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Identification and quantitative description of large pore path in unconsolidated sandstone reservoir during the ultra-high water-cut stage

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ABSTRACT

In unconsolidated sandstone reservoirs associated with fluvial sedimentation, large pore paths are likely to be formed under the long-term scour action of injected water. In this paper, the high-velocity non-Darcy flowing characteristics in large pore paths were analyzed. Based on the identification criteria for high-velocity non-Darcy flow, the identification criteria for large pore paths are established. According to the characteristic parameters of 101 relative permeability curves from the fluvial sedimentary units of the uncompartmentalized oilfields in Shengli oil region, the relation formulae between characteristic parameters of relative permeability curve and permeability are established. Considering the change of reservoir permeability and the relative permeability curve with permeability, a reservoir numerical simulation model is setup. The $Ng6^{3+4}$ development unit of the west seventh block of Gudong Oilfield is taken as a typical reservoir. The distribution position, area and volume of the large pore paths in $Ng6^{3+4}$ development unit are quantitatively described. The results show that the identification criteria of large pore paths which take into consideration the water–oil well spacing, production pressure difference and permeability can be used in the reservoir numerical simulation results to describe the large pore paths.

1. Introduction

Unconsolidated sandstone reservoirs associated with fluvial sedimentation show the characteristics of positive rhythm longitudinally. Because of the weak cementation strength, high permeability and heterogeneity, the local area's permeability further increases under the long-term scour action of injected water. Large pore paths are likely to be formed, which are not conducive to the production (Dou et al., 2001).

The interwell tracer test results of 39 well groups in Gudong Oilfield of Shengli Oilregion showed that (Wang, 2006) large pore paths had a development rate of 34.7%, permeability 8000–$80{,}000 \times 10^{-3}\,\mu m^2$. The average permeability is $10{,}000 \times 10^{-3}\,\mu m^2$ which is more than 6 times the permeability at early development stage. The thickness of a large pore path is generally very small, only occupying 1–8% of the thickness of the water accepting layer. Some are even only a few centimeters thick; however, the water absorption rate can reach more than 90% of the water injection rate of the entire well. The presence of large pore paths causes serious invalid water injection–production cycle, which affects the result of water flooding development. Accurate large pore path identification and descriptions can prove to be an important guiding to improve oil recovery as water plugging and profile control at the ultra-high water cut stage.

There are many domestic and foreign scholars who have done research on large pore path identification and description. In this literature, the large pore path is also named 'the thief zone', 'high permeability streak', 'super-K interval', among others. Felsenthal and Gangle (1975) defined a thief zone as a relatively thin layer comprising 5 percent or less of the net pay thickness and taking more than 25 percent of the injected water in a given well. As such a well-to-well tracer test was used to determine the thief zone permeability and direction. Brigham et al. (1983) analyzed the tracer production curve to identify the large pore path. The inter-well connectivity, directionality of permeability and heterogeneity were discussed. Jiang et al. (1997) used the probability model to determine the geological parameters of large pore paths. Al-Ajmi et al. (2001) introduced a new measure to quantify super-K intervals from flowmeter data. Super-K quantification was accomplished by deriving fluid flow Index from flowmeter surveys. Dou et al. (2001) combined the reservoir engineering method with the gray theory method to study whether large pore path was formed or not and the direction of its extension.

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Nomenclature

v	flowing velocity, cm/s
dp/dx	pressure gradient
c	constant value related to the porous media and fluid
n	flowing index, 1/2–1
R_e	Reynolds number
K	permeability, μm^2
μ	viscosity, mPa s
ρ	density, g/cm^3
Φ	porosity, fracture
k_r	relative permeability
p	pressure, 0.1 MPa
S	saturation
B	volume coefficient
q_v	production rate, cm^3/s
f_w	water cut, %
k_{rwi}	water relative permeability at maximum water saturation
S_{wc}	connate water saturation
S_{or}	residual oil saturation
S_w	water saturation
p_c	capillary force between water phase and oil phase, 0.1 MPa

Subscripts

o	oil phase
w	water phase
g	gravity acceleration

Shi et al. (2003) established the well test interpretation model of the large pore path, using the typical curve fitting method to determine the existence of big channels. Liu and Liang (2004) used the well pressure drop testing techniques to determine the existence of large pore paths. Shang and Wan (2004) and Ying and Chen (2005) proposed to use the method of hydraulic detection to determine the existence of large pore paths in the reservoir. Men and Huang (2007) used the logging curve characteristics and the Fischer criterion to identify large pore paths. Feng et al. (2011) showed that dimensionless pressure index can identify thief zones easily and verified its validity from both the synthetic model and the pilot test. Davies and van Dongen (2013) presents inter-well communication as a means to detect the location of thief zones in a controlled acid jetting (CAJ) well using distributed temperature sensing (DTS) technology along with a production logging tool and water flow log for the first time. Kocabas and Maier (2013) developed a novel analytical unsteady state two dimensional solution for significant heterogeneity that may exist in an oil reservoir namely a high permeability streak located in an immobile matrix.

At present, most researches focused to determine whether the large pore paths are formed or not at a specific time point. The few existing quantitative description methods are primarily based on certain assumptions and these assumptions are quite different from the actual situation, so the reliability of the results is not high enough. The studies on large pore path parameters such as the location, permeability, distribution area and volume are relatively few and the studies on the flowing law in the large pore path are fewer.

This article draws from the flowing behavior of high-velocity non-Darcy flow in the large pore paths to establish the identification method of large pore paths. The reservoir simulation system considering the time-varying characteristics of permeability and relative permeability curve is built, and the research is conducted on large pore path identification and quantitative description.

2. Definition criteria for large pore path

2.1. High-velocity non-Darcy flow characteristics in large pore paths

As unconsolidated sandstone reservoir associated with fluvial sedimentation is subject to long-term scour action of injected water, the remaining oil saturation at the bottom with high permeability is closer to the residual oil saturation. In a local area, the permeability is increased, the flowing resistance is decreased, and the flowing velocity of fluid is very high.

According to the statistics provided by Wang (2006), when the distance between water and oil wells is 212 m, the average flowing velocity of water is 3.48 mm/s for the well groups with developed large pore paths. If Darcy's linear flow law is used in the calculation, the water flowing speed would only be 0.314 mm/s, which is different from the actual speed by over 10 times. In the calculation process, it is assumed that there is only water flow in large pore paths. The water viscosity is 0.5 mPa s, the permeability in large pore path is $10{,}000\times10^{-3}\ \mu m^2$, the porosity is 0.3, and the injection–production pressure difference is 2.0 MPa.

Therefore, the flow of fluid in the large pore paths does not accord with the linear flow law, but accord with the high-velocity non-Darcy flow. With the high-velocity non-Darcy flow, the flowing velocity can be calculated using (Katya Hof, 1961)

$$v=c\left(\frac{dP}{dx}\right)^n \tag{1}$$

where c is a constant value related to the properties of porous media and fluid. Usually, $c=k/u$.

When the flowing index n is 0.65, the calculated water flowing speed will be 3.6011 mm/s, which is very close to the field measured value. Therefore, the flowing behavior in large pore paths is not linear Darcy flow but high-velocity non-Darcy flow.

2.2. Definition criteria for large pore paths

The identification methods of high-velocity non-Darcy flow mainly include Katya Hof formula (Katya Hof, 1961), Geertsma formula (Geertsma, 1974), Belhaj formula (Belhaj et al., 2003), etc. Through the comparative analysis of the calculation results from the three formulas, this paper chooses Katya Hof formula to judge high-velocity non-Darcy flow.

The Katya Hof formula (Katya Hof, 1961) is written in the following form:

$$R_e=\frac{v\sqrt{K}\rho}{17.5\mu\phi^{1.5}} \tag{2}$$

By substituting Formula (1) into Formula (2), the following is obtained:

$$R_e=\frac{K^{1.5}\rho}{17.5\mu^2\phi^{1.5}}\left(\frac{dP}{dL}\right)^n \tag{3}$$

When $R_e\le 0.2$–0.3, the flowing law is linear flow, when $R_e>0.2$–0.3, the flowing law is high-velocity non-Darcy flow. According to Formula (3), Reynolds number can be calculated