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ORIGINAL PAPER - PRODUCTION ENGINEERING

An improved method to study CO_2–oil relative permeability under miscible conditions

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Abstract Relative permeability curves are crucial parameters for reservoir engineer and reservoir commercial simulator to predict reservoir performance throughout the life of a reservoir, but meet difficulties in laboratory to obtain reliable data under miscible conditions due to the lack of proper testing and formulation methods. Up to now, most relative permeability curves are measured in short core segments by core flooding, which can hardly display miscible flooding features for early gas breakthrough and insufficient contacting time between CO_2 and oil. In addition, the commonly used analytical and semi-analytical data processing methods are not suitable for miscible flooding for ignoring the mechanism of vaporizing and dissolving mechanism. In this study, slim tubes (101 and 1,528 cm in length) and long composite cores (74.46 cm in length) instead of conventional core segments were used to acquire reliable experimental data of CO_2 flooding under miscible or near miscible condition. Then, using improved empirical Corey model which assumes shape defining factor b_{og} is a function of displacement pressure P combined with history-matching method to calculate relative permeability curves under near miscible and miscible conditions. Results indicated core length is another important parameter to simulate miscible flooding other than pressure, temperature and oil composition, and using long composite cores and improved data processing method more reliable data can be obtained compared with conventional measured method. It is found residual oil saturation in short slim tube is 16.25 % higher than that of long slim tube and CO_2 relative permeability is lower in short slim tube/core segment than in long slime tube/long composite cores.

Keywords Long core flow tests · Miscible conditions · Relative permeability · Improved method

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Introduction

CO_2 EOR is the first option to implement CO_2 geological sequestration because of the additional economic benefit, existing infrastructure and knowledge of petroleum engineering and operations (Holt et al. 2000). Experimental studies showed that oil recovery factor after CO_2 injection improved up to 60 % of original oil in place while this value was only 44 % for water flooding (Hadlow 1992; Taber et al. 1997). The increase in oil recovery is mainly due to swelling of crude oil by CO_2, which help to reduce interfacial tension and crude oil's viscosity. By approaching the miscible conditions, these changes can be introduced in relative permeability curves in multi-contact miscible displacement (Al-Wahaibi et al. 2005, 2006). Unfortunately, most of the recent relative permeability data under miscible or near miscible conditions can not be directly used in commercially available compositional simulators due to the uncertainty of measurement and lack of proper formulation (Prieditis and Brugman 1993; Dria et al. 1993).

Firstly, there is no proper way of measuring CO_2–oil relative permeability curves under miscible condition due to the slow development of dynamic miscibility. In CO_2

miscible flooding process, miscible displacement between oil and CO_2 is caused by the extraction of light and intermedium hydrocarbons into CO_2 and dissolution of CO_2 into oil (Okuno and Xu 2013; Wang and Pope 2001). CO_2 and oil are not miscible with each other during their first contact but will become miscible at CO_2 front gradually after multiple contact process. Component mass transfer between the CO_2 phase and the oil phase will generate a miscible zone, and distances are required for the development of dynamic miscibility (Shtepani 2007). It is concluded by some researchers (Omole and Osoba 1989; Ekundayo and Ghedan 2013) that core lengths in range of 0.5 to 6 m might well be below the minimum length required for the development of dynamic miscibility. Therefore, for better performance and accuracy of recovery process under miscible flooding, it is recommended to measure relative permeability curves with long composite cores. Unfortunately, most current relative permeability curves were obtained in conventional core segments which can hardly simulate real miscible flooding process (Shtepani 2007; Prieditis and Brugman 1993; Ren et al. 2011). In general, conventional core segments are 3 to 7 cm in length, and short core segment frequently led to early CO_2 breakthrough and inadequate time for vaporizing before it enriched enough to get miscible with reservoir oil (Ekundayo and Ghedan 2013). Therefore, direct application of relative permeability curves generated from conventional core segments may induce significant errors in predicting reservoir performance in miscible condition.

Furthermore, improper interpretation of laboratory experimental data may also add further errors to reservoir simulation. In principle, three major approaches—analytical methods, semi-analytical methods and history-matching methods can be used to determine two-phase relative permeability from unsteady state displacement experiments (Hussain and Cinar 2010). However, analytical methods and semi-analytical methods failed to represent miscible flooding relative permeability for their ignorance of capillary pressure effects and vaporizing mechanism (Gu and Oliver 2005). History-matching methods iterate the laboratory core flooding pressure and production data by changing the relative permeability values. Unlike analytical and semi-analytical methods pointed defects can be removed easily. This possibility encourages us to use this inverse modeling technique to calculate CO_2 flooding relative permeability curves under near miscible and miscible conditions (Watson et al. 1984; Reynolds et al. 2004; Eydinov et al. 2007). However, most current relative permeability representation models have nothing to do with injection pressure or interfacial tension (IFT) which is crucial scaling factor for miscible displacements.

To provide representative laboratory measured relative permeability data for reservoir simulators, this paper discusses how to obtain more reliable data of CO_2 miscible flooding in laboratory and how these data could be used in an improved empirical Corey model which incorporates injection pressure as a scaling factor.

Experimental studies

Four sets of relative permeability experiments were conducted to obtain reliable data for CO_2 flooding. Since distances are required for the development of dynamic miscibility and existence difficulties to conduct a long real core flooding due to low permeability, long experiment time and severe sleeve corrosion, two experiments were conducted in slim tubes to study the effect of core length on miscible process and displacement efficiency. Then based on natural cores and reservoir fluid of Jilin oil field, long composite core and short core segument experiments of CO_2 flooding were preformed above MMP in the presence of irreducible water saturation to study CO_2–oil relative permeability in natural cores.

Materials

The experimental design adopts unsteady state procedure under reservoir temperature and reservoir pressure in which effluent production from the core sample was recorded by liquid meter and gasometer. The injected fluid CO_2 with purity of 99.95 % and its physical properties have been calculated with PVTi simulator. The crude oil used in the experiments is recombined according to GOR of the stock-tank oil and gas from the ground separator of a well in Block H79 of Jilin oil field. The reservoir description and fluid properties are exhibited in Tables 1 and 2.

The effect of core length experiments was conducted in slim tubes of different lengths. The slim tube used in this study was made of Hastelloy C tubing. The coiled tubing was packed with 120 mesh sand and mounted horizontally inside an air bath to alleviate the influence of gravity. The physical properties of the two slim tubes are shown in Table 3.

The long real core flooding experiments were performed on the low-permeable natural core samples from Block H79 in Jilin oil field. Ten natural cores were selected and ordered according to the length and permeability based on Bradley's law. End effect was eliminated by adding filter paper between the natural cores. The total length of core group is 74.45 cm, and the average porosity and permeability are 15.28 % and 6.06×10^{-3} μm^3, respectively. The parameters for the cores utilized in the tests are shown in Table 4.

Table 1 Block Hei-79 reservoir descriptions and its fluid properties

Average reservoir burial depth (m)	2,400
Gross sand layers (m)	Range from 11.2 to 18.2 m
Average porosity (%)	12.7
Average permeability (10^{-3} μm^2)	3.5
Reservoir temperature (°C)	98.9
Original reservoir pressure (MPa)	24.15
Oil viscosity at the reservoir condition (mPa s)	Vary from 1.85 to 2.18 mPa s
Oil density at the reservoir condition (kg/m^3)	761.5
Averaged formation water salinity (mg/l)	14,607

Table 2 Live oil properties and oil compositions

Density (kg/cm^3)	Viscosity (mPa s)	Saturation pressure (MPa)		GOR (m^3/m^3)		
(a) Live oil properties						
761.5	1.85	7.1		30		
Components	C1	C2	C3	C4–C7	C8–C20	C20+
(b) Live oil compositions						
Mol fraction (%)	25.353	3.818	1.670	6.040	38.087	25.096

Table 3 Properties of the slim tubes

Slim tubes	Length (cm)	Diameter (mm)	Porosity (%)	Permeability (10^{-3} μm^2)
No. 1	1,528	4	31.4	5
No. 2	101	4.4	34.17	7

Table 4 Properties of the cores used in long core experiment

Order	No	Diameter (cm)	Length (cm)	Porosity (%)	Permeability (10^{-3} μm^2)
1	H-1	2.5	8.422	11.43	6.10
2	H-60-2	2.5	8.104	12.06	5.63
3	H-35	2.5	8.066	13.77	6.95
4	H-24-3	2.5	7.64	18.29	4.60
5	H-34-3	2.5	7.87	13.32	7.80
6	H-60-1	2.5	5.984	23.58	4.51
7	H-10	2.5	6.386	19.06	8.72
8	H-8	2.5	8.05	12.47	4.01
9	H-60-5	2.5	7.32	17.23	8.746
10	H-26-2	2.5	6.61	14.95	9.33
Total length	74.46	Average porosity	15.28	Average permeability	6.06

Apparatus and experimental procedure

The unsteady displacement experiments are performed in CFS-200 core flooding system, which consists of an injection system, four piston accumulators, a TEMCO BP-100 back pressure regulator, a long core holder/slim tubes, a confining pressure system, three differential pressure measurement system, an oil–gas separator, a gasometer and computer system for data acquisition and process control. Figure 1 provides a schematic illustration of the experimental apparatus used to measure relative permeability curves.

Lead is used as a sleeve material to avoid the diffusion and penetration of CO_2 through the rubber core sleeves. The ductility of lead sleeve allowed a confining external overburden pressure to be transferred to the core in a radial mode to simulate reservoir overburden pressure. The steel core holder can simulate reservoir confining pressures of up to 50 MPa. This pressure is applied by filling the annular space between the core sleeve and the core holder with non-damaging saline brine. Test fluids were stored in titanium accumulators that were connected to a variable-rate injection pump. The CO_2 cells were kept outside the oven with a temperature-controlled air bath for safety reasons. However, the injected CO_2 was initially passed through stainless steel coils to heat up to reservoir temperature before it entered the core sample. The simulated reservoir temperature was regulated by a high-quality thermocouple. Pressure readings across the core sample were instantly recorded by high-precision pressure transducers that were digitally synchronized to a laboratory PC.

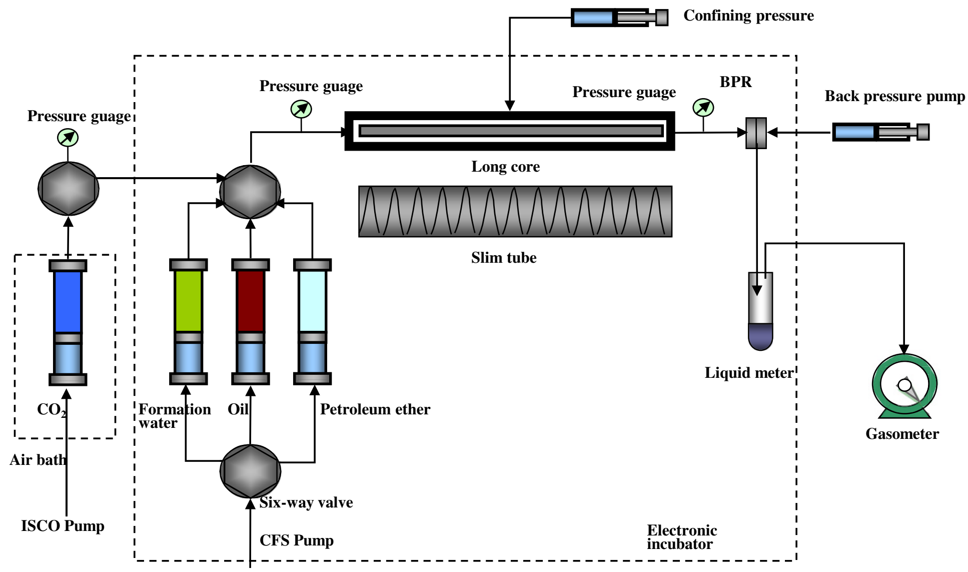
The experiments were performed as follows: (1) clean the core or slim tube with solvent, dry with hot nitrogen and evacuate, and then saturate the core with the formation water. (2) Assemble the cores in long core holder and upload confining pressure and back pressure, generally confining pressure is 2–3 MPa higher than back pressure, heat the thermostatic oven to reservoir temperature at 98.9 °C and keep it constant. (3) Saturate the core or slim tube with live oil, measure the oil-phase permeability. (4) Inject CO_2 at a setting constant rate of 0.2 cc/min; record the injection volume, pressure, instantaneous oil and gas production data dynamically.

Mathematical model

End effect elimination

The construction of long cores caused strong interface between core segments when capillary contact was not maintained between contiguous segments, which led to strong effect on the saturation distributions. One of the

Fig. 1 The schematic diagram of core flood laboratory



effective ways to decrease the end effect caused by capillary pressure is to put a filter paper between the core segments, the other is increase the flow rate or differential pressure. Rapoport formula shown in Eq. 1 is used to determine the displacement pressure to eliminate end effect. It can be calculated from interfacial tension σ, permeability k and porosity ϕ as shown in Eq. 1.

$$\frac{\sigma \times 10^{-3}}{\Delta p\sqrt{k/\phi}} \leq 0.6 \tag{1}$$

Fluid volume calibration

The gas production volume was measured at ambient temperature and pressure, which contains not only produced CO_2 but also light hydrocarbons escaped from oil, therefore, the instantaneous gas production needs to be calibrated to get the gas production volume under experimental pressure and temperature. According to GOR and the EOS for real gas, the CO_2 production can be calculated using Eq. 2

$$V_{gi} = V_{gi-1} + \frac{2Z_i P_a T}{(P_{i1} + P_{i2} + 2P_a)\cdot(\Delta V_{gi} - \mathrm{GOR}\cdot\Delta V_{oi})T_a} \tag{2}$$

where V_{gi-1} and V_{gi} are accumulated gas production at time $i-1$ and i; $\mathit{\Delta} V_{oi}$ is accumulated oil production at time i; P_{i1} and P_{i2} are inlet and outlet pressures of the core holder; P_a and T_a are ambient pressure and temperature; T is experimental temperature, Z_i is CO_2 compressibility factor at temperature T and average pressure $\frac{P_{i1}+P_{i2}}{2}$; and GOR is gas–oil ratio.

In addition, oil production was measured at ambient temperature and pressure with no dissolved gas, which should be calibrated according to oil volume factor at testing temperature P and testing pressure T. As shown in Eq. 3.

$$V_{oi} = V_{oi-1} + B_o \cdot \Delta V_{oi} \tag{3}$$

Methods to obtain relative permeability for CO_2 miscible flooding

After more reliable experimental data have gained, we need proper interpretation method to get representative relative permeability curves. In general, there are two types of components to determine relative permeability curves: endpoints and shape factors (Eydinov et al. 2007). Endpoints could be measured directly by core flooding, while shape factors are depending on the fluid/fluid interactions and usually obtained by empiric. Up to now, the proper formulation of relative permeability curves under miscible flooding is mostly based on empirical Corey model (Lee and Seinfeld 1987; Yang and Watson 1991). Therefore, in this paper, Corey model combined with history-matching method is used in this paper to obtain CO_2–oil relative permeability curves.

For the oil/gas system:

$$k_{rg} = a_g\left(\frac{S_g - S_{gc}}{1 - S_{org} - S_{wc} - S_{gc}}\right)^{b_g} \tag{4}$$

$$k_{rog} = a_{og}\left(\frac{1 - S_{org} - S_{wc} - S_g}{1 - S_{org} - S_{wc} - S_{gc}}\right)^{b_{og}} \tag{5}$$

where k_{rg} and k_{rog} are relative permeability of gas and oil phase, respectively; a_g and a_{og} are gas relative permeability at $S_g = 1 - S_{org} - S_{wc}$ and the oil relative permeability at $S_g = S_{gc}$, respectively; S_g is gas saturation; S_{org} is residual oil saturation; b_g and b_{og} are exponential factors.

Every parameter in Corey model can be obtained directly by laboratory measurements except b_g and b_{og}, they are exponential factors defining shapes of relative permeability curves. It is confirmed that phase transition has no concern with gas relative permeability, thus b_g is a constant parameter with empirical value of 3.5. To get the value of b_{og}, interfacial tension is usually used as scaling factor to estimate the miscible flooding performance (Shtepani 2007). However, high-temperature and high-pressure interfacial tension test could be very costly, while this value calculated from PVT modeling needs high quality of laboratory PVT data and procedure (Ren et al. 2011). Since interfacial tension is a function of temperature, pressure and composition of target reservoir oil. For a specific oil reservoir, reservoir temperature and oil composition are considered to be constant, then interfacial tension between CO_2 and oil only depends on reservoir pressure. Thus, we could use pressure as a scaling factor to estimate the miscible flooding performance. Generally, b_{og} equals to 1 represents miscible flooding and 3 represents immiscible flooding, suppose the exponential factor b_{og} is between 1 and 3 (Li et al. 2012), and according to linear interpolation function, exponential factor b_{og} can be written as follows:

$$b_{og} = \begin{cases} 1 & P \geq P_{mmp} \\ \frac{2P + P_{nm} - 3P_{mmp}}{P_{nm} - P_{mmp}} & P_{nm} < P < P_{mmp} \\ 3 & P < P_{nm} \end{cases} \tag{6}$$

where P_{mmp} is minimum miscibility pressure, P_{nm} is critical immiscible pressure. Critical immiscible pressure means the maximum pressure for an immiscible flooding and can be determined by IFT. It is proved when injected gas and oil interfacial tension is higher than 7 dyne/cm, gas injection can be considered to immiscible flooding (Guo et al. 2000; Ren et al. 2011).

Results and discussion

Determination of MMP and IFT

Laboratory slim tube experiments and field experience have shown that oil recovery of CO_2 flooding depends on pressure, the higher the reservoir pressure the greater the oil recovery because dynamic miscibility condition is more likely to be obtained. The miscibility between CO_2 and oil decreases interfacial tension and capillary forces, which could help recover essentially all of the remaining oil in theory. MMP is used to define as the threshold pressure to achieve miscibility in situ between injected gas and reservoir oil. To measure MMP in laboratory, grain-packed coil of considerably large length and relatively small diameter is recommended as it helps to avoid unfavorable effects of fingering, transition zone length and transverse compositional variations (Elsharkawy et al. 1992; Randall and Bennion 1988). A 1,528-cm length and 4-mm diameter slim tube, Jilin recombined oil and pure CO_2 are used to determine MMP of the aimed field; the ultimate oil recovery was obtained after 1.2 hydrocarbon pore volume (HCPV) injection in different pressure steps. The plot of oil recovery versus pressure is shown in Fig. 2. The point in which the trend of recovery plot has been changed sharply is MMP which is 22.8 MPa in this case, indicating CO_2 injection can achieve miscible flooding at initial reservoir pressure in theory.

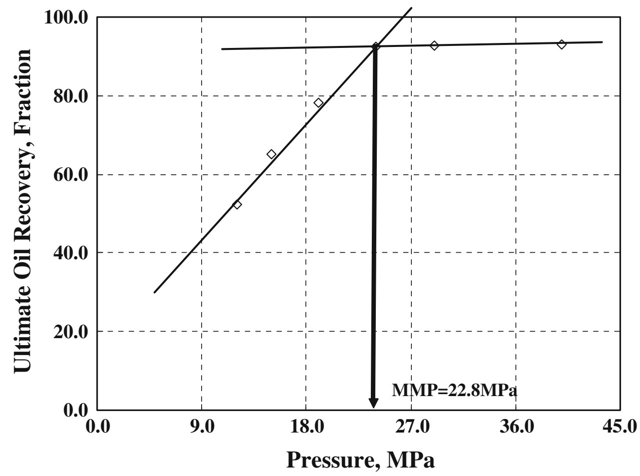


Fig. 2 Oil recovery versus pressure in slime tube test

Table 5 showed the measured interfacial tension between CO_2 and crude oil under different pressures. It was measured with DSA100 contact angle meter at reservoir temperature. As can be seen from Table 5, at testing pressure of 9 MPa, IFT is 7.35 mN/m and demonstrated Pnm of this system is about 9 MPa. Thus, when injection pressure is lower than 9 MPa, CO_2 flooding is under immiscible state. When pressure increases from 19 MPa to MMP, IFT decreases sharply from 1.54 to 0.12 mN/m which demonstrated the miscibility between CO_2 and oil. When pressure varies from Pnm to P_{mmp}, IFT is approximately a linear function of pressure. When pressure is higher than MMP, because of the miscibility of CO_2 and oil, the contacting surface disappears, and IFT is nearly 0.

The effects of core length to oil recovery

Figure 3 is oil recovery in slim tubes under the same back pressure 24.5 MPa. As can be seen, oil recovery variation curves are quite different in the two slim tubes. In short slim tube with length of 101 cm, gas breakthrough early at 0.82 PV, then oil recovery increases slightly and ultimate oil recovery is 74.20 % at 1.2 PV. In long slim tube with length of 1,528 cm, gas breakthrough later at 0.92 PV and

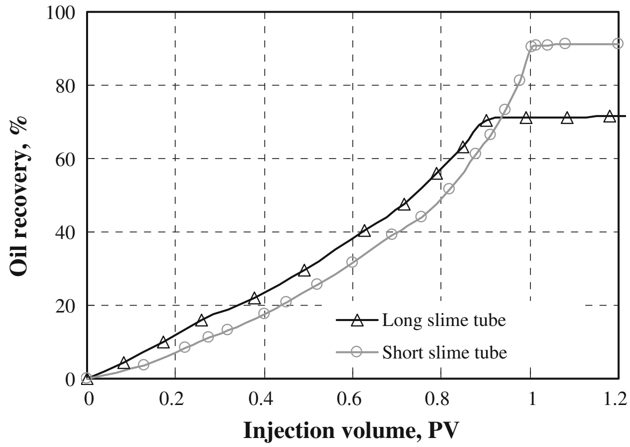


Fig. 3 Oil recovery versus injection volume in long and short slim tube tests

Table 5 IFT between CO_2 and oil at different pressures

Pressure (MPa)	IFT between CO_2 and oil (mN/m)
9	7.35
12	5.86
15	3.67
19	1.54
24	0.12
29	0.006
40	0

ultimate oil recovery is 90.45 % at 1.2 PV. In addition, the maximum pressure differential in long slim tube is 3.35 MPa, while it is 2.53 MPa in short slim tube. The higher pressure differential is caused by CO_2 compression, which supplies opportunity of extraction of light and medium hydrocarbons from oil and dissolution of CO_2 into the oil. In short slim tube flooding, although the injection is done above MMP, dynamic miscibility seems not to be achieved due to early gas breakthrough, insufficient contact time and unfavorable IFT (Table 5).

The effects of core length on relative permeability curves in slim tubes

With experimental data of endpoints, calculated shape factor b_{og} and empirical shape factor b_g, the initial guess of CO_2–oil relative permeability curves was measured, then using history-matching method we reversed the curves by matching production data. The final results of CO_2–oil relative permeability curves are shown in Fig. 4. As can be seen in Fig. 4, CO_2–oil relative permeability curves in long slim tube are nearly two intersecting straight lines, and endpoint of gas relative permeability at residual oil saturation is 1. However, these features in short slim tube are different: (1) oil-phase relative permeability decreases faster and gas phase relative permeability increases slower with gas saturation, (2) crossing point is lower and endpoint of oil relative permeability at residual oil saturation is 0.473, (3) residual oil saturation is 16.25 % higher.

It seems that CO_2 flooding in short slim tube is not under miscible flooding but near miscible flooding although the pressure is higher than MMP. With CO_2 injected into pores, CO_2 contacted and dissolved into the oil while extracting light hydrocarbons into CO_2, in this way CO_2 got enriched. The enriched CO_2 gathered at the leading edge of displacement, however due to the insufficient length of core, CO_2 breakthrough early from production well and generated a communication path before it enriched enough to achieve fully miscible flooding. Inadequate time of extracting and vaporizing light and medium hydrocarbons caused low rate of mass transfer. Consequently, oil recovery, endpoints and oil-phase relative permeability are affected.

Length determination of long composite cores

Trapping and mobilization of fluids in a porous medium can be described by complex interactions between viscous, gravity and capillary forces in a complex way. Slim tube test has merit of simulating miscible process via extremely long contacting distance, but fails to simulate natural core structure and wettability. Besides, slim tube test is often conducted without irreducible water saturation. But the presence of irreducible water would expect to reduce oil recovery and affect endpoints by increasing capillary force and decreasing flow channels. Therefore, natural core is recommended.

However, implementing CO_2 miscible flooding process in several meters long composite cores under HTHP is very difficult. At first, the core was designed to 200 cm in length, but the extremely high injection pressure and severe corrosion problem made the attempt a failure. After several times testing experiment, the core length was decided to 74 cm which is still ten times longer than conventional core segments. Although the length of the core may not be long enough to develop dynamic miscible flooding, it is a great improvement over the conventional core segments.

The effects of core length on relative permeability curves in natural cores

CO_2 flooding was then conducted in natural cores with lengths of 74 and 7.2 cm to study the effects of core length on relative permeability curves in real cores. The experimental conditions and data processing method used are the same as in slim tube. Figure 4 shows the history-matching

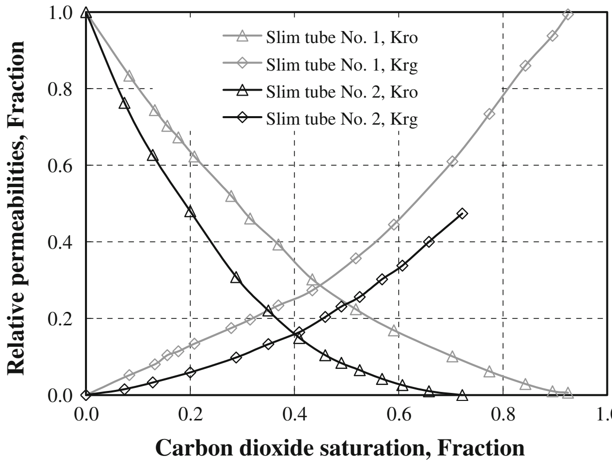


Fig. 4 Relative permeability curves in long and short slim tube tests

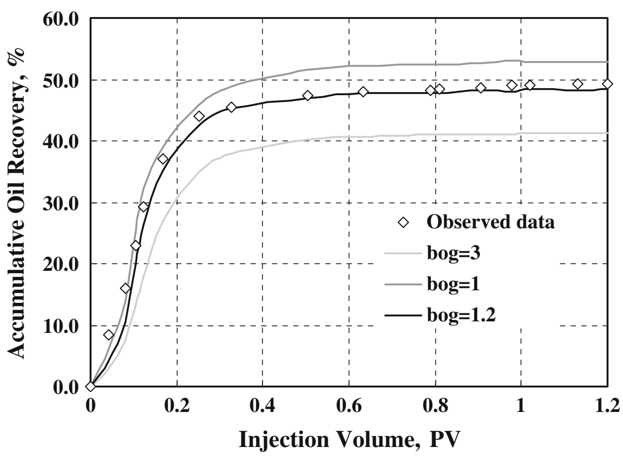


Fig. 5 History-matching production data with different b_{og} at back pressure 24.5 MPa in core test

data at long core test with different b_{og} values using Eqs. 4–6. As can be seen from Fig. 4, the calculated data fits well with reference production history at b_{og} equals to 1.2 which indicated CO_2 did not develop into full miscible flooding in 74-cm length natural cores. This is consistent with the results in slim tubes. In addition, it can be found in Fig. 4, oil recovery is affected by relative permeability shape factors and deviation of simulated oil recovery was occurred at the middle and late stage of core flooding.

Figure 5 provides the CO_2–oil relative permeability curves in long composite cores and short core segment. As can be seen from the figure, both CO_2–oil relative permeability curves in long and short real cores are not two interacting lines and endpoints of CO_2 relative permeability are not equal to 1. In addition, relative permeability endpoints are different. $K_{rg}(S_{org})$ is 0.431 in long composite cores, while this value is 0.249 in short core segment, and S_{org} is 0.275 in long composite cores, while this value is 0.333 in short core segments (Fig. 6).

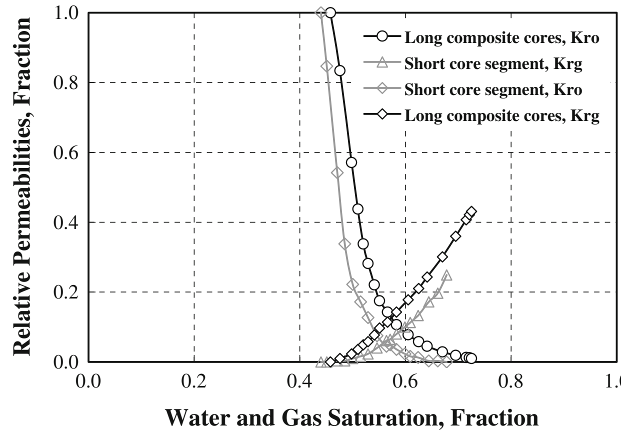


Fig. 6 Relative permeability curves in long and short real cores

Obviously, with new data processing method and long composite cores, the relative permeability curves for CO_2 flooding obtained in this paper are more reliable. Firstly, combined with improved Corey model and history-matching method effects of capillary pressure and vaporizing mechanism can be incorporated in relative permeability curves. Secondly, short core segment failed to simulate mass transfer mechanism due to early gas breakthrough and more oil remained in pores. Thirdly, longer contacting time between CO_2 and oil strengthens the vaporizing and dissolution mechanism which helps to decrease oil viscosity and IFT. However, it is should be noticed, long composite cores and new data processing method in this paper improved CO_2–oil relative permeability curves obtained in laboratory, but it is still failed to simulate the fully miscible flooding in natural cores.

Conclusions

Slim tubes and natural cores in different lengths were used to simulate strong extraction and vaporization mechanism between CO_2 and oil during the CO_2 injection process above the MMP. This is to provide reliable basic data for CO_2–oil relative permeability data process under miscibility condition. Then a new method launched to yield relative permeability for miscible flooding which considered the shape factor b_{og} as a function of pressure as a first guess and then inverted the final relative permeability curves by history-matching method.

1. Experimental results demonstrated that the early gas breakthrough and inadequate contacting time in conventional core segment led to weak mass transfer and phase transition between CO_2 and oil, and this is reason why current relative permeability curves failed to predict miscible flooding performance. Therefore,

long composite core is recommended to implement CO_2 and oil relative permeability under miscible or near miscible flooding.

2. By considering shape factor b_{og} as a function of displacement pressure, CO_2 flooding relative permeability could be determined under different degrees of miscible conditions via classic Corey model. However, due to the insufficient core length and influence of irreducible water, relative permeability curves should be corrected by history-matching method by matching measured production data.
3. The CO_2–oil relative permeability curves obtained in slim tubes and natural core in different core lengths showed core length is another important factor to achieve miscible flooding other than pressure, temperature and oil composition. Both CO_2–oil relative permeability curves in 101-cm length slim tube and 74-cm length long composite cores depicted near miscible flooding features, while CO_2–oil relative permeability curves in 1,528-cm length slim tube depicted miscible flooding features in CO_2 flooding test above MMP.
4. Although CO_2–oil relative permeability curves obtained in long composite core failed to simulate fully miscible condition, it is more reliable than that of short core segment. It is showed CO_2 and oil-phase relative permeability increased and residual oil saturation decreased in long composite cores due to stronger vaporizing and dissolution mechanism and lower capillary force.

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