Marine and Petroleum Geology 40 (2013) 115–134

Contents lists available at SciVerse ScienceDirect

Marine and Petroleum Geology

journal homepage: www.elsevier.com/locate/marpetgeo

A permeability model for naturally fractured carbonate reservoirs

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ARTICLE INFO

Article history:
Received 27 April 2012
Received in revised form
27 October 2012
Accepted 2 November 2012
Available online 13 November 2012

Keywords:
Petroleum geology
Statistical fracture analysis
Structural modeling
Numerical modeling
Reservoir simulation

ABSTRACT

Based on a detailed structural study performed on a reservoir surface analogue, a fracture permeability model for carbonate reservoirs is proposed. This involves four hierarchical systems, each one assumed to convey fluids exclusively to that of immediately higher order. New basic equations are then provided, simulating hydrodynamic reservoir response. The large scale, first-order structures consist of faults, to which high-permeability structures (damage zones) are associated. At the meter scale, stratabound joint systems, together with bedding joints bounding the mechanical layers, form a connected network transporting fluids to the fault system. At a lower scale, down to crystal size, non-stratabound joints constitute a pervasive and capillary fracture network which conveys fluids within the rock mass. The non-fractured host rock constitutes the lower permeability system (at the crystal scale). As no published works include an effective integration of detailed structural and numerical models, the present study aims at covering a significant gap in the literature, also providing appropriate theoretical basis for subsequent studies on fracture network modeling and reservoir simulation. Besides its application in the field of reservoir development and management, the illustrated model may also be useful in environmental studies involving ground fluids such as e.g. in the field of special/toxic/nuclear waste management.

1. Introduction

Reservoir simulation is the main tool in modern reservoir management. The possibility to predict reservoir response to several techniques of oil and gas recovery enables the selection of the economically most attractive strategy to optimize oil production (e.g. Gharbi, 2004; Adamson et al., 1996). A correct characterization of the fracture network (FN) plays a central role in reservoir simulation. In fact, physical models describing the hydraulic behavior of fractured reservoirs ascribe to fracture systems a major role in controlling rock permeability (Warren and Root, 1963), particularly in low-porosity reservoirs (Schmoker et al., 1985; Nelson, 2001). Furthermore, reservoir characterization approaches based on the use of decline-curve analysis require the knowledge of appropriate probability models for fracture attribute statistical distribution (Camacho-Velazquez et al., 2008).

Most numerical simulation criteria use relatively simple structural models to characterize the 3D space. In the present paper we propose a novel approach intended to provide a more realistic description of permeability structures within a naturally fractured carbonate reservoir. The key issue of our approach lies in the identification of fracture sets showing specific statistical behaviors. For each fracture set, the correct probability distribution model is provided for several fracture attributes (with particular reference to opening displacement and fracture density) over a range of scales. As maximum fracture density (MFD, detectable at the micro-scale) can substantially affect the dynamic response of the fractured rock, this parameter – and its dependence on grain size – is also analyzed.

A further main research topic of this study deals with the analysis of hydrodynamic behavior of the proposed structural model for reservoir rocks. The related flow equations are discussed and new basic finite difference equations derived. These latter may allow one to obtain more effective and reliable numerical simulation algorithms. We point out that this work provides the first step toward the implementation of a full numerical model. Additional work would be required in order to provide a technique that can be applied to reservoir simulation, an issue that is beyond the scope of this paper, being object of a future specific research project.

The present model is based on the results of fracture analysis carried out on a series of carbonate outcrops in the Sorrento

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http://dx.doi.org/10.1016/j.marpetgeo.2012.11.002

Peninsula (Italy), which have been selected as a surface analogue of the buried reservoir of the large Basilicata oil fields in the Southern Apennines (Shiner et al., 2004; Guerriero et al., 2010). The analyzed succession displays structural features that are very common in carbonate rocks. Therefore the proposed model, effectively integrating well established concepts concerning the occurrence of different joint typologies in bedded rocks (Odling et al., 1999) and the hierarchical organization of flow in carbonate rocks (Massonnat and Viszkok, 2002), may be of general applicability to carbonate reservoirs.

2. Why is a new fracture network model needed?

Most recent theories on fracture network characterization and hydrodynamic simulation appear to show serious limitations:

(1) A common statistical behavior is often assumed for all fractures contained within a given rock volume. However, carbonate rocks commonly display various typologies of fractures, characterized by different statistical behaviors. For instance, some fracture sets show a self-similar behavior, whilst some others are size restricted. Fractures do also behave statistically significantly different with respect to spatial fracture distribution (e.g. random, clustered, regular) and probability distribution of fracture aperture, length etc.

(2) Many studies commonly assume that fracture parameters such as attitude, aperture and density, can be readily 'translated' in terms of permeability coefficients to be applied to the entire 3D space of a reservoir. Accordingly, single porosity models assign a permeability tensor to each specific point/cell of the reservoir. On the other hand, dual-porosity models (Warren and Root, 1963) cannot operate at different scales (as it is proposed in this study). In such models, the FN is usually assumed as consisting of faults and a matrix including all further minor fractures. The behavior of each grid-point of the permeable matrix (made up of fractured rock) is described by a permeability tensor. However, as illustrated below, it can be shown that elementary volumes of fractured porous rock characterized by the same permeability in steady-state conditions can exhibit substantially different dynamic behavior in the case of non-steady-state flow. Therefore, a permeability tensor cannot be used to describe the dynamic behavior of a rock elementary volume in a non-steady-state flow, without introducing significant approximation errors.

These issues are dealt with in the following two sections.

2.1. Previous studies on reservoir structural characterization

Most of recently adopted criteria for FN characterization within fractured reservoirs consider fracture attributes (e.g., aperture, fracture density, etc.) as random variables (RV) distributed within the reservoir volume according to certain − experimentally established − statistical models. A common approach in these studies (Belfield, 1994; Delay and Lamotte, 2000; Sahimi, 2000; Tran and Rahman, 2006; Tran et al., 2006; Etminan and Seifi, 2008; Mata-Lima, 2008) consists in producing some determination of those RV affecting reservoir behavior (e.g. fracture density, porosity, permeability), whose statistical distribution is in agreement with observational data. In addition, when such determinations are used as input parameters for reservoir simulators, it is required that the analysis yields results matching with real production data. In Etminan and Seifi (2008), as well in Mata-Lima (2008), the simulation of parameters describing the FN is carried out by direct sequential simulation (Soares, 2001), while preserving the variogram (spatial variability; e.g. Diggle and Ribeiro, 2007) of porosity, permeability and other RV of interest. The permeability field defined in this way provides the input for reservoir simulations. The reservoir dynamic response is then compared with real production data (history matching), and this procedure is repeated until the disagreement between simulation and real production data reaches a desirable minimum. In Delay and Lamotte (2000), in addition to variogram preservation of FN attributes, the entropy is introduced as spatial disorder descriptor of the RV under consideration. Further authors make the assumption that the FN shows fractal and/or multi-fractal scaling (Belfield, 1994; Sahimi, 2000; Tran and Rahman, 2006; Tran et al., 2006; Camacho-Velazquez et al., 2008). However, as it will be shown below, not all fracture sets observed in carbonate rocks show fractal geometry. Although previous studies provide fundamental theoretical tools for FN characterization and simulation, they are funded on simplified structural models not always appropriate for a fully correct interpretation of fracture characteristics. The major limitations of these simplified models are related with the assumption of a common statistical behavior for all fractures contained within the rock mass. The main goal of our study approach is to provide, by means of an appropriate statistical analysis, correct probability models of fracture attribute distribution for different fracture types (as well as bedding joints) that can be encountered in a fractured carbonate reservoir.

2.2. Steady-state and dynamic behavior of fractured rock

In order to illustrate how elementary volumes of a fractured porous rock showing similar permeability values in steady-state conditions can exhibit substantially different dynamic behavior, we have carried out numerical simulations involving two two-dimensional fractured porous bodies B_1 and B_2, constituted by the same porous and permeable medium (Fig. 1a). Each of these bodies, having a square section of 10 cm each side, contains two orthogonal fracture sets with constant spacing and aperture values. B_1 shows higher values of fracture spacing and aperture than B_2, but both exhibit the same permeability value for steady-state flow. The simulation has been performed by difference equations, with the following boundary conditions:

$$h = 0.01, \text{ at each grid point}, \quad \text{for } t = 0;$$

$$h = 0, \text{ along the upper side, and}$$
$$h = 0.01 \text{ along the lower side, for } t > 0.$$

where h (here expressed in meters) is the hydraulic head, t is time and the fluid flow is supposed to be parallel to the lateral sides. The results have been compared with the behavior of an elementary volume of non-fractured porous medium, having the same permeability of B_1 and B_2.

The simulation reveals that B_1 and B_2 show very different dynamic response and release fluid slower than the equivalent porous medium. System B_1, characterized by higher values of fracture spacing, releases fluid much slower than B_2 (Fig. 1b and c). The diagram in Figure 1c shows the discharged volume of fluid − calculated by time integration of the difference between ingoing and outgoing flow across the boundary surface − as a function of time. Note that, in order to release 50% of the total fluid volume (2×10^{-8} m^3), the body B_1 needs a time that is more than one order of magnitude larger than that needed by body B_2.

The different behavior of bodies B_1 and B_2 occurs because the average time spent by a fluid particle contained within the matrix to reach a fracture is proportional to the average path, i.e. one half