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CHANGES IN ROCK PERMEABILITY NEAR-WELLBORE DUE TO OPERATIONAL LOADS

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Abstract. The paper presents the results of studies of changes in the permeability of rocks in the bottom hole zone of wells in the process of oil production. Using the exponential equation for predicting the permeability of the rock with a change in reservoir pressure based on the data of well test data, an improved model is proposed. The developed model takes into account operational conditions that lead to a change in the structure of the rock matrix and oil degassing as a result of a reservoir pressure decrease. The proposed model includes empirical parameters. The model describes the hysteresis of the rock permeability for oil during the subsequent decrease and increase in reservoir pressure. For the model under consideration, the average change (decrease) in the permeability at the wellbore with an increase and subsequent decrease in the load is 30% of the initial value. Using the proposed model, numerical hydrodynamic calculations of the change in the time of oil production with a change in pressure were carried out. The lower the reservoir pressure, the longer the period of oil production. A significant decrease in reservoir pressure at the initial stages of oil production and its subsequent production leads to an increase in the terms of the development of recoverable oil reserves.

Keywords: stress-sensitive reservoir, rock, matrix, permeability, oil production

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1. Introduction

The permeability of rocks is sensitive to changes in their stress state caused by changes in reservoir pressure. The change in reservoir pressure in rock pores leads to a change in effective pressure which represents a difference between lithostatic pressure and reservoir pressure [1]. With an increase in effective rock pressure associated with a decrease in reservoir pressure during oil recovery, the matrix is compressed, compacted, resulting in a

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decrease in the permeability of the rock and, in the long term, a decrease in the well flow rate and oil production in the field as a whole.

Exponential [2-4], power [5-7], logarithmic and power [8], as well as other combined [9,10] empirical equations are used to model the changes in the permeability of rocks under the action of effective rock pressures. Information on the relations used can also be found in [11].

There are no doubt that modeling in laboratory conditions on core samples is necessary to understand what equations should be used to predict changes in rock permeability with a change in effective pressure. However, a feature of the mentioned equations is that they do not take into account the influence on the rock permeability of the processes that are often observed in field conditions during oil production. These include, in particular, a change in the rock structure and oil degassing.

A change in the structure of the rock is observed when the effective pressure exceeds the ultimate strength of the rock. In this case, the change in the structure is determined by the process of destruction of the porous rock matrix, the fragments of which block the channels connecting the pores. As a result, during pumping the liquid through the rock at a constant flow rate, an additional pressure drop occurs ΔP, which leads to a decrease in rock permeability k, since $k \sim 1/\Delta P$. As a result of such a change in the rock structure the permeability of the matrix also irreversibly decreases [12]. This means that with a decrease in effective pressure (an increase in reservoir pressure in the pores of the rock), the permeability will not be restored to its original value. A similar case is often observed in the near-wellbore zone of the reservoir, where there is an intensive decrease in reservoir pressure $P_{res.}$ to bottom hole pressure P_{BH} as the flow of oil approaches the well.

Degassing of oil, associated with the release of gas from oil with a decrease in reservoir pressure below the saturation pressure of oil with gas, leads to the appearance of two phases in the rock. In this case, with an increase in the amount of released gas, the relative phase permeability of the rock for gas will increase, and the permeability for oil will decrease [13]. Moreover, the process is irreversible. If the effective pressure is increased, then not all of the gas released into the free phase will dissolve back into oil, and the phase permeability of the rock for oil will not reach the initial value. This phenomenon is observed in laboratory conditions but is not taken into account when predicting changes in the permeability of the near-wellbore formation zone.

In connection with the mentioned above, in order to predict the technological parameters of oil field development, such as well flow rate and pressure distribution in the reservoir, it is necessary to take into account the permeability hysteresis caused by changes in the rock structure and oil degassing. To overcome such an issue, this article proposes to modify the existing relationships in such a way that they take into account these phenomena.

The basis for the construction of model relationships is given by the studies carried out by many authors both on the study of permeability depending on changes in the structure of rocks, and on the study of permeability depending on the presence of two-phase flow in the rock under conditions of oil degassing.

Based on experimental data from the results of well testing in Section 2 an improved model of changes in rock permeability under conditions of a changed structure of the matrix material and degassing is constructed. Using the model obtained numerical modeling of changes in rock permeability was performed in Section 3 taking into account its deformation under degassing conditions. Section 4 concludes with the results obtained.

2. Formulation of the rock permeability change model

When extracting oil from a reservoir, two factors should be pointed out, the action of which leads to a decrease in reservoir pressure $P_{res.}$. The first factor takes into account the decrease in reservoir pressure from the initial pressure value $P_{res.0}$ down to a certain current $P_{res.}$. In models [2-11], the value $P_{res.}$ is assumed to be the same over the entire area of the reservoir and equal to the value in its remote area from the well. The second factor is related to the existence of a non-uniform distribution of reservoir pressure in the rock, i.e. relation of $P_{res.}$ on the distance to a well: reservoir pressure decreases from $P_{res.}$ to P_{BH} as oil approaches the production well from a remote part of the formation, the so-called depression funnel or pressure drawdown on the reservoir $\Delta P = P_{res.} - P_{BH}$ is observed (Fig. 1a).

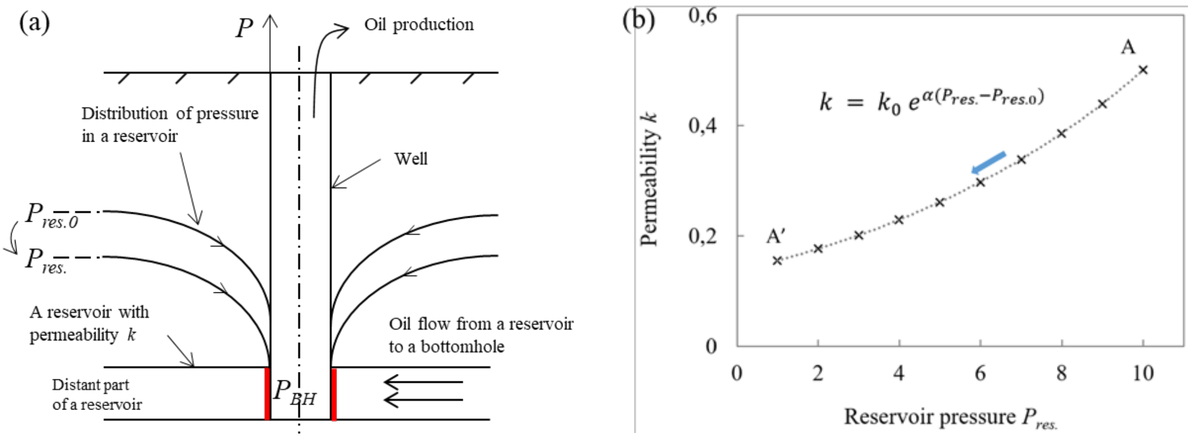

Fig. 1. Distribution of rock characteristics during oil production: (a) change in reservoir pressure with distance from the well; (b) dependence of the rock matrix permeability on reservoir pressure without taking into account operational conditions (on the example of the model in [4])

The factors described above lead to a decrease in rock permeability. Modeling the change in permeability in a remote part of the reservoir (in the area where the well operation does not affect the pressure in the reservoir) depending on pressure can be performed in laboratory conditions on core samples using equations such as in [2-11] (see Fig. 1b). At the same time, the effect of pressure reduction around the well on rock permeability is not taken into account in [2-11].

We will show below how to formulate a model that takes into account both factors described above. As an example, we will proceed from the model of V.N. Nikolaevsky and A.T. Gorbunov [4]. To predict changes in rock permeability k with a decrease in pressure changes, they proposed an exponential equation:

$$k = k_0\, e^{\alpha(P_{res.}-P_{res.0})}, \tag{1}$$

where initial reservoir permeability k_0, initial $P_{res.0}$, and certain current $P_{res.}$ reservoir pressures and rock matrix deformation coefficient α , MPa^{-1} are considered as independent parameters.

In order to take into account the change in rock matrix permeability in the well area, caused by pressure drawdown on the formation, it is necessary to enter the bottom hole pressure P_{BH}. Keeping the functional (exponential) relationship between permeability and pressure, we change the argument $P_{res.}$ for a convex combination $\alpha P_{res.} + \beta P_{BH}$, where $\alpha + \beta = 1$. In the limiting case when the well is closed and the pressure in the reservoir $P_{res.} = P_{BH}$, we have the model (1). Since the task is to build another model, it is necessary to specify α and β. The easiest way to choose is to take into account the influence of reservoir and bottom hole pressures in a symmetrical way, i.e. $\alpha = \beta = 1/2$. Then equation (1) is reduced to the form

$$k = k_0\, e^{\alpha_d\left(\frac{P_{res.}+P_{BH}}{2}-P_{res.0}\right)}. \tag{2}$$

Relation (2) describes the change in rock permeability k using known values of field parameters. Equation (2) is substituted with the permeability value obtained experimentally from the results of well tests [14]. The values $P_{res.}$ and P_{BH} correspond to the current values of reservoir pressure and well bottom hole pressure during well test, k_0 and $P_{res.0}$ correspond to the initial permeability and reservoir pressure. The only selectable parameter is the empirical deformation factor α_d, the selection of which is given in [15].

Equation (2), on the one hand, when the well is shut off ($P_{res.} = P_{BH}$) allows determining the change in rock permeability with a decrease in pressure in the reservoir from $P_{res.0}$ down to $P_{res.}$ during oil production. On the other hand, when the well is shut-in, the bottom hole pressure is lower than the reservoir pressure $P_{BH} < P_{res.}$, therefore substituting the value of the current bottom hole pressure P_{BH} in the equation (2) will allow determining how much rock permeability is changed, taking into account the pressure drawdown during well operation. Thus, in addition to the main change in permeability due to a decrease in pressure in the reservoir, an additional contribution of a change in permeability in the well zone is taken into account.

Equation (2) describes the change in permeability when the reservoir pressure is above the saturation pressure level $P_{sat.} < P_{res.}$, which corresponds to a zone AB in Fig. 2. Existence of saturation pressure $P_{sat.}$. leads to hysteresis in permeability behavior. The effect of hysteresis is shown in Fig. 2 and is represented as a discrepancy between the curves of changes in rock permeability for oil between its values with a decrease and a subsequent increase in reservoir pressure.

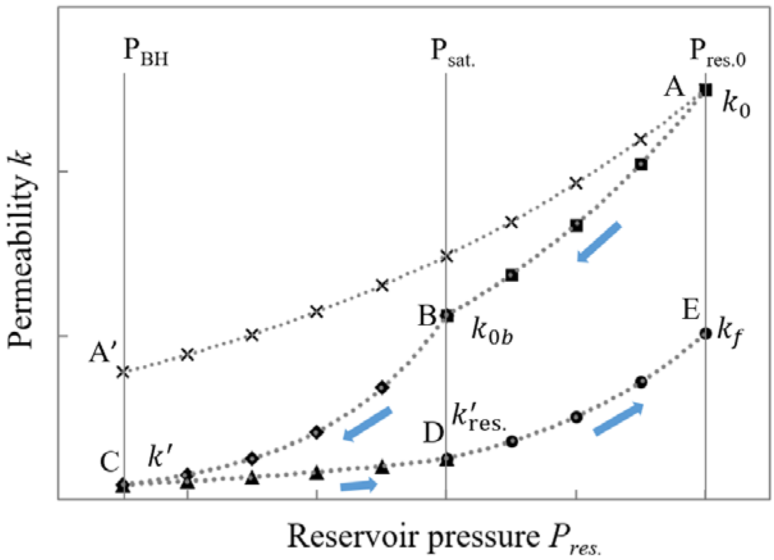

Fig. 2. Hysteresis of rock permeability for oil with a decrease in reservoir pressure taking into account additional changes in the matrix due to pressure drawdown during well operation and taking into account oil degassing due to a decrease in reservoir pressure below the saturation pressure of oil with gas (curve ABCDE). The curve AA′ corresponds to a change in permeability with a change in reservoir pressure according to the model [4], which does not take into account operational factors

Let us explain from the point of view of physics the hysteresis of rock permeability with respect to oil. If reservoir pressure becomes equal to saturation pressure. If reservoir pressure becomes equal to saturation pressure $P_{res.} = P_{sat.}$ two-phase flow begins in the reservoir near the well and the initial permeability is equal to the value $k = k_{0b}$. With a further decrease in pressure below the saturation pressure in the region BC bottom hole pressure becomes the dominant parameter that affects the permeability of the rock. Therefore, in the area *BC* by formation pressure we mean bottom hole pressure. The lower the bottom hole pressure in the reservoir than saturation pressure, the more intense the degassing of oil and, as a result, the decrease in the phase permeability for oil. With an increase in bottom hole pressure in the area *CD*, initial permeability in which $k = k'$, the gas released from the oil at the previous stage begins to dissolve back into the oil. However, the permeability of the matrix is not completely restored, since part of the usable space in pores is already irreversibly occupied by free gas, and the changed structure of the matrix does not allow the rock to return to its original state. Thus, we obtain the hysteresis of the permeability behavior (curve ABCDE).

Due to the conservativeness of the modeling ideology, we will keep the functional relationship (1) between the permeability and pressure for the *BC* area by changing the argument in the equation:

$$k = k_{0b}\, e^{\alpha_1 (P_{BH} - P_{sat.})}. \tag{3}$$

The parameter α_1 is chosen empirically for the region *BC*. To describe the change in permeability with increasing pressure in the area from bottom hole pressure P_{BH} up to saturation pressure $P_{sat.}$ we denote the pressure in the reservoir in this area as $P_{res.}$, then for the region *CD* we get:

$$k = k'\, e^{\alpha_2 (P_{res} - P_{BH})}, \tag{4}$$

where the parameter α_2 is chosen empirically.

With a further increase in reservoir pressure in the *DE* region, the free gas is already partly dissolved back into the oil. The other part of the undissolved gas remaining in the free state reduces the phase permeability of the rock for oil. In addition, the changes acquired by the rock matrix do not allow the permeability to take its original value, at a similar pressure in the reservoir. Therefore, the initial for the region *DE* the permeability of the rock is equal to the value $k = k'_{res.}$, the value of which is higher than the value of the initial permeability of the rock at the previous stage *CD*, but below the initial permeability in the areas *AB* and *BC* $k' < k'_{res.} < k_{0b} < k_0$.

In the region *DE* the rock permeability equation has a similar to (2) form:

$$k = k'_{res.}\ e^{\alpha_d \left(\frac{P_{res.} + P_{BH}}{2} - P_{res.}\right)}. \tag{5}$$

At the boundary of the *DE* region, with increasing pressure in the reservoir, the final permeability is k_f, which is lower than the original $k_f < k_0$. As a result of the decrease and subsequent restoration of the reservoir and, accordingly, effective pressure, the rock and the fluid contained in the pores undergo irreversible changes, which lead to permeability hysteresis.

Estimation of the change of empirical parameters α_1 and α_2 for different values of rock permeability can be performed based on the analysis of well test results. It was found that in the range of empirical parameters α_1 in (3) and α_2 (4) the following approximations can be specified (Fig. 3):

$\alpha_1 = 0.3247 - 0.03 \times ln(k/k_{av.})$, ($k$ = 0.01…1.27 ×10^{-3} μm^2),

$\alpha_2 = 0.25 + 0.015 \times ln(k/k_{av.})$,

where $k_{av.}$ and $k/k_{av.}$ denote to average and relative permeability of sandstone. Empirical parameter values α_d are also selected based on well test results.

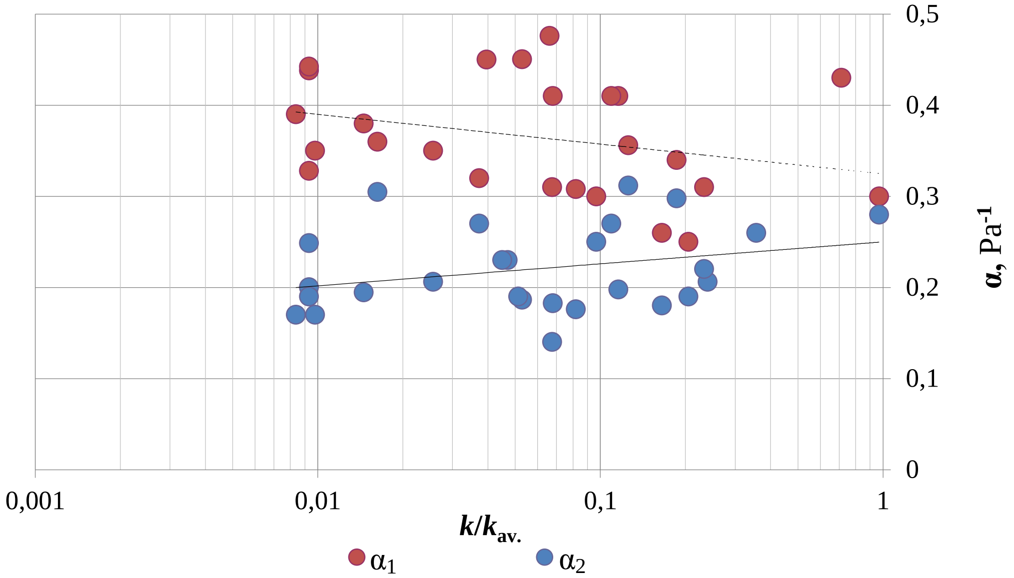

Fig. 3. Dependence of empirical parameters α_1 and α_2 on the rock's relative permeability

It is seen from Fig. 3 that with an increase in reservoir permeability, and the values of the parameter α_1 decrease, the values of parameter α_2 increase. From the point of view of the model (2)-(5), a decrease in the empirical parameter α_1 with a decrease in relative permeability corresponds to a decrease in reservoir pressure, a change in the rock matrix, and oil degassing, which manifests itself in an increase in the slope of the curve *BC* (see Fig. 2). An increase in parameter α_2 with a decrease in relative permeability corresponds to an increase in reservoir pressure, dissolution of released free gas in oil, and an increase in rock permeability at the interval *CD*.

Equations (2)-(5) were obtained for clastic (sandstone) reservoirs of the Perm region of porous type as a result of experimental studies of a number of production wells (well test). Under similar conditions, relations (2)-(5) allow predicting of the change in permeability in other producing wells without conducting well tests. In addition, relations (2)-(5) are of great importance for modeling the development of oil fields and predicting optimal scenarios for oil production from the fields with similar characteristics of the rock and the oil that saturates it.

Considering that during the development of an oil field, a decrease in rock permeability in the near-wellbore zone leads to an increase in the terms of oil extraction from the reservoir, it is relevant to predict the change in the permeability of the rock using the obtained model (2)-(5). In section 3 a numerical simulation of the change in permeability in a hydrodynamic simulator is performed.

3. Numerical simulation using the refined model

Numerical modeling allows predicting the dynamics of technological indicators of oil deposit development, taking into account changes in rock permeability during reservoir deformation. Hydrodynamic modeling was performed in a hydrodynamic simulator Tempest (ROXAR). In the simulator, the flow of oil (o), water (w), and gas (g) in a porous medium obeys the Darcy law, the equations of continuity of the flow of a weakly compressible multiphase fluid, and the Newtonian flow.

Continuity equations for water, oil, and gas include formation permeability k. Permeability changes its value with changes in reservoir pressure.

The following calculation algorithm is proposed:

1) determining the pressure in the reservoir and saturation of the reservoir with oil, water, and gas by solving the material balance equation;

2) calculation of effective pressure;
3) calculation of reservoir permeability;
4) determination of fluid flow between cells.

To study the effect of pressure changes on deformation, permeability, and productivity, a model of a field area with two wells was created using the example of a typical oil reservoir in Perm region. Modelling on a field section with two wells allows for evaluation of the dynamics of oil production under various scenarios for changing reservoir pressures and creates the basic foundations for regulating production at oil fields.

The main parameters of the reservoir are given below:

Permeability, $\times 10^{-3}$ μm^2	100
Reservoir thickness, m	10
Porosity, %	20
Depth, m	1400
Gas saturation pressure, MPa	8.6
Pore pressure, MPa	16
Bottom hole pressure, MPa	10
Injection pressure, MPa	22

Figure 4 shows a 3D model of the reservoir area at the end of development with water injection.

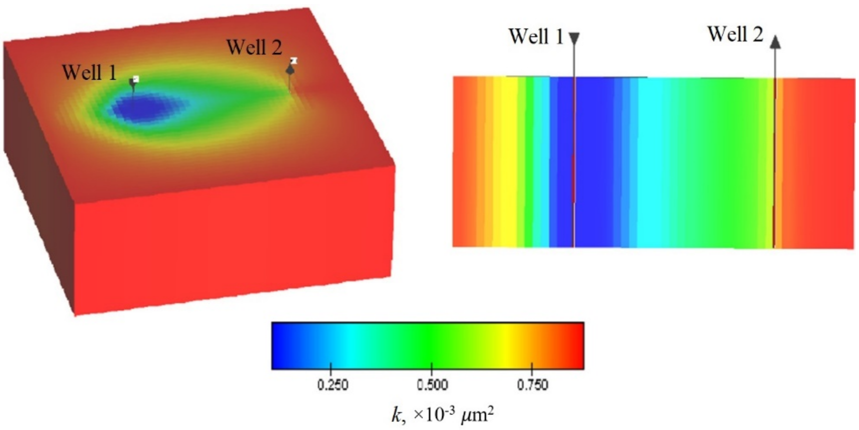

Fig. 4. A 3D model of the reservoir area at the end of development with water injection (one of the options): Well 1 represents an injection well; Well 2 represents a production well

It was obtained during modeling, that the permeability near the production well decreases more intensively than the permeability at the periphery (which confirms the experimental well test data). In addition, the average reservoir permeability in the absence of water injection into the reservoir (that is, without compensation/restoration of reservoir (pore) pressure) at the end of development becomes 30% lower than the initial permeability (Fig. 5). It can be seen from the fluid pressure contours that the pressure gradients change dramatically in the area of change in the structure of the rock matrix (blue color). The pressure profiles were strongly influenced by permeability and porosity. This means that an increase in the experimental parameters for porosity and permeability presented in this paper leads to a strong change in the rock matrix, with a decrease in pressure, as can be seen in the vertical section (Fig. 4 on the right), which can be interpreted as a decrease in permeability caused by a change in the structure of the rock with constant productivity of the production well.

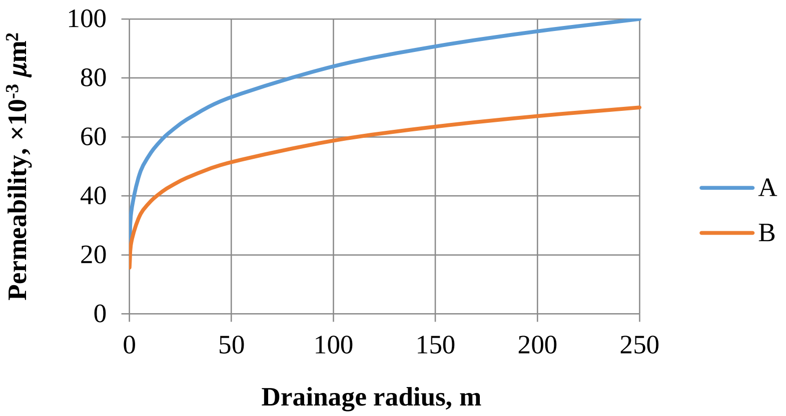

Fig. 5. Dependence of the permeability on the drainage radius without water injection at the beginning of modeling (A) and after a year of production (B)

4. Conclusion

Using experimental data from the well testing on oil fields in the north of the Perm region an improved model of changes in rock permeability during oil production was obtained. The model is based on the exponential dependence of rock permeability. In addition to the parameters generally accepted in models, the refined model additionally contains saturation pressure (to take into account oil degassing) and pressure at the bottom of the well (to take into account changes in the structure of the rock). The resulting model describes the hysteresis of the rock matrix permeability caused by the technological conditions during well operation. According to the results of numerical modeling using the refined model in the simulator, it was obtained that the average reservoir permeability in the absence of water injection into the reservoir (without compensation/restoration of reservoir pressure) at the end of development becomes 30% lower than the initial permeability. Taking into account the additional influence of the degassing effect, the permeability of the rock around the well is not overestimated and approaches the real one. Taking into account the change in the structure of the rock and the corresponding decrease in permeability as a result of oil degassing, the period for the development of the oil field increases, which has to be taken into account in reservoir engineering.

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