VII Brazilian Symposium on Rock Mechanics – SBMR 2016
Rock Mechanics and Rock Engineering for Innovation and Development
ISRM Specialized Conference 19-22 October, Belo Horizonte, Minas Gerais, Brazil

Hydraulic Fracturing in Unconventional Gas Reservoirs: simulation using discrete element methods

D. C. Arrieta
PUC-Rio, Rio de Janeiro, Brasil, cerro.dalma@puc-rio.br

S. A. B. da Fontoura
PUC-Rio, Rio de Janeiro, Brasil, fontoura@puc-rio.br

G. L. Righetto
PUC-Rio, Rio de Janeiro, Brasil, righetto@puc-rio.br

SUMMARY: Development and deployment of shale gas formations around the world are relatively recent; it started in United Stated in the late 1990. From the obtained results with the application of hydraulic fracturing as a method of stimulation, the study and evaluation of other prospects of shale gas in other places in the world was encouraged. However, the analysis, study and characterization of this kind of reservoirs are difficult, because it must be taken into account several factors such as geology, mineralogy, petrophysics, geochemistry among others. Hydraulic fracturing is a complicated coupled hydromechanical process, with a high degree of difficulty, especially in shale gas reservoir, where natural fractures exist. In this paper, a numerical study is conducted to investigate the hydromechanical behavior of a natural fracture during fluid injection. UDEC (Universal Distinct Element Code) software based on discrete elements method was employed to numerical modeling development. UDEC has the ability to model the hydromechanical behavior of a fracture including phenomena such as fracture enlargement, closure, slippage, and dilation under contact or separation conditions. This numerical investigation presents numerical models of reservoir with random natural fractures (*voronoi* distribution), which were created aiming to represent the network complexity of natural fractures in shale gas formations. The numerical study results show the hydromechanical system behavior, which is dependent strongly to parameters variation such as *in situ* stress, fluid fracturing viscosity and fluid injection flow rate. Therefore, these results provide a better understanding of fracturing mechanisms and pressure response of a hydraulic fracturing treatment in a non-conventional naturally fractured reservoir.

KEYWORDS: Naturally fractured formations; shale gas; hydromechanical behavior; hydraulic fracturing.

1 INTRODUCTION

In recent decades, a variety of factors has been combined to promote the interest of the oil industry in exploration and exploitation of shale formations, which traditionally were seen as source rocks and seal, rather than reservoir rocks. However, after the observed occurrence of natural gas during drilling of a natural fractured shale, in 1821 in the Appalachians basin (Curtis, 2002), this rock is considered now such as economic output prospectus. However, its profitability is reduced due to low values of porosity properties (2-8%) and permeability (10-100 nanoDarcy) (Cipolla, 2010).

According to the type of hydrocarbon present in its structure, the shale resource can be divided in two major groups. Shale oil and shale gas are distributed throughout the world representing 10% of oil and 32% of technically recoverable natural gas (EIA, 2014); this is one of the main incentives of the industry interest.

In shale gas formations, the Hydraulic Fracturing (HF) is an essential procedure for its development, which is complemented with the horizontal drilling technique, optimizing the volume and gas flow / oil from shale layers into the well (Castro, 2015).

In HF treatment, the fractures propagation depends strongly on the field stress and orientation planes of natural fractures. These variables severely commit the ability to predict the HF geometry, as well as the treatment effectiveness. It is due to the fracture properties in the formation are not studied in detail due to the generated economic layoffs.

Fluid flow through the fractures system in the formation is an important variable to be analyzed in HF projects, it must be a sufficient injection and viscosity rate to approaching the desired dimensions in the projected fracture network, ensuring also the proppant suspension, entry and positioning.

Analysis of involved parameters of exploration projects and shale gas reservoirs exploitation are compared and validated through numerical modeling. This is a fundamental element in development of these projects, because they make them more realistic if it compare to real field.

2 NUMERICAL MODELING

2.1 Numerical Modeling of Hydraulic Fracturing in Naturally Fractured Reservoirs-Shale Gas

In this study, the numerical modeling development was performed using the discrete elements method, through UDEC 5.0 software (Universal Distinct Element Code). The hydraulic fracturing analysis consist in two steps; the first step is the initial consolidation of rock mass, which is drilled and, the second step is the fluid injection at constant flow rate, considering the outer limits block as impermeable. In this approach, a naturally fractured formation is represented by plate sets separated by a discrete network of pre-existing fractures in the rock mass. Numerical simulations were performed through a fully coupled hydromechanical model. Fluids flow only occurs within fractures, separating the low permeability blocks. Initially, the formation saturation is 100%, this fluid for developed modelling of permanent flow, only has the property to stablish pore pressure in fractures. It should be noted that this fluid is different to the injected fracturing fluid, which take into account variables such as viscosity, density and Bulk modulus. Rock blocks were modeled as elastic and impermeable, the fracture network is explicitly represented by *voronoi* tessellation randomized, which simulates the rock structure. The existing fractures deform elastically and it can only open or shear (governed by Coulomb friction model) as function of pressure and total stresses.

2.2 UDEC Simulations of Hydraulic Fracturing

A series of 5 simulation cases were performed in order to evaluate the influence of the various parameters on the natural fracturing shearing and fracture network developed. Each simulation case evaluated the parameters variation and their influence on variables such as pore pressure distribution, shear and normal displacement, fracture opening and pressure injection.

For each simulation case (Table 1), a solution was found for stress equilibrium, injection rate and then fluid viscosity. The materials properties (intact rock and fracture networks) are shown at Table 2.

2.3 UDEC Model Setup, Fracture Network and Boundary Conditions

For model development in UDEC, must be define, the block and fractures geometry, material constitutive models, *in situ* stresses, boundary conditions and UDEC parameters such as round (ro), which is the rounding distance for all blocks and edge (v), which is the maximum edge length of triangular zones of finite difference mesh.

A two-dimensional model (40x40m) was constructed with a horizontal well, and was 40mx40m. The fracture network used in the simulations was created from UDEC and was explicitly represented by *voronoi tessellation* randomized. The network *voronoi* consisted in a trace length of 1m. (Figure 1).

Fracture normal and shear stiffness were set as $1x10^4$ MPa/m e $1x10^3$ MPa/m respectively. Fracture friction angle was set as 30°, fracture cohesion as 1 MPa, fracture dilatation angle as 10° and fracture tensile as 0.5 MPa (Table 2). The joint hydraulic property - fracture permeability, was $8.3x10^7$ $MPa^{-1}s^{-1}$. The models initialization was using the stress and mechanical properties observed in Table 1 and Table 2 respectively. Once the models were initialized, the boundary conditions were applied, the well was drilled and the models were stopped to equilibrium prior the application of injection rate associated with the hydraulic fractures.

According to Figure 2, for fracture network propagation was applied an injection rate in the well (model center). This injection rate was 135 bpm (Table 1).

The initial stress ratio was 1. For subsequent simulations for each case in Table 1, was increased until 2 was reached.

2.4 Simulation Results

In this stage, is shown the effect of stress ratio variation on variables such as pore pressure, tendency of fluid flow injected, normal and shear displacement, injection pressure and fracture opening. Three models were constructed for minimum principal stress σ_h variation, while keeping constant the maximum principal stress σ_v (Figure 3), and three models for inverse case (Figure 4).

2.4.1 Stress Ratio Effect on Injected Fluid (Flow Rate)

Figure 5 through Figure 7 show the simulation results for each of 5 stress ratio variations. Note that, the red point is the injection point, and the blue and green portion of the fracture system represents the fluid flow extended through the fractures.

The fluid flow, as presented in Figure 6 and Figure 7, was dominant in the horizontal direction for higher stress ratio (ratio 2) in both two models A and B, it was conforming to higher *in situ* stress anisotropy. This indicates that fractures opening parallel to the maximum principal stress seeking minimize the fracture work. However, for higher isotopy (ratio 1 in both two models A and B) the flow fluids tendency was symmetric in all direction.

2.4.2 Stress Ratio Effect on Pore Pressure Distribution

Similar results to previous were observed for pressure diffusion effects (Figure 8 to Figure 10), thus, for higher stress anisotropy (ratio 2) in model A and model B, can be observed that the pore pressure distribution is parallel to the maximum principal stress. Isotropic stress in rock results in uniform pore pressure diffusion into the formation, according to ratio 1 in both two models A and B. Similarly, it can be observed that an increment in the maximum principal stress (Model B – ratio 2) results in value of 15MPa, whereas, for lower values in minimum principal stress (Model A – ratio 2) the pore pressure value is 10 MPa. This is related with the increase of intermediate principal stress.

2.4.3 Stress Ratio Effect on Rock Blocks Displacement

The rock blocks located around the injection point rotated slightly around it, opening the fractures, which increase the rock conductivity (Figure 11 through Figure 13). According to Figure 13 higher blocks rotation is developed for higher stress anisotropy (ratio 2) in both two models, Model A and Model B. This induces to shear displacements and fracture opening as showed in Figure 16 and Figure 19.

Additionally, the behavior of blocks displacement is governed by stresses ratio, thus, uniform displacements are developed for higher isotropy (ratio 1), and asymmetric displacements, perpendiculars to minimum principal stress are developed for higher stress ratio (ratio 2) in both models, Model A and Model B.

2.4.4 Stress Ratio Effect on Rock Shear Displacement

Figure 14 through Figure 16 show the fracture shear displacements after hydraulic fracture treatment is completed. When the injection process starts and fluid get into the formation, the natural fracture is dilated once compressive normal stress is exceeded. If fluid flow continues, the dilated natural fracture becomes part of hydraulic fractures network, i. e., it becomes in a hydraulic fracture and propagates through the natural fractures. Fractures propagation, at the large scale, will tend to remain on average at 90° to the direction of σ_h (minimum horizontal stress) because of global work minimization requirements (Dusseault, 2014). Thus, it can be observed in Figure 16 that, for higher stress anisotropy (ratio 2) the trend of shear displacement is strongly marked in this direction, for both two models (A and B). For stress ratio R=1, it can be observed more uniform shear displacement in all directions, governed by the *in situ* stress isotropy. It is interesting to note that a branch is developed in fractures trajectory, specifically in isotropic stress levels in both two models, A and B; and higher stress ratio (ratio 2) in model B. The multidirectional branch reaches higher levels in isotropic stress (Figure 14)

2.4.5 Stress Ratio Effect on Rock Normal Displacement

In Figure 19 can be observed that, higher stress ratio (ratio 2) in both two models A and B, results in hydraulic fractures network perpendicularly directed to the minimum principal stress applied in the formation.

Considering the fractures opening developed in both two models A and B, it can be observed, in Figure 20, an increase in this variable according to the increase in stress ratio.

Similar to the previous results, Figure 3 and Figure 4 presents a monitoring point (2.7031, 0.1257) for fractures growth on different stress ratios. Through Figure 20, it can be observed higher fractures opening for stress ratio 2 in both models (A and B). It can be explained based in anisotropic stress distribution in the formation. Anisotropic stress distribution influences in fractures distribution, which displacing mainly in the maximum principal stress direction.

It is possible to analyze the influence of intermediate principal stress σ_m on fracture opening. It may be influenced in different ways according to the stress changes on formation. Through Figure 21 can be observed, that changes in the minimum principal stress produces smaller fractures opening for an increase of intermediate principal stress. Similarly, higher values of fractures opening can be observed for lower intermediate principal stress, according to higher stress anisotropy (ratio 2). On the other hand, an increase on maximum principal stress develops higher fractures opening, reaching higher values according to higher stress anisotropy (ratio 2).

2.4.6 Stress Ratio Effect on Pressure Injection

Injection pressure is one of the principal variables to monitoring during hydraulic fracturing process, thus, the effect of parameters such as *in situ* stress on pressure injection should be monitored. In Model A, the injection pressure reaches higher values for higher stress isotropy (ratio 1), and decreases with the increase of stress ratio. Thus, for ratio 2, there will be a greater ease to fluid entry in the formation, relieving the injection pressure into the well. However, in Model B, were developed lower values of injection pressure for stress ratio 1, as compared with stress ratio 1.3 and 2. The previous behavior is opposed to Model A.

Finally, the previous results may be explained through the intermediate principal stress in the formation $((\sigma_{xx}+\sigma_{yy})/2)$, when it is increasing, the injection pressure is increasing (Figure 22).

A more detailed analysis of studied phenomena in this work can be found at Cerro (2016).

3 FIGURES AND TABLES

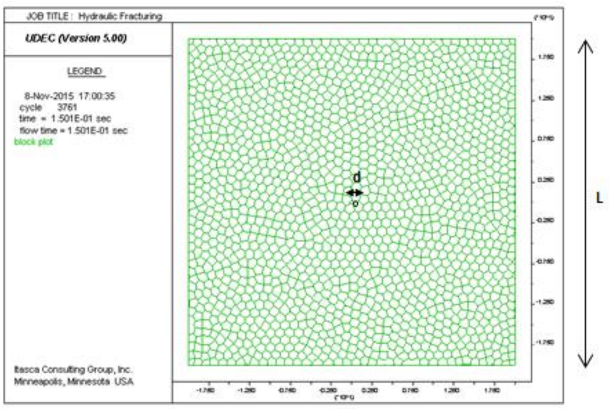


Figure 1 Model geometry.

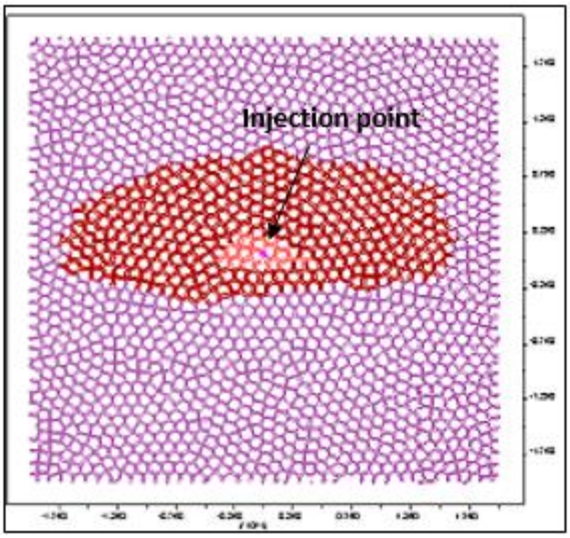


Figure 2. Example UDEC simulation result showing pore pressure distribution and the injection point.

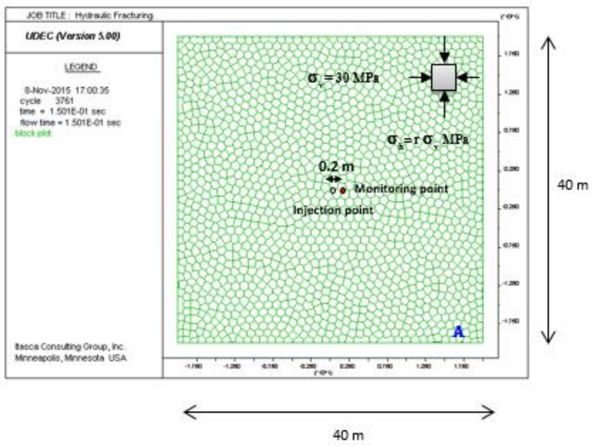


Figure 3. Numerical model A, σ_h variation.

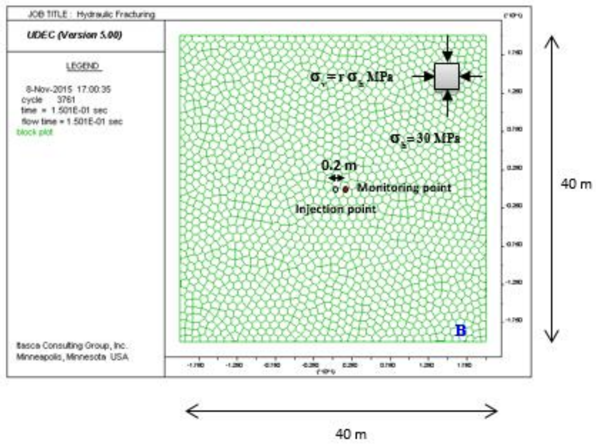


Figure 4. Numerical model A, σ_H variation.

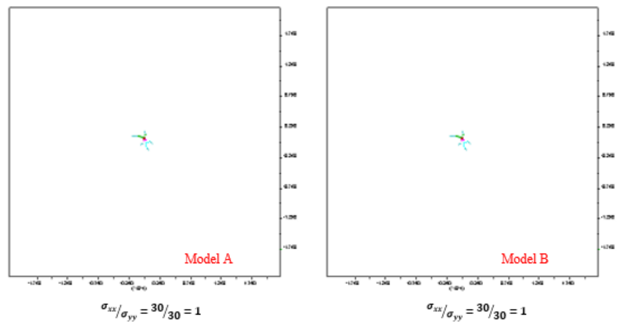


Figure 5. Fluid injected region for Case “1”- stress ratio 1

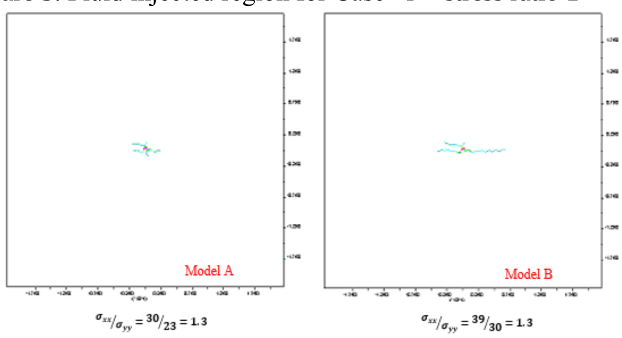


Figure 6. Fluid injected region for Cases “2 and 4” - stress ratio 1.3.

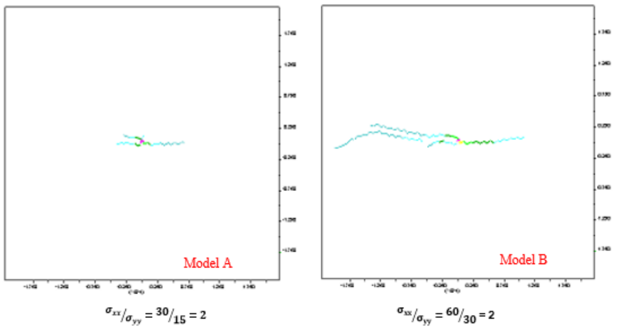


Figure 7. Fluid injected region for Cases "3 and 5" - stress ratio 2.

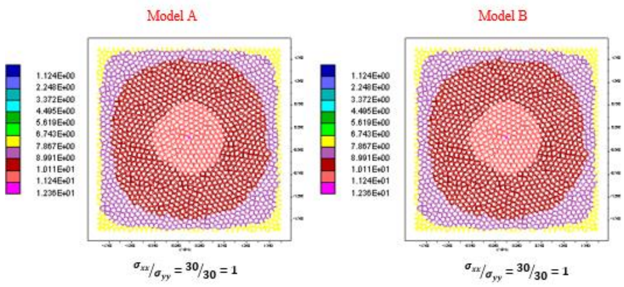


Figure 8. Pore pressure diffusion for Case "1" - stress ratio 1.

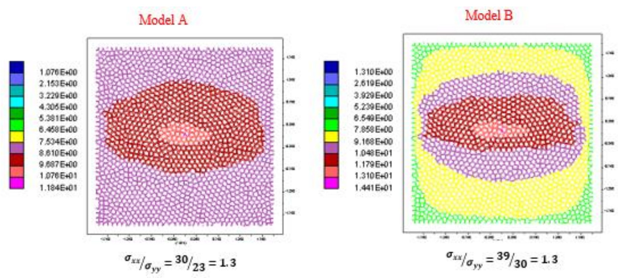


Figure 9. Pore pressure diffusion for Cases "2 and 4" - stress ratio 1.3.

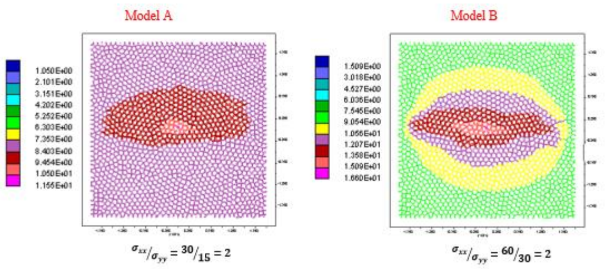


Figure 10. Pore pressure diffusion for Cases "3 and 5" - stress ratio 2.

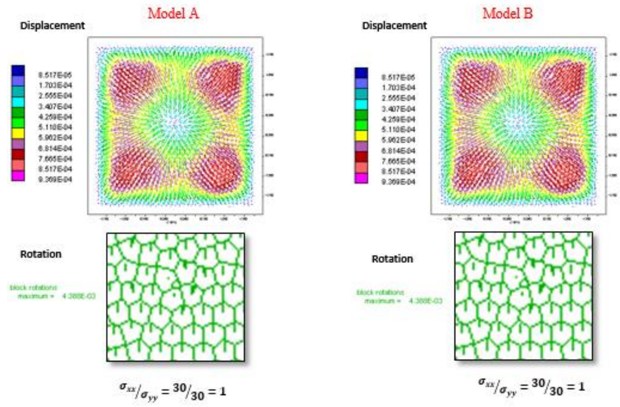


Figure 11. Block displacements and rotation for Case "1" - stress ratio 1.

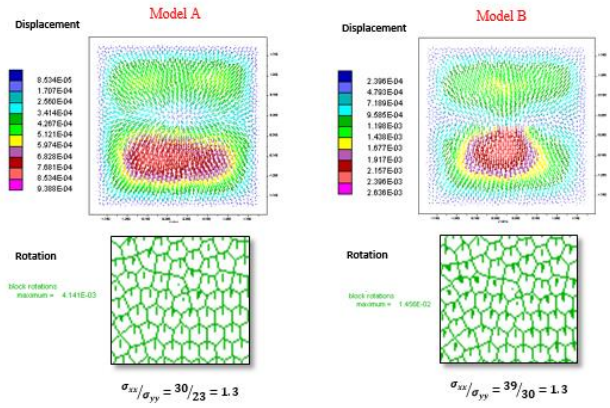


Figure 12. Block displacements and rotation for Cases "2 and 4" - stress ratio 1.3.

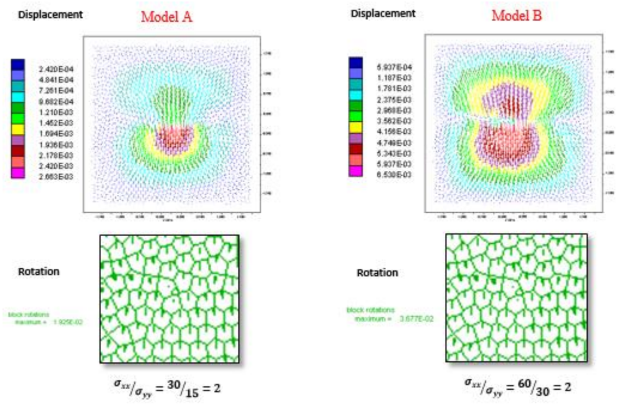


Figure 13. Block displacements and rotation for Cases "3 and 5" - stress ratio 2.

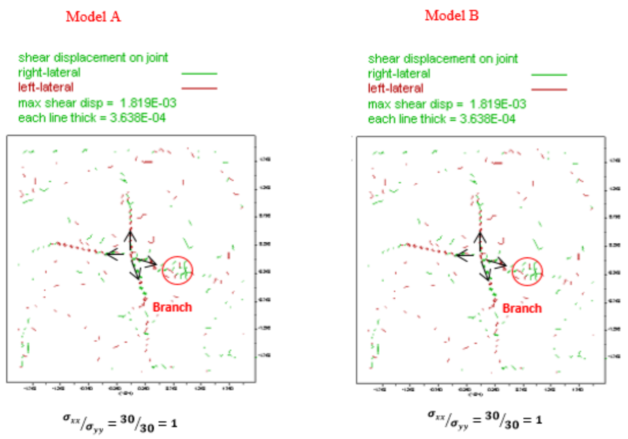


Figure 14. Block shear displacements for Case "1" - stress ratio 1.

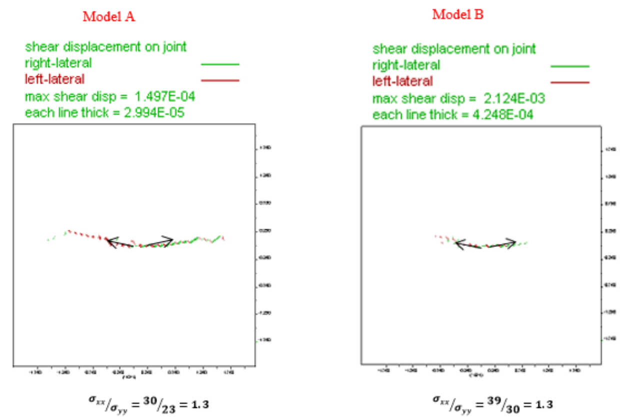


Figure 15. Block shear displacements for Cases "2 and 4" - stress ratio 1.3.

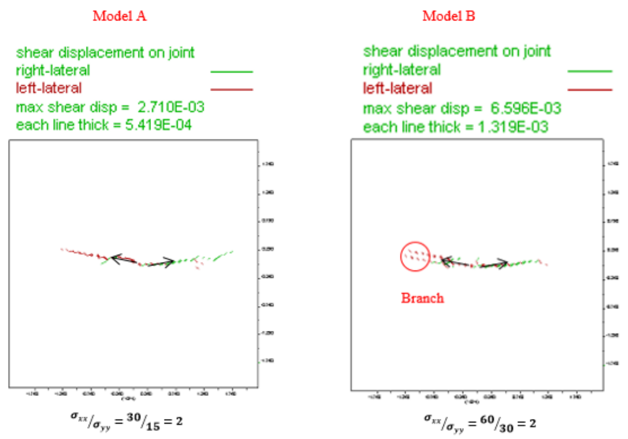


Figure 16. Block shear displacements for Cases "3 and 5" - stress ratio 2.

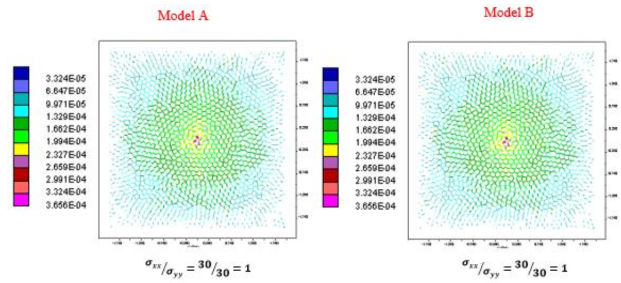


Figure 17. Block normal displacements for Case "1" - stress ratio 1.

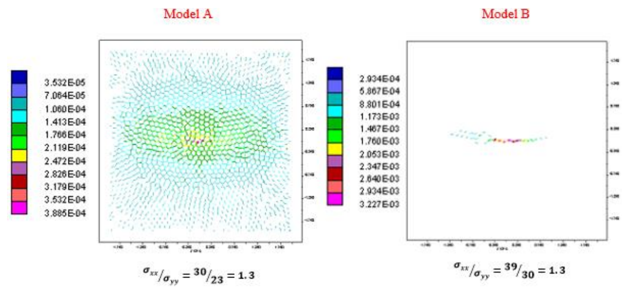


Figure 18. Block normal displacements for Cases "2 and 4" - stress ratio 1.3.

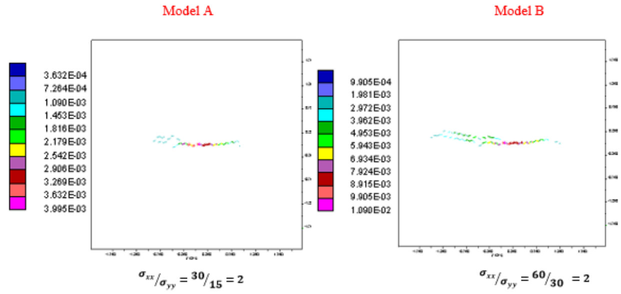
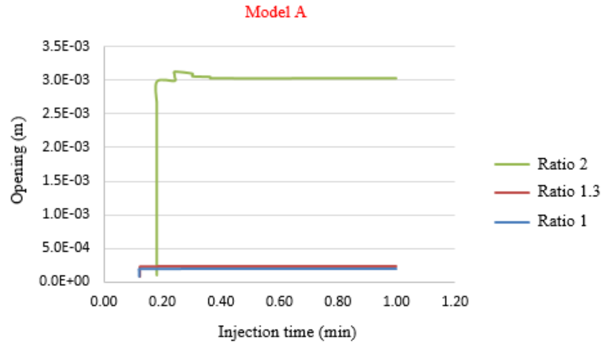


Figure 19. Block normal displacements for Cases "3 and 5" - stress ratio 2.



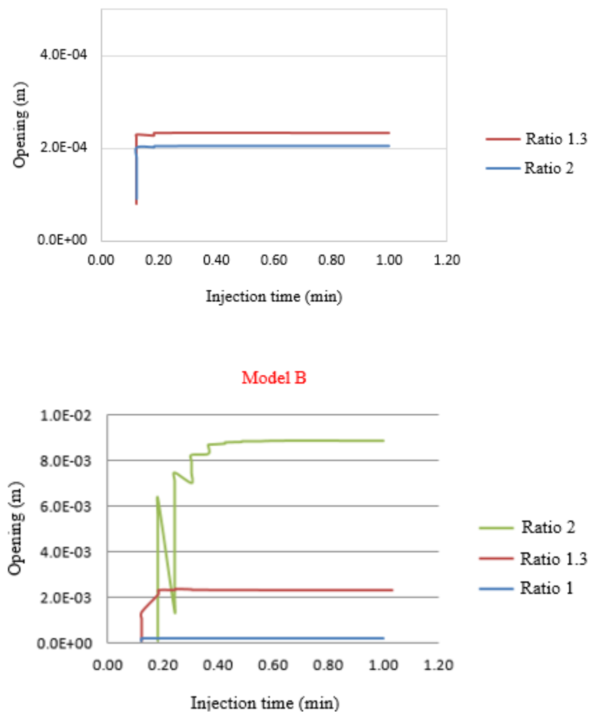


Figure 20. Fracture opening in function of stress ratio in analytic point (2.7031, 0.1257).

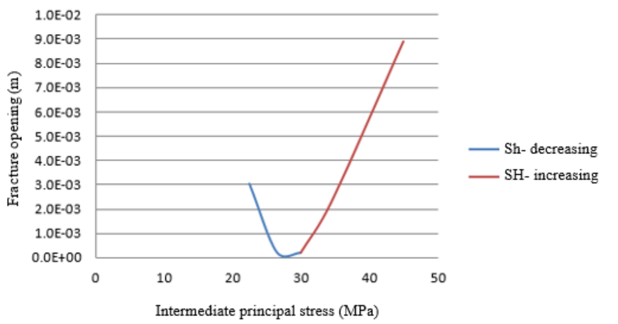


Figure 21. Fracture opening in function of intermediate principal stress.

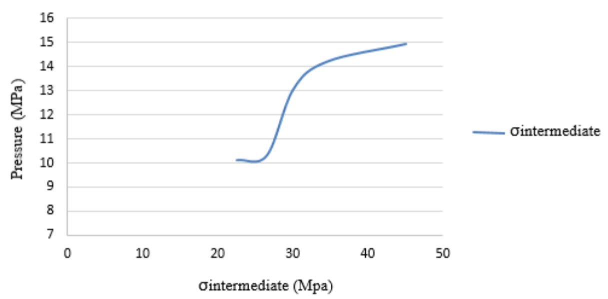


Figure 22. Growth trend of injection pressure as function of intermediate principal stress.

Table 1. Simulation cases for UDEC modeling

Simulation Case	**1**	**2**	**3**	**4**	**5**
Ratio [σ_v/ σ_h]	1	1.3	2	1.3	2
σ_v (σ_{xx}) (MPa)	30	30	30	39	60
σ_h (σ_{yy}) (MPa)	30	**23**	15	30	30
P_p (MPa)	7.69	7.69	7.69	7.69	7.69
Injection rate (bpm)	135	135	135	135	135
Fluid Viscosity (cP)	1	1	1	1	1

Table 2. Material properties.

Properties	**Values**
Intact Rock	
Density (kg/m^3)	2.7x10^3
Bulk modulus (GPa)	43.93
Shear modulus (GPa)	30.25
Fractures	
Normal stiffness (MPa/m)	10 x10^3
Shear stiffness (MPa/m)	1 x10^3
Friction angle	26°
Cohesion (MPa)	0.1
Dilation angle	10°

CONCLUSIONS

The geometric idealization of models, attempted to satisfy some geologic conditions (rock structure, principal stresses orientation) and numerical conditions (fractures propagation plane).

The achieved results, showed that the trend of hydraulic fractures follow the natural fractures instead to break the intact rock.

The global orientation of fractures growth remains perpendicular to minimum principal stress.

- Fluid flow occurs in maximum principal stress direction for higher stress ratio (ratio 2).
- Pore pressure diffusion occurs in the maximum principal stress direction.
- Slightly rotation blocks around injection point involve fractures opening with

high hydraulic conductivity, which reach high values from higher stress anisotropy (ratio 2).

- Injection pressure increase with stress ratio increase.
- Anisotropic stresses field involves higher values of pressure injection.
- The fracture opening and its conductivity reach higher values from higher anisotropy stresses on rock. Similarly, there is a higher interconnection to well area.

In conclusion, stress ratio affects mainly the network fractures orientation and distribution, once the network fractures is propagated in maximum principal stress direction.

ACKNOWLEDGEMENTS

The authors would like to thank to Itasca for providing the academic license of the software UDEC.

REFERENCES

Castro, L., Craig, S., Micheli, R., Livescu, S. (2015) Overcoming extended-reach challenges for annular fracturing. *Society of Petroleum Engineers, SPE 173683-MS, SPE/ Coiled Tubing & Well Intervention Conference & Exhibition*.

Cerro, D.C. (2016) *Hydraulic fracturing in unconventional gas reservoirs: simulation using discrete elements method*. Pontifícia Universidade Católica do Rio de Janeiro (*in Portuguese*).

Cipolla, C.L., Lolon, E.P., Erdle, J.C., Rubin, B. (2010) Reservoir modeling in shale-gas reservoirs. *Society of Petroleum Engineers, SPE 125530- PA, SPE Reservoir Evaluation & Engineering.*

Cundall, P.A. (1978) Computer modeling of jointed rock masses. *8th international conference on computer e advances in geomechanics, siriwardance*.

Curtis, J.B. (2002) Fractured shale-gas systems. Bulletin of the American *Association of Petroleum Geologist 86 (11), p. 1921-1938.*

Dusseault, M.B. (2013) Geomechanical aspects of shale gas development. *Rock Mechanics for Resource, Energy and Environment, p. 39-56.*

EIA. Shale oil and shale gas resources are globally abundant. Access: May 19. 2015. available *in: http://www.eia.gov/todayinenergy/detail.cfm?id=14431*.

Nagel, N.B., Sanchez, M.A., Lee, B. (2012) Gas shale hydraulic fracturing A numerical evaluation of the effect of geomechanical parameters. *Society of Petroleum Engineers, SPE 152192-MS, SPE Hydraulic Fracturing Technology Conference.*