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The microscale analysis of reverse displacement based on digital core

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ABSTRACT

The recovery of the reservoir is always the center of development because of its renewable characteristic. There are many methods designed to enhance the development of residual hydrocarbon, such as water flooding, polymer flooding, and the adjustment of well pattern. But the microscale mechanisms of fluid flow in porous media is still ambiguous, especially for reverse flooding. So in-situ displacement experiment based on CT scanning was designed in this paper to analyze the trapped oil after various flooding. In pore scale level, the total number of residual oil and average volume were counted. For further observing distribution changes, we classified the shape of residual oil based on shape factor and Euler number, and calculated the corresponding proportion. These results show that the adjustment of flow streamline can effectively improve oil recovery after water forward flooding and polymer displacement.

1. Introduction

Crude oil, still one of the most significant energy sources, gets more and more attention from the whole world, when other new energies constantly impact the economic market (Bondia et al., 2016). So advanced and low-cost development technologies are gradually put forward to improve production of a single well in the present well pattern or by infilling a few wells. After water flooding, tertiary recovery, also called enhanced oil recovery techniques, is usually used in many oilfields. This period includes immiscible gas flooding (injecting easily immiscible gas N_2, CH_4, CO_2 or other gas) (Aycaguer et al., 2001; Cao and Gu, 2013), surfactant flooding (Gale and Sandvik, 1973), polymer flooding (Shah, 2012), etc., but the investment of these methods is usually pretty high (Bahrami et al., 2016). Adjusting flow streamline is also an effective way to move residual oil, even after the tertiary period (Berg et al., 2015; Zeng et al., 2008). Herein, water flooding, polymer flooding and reverse water flooding are designed to reveal development.

To better understand the performance and principle of flow, there are four main scales: huge scale, large scale, small scale and micro scale (Teklu et al., 2013). In huge and large scales, oil engineering methods and reservoir simulation are the main tools to analyze history and predict future performance in whole (Larter et al., 2003). Small scale mainly contains lab experiments, such as core displacement experiments, core-scale experiments of physical properties, smart field tests, etc. Micro-scale research, as a vital part of law cognition, can be realized by using visible models or based on photoelectric technologies. Computed tomography (CT), introduced to porous media analysis in 1991 (Dunsmuir et al., 1991), can provide lossless images, the pixels of which can reach micrometer or even nanometer level (An et al., 2016; Yang et al., 2015). For well pattern adjustment, many macroscale methods are proposed, such as drilling infill wells, linear injection, water plugging, shutting down high water cut well and water injection profile control (Cassinat et al., 2002; Sheng, 2010). However, there is little research regarding streamline adjustment in microscale level. So μCT experiments, combined with core-scale displacement tests, are used herein to analyze reverse displacement, which means the conversion of inlet and outlet.

The whole period is completed without moving the core holder from CT facilities to guarantee that the object zone always stays in the scanning scope. We can compare same location to exclude the effect of structures. This in-situ displacement is achieved by designing a special fixable holder and a moveable pressure injection pump based on conventional CT machines.

In this study, we focused the attention on oil distribution properties after various flooding methods. The two core samples were first saturated with water and displaced with oil to establish initial oil and connate water conditions by simulating initial transportation of the water wetting reservoir (Li et al., 2015). Then the circuits were designed to simulate water forward displacement, polymer injection and water reverse flooding, respectively. After

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every displacement stage, a scan was conducted and the quantitative measurements of residual oil were determined by image analysis.

2. Experimental section

One standard size core is made by quartz sand with an absolute Klinkenberg-corrected gas permeability of 505mD, and the core is 25 mm in diameter and 10 cm in length. Then two sub-volume cylindrical core plugs are drilled from two ends with the length of 4 cm and the diameter of 10 mm, because of the limit of the core holder. These two cores from the same matrix can have similar parameters, which allows the comparison of results to be more reasonable. The porosity of these two samples are 26% and 26.8%, respectively.

Quartz sand is water wetting, but we found that the core cannot be saturated by water completely with residual air in the corner and small pores. A small amount of gas may have little effect for macroscopic experiments, however, this phenomenon brings uncertainty for micro-scale experiments and analysis. Kumar (Kumar et al., 2010) used plasma water to clean the core by conversing walls into strongly water-wet conditions, which can achieve acceptable saturation with water. A new workflow is designed to let more water occupy pore space without changing of the wall characteristic. The flowchart process steps (in order) are:

(1). Clean the core by distilled water.
(2). Saturate under vacuum with 0.25 M CsI-H_2O for one day.
(3). Seal core by carbon fiber holder. Centrifuge in 0.25 M CsI-H_2O to residual space.
(4). Saturate core with 0.25 M CsI-H_2O again.
(5). Seal core. Put core into refrigerator with constant temperature of -10 °C for one day.
(6). Unfreeze core.
(7). Saturate core with 0.25 M CsI-H_2O the third time.

After saturating the core with water, we fixed a carbon fiber core holder on the sample seat of the CT facility, and it was not moved during the whole experiment to guarantee that the same region was scanned at different stages. First, the plug in this flow cell was imaged at full water saturation with a micro computed tomography at a nominal resolution of $(4\ \mu m)^3$. Then the formation of the reservoir was simulated by using oil to flood the original water until there was no water flowing out, hereafter sealing the core for one day to reach the balance state and scanning the original distribution of oil and residual water.

For one core sample, CsI-H_2O filled piston can (6) (as shown in Fig. 1) was used to simulate water flooding in primary or secondary recovery at constant flux 0.05 mL/min. After 20 PV of water was injected (no oil flow out), valve (9) was connected with gauge (16), and valve (14) was used as an exit to achieve converse flooding. For the other core, after 20 PV of water was injected, piston can (8) was opened to inject a polymer slug, and then water was used to flood until there was no oil improved in the beaker. Reverse displacement was also realized for this model.

3. Results and analysis

As previously mentioned, there are two samples used in the experiments. Each stage was scanned and analyzed to get the microscale mechanisms of driving based on these two cores. As shown in Fig. 2, the 300^3 pixel sub-volume (B) is cut from the 3D gray image obtained by CT scanning (A).

The phases have different gray values due to their different absorption of X-rays. Therefore, the two gray threshold values are determined by implementing characterization of verge among these three phases, and relative radio density maps are represented by value 0, 1 and 2 (Valvatne and Blunt, 2004).

For the first model, the 2D segmented images of the same position are shown in Fig. 3. The area of each image is $1.2\ mm \times 1.2\ mm = 1.44\ mm^2$. From A to E, each image corresponds with a stage: original stage, after 1 PV water flooding, 20 PV water flooding (no oil is flooded out), polymer flooding and reverse water flooding, respectively. Fig. 4 shows the residual oil clusters (Rücker et al., 2015) in 3D for each process stage. The compared area positions are all the same for each process step to minimize the effect of other irrelevant factors.

Figs. 3 and 4 can qualitatively show that the area of residual oil is declining in the process, which means these three development types are all reasonable stimulation methods. Then the distribution is analyzed by calculating the water saturation, average volume of residual oil ($\overline{V}$), number of oil clusters and proportion of different types.

The total volume (V_{total}) and number (N) of residual oils can be calculated by analyzing the image information, so the average volume can be calculated through the following equation:

$$\overline{V} = \frac{V_{total}}{N} \tag{1}$$

The number of residual oils reflects the degree of oil scattering, and the value of $\overline{V}$ is affected by this number besides water saturation. So the average value of oil volume can implicate the efficiency of flooding at different stages in the microscale level.

The various shapes, as shown in Table 1 and Fig. 5, will occur in the flooding process, which is sorted based on shape factor G and Euler number EN.

$$G = \frac{6\sqrt{\pi}V}{S^{1.5}} \tag{2}$$

G represents 3D shape factor; V is the volume of residual oil, μm^3; S is the surface area of oil cluster, μm^2. Shape factor is a parameter defined to describe whether the real shape trends regular geometry, equaling 1 when the oil is a ball. Correspondingly, if the distribution is very complex and irregular, the shape factor will be very small.

And the Euler number is a property about topological structure (Kong and Rosenfeld, 1989), defined via following equation:

$$E_N = b_0 - b_1 + b_2 \tag{3}$$

where Euler number is represented by E_N; b_0 is the number of connected objects; b_1 is the number of holes, also called handles or tunnels, that is the maximum of non-separating cuts; b_2 is the number of cavities.

The large patchy oil shape with large volume usually appears in the unswept area, and the structure is extremely complex (Kovscek and Radke, 1996). So the shape factor G will be small as the denominator of area S is huge for this case. We defined the threshold value as 0.1 to identify large patchy residual oil. When the G value increases to 0.1 but less than 0.3, the oil cluster is in the network shape, which is used to describe complex and big residual area occupying several pores and throats. The multi-pore shape means residual oil stays in few spaces, which is the stage after network shape because of flooding. At the same time, throat and film shape oil usually occur in throats or spread along the wall via further displacement. The multi-pore structure and the throat and film shape have similar shape factor values ($0.3 \le G < 0.7$), but the distributions have notable differences. The Euler number, as a topological parameter, is calculated to distinguish them, and the