Water Science and Engineering, 2009, 2(1): 103-111
doi:10.3882/j.issn.1674-2370.2009.01.010

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Effect of electroosmotic flow on brine imbibition in porous media

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Abstract: Based on Darcy's Law and the Helmholta-Smoluchowski equation, an imbibition velocity formula for the water phase with an electric field was deduced, showing that the imbibition velocity with an electric field is to various extents not only related to the rock permeability and characteristic length, the fluid viscosity, the oil-water interface tension and the gravity of the imbibing brine, but also to the fluid dielectric permittivity, zeta potential, applied electric field direction, and strength. Imbibition experiments with electric fields that are different in direction and strength were conducted, showing that application of a positive electric field enhances the imbibition velocity and increases the imbibition recovery ratio, while application of a negative electric field reduces the imbibition velocity and decreases the imbibition recovery ratio. The imbibition recovery ratio with a positive electric field increases with the strength of the electric field, and the imbibition recovery ratio with a negative electric field is lower than that without an electric field.

Key words: *imbibition; imbibition velocity; electroosmotic flow; electric field direction; electric field strength*

1 Introduction

Imbibition is a process of immiscible displacement through which a non-wetting fluid in a porous media is spontaneously expelled by the surrounding wetting fluid. Injected water mostly crosses the flow during waterflooding through highly permeable fractures. The mass exchange between fracture fluid and matrix fluid is a determinant in the production of oil in fractured low permeability reservoirs. Therefore, numerous investigations have been published to characterize the mass exchange between fracture fluid and matrix fluid due to capillary force.

The capillary force between the residual phase and imbibing phase is closely related to many factors, including permeability, porosity, pore-throat ratio, wettability, and interface tension (Akin and Kovscek 1999). The influences of various physical properties and characteristics of fractured reservoirs on the imbibition process are extremely distinct.

This work was supported by the National Key Basic Research Development Program of China (Grant No. 2002CCA00700).

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Received Sep. 2, 2008; accepted Feb. 16, 2009

Capillary force, the matrix block's continuity, the fracture's relative permeability, counter-current imbibition and co-current imbibition have been investigated (Kazemi et al. 1992; Mattax and Kyte 1962). The rock shape and size have also been shown to be significant to the imbibition in fractured reservoirs (Handy 1960; Morrow and Mason 2001). The relationship between the invading form and the fluid flow characteristics in micro-pores has been illustrated in detail (Cuiec et al. 1994). Wettability, the viscosity ratio, and the interface tension between the wetting phase and the non-wetting phase also impact the imbibition. Additionally, the injection rate of the imbibing phase has been a matter of concern (Zhang et al. 1995). The initial saturations of the wetting phase and the non-wetting phase are also vital to the imbibition process (Viksund et al. 1998; Morrow and Mason 2001). Computed tomography technology has been utilized to investigate imbibition frontal advance and development. The fluid saturation profile of the imbibing phase in a porous media has been obtained (Akin et al. 2000). Temperature and potential-determining ions can affect wettability and the imbibition oil recovery from carbonates. Spontaneous imbibition has been promoted by altering ion concentrations and species on the surface of rocks (Zhang and Austad 2006).

Electroosmotic flow is a process in which the surfaces of porous media generally acquire charges when placed in contact with the solution, so that the solution also becomes charged and the charged ions in the solution are thus set in motion by the application of an electric field (Long et al. 1999). Electrolyte solution in a micro-tube can generate motion by applying an appropriate electric field at both ends of the capillary (Harrison et al. 1992). The difference between pressure-driven flow and electric-driven flow has been compared. The electroosmotic force has been proven to be dominant in the vicinity of the wall region, which is relevant to the zeta potential (Yang et al. 2001). The driving force for the electroosmotic flow in microchannels depends on the local net-charge density and the strength of the externally applied electrical field. The net-charge density is related to the zeta potential. Consequently, the zeta potential determines the electroosmotic flow behavior. The electroosmotic flow rate increases with zeta potential (Ren and Li 2001). The zeta potential has taken on a step change for electroosmotic capillary flow, and the pressure-driven flow and electroosmotic flow has been described by uniform equations (Herr et al. 2000). The flow velocity with an electric field and that without an electric field have been calculated. The results show that the flow velocity ratio gradually increases with electric field strength. The flow velocity with an electric field is 1.75 times that without an electric field as electric field strength rises to 4.5 V/cm (Amba et al. 1965; Aggour et al. 1994). The electroosmotic flows in micro-channels with different diameters have been investigated. The electroosmotic flow rate has been proven to gradually increase with electric field strength and diameter (Rathore and Horváth 1997). A mathematical model has been developed for estimating the effect of electroosmosis on water-displacing oil process in porous media (Yun et al. 1999).

The idea of enhanced oil recovery (EOR) through a direct current electrical field has been developed in the U.S.A. Early research aimed to investigate the effect of electroosmotic flow on oil-water relative permeability. Further studies indicated that an applied direct electric field could increase the flow rate of the oil phase or water phase. Furthermore, application of the direct electrical field in oilfields has proven that it is an effective enhanced oil recovery method. Due to the slow flow velocity of fluid in low permeability reservoirs, the application of waterflooding in reservoirs is restricted. In order to increase oil recovery in tight matrix reservoirs, imbibition has been extensively used in low permeability reservoirs. However, the imbibition velocity is very slow. The electroosmotic action can increase the waterflooding velocity. Certainly, a direct electric field can affect imbibition velocity. Previous studies have mainly been concerned with the imbibition process and electroosmotic flow. Few studies have examined the relationship between the imbibition process and electroosmotic flow. It has been proven that charge distribution on a rock surface and the electroosmotic flow rate of fluid can be changed by application of a direct current electric field. In addition, the changes of charge distribution on a rock surface alter the rock wettability and surface properties. Moreover, the process can improve or restrain imbibition. This study investigated the imbibition process with direct electric fields that are different in direction and strength, combining the mathematical equations derived from Darcy’s Law and the Helmholtz-Smoluchowskl equation.

2 Theory

Imbibition axial sections of core surrounded by brine are depicted in Figs. 1 and 2, in which the grey part represents oil saturating the core and the white part represents brine being imbibed by the core. The boundary between the grey part and the white part denotes the oil-water interface of imbibition. The stress of the imbibing fluid front is the combination of the forces of the oil-water interface tension, the gravity of the imbibing brine, and the applied electric field. The gravity direction is vertically downward. The electric field force direction is dependent on the direction of the applied electric field. The direction of the oil-water interface tension is determined by the interfacial shape of the oil-water interface in cores and is generally opposite to the inward convex shape of the oil-water interface. The direction therefore is downward for imbibing brine on the top, upward for that at the bottom, and horizontally inward for that on the side face. The stress of the imbibing fluid front is correspondingly divided into three cases: stresses on the top, on the side face, and at the bottom. The stresses on the top and at the bottom are subject to the combined forces of gravity, the electric field and the oil-water

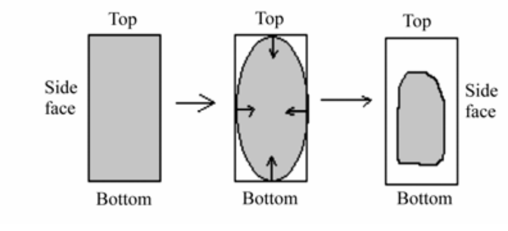

Fig. 1 Axial sectional drawing of imbibition process

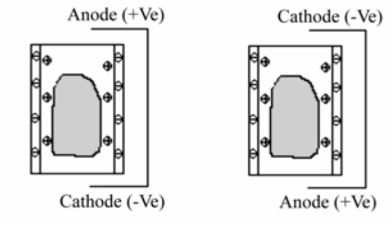

Fig. 2 Sketch of electroosmotic flow and imbibition

interface tension in the vertical direction. The stress on the side face contains the force of gravity, the electric field force in the vertical direction, and the oil-water interface tension in the horizontal direction.

The electroosmotic velocity in the direct current electric field can be calculated according to the Helmholtz-Smoluchowski equation below:

$$v_{\mathrm{e}} = -\frac{\varepsilon E \xi}{\mu} \tag{1}$$

where v_{e} is the electroosmotic velocity; ε is the dielectric permittivity of the electrolyte solution; E is the axial electric field strength, assuming a positive electric field to face vertically downward and a negative electric field to face vertically upward; ξ is the zeta potential; and μ is the viscosity of the solution.

The imbibition velocity can be derived from Darcy's Law:

$$v_{\mathrm{d}} = \frac{K}{\mu}\frac{G \pm P_{\mathrm{c}}}{L} \tag{2}$$

where v_{d} is the imbibition velocity; K is the core permeability; G is the gravity of the imbibing fluid; P_{c} is the capillary force; and L is the core length. The imbibing fluid velocity in an electric field can be formulated by combining Eqs. (1) and (2):

$$v = v_{\mathrm{d}} + v_{\mathrm{e}} \tag{3}$$

Imbibition velocities of various parts' fluid are different due to different stress states in the electric field. The electric field direction and strength are also significant to the imbibition process. The imbibition velocity on the top is described as follows:

$$v_1 = \frac{K}{\mu}\frac{G + P_{\mathrm{c}}}{L} + \frac{\varepsilon E \xi}{\mu} \tag{4}$$

The imbibition velocity at the bottom is as follows:

$$v_2 = \frac{K}{\mu}\frac{G - P_{\mathrm{c}}}{L} + \frac{\varepsilon E \xi}{\mu} \tag{5}$$

The imbibition velocity on the side face is as follows:

$$v_3 = \sqrt{\left(\frac{K}{\mu}\frac{G}{L} + \frac{\varepsilon E \xi}{\mu}\right)^2 + \left(\frac{K}{\mu}\frac{P_{\mathrm{c}}}{L}\right)^2} \tag{6}$$

As shown in the equations above, the imbibition velocity with an electric field is not only related to the rock permeability and characteristic length, the fluid viscosity, the oil-water interface tension, and the gravity of the imbibing brine, but also to the fluid dielectric permittivity, zeta potential, applied electric field direction, and strength.

3 Experiments and results

3.1 Experimental procedure

The experimental setup consisted of two parts: an imbibition cell and a direct current (DC) electrical source system, shown in Fig. 3. The DC electrical source was applied to the imbibition cell, and the voltage between the two ends of the core was regulated as required. The core was placed vertically in the imbibition cell. The imbibing oil was measured with the scales in the imbibition cell.

The cores whose permeability were 157.49×10^{-3} μm^2 and whose porosity were 25%, were artificial sandstone manufactured with a compound of quartz sand, clay, and a cementitious agent. The clay content was about 30%. The diameter and length of the cores were 2.54 cm and 8.00 cm, respectively. Oil was simulated with a mixture of Changqing crude oil and kerosene with a volume ratio of 1∶4. The brine was a NaCl solution with a salinity of 25 g/L.

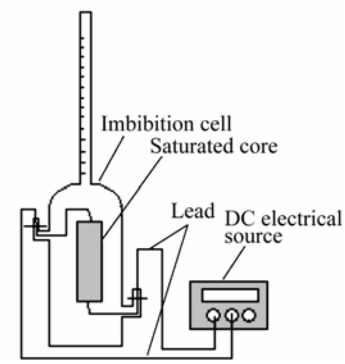

Fig. 3 Sketch of experimental setup

3.2 Results

3.2.1 Effect of electric field direction on imbibition

Three cores with the same permeability were chosen. After being dried and weighed, they were thoroughly evacuated with a vacuum flask and saturated in the simulation oil. The experimental temperature was set at 30℃ in order to avoid the effect of brine evaporation in high temperatures. Generally, the reservoir temperature is higher than the experimental temperature. However, the effect of temperature on the imbibition process is dependent on the viscosity of crude oil. The viscosity of the simulation oil is 1.883 MPa·s at 30℃, which is close to that in the reservoir. Therefore, this temperature was adopted in the experiments. The initial oil saturation was 100%, in order to maintain the same initial saturation. All oil-saturated cores were put into imbibition cells filled with brine. This assumes that the positive electric field is with the upper anode and nether cathode. In contrast, the negative electric field is with the nether anode and upper cathode. No electric field was applied to the first cell. A positive electric field was applied to the second cell, and a negative electric field was applied to the third cell. The voltage of the applied direct current was 5 V, and the strength of the applied electric field was about 92 V/m.

Fig. 4 shows the experimental results on the effects of the electric field on the imbibition flow rate. The imbibition flow rate with a positive electric field was higher than that with a negative electric field or without an electric field. Moreover, the increment of the imbibition flow rate in the initial period is evident. The imbibition flow rate with a negative electric field changed little in the initial period, but decreased in the later period. Fig. 5 illustrates that a positive electric field improves the imbibition recovery ratio, and a negative electric field restrains the imbibition recovery ratio.

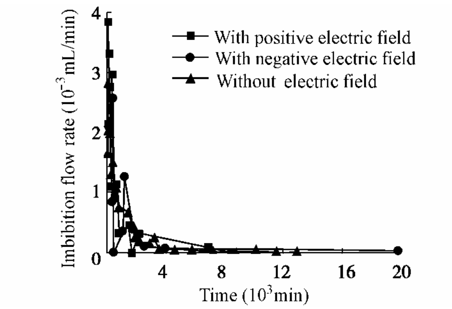

Fig. 4 Effect of electric field direction on imbibition flow rate

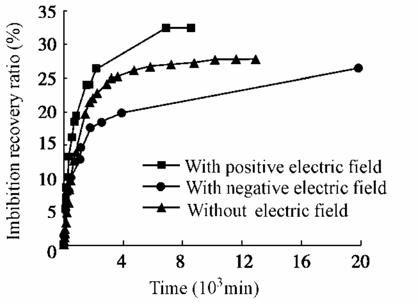

Fig. 5 Effect of electric field direction on imbibition recovery ratio

3.2.2 Effect of electric field strength on imbibition

The other two cores, both of which had a permeability of 171×10^{-3} μm^2, were chosen. The porosity of the cores was 23.29%. The initial oil saturation was about 67.94%. The cores were put into imbibition cells containing NaCl brine with a salinity of 25 g/L. No electric field was applied to the first cell, and an electric field with a step increase in strength was applied to the second cell. In the initial period, a negative electric field was applied to the second cell. About 7 500 minutes later, the imbibition process slowed down and even stopped. Therefore, the negative electric field was changed to a positive electric field.

As shown in Fig. 6, the imbibition recovery curve with an electric field can be divided into two sections. One part is the lower imbibition recovery section with a negative electric field, and the other is the higher imbibition recovery section with a positive electric field. These sections were both compared with the imbibition recovery curve without an electric field. The results show that the application of a negative electric field reduces the imbibition recovery ratio. In contrast, the imbibition recovery ratio increases quickly with electric field strength as the electric field direction is changed to the positive. Fig. 7 shows that the imbibition flow rate also increase with electric field strength as a DC electric field is applied. As the electric field strength increases, the imbibition flow rate appears to increase. Fig. 8 shows that the imbibition recovery ratio makes step increase with electric field strength.

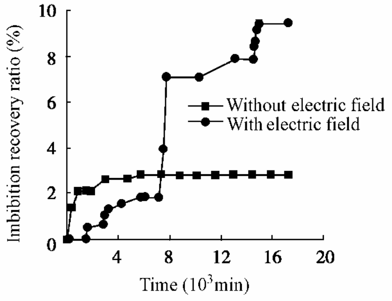

Fig. 6 Effect of electric field strength on imbibition recovery ratio

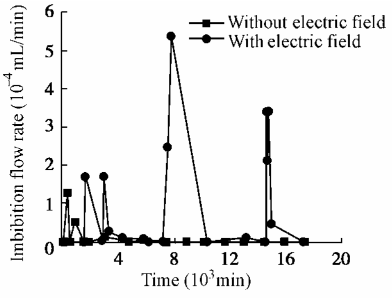

Fig. 7 Effect of electric field strength on imbibition flow rate

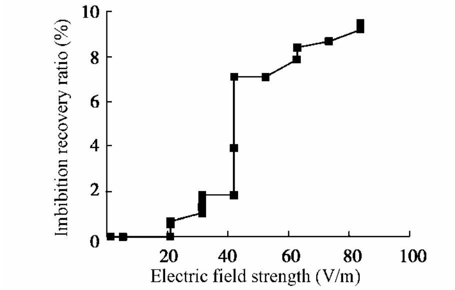

Fig. 8 Effect of electric field strength on imbibition recovery ratio

4 Discussion

Imbibition is a process by which the wettability phase is imbibed by the matrix block and displaces the non-wettability phase due to capillary forces. Imbibition velocity is related to oil-water interface tension and gravity. Electroosmotic flow is a phenomenon that electrolyte solution in a porous media sets in motion by application of an electric field. Certainly, there are definite relationships between the imbibition and electroosmotic flow.

It is conceptually indicated by Eqs. (4), (5) and (6) that the imbibition velocity with an electric field is dependent on electric field direction and strength as reservoir properties are fixed. As a positive electric field is applied, the electric field direction is identical to the gravity direction. Generally, the sandstone surface has a negative charge. According to the electric double layer theory, pore surfaces in contact with electrolytes can adsorb counter ions and form a diffuse electric double layer. As a positive electric field is applied, brine in the slippage layer flows towards the cathode of the electric field due to electroosmotic flow. The electroosmotic flow rate promotes the imbibition velocities on the top and on the side face, and decreases those at the bottom. The reason is that a vertically downward velocity is produced due to electroosmotic flow. The velocity is a cumulative downward velocity component on the top or on the side face, which means that the imbibition velocity is reinforced. In contrast, the imbibition velocity is weakened at the bottom because its direction is upward, opposite to the electroosmotic flow direction. Similarly, the electroosmotic velocity is upward as a negative electric field is applied. The velocity improves the imbibition process at the bottom and reduces those on the top and on the side face. The reason is that the applied negative electric field direction is the reverse of gravity. The vertical stress is reduced, which contributes to the decrease of the imbibition velocities on the top and on the side face and the increase of those at the bottom. Compared to the influence of positive and negative electric fields on imbibition, it is clear that electroosmotic flow promotes the imbibition velocities on the top and on the side face, and decreases those at the bottom as a positive electric field is applied. Overall, a positive electric field increases the imbibition. Conversely, electroosmotic flow decreases the imbibition velocities on the top end and on the side face, and increases those at the bottom as a negative electric field is applied. Overall, a negative electric field decreases imbibition. It is noted from

Eqs. (4), (5), (6) that electroosmotic flow is positively correlated with electric field strength. As a positive electric field is applied, imbibition velocity gradually increases with electric field strength. As the positive electric field is changed to a negative electric field, imbibition velocity gradually reduces with the increase in electric field strength.

Additionally, the application of the DC electric field can affect the properties of reservoir fluids. Some research indicates that the apparent viscosity of crude oil decreases with DC electric field strength at a low shear rate, and the interfacial tension between oil and water also declines slightly as a DC electric field is applied. However, as the viscosity of oil is lower, the effect is negligible. Certainly, all factors in the DC electric field contribute to the increase in the imbibition recovery ratio.

The analysis above can be proven through the results of the experiments. The positive electric field improves imbibition and the negative electric field restrains imbibition. With the initial increase in negative electric field strength, the imbibition recovery ratio is lower than that without an electric field. As the electric field direction is changed to the positive, the imbibition velocity and recovery ratio increase quickly.

Combining laboratory results and theoretical analysis, an applied electric field can improve or restrain the imbibition process, depending on the direction and the strength of the electric field. The positive electric field increases the imbibition velocity and recovery ratio, and the negative electric field reduces the imbibition velocity and recovery ratio. The imbibition recovery ratio increases with electric field strength as a positive electric field is applied.

5 Conclusions

According to an equation that describes the imbibition process and electroosmotic action synthetically, the imbibition velocity with an electric field is dependent on the rock permeability and length, the fluid viscosity, the oil-water interface tension, and the gravity of the imbibing brine, in addition to the fluid dielectric permittivity, zeta potential, electric field direction, and strength.

An applied positive electric field increases the imbibition velocity and improves the imbibition recovery ratio. An applied negative electric field reduces the imbibition velocity and decreases the imbibition recovery ratio.

The imbibition recovery ratio with a negative electric field is lower than that without an electric field. As the electric field direction is changed to the positive, the imbibition recovery ratio rises quickly, and increases continuously with electric field strength.

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