Study of filtration processes of a two-phase fluid in a zonal-inhomogeneous fractured-porous medium

A A Pyatkov¹, S P Rodionov¹, V P Kosyakov¹ and N G Musakaev¹,²

¹Tyumen Branch of Khristianovich Institute of Theoretical and Applied Mechanics of SB RAS, Taymirskaya Str. 74, 625026, Tyumen, Russia
²Industrial University of Tyumen, Volodarskogo Str. 38, 625000, Tyumen, Russia

pyatkovi80@mail.ru, rodionovsp@bk.ru, hammer-rav@mail.ru, musakaev@ikz.ru

Abstract. A significant amount of proven reserves of hydrocarbons are contained in the fields to some extent have fracturing. Fractures have high conductivity, and, therefore, have a significant impact on the process of extracting oil from the reservoir. In this regard, it is necessary to investigate the filtration processes of a mixture of water and oil in fractured-porous reservoirs. In this paper, the task of selecting options for the appointment of injection and production wells in a zonal-inhomogeneous fractured-porous reservoir to the most complete extraction of oil from the reservoir. A study was also made of the influence of the intensity of water injection on the efficiency of oil recovery from a fractured-porous reservoir. The tasks were solved using our own three-dimensional two-phase hydrodynamic simulator based on the model of dual porosity-permeability.

1. Introduction

Naturally fractured reservoirs contain a significant share of the world's hydrocarbon reserves [1]. Despite the small relative volume of fractures, they have high conductivity and, therefore, can have a qualitative effect on the production of hydrocarbons [2]. From practice, there are cases of increased oil recovery with a decrease in the rate of water injection. This situation is typical of fractured-porous reservoirs. While under homogeneous reservoir conditions, a decrease in the rate of water injection does not lead to an increase in oil recovery. In addition, changing the direction of seepage fluids in fractured porous reservoirs can also lead to an increase in oil recovery.

The distribution of stresses in a real reservoir is inhomogeneous. Fractures in such a reservoir can be found both in the compaction zones and in decompaction zones. Therefore, aperture of a fracture (and hence its permeability) will depend on which of these zones it will be in. In addition, fracture aperture can be influenced by the change in pressure during non-stationary flooding. In connection with the above, the study of flow in fractured reservoirs is relevant. In particular, it is of interest to study the effect of the rate of water injection and changes in the direction of seepage fluids in a fractured-porous reservoir on the process of oil production.

The purpose of this work is to study the effect of the intensity of water injection on the efficiency of oil extraction from a fractured-porous reservoir, as well as solving the problem of selecting options for the appointment of injection and production wells in a zonal-inhomogeneous fractured-porous reservoir.
2. Mathematical model
To describe the motion of a weakly compressible fluid (oil and water) in a fractured-porous medium for each continuum, the following system of equations is used, including the equations for the conservation of phase masses and the general Darcy law [3]:

\[
S_l (\phi \beta_l + \beta_c) \frac{\partial p}{\partial t} + \phi \frac{\partial S_l}{\partial t} + q = \text{div}(v)
\]

\[\quad (l = w, o)\]

\[v = -k \frac{k_o}{\mu_l} \text{grad}(p)\]

\[S_n + S_p = 1\]

In the presented equations, the subscript \(l\) below indicates the values related to the \(l\)-th phase \((l = w - \text{water}, l = o - \text{oil})\), \(p\) is the pressure, \(S\) is the saturation, \(v\) is the velocity vector, \(\mu\) is the viscosity, \(k_o\) is the relative permeability, \(k\) is the absolute permeability, \(\beta\) is the fluid compressibility, \(\phi\) is the porosity, \(\beta_c\) is the rock compressibility, and \(q\) is the intensity of internal sources (wells). It is assumed that the influence of gravitational and capillary forces is negligible. The flow of fluid between the continua is proportional to the difference in reservoir pressures in them [4, 5].

The dependence of the fracture permeability \(k_f\) on the pressure \(p\) was given in the form [6]:

\[k_f = k_0^f \left[1 - \alpha \left(p_0 - p\right)\right]^3,\]

where \(k_0^f\) is the fracture permeability at initial reservoir pressure \(p_0\), \(\alpha\) is the parameter of the fractured medium, which depends on the elastic properties and geometry of the fractures. The calculations were made by the method of control volume on an irregular grid.

3. The problem of selecting the options for the appointment of injection and production wells in the zonal-inhomogeneous fractured-porous reservoir
In practice, it is mainly necessary to work with reservoirs that are anisotropic in permeability. One example of such reservoirs can serve as a zonal-inhomogeneous fractured-porous reservoir. In such reservoirs it is possible to allocate a high-permeable zone and a low-permeable zone. The system of fractures can be located both in the low-permeable zone and in the high-permeable zone. For the most effective development of the field, it is necessary to solve the problem of well placement. Namely, to determine the production or injection wells are most advantageous to have in the area with fractures.

Let us consider the model of a zonal-inhomogeneous fractured-porous reservoir. Let the reservoir consist of two zones with different permeability. The system of fractures is contained in the zone with less permeability. Consider two options for well placement: injection wells are located in the zone with fractures (model 1), production wells are located in the zone with fractures (model 2). The models of a zonal-inhomogeneous fractured-porous reservoir are shown in figure 1.

The parameters of the reservoir, fluids and modes of operation of wells took the following values: the size of the reservoir - 1000×1000×5 m; porous reservoir porosity - 0.2; fractured reservoir porosity - 0.05; initial/residual water saturation - 0.2; residual oil saturation - 0.2; the pore permeability is 100 mD and 400 mD; the initial permeability of fractures is 500 mD; the initial reservoir pressure is 100 atm; water/oil viscosity ratio - 1/10; bottomhole pressure (production wells) - 50 atm; bottomhole pressure (injection wells) - 200 atm; the compressibility of water, oil and porous media is 5·10^{-5}, 5·10^{-4} and 3·10^{-4} 1/atm, respectively. The calculation is carried out until reaching a water cut of production wells of 0.98. The types of relative phase permeabilities for pores and fractures are shown in figure 2. Figure 3 shows the dependences of oil recovery factor and water cut on time for models 1 and 2.
Figure 1. Zonal-inhomogeneous fractured-porous reservoir models. Injection wells are located in the fractured zone (a). Production wells are located in the fractured zone (b).

Figure 2. The types of relative phase permeabilities.

Figure 3. Typical dependencies of oil recovery factor (a) and water cut (b) on time for models 1-2.

From figure 3a it can be seen that the final ORF for model 2 is higher than for model 1. In addition, the maximum water cut of producing wells is achieved faster than for the model 1. From figure 3b it can be seen that for model 1 the water cut profile is similar to the water cut profile of a medium with one porosity and one permeability. While for model 2, the water cut profile looks similar to the water cut profile for a medium with double porosity and double permeability. Thus, the model 2 is more
effective – a model with producing wells located in a low-permeable zone. To explain the results, refer to figures 4a, 4b. They show the flow of oil and water between the pores and fractures, respectively.

![Figure 4](image)

**Figure 4.** The intensity of the exchange of water and oil between fractures and pores for models 1-2.

From figure 4a and 4b, it can be seen that for model 2 most of the development time was the flow of oil from the pores into the fractures. The result is that oil quickly reached production wells through highly conductive fractures. In model 1, oil, on the contrary, flowed from fractures into the pores. As a result, oil slowly reached production wells. Also a disadvantage of the model 1 is the following circumstance. Water injection in this model occurs in the fractured zone of the reservoir, because of which the water quickly breaks through the system of fractures into the highly permeable zone of the reservoir, increasing the water cut of producing wells. In model 2, on the contrary, the system of fractures is not prone to water flooding directly from the wells and most of the development time through it is oil is filtered.

These circumstances explain the advantage of model 2 over model 1. Thus, it is more advantageous to place production wells in a fractured zone in a zonal-inhomogeneous fractured-porous reservoir.

4. **Investigation of the influence of the intensity of water injection on the efficiency of oil recovery from a fractured-porous reservoir**

The study was conducted using a synthetic reservoir model developed by the row scheme of arrangement of wells. In view of the use of the double porosity and dual permeability model, we consider that the all reservoir is covered by a connected network of small fractures. When the reservoir pressure \( p \) is less than the initial pressure \( p_0 \), the fractures are closed, and their permeability becomes equal to 0.1 of the pore permeability. When the reservoir pressure \( p \) is greater than the initial pressure \( p_0 \), the permeability of fractures is determined by formula (2). The parameters of the reservoir, fluids and modes of operation of wells took the following values: the dimensions of the reservoir - 1000×1000×10 m; porosity of the pore collector - 0.16; fractured reservoir porosity - 0.04; initial/residual water saturation - 0.2; residual oil saturation - 0.2; the pore permeability is \( 10^3 \) mD; the initial permeability of fractures is \( 10^4 \) mD; the initial reservoir pressure is 35 atm; water/oil viscosity ratio - 1/300; bottomhole pressure (production wells) - 30 atm; bottomhole pressure (injection wells) - 60 and 40 atm; the compressibility of water, oil and porous media is 5·10^{-5}, 5·10^{-4} and 3·10^{-5} 1/atm, respectively. The calculation is carried out until reaching a water cut of production wells of 0.98. The types of relative phase permeabilities for pores and fractures are shown in figure 2.

In figure 5 schematically shows a synthetic model of an oil reservoir developed using a row scheme of arrangement of wells.
In the case of operation of wells with constant bottomhole pressures (case 1), 2 zones are conventionally formed in the reservoir. The first zone (I) is the area in which the reservoir pressure $p$ is higher than the initial reservoir pressure $p_0$. Fractures are revealed and their permeability is according to the formula (2). In this area, filtration is mainly carried out by fractures. The second zone (II) is the area in which the pressure is less than the initial reservoir, the fractures are closed. In this area, filtering is carried out both by pores and fractures. For the second version of the calculation (case 2) after 200 days after the start of the calculation, the well operation mode is changed (the bottomhole pressure in the injection wells decreases from 60 atm to 40 atm). As a result, an additional part of the porous reservoir (IIa) is involved in the development. In figure 6 shows the dependences of the ORF and water cut on the pumped pore volume for both calculation cases.

From figure 6, it can be seen that case 1, which implies a reduction in bottomhole pressure at injection wells, has a finite oil recovery rate higher than case 2 with a constant mode of operation of injection wells. This is explained by the fact that after reducing the bottomhole pressure at injection wells, an additional part of the porous reservoir (area IIa) is involved in the development, which helps reduce the water cut at the production wells (green and purple curves). Thus, the reduction of bottomhole pressure at injection wells, when developing a fractured porous reservoir, can lead to an increase in oil recovery.
5. Conclusion

On the example of a synthetic model of an oil field with a zonal-inhomogeneous fractured- porous type of reservoir, the problem of selecting options for the purpose of injection and production wells was solved. It is established that it is more profitable, in terms of oil recovery, to have producing wells in the fractured zone of the reservoir. This arrangement of wells allows not only to increase the final oil recovery factor, but also to reduce the time required to achieve the maximum water cut of producing wells. The result is obtained using a double porosity and double permeability model.

On the example of a synthetic model of an oil field with a fractured-porous type of reservoir, a positive effect from the point of view of oil recovery from a decrease in the rate of water injection was demonstrated. It is established that the decrease in the rate of water injection can reduce the water cut of products and increase the final oil recovery factor. The result is obtained using a double porosity and double permeability model. To assess the overall efficiency of reducing the rate of water injection, it is necessary to use economic criteria, since the increase in the volume of oil produced increases the time required to achieve the maximum water cut of producing wells.

Acknowledgments

The research was supported by Russian Science Foundation (project № 18-19-00049).

References

[1] Saidi A M 1983 Society of Petroleum Engineers 361
[2] Weber K J 1986 Reservoir Characterization 487
[3] Aziz Kh and Settari A 1979 Petroleum reservoir simulation (London: Applied Science Publishers)
[4] Warren J E and Root P J 1963 Society Petroleum Engineers 3 245
[5] Kazemi H, Merrill L S Jr and Zeman P R 1976 Society Petroleum Engineers 16 317
[6] Basniev K S, Kochina N I and Maximov M V 1993 Underground Hydromechanics (Moscow: Nedra)