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Optimization of polymer flooding design in conglomerate reservoirs

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ABSTRACT

The polymer flooding can be a very promising, cost-effective enhanced oil recovery (EOR) strategy in the development of conglomerate oil reservoirs, especially when the reservoirs reach very high water-cut in production. The key to success for a polymer flooding is to use the full potential of mobility control under the premise of good compatibility between polymer and reservoirs. Polymer is easy to be adsorbed and also potentially clogs the formations especially when the pressure gradient is small in the reservoir. Meanwhile, polymer efficient viscosity has a huge impact on polymer mobility control. The method of polymer flooding optimization design is described in a formation of interest called Karamay conglomerate reservoir (Xinjiang Province, China). We've compared the pore structure difference between conglomerates and sandstones, measured hydrodynamic characteristic sizes of polymer molecular and ensured the maximum polymer molecular weight and concentration for corresponding permeability. Then different pore structure cores were used to investigate the rheology of polymer transport in conglomerates and sandstones. A model were built by using the water-oil relative permeability curves and polymer rheology experimental data, which was utilized to calculate the minimum viscosity of the polymer solution required for a high-performance mobility control in polymer flooding. In the study we have found that 1) conglomerate with the shallower depth and tortuous pore structure has about three times shear rates than single pore structure sandstone in the same flow velocity; 2) the viscosity range of a high-performance polymer for conglomerate reservoirs is determined to be 25.1 cP–29.4 cP at shear rate of 7.34 s^{-1} for Upper Karamay formation, and 8.6 cP–12.8 cP s at shear rate of 7.34 s^{-1} for Lower Karamay formation. It implies that polymer flooding should be using by injection of polymer solutions in each layer.

1. Introduction

Conglomerate oilfield is an important supplement to the whole world oil and gas production. For example, conglomerate formations account for 51.1% of its total original oil in place (OOIP) in Karamay oilfield (Xinjiang Province, China), which yields more than 1.5 million barrels per year. In typical water flooding of the conglomerate reservoir, the strongly intrinsic heterogeneity leads to the pre-mature water breakthrough, followed by high water cut and poor swept efficiency. (Hou et al., 2012). Therefore, a tertiary oil recovery technique is required to further develop conglomerate reservoir. Among EOR techniques, polymer flooding has been proposed as an economic and mature method to improve sweep efficiency, which is the biggest problem conglomerate reservoirs have faced (Simlote et al., 1985). In a design of polymer flooding pilot test, the selection of polymer and its concentration is the most crucial problem to be resolved. Small polymer molecule usually results in low viscosity and then poor mobility control in the oil recovery process. Ultra-high polymer molecule may be easily adsorbed on the rock matrix and block pore throats (Zhang et al., 2011). The investigation of the matching relationship between polymer solution and pore throats enhances the selection of polymer molecule and its appropriate range of concertation. Meanwhile, the mechanism of polymer transports in the conglomerate can be described with transport and in-situ rheology study of polymer (Dauben and Menzie, 1967; Cannella et al., 1988). Furthermore, the minimum polymer concertation can be studied by calculating the mobility ratio using water-oil relative permeability curves (Gogarty et al., 1970; Chang et al., 1978). Then the range of acceptable polymer solution viscosity is determined.

The matching relationship between polymer solution and pore throats of reservoir rock have been discussed by many researchers. Ball and Pitts (1984) applied Fox-Flory equation and Kozeny-Carmen equation to calculate the radius of gyration of a polymer molecule and also a hydraulic radius in a capillary bundle model. They found

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polymer molecules can flow easily when the ratio of capillary radius to polymer gyration radius is great than 4. Cheng et al. (2000) used Flory theory to calculate polymer root-mean-square (RMS) gyration radius and found the ratio of pore throat radius to RMS gyration radius should be great than 5 when the resistance factor of a polymer solution tails off. Zhu et al. (2006) studied the polymer hydrodynamic radius using the dynamic light scattering (DLS) and found that the average radius of pore throats of rock sample should be 4–16 µm on which polymer can be used according to the "bridging" principle. However, all the above methods only focused on the size of polymer molecular monomers. The more attention should be paid to the aggregate of polymer molecular. Recently, a method of nuclear-pore membrane filtration was proposed to measure polymer microspheres sizes by Hua et al. (2013) and then this method was revised by Y Li et al. (2014); D Li et al. (2014), who added flowing tests to explore the relationship between polymer hydrodynamic characteristic size and pore throat radii. They concluded both the polymer molecule and its concentration affect the hydrodynamic characteristic size which can reflect the polymer aggregation size. Yin et al. (2014) found that the compatibility between a polymer solution and rock sample is reached when the ratio of median pore-throat radius to polymer hydrodynamic characteristic size is about 5.5–6. Nie et al. (2010) successfully selected the suitable molecular weight for conglomerate reservoir with membrane filtration. However, he only focused on high molecular weight for high permeability reservoir.

A main mechanism for polymer-enhanced oil recovery is its higher viscosity than water. However, it is hard to determine polymer effective viscosity in the reservoir. Three flow regimes have been identified for this non-Newtonian fluid: Newtonian flow behavior, shear-thinning behavior and thickening behavior (Delshad et al., 2008). The apparent viscosity along varying shear rate can be measured using rheometer for the first two flow behaviors. And the relationship between velocity and shear rate can be calculated by various shear rate models. The commonly used equations for shear rate calculation were developed based on the flow of a power-law fluid in a bundle of capillary tubes or a permeable medium (Hirasaki and Pope, 1974; Cannella et al., 1988). Correction factors were used to modify shear rate with polymer flow in real core samples. Then the effective viscosity can be ensured with the suitable correction factor. Cannella et al. (1988) obtained a correction factor of 6 for xanthan gum polymer flowing in rocks. Balhoff and Thompson (2006) estimated the value of correction factor to be about 1.46 for flow of polymer in bead packs. Koh (2015) found correction factor was 1.1 for HPAM in Bentheimer sandstone. All the above-mentioned results were generalized from the studies in the homogeneous rock samples, i.e., pore structure parameters such as mean or maximum pore throat radius is well correlated with the permeability of the rock sample. Therefore, these correlations might not be valid for conglomerate formation because of its intrinsic heterogeneity and micro-anisotropy.

Mobility control is normally the desired effect when flooding with a polymer solution. The higher viscosity of polymer solution is injected, the more stable oil bank is formed ahead in the rock. And then the water cut is reduced in the production well. Lake (1989) defined the mobility ratio as of the ratio of the mobility of displacing phase to the mobility of displaced phase. To improve oil recovery, the mobility ratio of less than 1 is desired. Gogarty and et al., (1967, 1970) discussed the method of using relative-permeability curves and experiments to design adequate mobility control for micellar solutions flood. Jiang et al. (2010) used permeability reduction factor and polymer rheology to calculate viscosity range which can provide effective mobility control. Morelato et al. (2011) confirmed an increased viscosity of polymer solution produces the favorable mobility ratios in the displacement and this leads to an improved oil recovery in a reservoir simulation study. Sheng (2012) took into consideration of recoverable oil saturation and provided a criterion for mobility control design in multiphase displacement processes.

All the studies discussed above focus on the sandstone formation. Conglomerate is a terrigenous sedimentary rock type containing large, usually rounded rock fragments. It has more tortuous pore structure and heterogeneity than sandstone (Shafiei and Dusseault, 2008; Guo, 2009). Therefore, the experience gained from sandstone reservoirs may not be valid for the conglomerate reservoirs. In this paper, the matching relationships between polymer molecules, pore throat radius and mobility control have been integrated to explore a suitable viscosity range for a polymer flooding in conglomerate reservoirs. Karamay conglomerate reservoir is used as a field case in this study, which possesses the permeability of 50–200 mD. Conglomerate pore structures and polymer hydrodynamic characteristic sizes are analyzed in order to ensure the largest polymer concentration can be injected without any formation damage. Meanwhile, polymer transport rheology in two formations which have different pore structures were investigated to obtain suitable correlations in the shear rate model. Combined with water-oil relative permeability curves, these parameters were used to evaluate the effect of mobility control. In the end, we have proposed the range of acceptable polymer viscosity for Karamay conglomerate reservoir by integrating all the criteria.

2. The characterization of conglomerate rock and polymer molecular size

Two parameters should be taken into account in order to calculate the optimum polymer concentration and viscosity needed in a polymer flood. The first parameter is the pore structure of the conglomerate. The thin section analysis and mercury-injection capillary pressure (MICP) curves on a reservoir rock were used to study the pore structure. The other parameter is the hydrodynamic characteristic size of polymer molecules. The microporous membrane filtration technique was used to investigate the polymer molecular size. According to matching relationship between polymer and conglomerate reservoir, it exists an upper limit of polymer concentration which can be used in a polymer flood.

2.1. Conglomerate reservoir properties

Block 1 of Karamay Oilfield has been under water flood for more than 40 years and the infill drilling to optimize the well pattern was performed in 2011. Currently, this oilfield is produced using 150 m well spacing and inverted seven-spot pattern. Initially, a quick screening showed the oilfield is a good candidate for polymer flood. Its main oil-bearing zones are in Upper Karamay and Lower Karamay formation. Upper Karamay formation is a braided river delta sedimentation with an average porosity of 20.1% and permeability of 121 mD. Lower Karamay formation is alluvial fan sedimentation with an average porosity of 16.7% and permeability of 49 mD. The mineralogy study of the reservoir shows that it contains inequigranular conglomerate, sandy conglomerate, inequigranular sandstone. A coring operation was conducted in this block, and reservoir cores were obtained from the operator. Mercury-injection capillary pressure (MICP) tests were conducted following the SY/T 5346-2005 standard procedure on the two representative core samples from Upper and Lower Karamay formation, respectively. We then analyzed the pore structure using thin section images and pore throat size distribution by MICP curves. Obvious differences can be seen by comparing conglomerate reservoir rock with sandstone (from Daqing oilfield).

As shown in Fig. 1, the distribution of sandstone grain sizes is more uniform than conglomerates. The conglomerate is a coarse grain rock cemented by gravel and sand. Compared with sandstone, the diagenesis of conglomerates normally takes place in a shallower depth and then possesses more tortuous pore structures. Hence, the conglomerate usually has the characteristic of poor pore connectivity. Fig. 2 presents the correlation of largest pore radius with rock permeability for sandstones and conglomerates, which were obtained from MICP study. As expected, a good correlation between pore size and permeability is