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The oil recovery enhancement by nitrogen foam in high-temperature and high-salinity environments

Lin Sun [a,b], Peng Wei [a,b,*], Wanfen Pu [a,b,*], Bing Wang [c], Yijun Wu [d], Tao Tan [e]

[a] State Key Laboratory of Oil and Gas Reservoir Geology and Exploitation, Southwest Petroleum University, Chengdu, Sichuan 610500, China
[b] School of Petroleum and Gas Engineering, Southwest Petroleum University, Chengdu, Sichuan 610500, China
[c] Yumen Oilfield of Chinese National Petroleum Corp., Yumen, Gansu 735211, China
[d] Chuanqing Drilling Engineering Company Limited the Project Management, Ordos, Inner Mongolia 017000, China
[e] Sinopec Northwest Oilfield Branch Company, Urumqi, Xinjiang 830001, China

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A B S T R A C T

This article is designed for the application of Cocamidopropyl hydroxyl sulfobetaine (CHSB) in the nitrogen foam flooding under the high-temperature and high-salinity environments. Firstly, foam properties of CHSB were evaluated at different temperatures and varying salinity, as well as the effect of concentration on foam properties, and the long-term foam properties of CHSB were developed under different concentration. Then, a series of researches on controlling mobility of nitrogen foam were conducted in the sand-packs. Finally, nitrogen foam flooding was carried out in the sand-model and oilfield site. Results indicated that high-temperature was unfavorable to foam stability, and high-salinity could favor its stability. When CHSB was used as foaming agent at the concentration of 0.2 wt%, it showed excellent performance at the temperature of 120 °C and the salinity of 22×10^4 mg/L and good long-term stability after aging for 60 days. The foam flooding experiments showed that mobility reduction factor of foam increased with the residual oil saturation decreased or as the permeability declined in the high-temperature and high-salinity, and the residual resistance factor of foam during the subsequent waterflooding with 5 days shut-in was 3.8, which was obviously higher than that without shut-in or with shut-in in oil-free environment. The displaced area in sand-model was lager and wider in the presence of 5 days' shut-in than that in the absence of shut-in, and the water cut could be reduced to 38% and the enhanced oil recovery was about 17.8% after 5 days' shut-in. The oilfield test showed that the validity period of high oil production rate was more than half year and 2400 t of crude oil was produced in all.

1. Introduction

Tahe S block reservoir is located in the Akkol Uplift structure of southern Tarim basin, a typical positive rhythm sandstone reservoir, and its major oil-producing stratum is about 150 m thick with the depth of 3671 m. The analysis of rock physical property indicates that the porosity of S block reservoir is mainly distributed between 17% and 23% (averaging at 21.1%), and the permeability is mainly concentrated on $32–1048 \times 10^{-3}$ μm^2 (averaging at 380×10^{-3} μm^2). The horizontal permeability contrast of S block reservoir is 1.22–1.69, which indicates a relatively weak plane heterogeneity. However, its internal longitudinal permeability has obvious differences and the variation coefficient of permeability is 1–1.54, which shows the superior vertical heterogeneity. The current status of oilfield exploitation in the Tahe S block reservoir is described in the following sections. Due to the early water production and serious water channeling, the wells with low productivity and low profit (the oil production rate is lower than 5 t/d) might represent as much as 65～75% of total wells in S block reservoir, and the wells with high water-cut (more than 90%) take up 40%, which ultimately results in low oil recovery in the reservoir and big amount of remaining oil concentrated in the upper/interwell area of the block. Hence, it is imperative that a potential and applicable enhanced oil recovery (EOR) technique to be developed in accordance with Tahe S block reservoir condition.

The EOR technique can be classified into four main categories: chemical flooding, gas flooding, thermal recovery and microbial flooding (Nelson and Pope, 1978; Bath, 1989; Islam, 1994; Feng et al., 2002). Most of them, however, cannot be applied to the condition of Tahe S block, which has been characterized by high-temperature (106 °C～117 °C), high-salinity (the salinity of

* Corresponding authors at: School of Petroleum and Gas Engineering, Southwest Petroleum University, Chengdu, Sichuan 610500, China.
E-mail addresses: shibadin@qq.com (P. Wei), ice500wp@163.com (W. Pu).

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formation water is about 22×10^4 mg/L, and calcium and magnesium is more than 1.2×10^4 mg/L), and high vertical heterogeneity. For example, gas breakthrough tends to occur in strong heterogeneous reservoir with gas flooding, microbial flooding shall be excluded by harsh conditions of high-temperature and high-salinity, and thermal recovery can hardly be employed in the reservoir with great depth. As we all know, most of methods in chemical flooding may not necessarily apply to the high-temperature and high-salinity reservoir, such as: polymer flooding, ASP compound flooding and caustic flooding (Pope et al., 1979; Liu et al., 2008; Chan et al., 1979). But, foam flooding can be carried out under wide ranges of temperature and salinity conditions and functional in profile controlling of the strong heterogeneity reservoir. Furthermore, it has been applied to some reservoirs in Shengli oilfield, Henan oilfield, Liaohe oilfield and so on, and has a significant effect on increasing oil recovery.

Foam flooding has been developed as a kind of mature oil displacement technique since 1960s. With respect of gas phase in foam, foam flooding is subdivided into carbon dioxide foam flooding, air foam flooding, nitrogen foam flooding and hydrocarbon gas foam flooding. Nitrogen foam flooding has been progressed in the oilfield exploitation with low cost and zero corrosive. Some of the prominent features of nitrogen foam flooding are presented as follows. Firstly, foam's basic feature is “big control and small not control” in the porous media (Kovscek and Bertin, 2003). When the heterogeneous of porous media is considered, foam's migration is driven into the high-permeability zone with larger porosity and better connectivity, where foam is comparatively easy to generate and transport via its formation mechanisms (lamellae snap-off, lamellae lag, and lamellae trapping) (Mast, 1972; Owete and Brigham, 1987). The obvious Jamin Effect will be presented at the pores and throat holes, which causes the high-flow resistance in high-permeability and the diversion of foam flow to the less permeable zones. Secondly, nitrogen is nearly insoluble in water and oil and also has quite strong expansion (Farajzadeh et al., 2009), which can accumulate high flexibility energy and maintain reservoir pressure during the flooding. Meanwhile, nitrogen can migrate upward to the top of the reservoir by gravity segregation, thus increasing the oil displacement. Finally, the surfactant also known as surface active agent, may adsorb at the water-oil interface or oil-rock interface and play some role in reducing the interfacial tension between oil and water or modifying the wettability of reservoir (Alveskoga et al., 1998), which improves the microscopic displacement of oil.

Effective performance of surfactant in foaming and stabilizing under the harsh condition of S block reservoir, which is quite a significant purpose. In the last few years, many researchers have delved into the properties of foaming agents under the conditions of high-temperature and high-salinity. Zhao et al. (2012) screened out the optimum foaming formula (including 0.4% alkyl hydroxyl sulfobetaine, 0.04% dodecanol and 0.1% quaternary ammonium salt surfactant) which can be applied in a very wide range of salinity of $(1-16) \times 10^4$ mg/L. Sun et al. (2015a) studied that the combined system mainly composed of Polyoxyethylene ether sulfonate and sulfo betaine can create good foaming ability and foam stability at 100 °C and 20.5×10^4 mg/L. Amro et al. (2014) found that Ethoxylated amine surfactant is used for foaming agent and can improve the oil recovery at the temperature of 120 °C in the presence of 22%TDS. In steam flooding, nitrogen foam with high-temperature resistance is commonly added owing to its good mobility controlling (Li at el., 2011). Pang et al. (2015) found that long-chain alkylaryl sulphonates displays favorable foam stability and excellent foam mobility reduction at 275 °C, and nitrogen foam can effectively modify the injection profile and thus make steam and hot water uniformly migrate in reservoirs. As reviewed above, sulfobetaine surfactant is always a hot topic and potential research focus on EOR by foam flooding under harsh reservoirs with high-temperature and high-salinity (Zhang et al., 2013).

However, most researchers failed to heed the most basic fact that foaming agent must remain chemical stable in the duration of foam flooding. Chemical stable can improve the effective period of displacement. Therefore, further study is essential to focus on foaming agents which have outstanding properties of temperature tolerance and salt resistance properties. In our study, cocamidopropyl hydroxyl sulfobetaine (CHSB) was chosen as foaming agent, followed by a series of tests. Firstly, the foam volume and half-life time were investigated at different temperatures and under different salinities to see how these properties were altered, and the long-term stability of foaming agent was also explored. Then, some sand-pack experiments were carried out and the foam performance under different oil saturation and with different permeability were studied, respectively. The migration and stability of foam during the subsequent waterflooding were also researched. Finally, the enhancement of oil recovery of foam flooding in the plate model was performed, which was mainly designed with two cases, in which the model was shut in for 5 days or shut-free after the foam injected.

2. Experiment section

2.1. Materials

CHSB was used as a foaming agent and supplied by Kelong Industry (Chengdu, China), and the molecular schematic diagram was shown in Fig. 1. The composition of Tahe formation brine used in the research was listed in Table 1. The crude oil was provided by Tahe Oilfield, China, with a density of 0.9151 g/cm3 at 120 °C, and the saturated hydrocarbon composition was analyzed by 7890B gas chromatography (Agilent Technologies Ltd., America), and the results are presented in Fig. 1. The sand in this study was supplied by Pixian Ltd (China). The nitrogen used in this study was supplied by Xinju Ltd. (Chengdu, China), with a purity of 99.9 wt%.

2.2. Experiment setup

A physical modeling device (provided by Chengdu Core technology Co. Ltd., China) was used to conduct all foam flooding experiments, which could be operated in high-pressure and high-temperature. In each flooding experiment, the temperature was at 120 °C, and the back-pressure was 20 MPa. The schematic of foam flooding in the sand-pack was presented in Fig. 3. The injection rate of formation brine was 0.5 ml/min, and nitrogen foam was also injected at 0.5 ml/min under the pressure of 20 MPa. The gas liquid ratio of nitrogen foam was 2:1, and the injection rate of nitrogen was controlled by F-112AI mass flow meter (Bronkhorst Ltd., Netherlands) under high-pressure.

The inside size of the sand-pack was Ø25mm × 50 mm. Sand-packs were filled with sand (particle diameter is 0.212–0.425 mm) and then packed solid and tight, which were used for simulating reservoir permeability condition, and their physical properties were presented in Table 2. The experiments of oil treatment were conducted by the following steps: firstly, the sand-pack was saturated with brine and pore volume was recorded; then, the oil was injected until the water cut reduced from 100% to 0, and the water cut also decreased to 50% and 90% in order to get different levels of initial oil saturations (1-1, 1–2 and 1–3 in Table 2); finally, oil was displaced by brine until no more oil was produced and oil residual saturation was calculated.

The inside size of the sand-model was 98 mm × 98 mm × 30 mm. The sand-model was filled by quartz sand with different particle sizes, and formed three distinct layers