A Review of Imbibition Mechanism and Development of Low Permeability Reservoir

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Abstract: Low permeability reservoir has low porosity and permeability, small pore radius, large capillary force and poor effect of conventional water injection development. The study shows that the imbibition is influenced by rock and fluid properties. It will play a guiding role in the development of low permeability reservoir by studying the mechanism and influencing factors of imbibition and mastering the influence of different factors on the imbibition recovery. Imbibition is also an important reason for fracturing fluid loss. It is of great significance to determine fracturing fluid volume and optimize reflux design to fully study the suction capacity and rate of the matrix.

Keywords: Low Permeability Reservoir; Spontaneous Imbibition; Enhanced Recovery; Imbibition Mechanism; Rock Properties

Introduction

Absorption refers to the process in which the wetted phase enters the pore throat under the action of capillary force to displace the non-wetted phase [1]. The capillary force is the main driving force in the absorption process [2]. During the exploitation of low permeability reservoir, water channeling is very serious at the later stage of water injection due to the formation heterogeneity, and it is difficult to achieve good results by conventional water injection development. Low permeability reservoir has low porosity and permeability and large capillary force, which can be used as driving force for oil displacement and increase development effect. Therefore, it is of great significance to study the imbibition mechanism under capillary force for the development of low permeability reservoirs. The imbibition is also of great significance for studying the filtration of fracturing fluid. During hydraulic fracturing, the backflow rate of fracturing fluid is low, only 10%~50% [3], and the rest is retained in the pores or enters the formation, causing damage to the reservoir. It is found that the spontaneous imbibition of water-based fracturing fluid in shale is the main reason for a large amount of filtration in the backflow process of fracturing fluid. Fully studying the imbibition capacity and imbibition rate of matrix plays an important role in determining the volume of fracturing fluid, optimizing the backflow design and guiding oil and gas production [4].

1. Imbibition mechanism

Osmosis is divided into forward osmosis controlled by gravity and reverse osmosis controlled by capillary force [1]. The research shows that [1,5], when the permeability is high, the pore radius is large, and the interfacial tension is small, the imbibition is a forward imbibition controlled by gravity, that is, the liquid suction direction is consistent with the oil drop discharge direction, and the imbibited oil drops are concentrated on the upper surface of the core; When the permeability is low, the pore radius is small, and the interfacial tension is large, the imbibition is a reverse imbibition controlled by capillary force, that is, the direction of liquid suction is opposite to the direction of oil drop discharge, and the imbibited oil drops are distributed on each side and top of the core. Some studies suggest that [6], the imbibition mainly occurs in medium and small pores, and capillary pressure is the main driving force in the imbibition process.

In addition to spontaneous imbibition, some scholars have conducted experimental studies on imbibition under displacement conditions. Zhu Weiyao et al. [2] used heavy water displacement to simulate oil, and used NMR relaxation time spectrum to explore the imbibition mechanism under displacement conditions. The results show that the displacement is dominant at the initial stage of water drive. With the water drive, the displacement gradually weakens and the imbibition gradually increases. The reason is that under the action of driving force, water mainly enters into the larger capillary channels. With the oil displacement, the crude oil in the larger capillary channels gradually decreases, and the role of capillary imbibition in oil recovery gradually increases. In the displacement experiment, there is an optimal displacement speed, at which the imbibition efficiency is the highest [7]. This study is helpful to determine reasonable water injection volume and water injection rate in the process of water injection, so as to obtain the best oil recovery effect.

2. Factors affecting imbibition

2.1 Rock properties

The rock wettability, formation porosity, permeability, clay mineral content, organic content, etc. have a great impact on the imbibition effect.

The studies found that the degree of imbibition has the following rule: strong water wet core>medium water wet core>weak water wet core, and there is almost no imbibition in oil wet core [2,9]. Different scholars have found that surfactants can be used to change the wettability of rocks, changing the oil wet core into the water wet core, and changing the capillary force from oil displacement resistance to power, thus improving the imbibition effect [8,10-11]. Wei Falin et al. [12] carried out imbibition experiments on oil wet cores. The results show that CTAB (cetyltrimethylammonium bromide) cationic surfactants can change the wettability of rocks through adsorption and formation of reverse micelles.

Porosity and permeability of rocks have a crucial influence on spontaneous imbibition. It is generally believed that porosity and permeability increase, capillary pressure decreases, and imbibition efficiency decreases. However, Liu Xiangjun et al. showed that the ultimate recovery factor of ultra-low porosity and low permeability cores increased with the increase of porosity and permeability [13]. This is because the thickness of the adsorbed liquid film on the solid surface of the ultra-low permeability core is in the same order of magnitude as the core micro pore radius, and the capillary pressure is not enough to overcome the viscous force. Therefore, with the increase of porosity and permeability, the number of micro channels that can be activated by capillary pressure increases, and the ultimate recovery increases.

2.2 Fluid properties

The fluid in the imbibition system mainly includes crude oil and imbibition liquid. At present, the most widely used imbibition liquid is surfactant solution. Surfactants increase imbibition recovery mainly by reducing interfacial tension and improving wettability. Since the main driving force of imbibition is capillary force, which is closely related to interfacial tension and contact angle, the influence of interfacial tension and contact angle on imbibition should be emphatically considered in the study.

BABADAGLI in the experimental study of spontaneous imbibition of surfactant, the imbibition effect is measured by recovery rate and final recovery factor [8]. The experiment shows that non-ionic surfactant can increase the recovery rate and ultimate recovery factor of heavy oil in water wet sandstone. However, when surfactant is added in the dialysis experiment of light crude oil, although the final recovery factor has slightly increased, the recovery rate has not increased.

2.3 Other factors

2.3.1 Bound water

The existence of irreducible water is an important factor affecting the imbibition recovery. Zhu Weiyao et al. [2] showed that the ultimate recovery of cores with unsaturated irreducible water is higher than that of cores with saturated irreducible water, because irreducible water mainly occupies small capillary channels with strong imbibition, greatly reducing the role of capillary force in water absorption and oil drainage. It is suggested that the spontaneous imbibition experiment should be carried out after the irreducible water is established according to the reservoir conditions, so as to obtain the effect close to the actual reservoir. It is considered that the influence of initial water saturation on spontaneous imbibition is determined by the enhancement of water mobility and the weakening of capillary force. The experiment shows that the interaction between the absorbed water and clay minerals can change the pore structure of shale, and then affect the fluid migration. The interaction between oil and clay minerals can not be ignored, and can even change the wettability of the core, making the core wet from water to oil. Because the anisotropy of shale makes the imbibition process more complex, more targeted research is needed. In addition, the boundary conditions of the core also have a greater impact on the recovery degree, and the recovery degree of the core opened at both ends is higher than that of the core opened at one end.

2.3.2 Temperature and pressure

The influence of temperature and pressure on imbibition can not be ignored. Li Aifen [5] believes that temperature is not a direct factor affecting the imbibition, but affects the imbibition by changing the viscosity of the simulated oil. Zhou et al. [3] found that the temperature will affect the imbibition during the experiment of shale gas reservoir, and the total imbibition volume will decrease as the temperature increases. The temperature represents different formation depths. When the temperature rises, the surface tension of rocks and fluids decreases, thereby reducing the capillary force. However, the high pressure condition of the formation may increase the driving force of the imbibition. Future research should start to analyze the combined effect of temperature and pressure on the spontaneous imbibition.

2.3.3 Infiltration mode

Peng Yuqiang et al. The results show that the final recovery factor of direct imbibition with surfactant solution is higher. Therefore, when using imbibition technology for oil recovery in neutral sandstone reservoirs, surfactant should be selected and imbibition of surfactant should be carried out as early as possible.

3. Application in oilfield production increase

At present, there is little field application of imbibition oil production. Based on imbibition simulation experiment, water injection huff and puff test has been carried out in Sha-3 Middle Reservoir of Block Wen 72, and it has been successful. Water injection is carried out after oil production is stopped, and oil-water imbibition exchange is carried out after the well is shut in for 3 months. After the well is opened, the oil production reaches 16.2 t/d, which confirms the possibility of improving the recovery efficiency of low permeability reservoirs by imbibition method.

Conclusion

Surfactant solution can promote the imbibition of low-permeability reservoirs. The use of surfactant solution in combination with clean fracturing fluid can increase oil production and achieve stimulation effect. The low residue characteristics of clean fracturing fluid can also reduce formation damage. The properties of core, crude oil and surfactant have a great influence on imbibition. The best oil recovery effect can be achieved only when different formation conditions match the corresponding surfactant. Therefore, it is necessary to simulate the formation conditions and conduct targeted experimental research before fracturing construction. Future research should focus on the relationship between micro pore structure and spontaneous imbibition, and the combined effect of temperature and pressure on imbibition. While increasing the oil recovery effect, the reservoir damage is minimized.

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