Impact of Thermally Reactivated Micro-Natural Fractures on Well Productivity in Shale Reservoirs, a Numerical Study

Abstract

Recovered core samples and extensive outcrops studies have proved the existence of natural fractures in many tight formations. These natural fractures are likely filled with diagenetic materials such as clays, quartz or calcite. In this numerical study, we suggest that small cemented natural fractures, exposed to the surface of the hydraulic fracture, can be opened by the induced tensile stress due to the temperature difference between the cold fracturing fluid and hot formation. Cohesive zone model (CZM) is utilized here to simulate these natural fractures. Tensile strength of diagenetic cements, temperature difference between the fracturing fluid and formation, fractures spacing, and rock conductivity are the parameters controlling the opening and length of reactivated micro-fractures. Reactivated natural fractures may improve the rock permeability in the vicinity of the hydraulic fracture; however, the amount of permeability enhancement depends on the density and width of reactivated fractures. Contribution of these micro natural fractures to cumulative gas production from a shale reservoir is investigated by modifying the transmissibility coefficient in the dual porosity and dual permeability model. Transmissibility coefficient is then modified accordingly to estimate increase in gas production from the reactivated natural fractures in the reservoir simulator. Reservoir simulation results suggest that reactivated natural fractures in the tight formations at early stages can improve gas production up to 25% which may improve net present value of the project; however, their effect significantly reduces to 3% in long term cumulative production.

Keywords: Cemented Natural Fractures, Cohesive Zone Model, Hydraulic Fracturing, Gas Reservoir Modeling, Transmissibility Coefficient, Tight Formations, Induced Thermal stresses

Introduction

Hydraulic fracturing treatments have played a crucial role in boosting hydrocarbon production from low permeability reservoirs. Induced fractures significantly improve wellbore-formation contact area and consequently increase the production rate. Injection of highly pressurized fracturing fluid fractures the formation to create a highly permeable conduit for the reservoir fluid to produce. The direction of hydraulic fracture propagation depends on the direction of the minimum principal stress as well as natural fractures (Economides and Nolte, 2000; Dahi Taleghani and Olson, 2011). Core and outcrop studies, advanced logging tools, microseismic techniques and well testing analysis have proved the existence of natural fractures in many unconventional reservoirs. In naturally fractured reservoirs, arrest and diversion of hydraulic fracture front into the pre-existing natural fractures have been the subject of many experimental and theoretical studies (Warpinski and Teufel, 1987; Potluri *et al.* 2005; Dahi Taleghani *et al.* 2013; Gonzales-Chavez *et al.* 2015).

Natural fractures are mechanical discontinuities with the lengths varying from micrometers to kilometers (Narr *et al.*, 2006). These fractures may act as conductive paths for the fluid flow in the low permeability reservoirs affecting the ultimate recovery. However, they can also increase the leakoff volume during the fracturing treatments leading to early screenouts or poorly propped hydraulic fractures. Contribution of natural fractures in the hydrocarbon recovery is more significant in the tight formations with low permeability than permeable reservoirs (Nelson, 2001). Existence of natural fractures in the outcrop samples could be an indicative of their existence in the subsurface; however, characterization of natural fractures in subsurface is not a trivial task. Most of the outcrop studies are qualitative and the existing models studying the interaction of natural fractures with the hydraulic fracture mainly consider the contribution of large natural fractures, i.e. fractures with the dimensions comparable to the size of hydraulic fracture, on the hydraulic fracture growth (Jeffrey *et al.*, 2009; Dahi Taleghani and Olson, 2014). However, the lognormal distribution of natural fractures, shown in Figure 1, demonstrates that small natural fracture exist orders of magnitudes more frequent than the large natural fractures. Hence, the role of small-size natural

fractures may be as important as the large natural fractures since the small fractures exist in large numbers. Length of Small natural fractures varies from micro- to centimeter; therefore, injected proppants cannot enter inside these small fractures to keep them open.

Figure 1. Power-law aperture-size distribution in Groove Creek and Kinlaw formations shows micro-fractures have larger frequency than large size fractures (Plot borrowed from Gale, 2002).

In contrast to the driving force of the main hydraulic fracture, the magnitude of induced thermal stresses, only a few MPa, is not large enough to initiate new fractures in the rock, but it may be sufficient for opening pre-existing micro natural fractures even if they are filled with the diagenetic materials. Cement bonding is usually much weaker than the rock strength. Parameters controlling the opening of these small fractures are tensile strength of cement materials filling the fractures, temperature difference between the fracturing fluid and the formation, and microfractures' density. Induced thermal stress in a homogenous isotropic elastic half-plane due to heat conduction can be shown by the Equation (1) (Nemat-Nasser *et al.*, 1978). The elastic half-plane is at the initial temperature of T_0 ; however, temperature at its surface suddenly drops to the temperature of T_1 . δ is a length scale where s specific temperature gradient has been formed. The rest of parameters are defined in the nomenclature.

$$\frac{d\sigma}{dx} = \frac{2D_T\beta_s(T_0 - T_1)}{3\sqrt{\pi}} e^{-\left(\frac{x\sqrt{3}}{\delta}\right)^2}, \quad \delta = \left(\frac{tk}{\rho C}\right)^{0.5} \quad (1)$$

Rock thermal failure due to injection/circulation of cold water into the brittle hot rocks is a known phenomenon (Perkins and Gonzales, 1985). The effect of temperature changes in stress redistribution and consequently fracture opening is mainly studied in hot dry geothermal reservoirs rather than hydrocarbon reservoirs. For instance, Zhou *et al.* (2010) have only considered thermal fracture initiation in a homogeneous rock. In a reservoir with multiple natural fracture sets, stress shadow effect of neighbor cracks may lead to competition or arrest of advancing cracks. Opening of small fractures in large numbers may significantly improve well productivity by increasing fracture-formation contact area and rock overall permeability. Since the fracturing fluid is injected at the ambient temperature at the surface and it has a high velocity in the tubing, its temperature is lower than the reservoir temperature when it initially exposes to the surface of hydraulic fracture. This temperature difference induces tensile stress on the surface of the hydraulic fracture. If the induced stress exceeds the tensile strength of cementitious materials filling the natural fractures, natural fractures starts opening to relax the excessive stress. The required energy to open small natural fractures is less than the energy required for opening large natural fractures. Temperature gradient as the driving force for thermal failure is a function of parameters like injection rate, tubing size, fracture width and length. This study aims to quantitatively estimate the impact of opening small pre-existing natural fractures due to thermal stress and its contribution to the hydrocarbon recovery. The potential shale gas reservoirs to show this phenomenon should have high temperature like Eagle Ford in South Texas or Haynesville in Texas/Louisiana. These reservoirs are deep enough to have high temperature. For the low temperature fracking fluid, liquid nitrogen can be used to cool the fracturing fluid.

Natural Fractures Characterization

Fractures are discontinuities formed to alleviate excessive pore pressure or stress in the rock mass with possibly self-affine or fractal structures like the fracture pattern shown in Figure 2. Natural fractures can cause significant

heterogeneity and anisotropy in permeability and strength of the rock. There are several ways to guess fracture patterns in the subsurface like outcrop studies, production data, reservoir core study and image logs (Narr *et al.*, 2006). Among these methods, outcrops, if available, are the most direct way to study natural fractures geometry. Natural fractures may be identified during drilling phase by considerable mud loss, bit chatting and bit drops, or in the early stages of production by heterogeneity in production and productivity index. Natural fracture characterization may also be achieved by integration of microseismic data, well log, treatment data and production history which involved more complicated workflow (Puyang *et al.* 2015).

Natural fractures may play an important role in well stimulation as they act as preferred paths for fracture path development. Open natural fractures increase reservoir overall permeability and consequently the hydrocarbon production, however, fully cemented fractures may act as barriers against fluid flow. Degree of cementation in natural fractures depends on the burial depth at the time of fracturing and its history after joint formation, mineralogy of host rock and its fluid chemistry (Gale, 2002). Field studies suggest that fractures with small apertures, mainly less than a critical threshold, are probably fully filled with mineralized materials (Laubach, 2003), further geochemical analyses have confirmed these findings in other formations (for instance see Olson *et al.*, 2009). These diagenetic minerals may contain calcite, dolomite or quartz. Figure 3 shows a broken face of natural fractures sealed with calcite recovered from Barnett shale. Compositions of cementing materials and its formation conditions have crucial impacts on the mechanical strength of the cemented fracture. If the cementing materials inside the natural fracture are stiffer than the host rock, they absorb larger portion of the applied stress with respect to the host rock; therefore, it is not surprising that the cemented fracture is so exposed to failure. Some lab measurements in the Barnett shale suggest that the digenetic materials filling the fracture have tensile strength about 10 times less than the tensile strength of the rock matrix (Gale *et al.*, 2007).

Figure 2. Distribution of natural fractures in flagstones, Caithness, Scotland shows an example of possible joints distribution in the subsurface. (Source: Mike Norton, Wikipedia)

Figure 3. A sealed natural fracture with calcite dictated the fracture growth path in a rock sample from Barnett shale. (Picture is borrowed from Gale *et al.*, 2007)

Cohesive Zone Methods

Linear elastic fracture mechanics (LEFM) has been a powerful tool to model fracture behavior in brittle rocks, however, it fails to predict fracture propagation in soft rocks. Lack of capability to predict fracture initiation is another drawback of Griffith's criterion usually used in LEFM. The cohesive zone method (CZM) is a more general theory to describe fracture behaviors without the above-mentioned limitations. Cohesive zone model can predict fracture initiation and propagation in brittle, ductile, and cemented materials. Dugdale (1960) and Barenblatt (1962) introduced the theory of cohesive zones to incorporate material inelastic behavior at the fracture tips. Barenblatt argued that molecular cohesive forces creating a non-linear bonding zone at the crack tip (AKA fracture process zone) while tensile strength and cohesive toughness control the damage of these bonds. Considering cohesive forces removes the stress singularity at fracture tips which has always been one of the main drawbacks of LEFM. Elies *et al.* (2002) has provided a comprehensive review of the advantages and disadvantages of the CZM. A significant limitation in CZM is the pre-defined paths of fractures which require a prior knowledge of fracture path or its dynamic adjustment during the simulation.

Figure 4. The schematic picture of natural fracture modelled cohesive zone method. Cohesive failure occurs in three phases: initiation, evolution, and removal of the cohesive zone at the complete failure.

Cohesive failure occurs in three phases: initiation, evolution, and removal of the cohesive zone upon reaching the complete failure (see Figure 4). Cohesive degradation corresponds to fracture initiation. Stress-strain relationship in the cohesive zone should be described by a traction-separation law (TSL). The bilinear TSL, shown in Figure 5, is used in this study due to its popularity for cementitious and granular materials. This type of TSL assumes linear behavior before reaching the maximum tensile strength of the cohesive zone. Damage initiates if separation of the faces in the cohesive zone reaches the critical value δ_0 which is called the critical separation point. Beyond this point, the degradation of cohesive element further develops as the complete failure occurs at δ_f where the cohesive forces are gone and fracture propagates. Slope of the elastic segment and the area of traction-separation curve are known as cohesive stiffness and cohesive energy, respectively. Fracture initiation in the bilinear cohesive law is determined by either the critical separation point δ_0 or the maximum tensile strength. Fracture propagation is controlled by the failure point, δ_f , or the cohesive energy. Quadratic stress damage criterion is used here to predict failure initiation.

$$\left\{ \frac{t_n}{t_{n0}} \right\}^2 + \left\{ \frac{t_s}{t_{s0}} \right\}^2 + \left\{ \frac{t_t}{t_{t0}} \right\}^2 = 1 \quad (2)$$

where t_n , t_s , and t_t are values of the normal and tangential traction stress components acting on the cohesive zone and t_{n0} , t_{s0} , and t_{t0} represent the cohesive maximum tensile strength values in the principal directions of the failure plane. Failure initiates if summation of these ratios becomes equal to one.

Figure 5. Bilinear traction-separation law.

Semicircular Bending Test

Extensive laboratory studies have shown that cohesive zone models can better describe the inherent nonlinear nature of interfacial fractures in granular materials. The main challenge in using cohesive models is choosing, or being more precise, measuring cohesive model parameters in the lab. Semicircular bending test (SCBT) is a laboratory experiment that determines when the rock will fail when under a particular applied force. Sierra *et al.* (2010) performed a semicircular bending test for the Woodford shale samples to monitor fracture initiation-propagation, and to measure the Woodford shale mechanical properties. Based on these tests, he suggests that fracture roughness of the Upper Woodford shale is higher than fracture toughness of the middle and the lower Woodford shale. Percentage of clay content has significant impact on the magnitude of fracture toughness in the Woodford shale samples. Kerogen saturation impacts the rock mechanical properties and consequently rock failure in the shale reservoirs (Abousleiman *et al.*, 2016). Kerogen acts like a binding glue which can significantly affect the stress-strain curve in shale reservoirs. Abousleiman *et al.*'s experimental work is shown that the kerogen can significantly increase the rock tensile strength in the micro-scale.

In this study, we use the load-displacement curve for a test executed on a Woodford shale sample by Sierra *et al.* (2010), to inversely calculate the stiffness, strength, and energy of cohesive elements for our following numerical models. Indicated cohesive parameters are measured by matching the experimental load-displacement curve with the curve obtained from the numerical simulation of this test, shown in Figure 6. Table 1 presents the CZM parameters obtained from matching numerical and experimental works. It is notable that these parameters are dependent on the size of cohesive elements. If the size of cohesive element changes, the cohesive parameters needs to be adjusted as they are scale dependent. Small size of the cohesive element in the numerical simulation imposes significant computational costs especially for large models. To overcome this problem, one may increase size of the initial model and then the cohesive path in the upscaled model is meshed once with small cohesive element size and again with a large cohesive element size. Both models are supposed to generate same loading curves.

Figure 6. Match of experimental semi-circular bending test, obtained from the Sierra (2010), with the numerical semicircular bending test.

Table1. Cohesive properties used in the numerical simulation to match the displacement-load curve

Parameter	Value (Unit)
Cohesive strength	2.325 MPa
Cohesive stiffness	75 GPa
Cohesive Energy	100 Pa.m
Cohesive element size	0.0005 m

Results and Discussion

In hydraulic fracturing treatments, cold fracturing fluid reduces bottomhole temperature, and generates tensile stress on the surfaces of the hydraulic fracture. If this stress is larger than the tensile strength of cementing material inside the natural fractures, it may open these pre-existing fractures. Nemat-Nasser *et al.* (1978) discussed how induced thermal stress can initiate parallel cracks with uniform spacing in a homogenous plate. These induced cracks do not grow at the same rate. They initially propagate at the same rate before reaching a critical state. At the critical state, some of the cracks stop propagating while the rest propagate faster. This critical state is determined by the stress shadow of neighbor cracks. This process continues until there is no more energy in the system to be released. Similar scenario may happen for opening of pre-existing natural fractures.

The geometry shown in Figure 7 is used for finite element analysis of thermal reactivation of microcracks. For the sake of simplicity and reducing the computational cost, a small frame of the hydraulic fracture with the intersecting natural fractures is selected for modeling by ABAQUS. Due to symmetry of the fracture, only one surface of the hydraulic fracture is modeled here. Pre-existing cemented fractures are assumed to be vertical and perpendicular to the surface of the hydraulic fracture modeled with CZM. The cohesive-modeled fractures have the length of 10 cm. All boundaries are constrained for normal displacement except the surface of the hydraulic fracture. At $t < t_0$, the formation and embedded natural fractures are at initial formation temperature T_0 . However, at time $t \geq t_0$, temperature at the free surface of the hydraulic fracture for a time period of 100 seconds is linearly reduced to a pre-defined temperature which is 100°C less than formation initial temperature to mimic rock initial exposure to the fracturing fluid. Beyond this time, due to heat transport, temperature gradient is reducing. A summary of rock mechanical

properties and cohesive zone properties are listed in Table 2. Cohesive and rock properties are for the Woodford Shale formation (Sierra *et al.*, 2010; Abousleiman *et al.*, 2007).

Table2. Properties of cemented natural fractures and intact rock

Properties	Value	Unit
Rock density	2500 kg/m ³	Kg.m ⁻³
Rock Young's modulus	14	GPa
Poisson's ratio	0.2	
Thermal expansion coefficient	15*10 ⁻⁶	°C ⁻¹
Rock conductivity	0.1	W.m ⁻¹ .K ⁻¹
Rock specific heat capacity	1000	J.Kg ⁻¹ .K ⁻¹
Cohesive strength	2.265	MPa
Cohesive Stiffness	75 MPa	GPa
Cohesive energy	100	Pa.m
Cohesive element size	0.2	cm
Formation temperature	163	°C
In-situ stress	3.7	MPa

Figure 7. The two dimensional model representing a mosaic frame of hydraulic fracture with natural fractures embedded on the surface of hydraulic fracture.

In the primary numerical example, cracks spacing is assumed to be 1.25 cm on a rock matrix with cohesive elements properties listed in Table 2. Temperature at the surface of the hydraulic fracture is linearly reduced to 63 °C over 100 seconds. Simultaneously, the surface of the hydraulic fracture goes under linear loading and unloading. The maximum fluid net pressure is assumed to be 20 MPa. Figure 8 shows the temperature profile of the longest reactivated natural fracture along the cohesive path after 50 and 100 seconds. Sharp temperature gradient at the hydraulic fracture surface induces tensile stress on the natural fractures. The right axis in Figure 9 illustrates SDEG of cohesive elements along the cohesive path versus crack length. However, the left axis shows the opening of cemented cracks along the reactivated length. SDEG is the scalar stiffness degradation of the cohesive zone with a range from 0 to 1. This variable defines the magnitude of cohesive stiffness degradation once the damage in the cohesive interface has been initiated. SEDG of 1 means complete failure of the cohesive interface. The selected cracks in Figure 9 have the longest and shortest length of reactivation in the primary numerical example. This figure suggests that the crack with the longer length leads to the larger opening. However, Figure 10 shows that cumulative frequency of longer cracks is lower than the frequency of shorter ones. Cumulative frequency represents the total number of cracks with apertures equal or larger than a specific size. In Figure 10, apertures are measured at the surface of hydraulic fracture in which the maximum induced stress is available to open the cracks

Figure 8. Temperature distributions along the cohesive interface after 50 and 100 seconds. Minimum Temperature happens at the intersection of natural and hydraulic fracture.

Figure 9. Crack length vs. crack opening after 100 seconds for the longest and shortest cracks in the primary numerical example. Right vertical axis represents the cohesive interface SDEG which is the scalar stiffness degradation of cohesive interface with a range from 0 to 1. SDEG of 1 shows the complete failure of cohesive element.

Figure 10. Aperture-size distribution after elapsed time of 100 s for the primary numerical example. Aperture is measured at the surface of hydraulic fracture where cemented cracks cross the surface of hydraulic fracture.

Magnitude of temperature difference can affect total length of induced cracks since the larger temperature difference provides more energy for cracking. Figure 11 depicts the influence of fracturing-fluid and formation temperature difference on the activated length of cracks. This figure shows that for the same cumulative frequency, larger temperature difference reactivates larger crack by feeding more energy to the system to induce cracking.

Figure 11. Length-size distribution after elapsed time of 100 s for the spacing of 1.25 cm, and temperature differences of 100°C and 50°C at the end of elapsed time.

Conductivity of shales at the ambient conditions varies from 0.5 to 2.2 W/m.K (Gilliam and Morgan, 1987). Figure 12 shows the role of rock conductivity on the activated cracks lengths. Figure 12 suggests if thermal conductivity is very low, it is more expected that all of the activated cracks have more uniform length. This observation may be explained by the importance of thermal conductivity on the heat transfer. Rock thermal conductivity dictates the rate of heat transfer in the system. Lower formation thermal conductivity results in less heat transfer across the formation and lower available energy for the crack propagation. The magnitude of available energy for the thermal conductivity of 1 W/m.K, or smaller than 1, is not large enough to overcome the critical energy to induce non-uniform cracking.

Figure 12. Length-size distribution for three shale thermal conductivities. If the rock thermal conductivity is very low, it is more expected that all of the activated cracks have more uniform length.

Natural fractures can show different resistance against opening. This resistance depends on the diagenetic materials filling materials and the degree of cementation. Tensile strength of cementitious materials and its interfaces with the host rock can affect the cohesive properties. Figure 13 pictures the crack-length distribution of natural fractures with two different cohesive properties. Critical separation and critical failure points of the weaker cohesive interface are half-time smaller than their values for the stronger interface. This figure shows that the minimum length of activated cracks in the weaker interface is significantly larger than the minimum in the stronger interface. The available energy to induce cracking in both of these cases is the same. However, the weaker interface experiences the damage and complete failure faster than the stronger interface. Since the amount of energy is required to damage the weaker

interface is smaller than the stronger interface and both of the systems have the same amount of energy available to induce cracking, the extra energy in the model with the weaker interface is consumed to increase the crack length.

Figure 13.Length-size distribution for two cohesive interfaces after elapsed time of 100 s. Critical separation and critical failure points of the weaker cohesive interface are half of their values for the stronger interface.

Fractures spacing can affect the length and width of activated fractures. Figure 14 and 15 show the average crack length and width with different spacing. These figures suggest the stress shadow effect of neighbor cracks can influence both length and width of reactivated cracks. For small spacing, a crack should first overcome the extra stress imposed by the neighboring cracks which mean less amount of energy is available to propagate deeper and wider. At larger spacing, the induced stress field of neighbor cracks is less effective on the adjacent cracks growth and the activated cracks show more uniform distribution.

Figure 14.Average crack length at different cracks spacings. In small spacing case, a crack should first overcome the imposed stress by the neighbouring cracks which equals to less available energy to propagate deeper.

Figure 15.Average crack width at different cracks spacing after elapsed time of 100. Stress shadow effect leads to narrower cracks.

Figure 16. Total reactivated cracks length per length of hydraulic. Total activated cracks length is equal to the cumulative length of activated cracks lengths for a specific cracks spacing.

Reactivated microcracks, as shown in Figure 16, increase the formation-fracture contact area as well as the rock permeability along the fracture in the direction normal to the fracture plane. These microfractures may increase the leak-off volume during fracturing treatments. Effect of these activated microfractures can be incorporated into the calculation of equivalent wellbore radius and skin factor for productivity related analysis. In the equivalent wellbore radius, the inflow surface areas only include inflow areas of wellbore and hydraulic fracture. However, inflow area can be modified to include the microcracks contribution as pictured in Figure 17. Below equation describes the revised version of equivalent wellbore radius for the natural fractures

$$r'_w = 0.6x_f \pm 0.6 \frac{x_{nf}h_f}{h} \quad (3)$$

where r'_w , x_f , x_{nf} , h_f , and h are equivalent wellbore radius, hydraulic fracture length, cumulative length of activated natural fractures, average natural fractures height, and reservoir height (Economides *et al.* 2012). The positive sign in Equation (3) indicates the favorable effect of reactivated microfractures i.e. they improve the hydrocarbon production; however, the negative sign shows the effect of capillary trapping on the effectiveness of induced hydraulic fracture. The Folds of Increase (FOI) in the hydrocarbon production are usually calculated with the revised value of equivalent wellbore radius to study the impact of hydraulic fractures

$$FOI_{pss} = \frac{\ln(\frac{r_e}{r'_w}) - 0.75}{\ln(\frac{r_e}{r_w}) - 0.75} \quad (4)$$

where r_e and r_w are reservoir and wellbore radius. This method does not provide a way to incorporate the effect of enhanced permeability caused by microfractures. Therefore, it is more realistic to modify the transmissibility coefficient in the dual porosity-permeability model to include contribution of natural fractures.

Figure 17. Schematic picture of equivalent wellbore radius including the wellbore inflow area, hydraulic fracture inflow area and activated natural microcracks inflow area.

In dual porosity model, porous media include two distinct volumes, rock matrix with the large storage capacity and low flowing capacity and fracture with lower storage capacity and high flowing capacity. Barenblatt *et al.* (1960) introduced the Equation (5) for the single-phase fluid flow in the rock matrix and fracture where K , P , C , μ , and S are permeability, pressure, compressibility, viscosity, and fracture-formation contact area. The subscripts of 1

and 2 refer to matrix and fracture, respectively. Natural fractures can affect the variable S by enhancing fracture-formation contact area. Opened natural fractures would also improve the reservoir permeability for the areas nearby the hydraulic fracture. Barenblatt did not consider effects of fracture and rock compressibilities.

$$\begin{aligned}\frac{K_1}{\mu} \nabla P_1 &= \Phi_1 C_1 \frac{\partial P_1}{\partial t} - \phi_1 \frac{\partial P_2}{\partial t} + \frac{SK_1}{\mu} (P_1 - P_2) \\ \frac{K_2}{\mu} \nabla P_2 &= \Phi_2 C_2 \frac{\partial P_2}{\partial t} - \phi_2 \frac{\partial P_1}{\partial t} + \frac{SK_2}{\mu} (P_1 - P_2)\end{aligned}\quad (5)$$

Kazemi *et al.* (1976) developed the Barenblatt's work to account for the multiphase systems, shown in Equation (6) in which K , K_r , P , q , S , permeability, relative permeability, pressure, production/injection rate, and saturation, respectively. The rest of parameters are defined in the nomenclature. Their model considers the effects of gravity force, relative fluid mobilities, imbibition and variation in reservoir properties and they used a transfer function to couple the matrix fluid flow with the fracture fluid flow.

$$\begin{aligned}\nabla \lambda_{cf} (\nabla P_{cf} - \rho_\alpha g \nabla D) &= \frac{\partial}{\partial t} \left(\frac{\phi S_\alpha}{B_\alpha} \right) + q_{cf} + \tau_{cm-f} \\ \tau_{cm-f} &= \frac{\partial}{\partial t} \left(\frac{\phi S_\alpha}{B_\alpha} \right)_m \\ \lambda_{cf} &= \frac{K_{r_{cf}} K_f}{\mu_\alpha B_\alpha}\end{aligned}\quad (6)$$

To account for the influence of natural fractures in Kazemi *et al.*'s formulation, one can adjust their transmissibility coefficient which is the ratio of effective permeability to fluid viscosity and formation volume factor. In vicinity of the hydraulic fracture, formation transmissibility should be a weighted average of matrix and natural fractures transmissibilities, as shown in Equation (7) where λ , L , and w are transmissibility, length, and width. Subscripts RM and NF refer to rock matrix and natural fracture. Figure 18 illustrates the schematic picture of a reservoir block including rock matrix and reactivated natural fractures. This modified transmissibility coefficient, considering the effect of natural fractures, can be used for areas in the vicinity of hydraulic fracture.

$$\begin{aligned}K_{NF} &= \frac{(w_{NF})^2}{12} \\ \bar{\lambda} &= \frac{\frac{L_{NF} + L_{RM}}{L_{NF}} + \frac{L_{RM}}{\lambda_{RM}}}{\frac{\sum_1^n w_{NF_n} \lambda_{NF} + w_{RM} \lambda_{RM}}{\sum_1^n w_{NF_n} + w_{RM}}}\end{aligned}\quad (7)$$

Figure 18. Schematic picture of a reservoir block including rock matrix and reactivated natural fractures.

In the low permeable shale reservoirs, hydrocarbon production from the hydraulic fractures and natural fractures dictates the economic success of a well. To illustrate effect of micro-natural fractures in hydrocarbon production, authors compare the cumulative gas production in a hydraulically fractured shale reservoir, having a horizontal well, for two different scenarios where the reactivated cracks either do or do not cross the surface of hydraulic fracture. In this reservoir simulation, effect of capillary trapping is ignored for the sake of simplicity, and it is assumed that all of the reactivated natural fractures boost fluid flow from the reservoir into the wellbore. As it is shown in Figure 9, crack opening reduces with crack length. To determine cracks length and width in the reservoir simulation, authors assume that all of the cracks have once apertures equal to the shortest crack aperture shown in Figure 9. Then to measure the average crack length, authors calculate the area of crack opening-length diagram in Figure 9 for the shortest crack and divide it by the related aperture. This means that all of the reactivated fractures in the reservoir simulation have the width of 0.163 mm and length of 0.48 cm. The reservoir volume for gas production from the assumed shale reservoir is equal to 23-acre $\times$ 270-ft. Effect of natural fractures is modeled by the modified transmissibility coefficient ratio. Equation (7) suggests a modified transmissibility ratio of 2.17 for the hydraulic fracture by considering the contribution of natural fractures. Table 3 lists the properties of the shale gas reservoir as well as the horizontal well. Commercial reservoir simulator, CMG, is used to model the gas production from this reservoir. Due to the limited number of grids cells available for numerical simulation in our version of CMG, we only assume that one hydraulic fracture crosses middle of the horizontal well. Figure 19 shows the increase in cumulative gas production after one year and five years of production. Figure 20 illustrates the percentage of increase in production during 5 years. These figures suggest that natural fractures are significantly effective at early stage of production. This observation is due to small formation permeability which restricts the rate of hydrocarbon drainage from the reservoir into the natural fractures and hydraulic fracture after fractures are fully drained. The magnitude of difference in cumulative production in Figure 20, for the cases with and without effect of natural fractures, is only for the indicated reactivation length of natural fractures in this study. In reality, the reactivated length of natural fractures may be larger than what we calculate in this study. For instance, the calculated parameters for the cohesive interface are representative of the shale rocks and not completely the cemented materials inside the natural fractures in the shale reservoirs. It is shown that cemented materials filling the natural fractures have lower strength than the host rock (Gale *et al.*, 2007). Therefore, natural fractures are susceptible to fail. In the reservoir simulation, only one hydraulic fracture crosses the horizontal wellbore in this study, however in real situations, 15 to 23 stage hydraulic fractures are connected to the horizontal wellbore which means our rough estimate for increase in cumulative production in Figure 19 can be at least one order of magnitude larger.

Table3. Properties of gas reservoir

Properties	Value	unit
Matrix porosity	0.03	
Matrix permeability	1×10^{-4}	md
Langmuir adsorption constant (CH ₄)	0.002	psi ⁻¹
Maximal adsorbed mass (CH ₄)	0.1	gmole.lb ⁻¹
Rock density	120	lb.ft ⁻³
Hydraulic fracture permeability	10000	md
Propped hydraulic fracture width	0.00833	ft
Hydraulic fracture half-length	350	ft
Hydraulic fracture height	210	ft
Average natural fracture length	0.0157	ft
Average natural fracture width	0.000534	ft
Natural fractures spacing	0.041	ft
Rock compressibility	10^{-6}	psi ⁻¹
Initial pressure	2500	psi
Bottom-hole pressure	500	psi
Length of horizontal well	550	ft

Figure 19. Cumulative gas production after 1 year, left figure, and 5 five years, right figure.

Figure 20. Percentage of increase in cumulative gas production during 5 years in a semi-log graph.

Reactivated natural fractures, as shown in Figures 19 and 20, can improve the fluid recovery in the shale reservoirs. However, these small opened cracks can act like a two edged swords. Most of the hydraulic fracturing treatments use water as the based fluid for fracturing fluid. In water wet formations, since the width of reactivated cracks, as shown in Figures 9 and 15, are significantly small, capillary pressure for these cracks can be large enough to suck in the fracturing fluid and trap it inside the natural fractures. The reservoir pressure at the early stages of production can push out the trapped water inside the reactivated natural fractures; however, during production as the water cut increases along with drop in the reservoir pressure below the capillary pressure, a significant drop in the hydrocarbon production is expected as the produced water will be trapped inside the reactivated natural fractures.

Conclusion

Considerable temperature difference between fracturing fluid and reservoir would induce thermal tensile stress on the surface of the hydraulic fracture. The induced tensile stresses may open cemented natural fractures, improving the formation-fracture contact area as well as enhancing the rock permeability in the vicinity of the hydraulic fracture. Most of natural fractures are much smaller than the hydraulic fracture; however, their presence in large population can have a considerable impact on production. Right after stimulation, these natural fractures are drained by the drive of reservoir pressure. As production continues and water cut increases, the water is being trapped in these natural fractures (capillary trapping) and act as barrier against gas production. Cohesive interface theory has been utilized here to model reactivation of natural fractures due to induced thermal stresses. Semicircular bending test of the Woodford shale samples are used to derive cohesive properties required for numerical simulations. This study suggests that the length and width of reactivated length depends on the spacing of natural fractures, rock thermal conductivity, temperature difference between fracturing fluid and reservoir, as well as the strength of diagenetic materials filling natural fractures. Larger natural fracture spacing results in longer and more uniform activated cracks since the stress shadow effect diminishes as fracture spacing increases. Injecting a colder fracturing fluid into a reservoir with larger thermal conductivity increases the length of reactivated fractures. The impact of reactivated

natural fractures can be translated into transmissibility coefficient of the hydraulic fracture to incorporate their impact on permeability enhancement near fractures.

Nomenclature

B	Formation volume factor
C	Specific heat capacity
D	Depth
D_T	Tangent constitutive tensor
K	Permeability
K_r	Relative permeability
L	Length
P	Pressure
S	Saturation
f	Fracture
g	Gravitational acceleration
h	Reservoir height
h_f	Average natural fractures height
k	Thermal conductivity
m	Matrix
q	Production/injection rate
r_e	Reservoir radius
r_w	Wellbore radius
r'_w	Equivalent wellbore radius
t	Time
w	Width
x_f	Hydraulic fracture length
x_{nf}	Cumulative length of reactivated natural fractures
α	Phase
β	Volumetric thermal expansion coefficient
μ	Viscosity
λ	Transmissibility
ρ	Density
ϕ	Porosity
τ	Transfer function

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