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Evaluation of the inter-porosity exchange coefficient inferred from well test in a fractured reservoir with a non-uniform distribution pattern: A numerical study

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ABSTRACT

Characterisation of the fractured reservoirs is of great importance as reservoirs of this type represent a significant proportion of the aquifers and petroleum reservoirs in the world. Well test is one of the main tools for this purpose. Inter-porosity fluid exchange coefficient is one of the parameters that should be determined in this kind of reservoirs as a result of well test.

This paper investigates the inter-porosity fluid exchange coefficient inferred from well test in non-uniformly distributed fractured reservoirs through numerical fracture network and flow modelling. Here, we examine the impact of the fracture distribution and pumping well location on the reservoir hydrodynamic response during a well test by numerical simulation. To do so, several synthetic fractured models are prepared by use of a commercial geo-modeller. Numerous well tests are simulated in these models and their hydrodynamic responses to the pumping well are recorded and interpreted applying classical methods of well test interpretation in fractured reservoirs.

Finally the inferred inter-porosity fluid exchange coefficients are compared; it is shown that, in a non-uniformly fractured system, this coefficient value is highly dependent on the fracture distribution pattern, pumping well location and its connectivity to the flow-path network. Consequently, we demonstrate that the standard and classic methods of the average matrix bock dimension estimation by well test may be very sensitive to the pattern of fracture distribution (uniform or non-uniform).

1. Introduction

A large percentage of hydrocarbon reservoirs are naturally fractured. These kinds of reservoir are highly heterogeneous since they generally include several fracture sets with different geometric and hydrodynamic properties.

A combination of information from various sources allows a reliable characterisation of the system. Data from surface geophysics (seismic, electric, magnetic, etc.), well logs transient pressure analysis, cores and fluids analysis, as well as production history can be used to estimate reservoir characteristics.

One of the main tools for reservoir characterisation is well test. During the last 50 years, the large number of studies on the behaviour of naturally fractured reservoir reflects the importance of well test in the characterisation of this type of producing formation.

In most studies dealing with this kind of reservoir many simplifications and assumptions are generally considered for reservoir and flow modelling. One of the main assumptions is uniform distribution of the fracture network. This paper discusses the probable variation of the well test hydrodynamic response (and inferred hydrodynamic parameters) as a function of the well location in a non-uniformly distributed fracture network. Also the impact of the fracture network distribution (fracture spacing and length) on hydrodynamic response of a fractured reservoir is examined. Furthermore, the probable variation of fractured reservoir parameters inferred from well test such as inter-porosity exchange coefficient and fracture storativity ratio is investigated.

In this study, three main questions are addressed: (1) does the well test hydrodynamic response varies as a function of the well location in a non-uniformly distributed fracture network? (2) What are the hydrodynamic parameters inferred from well test interpretations that change with the pumping well location and variation of fracture network distribution? (3) Are the fracture

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network distribution parameters (e.g., fracture length and fracture spacing) which lead to variations of well test response in different locations?

In a first step, we simulate various fractured reservoir that comprises two perpendicular sets of fractures with a non-uniform distribution patterns (exponential distribution of fracture spacing).

In a second step, well test simulations are performs at different locations, for each synthetic fracture network model. Subsequently an analysis of data inferred from well test interpretation is presented.

The basic idea of this work is to investigate how a change in the pumping well location in a non-uniform fractured reservoir may affect the reservoir hydrodynamic and to answer three above mentioned questions.

2. History of fractured reservoir modelling

Cinco-Ley (1996) has shown that naturally fractured reservoirs may behave according to a variety of conceptual reservoir flow models: (1) homogenous reservoir, (2) composite reservoir, (3) anisotropic reservoir, (4) single fracture reservoir and (5) double porosity reservoir.

2.1. Conceptual reservoir flow models

Homogeneous reservoir: This model considers that reservoir properties are constant and do not vary through the reservoir. Fractures and matrix block act as a single medium so that fluid production is caused by the simultaneous expansion of both elements, and fluid transfer between them, if any, occurs instantaneously without resistance.

This behaviour is exhibited by either a heavily fractured reservoir with small matrix blocks, or by a fractured reservoir in which fluids are contained mainly in the fracture system.

Composite reservoir: Some naturally fractured reservoirs are fractured regionally and comprises discrete features (faults and fractures) distributed at a regional scale. Therefore, they may be considered as constituted of two regions: a high and low permeability region. In this case, the reservoir behaves as a composite radial system (van Poolden and Bixel, 1967). It means that there are two regions with different hydraulic properties. A radial high permeable region around the well and a lower permeable zone far from the production well.

Anisotropic reservoir: Some naturally fractured reservoirs exhibit parallel fracture planes. When the fracture network comprises one main sub-parallel fracture set, the reservoir behaves as an anisotropic reservoir. The well test is the ideal tool to evaluate the anisotropy parameters. Ramey (1975) presents a methodology for interpreting this kind of test.

Single fracture reservoir: Sometimes a well is producing near a major fracture so that high flow rates are possible. The main fracture may present a permeable fault near the well. This is also can be detected by well test. Abbaszadeh and Cinco-Ley (1995) suggest a set of type curves to analyse this case.

Double porosity reservoir: Dual porosity models are based on hypothesis that the well intersects the secondary porosity (fracture continuum) which itself drain the primary porosity (matrix continuum). That is, the matrix blocks act as a uniformly distributed source in a fracture medium. Barenblatt et al. (1960) first introduced this concept and proposed a formulation for a radial flow of a slightly compressible fluid towards the well according to this conceptual model. They assumed that in a dual porosity reservoir, a porous matrix of lower permeability (primary porosity) is adjacent to higher permeability medium (secondary porosity).

The resulting transfer flow rate from the matrix continuum to the fracture continuum, per bulk volume unit, is expressed as

$$m=\frac{\rho\,\lambda}{\mu}(p_m-p_f) \tag{1}$$

where m is the fluid flow mass which flows from matrix to the fracture per unit of time and per unit of rock volume, ρ and μ are the fluid density and viscosity, p_m and p_f are the matrix and fracture pressure, respectively. λ is a dimensionless parameter representing the characteristic of the fractured rock.

An approximate solution to this problem was presented by Warren and Root (1963), resulting in a characterisation of the fractured reservoir by two parameters ambiguously related to the actual shape of matrix and fractures, matrix block dimensions, and hydrodynamic properties of the reservoir: fracture storativity ratio (ω) and inter-porosity exchange coefficient (λ)

$$\omega=\frac{(\phi V c_t)_f}{(\phi V c_t)_f+(\phi V c_t)_m} \tag{2}$$

V is the ratio of the total volume of one continuum (fracture or matrix) to the bulk volume, whereas φ is the porosity of that continuum; subscripts f and m refer to fracture and matrix continuum respectively. The second parameter is the inter-porosity exchange coefficient

$$\lambda=\alpha r_w^2\frac{k_m}{k_f} \tag{3}$$

where λ indicates how easily fluid can flow from the primary to the secondary porosity. α is called shape factor that depends on the geometry of the inter-porosity flow between the matrix and the fracture and may be related to matrix block size and its geometry; r_w is the production well radius; k_m and k_f are matrix and fracture permeabilities, respectively.

2.2. Shape factor formulation and use in flow modelling

Warren and Root (1963) proposed the following expression for the shape factor α:

$$\alpha=4n\frac{(n+2)}{L^2} \tag{4}$$

where n is the number of sets of fractures (1, 2 or 3). For cubic matrix blocks with a fracture spacing of L, α has a value of $12/L^2$, $32/L^2$, $60/L^2$ for one, two and three sets of fractures, respectively.

The use of the shape factor in numerical simulation was introduced by Kazemi et al. (1976). Using a finite-difference formulation for the flow between the matrix and the fracture, they showed that for a three-dimensional (3D) case

$$\alpha=4\left(\frac{1}{L_x^2}+\frac{1}{L_y^2}+\frac{1}{L_z^2}\right) \tag{5}$$

With L_x, L_y and L_z the average block dimension (fracture spacing) along the x, y and z direction, respectively. For $L_x=L_y=L$ $_z=L$, λ has a value of $12/L^2$ for three sets of fractures. For one and two sets of fractures, the values of λ are $4/L^2$ and $8/L^2$, respectively. The shape factors proposed by Kazemi et al. (1976) are used in a number of commercial softwares (Firoozabadi and Thomas, 1990). Ueda et al. (1989) showed that Eq. (5) is equivalent to assuming a linear pressure gradient between the centre of a matrix block and the fracture.

The shape factors described previously appear to be based only on the geometry of the fractured reservoir, and do not account for the pressure gradient that exists in the matrix. Coats (1989) included pseudo-steady state matrix-fracture diffusion in his derivation of a matrix-fracture flow equation. He obtained shape factors exactly twice bigger than those of Kazemi et al. (1976).