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Numerical simulation of shale gas flow in three-dimensional fractured porous media

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ABSTRACT

In this study, a Computational Fluid Dynamics (CFD) solver able to simulate shale gas flow as fluid flow in a porous medium on the macro level is presented. The shale gas flow is described by means of a tailored governing equation with both fluid properties and permeability expressed as a function of the effective pore pressure (stress effect) and with Knudsen effects included through an apparent permeability. This CFD solver, developed in the OpenFoam framework, allows for the simulation of three-dimensional fractured geometries without limitations on the shape of the domain. The solver was assessed and validated against literature data showing good agreement in terms of both recovery rate and pressure field profiles. The solver was then used to explore two different phenomena affecting shale gas dynamics: the diffusion behaviour and the influence of fracture geometry. It was shown that shale gas flow, on the macro level, is a diffusion-dominated phenomenon, and its behaviour can also be qualitatively represented by a diffusion equation. It was also shown that the early behaviour of shale gas flow is dictated by the fracture geometry, and that the reservoir dimensions have no effect on the flow at early times. Finally, a newly developed "dual-zone" solver, where the shale matrix and the fracture network are modelled as two distinct domains interacting through the common boundaries, is presented and discussed.

1. Introduction

In recent years, there has been a renewed interest into alternative hydrocarbon fuels (Youtsos et al., 2013). Shale gas has become increasingly important after the development of effective technologies for the extraction of these trapped hydrocarbons (Mohaghegh, 2013). In addition to shale gas, shale oil and oil shale constitute part of the current shale hydrocarbon production. It is estimated that the world shale deposits contain around 3 trillion barrels worth of oil (Fan et al., 2010). Because of this potential for the future energy supply, there is a great interest from the energy industry to improve the understanding of the flow of gas in tight and unconventional reservoirs in order to be able to correctly predict production rates (Ma et al., 2014).

Several attempts have been done in the past to model the gas flow in shale and tight reservoirs, ranging from analytical and semi-analytical models to numerical simulations. The very early analytical models involved very simple geometries such as a single vertical fracture or a single horizontal fracture (Gringarten et al., 1974). These early models were followed by semi-analytical models, such as the ones proposed by Patzek et al. (2013) and by Blasingame and Poe (1993). Patzek et al. (2013) studied a very simple configuration of the Barnett shale through a model derived from a non-linear diffusion equation. Desorption was neglected and results were compared with data extracted from real wells giving some insight into the dominant parameters which affect the asymptotic behaviour of the reservoir depletion. Although very fast, most of the analytical and semi-analytical models suffer to capture the non-linearity in shale gas compressibility, viscosity, and compressibility factor due to the use of a pseudo-pressure approach, rather than solving the real gas equation (Houze et al., 2010). Furthermore, these models also have difficulties in reproducing the typical characteristics of shale gas reservoirs which involve desorption, multiphase flows and complex geometries (Houze et al., 2010). Recently, some attempts to include non-linearities of shale gas properties in analytical models have been performed (Ma et al., 2014; Wu et al., 2015), however the applicability to complex reservoirs needs further assessment and there is still need for an approach able to give more detailed information about the shale flow in completely three-dimensional domains.

In this scenario, numerical simulations offer the possibility to capture the non-linearities that in general analytical methods fail to adequately model as well as the possibility of accurately reproducing complex reservoir shapes. Furthermore, numerical

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simulations can be extensively used to perform a sensitivity analysis on the main parameters that affect shale gas production. The main limitations of numerical simulations are related to the computational cost which however is mitigated by the increasing availability of computational resources. Numerical simulations based on a finite element approach were shown to be able to match historic production data of shale gas (Miller et al., 2010; Jayakumar et al., 2011). Cipolla et al., 2009 investigated some of the parameters which may affect the gas flow, such as the description of the flow from the matrix to the fracture network, stress sensitive fracture conductivity, and desorption. A discrete approach to the grid rather than a dual porosity model approach was utilized and it was concluded that desorption might not be of importance in certain shale reservoirs, but important in others. It was also concluded that the stress effect on the fracture network is more evident during later stages of production rather than at earlier stages and this could lead to optimistic production forecasts (Cipolla et al., 2009). Further understanding of the shale flow was achieved by Freeman et al., 2013. The major parameters of shale flow were identified as the ultra-tight permeability of shale, configuration of the hydraulically fractured horizontal wells, multiple porosity and permeability fields, and desorption (Freeman et al., 2013). In addition, three regimes of flow in typical fractured shale reservoirs were noticed: formation linear flow, transitioning into compound formation linear flow, and eventually transforming into elliptical flow (Freeman et al., 2013). It was also concluded that due to the very low permeability in shale, the flow is controlled by the configuration of the fracture network, with and without desorption effects (Freeman et al., 2013). Furthermore, Moridis et al. (2010) explored the difference between shale gas reservoirs and tight sand reservoirs using a multiphase solver based on the Darcy equation. It was concluded that these types of reservoirs differ from each other in the contribution of desorption. While desorption can be neglected for tight sand reservoirs, significant deviations from field data are observed if desorption is neglected for shale (Moridis and Freeman, 2014).

Earlier, Kwon et al. (2001) suggested that shale permeability of the Wilcox shale is a function of effective pressure. It was noticed that permeability decreased from $300 \times 10^{-21}\ \mathrm{m}^2$ to $3 \times 10^{-21}\ \mathrm{m}^2$ when the effective pore pressure increased from 3 MPa to 12 MPa. A cubic power pressure dependent equation of permeability was introduced to best fit the experimental values of shale permeability (Kwon et al., 2001). Later on, Freeman et al. (2011) explored the compositional change of natural gas from shale reservoirs with time. Many reasons were suggested for this phenomenon, but the most important ones are the selective desorption from the surface of the matrix and the non-Darcy flow which is the result of the nano-pores of shale. A dependency between the natural gas composition and the Knudsen number (which controls the non-Darcy flow) and eventually the permeability was suggested. Freeman et al. (2011) placed a large importance on the Knudsen number and used it to alter permeability into an apparent permeability as suggested by Klinkenberg (1941) and Javadpour (2009). Apparent permeability allows retaining the form of the Darcy equation, while capturing the Knudsen effect within the apparent permeability (Freeman et al., 2011). Further efforts in the understanding and modelling of shale gas flow include a sensitivity analysis of the fracture geometry (Yu et al., 2014), the use of the finite elements method (Fan et al., 2015), and a numerical solver that includes slip flow, Knudsen diffusion, and desorption (Shabro et al., 2012).

Although some aspects of shale gas flow have been already investigated, there is still need of improving the knowledge of shale gas flow in geometries close to the intricate configurations represented by the fracture network of real reservoirs. In order to do that, a solver able to accurately model the shale flow in every kind of geometry is required. In this work a new solver for shale gas flow predictions is proposed and assessed with the main aim of: (i) developing a numerical method able to solve a generic three-dimensional shale reservoir, (ii) analyse the sensitivity of shale gas flow to the shape and the physical properties of the reservoir. The newly developed tools also include a dual domain approach where both the matrix and the fracture are included in the domain and modelled as media with different properties interacting through the common boundaries, offering hence greater accuracy in the flow rate prediction as a function of fracture geometry. Both the mathematical model and the approach used for shale gas simulation make the proposed approach different from the existent commercial solver and models available in literature.

2. Method

Shale reservoirs usually consist of a porous material (which in the following will be referred to as *matrix*) perforated by an intricate network of *fractures* used to collect the gas trapped in the pores. Despite the porous nature of the matrix, the shale gas flow has some peculiarities and cannot be described as the typical flow in porous media.

The major factors affecting shale gas production modelling and eventually forecast are identified as follows. The shale reservoir has a ultra-low permeability and nano-pores, which could lead to a Knudsen diffusion contribution to the flow. This suggests the use of an apparent permeability which includes matrix permeability as well as Knudsen diffusion effects (Javadpour, 2009), while maintaining the use of a Darcy equation. The permeability depends on the effective pressure (stress effect), which is the difference between confining pressure and pore pressure (Kwon et al., 2001). Due to the ultra-low permeability, the fracture network has the largest influence on how the flow proceeds. Finally no consensus has been reached on the role of adsorption. Hill and Nelson (2000) suggest that 20–85% of total shale storage is in the form of adsorption, however the majority may never be produced. Others suggest that it could be neglected for certain reservoirs (Patzek et al., 2013). In this work the desorption of shale gas is not considered. This choice is motivated by the fact that, according to the literature (e.g. Patzek et al., 2013) in the cases used for validation (Barnett shale) the desorption can be neglected. However, it is important to point out that the approach presented here is in principle not limited to cases without desorption since this phenomenon can be included in the formulation through the Langmuir isothermal theory (Shabro et al., 2012). This will be attempted in future works.

Starting from the typical equations describing the fluid dynamics, a mathematical model for the shale gas flow can be derived (Chen et al., 2006; Gruber, 2014). The following assumptions are considered in the following: (a) single phase flow; (b) gas is assumed to be pure methane (single species); (c) isothermal conditions; (d) negligible gravitational effects; (e) no sources or sinks within the shale matrix; (f) porosity constant in time; (g) permeability is treated as a scalar (isotropic matrix); (h) permeability is a function of effective pressure; (i) no desorption (the gas is only stored within the pore spaces). In the following the mathematical model used in this work is first presented followed by a description of the developed numerical solver and the models adopted for shale properties. All the symbols are defined in Appendix C.

2.1. Mathematical model

The typical representation of a continuum in Computational Fluid Dynamics (CFD) problems, generally involves equations representing the conservation of mass, species, momentum and