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Preparation and application of a barium sulfate descaling and deblocking agent for low-permeability reservoirs

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During water injection development in low-permeability reservoirs, $BaSO_4$ scaling is prone to occur due to incompatibility between high-salinity formation water and injected water, severely affecting oilfield development efficiency. This paper systematically developed and evaluated the performance of a composite $BaSO_4$ scale remover. Chelating agents, conversion agents, dispersants, and penetrants were optimized to construct an efficient composite scale removal system. Combined with core flooding experiments, operational parameters and processes were optimized. The results show that an efficient scale removal system was developed: 15% DTPA-5K + 8% $C_6H_{11}O_7Na$ + 6% DTPMP + 0.2% JFC (balance water), achieving a scale removal efficiency of 98.4% at pH = 11. Simulated core experiments indicated a permeability recovery rate of 87% at an injection rate of 0.02 mL min^{-1} and an injection volume of 1.5 PV. Field applications demonstrated that this system effectively removes $BaSO_4$ scale blockages in injection and production wells. For injection well A21, the injection pressure decreased by 20.8%, water injection volume increased by 200%, and liquid production increased by 136% after treatment. For production well P17, liquid production increased by 136%, oil production increased by 148%, and flowing pressure increased by 31.8%. The research results provide theoretical basis and technical support for the prevention and treatment of $BaSO_4$ scale in low-permeability reservoirs.

1. Introduction

Low-permeability reservoirs hold significant importance in China's oil and gas resources, but they commonly face severe scaling issues during water injection development, particularly the formation and deposition of barium sulfate ($BaSO_4$) scale, which severely blocks reservoir pore throats, leading to increased injection pressure, reduced water injection volume, and production loss.[1–3] The primary cause of scaling is the presence of barium ions (Ba^{2+}) in the formation water and high concentrations of sulfate ions in the injected water. Due to the extremely low solubility of $BaSO_4$ scale ($K\text{sp} = 1.08 \times 10^{-10}$), coupled with the low permeability and complex pore structure of low-permeability reservoirs, scaling is more likely to occur. The scaling process is influenced by multiple factors such as ionic composition, temperature, pressure, and pH, making the mechanism complex.[4] $BaSO_4$ scale is a typical "pH-insensitive" scale, making traditional acid washing almost ineffective for removing such blockages.[5] Nikki *et al.*[6] found that the macrocyclic compound diazabicyclo[18.0]crown-6 exhibited the strongest chelating properties toward $BaSO_4$, enabling its rapid dissolution within 30 minutes at pH 8 and room temperature. Kelland *et al.*[7] developed a novel $BaSO_4$ dissolver, macrocyclic polyamino-polycarboxylate, which significantly enhances dissolution rates. However, macrocyclic chelating agents are costly and impractical for field deployment. Research by Kelland *et al.*[8] indicates polyamino polyphosphates exhibit dissolution capabilities at extremely high pH levels. Polyamino polycarboxylates, employed as $BaSO_4$ solvents, possess strong complexation abilities, multiple coordination bonds, and high complex stability constants. Consequently, recent development efforts for $BaSO_4$ descaling agents have primarily focused on amino polycarboxylate chelating agents. Among these, aminocarboxylate chelating agents like EDTA and DTPA are widely applied due to their strong Ba^{2+} chelation capacity.[9–11] However, single chelating agents suffer from low transport efficiency, incomplete reactions, and high costs in low-permeability reservoirs.[12–14] In recent years, composite scale inhibitors have gained prominence due to their synergistic effects. The incorporation of solubilizers and dispersants can significantly enhance both scale removal efficiency and economic viability.

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Common solubilizers include strong alkalis like NaOH or KOH, or weak alkalis such as K_2CO_3 or Na_2CO_3, which enhance the solubility of amine-carboxylate chelating agents like EDTA and DTPA, thereby improving chelation performance. Dispersants typically employ sodium polyacrylate, polyphosphates, and other scale inhibitors to further disperse and modify the crystallization of $BaSO_4$.[15–17] Mahmoud *et al.*[18] demonstrated that in EDTA solutions, using K_2CO_3 to convert $BaSO_4$ into $BaCO_3$ increased the solubility of $BaSO_4$ from 62% to 90%. Hany Gamal *et al.*[19] employed DTPA as the chelating agent, oxalic acid and tannic acid as activators and nonionic surfactants, achieving a $BaSO_4$ dissolution efficiency of 91.3% at 90 °C. Ford *et al.*[20] successfully applied a descaling agent composed of strong alkali solution, polymeric aminopolycarboxylic acid DTPA, and an enhancer in the Alwan North oilfield in the North Sea, Europe. This formulation exhibits exceptional dissolution capability for $BaSO_4$, achieving high dissolution rates within 1 hour. Wang *et al.*[21] developed the SS-1 descaling agent by blending EDTA as the primary chelating agent with a self-synthesized polyhydroxy polymer permeation dispersant and KOH as auxiliary agents. This formulation achieved nearly 100% descaling efficiency against barium-strontium sulfate scale.

Given the characteristics of low porosity and low permeability, strong heterogeneity, and complex structure of low-permeability reservoirs, the composite plugging removal agent for $BaSO_4$ blockage needs to possess strong chelating ability. This study proposes, on the basis of a strong chelating agent, adding a conversion agent to transform $BaSO_4$ into a water-soluble barium salt, along with a rapid dispersant and a strong penetrant, to enhance the dissolution rate of $BaSO_4$ through synergistic effects, thereby constructing an efficient composite scale removal system. Based on the geological characteristics and water quality conditions of the Chang 8 reservoir in the Jiyuan Oilfield, combined with core flooding experiments, the injection parameters of the high-efficiency composite scale remover were optimized. Field trials were conducted to verify its plugging removal effectiveness, aiming to provide technical reference for $BaSO_4$ scale removal in low-permeability reservoirs.

2. Experimental materials and methods

2.1 Experimental materials

(1) Simulated cores and simulated formation water: simulated cores from the typical ultra-low permeability Chang 8 reservoir of the Jiyuan Oilfield in Changqing Oilfield were used. Permeability: 0.026–0.22 mD (average 0.078 mD); porosity: 8–12% (average 10.94%). Simulated formation water was prepared based on the formation water of the Chang 8 reservoir in the Jiyuan Oilfield. Cations: $Na^+ + K^+$: 30 000 mg L^{-1}; Ca^{2+}: 10 000 mg L^{-1}; Mg^{2+}: 800 mg L^{-1}; Ba^{2+}: 500 mg L^{-1}; Sr^{2+}: 50 mg L^{-1}. Anions: Cl^-: 50 000 mg L; SO_4^{2-}: 500 mg L; HCO_3^-: 600 mg L^{-1}.

(2) Experimental materials: sodium hydroxide, oxalic acid, citric acid, cinnamic acid, salicylic acid, sodium carbonate, sodium gluconate, sodium formate (analytical grade, purity: 99.9%, Shanghai Macklin Biochemical Technology Co., Ltd); ethylenediaminetetraacetic acid (EDTA), EDTA-4Na, diethylenetriaminepentaacetic acid (DTPA), DTPA-5Na (Wuhan Xingzhongcheng Technology Co., Ltd); fatty alcohol polyoxyethylene ether (JFC), octylphenol polyoxyethylene ether-10 (TX-10), dodecyl dimethyl betaine (BS-12), cocamidopropyl betaine (CAB) (Jiangximo Chemical Co., Ltd); bulk barium sulfate scale samples from gathering pipelines in the Jiyuan Oilfield of Changqing Oilfield.

(3) Experimental equipment: LDY-type flow test instrument (Hai'an Petroleum Instrument Co., Ltd); RE-2000B rotary evaporator (Shanghai Yarong Biochemical Instrument Factory); DF-101S thermostatic heating magnetic stirrer (Gongyi Yihua Instrument Co., Ltd); FA2004 electronic balance (Shanghai Anting Electronic Instrument Factory); PHS-3C pH meter (Shanghai Leici Instrument Co., Ltd).

(4) Description of actual site conditions: the Ji Yuan Oilfield is situated in the western part of the Ordos Basin. Its reservoirs exhibit typical low permeability characteristics of small-pore, fine-throat reservoirs, with an average pore size of 65 μm, an average throat radius of 0.25 μm, an average porosity of 12.18%, and an average permeability of 1.33×10^{-3} μm^2.[22] This classifies it as a typical low-permeability oilfield, necessitating water injection for development. Due to the high mineralisation of reservoir water in the Ji Yuan Oilfield, it commonly contains substantial amounts of barium and strontium ions, whilst the injected water contains sulphate ions. This severe incompatibility between the two water types has led to scaling in the injection formations, wellbore, and surface systems. This has caused blockages in the injection formations, increased injection pressure, leakage in well tubing, rods, and pumps, as well as reduced diameter and blockages in the production and gathering systems, posing significant hazards to production.[23] Analysis of the ionic characteristics of historical formation water and injection water, coupled with scale sample composition studies, revealed that scaling primarily involving $BaSO_4$ deposits is responsible for blockages in the near-wellbore zones of injection wells and in the wellbore of production wells within the Ji Yuan Oilfield. For instance, prior to descaling operations at injection well A21, formation pressure stood at 25 MPa, initial injection pressure at 12 MPa, and daily injection volume at 35 m^3 day^{-1} – substantially below allocation requirements. Field data analysis indicated that $BaSO_4$ blockages in the near-wellbore zone caused sustained injection pressure increases, sharply reduced injection volumes, and declining water drawdown rates, severely impairing injection efficiency. Prior to descaling operations on production well P17, formation pressure stood at 20 MPa, with daily liquid production at 8.5 m^3 day^{-1} (oil: 2.1 m^3 day^{-1}, water: 6.4 m^3 day^{-1}). The dynamic liquid level was 1500 m (relatively deep), liquid production was gradually declining, water cut remained stable, and liquid level recovery was slow – dynamic characteristics consistent with scaling blockage. Based on historical pump inspection records, the blockage was attributed to $BaSO_4$ scaling within the reservoir.

2.2 Experimental methods

2.2.1 Scale remover performance evaluation method. Scale remover performance was evaluated using the scale removal efficiency, defined as the dissolution effect of a certain concentration of scale remover on 1 g of $BaSO_4$ scale sample. First, the chelating agent was added to deionized water to prepare a solution of a certain mass concentration. Then, 100 mL of the chelating agent solution was added to a conical flask along with 1 g of $BaSO_4$ scale. Place the flask in a water bath maintained at 90 °C and react for 24 hours at a stirring speed of 50 rpm, then removed, filtered, dried, and weighed. The scale removal efficiency was calculated as follows:

$$W = \left(1 - \frac{M_2 - M_1}{1}\right) \times 100\% \tag{1}$$

where: W = scale removal efficiency, %; 1 = mass of $BaSO_4$ scale (dry), g; M_1 = mass of dried filter paper, g; M_2 = total mass of dried filter paper and undissolved scale after filtration, g.

2.2.2 Simulated core scale removal effectiveness evaluation. First, cores were cleaned of oil, dried, and basic physical parameters such as permeability and porosity were measured. Then, core flooding experiments were conducted using an LDY-type flow test instrument. Temperature was controlled at 90 °C (simulating formation temperature), confining pressure at 10 MPa (simulating formation pressure). Simulated formation water was used for forward flooding until pressure stabilized, and the original permeability K_0 was measured. Cores saturated with Ba^{2+} formation water were then immersed in a high sulfate ion solution and aged statically at 90 °C for 7 days to induce scaling. The aged/scaled cores were then forward flooded with produced water until permeability stabilized, and the damaged permeability K_1 was measured. Finally, the scale remover solution was used for reverse flooding to remove the plugging. During the scale removal experiment, confining pressure was maintained at 10 MPa. Different flooding rates and injection volumes were tested until permeability stabilized. The post-treatment permeability is denoted as K_2. The formulae for permeability (K) and recovery permeability (R) are as follows:

$$K = \frac{Q\mu L}{A\Delta P} \tag{2}$$

$$R = \frac{K_2}{K_1} \times 100\% \tag{3}$$

In eqn (2), Q denotes the fluid flow rate through the injected core, $cm^3\ s^{-1}$; μ represents the viscosity of the injected fluid, mPa s; L is the core length, cm; A is the cross-sectional area of the core, cm^2; ΔP is the displacement pressure difference, MPa. K_0, K_1, and K_2 can all be calculated using eqn (2). In eqn (3), K_2 and K_1 denote the core permeability after and before descaling, respectively, in metres per day.

3. Results and discussion

3.1 Development of composite scale remover

3.1.1 Selection and evaluation of main chelating agent. Extensive literature and engineering applications[24–26] show that for insoluble $BaSO_4$ scale removers, chelating agents are typically used as the main component. Chelating agents form stable, water-soluble chelates with Ba^{2+}, "locking" the scale-forming Ba^{2+} ions and preventing them from combining with SO_4^{2-} to form $BaSO_4$ precipitate. Commonly used chelating agents are EDTA and its sodium salts, DTPA and its sodium (potassium) salts, which offer good cost-effectiveness. Therefore, EDTA (ethylenediaminetetraacetic acid), EDTA-4Na, DTPA (diethylenetriaminepentaacetic acid), DTPA-5Na, and DTPA-5K were selected for evaluation. Solutions of different concentrations (3%, 6%, 9%, 12%, 15%, 18%, 21%) were prepared, pH was adjusted to 11, and performance was evaluated according to the method described in Section 2.2.1. Results are shown in Fig. 1.

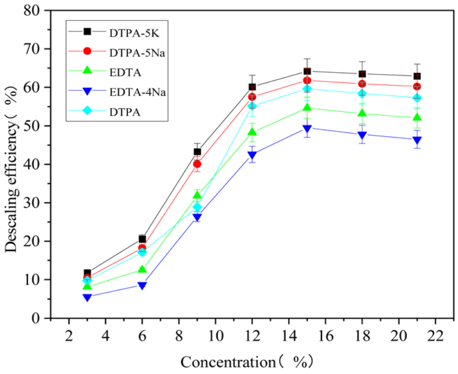

Fig. 1 Effect of different concentrations of chelating agents on scale removal performance.

Fig. 1 shows that for the five chelating agents EDTA, EDTA-4Na, DTPA, DTPA-5Na, and DTPA-5K, the scale removal efficiency initially increased and then stabilized with increasing concentration. At the same concentration, DTPA, DTPA-5Na, and DTPA-5K exhibited higher scale removal efficiency than EDTA and EDTA-4Na. Among them, DTPA-5K showed the highest scale removal efficiency at the same concentration. The scale removal efficiency of DTPA-5K initially increased and then slightly decreased with increasing concentration. Below 15%, higher DTPA-5K concentration resulted in a higher scale removal efficiency. This is because under low concentration conditions, increasing DTPA-5K concentration shifts the equilibrium $Ba^{2+} + DTPA^{5-} \rightarrow Ba\text{-}DTPA^{3-}$ to the right, increasing the scale removal efficiency. However, when DTPA-5K concentration is too high, the high concentration of DTPA-5K molecules not only adsorb on the surface of the $BaSO_4$ scale creating steric hindrance but also compete with each other, reducing the available chelation adsorption sites,[27] weakening the chelation effect and thus lowering the scale removal efficiency. Therefore, increasing the amount of DTPA-5K cannot infinitely improve the scale removal efficiency.[28] As seen in Fig. 1, at a DTPA-5K concentration of 15%, the scale removal efficiency was 94.2%, showing good descaling effect. Further increasing the concentration showed a decreasing trend.

3.1.2 Screening of conversion agent. Chelating agent DTPA-5K exhibits good performance against insoluble $BaSO_4$. The chelating agent causes the dissociation of Ba^{2+} from the

$BaSO_4$ scale through adsorption and chelation. Some of the dissociated Ba^{2+} can be effectively and promptly chelated, forming stable complexes, while another part may recombine with SO_4^{2-} to form $BaSO_4$ precipitate.[29] Conversion agents can promptly and effectively bind Ba^{2+}, converting it into soluble or easily soluble substances.[30] In the experiment, sodium carbonate (Na_2CO_3), sodium gluconate ($C_6H_{11}O_7Na$), sodium formate (HCOONa), and potassium formate (HCOOK) were used as conversion agents to rapidly convert Ba^{2+}, further increasing the dissolution rate of $BaSO_4$ scale.

To investigate the effect of conversion agents on the scale remover's performance, under conditions of 90 °C, pH = 11, and 24 hours, based on a DTPA-5K concentration of 15%, different conversion agents were added at concentrations of 2%, 4%, 6%, 8%, 10%, and 12% to investigate the effect of different conversion agents on the dissolution efficiency of $BaSO_4$ in the presence of a chelating agent.

Fig. 2 shows that the four conversion agents promoted the scale removal performance of the system to varying degrees. At low concentrations, all four conversion agents not only failed to effectively promote the efficiency of the main chelating agent but also slightly reduced it. This might be due to competitive effects of the conversion agents, leading to increased formation of insoluble products and reduced efficiency of the main chelating agent. However, with increasing concentration of the conversion agents, they promoted the scale removal efficiency to different extents. Sodium carbonate, sodium formate, and potassium formate showed limited promotion, while sodium gluconate demonstrated good promoting effects. This is because multiple hydroxyl (–OH) and carboxylate ($-COO^-$) groups in the sodium gluconate molecule can act as coordinating groups, forming stable, water-soluble complex ions through coordination with Ba^{2+}. In fact, under alkaline or neutral conditions, a single Ba^{2+} ion can coordinate with one or more gluconate ions to form solubilized complexes. When the mass concentration of sodium gluconate was 8%, the scale removal rate of the system reached 95.4%.

3.1.3 Screening of dispersants. Studies show that the main mechanism of dispersants in $BaSO_4$ scale removal systems is through the "threshold effect" and crystal lattice distortion.[31] Organic phosphonates such as DTPMP (diethylenetriamine pentamethylene phosphonic acid), HEDP (hydroxyethylidene diphosphonic acid), and ATMP (aminotris(methylene phosphonic acid)) are efficient dispersants. The phosphonate groups ($-PO_3H_2$) in their molecules can strongly adsorb onto the active growth sites of $BaSO_4$ crystals, either preventing further crystal growth or causing distortion, preventing the formation of hard scale layers. Instead, they form dispersed, soft flocs that are easily carried away by fluid flow.[32]

100 mL of the prepared solution containing 15% DTPA-5K and 8% $C_6H_{11}O_7Na$ was added to a conical flask. Then, four different dispersants were added at concentrations of 2%, 4%, 6%, 8%, and 10%. The pH was adjusted to 11 using potassium hydroxide. Subsequently, 1 g of $BaSO_4$ scale sample was added, and the flask was placed in a constant temperature water bath at 90 °C for 24 hours to investigate the effect of different concentrations of dispersants on the dissolution efficiency of $BaSO_4$ in the presence of a primary chelating agent and a conversion agent.

Fig. 3 shows that the three dispersants DTPMP, HEDP, and ATMP had different effects on $BaSO_4$ dispersion. The scale removal efficiency decreased slightly with increasing concentration of HEDP and ATMP, but DTPMP positively and effectively promoted scale removal efficiency. The highest efficiency was achieved at a DTPMP mass concentration of 6%. Therefore, by screening the types and concentrations of chelating agents, conversion agents, and dispersants, the optimized formula for the $BaSO_4$ scale remover was obtained: 15% DTPA-5K + 8% $C_6H_{11}O_7Na$ + 6% DTPMP, with pH adjusted to 11 using KOH.

3.1.4 Screening of penetrants. To further improve the $BaSO_4$ scale removal efficiency, considering that the scale remover system is strongly alkaline and low-permeability reservoir formation water contains a certain concentration of divalent ions, nonionic and amphoteric surfactants were selected as penetrants. These types of penetrants are stable under alkaline conditions, possess excellent wetting, penetrating, and emulsifying abilities, and do not precipitate with the ionic chelating agent DTPA-5K, offering excellent wetting and penetration properties.[33–36] The nonionic surfactant penetrants JFC (fatty alcohol polyoxyethylene ether) and TX-10 (octylphenol polyoxyethylene ether-10), and the amphoteric surfactants dodecyl dimethyl betaine (BS-12) and cocamidopropyl betaine (CAB) were used in the experiment. The base formula for the scale remover was: 15% DTPA-5K + 8% $C_6H_{11}O_7Na$ + 6% DTPMP, with pH adjusted to 11 using KOH.

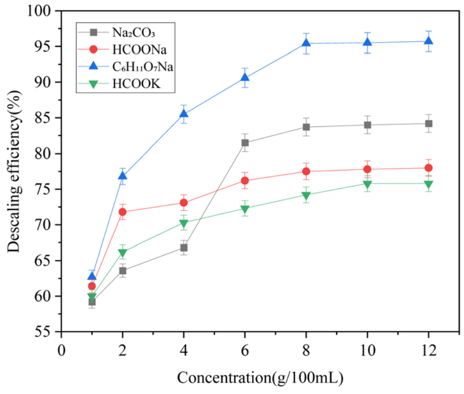

Fig. 2 Effect of conversion agents on scale removal performance.

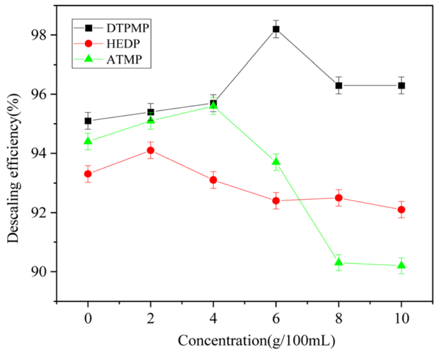

Fig. 3 Effect of dispersant concentration on scale removal efficiency.

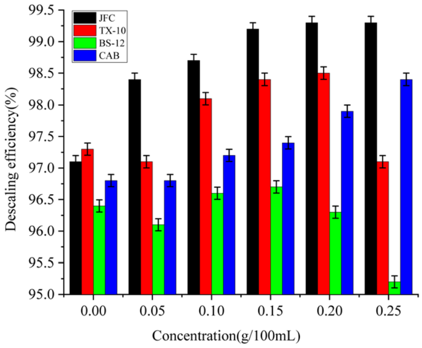

Fig. 4 Effect of penetrant concentration on scale removal efficiency.

Fig. 4 shows the effect of four penetrants (JFC, TX-10, BS-12, CAB) at different concentrations on the $BaSO_4$ scale removal efficiency. The results indicate that the nonionic surfactant JFC achieved the best scale removal effect at a concentration of 0.2%, with a removal efficiency of 98.4%, significantly outperforming the other three penetrants. TX-10, BS-12, and CAB showed limited improvement in scale removal efficiency within the same concentration range, and even exhibited a declining trend at high concentrations. This suggests that JFC has good synergistic wetting and penetration effects in strongly alkaline systems, effectively promoting the entry of the scale remover into low-permeability pore throats and ensuring full contact with $BaSO_4$ scale, thereby significantly improving the overall scale removal efficiency. Integrating the optimization results of chelating agent, conversion agent, dispersant, and penetrant, the optimal scale remover system is: 15% DTPA-5K + 8% $C_6H_{11}O_7Na$ + 6% DTPMP + 0.2% JFC, with pH adjusted to 11 using KOH.

As injection velocity increased from 0.5 mL min^{-1} to 2.0 mL min^{-1}, the average efflu-ent Ba^{2+} concentration decreased from 485 mg L^{-1} to 445 mg L^{-1}, and the scaling mass in-creased from 3.1 mg to 9.3 mg. Higher flow velocity enhances convective diffusion of ions, promoting rapid contact and reaction between Ba^{2+} and SO_4^{2-}. Simultaneously, fluid shear forces may inhibit the back-migration or erosion of formed scale particles, leading to increased scaling, predominantly near the inlet region.

3.2 Evaluation of scale removal efficiency in simulated low-permeability cores

3.2.1 Effect of different injection rates on scale removal effectiveness.

Core parameters: initial permeability $K_0 = 0.50$ mD, permeability after scaling $K_1 = 0.07$ mD, core scaling damage rate $R = 86\%$, indicating severe scaling induced artificially in the low-permeability core. The injection volume of the scale remover was fixed at 1.5 pore volumes (PV). The effect of different injection rates on scale removal effectiveness was discussed through core flooding experiments.

From Table 1, showing the effect of different injection rates on scale removal efficiency, it can be seen that as the injection rate increased, the scale removal efficiency first increased and then slowly decreased. The optimal injection rate was 0.02 mL min^{-1}. This is because an appropriate increase in injection velocity enhances the flushing force of the descaling agent liquid against the scale layer to a certain extent. This rapidly strips loose scale deposits, continuously exposing new scale surfaces, leading to more complete reactions and increased descaling efficiency. However, when the injection velocity is excessively high, the high-speed descaling fluid tends to form finger-like flow patterns or turbulent flow. This results in insufficient contact time with the scale deposits, preventing the descaling agent from fully diffusing. Consequently, descaling efficiency decreases. Furthermore, the large volume of detached scale particles, propelled by the high velocity, can become lodged in orifices and throats, forming new blockages. This ultimately reduces the effective volume reached by the descaling process. At the optimal injection rate, the scale remover could effectively transport to the deep parts of the low-permeability reservoir while ensuring sufficient contact and reaction time with the scale in the core, achieving a core permeability recovery of 87%. For low-permeability reservoirs, injection rates that are too fast or too slow will lead to decreased scale removal effectiveness. Field operations should maintain a low injection rate to ensure sufficient contact time between the scale remover and the scale in the formation for high efficiency.

3.2.2 Effect of different injection volumes on scale removal effectiveness.

Core parameters: initial permeability $K_0 = 0.50$ mD, permeability after scaling $K_1 = 0.07$ mD, core scaling damage rate $R = 86\%$, indicating severe scaling induced artificially. The injection rate of the scale remover was fixed at 0.02

Table 1 Effect of different injection rates on scale removal effectiveness

Injection rate (mL min^{-1})	Restored permeability (K_2, mD)	Permeability recovery rate (R, %)	Net permeability increase (%)	Pressure response characteristics
0.005	0.40	80.0	73.0	Very low and stable pressure, sufficient reaction but low efficiency
0.02	0.435	87.0	80.0	Pressure stable, slowly decreasing, optimal transport
0.05	0.41	82.0	75.0	Moderate initial pressure, decreasing relatively quickly
0.10	0.36	72.0	65.0	High initial pressure, decreasing rapidly

Table 2 Effect of different injection volumes on scale removal effectiveness

Injection volume (PV)	Restored permeability (K_2, mD)	Permeability recovery rate (R, %)	Net permeability increase (%)
0.005	0.40	80.0	73.0
0.02	0.435	87.0	80.0
0.05	0.41	82.0	75.0
0.10	0.36	72.0	65.0

mL min^{-1}. The effect of different injection multiples on scale removal effectiveness was discussed through core flooding experiments. Data analysis from Table 2 on the effect of different injection volumes shows that as the injection volume increased, the scale removal efficiency gradually increased. The optimal injection volume was 1.5 PV. At this dosage, the permeability recovery rate reached 87%, achieving a good ideal effect. Continuing to increase the injection volume resulted in negligible growth in recovery rate (only 1–2%). Considering the significant increase in cost with more scale remover, 1.5 PV was selected as the economical and effective standard slug size. The core simulation results indicate that for $BaSO_4$ scaling in low-permeability reservoirs, using process conditions of an injection volume of 1.5 PV and an injection rate of 0.02 mL min^{-1} ensures that the scale remover can effectively enter the micropore throats of the low-permeability reservoir, with sufficient dosage and contact time to react with deep-seated $BaSO_4$ scale, while avoiding waste and economic inefficiency caused by excessive speed or volume.

3.3 Application effectiveness of $BaSO_4$ plugging removal in low-permeability reservoirs

Considering the petrophysical characteristics of low-permeability reservoirs prone to $BaSO_4$ scaling and the difficulty in dissolving $BaSO_4$, the plugging removal scheme adopted the core concept of "low-rate injection + optimized slug + extended reaction time". The aim is to push a sufficient amount of scale remover solution into the deep formation at a low flow rate and allow sufficient shut-in time for the chelation reaction between the scale remover and $BaSO_4$ scale, ultimately achieving the target of near-wellbore permeability recovery.

3.3.1 Plugging removal scheme. The formula used for the low-permeability reservoir $BaSO_4$ plugging removal system: 15% DTPA-5K + 8% $C_6H_{11}O_7Na$ + 6% DTPMP + 0.2% JFC (balance water), with pH adjusted to 11 using KOH.

Injection rate (flow rate): following the principle of low rate and low pressure to ensure the scale remover enters low-permeability pore throats rather than merely creating breakthrough channels. Based on conversion from wellbore size to core scale, the field injection rate should be controlled within a low range of 0.3–0.8 m^3 h^{-1}. The initial rate should be at the lower limit and slowly increased depending on the injection pressure response. Treatment volume (injection volume): controlled at 1.0–1.5 PV (pore volume). 1.0 PV can be injected first and slightly adjusted based on historical scaling conditions. PV estimation: $PV = \pi \times r^2 \times h \times \varphi$ (r: wellbore radius, h: treated interval thickness, φ: porosity) Pumping procedure: preflush: 5–10 m^3 of 2% KCl brine to pre-treat the formation and stabilize clay minerals. Main treatment fluid: the calculated volume of 1.0–1.5 PV scale remover solution. Overflush: 5–10 m^3 of 2% KCl brine to push the main treatment fluid in the wellbore and near-wellbore zone deeper into the formation. Shut-in reaction time: $BaSO_4$ dissolution is slow; sufficient reaction time of 48–72 hours must be ensured. For severe scaling or lower formation temperature, it can be extended to over 72 hours. Flowback procedure: controlled flowback to avoid pressure surges causing formation sanding or fines migration. After opening the well, control the flow using a 3 mm–5 mm choke, maintaining stable production pressure differential. Continuously monitor the Ba^{2+} ion concentration in the flowback fluid. Resume normal production after the concentration drops to the background level.

3.3.2 Plugging removal effectiveness. (1) Injection well treatment: well A21 is an injection well in the Jiyuan Oilfield. The injection pressure continued to climb, and the injection volume sharply decreased. Based on the ionic characteristics of historical formation water and injected water, it was judged that $BaSO_4$ scaling caused near-wellbore blockage. Before treatment: formation pressure: 25 MPa, initial injection pressure: 12 MPa, daily water injection volume: 35 m^3 day^{-1} (far below the allocated requirement). Treatment was performed *via* bullheading without pulling tubing. Injection rate: 0.5 m^3 h^{-1} (low rate), scale remover slug: 1.5 PV, shut-in reaction time: 60 hours. The operation achieved significant success. Injection pressure decreased substantially, and water injection volume far exceeded the allocated requirement, effectively removing the near-wellbore $BaSO_4$ scale blockage and achieving the target of over 85% permeability recovery as expected in the plan. Subsequent continuous monitoring and injection of scale inhibitor are required to prevent re-scaling (Table 3).

(2) Production well treatment: Well P17 is a production well (oil well) in the Jiyuan Oilfield. The well's liquid production gradually declined while water cut remained stable, and fluid level recovery was slow, with dynamic characteristics consistent with scaling blockage. Combined with historical pump inspection records, it was concluded that reservoir blockage was caused by $BaSO_4$ scaling. Before treatment: formation pressure: 20 MPa, daily liquid production: 8.5 m^3 day^{-1} (oil 2.1 m^3 day^{-1}, water 6.4 m^3 day^{-1}), dynamic fluid level: 1500 m (deep). Treatment was performed *via* tubing injection. Injection rate: 0.4 m^3 h^{-1} (low rate), scale remover slug: 1.0 PV, shut-in reaction time: 70 hours. The operation achieved the expected results. Both liquid and oil production increased significantly, and the dynamic fluid level rose noticeably, indicating effective restoration of formation fluid supply capability. This shows the

Table 3 Changes in indicators for Well A21 before and after treatment

Evaluation indicator	Before treatment	After treatment (stabilized)	Change rate (%)
Wellhead injection pressure	12 MPa	9.5 MPa	−20.8%
Daily water injection volume	35 m^3 day^{-1}	105 m^3 day^{-1}	+200%
Injection pressure drop	—	2.5 MPa	Significantly reduced
Apparent injectivity index	2.9 m^3 (d^{-1} MPa^{-1})	11.1 m^3 (d^{-1} MPa^{-1})	+283%

Table 4 Changes in indicators for Well P17 before and after treatment

Evaluation indicator	Before treatment	After treatment (stabilized)	Change rate (%)
Daily liquid production	8.5 m^3 day^{-1}	20.1 m^3 day^{-1}	+136%
Daily oil production	2.1 m^3 day^{-1}	5.2 m^3 day^{-1}	+148%
Dynamic fluid level	1500 m	850 m	+43.3% (rise)
Flowing pressure	8.5 MPa	11.2 MPa	+31.8%

blockage was effectively removed, and formation permeability was improved. The well was later connected to a capillary chemical injection system for long-term scale prevention (Table 4).

4. Conclusions

(1) An efficient composite $BaSO_4$ scale remover was successfully developed. The optimized formula is 15% DTPA-5K + 8% $C_6H_{11}O_7Na$ + 6% DTPMP + 0.2% JFC (balance water), achieving a scale removal efficiency of 98.4% under conditions of $pH = 11$ and 90 °C.

(2) Core flooding experiments showed that the injection rate and volume of the scale remover significantly affect the plugging removal effectiveness. The optimal process parameters are an injection rate of 0.02 mL min^{-1} and an injection volume of 1.5 PV, resulting in a core permeability recovery rate of 87% and a net permeability increase of 80%. Low-rate injection and an adequate slug ensure the scale remover effectively acts on low-permeability pore throats, avoiding ineffective breakthrough and waste.

(3) Field applications demonstrated that this composite scale remover system can effectively remove $BaSO_4$ scale blockages in injection and production wells in low-permeability reservoirs. For injection well A21, the injection pressure decreased by 20.8%, and daily water injection volume increased by 200%. For production well P17, liquid production increased by 136%, and the dynamic fluid level rose by 43.3%, confirming the applicability and reliability of the system.

(4) The process scheme of “low-rate injection + optimized slug + extended reaction time” developed in this study combines high efficiency and economic feasibility. It is suitable for scale removal and plugging removal of $BaSO_4$ scale in low-permeability reservoirs and has value for broader application.

Author contributions

Methodology, Yang Haien, Xie Xuan, Dou Miao and Yan Tong; software, Yang Haien and Xie Xuan; valida-tion, Yang Haien, Xie Xuan, Dou Miao and Wei Ajing; formal analysis, Yang Haien, Wei Ajing and Yan Tong; investigation, Yang Haien and Lei Ming; resources, Ma Chao, Yan Tong; data curation, Yang Haien and Ma Chao; writing—original draft preparation, Yang Haien, Xie Xuan and Dou Miao; writing—review and editing, Wei Ajing, Yan Tong, Lei Ming and Ma Chao; visualization, Yang Haien; supervision, Xie Xuan; project administration, Dou Miao; funding acquisition, Wei Ajing.

Conflicts of interest

The authors declare that there are no competing interests regarding the publication of this article.

Data availability

All data supporting this study are included in the article.

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