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Effect of fluid injection rate on the hydraulic fracture propagation characteristics

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Abstract. Numerical simulations using UDEC were performed to better understand the role of fluid injection rate on hydraulic fracture evolution characteristics and the associated changes in the in-situ stress field. The length and width of hydraulic fracture, wellbore pressure and stress distribution were monitored during fluid injection at four different rates - 0.8330, 0.4165, 0.2083 and 0.0833 m³/s. An efficient fracture growth was displayed in the cases of higher injection rates where fracture length and width rapidly increased with injection time. The wellbore breakdown pressure was highest at the highest fluid injection rate case, although the variation of breakdown pressure among the other cases was insignificant. The minor principal stress distribution after 9 seconds of fluid injection under all four cases of injection rate showed that the earlier propagation of the hydraulic fracture in the cases of higher injection rate results in a relatively more significant stress redistribution.

1. Introduction

Production of unconventional gas such as coal seam gas, shale gas, and tight gas uses hydraulic fracturing where the reservoir rocks are fractured by high pressure fluid to unlock trapped gas. In addition, enhanced geothermal systems (EGSs) are developed by hydraulic stimulation of geothermal reservoirs to extract geothermal energy [1]. The direction and extent of the hydraulically-stimulated fractures depend on factors such as in-situ stress, properties of the reservoir rock, injection flow rate and the viscosity of the fracturing fluid [2]. While creating a greater stimulated reservoir volume (SRV) is targeted during gas production, geothermal energy extraction is benefitted from establishing an efficient hydraulic link between injection and production wells by hydraulic fracturing [3].

In general, the type of fracturing fluid and fluid injection rate are operational parameters that can be altered to achieve an optimum discrete fracture network by hydraulic fracturing as required, whereas reservoir-related parameters such as reservoir rock properties and in-situ stress state remain unchangeable [4]. According to Wang et al. [5], the fluid injection rate is the first critical factor to be considered among many other factors that affect the hydraulic fracturing response. Higher injection rates generally result in higher fracturing effectiveness [5]. Hydraulic fracturing experiments of Wang et al. [6] on naturally fractured and laminated blocks with varying injection rates showed increased roughness of the created fracture surfaces at higher injection rates, and the effectiveness of hydraulic fracturing is improved by higher injection rates. Wang et al. [6] also observed a weaker interaction between hydraulic fractures and pre-existing fractures at low injection rates. An obvious effect of pressurization rate by fluid injection on the wellbore breakdown pressure has been reported in the literature; while some studies report a higher breakdown pressure for higher injection rates (e.g. [7-9]),

some other studies show the opposite behaviour (e.g. [10]). Morgan et al. [11] conducted hydraulic fracturing experiments on Opalinus Clay Shale specimens using four injection rates - 0.0059, 0.0188, 0.0807, and 0.3903 mL/sec – and observed that higher injection rates increase the effective fracturing area, but with less consistency and predictability. Numerical simulation of Kresse et al. [12] observed a more complex fracture network at higher injection rates and lower stress anisotropies. Kresse et al. [12] also concluded that injection rate and fracturing fluid viscosity combinedly play a major role in the outcome of hydraulic fracture-natural facture interaction.

This study employs a distinct element method-based numerical simulation program to better understand the role of fluid injection rate on hydraulic fracture geometry and wellbore breakdown pressure. In addition, the stress redistribution characteristics are also explored, which can have decisive impacts on hydraulic fracture initiation and propagation behaviour during multi-stage hydraulic fracturing. The following sections describe the numerical simulation procedure and the results and discussion.

2. Numerical simulation

Fully-coupled hydro-mechanical simulations were performed using Universal Distinct Element Code (UDEC) software by Itasca Pty Ltd. UDEC is a two-dimensional distinct element method-based software, and it uses a 'Lagrangian' calculation scheme, which enables modelling large movements and deformations of a blocky system. The blocks can be made deformable by discretizing them to triangular finite-difference zones, which behave according to a prescribed linear or nonlinear stress-strain law. In UDEC, the discontinuities are treated as boundary conditions between blocks and large displacements along discontinuities and rotations of blocks are possible.

Models of 1000 m x 1000 m were first created for which minor principal stress (σ_3) of 80 MPa was applied in the vertical direction, and major principal stress (σ_1) of 160 MPa was applied in the horizontal direction (Figure 1). A centric horizontal discontinuity was embedded in the model, which will act as the hydraulic fracture. This is a simplified arrangement for the hydraulic fracture assuming that the hydraulic fracture propagation is perpendicular to the minor principal stress direction. Previous studies such as Anderson [13], Lawn and Wilshaw [14], Xu et al.[15] and Zangeneh et al. [16] report that the tensile fracture propagation in homogeneous and isotropic materials is generally perpendicular to the minor principal stress direction. The fluid is injected to the domain nearest to the centre of this initially sealed discontinuity – i.e. the centre of the model – during simulations (the injection domain represents the fluid injection wellbore). The contacts of the discontinuity are broken upon receiving sufficient fluid pressure, after which the fluid flow is permitted along the hydraulic fracture. Fluid injection rate was varied to 0.8330, 0.4165, 0.2083 and 0.0833 m^3/s. The fracture length, width and wellbore pressure were recorded during fluid injection.
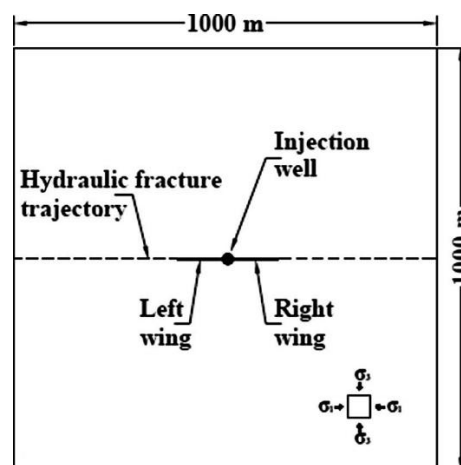

Figure 1: The geometry of a typical UDEC model

Elastic/plastic Mohr-Coulomb constitutive model was assigned to the blocks, while the Coulomb slip model with a residual strength was prescribed to the hydraulic fracture. The properties used for block material, hydraulic fracture, fracturing fluid, and injection rates are outlined in Table 1.

Table 1: Properties assigned for the blocks, fractures and fracturing fluid of UDEC models

Block (intact material) properties	
Density (kg/m^3)	2600
Elastic modulus (GPa)	50
Poisson's ratio	0.25
Cohesion (MPa)	25
Friction angle (°)	53
Fracture properties	
Cohesion (MPa)	25
Residual cohesion (MPa)	0
Friction angle (°)	53
Residual friction angle (°)	0
Dilation angle (°)	20
Fracture toughness (MPa.m$^{1/2}$)	1.5
Fracturing fluid properties (incompressible)	
Density (kg/m^3)	1000
Viscosity (Pa.sec)	0.001
Injection rate (m^3/sec)	0.8330, 0.4165, 0.2083 and 0.0833

3. Results and discussion

The UDEC models were validated by comparing fracture geometries and wellbore pressure variations with injection time with those derived using KGD analytical fracture model [17, 18], and this procedure is reported in Wasantha et al. [2]. The geometry of the propagating hydraulic fracture (i.e. length and width at the wellbore) against fluid injection time for different injection rates is shown in Figures 2a and 2b. According to Figures 2a and 2b, a particular fracture length and width can be reached with less injection time when the injection rate is higher. In other words, a higher injection rate maximizes the fracture propagation efficiency. This behavior is consistent with the results of similar studies in the literature (e.g. [5, 6]).

The wellbore pressures at different injection rates in Figure 2c show that the breakdown pressure (the first failure of contacts) is not significantly affected by the fluid injection rate. However, the highest injection rate shows a notably higher breakdown pressure compared to the other injection rates. Therefore, this study appears to support the trend of higher breakdown pressures at higher injections rates.
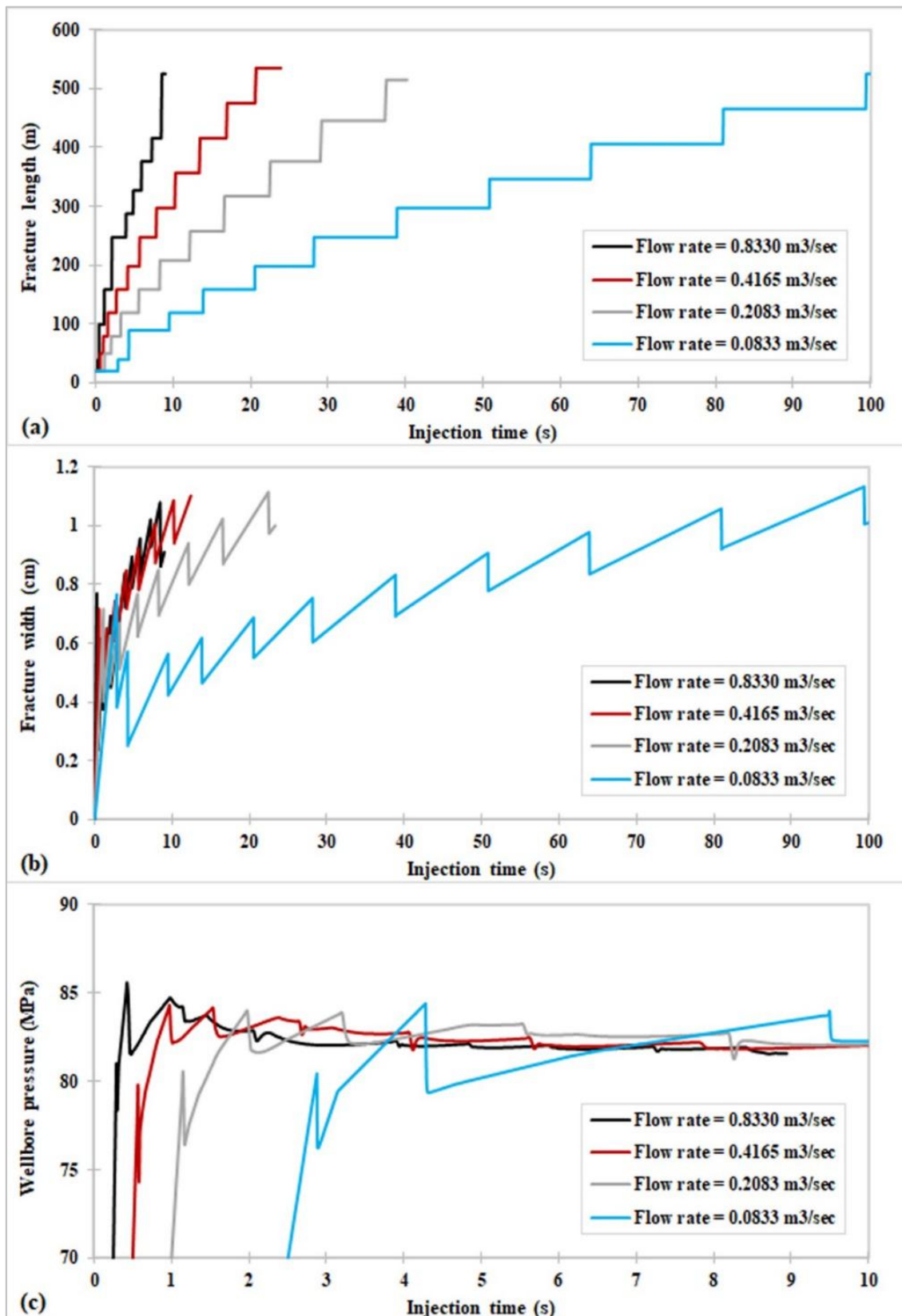
Figure 2: Characteristics of hydraulic fracture propagation; (a) fracture length, (b) fracture width and (c) wellbore pressure against injection time

The stress field in models continuously evolves with hydraulic fracture propagation. We compared the minor principal stress distribution after 9 seconds of fluid injection under all for cases of fluid injection rates considered, as shown in Figure 3 (the models show different lengths of the hydraulic fractures after 9 seconds of fluid injection due to the different fluid injection rates used). The stress is redistributed over a larger area surrounding the hydraulic fracture for higher injection rates due to the longer length of the propagated fractures. The maximum minor principal (compressive) stress seems to be higher for lower injection rates as a result of the hydraulic fracture being at the early stages of propagation under lower fluid injection rates. These different stress redistribution characteristics can have implications on the hydraulic fracture propagation during subsequent fracturing stages in the case of multi-stage fracturing.
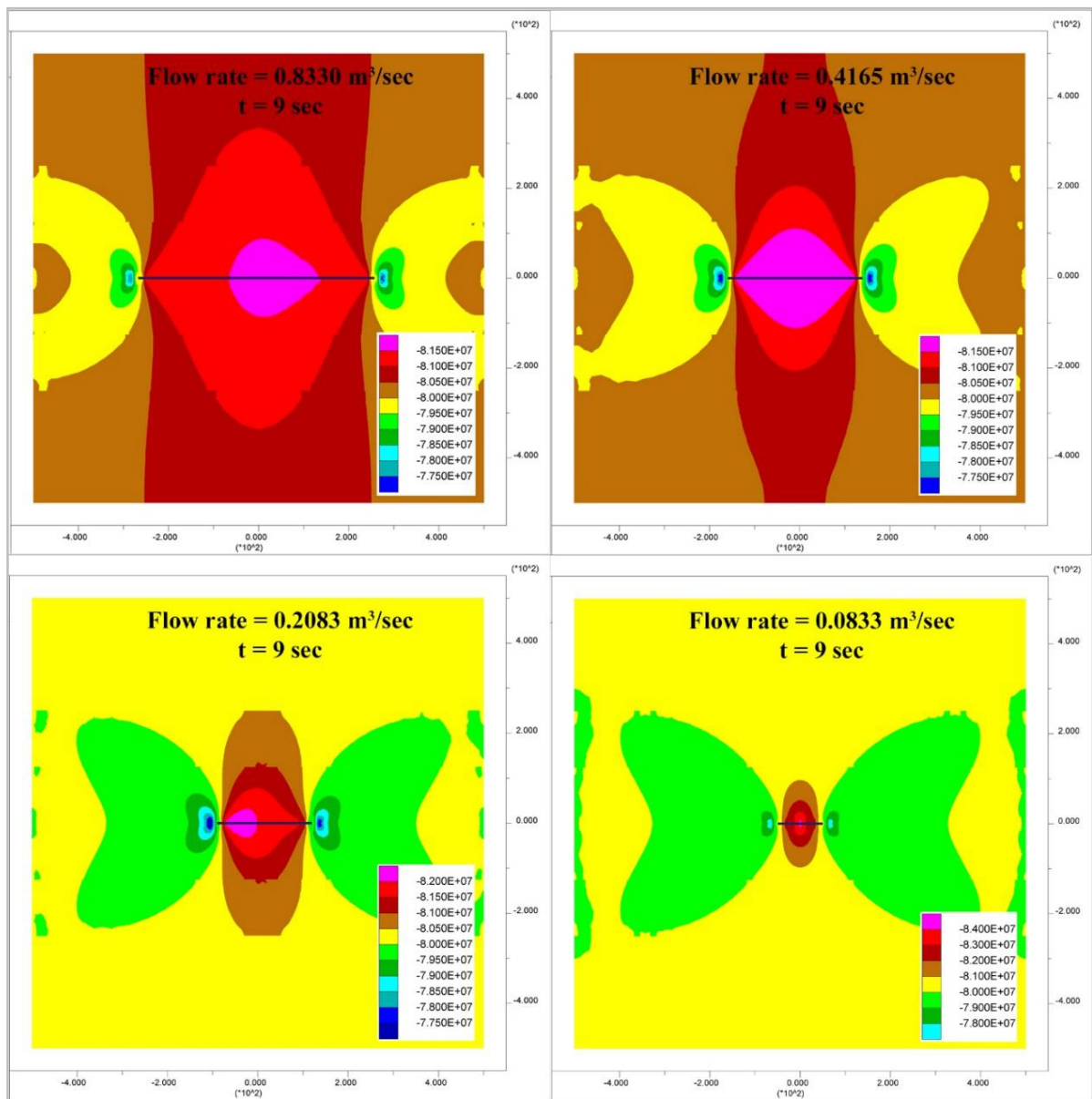

Figure 3: Minor principal stress distribution patterns after 9 seconds of fluid injection at different injection rates

4. Conclusions

The effect of fluid injection rate on hydraulic fracture propagation characteristics was numerically investigated using UDEC software. The simulations performed with four different fluid injection rates revealed some critical insights into fracture geometry evolution, wellbore breakdown pressure, and stress redistribution characteristics. More efficient fracture growth (length and width) was observed under higher injection rates, which agrees with the observations of previous studies. Wellbore breakdown pressure was highest in the case of the highest injection rate, although the variation was insignificant within the other three cases of injection rate. The minor principal stress redistribution patterns after 9 seconds of fluid injection for all cases of injection rates showed a significant stress redistribution for higher injection rates as a result of longer hydraulic fracture developed.

Acknowledgments

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