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ON DAMAGE PROPAGATION IN A SOFT LOW-PERMEABILITY FORMATION

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INTRODUCTION

In this presentation, we develop a mathematical model of fluid flow with changing formation properties. The modification of formation permeability is caused by development of a connected system of fractures. As the fluids are injected or withdrawn from the reservoir, the balance between the pore pressure and the geostatic formation stresses is destroyed. If the strength of the rock is not sufficient to accommodate such an imbalance, the cementing bonds between the rock grains become broken. Such a process is called damage propagation. The micromechanics and the basic mathematical model of damage propagation have been studied in [7]. The theory was further developed in [3], where new nonlocal damage propagation model has been studied. In [2] this theory has been enhanced by incorporation of the coupling between damage propagation and fluid flow. As it has been described above, the forced fluid flow causes changes in the rock properties including formation permeability. At the same time, changing permeability facilitates fluid flow and, therefore, enhances damage propagation.

One of the principle concepts introduced in [3] and [2] is the characterization of damage by a dimensionless ratio of the number of broken bonds to the number of bonds in pristine rock per unit volume. It turns out, that the resulting mathematical model consist of a system of two nonlinear parabolic equations.

As it has been shown in [6] using modeling of micromechanical properties of sedimentary rocks, at increasing stress the broken bonds coalesce into a system of cracks surrounding practically intact matrix blocks. These blocks have some characteristic size and a regular geometry. The initial microcracks expand, interact with each other, coalesce and form bigger fractures, etc. Therefore, as the damage is accumulated, the growing system of connected fractures determines the permeability of the reservoir rock.

Significant oil deposits are stored in low-permeability soft rock reservoirs such as shales, chalks and diatomites [9, 10]. The permeability of the pristine formation matrix in such reservoirs is so low that oil production was impossible until hydraulic fracturing was applied. For development of correct production policy, it is very significant to adequately understand and predict how fast and to what extent the initial damage induced by drilling and hydrofracturing will propagate into the reservoir.

The importance of fractures for rock flow properties is a well-established and recognized fact [4, 9, 5]. Different conceptual models have been developed [8]. In this study, we propose a damage propagation model based on a combination of the model of double-porosity and double-permeability medium [4] and a modification of the model of damage propagation developed in [2].

THE MODEL

One of the basic assumptions of the dual porosity model proposed in [4], see also [1], states that the pore space in many natural rocks can be put into two categories. The first category consists of the “classical” pore matrix, where the pores are the openings between the grains. Bigger pores, pore bodies, are connected by narrow channels, pore throats. The geometry and the sizes of pores determine the porosity and the permeability of the rock. The whole rock consists of matrix blocks surrounded by fractures. Fractures are the regions where the bonds between the grains are broken and the broken links coalesce into two-dimensional structures. The length scales of fractures can vary in a wide range. However, due to small apertures, the total volume of the fractures is small in comparison with the volume of matrix pores. At the same time, the geometry of fractures is simpler than that of matrix pore channels, therefore, if a pressure gradient is applied, the fractures transport the fluids much easier than the matrix. Consequently, the fluid in the matrix blocks first flow into the surrounding fractures, after what it can be transported away through the connected system of fractures. Thus, the matrix blocks support the fluid storage capability of the rock, whereas the system of fissures determines the permeability.

Often, the fracture permeability is an anisotropic parameter, *i.e.*, the Darcy velocity is not necessary co-directed with the pressure gradient [9, 10]. For simplicity, in this study we assume that the difference between the eigenvalues of the permeability tensor can be neglected and the fracture permeability coefficient k_f is a scalar quantity.

Further, we assume that both the matrix blocks and the connected fractures are intertwined in a representative elementary volume. Therefore, at each point of the rock both conducive fractures and matrix are present simultaneously. The fluid pressures in the matrix blocks, p_m , can be different from fluid pressures in the fractures, p_f . At every point of this dual medium the difference between two pressures defines the rate of the cross-flow between the media, q . Using dimensional considerations, it has been obtained in [4] that

$$(1) \quad q = \alpha \frac{p_m - p_f}{\mu}$$

where μ is the fluid viscosity. Dimensionless coefficient α depends on the characteristic length L associated with the matrix blocks, on the permeability of the matrix k_m and on the geometric structure of matrix-fractures

configuration. In a homogeneous reservoir elastic-drive equation for fluid pressure in the fractures, p_f , has the following form [4]

$$(2) \quad \frac{\partial p_f}{\partial t} - A \frac{\partial}{\partial t} \left(\frac{1}{\alpha} \nabla \cdot (k_f(\alpha) \nabla p_f) \right) = B \nabla \cdot (k_f(\alpha) \nabla p_f)$$

where

$$(3) \quad A = \frac{\beta_{mm} + \beta}{\beta_{mm} + \beta - \beta_{fm}}$$

and

$$(4) \quad B = \frac{1}{\phi_m \mu (\beta_{mm} + \beta - \beta_{fm})}$$

Here the coefficient β_{fm} characterizes the decrease of matrix porosity when the pressure in the surrounding fractures increases and coefficient β_{mm} characterizes the pore space expansion at increasing pore pressure in the matrix. Finally, β is the fluid compressibility. A similar equation can be obtained for the matrix pressure p_m . One can show that the two pressures are related by the following equation:

$$(5) \quad \begin{aligned} p_m = & e^{-\frac{B}{A} \int_0^t \alpha d\tau} \left[p_m|_{t=0} - \left(1 - \frac{1}{A} \right) p_f|_{t=0} \right] \\ & + \left(1 - \frac{1}{A} \right) p_f + \frac{B}{A^2} \int_0^t e^{-\frac{B}{A} \int_\tau^t \alpha d\xi} \alpha p_f d\tau \end{aligned}$$

In particular, if initially both fluid pressures were equal to the reservoir pressure p_r , then

$$(6) \quad p_m = \frac{1}{A} e^{-\frac{B}{A} \int_0^t \alpha d\tau} p_r + \left(1 - \frac{1}{A} \right) p_f + \frac{B}{A^2} \int_0^t e^{-\frac{B}{A} \int_\tau^t \alpha d\xi} \alpha p_f d\tau$$

The damage accumulation is increase in the number of broken bonds between rock grains. To quantify the damage, it was proposed in [3] to use the ratio of the number of broken bonds and the number of bonds in pristine rock, ω . Since the flow properties of the rock are determined by a connected system of fractures, it is natural to replace the parameters ω with coefficient α introduced in Eq. (1). In fact, the coefficient α is a function of ω . By virtue of Eq. (1), the increase of the coefficient α results in a faster fracture and matrix pressures equilibration.

Further weakening of the skeleton due to the damage accumulation may result in a significant rearrangement and collapse of the matrix blocks that may lead even more significant permeability changes. In this study, we consider the stage where such a collapse does not occur and both coefficients of fracture permeability k_f and matrix-fracture cross-flow α remain monotonically increasing functions of the damage parameter ω . Therefore, we assume a one-to-one correspondence between the two and parameter ω can be eliminated. In other words, the coefficients k_f and α are the damage

parameters. We select α as the basic damage parameter and express the fracture permeability as the dependent variable:

$$(7) \quad k_f = k_f(\alpha)$$

We remark that the parameter ω is not available for direct measurement, whereas both coefficients α and k_f can be determined, for instance, from a well test. Using the one-to-one correspondence between ω and α , the damage accumulation model [3] can be reformulated in terms of parameter α . Therefore, we obtain:

$$(8) \quad \frac{\partial \alpha}{\partial t} = \mathcal{G}(\alpha) \nabla \cdot (\mathcal{D}_\alpha(\omega, p_m) \nabla \alpha) + \mathcal{F}_\alpha(\alpha, p_m)$$

Here

$$(9) \quad \mathcal{G}(\alpha) = \frac{1}{\omega'(\alpha)}$$

Function \mathcal{G} characterizes the how the increasing number of broken bonds affects the cross-flow coefficient α . Function \mathcal{D} characterizes the spacial correlation between local damage accumulation at different locations. Finally, function \mathcal{F} determines the rate of damage accumulation at changing pore pressure. All three functions have to be determined from experiments.

To make the model complete, the differential equations must be complemented by initial and boundary conditions. To formulate these conditions, we need to analyze the dependence of the fracture permeability on the cross-flow factor α .

Let us start with initial conditions by assuming that the permeability of pristine rock is practically zero. If the rock is intact, the matrix blocks are large and the coefficient α is close to zero. At the same time, both the density and connectedness of the fracture system are scarce and therefore we can assume that

$$(10) \quad k_f(0) \approx 0$$

Moreover, at steady-state conditions, the pressures do not change, therefore, the pressures p_m and p_f are equal. Hence, we obtain the following initial condition

$$(11) \quad p_f|_{t=0} = p_m|_{t=0} = p_r$$

where p_r it the initial reservoir pressure.

Inasmuch as the pristine formation has a sparse system of fractures, the initial condition for the damage parameter can be formulated in the following way

$$(12) \quad \alpha|_{t=0} = \alpha_*$$

Now, let us proceed with the boundary conditions. At infinity, the reservoir is intact:

$$(13) \quad \lim_{x^2+y^2 \rightarrow \infty} p_f = \lim_{x^2+y^2 \rightarrow \infty} p_m = p_r$$

$$(14) \quad \lim_{x^2+y^2 \rightarrow \infty} \alpha = \alpha_*$$

It is known [1], that if initially the damage is localized in a finite zone, say, near a wellbore or a hydrofracture, then in many cases the solutions to quasi-linear parabolic equations like Eqs. (2) and (8) has a finite speed of propagation. The model can be formulated as a free-boundary problem.

Equations (2) and (8) are coupled. The structure of the solution needs to be determined from further analysis and numerical simulations.

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