Sand Free Rate Enhancement with Aqueous-based Self-healing System

Jianda Li1, Guicai Zhang1*, Jijiang Ge1, Wenli Qiao1, Ping Jiang1, Haihua Pei1,

1 School of Petroleum Engineering, China University of Petroleum(East China),
Qingdao, Shandong, 266580, P. R. China

*Corresponding author’s e-mail: 13706368080@VIP.163.com

Abstract: Unconsolidated sandstone reservoirs are susceptible to sanding problems. Traditional sand consolidation methods are often not environmental-friendly or ineffectively. This paper proposed a new sand consolidation treatment with aqueous-based self-healing system (ABSH) to maximize the sand free rate. The ABSH performs well with a relative lower dosage in laboratory tests. Sand consolidation performance and chemical resistance property were evaluated using the maximized sand free rate as indicators. After aging for 12 hours, the maximized sand free rate of consolidated sand pack could be prominently increased to 6600mL/h. Re-agglomeration ability between sand particles was illuminated by adhesion force tests. The adhesion force could be almost 90% of the original one after the contacting and separating process proceeded for three times.

1. Introduction
Sanding problem is a worldwide issue in oilfield development[1-6]. Sands co-production with hydrocarbons seriously threatens the oil production safety[7-13]. Sand consolidation with chemical treatment can offer a screenless alternative to exclude sand production[14-17]. However, compromise is stroke between permanent consolidation strength and lower regained permeability[18-20]. Furthermore, chemical consolidating agents are usually solvent-based with low flash point, which severely impacts the environmental and production safety[21-23].

In the present study, an aqueous-based self-healing system (ABSH) was proposed for inhibiting sand production. It should be noted that the ABSH was aimed to form a relative weak treatment rather than solid consolidation as traditional resins. Thus maximized sand free rate was adopted as an indicator to characterize the consolidation strength. The supramolecular interactions of self-healing composites contribute to the aggregate intensity and the re-agglomerating property of the sand grains.

2. Materials and methods
2.1 Materials
The low viscosity ABSH was prepared in laboratory. Potassium chloride, sodium bicarbonate and hydrochloric acid were supplied by Sinopharm Chemical Reagent Co., Ltd, China. Diesel was obtained from Sinopec Group, China. The crude oil was collected from Shengli Oilfield, China. 100/120 mesh quartz sands and high-purity quartz microspheres were purchased from Shili Abrasive Industry Co., Ltd, China. Unconsolidated sand packs prepared from quartz sands were embedded in steel tubing with flexible screens in both ends.
2.2 Apparatus
Physical simulation apparatus was fabricated to conduct flow tests. The flow chart of the experimental setup was shown in Fig.1. Particle size distribution was measured by NanoBrook 90Plus PALS Zeta Potential Analyzer. Adhesion force testing apparatus was set up to quantitative characterize the consolidation strength between quartz microspheres. The main structure of adhesion force testing apparatus was based on pressure transducer (0.1 μN resolution), motorized translation stage and probe (as shown in Fig.2).

![Fig.1 Flow chart of physical simulation apparatus](image)

![Fig.2 Schematic of adhesion force testing apparatus](image)

2.3 Experimental methods

2.3.1 Maximized sand free rate. (1) Saturate sand pack with 2%wt. KCl brine under vacuum. (2) Flow 0.5 pore volume of ABSH in the injection direction. Then inject 1 pore volume of 1%wt. sodium bicarbonate solution as reactant and displacement fluid. Displaced the pumped fluids with 1 pore volume 2%wt. KCl brine. Then aging for 12 hours under conditions of temperature. (3) Then the flow rate was started at 10 ml/min and then slowly steps up. Record the flow rate as the maximized sand free rate when the sands start to flushed out from the production end.

2.3.2 Adhesion force test. (1) The treated quartz microspheres were placed at the bottom of the pressure transducer and the tip of the probe separately. (2) The pressure transducer and the probe were immersed into water. Adjust the mechanical knob and motorized translation stage. A slight contact was established between the quartz microspheres. Zeroing the pressure transducer. (3) Setting for 12 hours, then the quartz microspheres were fully consolidated. Separate the quartz microspheres with a fairly low velocity (0.01 mm/s). The movement of the probe was controlled by programmable motorized translation stage. Record the interaction force history between quartz microspheres. The peak force was considered as the adhesion force between quartz microspheres.

3. Results and Discussion

3.1 Injection property
Particles carried by injected fluid would bridge the pore throat when the particle size was no less than one third of the pore throat diameter. Since the ABSH consisted of modified macromolecular, the compatibility of particle size and pore throat diameter should be considered. Generally, unconsolidated sandstone reservoirs were usually with a permeability between 0.5 to 8 Darcy. According to Carman-Kozeny formula, the average pore throat diameter of the formation with a permeability of 500mD was about 7 μm (assuming that porosity = 0.3, tortuosity = 1).

Particle size distribution of the ABSH was measured by NanoBrook 90Plus PALS Zeta Potential Analyzer. As displayed in Fig.3, the particle size was distribute mainly in 17.4nm, which was far less than the minimum size (7μm) that could bridging the pore throat.

The ABSH was feasible for injection according to sand pack flow tests. Inlet pressure curve was plotted by injected with KCl brine, ABSH, sodium bicarbonate solution and KCl brine successively. As plotted in Fig.4, inlet pressure of sand pack raised from 6.73KPa to 9.43 KPa when injected with 1 pore volume of ABSH. Subsequently, the inlet pressure kept climbing up while alkaline solution reacted with ABSH and form a network to bond sand particles together. Then a dramatic pressure decay occurred as the redundant consolidating agent was displaced by injection fluids.

3.2 Sand consolidation performance and chemical resistance property
In the process of oil field development, the injected working fluids as well as formation brine and crude oil pose a series of challenge for sand consolidation. Chemical resistance property of ABSH should be taken into consideration.

Diluted hydrochloric acid, sodium bicarbonate solution and KCl brine were recommended as injected fluids. Sand consolidation strength under various injecting conditions was evaluated. Fig.5 showed the maximized sand free rate plotted versus the mass fraction of injected fluid. ABSH incorporated preferable alkali tolerance since critical sand free rate barely changed after treated with 5%wt. of sodium bicarbonate solution. High-salinity brine posed an adverse impact on sand consolidation strength. Since the molecular chain entanglement between consolidating agent was weakened in high-salinity brine, which impaired the adhesion force between sand particles. As depicted in Fig.5, sand consolidation failed when confronted with 5%wt. of diluted hydrochloric acid. Desorption occurred when the adsorbed consolidating agent reacted with acid, so that the consolidated sand pack collapsed at a relatively low flow rate.

In order to clarify whether crude oil had an impact on sand consolidation strength, sand packs were prepared mixed with crude oil and quartz sands. It was shown by Fig.6 that, the maximized sand free rate tended to an apparent fall down when the mass ratio of crude oil and quartz sands was more than 5%. That might due to the surface of sand particles were occupied by crude oil, which meant it is hard for ABSH to penetrate into and absorb on it. As suggested, diesel could be pumped to preflush the wellbore region, thus the maximized sand free rate would be reserved to a large extent.
3.3 Re-agglomeration ability

The formation sands treated with ABSH incorporates the potential of re-agglomeration. The aggregation process would be accompanied by the restore of the reversible non-chemical crosslinking networks among sand particles.

The re-agglomeration property was then quantitative characterized by adhesion force tests. The consolidated quartz microspheres was operated to separate and re-contact. Interaction force history during the separation was recorded. Keep contacting for 12 hours. Then repeated the aforementioned process. Fig.7 illuminated that the adhesion force could be almost 90% of the original one after the contacting-separating process proceeded for three times. The re-agglomeration property of sand particles would greatly extend the life expectancy of sand consolidation. The self-healing agent was located at the contact point among sand particles. When flushed and detached, the treated sands would re-agglomerate accompanied by the renew contact (Fig.8).

4. Conclusion

(1) The ABSH was feasible for injection according to sand pack flow tests. Particle size of the ABSH was distribute mainly in 17.4nm, which was far less than the minimum size (7μm) that could bridging the pore throat.

(2) The ABSH performs well with a relative lower dosage in laboratory tests. After aging for 12 hours, the maximized sand free rate of consolidated sand pack could be prominently increased to 6600mL/h. Consolidation strength of sand packs could be impaired by high-salinity brine, acid fluids and crude oil. As suggested, the wellbore region should be prefushed with fresh water and diesel in the field tests.
(3) The re-agglomeration property was quantitatively characterized by adhesion force tests. The treated sand particles possess an admiring re-agglomeration property. The adhesion force could be 90% of the original one after the contacting-separating process proceeded for three times. The re-agglomeration property of sand particles would greatly extend the life expectancy of sand consolidation.

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