Changing characteristics of ultralow permeability reservoirs during waterflooding operations

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Abstract: The characteristics of ultralow permeability reservoirs changed after waterflooding. Thin-section analysis and scanning electron microscopy (SEM) of core samples from inspection wells indicated that calcite and barite were formed in ultralow permeability reservoirs during waterflooding operations. Some asphaltene precipitates on the surface of formation rock would influence the reservoir porosity, permeability, wettability, and electrical properties. In this paper, the changes of physical, electrical, and fluid properties of ultralow permeability reservoirs during waterflooding operations were analyzed. This provides important information to improve waterflooding performance in ultralow permeability reservoirs.

Key words: Ultralow permeability, waterflooding, reservoir change, waterflooding characteristics

1 Introduction

Low-permeability reservoirs in the Changqing Oilfield are characterized by low pressure coefficient and low natural drive energy. Water is required to be injected into the formation to provide sufficient drive energy to displace the crude oil and then enhance the ultimate recovery. The injection water, mainly taken from the Luohe Formation, has low salinity and is of the sodium-sulfate type. However, the formation water in the Chang 6 reservoir is of the calcium-chloride type, incompatible with the injection water, so scale is formed in the reservoir during waterflooding operations. This results in changes in the petrophysical properties of the reservoir, such as porosity and permeability. Many studies have focused on changes of petrophysical properties of medium to high permeability reservoirs during waterflooding operations (Yue, 1999; Zhang et al, 2000). Most research revealed that reservoir porosity and permeability increased and heterogeneity weakened to some degree after waterflooding (Wu, 2006; Huang et al, 2000). A few scholars have studied the effect of the water injection process on the petrophysical properties of low-permeability reservoirs (Abbasi et al, 2012; Wang et al, 2011; Xu et al, 2012). Several researchers thought that after waterflooding the reservoir porosity and permeability decreased due to grain migration and clay swelling induced by injection water in low-permeability reservoirs (Al-Muhaidib et al, 2012; Ghafoori et al, 2012). Based on the data from 9 inspection wells and the analysis of scaling origin, new minerals of

calcite and barite are shown to be formed in the process of water injection. Through analyzing the relationship of calcite and barite generated during waterflooding operations, the characteristics of low permeability reservoirs during waterflooding operations is further revealed.

2 Experimental

The contents of anions and cations in water were determined by ion chromatography and inductively coupled plasma-atomic emission spectrometry. Morphology and composition of minerals in core samples were identified with Leica 4500P polarizing microscope and Quant 400 scanning electron microscope. Porosity and permeability were measured with a CMS-300 core measurement system (American Core Laboratories).

3 General geology and inspection well design of reservoir

The Chang 6 Formation is one of main producing formations in the Changqing Oilfield. This reservoir consists of low-permeability, sandstone, with a permeability of 1.0×10^{-3} – $3.0 \times 10^{-3} \mu\text{m}^2$ and a porosity of 11%–15%. Its pressure coefficient is low (0.7). It is a well-sorted and fine-grained feldspar sandstone, with a high textural maturity and low mineralogical maturity. Most of the minerals have high sensitivity to acid, but low sensitivity to water. The cement content is about 10% mostly calcite, hydromica, chlorite and the zeolite laumontite.

The formation water of the study area is closed primary water, with a salinity of about 100 g/L. The water is of the calcium-chloride type. The injection water is of the sodium-

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Received March 22, 2012

sulfate type, with a salinity of 0.5-0.9 g/L. In oil production, scaling often occurs in wellbores and ground gathering

systems (Lohne et al, 2006). Most scale occurring in the producing formation is gypsum or barite (CaCO_3 and BaSO_4).

Table 1 Components of injection water and formation water in the Ansai and Jing'an blocks

Block	Water	Composition, g/L								Salinity g/L	Water type	Scale type
		K^+Na^+	Ca^{2+}	Mg^{2+}	Ba^{2+}	Cl^-	SO_4^{2-}	CO_3^{2-}	HCO_3^-			
Jing'an block	Formation water	12.645	2.0497	0.549	0.433	57.482	0	0	0.158	91.8	CaCl_2	BaSO_4
	Injection water	0.127	0.039	0.064	—	0.048	0.210	0.019	0.391	0.9	Na_2SO_4	CaCO_3
Ansai block	Formation water	11.832	22.289	0.122	0.497	58.258	0	0	0.034	93	CaCl_2	CaCO_3
	Injection water	0.073	0.043	0.027	—	0.040	0.076	0.026	0.240	0.52	NaHCO_3	BaSO_4

In order to study the changes of reservoir and fluid characteristics, 9 inspection wells were drilled at different directions into the river channel in Jing'an and Ansai blocks. The analysis of core samples from these wells indicated that some clay minerals were washed out and carried a distance to pores and pore throats in the reservoir, but the components and proportion of clay minerals were not significantly changed (Table 2).

Table 2 Relative content of clay minerals before and after waterflooding

	Relative content, %			
	Illite	Illite/Smectite	Kaolinite	Chlorite
Before waterflooding	8.0	13.8	23.2	55.1
After waterflooding	6.7	9.9	24.3	59.1

4 Change of reservoir characteristics and their effect on waterflooding operations

4.1 Reservoir characteristics

Core data from the 9 inspection wells indicated that the water-flushed zone had a relatively high permeability in the vertical direction, but the unswept zone had a relatively low permeability. For instance, the reservoir thickness of well LJ75-61 in the Jing'an block was 23.6 m, the thickness of the flushed zone was 6.5 m (accounting for 27.5%), and the residual oil saturation was 52.2%. The water-flushed zone was only in the relatively high permeability zone (Al-Bahlani and Babadagli, 2012). Scanning electron microscope (SEM) images (Fig. 1) clearly showed the presence of a large number of newly formed calcite crystals in pores in the water-flushed zone (relatively high permeability zone). This indicated that new minerals were formed after long-time waterflooding in the low permeability reservoir.

Fig. 1 Calcite content contrast in well WJ16-152 in the Ansai block

The rock debris components of inspection wells were similar to those of the initial reservoir. The major components were quartz and feldspar, and most of the interstitial matter was chlorite. However, the carbonate content increased distinctly in some samples, and it was mainly calcareous cement, which reduced pore radius of the formation after

waterflooding, and finally caused reduction of reservoir porosity, as shown in Table 3.

4.2 Formation mechanism of new minerals

The formation water of the Triassic Chang 6 reservoir is closed primary water (Ma et al, 2012), with a salinity of

Table 3 Lithology and pore throat parameter of rock samples before and after waterflooding in the Jing'an block

		Zone	Interstitial matter component, %				Reservoir pore space			
			Quartz	Feldspar	Chlorite	Carbonate	Intergranular pores, %	Feldspar dissolution pores, %	Matrix dissolution pores, %	Average reservoir pore space, μm
Average values before waterflooding		C6 ₂	1.30	0.20	5.10	1.80	6.55	0.94	0.40	62.85
After waterflooding	LJ75-60	C6 ₂	2.07	1.01	6.23	7.02	4.61	0.42	0.27	30.00
	LJ75-61	C6 ₂	0.63	0.55	6.16	11.23	3.03	0.53	0.30	31.33

approximately 100 g/L. The formation water was of the calcium-chloride type, but the injection water was of the sodium-sulfate type, which is incompatible with the formation

water. This led to the formation of calcium carbonate and barium sulfate during waterflooding operations, as shown in Table 4.

Table 4 A comparison between formation water and injection water in the Chang 6 reservoir

Block	Zone	Properties of formation water				Properties of injection water				Scales	Amount of scales g/L
		Ca ²⁺ g/L	Ba ²⁺ g/L	Type	Total salinity, g/L	SO ₄ ²⁻ g/L	HCO ₃ ⁻ g/L	Type	Total salinity, g/L		
Ansi	C6	16.3	0.658	CaCl ₂	100.1	0.206	0.298	Na ₂ SO ₄	0.87	CaCO ₃ , BaSO ₄	283, 282
Jing'an	C6	4.77	1.94	CaCl ₂	99.8	0.497	0.167	Na ₂ SO ₄	1.92	BaSO ₄ , CaCO ₃	846, 262

4.2.1 Calcite newly-formed in waterflooding operations

Analyses of core slices and energy spectrum indicated that before waterflooding the main carbonate mineral was ferroan calcite ((Ca,Fe)CO₃), the total content of FeO was relatively high, and iron-free calcite (CaCO₃) was not found. After waterflooding, abundant newly formed calcite, besides primary ferroan calcite, was found, and the TFeO content reduced significantly. When observing dyed core slices, the color of dyed primary ferroan calcite was fuchsia, and the calcite formed during waterflooding operations was red, as shown in Figs. 2 and 3.

Fig. 2 Primary ferroan calcite filled in pore space in the core sample from well ZJ30

Observations of thin sections and SEM images of core samples showed coarse crystal aggregates of primary ferroan calcite in void spaces. The crystals were flake-shaped (Chen

Fig. 3 Calcite formed during waterflooding operations in well LJ75-61

et al, 2012; Amiri and Moghadasi, 2012; Amiri et al, 2012), and were imperfect, owing to long-time crystallization. However, for calcite crystal aggregates generated in waterflooding processes in a short time, they are fine-grained crystals with rhombohedral shape, and some prismatic calcite were also generated (Allen et al, 1968; Du et al, 2012; Izgec, 2012), so the crystals were well-formed, as shown in Figs. 4 and 5.

4.2.2 Barite formed during waterflooding operations

Barite generated before and after waterflooding had the similar crystal morphology as calcite (Zhu et al, 1995; Zhao et al, 2011), but primary barite grew more slowly over a long time. Owing to the limited growing space in the rock, the primary barite formed before waterflooding occurred

Fig. 4 Coarse crystal aggregates of primary ferroan calcite with xenomorphic and flake crystal shape (well ZJ7)

Fig. 5 Calcite formed during waterflooding operations (well WJ16-152)

as xenomorphic crystals, and usually appeared as coarse large aggregates. However, barite crystals formed during waterflooding operations were idiomorphic and usually appeared in tiny columnar aggregates after a short growing time, as shown in Figs. 6 and 7.

Fig. 6 Primary barite in pore space in well ZJ7

4.2.3 Asphaltene formed during waterflooding operations

In the process of waterflooding, heavy components in crude oil precipitated and some components in oil might be oxidized by the higher concentration of oxygen dissolved in the injection water (Milliken et al, 2012). As a result, the asphaltene precipitates formed would block the pores and pore throats and then change the reservoir wettability, as shown in Fig. 8.

Fig. 7 Barite formed during waterflooding operations in well LJ87-41

Fig. 8 Asphaltene precipitates generated during waterflooding operations in well LJ87-41 in the Jing'an block

5 Characteristics and origin of pore throats

Initial knowledge about the effect of waterflooding on ultra-low permeability reservoirs can be obtained by analyzing inspection well cores and described as follows:

1) Newly-formed minerals block up pores

Because the injection water was incompatible with the formation water, newly-formed minerals, such as calcite (Fig. 5) and barite (Fig. 7), and asphaltene precipitates (Fig. 8) would block up pores during waterflooding operations, so the reservoir porosity reduced.

2) Clay minerals swell and fill pores and pore throats

Clay minerals, such as illite, would swell due to injection water and infill pores and pore throats, causing a reduction in reservoir porosity (Fig. 9).

Fig. 9 Illite in pore space in well Wj16-151 in the Ansai block

3) Particles detached from rock plug up pores

In the production process, water flush causes chlorite particles to detach from the rock and plug up pores (Fig. 10).

The pore-throat size distribution (Fig. 11) shows that a lot of high capacity channels existed in the reservoir before waterflooding; but small pore-throats were developed after waterflooding, and pore-throat size was distinctly centralized around a certain value. Mercury intrusion curves of core samples from inspection wells indicate that because most large pores and throats were filled with newly-formed minerals, the pore throats in the reservoir became smaller and the small size of the pore throats results in high replacement pressure (Fig. 12). After water injection, the mercury intrusion curve of cores became more flat. This indicates the reservoir heterogeneity improved in some degree.

Fig. 10 Chlorite particles detached from rock plugged up pores in well LJ87-41 in the Jing'an block

Fig. 11 Distribution characteristics of throats before and after waterflooding in the Jing'an block

Fig. 12 Mercury intrusion curves before and after waterflooding in the Jing'an block

6 Change of reservoir electrical properties

The oil saturation calculated from logging the reservoir in immediate vicinity of the inspection wells was in accordance with that from the nuclear magnetic resonance method and pyrolytic analysis, but had a large difference from the saturation analyzed by conventional logging, so the saturation analyzed by conventional logging was unfit to interpret reservoir oil saturation at a high water-cut stage. Therefore, the parameters

in the Archie equation were re-determined through testing the electrical properties of core samples from inspection wells. The results indicated that the reservoir lithology index a and the saturation index n had great changes after waterflooding (a changed from 4.5 before waterflooding to 12.6 after waterflooding, and n changed from 1.6 to 3.5). The oil saturation interpreted by conventional logging was calibrated using the new parameters (a, n) and its value was near to the results obtained by other methods, as shown in Fig. 13.

Fig. 13 Oil saturation obtained by different methods

7 Change of percolation characteristics and its effect on waterflooding

7.1 Percolation characteristics after waterflooding

Reservoir permeability reduced because the pores and pore throats in the reservoir were blocked by newly-formed minerals, such as calcite and barite, during waterflooding operations. Compared with the permeability before waterflooding, the permeability in the WY block decreased by 17%–43% after waterflooding, with an average of 32%. More newly-formed calcite resulted in a more significant reduction in permeability. Barite had a similar effect on reservoir permeability as calcite, as shown in Figs. 14 and 15.

Relative permeability curves indicated that the oil relative permeability decreased more quickly after waterflooding, but the water relative permeability increased more quickly and the area of two-phase seepage became narrower.

Fig. 14 The effect of calcite formed during waterflooding operations on permeability

Fig. 15 Relative permeability curves before and after waterflooding in the WY block

7.2 Effect of the change of reservoir properties on waterflooding performance

Core analyses (from the inspection wells) indicated that the producing reserve in the vertical direction of the reservoir was unbalanced and the remaining oil was controlled by reservoir physical properties (Poynton et al, 2004). The water flooded layer had relatively high permeability and low

remaining oil saturation; but the unswept zone had relatively low permeability and high remaining oil saturation.

The reservoir thickness of well LJ75-60 was 22.6 m, and the thickness of the water-flushed zone of a relatively high permeability was 6.4 m (accounting for 28.7%). The vertical producing degree of well LJ75-60 was relatively low, as shown in Fig. 16.

Fig. 16 Vertical permeability in well LJ75-60

Low oil recovery from the low-permeability zone in the Chang 6 reservoir was due to strong heterogeneity and waterflooding affecting mainly in the high permeability zone (Sadooni, 2012). However, during waterflooding operations, some minerals would be formed in high permeability channels and these then reduced the reservoir porosity and permeability. This may reduce reservoir heterogeneity and improve oil recovery, especially enhancing oil recovery from relatively low permeability zones.

8 Conclusions

1) The water injected into the formation was incompatible with the formation water in the Chang 6 reservoir. The pores were blocked up easily by newly-formed minerals, such as calcite and barite, and grains broken off during waterflooding operations. Moreover, swelling of illite and other clay minerals triggered by injection water might also cause a reduction in reservoir porosity and permeability.

2) In a relatively high permeability zone, both porosity and permeability decreased because pores and pore throats were plugged by newly-formed calcite and barite, swollen clay minerals, and clay mineral grains broken off during water injection. Therefore, the injection pressure and the threshold pressure gradient increased and the reservoir heterogeneity was modified, so it is beneficial to recovering oil from relatively low permeability zones.

3) In view of decrease of porosity and permeability caused by new minerals, clay mineral swelling and asphaltene precipitates during waterflooding operations, some measures might be taken to reduce damage to reservoirs, such as using an appropriate surfactant, and so on.

4) Core analyses indicated the ultra-low permeability reservoirs were inhomogenous in the vertical direction,

waterflooding in this reservoir might be inefficient. Through analyzing the characteristics of ultralow permeability reservoirs during waterflooding operations, some methods could be proposed to enhance oil recovery.

Acknowledgements

The authors are grateful for the financial support from the major science and technology project of Petrochina (Key Technology Study of Stable Production and Enhanced Oil Recovery in the Changqing Oilfield. No. 2011E-1305).

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(Edited by Sun Yanhua)