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Multi-branched growth of fractures in shales for effective reservoir contact: A particle based distinct element modeling study

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ABSTRACT

The complexity of a stimulated fracture network is important for hydrocarbon extraction from tight shales. Branched-interconnected-complex fracture networks are preferable for a better production due to a larger contact area compared to unconnected-single fractures. The presented numerical modeling study aims for a better understanding of the hydraulic fracturing process in shale formations to eventually achieve these kinds of fracture networks. In this study, a two dimensional particle based distinct element method (DEM) is used to systematically investigate the influence of specific model parameters on the resulting fracture patterns. The applicability of the model is critically discussed and technical measures to increase hydraulic fracture complexity are proposed.

1. Introduction

The development of artificial fractures due to hydraulic fracturing treatments is currently the main method used to produce hydrocarbons from tight shale formations. To increase production, the contact area of the fractures and the hydrocarbon bearing rock matrix needs to be maximized. The lower the matrix permeability, the less important is the hydraulic conductivity of these fractures and the more important becomes its area (Economides and Nolte, 2000; Cipolla et al., 2008). Therefore, the goal of hydraulic fracturing treatments in tight shale formations should be to develop complex fracture networks rather than single hydraulic fractures.

In recent years, it was understood that hydraulic fracturing treatments in heterogeneous naturally fractured shale formations do not often result in single tensile fractures with simple geometries as initially anticipated, but rather in the development of complex networks of pre-existing and new tensile and shear fractures (Cipolla et al., 2008). Complex fracture growth was identified by mine-back observations (Warpinski and Teufel, 1987), cored hydraulic fractures (Warpinski et al., 1993), pressure analysis (Weijers et al., 2000), microseismic mapping (Warpinski et al., 2005), and surface (Wright et al., 1998a) and subsurface (Wright et al., 1998b) tiltmeter mapping. In addition to these, laboratory (Zhou et al., 2008, 2010), analytical (Weijermars, 2011), and numerical (Hofmann et al., 2014, 2015; Safari and Ghassemi, 2015; Weng et al., 2011; Wu and Olson, 2013) studies were performed to identify and understand factors that affect hydraulic fracture complexity.

These investigations showed that intact rock properties, heterogeneities, natural fracture networks, and the local stress field strongly affect fracture growth and may lead to complex branching fractures. Additionally, multi stage fracturing treatments in horizontal wells are state-of-the art to exploit tight shale gas and oil shale reservoirs. These different stages also affect each other hydraulically and mechanically and add to the complexity. Besides the completion design, fracture complexity is also affected by treatment design parameters, such as fluid viscosity, flow rates, pressures, and treatment schedules.

Traditional continuum models have limited capabilities to investigate how these different factors influence fracture growth (Hofmann, 2015). An overview of the different modeling approaches (DEM, BEM, FEM, XFEM, …) with their advantages and disadvantages is given by McClure and Horne (2013). To better understand these complex processes, discrete element methods (DEM) became an increasingly useful tool (Lisjak and Grasselli, 2014). The particle based distinct element model Particle Flow Code 2D (PFC2D) (Itasca Consulting Group Inc, 2008) was recently used to investigate the influence of different natural and

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engineering factors on fracture development in tight granites for the development of enhanced geothermal systems (Hofmann et al., 2016a). However, a similar study was not yet done for typical shale reservoir properties. The presented study investigates the influence of specific PFC2D model properties and treatment parameters on the developing fracture patterns.

2. Methodology

2.1. Particle Flow Code 2D

The Particle Flow Code 2D is a two-dimensional distinct element method (DEM) model (PFC2D; Itasca Consulting Group Inc, 2008) in which a three dimensional rock mass can be represented by an assembly of cylindrical particles with finite height. The particles are bonded together at their contact points with parallel bonds (Potyondy and Cundall, 2004) having a finite strength and a finite volume of cementation to resist Mode I (tensile), Mode II (shear), and rotational loadings (Yoon et al., 2015a).

These parallel bonds can break in Mode I and Mode II under an applied load according to the Mohr-Coulomb failure criterion. At each time step the law of motion is applied to all particles and a force-displacement law is applied to each contact. Fig. 1 shows the Mohr-coulomb failure criterion for the parallel bonds and how shear and normal displacements and forces are related by shear and normal stiffness.

To model the hydraulic fracturing treatments, a fluid flow algorithm and an explicit hydro-mechanical coupling scheme are implemented. Flow of water with constant viscosity occurs through flow channels along the bonded particle contacts. These flow channels connect the polygonal pore spaces (“fluid reservoirs”) between the particles in which the fluid is stored. Each fluid reservoir is bounded by the surrounding particles. Fluid flow is calculated using the cubic law and assuming laminar flow between two smooth parallel plates:

$$q = -\frac{Ha^3 \Delta P_{f,x}}{12\mu L} \quad (1)$$

with the reservoir height H, the hydraulic flow channel aperture a, the fluid pressure difference between two neighboring pore spaces $\Delta P_{f,x}$, the fluid viscosity μ and the flow channel length L. The fluid pressure change $\Delta P_{f,t}$ in a pore space is calculated for each time step with:

$$\Delta P_{f,t} = \frac{K_f}{V_d}\left(\sum q\Delta t - \Delta V_d\right) \quad (2)$$

K_f is the fluid bulk modulus, V_d is the pore space volume, $\sum q\Delta t$ is the net sum of the flow volume entering and leaving the pore space and ΔV_d is the change of pore space volume resulting from mechanical loading. Forces are exerted by the fluid pressure in a pore space on the surrounding particles. Parallel bonds therefore may break if pore pressure increases due to fluid injection. For broken parallel bonds the fracture aperture is set to the aperture at zero normal stress a_0 and the pressure in the pore spaces connected by a broken bond is set to the average pressure between the two pore spaces. The two pore spaces become one pore space once the connecting bond is broken. A relation was implemented that relates the effective normal stress σ_n acting perpendicular to a contact (stress acting to close a flow channel) to the hydraulic aperture a of the corresponding flow channel for intact bonds (Hökmark et al., 2010; Yoon et al., 2015a):

$$a = a_i + (a_0 - a_i)\exp(-\alpha\sigma_n) \quad (3)$$

This correlation depends on the hydraulic aperture at infinite normal stress a_i, the hydraulic aperture at zero normal stress a_0 and a coefficient of decay α. At zero normal stress, the flow channels have their maximum aperture. With increasing stress, the flow channel aperture approaches asymptotically its minimum value, called “aperture at infinite normal stress”. This minimum aperture indicates that flow channels are closed and represent the matrix permeability of the intact rock mass. The coefficient of decay describes how fast the hydraulic aperture decreases with increasing normal stress. In this study all three parameters were matched to laboratory measurements of closure stress dependent hydraulic fracture apertures of aligned tensile fractures in shales (Table 1). The resulting effective normal stress dependent flow channel permeability is given in Fig. 2.

More details about PFC2D are given by Potyondy and Cundall (2004). Detailed descriptions of the fluid flow algorithm and the hydro-mechanical coupling scheme are given by Yoon et al. (2015b).

Some of the advantages of this modeling approach are that model inherent inhomogeneities represent the inhomogeneity of natural rock masses and that macroscopic rock properties are emerging from a simple set of microproperties. Therefore this direct approach is suited to better understand the system rather than just describing it with constitutive relationships. Additionally, it is possible to include large amounts of natural fractures in the model without significantly increasing the computational time and it is also possible to model microseismicity, which may be useful for future studies.

Even though no model is completely verifiable the presented approach has previously been validated by comparing modeling

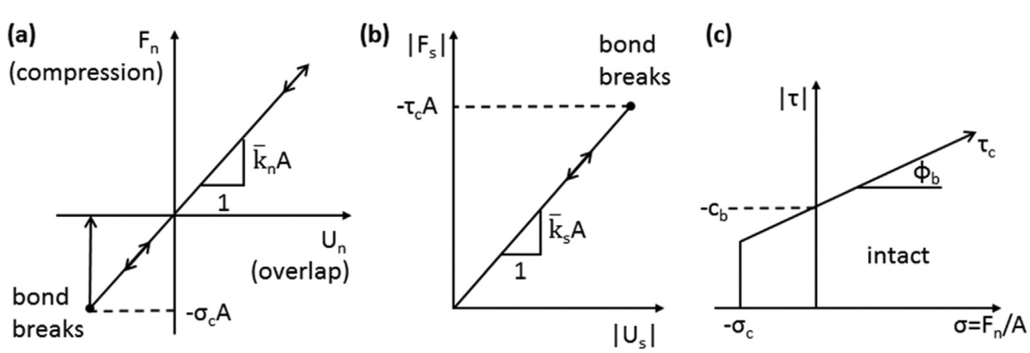

Fig. 1. Force-displacement behavior for bonded particles: (a) normal force versus normal displacement, (b) shear force versus shear displacement, and (c) strength envelope (redrawn from Itasca Consulting Group Inc (2008)). F_n = normal force, F_s = shear force, $-\sigma_c$ = tensile strength, U_n = normal displacement, U_s = shear displacement, k_n = normal stiffness, k_s = shear stiffness, c_b = cohesion, Φ_b = friction angle, τ_c = shear strength, A = contact area between two particles (Hofmann et al., 2015).