Physical simulation of fluid flow and production performance in extra-low permeability porous media

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Abstract: For extra-low permeability reservoirs, with a permeability of about $0.3 \times 10^{-3} \mu\text{m}^2$, fluid flow and production performance in cores were studied. A long core holder with a multi-location piezometric measurement was specially designed. An artificial long core, about 700 mm long and with a cross section of $45\text{mm} \times 45\text{mm}$, was used. In the experiment, pressure distribution along the core can be measured in real time. Single phase flow in the core was investigated. Different modes of production in long cores were also simulated including natural depletion, water flooding, and advanced water flooding. Through physical simulation, flow parameters were collected and production characteristics in extra-low permeability cores were studied. From experimental results, it can be seen that fluid flow in extra-low permeability cores is different from that in high permeability cores. Transmission of pressure in extra-low permeability cores is very slow, and it needs a long time for the pressure to become stable. The distribution curve of pressure along the core is nonlinear and the production rate in extra-low permeability reservoirs decreases sharply. The development effects of different production modes in extra-low permeability cores were compared with one another. Among the production modes, advanced water flooding has much potential for effective development of extra-low permeability reservoirs. Natural depletion and conventional water flooding can also be used in early production periods. In addition, the countermeasures and some ideas especially for the potential development of extra-low permeability reservoirs are suggested.

Key words: Extra-low permeability reservoirs, physical simulation, fluid flow, production performance

1 Introduction

Low permeability reservoirs form one of the most important resources for future petroleum production (Li, 2003). Among low permeability reservoirs, in which the permeability is less than $10 \times 10^{-3} \mu\text{m}^2$, was once thought to have no production value. In China, however, a number of new discoveries are of this type, such as the Xifeng Oil Field in the Ordos Basin (Wang and Cui, 2003). In recent years, considerable efforts have been made in the development of low permeability reservoirs ($1 \times 10^{-3} \mu\text{m}^2 < K < 10 \times 10^{-3} \mu\text{m}^2$). These initiatives include studies of: the fluid flow in porous media, patterns of spacing, water injection measures, and low-cost operating management in such low permeability porous media. Production of a million tons of oil per year has been achieved in this area. However, there is a great amount of resources in formations whose permeability is less than $1 \times 10^{-3} \mu\text{m}^2$. These are called extra-low permeability

formations by Chinese petroleum engineers (Li, 2003). The cores in this type of formation are largely different from those in conventional formations: high threshold pressure, relatively high filtrational resistance, low production ability, and difficulty in water injection, etc. Therefore, it is a difficult task to decide how to develop this kind of reservoirs. This paper is focused on reservoirs with the permeability of approximately $0.3 \times 10^{-3} \mu\text{m}^2$, so as to help solve the above problems.

2 Experimental

Limited to the length of cores (commonly 4-10 cm), it is found difficult to entirely simulate the real flow situation and real development process of the reservoir in conventional short core displacement experiments. In contrast, long core physical simulation can overcome the problems presented by short core experiments to a large extent, including low oil saturation, limited time for development, severe end function, difficulty in simulating the production process, and can simulate the actual reservoir conditions and flow conditions well (Li et al, 2004; Wang et al, 2006). As a result, the

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experimental results from long core physical simulation are much more relevant. However, physical simulation for extra-low permeability reservoirs, using long cores does have many difficulties which remain to be solved (Soroush and Saidi, 1999; Wang et al, 2007b).

In this research, a long core holder was specially designed, with multi-location piezometric measurement capacity. A rubber sleeve was used for sealing. It is practicable for tests with pressures from 0 to 35 MPa and temperature no more than 80 °C. Artificial long core, 700 mm long and 4.5cm×4.5cm cross-section, was used in the study. The artificial long core was made of broken outcrop and was prepared according to special process, containing outcrop breaking, mineral mixing, and press forming. Inorganic adhesive agent and specific minerals were used in the core making. Besides mineral composition, properties like permeability, porosity and pore configuration were also considered during core making for exact simulation of extra-low permeability formations (with a permeability of $0.3 \times 10^{-3} \mu\text{m}^2$). That can be guaranteed by testing the properties of small samples drilled from different positions of the long core. The pressure transmitter was developed by the Kunlun Hai'an Corporation (Model number JYB-KO-HAG, measuring range is 10 MPa or 35 MPa, error is within $\pm 0.25\%$). A pump was used. The degree of precision for pressure and rate control were 0.1 MPa and 0.01 mL/min.

Fig. 1 displays the process of experiments.

Fig. 1 Flow diagram of experiments

1-Pump; 2-Intermediate storage tank; 3-Data acquisition system;
4-Long core holder; 5-Back-pressure valve; 6-Manual pump; 7-Gas cylinder

In experiments, the operation conditions were as follows: temperature 60 °C, confining pressure 25 MPa (can be adjusted according to pore pressure if necessary), displacement rate 0.02-5.0 m/d, and back-pressure at the outlet of the core holder 5 MPa (can also be adjusted if necessary).

Each experiment was prepared according to following procedures: First, the cut core was put in the core holder as soon as it had been dried. Pressure testing was needed to make sure there were no leaks. Then, the core was evacuated

for more than 24 hours. The mineralized water used was of the composition of typical formation water (Chen, 2007) of the Changqing Oil Field Company, PetroChina. Total salinity is 25,000 mg/L. Mineralized water was pumped into the core and the porosity was calculated according to the water volume deposited in the core. Finally, the original reservoir conditions were simulated by displacing water with oil. The oil was directly taken from Changqing Oil Field, with a viscosity of 1.18 mPa·s (70 °C). More than 48 hours displacement was carried out for abundant fluid exchange.

3 Fluid flow in extra-low permeability porous media

Different kinds of fluid have different flow characteristics in low permeability cores. With permeability varying, even a given fluid has different flow behavior in the core, especially when the permeability is less than $10 \times 10^{-3} \mu\text{m}^2$ (Zhang, 2007). Some special phenomena appearing in extra-low permeability cores have been revealed in previous reports (Swartzendruber, 1962; Spencer, 1989; Xu et al, 2007). The flow characteristics may be the essential reason for the production performance of an individual reservoir. Thus, it should be given the top priority in the process of study. Research results can, hopefully, help to realize the relation between fluid flow and production of extra-low permeability reservoirs.

Flow rate was changed in the experiment. The fluid flow in extra-low permeability cores at different flow rates were studied.

Fig. 2 shows the pressure distribution along the core at a constant flow rate (0.0556 m/d). It can be reflected that the pressure increase rate at each position is different. The dynamic change of pressure can be divided into two stages. The first stage (50-200 min) shows a significant pressure change; while, the second stage (200-350 min) shows only a slight change at each position. The second stage is regarded as the stable stage. For extra-low permeability cores, the transmission of pressure is rather slow, and the stabilization of pressure takes a long time, at least 6 hours in this case. The ultimate threshold pressure can reach a high value, and the average pressure gradient is high even at the low flow rate in one dimensional flow. In extra-low permeability formations, the volume of the pores is very small, and the pore connectivity is poor. So resistance to flow is high. That can explain the difficulty of water injection in extra-low permeability reservoirs. Fig. 3 reflects the influence of injection rate on pressure distribution (pressure distribution at the stable stage). The pressure distribution curve is not linear, especially when the injection rate is at high levels. The pressure reduction is not significant at the inlet, or pressure gradient is not large, while it becomes great at the outlet of the core. So the pore pressure decreases from inlet to outlet and the active pressure increases correspondingly. The pressure loss along the extra-low permeability core is severe, and permeable resistance is strong. Thus, that is the reason why energy consumption in production from extra-low permeability reservoirs is great and an effective displacement

system is difficult to design. The permeability along the core during injection process can be seen from Fig. 4. The value was calculated from pressure and flow rates measured in real time. It shows that the permeability decreases greatly with active pressure increasing. That results from the deformation of pores at a large active pressure. It has been proved that this deformation is irreversible (Warpinski and Teufel, 1992; Song, 2005). As a result, controlling of the drawdown pressure during production of extra-low permeability reservoirs is very important. If this principle is neglected, after a long time of production the permeability around the production well would become very low, and could not be reinstated by high pressure injection. How can we deal with this problem? Adjusting or changing the role of the injecting and producing regions may be another useful way. The significant change in permeability along the core caused by active pressure should also be considered in future reservoir simulation. The flow conditions of extra-low permeability reservoirs can not be improved by just increasing the displacement rate.

Fig. 2 The pressure distribution along the extra-low permeability core at different times
(Constant injection rate=0.0556m/d)

Fig. 3 Stable pressure distribution along the core at different flow rates

Fig. 4 Permeability distribution along the core at different flow rates

4 Production characteristics

The development mode of a given reservoir should be decided before full-scale development started. It is impossible to compare the differences among different development modes in a real reservoir. So it is not easy to choose the optimum one, unless by simulating numerically or physically. In this research, different development modes were simulated in extra-low permeability cores and experimental results were compared with one another.

4.1 Natural depletion

Each reservoir has natural energy before the opening of the formation. It is very fortunate if natural energy can be used to transport oil from the formation to the well or even up to the ground. Some reservoirs have high pressure before production, while others have low pressure. In the mode of natural depletion, natural energy can be used to the fullest extent, but a lot of oil is still left in the formation after depletion of the natural energy (Qin et al, 2007). So the recovery efficiency is low. On the other hand, it is economical because of less cost and investment to use natural energy. The development effect of natural depletion for extra-low permeability reservoirs was studied.

Confining pressure was 25 MPa. The original formation pressure was 15 MPa. Back-pressure at the outlet of the core holder was changed from 1 to 7 MPa, so the pressure differential was varied from 8 to 14 MPa. In the experiment, the flow rate of produced oil and pressure distribution along the core were recorded after the outlet valve of core holder was opened.

The production ability of a well or a formation can be measured by a parameter called the productivity factor. In this paper, the productivity factor J can be calculated according to the following equation.

$$J = \frac{\Delta V}{\Delta T \times A}$$

where J is the productivity factor, $\text{cm}^3/(\text{min} \cdot \text{cm}^2)$; ΔT is the time interval, min; ΔV is the volume of produced oil during ΔT , cm^3 ; A is the area of lateral section, cm^2 .

Fig. 5 shows the change of productivity factor during

production process with different producing pressure differentials. The curves can be divided into two parts according to the characteristics of the oil production rate (J). At the first stage of production, J declines sharply. Then, about 100 minutes later J becomes stable and maintains a low level. In the first stage, the higher the producing pressure differential is, the greater the index J . Whereas in the second stage, the differences in J under different producing pressure differentials are less obvious. The recovery factors under different producing pressure differentials are shown in Fig. 6. Experimental results indicate that the ultimate recovery factor of natural depletion is about 7%-13%. The higher the producing pressure differential is, the greater the ultimate recovery becomes. That is to say, the pressure differential has an impact mainly on the recovery factor at the initial period of production. That is because the pressure differential can represent two opposing roles. For the positive case, it is a kind of driving force, and for the negative case, it can lead to deformation of pores, and hence a decrease in permeability. Thus, in production, reducing the bottom-hole producing pressure for high production rate is a way which should be used in limited ranges. When the productivity factor becomes lower than a level in the natural depletion, the displacement mode should be changed as soon as possible.

Fig. 5 Oil productivity factor in natural depletion

Fig. 6 Oil recovery factor in natural depletion

4.2 Water flooding

Water flooding is a conventional development mode for oil production. While, for the development of low permeability reservoirs, whether to inject water or not is still a controversy (Qu and Kong, 2002). However, in fact, it is the most commonly used method for developing low permeability reservoirs in China (Li, 2003).

In water flooding, the displacement rate was 1.3 m/d. Confining pressure was 25 MPa. Back-pressure at the outlet of the core holder was 5 MPa. In the experiment, the composition, flow rate of produced liquid, and pressure distribution along the core were recorded after the outlet valve of the core holder was opened.

In water flooding, the oil productivity factor (as shown in Fig. 7) shows that the rate of oil production is relatively high at the beginning. After a few minutes, the rate of production declines greatly. In most production periods, the oil production rate maintains a very low level. Fig. 8 shows the change of water cut during the process. From experimental results, it can be inferred that flow of fluid in this situation is a piston-like displacement. So, water cut will maintain a low level when the rate of displacement is suitable. Without producing time limit, the ultimate recovery factor of water flooding can reach almost 60%, which is higher than expected

Fig. 7 Oil productivity factor during water flooding

Fig. 8 Water cut during water flooding

before. However, the production will last for a very long time. It should also be noticed that the core is an ideally homogeneous one. In a word, water flooding for extra-low permeability reservoirs can be used if the production rate is acceptable, but people have to accept production for a long time at an extremely low flow rate.

4.3 Advanced water flooding

Advanced water flooding is injecting water from an injection well before production starts in the production well. In this way, the formation energy is enhanced and the distortion of pore configuration can be prevented (Chen et al, 2003). So the oil production rate may be increased, and the ultimate recovery factor may also be enhanced. This development mode was paid much attention by petroleum engineers, and was thought to be the most effective way for improving the recovery factor of low permeability reservoirs (Chen, 2007; Wang et al, 2007a). In the oil field, people have to decide when they should begin to inject water, and what the suitable rate for injection is.

In physical simulation, the timing of water injection can be measured by the ultimate pressure through advanced injection and the location of flood front. That position has special definition as described below.

Before water flooding, the original formation pressure was 10 MPa, displacement rate was 1.3 m/d. Confining pressure was 25 MPa. Back-pressure at the outlet of the core holder was 5 MPa. In one group of tests, the ultimate pressure after injection was taken into account. In another group of tests, the position of the flood front was considered. Constant pressure injection was adopted in the experiment. The outside pressure stimulation can be transferred forward in extra-low permeability core sharply like a peak (called pressure front) in theory. However, it works like a slope in the core. The position at which the increment of pressure has reached 80% of the difference between the original pressure and the advanced injection pressure was defined as the position of flood front, and the distance between it and the inlet was called the front distance. During the experiment, the composition, the flow rate of produced liquids, and pressure distribution along the core were recorded.

Fig. 9 shows the oil recovery factor of the first group of tests under different advanced water injection pressures. The criterion for confirmation of recovery efficiency here is that J should not be too low. The point at which the pressure is 10 MPa means no advanced injection happened or the water injection pressure is the same as the original formation pressure. It is a reference point. The experimental results show that the oil recovery efficiency can not be enhanced if the formation pressure is increased only to 13 MPa by advanced water injection. The oil recovery factor can be enhanced greatly when the ultimate pressure is equal to or higher than 15 MPa, and can maintain a high level when the injection pressure is 15-22 MPa. However, increasing the pressure to 24 MPa before the opening of the core holder outlet does not work, the recovery factor is even lower than conventional direct water injection. So the high injection pressure does not always result in high recovery efficiency.

Fig. 9 Oil recovery factor for different advanced injection pressures

In the next group of experiments, the injection pressure was fixed at 20 MPa while the location of flood front was changed. The recovery factor of this group can be seen in Fig. 10. The first point (Position L of long core from entrance to outlet equals 0 cm) means that only high pressure injection was adopted. Obviously, from the trend, an appropriate position can be chosen for best timing of water injection. When chosen properly, the recovery can be enhanced to a large extent. From the result of this study, the pressure increment through advanced injection should be 50%-120%, and the position of flood front is 20%-65% of the whole length between injection and production wells. The suitable range of injection pressure is obtained on the precondition that the recovery efficiency is higher than the reference point, and the result only reflects this very case. So, it may be different from the ones reported in the literature. One of the most important reasons that advanced water injection works in extra-low permeability reservoirs is that the pressure of reservoir can be kept at a high level by the process. The loss of permeability and deformation of pores is also prevented.

Fig. 10 Relation between the oil recovery and the relative position of injection front

5 Conclusions

The following conclusions can be drawn from the experiments:

1) The critical problem for fluid flow in extra-low permeability cores is the deformation of pores caused by a decrease in pore pressure. That results in severe pressure loss from inlet to outlet, or an increase in pressure gradient. The strong permeable resistance is the reason for severe energy consumption along the injection direction. It is also the reason for difficulty in water injection and low oil production rate in extra-low permeability reservoirs.

2) For extra-low permeability cores, the porosity and permeability decrease greatly with the increase in active pressure. So controlling the production pressure differential during the production of extra-low permeability reservoirs should be given much more importance in the future. Conversion of injection and production regions may be a way for displacement of residual oil in extra-low permeability reservoirs.

3) For extra-low permeability reservoirs, natural depletion is effective, although its effect is limited. It is not a reasonable strategy to lower the bottomhole producing pressure greatly, because it will result in a great decrease in porosity and permeability around the production well.

4) The formation energy can be supplemented and a sharp decrease in oil production rate can be slowed down in different degrees by water flooding and advanced water flooding. The effect of the latter process is better, and it is also the potential way for the development of extra-low permeability reservoirs.

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