressure formation conditions of the target block. The injection system includes high-precision constant-speed constant-pressure displacement pumps, corrosion-resistant intermediate containers and gas booster devices; the production system is equipped with high-precision back pressure valves, oil-gas-water three-phase separators, precision gas flowmeters and on-line gas chromatographs, which can measure the production and composition of produced fluid in real time; the data acquisition system can automatically record core inlet pressure, outlet pressure, confining

pressure and temperature throughout the process, and the data acquisition accuracy meets the industry standard requirements.

Table 5: West-central core selection results.

Core Number	Porosity (%)	Permeability (mD)	Length (mm)	Total Length (mm)	Harmonic Average (mD)
1#	12.00%	5.32	50.51	301.56	5.80
3#	14.45%	22.30	49.62		
4#	15.45%	23.08	49.78		
16#	11.04%	2.57	50.4		
36#	14.59%	12.60	50.71		
37#	11.56%	3.49	50.54		

Table 6: Northern core selection results.

Core Number	Porosity (%)	Permeability (mD)	Length (mm)	Total Length (mm)	Harmonic Average (mD)
39#	12.21%	7.39	50.84	303.42	5.86
41#	12.21%	8.95	50.42		
42#	12.77%	5.04	49.95		
47#	13.52%	19.72	50.58		
48#	10.63%	2.06	50.29		
50#	9.57%	21.54	51.12		

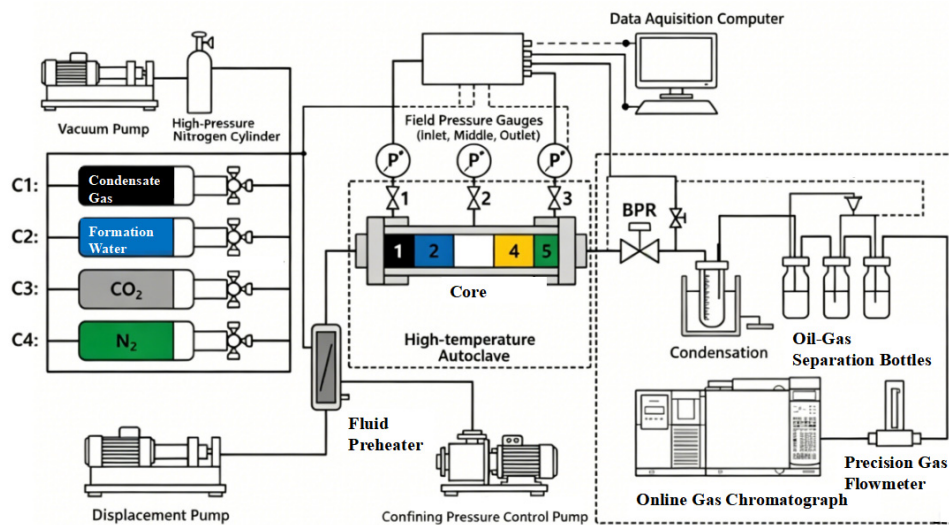


Figure 4: Flow chart of dual damage removal experiment.

3.2.2 Experimental Procedures

Two groups of cores from the west-central and northern wells of K Gas Reservoir were selected for long core displacement experiments to establish water lock damage and retrograde condensate-water lock

dual damage, and to carry out gas injection enhanced recovery research. The experiment is conducted throughout at the formation temperature of 102.5°C. The procedures are as follows:

- (1) First, perform constant-speed nitrogen displacement on the formation water-saturated core sample until no more water is produced at the outlet end to establish the irreducible water saturation of the core sample.
- (2) Load the core into the holder, close the inlet and outlet, inject condensate gas above the dew point pressure (40.58 MPa), set the back pressure valve tracking pressure to 48 MPa, and stop the pump when the pressure inside the core sample reaches 45 MPa (saturation-completion criterion: core pressure stabilizes at 45 MPa).
- (3) Reduce the pore pressure by gradually reducing the back pressure, with each stage proceeding only after the pressure stabilizes, until depletion to the current formation pressure: 16 MPa in the west-central area and 10 MPa in the northern area. Inject 0.2–0.3 PV of formation water at the inlet end of the western core to simulate water invasion, let it stand for aging for 12 h, and then continue to reduce the pressure to 16 MPa.
- (4) Open the gas inlet and inject CO₂ at a rate of 0.1 mL/min, and set the back pressure valve pressure to above the miscible pressure (28 MPa, miscible group) and below the miscible pressure (20 MPa, immiscible group), respectively.
- (5) Soak the well for 12 h, inject CO₂ at a constant speed for displacement until no oil-phase production is observed at the outlet for at least 30 consecutive minutes and the produced-fluid composition is stable as verified by online chromatography (end-of-displacement criterion), and then stop the gas flooding; record pressure, oil production and gas production in real time, analyze the composition of displaced fluid (CO₂/CH₄) by online chromatography, and evaluate the enhanced recovery effect.

It should be noted that the depletion target pressures differ among the experiments, corresponding to the present-day formation pressures of different zones of the target block: the NMR experiment uses the representative value of 15 MPa, while the long-core experiments are set at 16 MPa for the west-central area and 10 MPa for the northern area to reflect zonal differences; all the above pressure values are based on the same datum of an original formation pressure of 41.20 MPa and a dew point pressure of 40.58 MPa.

3.2.3 Experimental Results and Analysis

Fig. 5 shows the change diagram of condensate oil and condensate gas recovery factors in three groups of long core depletion experiments. The first and second groups are core samples depleted to the current formation pressure of 16 MPa in the west-central area under the influence of water invasion, and the third group is core samples depleted to 16 MPa under non-water invasion conditions. The condensate oil recovery degrees of the three groups of experiments are 22.51~26.50%, and the natural gas recovery degrees are 40.15~48.67%. In the early stage (>30 MPa), the pressure is high, the retrograde condensation phenomenon is weak, the displacement efficiency is good, and the recovery factors of condensate oil and condensate gas change approximately linearly with pressure drop; in the middle and late stages, due to the precipitation and accumulation of condensate oil, the liquid phase retention is enhanced, the gas-oil ratio rises rapidly, and the condensate oil recovery factor gradually slows down (Fig. 6).

After water injection to simulate water invasion in the first and second groups of experimental cores, the pressure rose to about 24 MPa, but due to the obstruction of the water lock effect, the increase in the recovery degree of condensate oil and gas slowed down. Compared with before water invasion, the natural

gas recovery factor increased by 10%, with a final recovery factor of 50.9%, and the condensate oil recovery factor only increased by 4%, with a final recovery factor of 23.8%~27.6%.

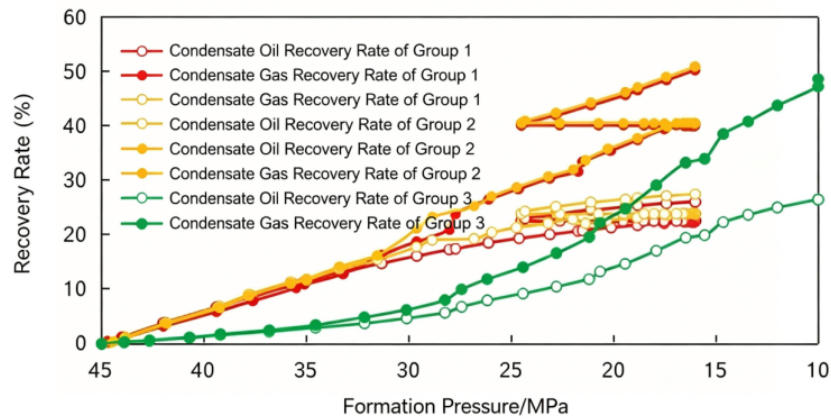


Figure 5: Depletion development recovery factor change curve.

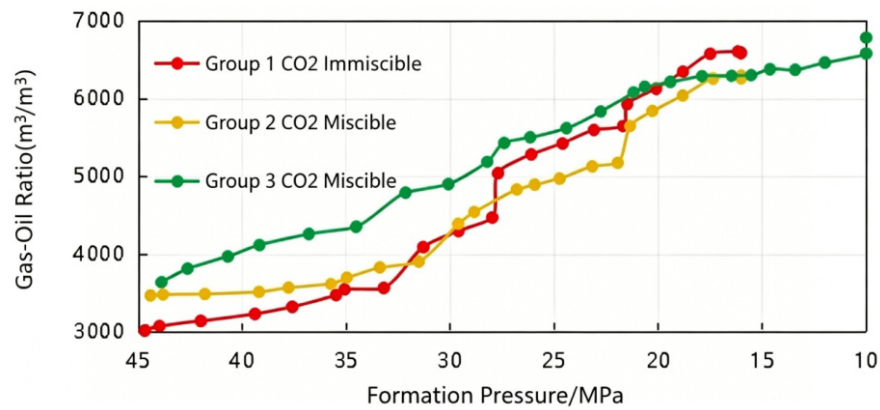


Figure 6: Depletion development gas-oil ratio change curve.

Figs. 7–9 show the comparison of condensate oil recovery factor, condensate gas recovery factor and gas-oil ratio changes in the three groups of experiments, respectively. The results show that under the experimental conditions of the first group, the CO₂-condensate oil system is immiscible, the increase range of condensate oil recovery factor is small (7%), more condensate oil remains in the core, and the retrograde condensate damage removal is weak; limited by water lock, retrograde condensate pollution and other factors, the natural gas enhanced recovery effect is the worst (25%), and the gas-oil ratio is larger. Under the experimental conditions of the second and third groups, the CO₂-condensate oil system reaches the miscible state. Miscible flooding enhances the diffusion-displacement and other effects between CO₂ and condensate oil, the oil-gas interfacial tension is greatly reduced, and the flow capacity of condensate oil is enhanced. The final condensate oil recovery factors are increased by 15.7% and 18.8%, respectively; however, due to the influence of water lock in the second group, the natural gas recovery factor is slightly lower than that of the non-water invaded core sample in the third group, with the recovery factors increased by 34.4% and 37.7%, respectively (the final natural gas recovery factors are 85.3% and 86.4%, respectively).

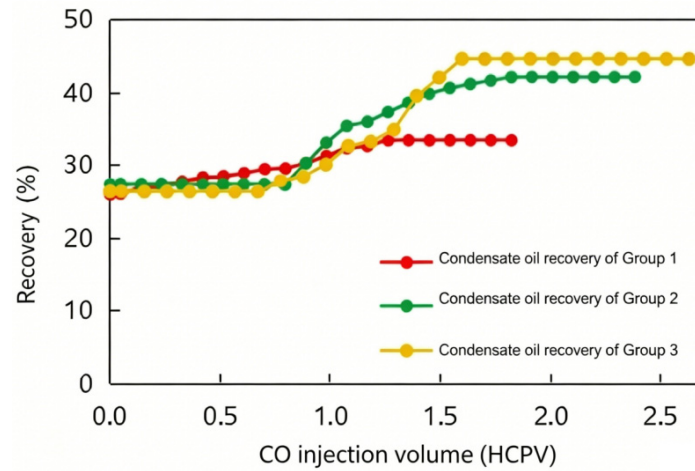


Figure 7: Comparison of condensate oil recovery factors in three groups of experiments.

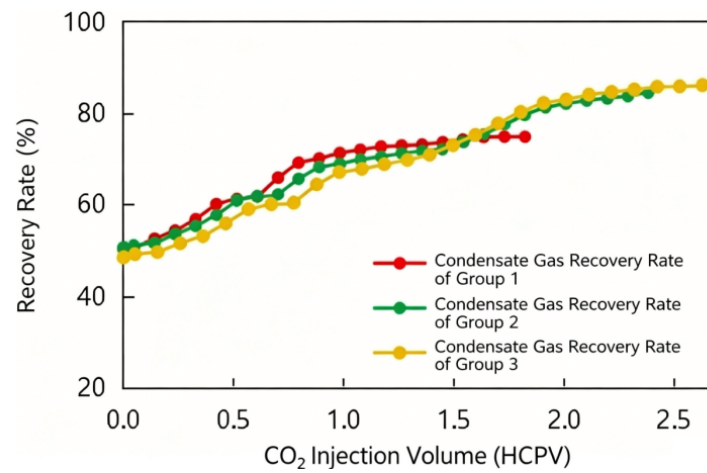


Figure 8: Comparison of condensate gas recovery factors in three groups of experiments.

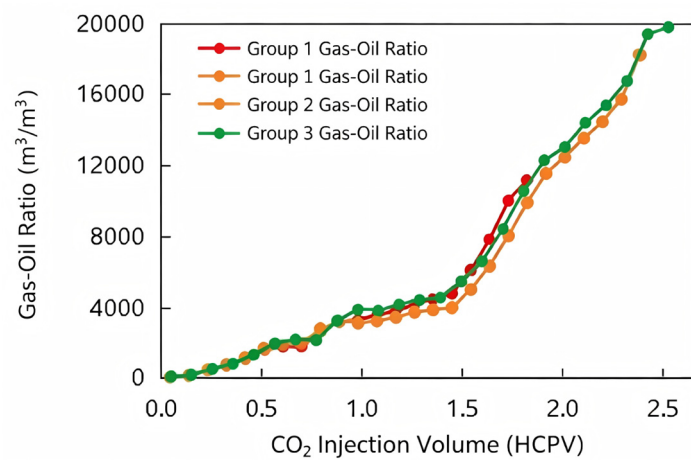


Figure 9: Comparison of gas-oil ratios in three groups of experiments.

4 Numerical Simulation Study on the Mechanism of CO₂ Injection for Enhanced Recovery

4.1 Construction of Gas Reservoir Numerical Model

4.1.1 Geological Model Grid Division and Attribute Parameters

This work adopts a three-dimensional three-phase compositional mathematical model, which solves pseudo-component mass conservation equations coupled with Darcy-phase flux for gas, condensate-oil and water phases. Phase equilibrium for each grid block is calculated via isothermal flash calculation. Full-field simulation is performed on the Petrel-RE platform with the INTERSECT simulator using a fully-implicit solution scheme; the time-step configuration is set as: initial time-step 0.5 d, minimum time-step 0.1 d, maximum time-step 60 d, with standard industry convergence tolerances for pressure and component mass balance. Core-scale validation of the same EOS-based model was previously completed using CMG-GEMTM 2022.

Based on the Petrel fine geological model of K Gas Reservoir, the model is reasonably upscaled in combination with the numerical simulation calculation accuracy and efficiency requirements. A grid size of 40 m × 40 m is adopted on the plane. Vertically, according to the stratigraphic division and interlayer distribution characteristics, the cap rock is divided into 1 grid, the main pay zone Layer-2 is divided into 15 grids, Layer-3 is divided into 19 grids, and the bottom water layer is divided into 3 grids. The final total number of grids of the model is 1.576848 million, and the upscaled geological reserves are 12.78 billion cubic meters, with an error less than 5% from the original geological reserves, meeting the accuracy requirements of numerical simulation.

The upscaling of model attribute parameters follows industry standards: net-to-gross ratio (NTG) adopts the arithmetic average algorithm, porosity adopts the NTG-weighted arithmetic average algorithm, permeability adopts the NTG-weighted harmonic average algorithm of the diagonal tensor, and saturation adopts the NTG-weighted arithmetic average algorithm, to ensure that the upscaled attribute field can accurately reflect the reservoir heterogeneity characteristics. The model is initialized by capillary-gravity hydrostatic equilibrium. The global fixed formation temperature is 102.5°C, the datum initial formation pressure is set to 41.20 MPa with hydrostatic gradient applied vertically. Initial saturations are constrained by capillary-pressure relationships with zonal irreducible-water saturation boundaries (34.8% for Type-I high-permeability reservoirs and 33.1% for Type-II-III low-permeability reservoirs). The initial hydrocarbon molar composition adopts the dew-point well-stream composition summarized in Table 3, consistent with the recombined experimental condensate gas. The core basic parameters of the model are consistent with the overview of the study area in Section 2. The average porosity of the main pay zone is 13.18%, the average permeability is 5.80 mD.

4.1.2 Fluid Phase Behavior Model Fitting

Based on the fluid laboratory analysis at the wellhead, the PVT i calculation program of SCHLUMBERGER Company is used to perform regression fitting on the experimental test parameters such as constant composition expansion and constant volume depletion. During the fitting process, the equation of state parameters in the compositional model are optimized and adjusted to improve the prediction accuracy of condensate gas properties. The SR-K equation is selected for phase equilibrium calculation. By adjusting the relative molecular mass, density, critical constants (P_c , T_c), acentric factor (ω), and component coefficients Ω_a and Ω_b in the equation of state for fractions $C_7 \sim C_{10}$, $C_{11} \sim C_{20}$, and $C_{21} \sim C_{68}$, the experimental data such as constant composition expansion and constant volume depletion are fitted. The fitting results are shown in Fig. 10, and the equation of state parameters of Block P in the K Gas Reservoir are determined (Table 7).

On the premise of not affecting the simulation results, according to the principle of similar component properties, the condensate gas well stream components are extended and merged into 7 pseudo-components.

Table 7: Equation of state parameters of K gas reservoir.

Component Name	Molecular Weight g/mol	Mole Percentage (%)	Critical Temperature (°C)	Critical Pressure (KPa)	ΩA	ΩB
CO ₂	44.01	0.38	31.55	73.87	0.427480	0.086640
N ₂ +C ₁	16.42	87.59	−85.99	45.36	0.359228	0.061721
C ₂	30.07	4.46	32.28	51.74	0.488533	0.072617
C ₃ ~C ₆	59.81	4.32	162.85	36.18	0.463511	0.07854
C ₇ ~C ₁₀	116.27	2.01	305.05	26.87	0.46224	0.078314
C ₁₁ ~C ₂₀	201.44	1.03	405.39	16.92	0.696613	0.074385
C ₂₁ ~C ₆₈ +	353.25	0.21	532.75	12.30	0.451604	0.087287

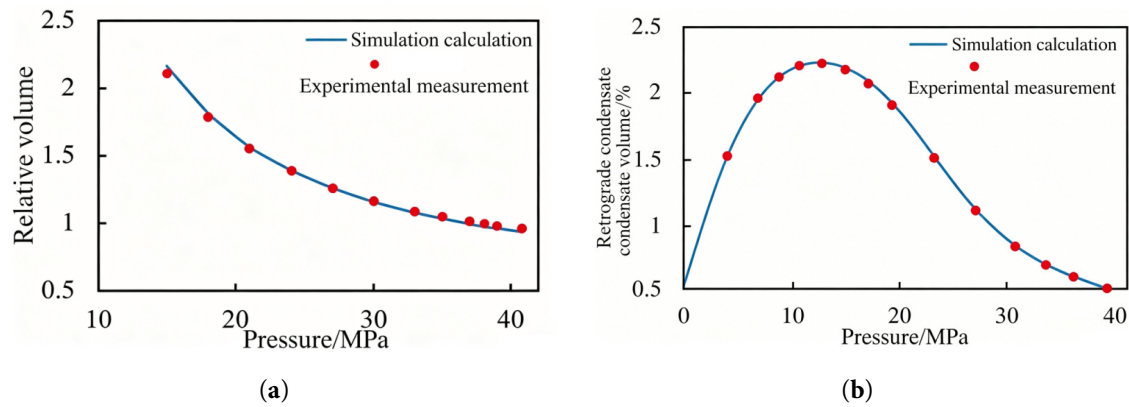


Figure 10: Phase behavior fitting diagram of K gas reservoir: (a) CCE experimental data fitting plot; (b) CVD experimental data fitting plot.

4.1.3 Relative Permeability Parameters

The relative permeability is obtained by normalizing the relative permeability curve of the core sample to get the average relative permeability curve conforming to the actual oil and gas reservoir (Table 8); the capillary pressure is also input into the model after normalization of the experimental capillary pressure curves of core samples, and is used together with the relative permeability curves to describe the capillary force effects of the oil-water and oil-gas phases. These rock-fluid functions are directly imported without secondary regression fitting, and are assigned zonally according to reservoir-quality classification to reflect reservoir heterogeneity.

Table 8: Relative permeability curve data of K gas reservoir.

Oil/Water Relative Permeability (f)			Oil/Gas Relative Permeability (f)		
Sw	Krw	Kro	Sg	Krg	Krog
0.3000	0.0000	1.0000	0	0	1
0.3746	0.0340	0.8087	0.0580	0.0000	0.7411
0.4112	0.0647	0.6549	0.0811	0.0254	0.5577
0.4478	0.1047	0.4977	0.1041	0.0518	0.4131
0.4844	0.1391	0.3663	0.1272	0.0793	0.3006
0.5210	0.1703	0.2598	0.1503	0.1078	0.2143
0.5576	0.2071	0.1569	0.1733	0.1373	0.1492
0.5942	0.2444	0.0664	0.1964	0.1679	0.1010
0.6308	0.2772	0.0266	0.2195	0.1995	0.0662
0.6674	0.3155	0.0056	0.2425	0.2321	0.0416
0.7040	0.3542	0.0000	0.2656	0.2658	0.0249
1.0000	1.0000	0.0000	0.2887	0.3005	0.0139
			0.3117	0.3363	0.0071
			0.3348	0.3731	0.0031
			0.3579	0.4109	0.0011
			0.3809	0.4498	0.0002
			0.4040	0.4897	0.0000
			0.7000	1.0000	0.0000

4.2 Production History Matching

A systematic history matching was performed on multiple dynamic indicators of Block P in the K Gas Reservoir, including daily gas, oil, liquid, and water production, with the water cut calculated from the liquid and water production dynamics and cross-checked. The matching results are shown in Fig. 11 (points are measured data, dashed lines are numerical simulation results); the measured and simulated values of each indicator agree well, with an overall matching rate exceeding 90.0%, and the water-production match reflects the water-invasion and water-cut dynamics of the gas reservoir, indicating that the model can reliably reproduce the historical production dynamics of the reservoir and providing a reliable model basis for subsequent development scheme prediction.

History matching follows a hierarchical workflow: preliminary trial calculation for model quality check, regional coarse adjustment for aquifer and large-scale inter-layer properties, and single-well fine tuning for local petrophysical parameters. The adjusted parameters are restricted within physically reasonable ranges, mainly including permeability multipliers, interlayer barrier geometry, and minimum mobile-water-saturation endpoints.

In addition, the fluid phase behavior, relative permeability, and CO₂–condensate displacement physics of the compositional model used in this paper have been validated at the core scale in our previous work [30], based on the same block and the same set of long-core experiments: the numerical simulations closely agree with the long-core experiments across the depletion stage (condensate recovery under varying reservoir pressures), the CO₂ immiscible flooding stage, and the CO₂ miscible flooding stage, with the depletion-stage

comparison also verifying the model's representation of the pressure–recovery relationship. Therefore, the field-scale predictions in this paper are built upon experimentally validated core model physics, and their reliability is well substantiated.

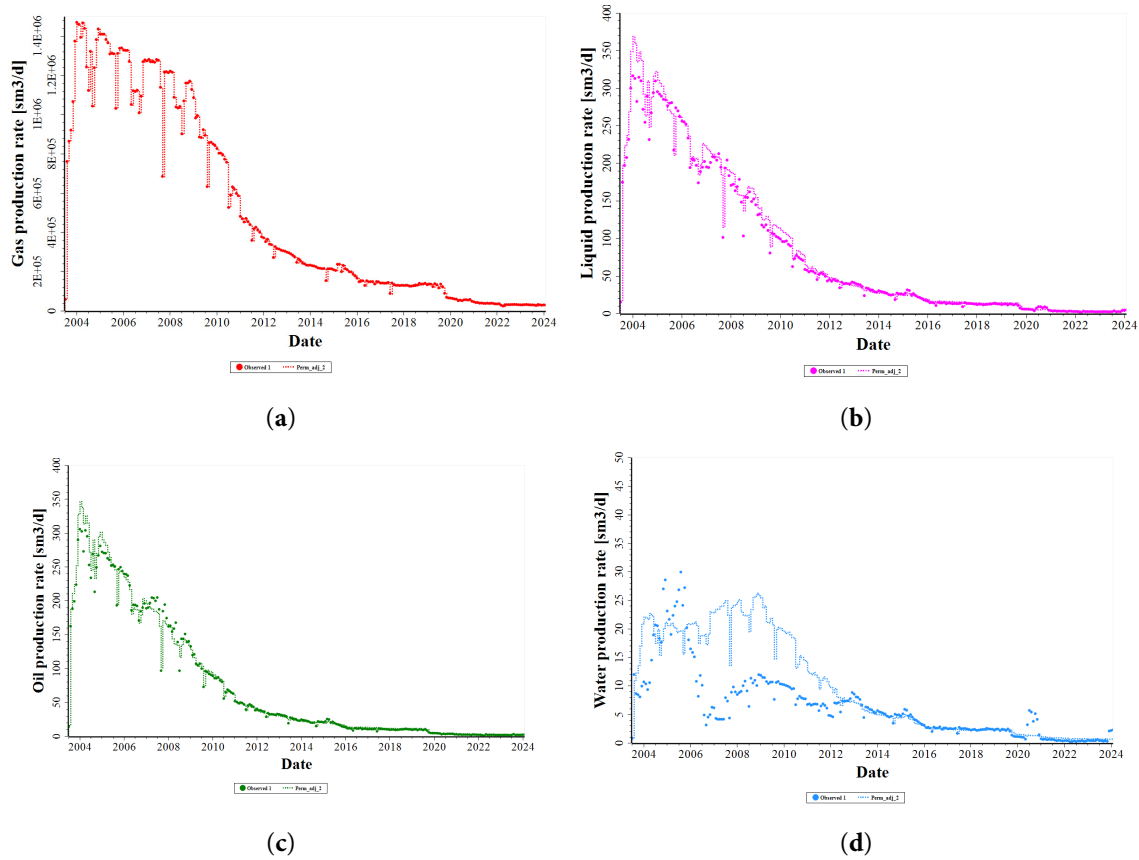


Figure 11: Numerical model history matching (points are measured data, dashed lines are numerical simulation fitting results): (a) daily gas production; (b) daily liquid production; (c) daily oil production; (d) daily water production.

History matching is performed for four production indicators: daily gas production, daily liquid production, daily oil production, and daily water production, with matching rates all exceeding 90% (daily gas production about 93%, daily liquid production about 91%, daily oil production about 90%, daily water production about 92%), and the matching accuracy meets the requirements of field numerical simulation. Combined with an upscaling error of geological reserves of less than 5%, industry-standard upscaling of attribute parameters, and EOS phase behavior fitted by regression based on CCE/CVD experiments, the three-dimensional compositional numerical model established in this paper has high precision and can provide a reliable basis for subsequent gas-injection parameter optimization and production prediction.

4.3 Optimization of CO₂ Huff and Puff and Continuous Displacement Parameters in K Gas Reservoir

Based on the 3D compositional model with a history-matching rate exceeding 90%, this section optimizes, in turn, the key parameters of two gas-injection modes: for CO₂ huff and puff, the single-well injection volume and the number of cycles are optimized, using the recovery-degree inflection point and the oil-exchange rate as criteria; for CO₂ continuous flooding, the injection rate and injection pressure are optimized, using whether formation pressure can be stably maintained above the miscibility pressure

and whether gas channeling occurs as criteria. The optimized parameters jointly constitute the field injection-production scheme and are used for development-performance prediction.

4.3.1 CO₂ Huff and Puff

The recovery degree of single-well controlled reserves in the eastern area of K Gas Reservoir is generally greater than 50%, and gas wells are shut down due to the inability to carry liquid caused by formation energy depletion. Comprehensively considering factors such as remaining reserves abundance, pressure distribution, physical property conditions and old well abandonment, Well X1 is located in the main channel, with good overall physical properties, good well condition and short shutdown time. At the same time, it has the advantage of low injection and high production compared with the other 3 available wells, so it is selected as the pilot test well for CO₂ injection enhanced recovery in the gas reservoir.

(1) Optimization of Single Well Huff and Puff Gas Injection Volume

For the optimization of single well huff and puff gas injection volume, the simulation process sets a gas injection cycle of 20 days, a well soaking time of 10 days, and a production time of 30 days, with a total of 60 days as one injection-production cycle. In this simulation, different cumulative injection volumes are simulated by changing the daily gas injection rate, with 5 schemes of 2.5, 5, 7.5, 10, and 15 t per day, corresponding to cumulative injection volumes of 1000 t~6000 t per cycle, respectively. Fig. 12 shows the change diagram of natural gas and condensate oil with gas injection volume. With the increase of gas injection volume, the per-cycle condensate oil recovery degree in the production stage shows a continuous increasing trend in the early stage, and an inflection point appears at 4000 t per cycle, basically stabilizing at about 335 cubic meters. The optimal injection volume is 4000 t per cycle.

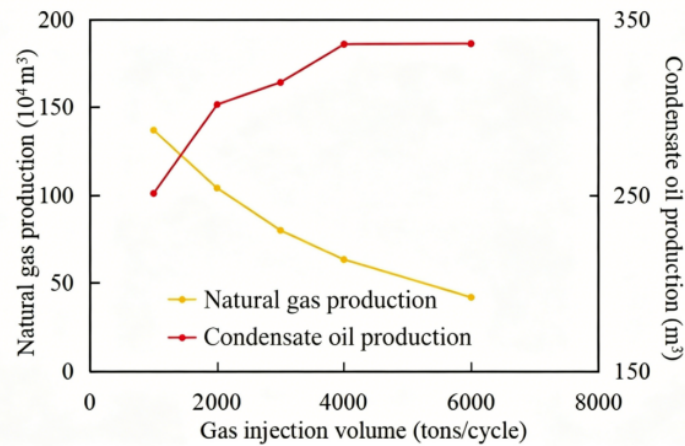


Figure 12: Change of natural gas and condensate oil with gas injection volume.

(2) Optimization of Gas Injection Huff and Puff Cycles

As shown in Table 9 and Fig. 13, although the condensate oil pollution around the well is significantly alleviated with the progress of huff and puff, the stage gas production decreases from 296,800 cubic meters in the first cycle to 193,800 cubic meters in the second cycle and then to 141,900 cubic meters in the third cycle, with the decline rate continuously expanding; the stage oil production decreases from 164.96 t in the first cycle to 102.33 t in the second cycle and then to 68.35 t in the third cycle, with each cycle's oil production reduced by about 40%~50% compared with the previous cycle; while the stage oil replacement rate decreases from 0.82 t per 10,000 cubic meters in the first cycle to 0.51 t per 10,000 cubic meters in the

second cycle and then to 0.34 t per 10,000 cubic meters in the third cycle, indicating that the efficiency of crude oil produced per unit gas injection volume is continuously decreasing. In the initial cycles, with the injection of CO₂, the reaction degree with oil and gas is more intense and the mass transfer effect is more significant, so the condensate oil recovery degree is higher; while with the continuous progress of cycles, the content of heavy hydrocarbons in the formation becomes higher, and miscibility becomes more difficult in the later stage, so the enhanced recovery capacity shows a downward trend with the increase of “huff and puff” cycles. Comprehensive comparison shows that the oil exchange rate of the third cycle huff and puff decreases significantly and the efficiency is reduced, so two cycles of huff and puff are optimal.

Table 9: Production parameters of each cycle of gas injection huff and puff.

Parameter	First Cycle	Second Cycle	Third Cycle
Stage Gas Production (10 ⁴ m ³)	29.68	19.38	14.19
Stage Oil Production (tons)	164.96	102.33	68.35
Stage Oil Replacement Rate (tons/10 ⁴ m ³)	0.82	0.51	0.34

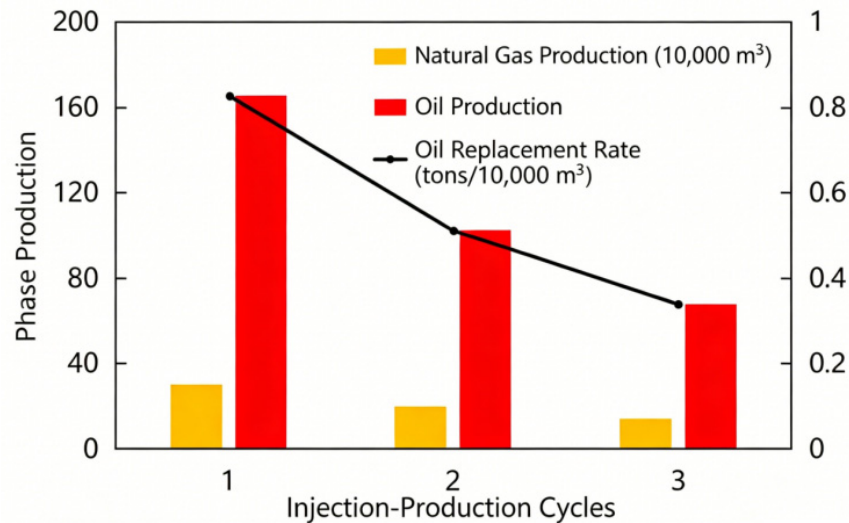


Figure 13: Comparison of production of each cycle of well X1 gas injection huff and puff.

(3) Gas Injection Huff and Puff Production Prediction

Fig. 14 shows the change in pressure and cumulative production of Well X1 during gas injection huff and puff. Based on the optimized huff-and-puff parameters, a deterministic numerical-simulation production prediction of Well X1 CO₂ huff-and-puff is carried out under the conditions of an injection volume of 4000 t per cycle, two huff-and-puff cycles, and a well-soaking time of 10 days. It is predicted that the cumulative production over two huff-and-puff cycles is about 491,000 cubic meters of natural gas and about 267 t of condensate oil can be produced by the end of the huff-and-puff stage; these results are subject to uncertainties in the geological model and injection-production parameters, and the actual development performance may vary to some extent.

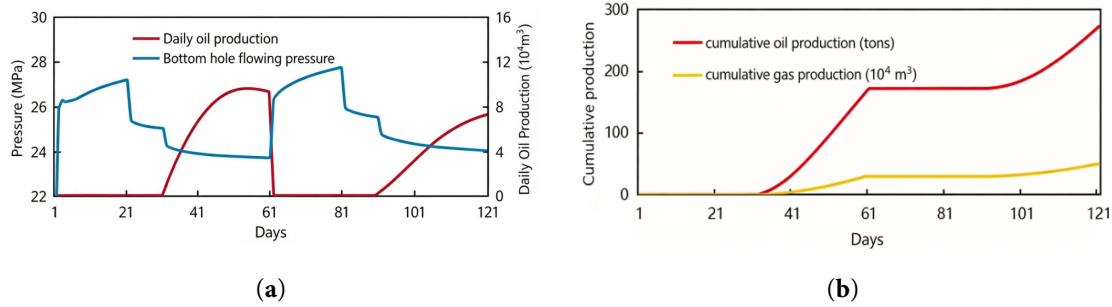


Figure 14: Production prediction of well X1 gas injection huff and puff: (a) pressure change; (b) cumulative production change.

Although huff and puff effectively promotes the removal of retrograde condensate pollution in the near-wellbore zone, CO_2 displaces natural gas to a distance in a piston-like manner during injection, and a large amount of CO_2 in the near-wellbore zone will be produced together with hydrocarbons, leading to a decline in natural gas production capacity. Therefore, huff and puff can only be used to verify the effect of removing condensate oil pollution, and establishing a reasonable injection-production relationship for the whole area is an effective way to enhance recovery.

4.3.2 CO_2 Continuous Flooding

(1) Optimization of Gas Injection Rate

Based on the current situation of old wells in the eastern area, the construction of the test area gives priority to using old wells to carry out continuous gas injection tests, and the well group selection is shown in Fig. 15. Well X1 in the low structural position is used as the gas injection well, and two adjacent wells X2 and X7 are used as production wells to form a 1-injection 2-production test area. Five injection rate schemes with daily gas injection of 80 t/d~400 t/d are designed, focusing on the pressure change in the test area (average formation pressure within 500 m of a single well) to judge the injection-production response time.

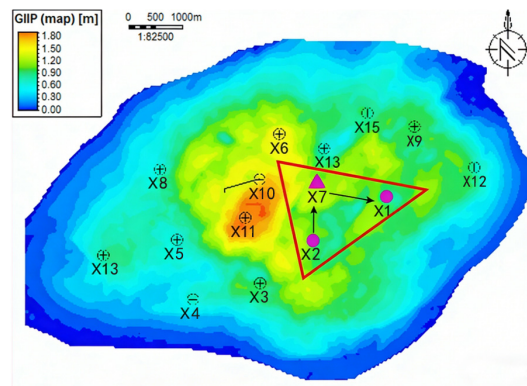


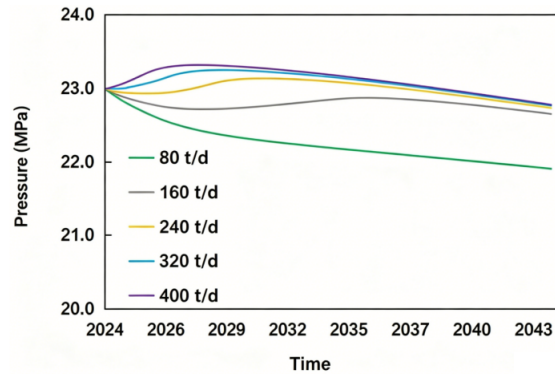
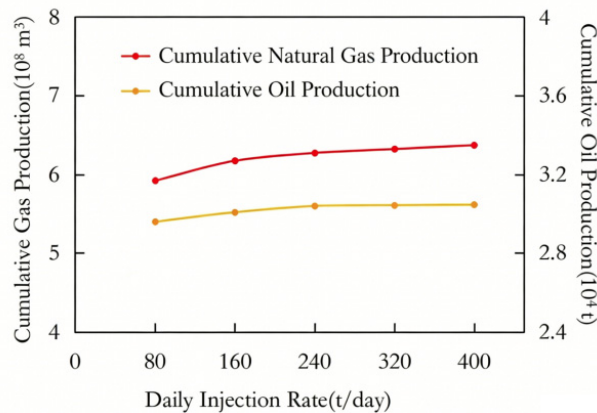
Figure 15: Selection of continuous gas injection well group in the eastern area.

Table 10 shows the statistics of the response time of the test wells. The well spacing between X2 and X1 is 1625 m, and the response time is 3~7 months; while the well spacing between X7 and X1 is 1343 m, and the response time is faster, 2~6 months. The faster the injection rate, the faster the response time of the two wells. When the injection rate reaches 240 t/d, the response of the two wells is basically stable, with about 4 months for Well X2 and 3 months for Well X7.

Table 10: Statistics of response time of test wells.

Injection Rate (t/d)	Response Time (Months) (Start of Pressure Rise)	Response Time (Months) (Start of Pressure Rise)
	X2	X7
80	7	6
160	5	4
240	4	3
320	4	3
400	3	2

Figs. 16 and 17 show the change in pressure and cumulative production with injection volume. The two wells start production after responding. Considering the regional injection-production balance, the total gas production rate is set to be consistent with the gas injection rate. The results show that when the injection rate is greater than 160 t/d, the pressure in the test area is basically consistent in the later stage and can reach the minimum miscible pressure. Through the change of cumulative oil and gas production under different gas injection rates, it is found that there is an obvious inflection point in the cumulative production curve when the gas injection rate is 240 t/d, and the later cumulative production results show small-scale fluctuations with the change in injection volume.

**Figure 16:** Pressure change with gas injection volume.**Figure 17:** Cumulative production change with injection volume.

Therefore, the reasonable injection rate is optimized to be 240 t/d. At this time, the later formation pressure is stable and reaches the miscible pressure, the stimulation effect is the best, and no obvious gas channeling occurs, which is conducive to the long-term production of the gas reservoir.

(2) Optimization of Gas Injection Pressure

Taking the bottom hole flowing pressure as the injection limiting condition, six injection pressures of 18–30 MPa are set to carry out injection pressure optimization. From the change diagram of the average formation pressure of the well group under different gas injection pressures (Fig. 18), it can be seen that the formation pressure shows a continuous downward trend under the injection pressure of 18 MPa, while the injection pressure of 20 MPa and above can realize the recovery and maintenance of formation pressure. Among them, the formation pressures of 24 MPa, 26 MPa, 28 MPa and 30 MPa remain stable in the later stage and are higher than the first-contact miscible pressure, while the injection pressure of 22 MPa is too low, and the formation pressure is difficult to maintain above the miscible pressure in the later stage. Therefore, when the pressure is greater than 24 MPa, better injection capacity can be obtained, and the formation pressure in the test area can be maintained above the first-contact miscible pressure.

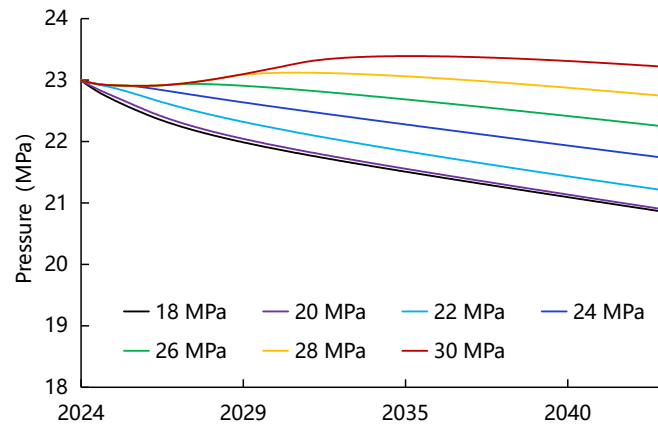


Figure 18: Comparison of different injection pressures.

- (3) Production Prediction based on the previously optimized gas injection parameters, it is predicted that the test well group will carry out the CO₂ continuous flooding enhanced recovery pilot test at a gas injection rate of 240 t/d. Considering the injection-production balance, the production wells are allocated a production of 60,000 cubic meters per day. The 20-year development production prediction indicators (Fig. 19) show that according to the optimized parameters, it is predicted that the test well group will carry out the CO₂ continuous flooding enhanced recovery pilot test at a gas injection rate of 240 t per day, and the production wells will be allocated production of 60,000 cubic meters per day, finally achieving injection-production balance. A deterministic numerical-simulation prediction based on the optimized parameters indicates that 15 years of continuous production can be realized, with production eventually stopped owing to large-scale CO₂ breakthrough, and a cumulative natural gas production of about 620 million cubic meters, a condensate oil production of about 35,000 cubic meters, and a CO₂ storage volume of about 1.125 million tons. Together with the sensitivity analysis of key parameters (injection volume, huff-and-puff cycles, injection rate, and injection pressure) in Section 4.3 and the model reliability indicated by a history-matching rate exceeding 90%, the selection of the optimal parameters has accounted for the influence of key parameter variations on the predicted results;

it should be noted that this paper does not include a formal probabilistic uncertainty quantification, and the predicted values should be regarded as a reference for scheme comparison, with the actual development performance subject to field implementation.

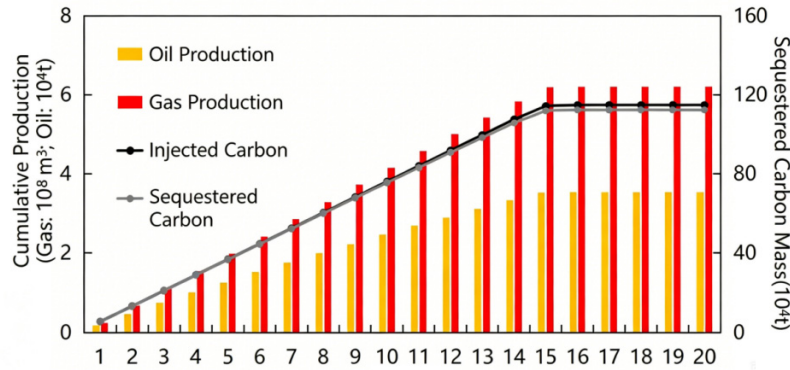


Figure 19: 20-year development production prediction indicators.

In summary, the optimized parameters of CO₂ huff and puff (4000 t/cycle, 2 cycles) and continuous flooding (240 t/d, injection pressure ≥ 24 MPa, production allocation 6×10^4 m³/d) jointly constitute the integrated injection-production scheme of the K Gas Reservoir. Accordingly, the well group is predicted to achieve 15 years of continuous stable production, with cumulative production of 6.2×10^8 m³ of natural gas and 3.5×10^4 m³ of condensate oil, and 112.5×10^4 t of CO₂ sequestration. Compared with the current depletion recovery of 36.77%, this scheme quantitatively demonstrates the dual contribution of parameter optimization to ultimate field-development efficiency and carbon storage.

5 Conclusions and Suggestions

- (1) The development dynamic characteristics and main controlling factors of reservoir damage of the K edge-bottom water condensate gas reservoir are clarified. Experimental results show that when the formation pressure drops below the dew point pressure, the precipitation of retrograde condensate oil can lead to a 60%~80% decrease in gas phase permeability; the non-uniform advancement of edge and bottom water causes bottom hole liquid loading, which changes the seepage pattern from early plane radial flow to composite radial flow, significantly increasing the gas phase flow resistance.
- (2) The microscopic superposition mechanism of water lock-retrograde condensate dual damage is revealed at the pore scale. Retrograde condensate damage has significant mesopore-macropore selectivity, and condensate oil preferentially precipitates and accumulates at the pore throats of mesopores and macropores, directly blocking the main gas phase seepage channels; water lock damage has significant micropore-small pore selectivity, and invaded water remains in the micropores in the form of an irreducible water film, further narrowing the seepage throats. Because retrograde condensation and water lock act on the complementary meso-/macropore and micro-/small-pore systems, their coexistence simultaneously blocks the main channels and the bypass throats, so that the gas-phase permeability damage rate is not only significantly higher than that of either single damage but also higher than their simple additive sum—a genuine synergistic damage.
- (3) The enhanced recovery effect of CO₂ injection for removing dual damage is quantitatively evaluated, and indicating that CO₂ miscible flooding can markedly mitigate reservoir composite damage. Compared with immiscible flooding, miscible flooding can increase the condensate oil recovery factor by

up to 18.8% and the natural gas recovery factor by up to 37.7%; CO₂ miscible flooding can achieve a final fluid production degree of 88.6% in mesopores and macropores, substantially mobilizing the condensate oil and free water retained in the pores and improving the fluid mobility.

- (4) A high-precision three-dimensional compositional numerical model of the K Gas Reservoir is established. Combined with the reservoir damage types, the gas reservoir is divided into a retrograde condensate zone and water invasion zone, and the key parameters of CO₂ injection development are optimized, yielding an optimal single-well huff-and-puff injection volume of 4000 t/cycle, an optimal number of 2 huff-and-puff cycles, an optimal continuous injection rate of 240 t/d for the well group, and an injection pressure of ≥ 24 MPa.
- (5) The injection-production scheme of K Gas Reservoir is optimized and formed; according to the optimized parameters, it is predicted that 15 years of continuous production can be realized, with cumulative production of 6.2×10^8 m³ of natural gas and 3.5×10^4 m³ of condensate oil, while numerical simulation predicts a CO₂ storage volume of about 112.5×10^4 t, demonstrating the application potential of synergizing enhanced recovery with CO₂ geological storage; a systematic evaluation of the retention factor and long-term storage safety is beyond the scope of this paper, and the related conclusion should be understood as an application prospect.
- (6) It should be noted that this study mainly characterizes the effect of CO₂ in removing dual damage through the NMR fluid production degree and the long-core recovery indicators, and has not yet directly measured the gas-phase (effective/relative) permeability of the cores before and after CO₂ treatment; in future work, measurements and quantitative comparisons of permeability before and after CO₂ treatment will be supplemented to further verify, in absolute values, the restoration of the reservoir seepage capacity.
- (7) Limited by the number of cores and the single recombined fluid composition, the laboratory experiments in this study cannot fully cover the heterogeneity and compositional variability of the entire reservoir; the experiments mainly serve to reveal mechanisms and provide parameters for the numerical model, while the influence of heterogeneity and the areal water-drive differences ("strong in the southwest, moderate in the east, weak in the north") on the whole reservoir is carried by the history-matched 3D compositional model that is zoned into retrograde-condensate and water-invasion regions, thereby reducing the risk of direct scale extrapolation. In future work, we will add experiments on cores from different zones and with different petrophysical properties, consider the spatial variability of fluid composition, and incorporate a finer characterization of the areal water-drive intensity, so as to further improve the reliability of extending the results to the whole reservoir.
- (8) Owing to the high cost and long duration of the NMR and long-core experiments, the experimental data in this paper are presented mainly as single measured values, without a systematic statistical assessment of experimental replicates and confidence intervals; in future work, replicate experiments and a statistical uncertainty analysis will be added to further strengthen the scientific robustness of the conclusions.
- (9) Limited by samples and experimental conditions, the NMR mechanistic analysis in this paper is based on a single representative core and does not cover multi-core comparison across the full permeability range; in future work, NMR comparative experiments will be carried out on cores of different permeability grades to further verify the universality of the pore-scale damage and removal mechanisms.
- (10) The K Gas Reservoir is located in the Junggar Basin, Xinjiang, where industrial processes such as natural gas purification decarbonization and coal chemical engineering in and around the basin can provide a stable CO₂ source; after capture and purification, the CO₂ can meet the purity requirement

for gas injection. CO₂ transport can be realized by pipeline, relying on the existing oil and gas gathering and transportation pipeline network in the basin, or by tank truck, both of which are engineering-feasible. The optimized injection scales in this study—4000 t per cycle for huff-and-puff and 240 t/d for continuous flooding—are comparable to the injection scales of CO₂ flooding field pilots already in operation in China, and are therefore engineering-implementable. The techno-economic evaluation of the full CO₂ capture–transport–injection–storage chain, carbon storage capacity accounting, and long-term safety monitoring remain topics for future research.

- (11) The risk of salt precipitation induced by dry CO₂ injection is not explicitly evaluated in the present compositional model. The formation water of the K Gas Reservoir has a moderately low salinity of 17,644.5 mg/L (CaCl₂ type), substantially below the halite saturation threshold; in the huff-and-puff scheme, the flowback stage after soaking can carry concentrated near-wellbore brine out with the produced fluids, mitigating salt accumulation. However, for the 15-year continuous injection scheme, a salt-scaling risk around injectors cannot be fully excluded. Coupling a salt-precipitation module into the compositional model to quantitatively evaluate salt damage and its long-term impact on injectivity is recommended for future work [31].

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