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Post-Treatment Assessment of Induced Fracture Networks

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Abstract

An integrated methodology is proposed to generate a grid of potential paths for hydraulic fracture growth in naturally fractured reservoirs based on formation properties and recorded microseismic maps. The generated grid can be further used for treatment simulation to determine induced fractures geometry, height growth and respected proppant transport in the induced fracture network. For different realization of natural fracture distributions generated by computer simulations, cohesive interface technique is used to model evolution of induced fracture network. Microsesimic map is used to

1.Introduction

By creating conductive flow paths from the reservoir to the wellbore, hydraulic fracturing technology significantly contributed to the spikes in gas production in the United States in the past few years (US Energy information Administration report, "Summary: US Crude Oil, Natural Gas, and Natural Gas Liquids Proved Reserves 2009). In recent years, production from unconventional shale gas reservoirs has been heavily relied on this technology as well. As such, research efforts have been centered on how to achieve the optimal fracture design with known reservoir characteristics or at least improving fracturing treatment design. The preliminary step in assessing any hydraulic fracturing job is identifying geometry of induced fractures. Accurate prediction of the fracture network geometry is a desirable objective yet rarely accomplished with modern fracturing technology. A model that is able to predict the geometry and evolution pattern of every individual fracture in the fracture network barely exists due to the fact that it is essentially impossible to collect every detail regarding individual fractures. It is notable that natural fractures may exist in a wide range of length and widths (Ortega et al. 2006), here we are mainly interested in natural fractures with comparable size with the hydraulic fractures. Small natural fractures may also open due to thermal stresses (Dahi Taleghani et al. 2013a) or residual plastic deformations (Dahi Taleghani et al. 2013b), since they will not affect the direction of fracture propagation, we ignored them here although they could affect the initial hydrocarbon production rate. Therefore, we set our objective to develop an optimal approach to describe the seemingly unmanageable spatio-temporal evolution of fracture patterns. While traditional models assuming simple symmetric wing or bi-wing type fracture networks are commonly appropriate for ideal homogenous reservoirs, they are inadequate in representing the complex nature of the fracture network in reservoirs with pre-existing fractures.

Historically, pressure dignostics (Nolte and Smith 1979, Nolte1991) and tiltmeter measurments (Warpinski et al. 1997) were the main tools for estimating fractures' geometry. Initial steps in pressure analysis include pressure data collection and processing; important information about formation, fracture and treatment may be obtained by identifying general pressure variation patterns, which are very similar to methods used in pressure transient analysis. Economides and Nolte (2000) have provided a complete review of classic pressure diagnostic techniques to infer critical parameters of the fracturing treatment, including fracture geometry, closure pressure, fracture height growth, formation pressure capacity, treatment efficiency, and fluid flow patterns. This approach has gained its popularity in early 1990's because pressure data is the least costly piece of information to collect in the field and this method was providing acceptable predictions for massive fracturing jobs in vertical well. Utilization of hydraulic fracturing to stimulate new developments in low permeability, naturally fractured formations like Barnett shale, which was frequently done in multiple stages though horizontal wells, posed new challenges in interpreting treatment pressure data. With introduction of hydraulic fracturing into the shale plays, which were usually naturally fractured, interactions between natural fractures and hydraulic fractures lead to the formation of complicated network of induced fractures.

In addition to the pressure analysis technique, microseismic data also helps in evaluating the effectiveness of the treatment design. Due to the complexity of data interpretation and associated cost, microseismic technology is still considered an expensive and more descrptive analysis tool. Because of the inherent properties of microseismic waves (low frequency and high noise to signal ratio), resolution in locating events cannot be better than 50 ft (Maxwell, 2008), which limits the application of this method to direct measurement of fracture spacing or intersection of fractures. Tiltmeters could not be effective for the system of multiple fractures. Micro-seismic data collected during hydraulic fracture treatments for Barnett Shale wells reveals a complex fracture geometry, where hydraulic fractures may propagate as multiple segments with different orientations influenced by pre-existing fractures, which lead to a cloud of event epicenters. Although micro-seismic mapping provides insights on the interaction of hydraulic fractures with natural fracture systems and stress regimes (Yingping et al. 1998), the phenomenon behind the scattered epicenters observed during fracture jobs are not fully explained (Rutledge and Phillips, 2003). Waters et al. (2006) provided a map of the microseismic events generated during a staged hydraulic fracturing treatment. The microseismic map does not show a narrow band perpendicular to the minimum horizontal stress, but there is a huge region of affected rock volume, extending hundreds to thousands of feet along the expected hydraulic fracture direction (parallel to the orientation of maximum horizontal stress). The cloud also extends hundreds of feet in the orthogonal direction. All these different evidence confirms the presence of a complex fracture network. The main reason for developing complex fracture pattern is the interaction between natural fractures and hydraulic fractures. One of the decisive factors in determining the geometry of the induced hydraulic fracture is the characteristics of the pre-existing natural fractures, and other formation properties that influence the fracture pattern, including in-situ stress state, permeability and mechanical properties, are also closely related to the existence of natural fractures.

Occasionally, the interactions between natural fractures and hydraulic fractures are investigated through laboratory experiment. The experiment results illustrated how different parameters, especially differential stress, could dominate the interactions between natural and hydraulic fractures (Warpinski, and Teufel, 1987). Further laboratory investigations confirm formation of complicated fracture networks in presence of natural fractures. Jeffery et al. (2009) conducted mineback field experiments and showed the growth of hydraulic fractures through a system of natural fractures. In such situations, the induced fracture tend to develop in a much complicated way due to diversion of the progressing hydraulic fracture into natural fractures, or simply opening these fractures (Warpinski and Teufel, 1987, Olson and Dahi Taleghani, 2009). This complexity can either be suppressed or utilized in some extent to benefit the reservoir productivity (Cipolla et al, 2010). Considering the fact that all pressure diagnostic techniques were built by assuming induced hydraulic fractures as a single-strand fracture, they are not reliable to interpret pressure data of a network of fractures.

In summary, tiltmeters and microseismic monitoring do not have sufficient resolution to identify small scale fracture complexity. However, it is possible to gather some qualitative data about far-field fracture complexity from fracture pressure analysis (Cipolla et al. 2008) and core studies. In an ideal approach, microseismic data in combination with other resources like pump data or bottomhole pressure, may provide better understanding of characteristics of induced fractures. Having access to such an integrated model can strongly influence future completion design and overall field development strategy. Of course, this integrated analysis would only be possible by incorporating pressure analysis for a system of multiple interacting fractures. Despite single fracture situation, pressure evolution in multiple fracture problems cannot be addressed with analytical soltuions and requires detailed numerical analyses.

Cipolla et al (2010) discussed how fracture network complexity may change bottomhole pressure during treatment as well as future production in comparison to the cases with single induced fracture. Through reservoir simulation, they claimed that the fracture conductivity required to maximize production is proportional to the square root of fracture spacing, thus indicated that fracture complexity is inversely proportional to the fracture conductivity requirement. Moreover, they argued that in complicated fracture networks, the average proppant concentration will become insignificant, and therefore it is less likely to impact the well performance.

Due to the limited access to the subsurface, modeling or so-called numerical experiments on different realiziation of natural fractures distibutions, which have the same overall statistical properties measured in the outcrops, could be a reasonable tool to predict potential pathways for fracturing fluid in the subsurface or correlating bottomhole pressure changes.

Xu et al. (2010) tried to address this issue by proposing a semi-analytical pseudo 3-D fracturing simulator to simulate the growth of hydraulic fracture networks (HFN) in the grid of equally-spaced natural fractures. The wiremesh model assumes a growing symmetric elliptical front for the development of induced fracture network. However, spatial and temporal distributions of microseismic events mapped during many hydraulic treatments reveal asymmetric and preferential direction. Presence of major or pre-existing natural fractures and their orientation could play a key role in the development of fracture networks in different directions. Fluid pressure and injection rate have been used for a long time to estimate fracture geometries. However, due to the complex geometry of induced fracture networks, these methods are not applicable in reservoirs with pre-existing natural fractures. To fill this gap, a set of realizations of mathematically equivalent fracture networks are developed here to represent the geometry of natural fracture network. In developing the equivalent networks, the assumptions of presence of perpendicular fracture sets and their alignment with the principal in situ stresses are relaxed. HFN realizations are not only constrained by the injection rate and the total mass of injected fluid, but also relate to temporal and spatial distribution of mapped microseismic events to honor the measured bottom hole treatment pressure. Integration of microseismic events into the analysis requires a sophisticated filtering to reduce the interference of microseismic events that are not generated along the hydraulically induced fractures. For instance, some of these events might have been induced by the reactivation of the fractures in the vicinity of stimulated zone. This mathematical model incorporates treatment pressure, injection rate, general characteristic of natural fractures, and formation mechanical properties to obtain HFN geometrical parameters. The proposed methodology is utilized in a multi-stage stimulation exercises in Barnett Shale wells. Simulated HFN using this technique is compared with the HFN produced using Xu et al. (2010) technique. Production data forecasted based on these fracture networks is compared at the end as the validation for the proposed technique. We show how location of mapped microseismic events may serve as a useful piece of data in combination with pressure analysis in predicting the geometry of the hydraulically-induced fracture network.

2.Hydraulic fracturing in Fractured Reservoirs

The size of natural fractures ranges from few millimeters (tiny fissures) to several thousand meters (faults). As opposed to natural fractures, hydraulic fractures are created artificially with the force of injected pressurized fluid. By generating a hydrostatic pressure that exceeds the minimum in-situ stress of the formation, fractures are opened up in a direction perpendicular to that of smallest resistance, i.e minimum principal stress.

Improved hydrocarbon production does not necessarily rely on hydraulic fracturing. In some cases, natural fractures may also contribute to the recovery of oil and gas. Natural fractures in formations with moderate permeability can serve as the flow path for hydrocarbons as well, and the presence of natural fractures may facilitate formation of a network of induced fractures. On the other hand, natural fractures may also negatively impact hydraulic fracturing treatment by extensive leakoff and reduced flow back (Warpinski, 1990). A large population of the natural fractures in the subsurface is cemented by diagenetic materials. Although they will not increase overall permeability initially, opening of these natural fractures will increase drainage area tremendously. Fortunately in most cases, these natural fractures act as weak paths for fracture growth, therefore if they are aligned in a favorable direction with in situ tectonic stresses, there is a good likelihood that these natural fracture can be opened during treatment (Gale et al. 2007, Dahi Taleghani and Olson, 2011). The intersections of natural fractures with hydraulic fractures result in irregular fracture pattern, including non-planar fractures or fracture branching. On one hand, opening of these natural fractures improve productivity of the formation, on the other hand, coealesence of these fractures into the hydraulic fractures makes pressure analysis and prediction of fracture growth quite complicated. Overall, interactions between natural fractures and hydraulic fractures make the fracturing design and execution more challenging. Investigation and understanding of their interaction are crucial in achieving successful fracture treatment in formations with natural fracture network.

There are three different directions a fracture could propagate when encountering a cemented natural fracture (Figure 1). Depending on the properties of the cement filling inside the natural fracture may act as a weak path, as a barrier, or it may have no effect on fracture propagation. In the first scenario (Fig. 1b), the natural fracture has no influence and the hydraulic fracture propagates in-plane without interruption, maintaining its orientation normal to the minimum horizontal stress. The fracture crossover may be a result of high strength cement in the natural fractures (comparable to matrix strength), unfavorable natural fracture orientation, or a fracturing pressure that is not high enough to overcome the normal stress perpendicular to the natural fracture. In the second scenario (Fig. 1c), when the hydraulic fracture intersects the natural fracture, the hydraulic fracture is deflected and the fluid is completely diverted into the natural fracture system. The natural fracture opens because it presents the path of least resistance as compared to straight-ahead propagation of the hydraulic fracture, likely because the natural fracture cement strength is less than that of the intact rock.

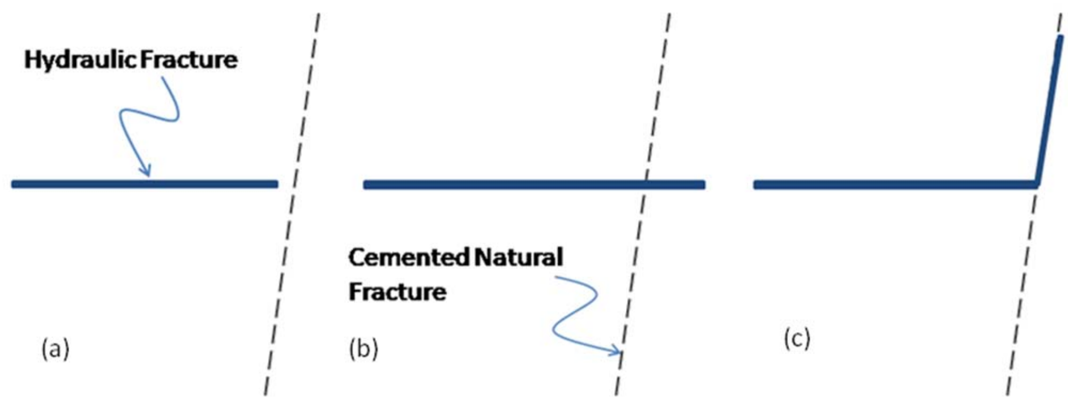


Figure 1. Possible scenarios for hydraulic fracture / natural fracture intersection. a) The hydraulic fracture (heavy solid line) as it approaches the natural fracture (dashed line) before intersection. b) The hydraulic fracture crosses the natural fracture without interruption. c) The hydraulic fracture is stopped by the natural fracture and fluid diverts along the natural fracture due to its reactivation.

Fracture propagation in fracture mechanics is a function of opening and shearing mode stress intensity factors, which are measures of stress concentration at the tip of the crack (Lawn, 2004). The two stress intensity factors are combined in the energy release rate fracture propagation criterion used in this research. The energy release rate, G, is related to the stress intensity factors through Irwin's relation (Lawn 2004). In the case that enough energy is available for fracture propagation and the crack has more than one path to follow (Figure 1), the most likely path for it to utilize is that with the maximum energy release rate, or the greater relative energy release rate (Dahi Taleghani and Olson, 2013). The details of energy criterion and its implementation can be found in Dahi Taleghani and Olson (2013).

3.Modelling Fracture Growth in presence of natural fractures

Modeling of fractures is generally classified into analytical and numerical categories. Analytical solutions (for instance Detourany, 2004) are limited to simple fracture geometries placed in homogenous, isotropic formations. For most situations, there is no closed form solution for propagation of fluid driven fractures. On the other hand, numerical simulation could obtain solutions for more complex problems. Many numerical techniques have been used to simulate propagation of hydraulic fractures such as Distinct Element Methods, Boundary Element Methods, and Finite Element Methods. In all of these models, force equilibrium and elasticity relations govern deformations of the rock, and the fluid flow inside the fracture is idealized as flow down a slot using lubrication theory (Batchelor, 1967).

Dahi Taleghani (2009) used an Extended Finite Element Method (XFEM) to address two-dimensional static and quasi-static problems. Crack propagations in strong and weak quasi-static form were described by deriving the governing equations from XFEM. By decomposing the displacement field into continuous and discontinuous parts, XFEM can approximate the behavior of hydraulic fractures and its interaction with natural fractures in a naturally fractured reservoir without any need for remeshing the problem for each increment of fracture propagation. Dahi Taleghani and Olson (2013) extended the numerical analysis of hydraulic fracture/natural fracture interaction to the case of cemented natural fractures. These fractures can be influential on geometric development of hydraulic fractures, which consequently affects the resultant gas production. They examined different scenarios of fracture interactions using an eXtended Finite Element Method (XFEM) numerical scheme that considers the fluid flow in the hydraulic fracture networks as well as the rock deformation.

Here, we used the cohesive interface approach to simulate fracture propagation in three dimensional geometries. Cohesive element approach limits the fracture propagation to predefined paths. In highly fractured formations since hydraulic fractures are growing through network of natural fractures by placing cohesive elements through natural fractures, it is possible to track potential paths in the development of a network of induced hydraulic fractures. Inserting cohesive properties at the tip of the fracture removes stress singularity at the tips, which improves numerical stability of the model.

To study the interaction between hydraulic fracture and natural fractures with different height, a three-dimensional model is required to incorporate interactions and coalescence of fractures with different sizes. The cohesive zone model assumes the existence of a fracture process zone characterized by a traction-separation law rather than an elastic crack tip region. The cohesive finite element method provides and effective alternate approach for quantitative analysis of fracture behavior through explicit simulation of the fracture process. The presence of the fissures will be modeled using cohesive elements.

Numerical models discussed above assume the geometry of natural fractures is given. Due to limited access to the subsurface to monitor fractures, simulation of natural fractures has been always considered as an option to predict fracture growth in the subsurface (Olson, 2004). Any hydraulic fracturing simulation is generally built upon existing formation and fracture properties, including formation geomechanical properties, treatment and petrophysical data as well as the exact location of natural fractures. However, the location and dimension of natural fratures cannot be determined accurately using seismic or logging tools. This limitation has restricted the application of commercial and academic fracturing simulators. To address this deficiency, several approaches have been taken to the industry. In the first approach, a fully random set of fractures are considered as natural fractures, and hydraulic fracture is assumed to only propagate through these fractures (Referece MFRac or McClure and Horne), which is not completely representing fracture distribution of formation of interest. Extensive outcrop studies in the last couple of decades demonstrate that joints distribution is not a fully random distribution and depending on the rock properties and tectonic history, it may range from a single set of parallel joints to multiple sets of intersecting joints (Ortega et al. 2000, Ortega et al. 2006). Additionally, depending on rock fracturing properties, each joint set could be equally spaced or clustered (Olson et al. 2008). Therefore, we may conclude that although we cannot come up with a deterministic distribution and location of natural fractures, characteristic distribution of natural fractures in different situation could be different, in otherwords, pattern of induced fracture networks is dictated by natural fractures and their orientation with respect to principal in situ stresses. Therefore, we need to set our goal to speculate the characteristic geometry of natural fractures in the subsurface rather than a deterministic approach of locating the exact location of each fracture as this problem is ill-conidtioned and does not have a unique solution.

4.Cohesive Element Technique

Cohesive zone model assumes the existence of a fracture zone characterized by a traction-separation law. The pre-defined surface is made up of elements that support the cohesive zone traction-opening calculation embedded in the rock and the hydraulic fracture grows along this surface. The fracture process zone (unbroken cohesive zone) is defined within the separating surfaces where the surface tractions are nonzero.

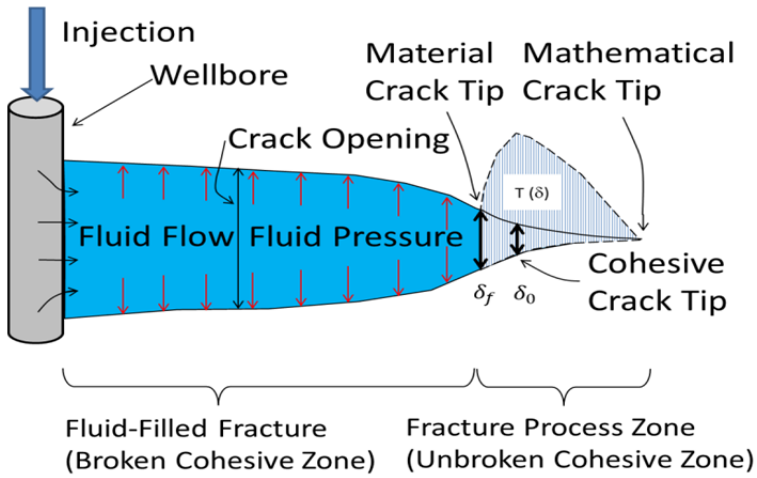


Figure 2. Embedded cohesive zone at the tip of a hydraulic fracture. Two zones can be identified: i) broken cohesive zone where tractionseparation law is not longer valid, and ii) unbroken cohesive zone where tranction separation law is valid.

There are three failure mechanisms present during fracture modeling: i) fracture initiation criterion, ii) fracture evolution law, and iii) choice of element removal upon reaching a completely damaged state. Fracture Initiation Criterion is referred to as the beginning of degradation due to stresses and/or strains satisfy certain damage initiation criteria that were specified. There are many fracture initiation criterion in ABAQUS. It could be assumed that initiation begins when maximum nominal or quadratic stress ratio or maximum nominal or quadratic strains reache to their critical values. Fracture Evolution Law Criterion is usually considered that the fracture propagates when the stress intensity factor at the tip exceeds the rock toughness. When the interface thickness is negligibly small, it may be straightforward to define the constitutive response of the cohesive layer directly in terms of traction versus separation.

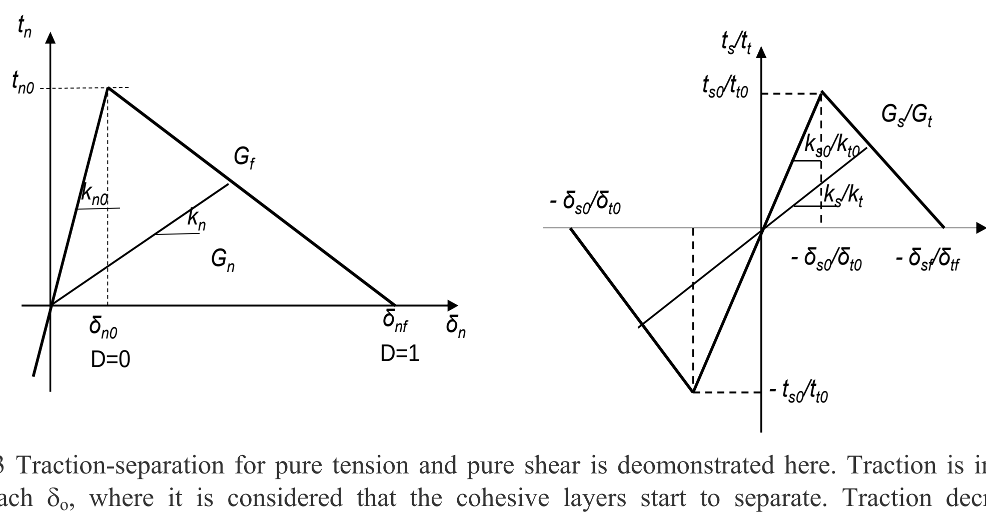


Figure 3 Traction-separation for pure tension and pure shear is deomonstrated here. Traction is increasing until reach δ_o, where it is considered that the cohesive layers start to separate. Traction decreases as separation is increasing until δ_f, where it is considered complete failure. Beyond this, traction separation law is not longer valid.

The relationship among $G_c, K,\ T_{max}, \delta_0, and\ \ \delta_f$

$$G_c = \frac{1}{2} T_f \delta_f = \frac{1}{2\alpha} T_f \delta_0 = \frac{T_f{}^2}{2\alpha K}, \tag{1}$$

where G_c is the cohesive energy, T_{max} is the cohesive strength, K is the initial cohesive stiffness, δ_0 and δ_f are the critical separation at damage initiation and complete failure respectively, and δ_0 is the ratio of critical separation at damage initiation and complete failure.

Since bilinear traction-separations laws are defined for pure normal and shear loading modes, general loading conditions which could be any arbitrary combination of normal and shear failure (mixed mode problem) require considering the combinatory effect of normal and shear modes. We used quadratic nominal stress law to combine different failure modes. Damage initiates when a quadratic interaction function involving nominal stress ratios (as defined below) reaches the value of one (Camacho and Ortiz,, 1996)

$$\left\{\frac{\langle t_n \rangle}{t_{n0}}\right\}^2 + \left\{\frac{t_s}{t_{s0}}\right\}^2 + \left\{\frac{t_t}{t_{t0}}\right\}^2 = 1, \tag{2}$$

where t_n, t_s and t_t represent the real values of normal and tangential (first and second shear) tractions across the interface, respectively. < > is the Macaulay bracket and

$$\langle t_n \rangle = \begin{cases} t_n,\ t_n \geq 0 & (tension) \\ 0,\ t_n < 0 & (compression) \end{cases}, \tag{3}$$

The metrics for damage is a scalar stiffness degradation index, D, which represents the overall damage of the interface caused by all stress components. The stiffness degradation index is a function of the so-called effective relative displacement, δ_m by combining the effects of δ_t, δ_s and δ_n,

$$\delta_m = \sqrt{\langle \delta_n \rangle^2 + \delta_s{}^2 + \delta_t{}^2}\,. \tag{4}$$

For linear softening, the damage evolves with the index (Mei, et al, 2010)

$$D = \frac{\delta_{mf}\,(\delta_{m,\max} - \delta_{m0})}{\delta_{m,\max}\,(\delta_{mf} - \delta_{m0})} \tag{5}$$

where $\delta_{m,\max}$ is the maximum effective relative displacement attained during the loading history. δ_{m0} and δ_{mf} are effective relative displacements corresponding to δ_{n0} and δ_{s0}, and δ_{nf} and δ_{sf} were as shown in Figure 4, respectively.

For nonlinear mechanics, the most robust criterion is described by the constitutive model of the cohesive zone proposed by Barenblatt (1962) and Hillerborg (1976). This law assumes that the cohesive surfaces are intact without any relative displacement, and exhibit reversible linear elastic behavior until the traction reaches the cohesive strength or equivalently the separation exceeds δ_0. Beyond this value, the traction reduces linearly to zero up to δ_f.Figure 4 shows that how the crack opening provides paths for tangential and normal flow inside the fracture. The fluid leakoff is normal flow. The tangential flow within the gap is governed by the lubrication equation (Batchelor, 1967), which is a combination of Poiseulle's flow

$$q = -\frac{w^3}{12\mu} \nabla p_f \tag{6}$$

and the continuity equation

$$\frac{\partial w}{\partial t} + \nabla \cdot q + (q_t + q_b) = Q(t)\delta(x, y). \tag{7}$$

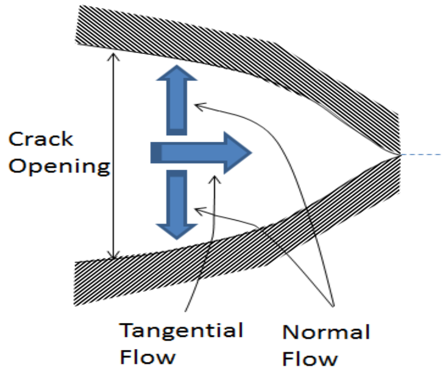


Figure 4. Two type of flows inside the fracture: i) tangential flow, which contribute to fracture opening, and ii) normal flow, which is the fluid that will be lost in the formation (better known as leak-off).

In the above equation, q(x,y,t) is the fluid flux in tangential direction, $\nabla p_f(x, y, t)$ is the fluid pressure gradient along the cohesive zone, w(x,y,t) is the crack opening, μ and Q(t) are fluid viscosity and injection rate, respectively. The $q_t(x, y, t)$ and $q_b(x, y, t)$ are the normal flow rates into the top and bottom surfaces of the cohesive elements, respectively. The normal flow rates are defined as

$$q_t = c_t(p_f - p_t) \tag{8}$$

$$q_b = c_b(p_f - p_b), \tag{9}$$

where p_f and p_b are the pore pressures in the adjacent pore fluid (poroelastic) material on the top and bottom surfaces of the fracture, respectively, and c_t and c_b define the corresponding fluid leakoff coefficients.

Chen et al (2009) and Sarris and Papanastasiou (2012) modeled the propagating hydraulic fracture in aplain strain geometry to generate GdK solution. They simulated the poroelastic hydrauilic fracturing problem, which is considering pressure in the reservoir and inside the fracture as well as the elastic case (which only consider fluid inside the fracture). We validated our simulation results with the results presented in Sarris and Papanastasiou (2012).

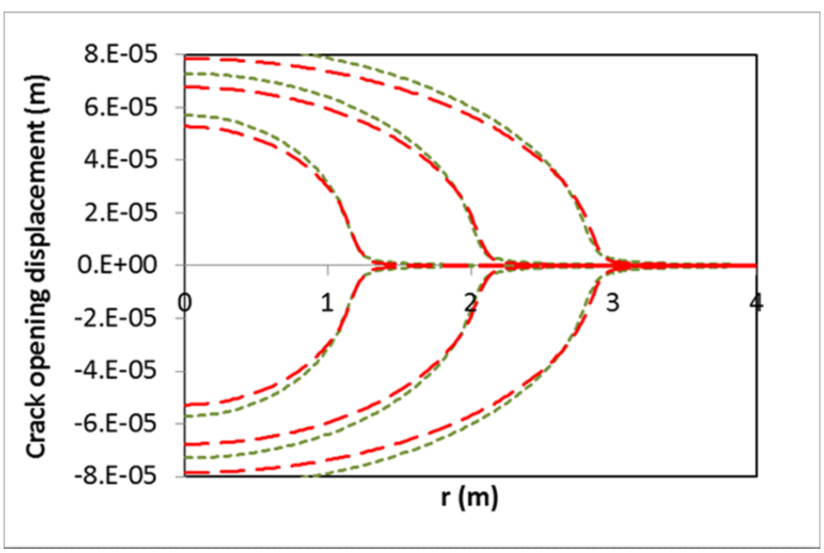
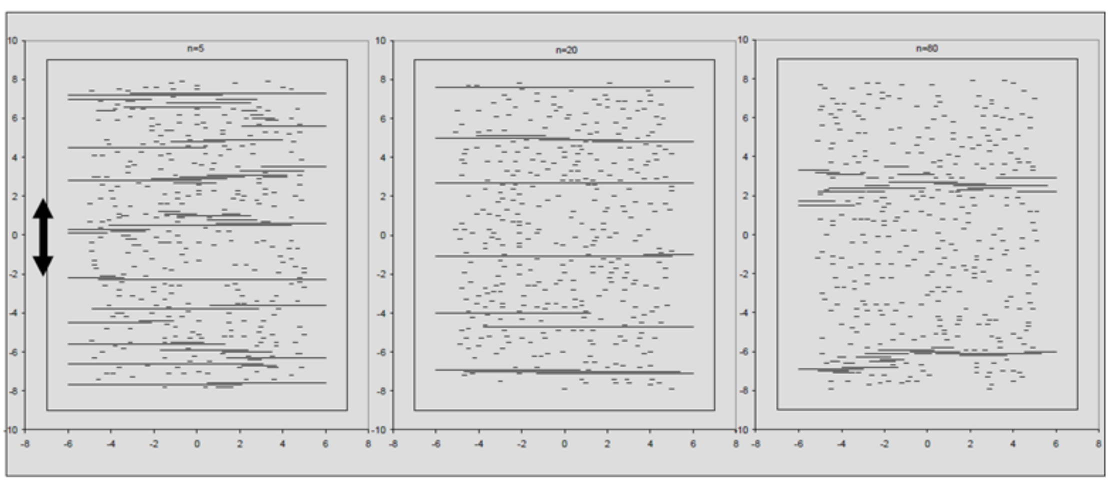


Figure 5 Fracture opening for a single GdK fracture compared with the results from Chen (2009).

5.Methodolgy for Grid Refinement

The main limitation in using deterministic models to simulate hydraulic fracturing growth in the subsurface is defining the location of natural fractures. One one hand due to the limited access to the subsurface determining the exact location of natural fractures using seismic and other tools is impossible and on the other hand, deterministic models show that there is no unique solution to determine natural fractures distribution using bottomhole pressure data. But we still need to know the geometry of induced fracture network to assess proppant transport and drainage area reached by induced fracture network.

The general approach to address this problem is assuming fractures as two perpendicular sets of parallel fractures. This approach is typically used for fluid flow in naturally fractured reservoirs asdual-porosity or dual-permeability models (Gilman and Kazemi 1988). Following this approach, Xu et al. (2010) developed a semi-analytical pseudo 3D fracturing simulator in an effort to predict the growth of hydraulic fracture networks and quantify the mechanical interactions among fractures and between fractures and injection fluid. By setting up equations on mechanical interactions between fractures and injected fluid, material balance and formation permeability, the simulator is capable of solving the equations simultaneously and obtaining solutions regarding the characteristic of the induced hydraulic fracturing networks. These techniques are very useful in understanding the physics of matrix-fracture fluid interaction, but they often represent an unrealistic assumption about fracture pattern geometry, where the reservoir is idealized as a stack of sugar-cubes. An alternative to this approach is to discretely represent the fractures. Hence, another approach proposed in the literature to address this challenge by assuming random distribution for natural fractures in the subsurface (Meyer and Bazan, 2011); however, core and outcrop studies revealed different pattern of natural fractures depending on lithologies and formation thickness (Mandl, 2005). Thus, mechanistic models have been used in the literature to generate possible realization of natural fractures distributions in the subsurface. Olson (2004) has shown that the spatial arrangement of fractures in a given network is strongly dependent on the subcritical crack growth parameters. Three regimes of growth have been identified as shown in Figure 6: 1) high subcritical crack index behavior, where fractures grow as clusters with a low median fracture length and the overall fracture intensity, 2) intermediate value subcritical index behavior, where fracture spacing is fairly regular and median length is larger, and 3) low subcritical index behavior, where spacing is again clustered with shorter fracture lengths but with much higher fracture intensity (the clusters are much more closely spaced than with high subcritical index cases).



n=5 n=20 n=80

Figure 6. Fracture distribiton is a function of bedthickness and subcritical crack index. The above realizations are generated for rocks with different subcritical crack index (borrowed from Olson 2004).

The results provided by mechanictic simulations (like Figure 5) have deterministic nature, therefore, different realization of natural fractures should be considered and filtered using Bayesian analysis to generate a fracture network with microseismic map very similar to the collected map in the field. It is notable that we assumed that shear microseismic event have been generated at the intersection of hydraulic fractures and natural fractures.

Considering the fact that accuracy in locating microseismic events is about 50ft, the located events may not provide practical information about the exact location of hydraulic fractures but they may provide valuable information about abundance of natural fracture and their overall spacings. The main objective, here, was to define the initial grid of cohesive fractures using the information provided by microseismic data. Since, running finite element simulation for thousand realizations could be very time consuming, random walk simulations were executed on natural fractures realizations to simulate growth of hydraulic fractures through the vicinity of the points microseismic events have been recorded at the associated times. Then, the cohesive element grids have been built by supposing these random paths rather than structured grids shown in Figure 7.

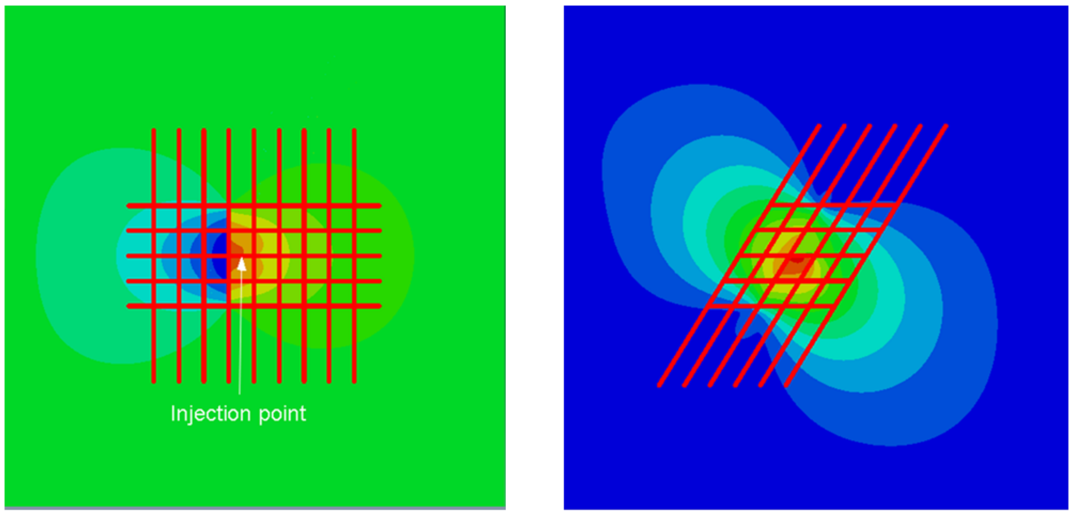


Figure 7. Grids of cohesive interfaces as potential paths for hydraulic fractures growth. In the right picture, two perpendicular sets of natural fractures is considered, while in the left picture two sets of natural fracture make 45 degrees angle with respect to each other. The wellbore is located in the middle of the grid. The colors show displacement map in the north-south direction.

By implementing the random walk algorithm that pass through the picked microseismic events, a set of initial paths for fracture growth has been generated for a field example in Barnett Shale and demonstrated in Figure 8. Only shear events have been picked generating random walks. Increasing the number of random walk realization definitely will increase the accuracy of the simulated fracture network.

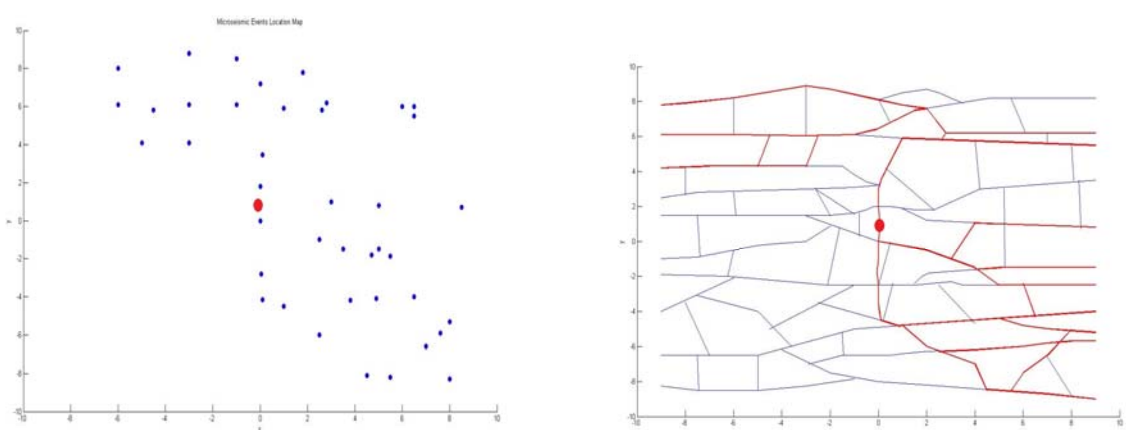


Figure 8. (a) Map of shear microseismic events till t=800 sec (b) the associated induced fracture geometry generated by random walk and passed finite element simulation to match bottom hole pressure.

6.Conclusion

An integrated methodology is proposed to generate a grid of potential paths for hydraulic fracture growth in naturally fractured reservoirs based on formation properties and recorded microseismic maps. The generated grid can be further used for treatment simulation to determine induced fractures geometry, height growth and respected proppant transport in the induced fracture network. The proposed methodology could address current limitations in simulations of hydraulic fracturing in natural fractured reservoirs that lack of precise distribution of natural fractures in the subsurface to make treatment design in these simulations more reliable.

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