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Impact of permeability heterogeneity on production characteristics in water-bearing tight gas reservoirs with threshold pressure gradient

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ABSTRACT

In order to investigate the effects of permeability heterogeneity on gas production in water-bearing tight gas reservoirs, the combined series of cores obtained from Sulige gas field, one of the important water-bearing tight gas reservoirs in China, were tested. Based on different scenarios of permeability heterogeneity, the low-velocity non-Darcy flow mathematical models considering threshold pressure gradient (TPG) were established. The finite difference method was applied to numerically solve the nonlinear mathematical model, and the corresponding numerical program was completed. The consistency between the numerical results considering TPG and the experimental data indicates the validity and accuracy of the mathematical models. The numerical and experimental results show that ignoring the influence of TPG in water-bearing tight gas reservoirs will lead to inaccurate assessment of the well productivity. For heterogeneous water-bearing tight gas reservoir development, the production wells allocated in high permeability region will boost the recovery. However the higher the initial constant production rate, the shorter the stable production time. So an appropriate production rate should be allocated to maximize both the economic and social benefits. This research can quantitatively analyze the impacts of permeability heterogeneity in water-bearing tight gas reservoir developments and optimize the production rate and production pressure accordingly.

1. Introduction

Worldwide rising gas demand is creating new opportunities for low/ultra-low permeability reservoirs to be exploited including tight gas (Jiang et al., 2014), shale gas (Chen et al., 2011; Han et al., 2013) and coalbed-methane (Takayuki, 2013). Water-bearing tight gas reservoir as one of the important unconventional reservoirs has attracted more and more attention for development. There are two obvious characteristics which strongly affect the development of water-bearing tight gas reservoir. One is that gas flow through low/ultra-low permeability media with irreducible water is low-velocity non-Darcy flow, namely gas flow with threshold pressure gradient (TPG). The other is that there exits great permeability heterogeneity in water-bearing tight gas reservoirs.

On the one hand, many scholars have conducted research on heterogeneous reservoirs (Mohammad et al., 2013; Zhu et al., 2011; Freeman et al., 2013; Song et al., 2014). An experimental method was introduced by Richard A. Dawe and Carlos A. Grattoni (Richard and Carlos, 2008) to investigate the effect of heterogeneities on miscible and immiscible flood displacements. The method is based on a two-dimensional, rectangular sealed plexiglass box filled with glass beads, with either permeability or wettability contrast. The effective permeability of the quadrant model was first investigated by Cardwell and Parsons (Cardwell and Parsons, 1945), and developed by others (King, 1996; Yeo et al., 2001). But the characteristics of the low-velocity non-Darcy flow in low permeability heterogeneous tight gas reservoirs cannot be reflected in these experiments due to the relatively large pore scale involved. A large number of articles have been published on the topic of the onset of convection in a heterogeneous porous medium (Nield et al., 2009; Kuznetsov

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et al., 2010; Nield et al., 2010), and some mathematical models have been built for heterogeneous porous media (Wu et al., 2006; Chen and Louis J. Durlofsky, 2006; Mohammad et al., 2013). Some scholars analyzed the influence of the reservoir heterogeneities on capillary pressure, saturation and relative permeability. But these researches are all based on the concept of Darcy flow, which can result in gas reserve overestimation, poor well deployment design, and further inducing to inaccurate prediction of the tight gas reservoir development potential and prospects.

On the other hand, many researches on low-velocity non-Darcy flow have also been investigated. The concept of threshold pressure gradient (TPG) was initially proposed by B.A.Florin in 1951 to study the flow in compacted mudstone and hard clay (Ge, 1982). In 1986, Wenguang Feng originally proposed the idea of low-velocity non-Darcy flow for gas analogous to that of oil in low permeability oil reservoirs (Feng, 1986). In recent years, many laboratory experiments have been conducted to study the low-velocity non-Darcy flow of gas in humid, low permeability rock samples. Gas flow is found to be heavily influenced by permeability and water saturation (Zhu et al., 2011; Wu et al., 2001; Liu et al., 2007; Yi et al., 2006). For dry and low water saturation rocks, the less the permeability, the more obvious the influence of slippage effect on gas flow; while as the water saturation increases, the influence of slippage effect decreases and that of capillary pressure increases, and the gas flow will behave as low-velocity non-Darcy flow.

In this paper, we aim at investigating the impact of permeability heterogeneity on gas production based on low-velocity non-Darcy flow theory in water-bearing tight gas reservoirs. In the first place, combined cores in series obtained from Sulige gas field, one of the important water-bearing tight gas reservoirs in China, are tested in laboratory to analyze the effects of permeability heterogeneity. In addition, based on different scenarios of permeability heterogeneity, the non-Darcy flow mathematical models considering TPG are established. The results of numerical calculation are compared with experimental data to verify the validity and accuracy of the mathematical models. At last, according to the mathematical models of the non-Darcy radial flow in permeability heterogeneous reservoirs, the factors influencing the gas production in water-bearing tight gas reservoirs are investigated quantitatively and the optimum range of the production rate and production pressure are suggested accordingly.

2. Experimental section

2.1. Experimental procedure

Following the similarity criterion, the combined series of core measurement apparatus is set up to simulate the reservoir heterogeneity, which is shown in Fig. 1. The main components of the experiment apparatus include gas supply device, pressure pump, core holder, pressure sensor, gas flow meter and data acquisition system. The samples are cored from Ordos Basin gas field in China,

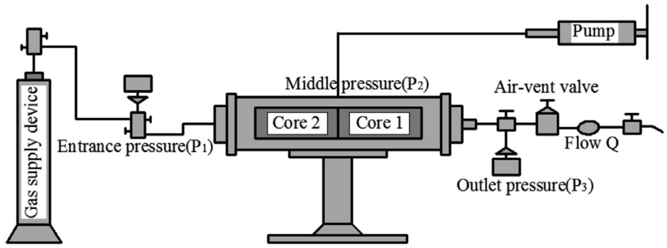

Fig. 1. Core measurement apparatus.

with the diameter being 25 $\times$ 10^{-3} m and the length being 50 $\times$ 10^{-3} m. The permeabilities of the samples are 1.007×10^{-15} m^2 and 0.102×10^{-15} m^2, respectively. These are used to simulate the high permeability zone and low permeability zone of the reservoir, respectively. Gas displacing water method is applied to acquire the required water saturation, formation water and nitrogen are the used water and gas, respectively. Note, the experiments are carried out under room temperature.

The steps included in the experimental process are:

Step one: dry the cores in the oven and measure their dry weights W_H/W_L; after that, vacuum the cores and saturate the cores using the formation water. When the cores are fully saturated, measure their wet weights W_{H0}/W_{L0}; an appropriate displacement pressure is determined based on the physical parameters (such as porosity, permeability) of the high/low permeability core, displace the core using the humidified nitrogen under this appropriate pressure till the water saturation becomes stable, and then measure the high/low permeability core weight W_{H1}/W_{L1}, and apply NMR to measure the water saturation S_{H1}/S_{L1}.

Step two: place the high, low permeability cores inside the core holder and make sure they connect each other closely, then apply the confining pressure (which is 3–5 Mpa higher than gas saturation pressure); as the confining pressure becomes stable, infill gas into the core holder till the gas pressure becomes 9.0 Mpa; close the inlet valve of the gas cylinder, deplete the gas at the designed outlet flow rate Q (the initial production allocation rate is 100 ml/min, 200 ml/min) controlled by the mass flow controller, and keep record of the production time, instantaneous gas rate, cumulative gas production, and outlet pressure.

Step three: after step two, again measure the high/low permeability core wet weight W_{H2}/W_{L2}, also apply NMR to measure the current water saturation S_{H2}/S_{L2}. To ensure the accuracy of the experiment, the interference from the water phase flow should be prevented. Thus the data recorded in step two is considered valid only after the differences of the two cores' water saturations S_1 and S_2 are both less than 3%.

2.2. Analysis of experimental results

Fig. 2 shows the experiment results for simulating the heterogeneous tight gas reservoir. In Fig. 2(a) Core 1 is the low permeability core, and Core 2 is the high permeability core. In this setting, the production well is equivalent to locating in the low permeability region; while in Fig. 2(b) Core 1 is high permeability, and Core 2 is low permeability. This setting equals to locating the production well in the high permeability region. The experiment results show: for the same initial production allocation rate, the stable production time of Fig. 2(b) is significantly longer than that of Fig. 2(a), and the cumulative gas production is also higher. This is because: for the heterogeneous model of "low permeability region near wellbore, high permeability region far away", the largest pressure drop occurs in the low permeability region, but the gas supplement is limited due to the high flow resistance, which results in the relatively short constant production time; while for the heterogeneous model of "high permeability region near wellbore, low permeability region far away", the high porosity and permeability in the near wellbore region ease the flow of the fluid, and guarantee a long stable production time. And as the production continues, gas in the low permeability zone will compensate the loss in the high permeability zone, thus extend the stable production time.

As shown in Fig. 2, when the initial production allocation rate decreases from 200 ml/min to 100 ml/min, the stable production time increases to 2.26 times of the original time in Fig. 2(a) and 2.27 in Fig. 2(b). This is probably due to: low production rate can