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Behavior of Flow through Low-Permeability Reservoirs

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Abstract

While pores and throats of low-permeability reservoir rock are very tiny, they have significant influence on flow behavior in those reservoirs. There may be large differences in throat sizes and their distribution in low-permeability formations, even though they have similar storage space and flowing channels. Equivalent radii of flowing throats for low-permeability reservoirs with similar permeabilities may be very different. Stronger liquid-solid interaction within finer pore throats having a large interface area and abundant hydrophilic clay tends to prevent water from flowing through.

This paper presents a systematic study of flow behavior in low-permeability reservoirs using (1) a constant-rate mercury injection test, (2) a nuclear magnetic resonance (NMR) core analysis, and (3) a seepage experiment. NMR results show that mobile fluid saturation in low-permeability formations is very different from that in normal reservoirs. In general, the less clay content and larger throat radii of the low-permeability rock, the larger the mobile fluid saturation. We conducted a series of seepage tests, with the results showing that at low velocity, the flow rate in low-permeability rock is not linearly correlated with pressure gradient, but rather is a function of pressure gradient. Based on experimental results, we propose a modified Darcy's law for describing the observed nonlinear flow phenomenon, which is implemented into a black-oil model simulator. Simulation results incorporating the nonlinear flow-behavior show that effective permeability near production and injection wells is higher, whereas the permeability further away from the wells is lower. Well performance predicted by the linear model overestimates production rates, while that predicted by the new, nonlinear model better matches the field production data.

Introduction

Pores and throats in low-permeability reservoir rock are very tiny, but their interface area is quite large, and interaction between pore surface and fluid is strong. Therefore, Darcy's law may not be in general valid for low-velocity flow. The relationship between flow velocity and pressure gradient in such porous media is a buckled curve. Only when the pressure gradient or flow velocity reaches a certain value does the relationship curve become a straight line. However, the straight line cannot intersect the origin when extrapolated. The intersection of extension for the straight line and the x-axis is called the "pseudo-threshold pressure gradient"[1-4]. Such a pseudo-threshold pressure gradient concept has been commonly used to describe nonlinear flow behavior in a low permeability reservoirs:

$$\mathbf{v} = -\frac{k}{\mu}\left(1-\frac{G}{\text{grad}\,(P)}\right)\text{grad}\,(P) \qquad (1)$$

where G is the pseudo-threshold pressure gradient, which is the distance from the intersection of the straight-line segment of pseudo-nonlinear flow to the origin point. This means that flow occurs only when the applied pressure gradient is greater than the pseudo-threshold pressure gradient. After the theory of flow through low-permeability reservoirs, based on the concept of pseudo-threshold pressure gradient, was established, several articles[5-7] appeared that reported testing for pseudo-threshold pressure gradient, productivity formula, and reservoir simulation technology. However, the concept of pseudo-threshold pressure gradient has not yet been used widely in oil development from low-permeability reservoirs. One main reason may be that the value of G from such experiments is very large. Only the pressure gradient near production and injection wells in waterflooding reservoirs could be greater than the pseudo-threshold pressure gradient. Then, according to the theory, no flow occurs further away from wells, because the driving pressure gradient is too small. However, this is generally not consistent

with the actual situations in oil production from low-permeability reservoirs, so many researchers and engineers have to reduce the value of G in simulation studies. These real-life situations underscore the physical significance of the pseudo-threshold pressure gradient and how to better describe nonlinear flow in low-permeability reservoirs.

Through experimental studies, this paper reveals some insights into the physical significance of the pseudo-threshold pressure gradient. It actually represents the integrated or combined effects of pore structure, liquid-solid interaction, and viscous forces of fluids, and is characteristic of flow capability in porous media. Results of this study show that a simple pseudo-threshold pressure gradient concept, Equation (1), cannot be generally used for describing the nonlinear flow in low-permeability reservoir. Therefore, we propose a modified Darcy's law to describe the observed nonlinear flow phenomenon, which is implemented into a black-oil model simulator. The simulation results with this model provide better matches to field production data than using a linear Darcy flow model.

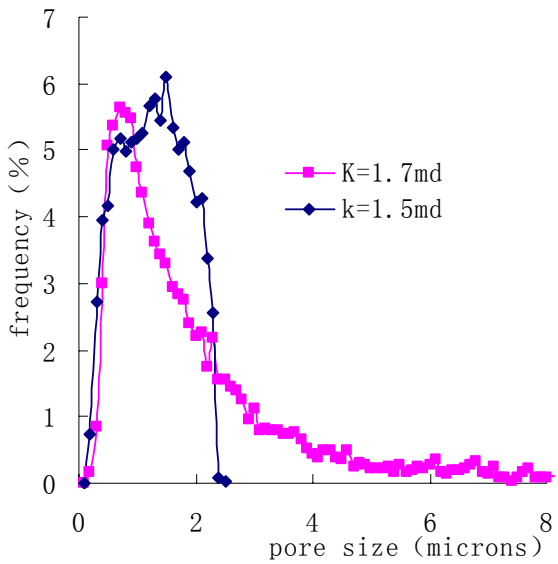


Fig. 1. Throat distribution curves of two cores with close gas permeability

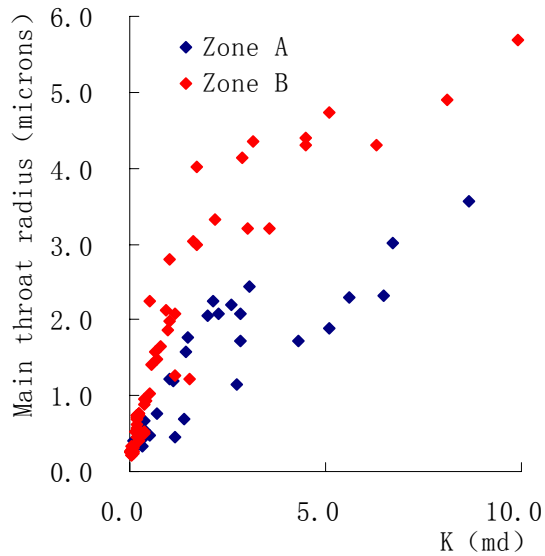


Fig. 2 Correlation of Rmail versus gas permeability of zone A and B

Pore Characteristics

A method involving a mercury injection test under constant pressure is used to study reservoir-pore-structure characteristics. This method is characterized by each pressure corresponding to a certain range of pore throat radii. The volume of the injected mercury corresponds to pore volume, controlled by the same-sized throats. In general, the relationship between throats and pores is not well defined for given porous materials. In this study, the advanced equipment for constant-rate mercury injection is used for pore structure analysis. A constant rate is maintained at 10^{-6} mL/s, which is close to a quasi-static flow process. This experimental method is able to provide a frequency for each range of throat size or radius and therefore provides a detailed description of reservoir formation pores structure.

Figure 1 shows the pore-throat distribution (using constant-rate mercury tests) of two cores with similar gas permeability. It is found in the experiment that throat distribution for cores with similar gas permeability may be very different. One is close to normal distribution; the other deviates from normal distribution, with many large throats on the right of the peak throat radius value (Figure 1). It is evident that permeability is directly proportional to the square of throat radii. The larger the throat size, the larger the contribution to permeability. A weighted throat radius, contributing to 95% permeability, is selected as the main throat radius. (Main throat radius reflects the size of reservoir pore space.) Figure 2 presents correlations of the main throat radius to gas permeability in two different zones. This figure shows that cores with the same gas permeability may be very different in main throat radius. Gas permeability is considered as the macroscopic representation of microcosmic pore structures. Therefore, the important parameter for describing the capability of flow through a porous medium is not gas permeability, but the main throat radius.

Liquid-Solid Interaction

Small pores, tiny throats, large interface areas, and high clay content in low-permeability formations all lead to strong interaction at the surfaces between pores or throats and fluids. This interaction generates a contact boundary layer with a certain thickness spreading over solids, which decreases the effective pore space. A parameter describing the liquid-solid interaction is mobile fluid saturation, which can be measured using nuclear magnetic resonance (NMR) testing technology. A diagram of relaxation time for T2 distribution spectrum of cores can be determined experimentally. The value of T2-time is

correlated to the ratio of interface area to pore volume. The larger the surface area, the less the T2-time, and the stronger the liquid-solid interaction. The frequency of the T2-time reflects the amount of same-sized throats. The larger the frequency, the larger the number of the same size throats. Based on the results from many experiments, frequency of 10 ms is selected as a cutoff value for fluid mobility in low-permeability reservoir rock. Fluid flow occurs only in throats in which the frequency is larger than 10 ms. Using this definition, one can determine mobile fluid saturation profiles[8].

Figure 3 presents our experimental results, showing the relationship between mobile fluid saturation and gas permeability for the two low-permeability zones A and B. This figure shows that the cores with similar gas permeability may have very different mobile fluid saturations, because of the differences in pore structure as well as clay content. Clay affects the pore space of low-permeability formations in two ways. First, fibrous clay (e.g., illite, montmorillonite) is easy to distribute on the surface of throats (in a bridge shape) and to divide large pore spaces into many small pores, increasing the degree of tortuosity of flow paths. Second, the higher the clay content, the greater the surface area, and the stronger the liquid-solid interaction. This will result in thicker fluid boundary layers on the solid surface or smaller pore spaces. Therefore, flow resistance increases, and the flow becomes more nonlinear, with an increase in clay content (as Figure 4).

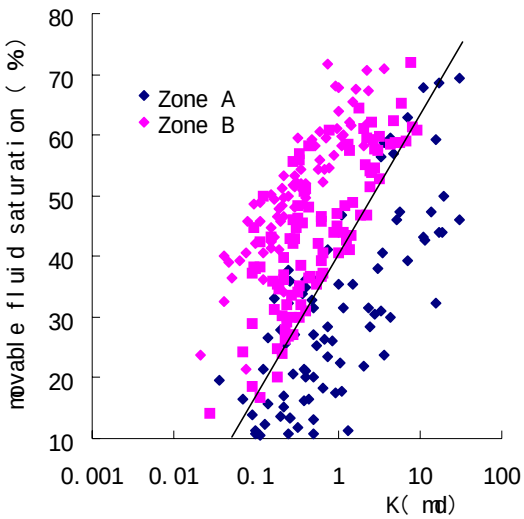


Fig. 3. Mobile fluid saturation of zone A and B

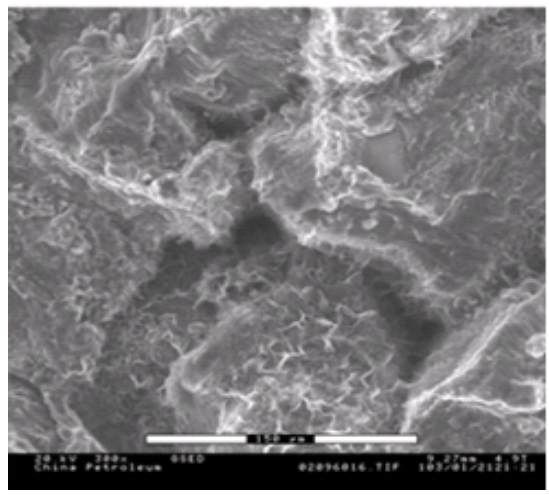


Fig. 4. Montmorillonite distribution in throats and pores

Relationship between Permeability and Pressure Gradient

In the experiment, low-permeability cores of Zone A and B are selected because of the large difference in pore structure, liquid-solid interaction, and clay content between them. Cores are first saturated under 10 MPa pressure, and then are used in experiment under a confined pressure of 4 MPa as Figure 5. The study has focused mainly on the condition of low-velocity flow. The difficulty at this stage of the experiment is measuring flow rate and pressure. The ISCO pump is used for injection under constant flow rate, while the outlet flow rate is measured using a calibrated weighting scale. A liquid-column manometer is employed under low-pressure conditions. The experiment is conducted by keeping a six-way valve at the same horizontal level as cores to reduce errors in pressure measurement.

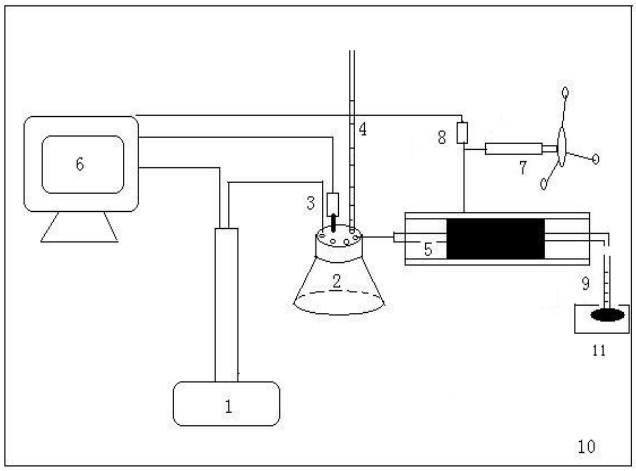
Table 1 lists the test data from one core experiment, in which the minimum flow rate is 0.001 mL/min. The flow rate measurement is checked to be consistent with calculations, using cumulative flow volume at outlet under steady state flow conditions. Then, core permeability is calculated using the flow rate and pressure data from the experiment given in Table 1. The permeability values show that when a low flow velocity and low pressure gradient exist, the resulting permeability is also low. With the increase in flow velocity, pressure gradient and permeability both increase, and flow becomes more nonlinear. Figure 6 shows the relationship between permeability and pressure gradient for the two different reservoir rock samples. It indicates that permeability increases with the increase in pressure gradient. When injected pressure gradient reaches a certain value, the permeability curves turn flat or become constant. The pressure gradient corresponds to the point of inflection for curves for Zone A, it is at about 3 MPa/m, and for Zone B is about 0.15 MPa/m;. However, it may not be very common for the pressure gradient to reach this large, critical value under actual flow conditions during reservoir development. In general, flow occurs mainly at the stage of permeability when it is changing with the change in pressure gradient. As shown in the experimental results, in low-permeability reservoirs, the effective permeability may no longer be constant, but rather a function of pressure gradient. This is very different from flow in intermediate-permeability and high-permeability reservoirs. Figure 6 also shows that different reservoirs can have different relationships between permeability and pressure gradient; therefore, the relationships can vary from site to site.

Why doesn't the relationship between flow rate and pressure in low-permeability reservoirs follow Darcy's law? On one

hand, according to the boundary-layer theory (Мархасин, 1987), the viscous forces at pore throat interfaces are much greater than that along pore throat centers, because of the strong liquid-solid interaction at pore-throat interfaces. The thickness of the boundary layer decreases with the increase in pressure gradient, which leads to a permeability increase accompanying an increase in pressure gradient. On the other hand, the pore throats may be approximated as numerous parallel capillaries. The largest radius of capillaries could be 10 times more than the smallest one. Pore throats of low-permeability reservoirs are mainly composed of throats less than 1 micrometer. Saturated by water and under a low pressure gradient, tiny throats keep water from flowing through. As a result, water may flow only through the larger throats. As the driving forces of pressure gradient increase, smaller throats begin to contribute to flow. These two phenomena both lead to increases in flowing areas, as well as increases in permeability that accompany increases in the pressure gradient. Consequently, the flow no longer follows a linear Darcy's law.

Table 1. Testing data and results

Rate at pump mL/min)	Rate at outlet （mL/min）	Pressure gradient （atm/cm）	Kw （md）
0.001	0.001	0.002	0.25
0.002	0.002	0.007	0.28
0.003	0.003	0.012	0.29
0.005	0.005	0.019	0.31
0.008	0.008	0.039	0.33
0.01	0.010	0.049	0.34
0.02	0.020	0.095	0.34
0.03	0.031	0.136	0.34
0.05	0.050	0.229	0.34
0.07	0.072	0.321	0.34
0.1	0.100	0.460	0.34
0.2	0.204	0.891	0.34
0.50	0.515	2.042	0.34



1 ISCO pump;2 six-way valve; ,8 pressure transducer; 4 hydrostatic gauge;5 core holder; 6 Computer; 7 Confining pressure pump; flowmeter;10 Air Bath; and 11 scale

Fig. 5. Experimental flow chart

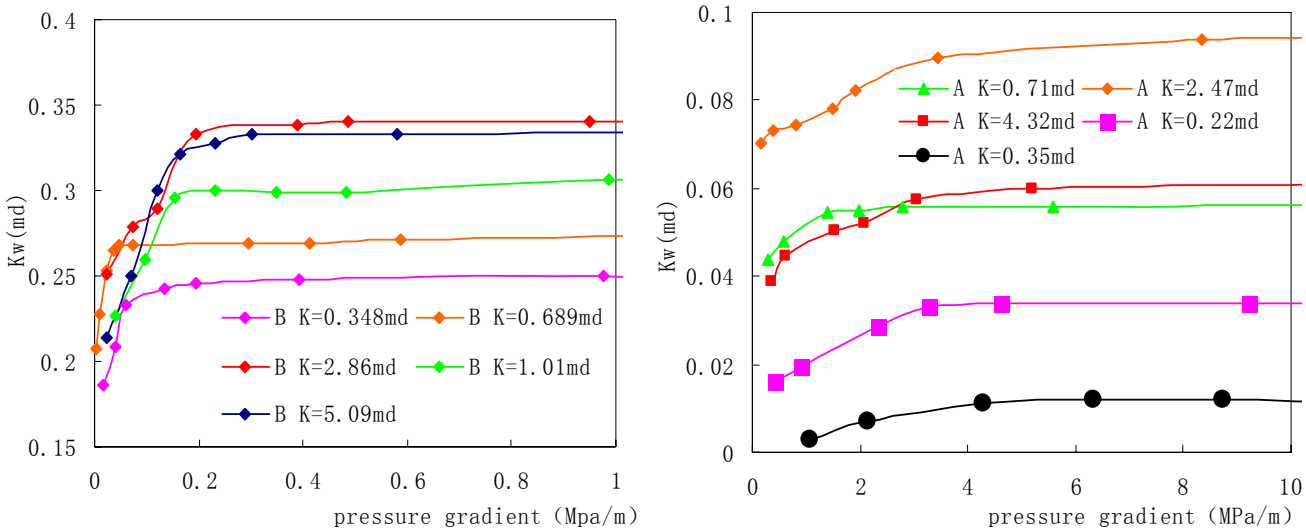


Fig. 6. Correlation of permeability (Kw) vs. pressure gradient

When considering the experimental conditions of Darcy's law using a sand packed model, one simple, implicit assumption is that all pore throats could contribute to flow under a given pressure gradient. This assumption leads to the conclusion that permeability is constant. However, the same assumption may not be applicable in low-permeability reservoirs, where Darcy's law is valid only when the pressure gradient reaches a certain threshold value. Our experimental data show the flow in low-permeability reservoirs is in general nonlinear.

Flow Equation

In this study, the general equation of motion, Equation (1), is extended to describe flow behavior in low-permeability reservoirs. In the model, the pseudo-threshold pressure gradient, G, is defined as the value between the beginning of pseudo-liner seepage and the origin point, or an average parameter of nonlinear flow ranges. Generally, the value of G determined from experiments is larger than its actual value in reservoirs. According to Equation (1), there may be no flow occurring in a large region between an oil-production well and an injector in a low-permeability reservoir. However, this is generally inconsistent with the situation in actual production, as discussed above. The value of G has to be reduced somehow when using Equation (1) in simulation studies for development planning or prediction. In doing so, there is a general lack of scientific basis of how much to reduce in a site-specific study**,** and thus the concept of the pseudo-threshold pressure gradient has not been widely used in field simulation studies in reservoir development and production analysis.

The experimental results above show that under reservoir conditions, permeability is a function of pressure gradient. Based on this observation, we propose an equation of motion to describe flow in low-permeability reservoirs, having the form

$$v = -\frac{k(\mathrm{grad}(p))}{\mu}\mathrm{grad}(P) \qquad (2)$$

where permeability k is treated as a function pressure gradient, to be determined by experiment or field data. As shown in Figure 6, the relationship between permeability and pressure gradient can be described simply by using an adjustment factor,

$$k(\mathrm{grad}(p)) = k \times \delta(\mathrm{grad}(P)) \qquad (3)$$

where $\delta(\mathrm{grad}(P))$ is a factor of adjustment no more than 1, a function of pressure gradient. When the pressure gradient reaches a certain value of G, $\delta(\mathrm{grad}(P)) = 1$, then the flow follows Darcy's law. With the adjustment factor, the relationship between permeability and pressure that the equation of motion [Equation (2)] describes the flow behavior varying from nonlinearity to linearity, covering the entire range of nonlinear and linear flow in low-permeability reservoirs.

Application

The governing equations of material balance, nonlinear flow equation, other equations of state, and boundary conditions are the same in form as that of the linear flow case in reservoir simulation. These equations are solved simultaneously in numerical simulation. Note that the additional nonlinearity, introduced by permeability dependence on pressure gradient in low-permeability reservoirs, needs to be handled in the theoretical model. This dependence, as described, for example, by Equation (3), introduces a highly nonlinear coupling term and may cause numerical difficulties. One method we tested is based on the functions determined from experiment for the adjustment factor, to explicitly handle the dependence of permeability on the pressure gradient in a black-oil model. Wu and Pruess[10] discuss a more general numerical approach for handling nonlinear permeability functions, using a fully implicit scheme in a multiphase flow simulator.

Figure 7 presents the relationship between the adjustment factor of permeability and pressure gradient. Figure 8 shows a simulation example, a single injector and producer in this model. Both the injector and the producer are located in the middle of two edges of the model. The maximum value of effective permeability is 10^{-3} μm^2 ($\delta(\mathrm{grad}(P)) = 1$). The pressure field and permeability field, simulated according to the nonlinear flow model, are shown in Figures 9 and 10. The three-dimensional diagram of pressure distribution (Figure 9) indicates that the change in pressure is greater in the regions near the injector or the producer. In the region far away from the two wells, the variation in pressure is smooth, with only small pressure changes. Figure 10 describes the simulated permeability field distribution corresponding to Figure 8, showing that with a large pressure gradient, the permeability near the wells is $0.9\text{-}0.95\times10^{-3}$ μm^2. In comparison, further away from the wells, changes in effective permeability are very small, because the adjustment factor is close to the minimum value when there is a small pressure gradient. Figure 11 shows a comparison of accumulative production rate, simulated first by Darcy's law flow model and then a non-Darcy's flow model of this work, under the same injection and production conditions (2 m^3/day). The result of this comparison (Figure 11) shows that for a low-permeability reservoir, using Darcy's law could significantly overestimate production rates. It is also found that the simulation results using the nonlinear model better match field production data.

Concluding Remarks

This paper presents a model using a modified Darcy's law, based on experimental results, for describing experimentally observed nonlinear flow phenomena in low-permeability reservoirs. The proposed model treats the effective permeability of

low-permeability rock as a function of pressure gradient to account for the fact that (1) the flow rate in low-permeability rock is not linearly proportional to the pressure gradient, nor does it follow Darcy's law in general; and (2) flow will not occur until the applied pressure gradient is larger more than a certain threshold value. Sensitivity simulation studies using the modified Darcy's law indicate that when incorporating nonlinear flow behavior, the model results are more realistic with respect to field data in terms of well performance, production rates, and predictions. Application of the model in field simulations is an ongoing activity.

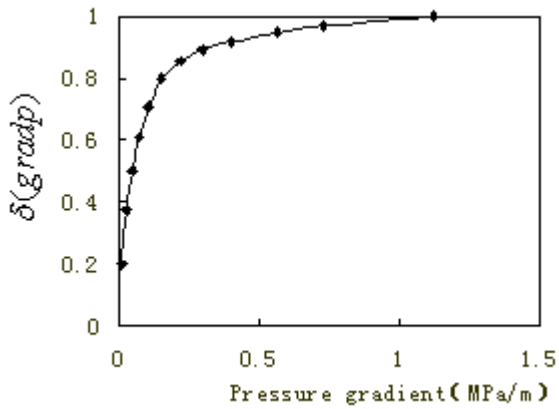


Fig. 7. Adjustment factor of permeability

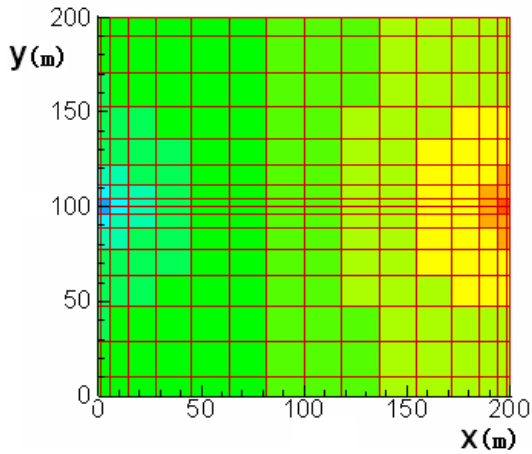


Fig. 8. Grid of reservoir model

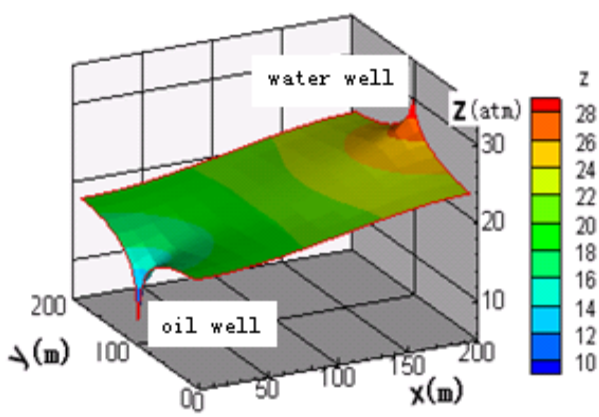


Fig. 9. Pressure distributions between oil and water wells

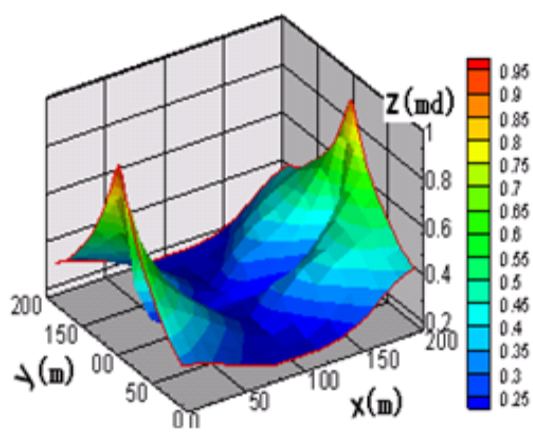


Fig. 10. Permeability field between oil and water wells

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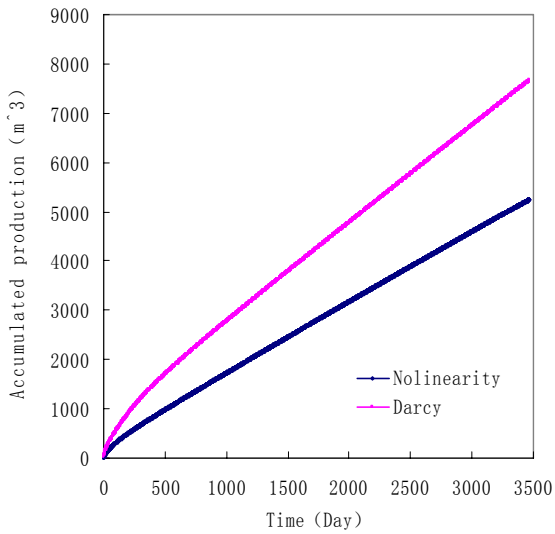

Fig. 11. Accumulative production predicted by Darcy law and nonlinearity flow model