MEASUREMENT OF THREE-PHASE RELATIVE PERMEABILITIES OF VARIOUS SATURATING HISTORIES AND WETTABILITY CONDITIONS

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ABSTRACT

The research of three-phase relative permeability is a key issue in oilfield development. In this study, three-phase relative permeabilities of water-wet and oil-wet outcrops with two saturating histories were investigated by steady physical simulation experiments using a CT dual energy scanning method. The experiment results clearly showed that there was significant effect of wettability on three-phase permeabilities. For water-wet cores, the isoperms of water were straight lines, suggesting that the three-phase relative permeability to water only depended on water saturation. The isoperms of oil were concave towards 100% oil saturation point, while the isoperms of gas were convex towards 100% gas saturation point, suggesting that the three-phase relative permeabilities to oil and gas depended on all the saturations. For oil-wet cores, all the isoperms of water, oil and gas were convex towards 100 % of its saturation, suggesting that the three-phase relative permeabilities to water, oil and gas depended on all the saturations. In addition, the isoperms of wetting phase were similar for the two saturation histories, while those of non-wetting phase were different. Even though the shapes of the isoperms were the same, the corresponding values of permeabilities and the positions of isoperms were different.

INTRODUCTION

With the development of the petroleum industry, people pay more attention to three-phase relative permeabilities. Stone predictive models [1, 2] are widely used to estimate three-phase relative permeabilities from more readily available two-phase data. However, these models rely on many assumptions so the predicted results are not satisfactory in some cases. In addition, the models are only effective for the water-wet cores. Laboratory measurement methods [3] can simulate 13 saturating histories of fluid flow that may possibly be realized in the reservoirs, and the results from it are more reliable. However, there are always some difficulties in measurements, including three-phase saturations accuracy and end effects. For this reason, despite the availability of some three-phase relative permeabilities using the laboratory measurements reported, there are no universally accepted conclusions on the shape of the isoperms [4]. Meanwhile few studies are available for oil-wet cores. In this study, three-phase relative permeabilities of both water-wet and oil-wet outcrops with DDI (water saturation decreased, oil saturation decreased and gas saturation increased) saturation history, which mostly happened in conventional gas injection process, were determined by steady state physical simulation experiments with the aid of CT scan technology. The effect on three-phase relative permeabilities by the reversed saturating history, IID (water saturation increased, oil saturation increased and gas saturation decreased), was also investigated.

EXPERIMENTAL

Core Samples and Fluids

The SX1 and SX2 sandstone outcrops from ShanXi in China were used in the experiment. Both of them were drilled from the same outcrop and their petrophysical parameters are listed in Table 1. The wettability of SX1 was water-wet, and that of SX2 was weak oil-wet by silicon oil treatment then aging for a week. The wettability was determined by Amott method. The refined oil (Caltex White Oil Phamra) was used, it was degassed by vacuum and its viscosity was 4.7 cP at 60 degC. 5wt% NaBr was used to improve the CT number of the aqueous phase. The purity of the injected nitrogen was 99.93%.

Experiment Set-up and Conditions

The experimental set-up is schematically shown in Figure 1. A LightSpeed 8 CT Scanner from GE was used for in-situ saturation measurements. The core samples and the fluids were scanned under 100 kV and 140 kV, and different scanning results were used for the three-phase saturations calculations [5]. The saturation measurement accuracy is fairly low due to the beam hardening effect, while it can be improved by our calibrating method [6]. Helical mode for CT was used to reduce scanning time. A CT image analysis software (CTIAS 1.0, developed by RIPED) was used to process CT data. For injection system, the constant-rate mode of pumps was imposed and the injection rates of three fluids were adjusted according to the different saturation histories. An overburden pressure of 10 MPa was maintained in the sleeve, and a back pressure of 2.5 MPa was maintained in all the experiments. A special PEEK coreholder was used, and the end effect can be eliminated by measuring the differential pressure and fluid saturations between two pressure measurement points in it.

Procedure

The steady-state method was used and all the experiments were conducted at ambient temperature. After establishing the irreducible water state in the core, brine and oil were simultaneously injected into the core, with increasing brine injection rate and decreasing oil injection rate as the total injection rate was maintained constant. Subsequently, DDI saturating history was simulated by injecting brine, oil and gas simultaneously, with decreasing brine and oil injection rates (keeping the ratio of brine and oil injection rate constant) while increasing gas injection rate as the total injection rate was constant. The injection rate of every fluid phase and the value of differential pressure transducer were recorded when the system reached steady state. Finally, the reversed saturation history IID was simulated by decreasing gas injection rate while increasing brine and oil injection rates. The relative permeabilities were calculated from Darcy's law.

RESULTS AND DISCUSSION

Three-Phase Relative Permeabilities of Water-Wet Core

According to the relative permeabilities of each fluid at different saturations, the isoperms of them for water-wet core SX1 were plotted as Figure 2. For water-wet core, water, oil and gas correspond to the wetting phase, the intermediate phase, and the non-wetting phase, respectively. According to the channel flow theory, the wetting phase (water) located in the small pores, the non-wetting phase (gas) located in the large pore spaces, are separated by the intermediate phase (oil). So the microscopic fluid distributions at the water-oil interface will be identical in a water-oil system and in a water-oil-gas system at a given water saturation. The three-phase relative permeability to water only depended on water saturation so the isoperms of water were a group of straight lines, and they were slightly affected by the saturation histories.

In the steady-state flow, all three phases had to compete for the same flow channels and gas would tend to occupy the center of the pore spaces. Some gas molecules were trapped and isolated by the mobile liquids, and there were interferences between water and gas, and oil and gas. As a result, the three-phase relative permeabilities to gas depended on all the saturations, and the isoperms of gas were convex towards 100% gas saturation point. As a non-wetting phase, gas had been trapped by advancing water and oil during IID. With water and oil saturations increased, more gas changed into discontinuous phase, and the gas relative permeabilities would decrease accordingly. However, gas was a continuous phase in DDI, and the gas relative permeabilities were fairly high because little gas was trapped. They depended more on the gas saturation. Therefore, comparing with IID, the curvature of the gas isoperms in DDI was larger and the positions of them with the same value were further away from 100% gas saturation point.

The variation of oil relative permeabilities was complex. In DDI, there were two occurrences of oil in the initial state without gas: continuous mobile oil and immobile oil trapped by water. When water saturation decreased as gas saturation increased, the intermediate phase, oil, moved to smaller pores due to the difference in its wettability against water and gas phases. It resulted in decreased oil relative permeabilities. At the same time, gas displaced water which had trapped oil and mobilized the trapped oil and improved the oil relative permeabilities. When more gas was injected, there was not much mobile oil left, and oil phase was almost discontinuous. As a result, the oil relative permeabilities decreased dramatically. The above discussion shows that the oil relative permeability depends on the saturation of the other two phases and the oil isoperms were concave towards 100% oil saturation point. In IID, oil was the wetting phase against gas, and it would trap some gas in the pores which were originally occupied by gas. It would bring Jamin effect to block oil flow. In addition, water would also trap some oil leading to the decrease of the oil relative permeabilities. As a result, the oil relative permeabilities depended on all the saturations in IID. The isoperms of oil were concave towards 100% oil saturation point, although the positions of them with the same value were closer to 100% oil saturation point compared with DDI.

Three-Phase Relative Permeabilities of Oil-Wet Core

The isoperms of water, oil and gas for oil-wet core SX2 were plotted in Figure 3. It clearly showed that three-phase permeabilities of water-wet core were quite different from those of oil-wet core. For oil-wet core, oil is the wetting phase, while water is the intermediate phase. Initial water occupied small pores and surrounded by oil, and it existed as discontinuous drops which would increase the flow resistance of oil. The oil relative permeabilities would change with the flow resistance when water and gas saturations were different. As a result, the oil relative permeabilities depend on all the saturations, and the isoperms of oil were convex towards 100% oil saturation point. In addition, oil was the wetting phase which would not be trapped by water or gas, so the isoperms of oil were slightly affected by the saturation histories.

The variation of water relative permeabilities in oil-wet core was similar to oil relative permeabilities in water-wet core. They mainly depend on two factors: distribution of water in the pore, and the amount of water trapped by oil. The former was governed by three-phase saturations and the latter by the saturation histories. It should be noticed that the initial state was simulated water (non-wetting phase) flooding oil (wetting phase), with small amount of discontinuous water drops. As a result, the increase of the water relative permeabilities by gas displacing trapped water was small. The isoperms of water in both saturation histories were convex towards 100% water saturation point, while the positions of them with the same value in IID were closer to 100% water saturation point comparing with DDI.

For gas, it was always non-wetting phase, whatever in water-wet or oil-wet core. As per the explanations for water-wet core, the isoperms of gas in both saturation histories were convex towards 100% gas saturation point. However, due to the different trapping gas capabilities of water and oil, the flow resistances would also be different. It resulted in the slight difference of the gas isoperms curvature.

CONCLUSIONS

Three-phase relative permeabilities of water-wet and oil-wet outcrops with DDI and IID saturation histories were investigated. The experimental results showed there was significant effect of wettability on three-phase permeabilities. For water-wet cores, the isoperms of water were straight lines, the isoperms of oil were concave towards 100% oil saturation point, and the isoperms of gas were convex towards 100% gas saturation point. For oil-wet cores, all the isoperms of water, oil and gas were convex towards 100 % of its saturation. In addition, the isoperms of wetting phase were similar for the two saturation histories, while those of non-wetting phase were quite different. Although the shapes of the isoperms were the same, the corresponding values and the positions were different.

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Table 1. Petrophysical Parameters of Core Samples

Sample No.	Porosity,%	K_{air},mD	Length,cm	Area,cm^2	I_{A-H}	Wettability	S_{wi},%	S_{or},%
SX1	15.0	654	18.54	5.11	0.65	Water-Wet	27.3	20.2
SX2	15.1	714	18.70	5.19	-0.23	Weak Oil-Wet	33.5	26.4

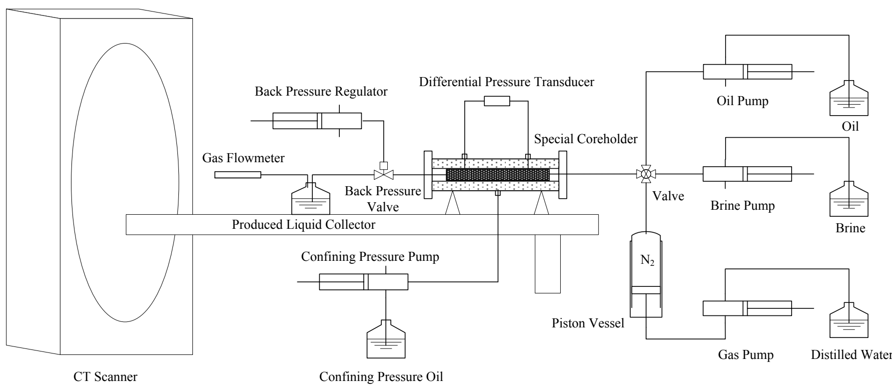

Figure 1. Experimental Schematic

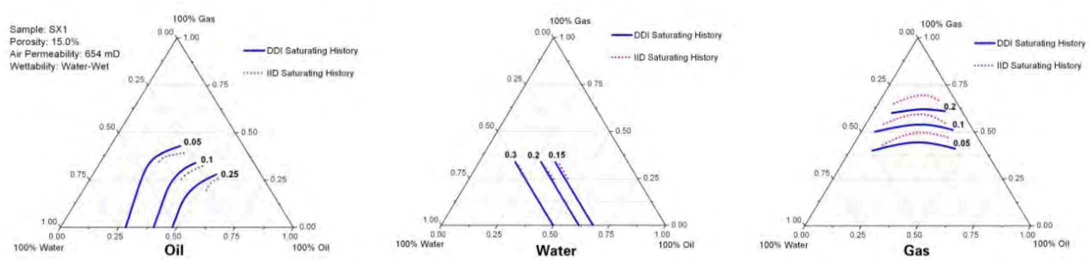

Figure 2. Isoperms of Water, Oil and Gas for Water-Wet Core SX1

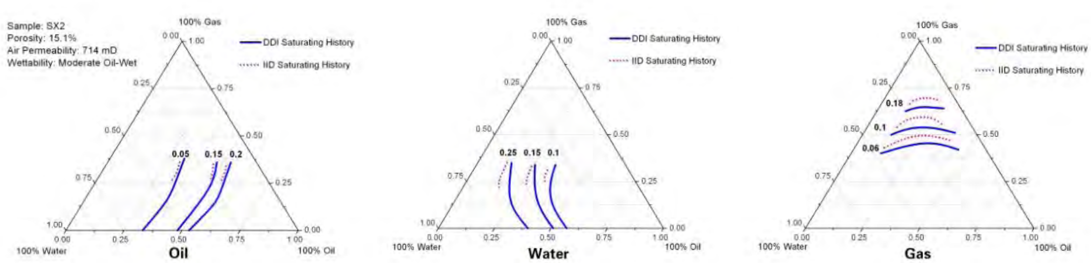

Figure 3. Isoperms of Water, Oil and Gas for Oil-Wet Core SX2