The Mechanical Behaviour during Multiple Injections and its Influence on Fracture Network

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Abstract. Many cases show that multiple injections fracturing serves as an effective method to increase the probability of creating complex fracture network for shale gas reservoirs. However, its mechanism is unclear. This paper, therefore, intends to use numerical simulation and theoretical models to explore this mechanism. Results indicate that the liquid fluid loss and friction along fractures act as catalysts to a large pressure drop between the initiation of fractures and the fractures tip during injection. But friction disappears when this injection terminates, and the fluid pressure decreases at the debut of fractures and increases at the fractures tips. Then the stress field changes synchronically. The probability of the extension and reorientation of fracture tip and the initiation and reorientation of weak point on the fracture surface may be multiplied. During the re-injection after a period of shut-in, the opened factures or weak points can easily propagate new fractures and does not need to overcome the resistance of the tensile strength or cohesion. Then larger volume of fracture network and more fractures can be created by multiple injections. Micro-seismic monitoring results verify the validity of the theoretical analysis and effectiveness of the method of multiple injections fracturing.

Introduction

Creating larger volumes and complex fracture network is a main goal of hydraulic fracturing for shale gas. One important means of forming a complex artificial fracture network is increasing net pressure. Of late, many studies have been made to create more complex fracture network for shale gas by adding temporary plugging[1-5] to increase net pressure in fractures or by reducing the spacing between fractures [6-10] to change the local stress. However, these methods are not cost-effective.

Kiel and Abhijeet Inamdar[11-13] pointed out multiple injection hydraulic fracturing can create more complex fracture network for reservoir with abundant natural fractures(they call it relax-frac). They infer that multiple injections can change the stress state of the reservoir, in order to achieve more complicated fracture network. But they failed to do any detailed analysis of the mechanism.

Their method was also reported in China. Fluid and proppant was pumped into reservoir two or more times within a short time [14- 19]. However these reports lay more emphasis on the times. The success of this method is dependent on proppant distribution and stress change.

A traditional model was used to optimize shut-in time between secondary and primary fracturing by He Tao and etc. [20]. They proposed formation pressure stabilization time between the first and secondary fracturing is a reasonable shut-in time. There are no reports on effect of the fluid pressure redistribution in fractures on fracture shape and stress field during hydraulic fracturing shut-in time.

This paper deals with the mechanical behaviour between fluid and rock during shut-in time and the mechanism of multiple injection operations to increase the complexity of the fracture network. The stress field and pressure in fractures were analysed during injection and shut-in time. The analysis shows that the pressure redistribution in fractures and stress redistribution will increase the

possibility of extending the fractures tip as well as opening the weak points on the fractures walls, increasing the fractures height along the extending direction.

The mechanical behaviour between fluid and rock during injection and shut-in time was used by the multiple injections fracturing to create more fractures. It is a cheap and effective method without needing more fluid and more complex operation.

Pressure Distribution during Injection and Shut-in

Pressure Distribution during Injection

In addition to the wellbore pressure drop, the pressure dropΔP_f associated with the crack can be divided into two areas during injection. The first is near the well, mainly caused by friction completion, such as casing perforations friction caused by perforation completion(Fig.1,$P_{wf}-P_{t0}=\Delta P_{hole}$). The second pressure drop area is from two parts. It comes from the friction between fracture surface and fracturing fluid druing flow.It is recorded asΔP_{f1}.It is also caused by fluid loss. It is recorded asΔP_2.

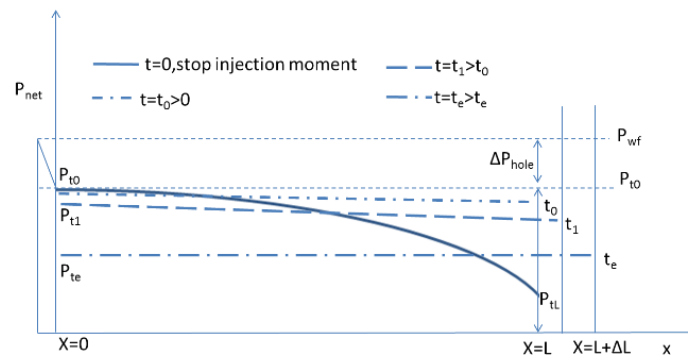$$\Delta P_f = P_{tL} - P_{t0} = \Delta P_{f1} + \Delta P_2 \qquad (1)$$

Fig. 1.The schematic diagram of net pressure distribution along the fracture extension direction during shut-in.

For example, a full three-dimensional fracture propagation model was used to calculate the pressure distribution during shut-in for CASE1 well in WY gas reservoir. Two types of fluid were used, one is slick water with low viscosity, the other is x-link with higher viscosity. The reservoir depth is 3000~3010 m, stress gradient is 0.015 MPa/m, pore pressure coefficient is 1.0, rock young's modulus is 26000 MPa, the poisson's ratio is 0.25, permeability is 0.1 mD, porosity is 0.1, rock fracture toughness is 2.2 MP • m$^{1/2}$. Two horizontal principal stress differences are 3 MPa, slick water viscosity is 2.0 mPa • s, x-link viscosity is 30.0 mPa • s, injection rate 14 m^3 / min, the injection fluid volume,180m^3.

Simulation results show that there is big net pressure difference between fracture entrance and fracture tip(Figure 2).Different fluid viscosities get different pressure. The pressure difference ΔP_f is about 3 MPa for slick water and nearly 9 MPa for x-link.

Pressure Redistribution during Shut-In

Three Stages during Shut-In for Fractures

It can be divided into three main stages according to fluid flow state and change of fracture shape during shut-in time. The first is unstable changing stage before fracture closure. The second is fracture stable closure stage. The third is after fracture closure stage.
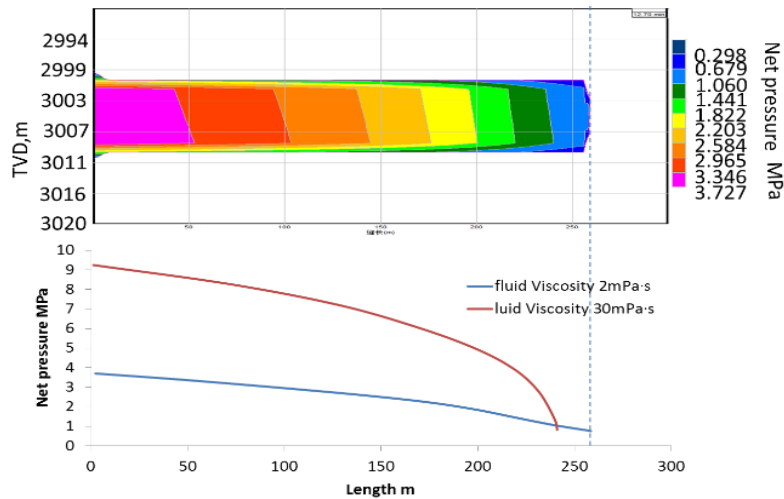
Fig. 2. Net pressure distribution along the fracture extension direction when stop injection moment for case1

(1)Unstable stage before the fracture closure . During this stage, the fluid continues to flow at very low rate. Friction between fuild and fracture wall is approximately 0MPa. It can also be divided into two stages based on the state of the fluid flow inside the fracture, one is water hammer stage and the other is stable freewheeling stage.

Water hammer stage : The dramatic pressure change was caused by the instantaneous shut-in, the fluid pressure alternately went up and down dramatically in pipes and fractures. Fluid flow still goes on during this stage.

Stable freewheeling stage: The bottom hole pressure shows sustained reductions and no fluctuations. However, due to big pressure difference between the fracture tip and fracuture start during injection, the pressure tends to lead to a state of equilibrium after injection is stopped. The fracture is in an unstable stage. Druing this satge, the fluid still flows within the fracture.

(2)The fracture stable closure stage. There is approximately same pressure along fracutre and no fracutre extending or initiation. Fracutre starts closing during this stage.

(3)After fracture closure stage: Fracture closes completely and fluid loss continues.

Pressure Distribution during Stable Freewheeling Stage

Here the pressure distribution during stable freewheeling stage is discussed as the mechanical behaviour between fluid and rock during this stage is more important and complex than other stages. Before shut-in, the fluid pressure distribution has a gradient from fracture start to fracture tip(P_{t0}~P_{tL}, Figure 1. Although the fracturing fluid still flows after injection is stopped during unstable changing stage, the rate is much less than injection. Therefore, the perforations friction and the bending fracture friction can be neglected. At this stage the fluid pressure will tend to balance for a very short time.The fluid pressure will reduce at the fracture entrance and increase at the tip(Figure 1, thus as the t_0, t_1, te time corresponding pressure curve. As the pressure wave propagation velocity in the liquid is very fast(about 1500m/s, the fluid pressure from the fracture entrance to the tip will reach the same with and little pressure drop just as Figure 1 shows (from Pt0 reduced to P_{t1}). The pressure re-distribution will lead to fracture extending continually or new fracture being created until the fluid pressure drops to a critical pressure Pte[21].
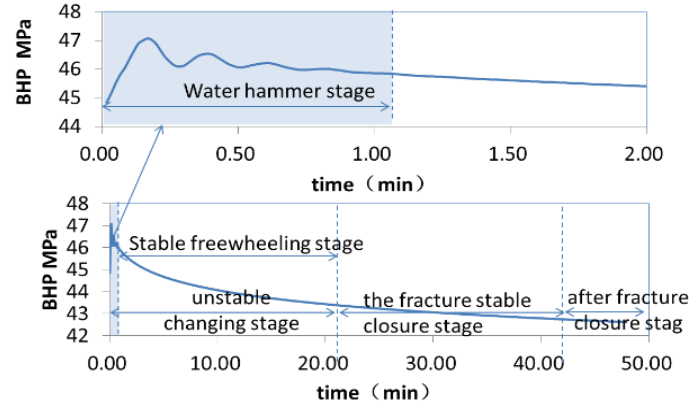
Fig. 3. The fluid pressure inside fracture distribution during shut-in in Well B

The Stress Field Changing during First Injection and Shut-in

Induced Stress Calculation Model

The stresses will change significantly during injection. They come from three parts. The first is from the fracture. The second from pore pressure. The third from temperature. For shale gas reservoir, the permeability is so low(Nano Darcy) that the reservoir temperature and reservoir pressure propagation distance is shorter in the vertical fracture orientation. The change of maximum and minimum principal stress caused by temperature and pore pressure increase on the same level for shale gas reservoir and it can be neglected [21].

Induced stresses caused by fracture can be calculated by the following equation (2)~(7).
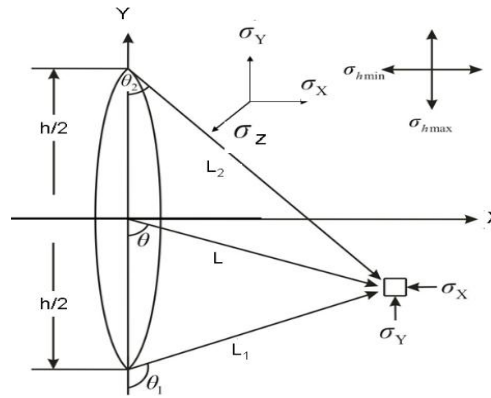

Fig. 4. The stress distribution schematic of artificial fracture height direction cross-section

$$\sigma_x = p_{net} \frac{L}{c} \left(\frac{c^2}{L_1 L_2} \right)^{\frac{3}{2}} \sin\theta \sin\frac{3}{2}(\theta_1 + \theta_2)$$

$$+ p_{net} \left[\frac{L}{(L_1 L_2)^{\frac{1}{2}}} \cos\left(\theta - \frac{1}{2}\theta_1 - \frac{1}{2}\theta_2\right) - 1 \right] \tag{2}$$

$$\sigma_z = -p_{net} \frac{L}{c} \left(\frac{c^2}{L_1 L_2} \right)^{\frac{3}{2}} \sin\theta \sin\frac{3}{2}(\theta_1 + \theta_2)$$

$$+ p_{net} \left[\frac{L}{(L_1 L_2)^{\frac{1}{2}}} \cos\left(\theta - \frac{1}{2}\theta_1 - \frac{1}{2}\theta_2\right) - 1 \right] \tag{3}$$

$$\sigma_y = v(\sigma_x + \sigma_z) \tag{4}$$

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$$\tau_{xz} = p_{net} \frac{L}{c} \left(\frac{c^2}{L_1 L_2} \right)^{\frac{3}{2}} \sin\theta \cos\frac{3}{2}(\theta_1 + \theta_2)$$

(5)

$$\begin{cases} L = \sqrt{x^2 + y^2} \\ L_1 = \sqrt{x^2 + (y+c)^2} \\ L_2 = \sqrt{x^2 + (y-c)^2} \end{cases}$$

(6)

$$\begin{cases} \theta = \tan^{-1}\left(-\frac{x}{y}\right) \\ \theta_1 = \tan^{-1}\left(-\frac{x}{y+c}\right) \\ \theta_2 = \tan^{-1}\left(\frac{x}{c-y}\right) \end{cases}$$

(7)

x,y are coordinates of a point, m; L is the distance from$(x, y)$to$(0,0)$, m;L_1 is the distance from (x,y) to $(0, h/2)$, m; L_2 is the distance to $(0, - h/2)$, m; θ,θ_1,θ_2 is L,L_1,L_2 line and Y-axis angle respectively, (if the θ,θ_1,θ_2 is negative then the angle can be used $\theta+180°,\theta_1+180°$ and $\theta_2+180°$ to replace respectively); H is fracture height, m; P_{net} the fracture net pressure. it equal to the difference between the pressure in the fracture and local minimum principal stress, Pa; $\sigma_x,\sigma_y,\sigma_z$ is principal stress in x,y,z directions respectively, Pa; v is Poisson's ratio, dimensionless; τ_{xz} is shear in z direction. it is perpendicular to the xy-planefor, Pa; c semi-fracture height, equal to $h/2$, m.

The Stress Changing on Fracture Surface at the Moment of First Injection Stopping

The stresses change along fracture on the surface is calculated by equations (2)~(7) for CASE1 well in WY gas reservoir when first injection is stopped (Figure 5). $\Delta\sigma_{hmax}$ is induced stress in maximum principal stress direction.$\Delta\sigma_{hmin}$ is induced stress in minimum principal stress direction. They are caused by P_{net}. σ'_{hmax} and σ'_{hmin} are maximum and minimum principal stress when the induced stresses taken into account.
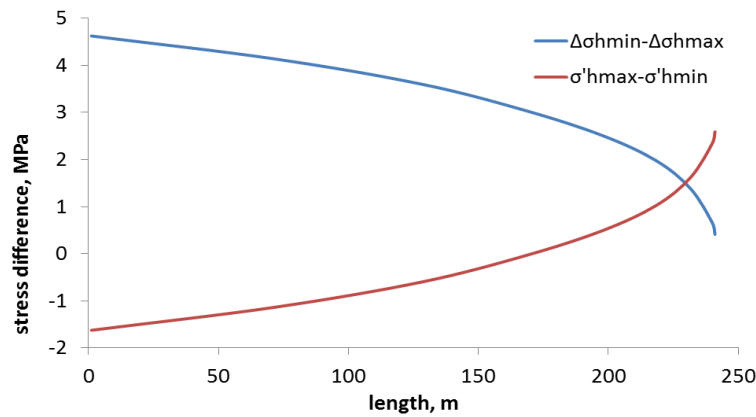

Fig. 5. The change of maximum and minimum principal stress difference along the fracture at the moment of instantaneous stop in the first injection

The Stress Changing on Fracture Surface during Shut-in

Simulation results show that the injection induced stress will lead to the difference between maximum and minimum principal stress $\sigma'_{hmax} - \sigma'_{hmin}$is smaller than original (Figure 6). As time increases, the difference becomes smaller and smaller druing shut-in.

At the begining of shut-in, the fluid pressure tends to balance. This balancing process will lead to the redistribution of net pressure and the redistribution of stresses (Figure 6, just as t_e, t_1, t_0 corresponding pressure curve).
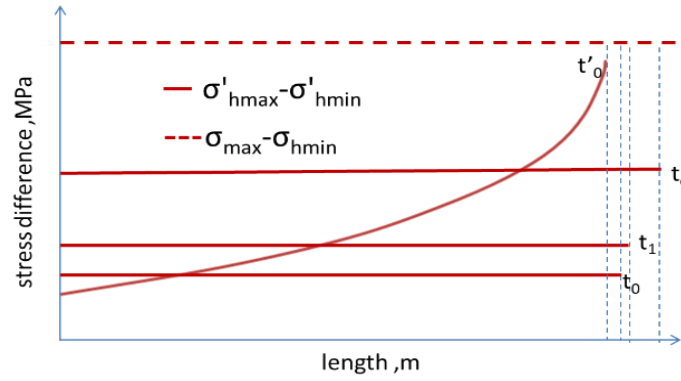
Fig. 6. The changing of maximum and minimum principal stress difference along the fracture druing shut-in

The Feasibility of Multi-Injection to Improve the Quality of Fracture Network for Shale Gas Reservoir

Breakdown conditions are the judging key for shale gas reservoir whether the fractures can become network or not. For the hydraulic fracturing process, there are two typical forms of failure, tensile failure and shear failure.

The Judging Conditions of Tensile Failure and Shear Failure

According to Perkins[23], the fracture will initiate and propagate when the net pressure is bigger than rock tensile strength druing hydraulic fracturing.

$$P_{net} \geq \sigma_T \tag{8}$$

In maximum principal stress direction, the fracture tip initiation and propagation criteria can be described as follows.

$$P \geq \sigma_{hmin} + \sigma_T \tag{9}$$

Howerer, in minimum principal stress direction the rock damage criteria can be described as follows.

$$P \geq \sigma_{hmax} + \sigma_T \tag{10}$$

To shear failure, the shear stress must overcome the rock shear strength (also known as cohesion) and friction [24].

$$\tau = C + \mu \cdot \sigma \tag{11}$$

τ is shear stress, MPa; μ is internal friction coefficient of rocks; C is inherent shear strength, MPa; σ is failure surface normal stress .

To shear failure, the shear stress must overcome the rock shear strength (also known as cohesion) and friction [24].

Analysis of Multi-Injection to Increase the Probability of Creating or Improving the Quality of the Fracture Network

Multi-injection can increase the probability of creating or improving the quality of the fracture network. The reasons are as follows:

First of all, first injection will change the maximum and minimum principal stress difference(Figure 5). The local maximum and minimum principal stress difference will become smaller than original during shut-in. It will also become smaller than injection period, especially far away from the fracture entrance.When next injection is executed, new fractures may initiate and propagate across the existing fractures surface. New fractures and existing fractures can form fracture network.

Secondly, multi-injection can increase the chances of rock tensile or shear failure.

The fluid pressure will redistribute after first injection, especially far away from fracture entrance. The larger the net pressure obtained by the injection, the greater the net pressure increased far away from fracture entrance during shut-in. This will improve rock damage possibility according to equations (8)~(11) . Just as the example in Figure 2, as the net pressure is smaller than 3MPa(maximum and minimum principal stress difference) from 90m to 260m (slick water) or from 230m to 240m (x-link), new fracture can not be created along existing fracture. However, when injection is stopped, the net pressure can become larger than 3 MPa from 90m to 260m (slick water) or from 230m to 240m (x-link) and new fractures may be created in these ranges.

Thirdly, if new fractures has been created during shut-in, then it can be initiated and propagated easily when rock is damaged.The reason is that the new fracture does not need to overcome rock tensile strength σ_T or cohesion C.

Analysis of Micro Seismic Monitoring Results during Shut-in

Abhijeet Inamdar and el. point out the micro-seismic data analysis shows that the micro-seismic events still occurred during shut-in at the Eagle Ford shale wells [12].The micro-seismic events can be increased by injection－shut-in－injection and the production can be increased too. This phenomenon also can be found when Sichuan Long ma xi shale gas was stimulated.(Figure 7~Figure 8).

One example n is the vertical well w2 stimulated by slick water and micro-seismic events. It shows that the fracture is single. During shut-in, micro-seismic events still occurred. During the second injection with pumping rate the same as first injection (about 15.9m^3/min), the net pressure was almost the same. However, the micro-seismic events show that more and more fractures were created and fracture network formed (Figure 7).

Another example is the horizontal well Y stimulated by slick water. Multi-injection was used and the micro-seismic events showed that the fracture had changed propagation direction (Figure 8).

Micro-seismic events show that multi-injection can contribute to creating complex fracture network.

Fig. 7. Micro-seismic data and performance curve of the vertical well w2 during two injection times
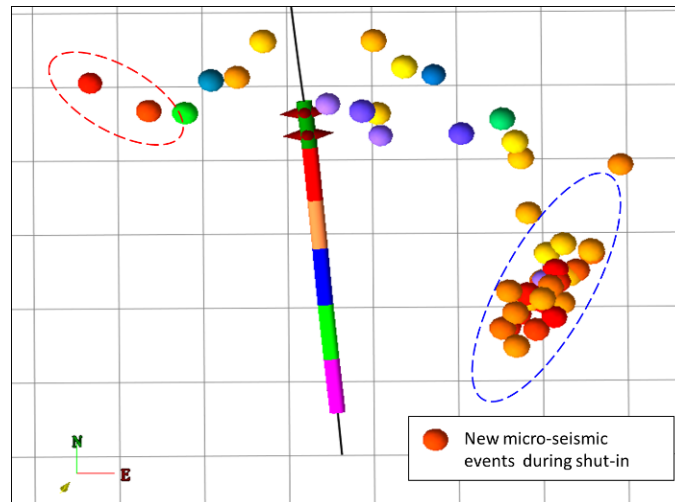
Fig. 8. Micro-seismic data of the the horizontal well Y during two injection times

Conclusions

1) There is big fluid pressure difference between fracture entrance and fracture tip during injection. The pressure will redistribute during shut-in. Injection and stopping can increase the pressure inside fracture, especially near fracture tip.

   2) Maximum and minimum principal stress difference changed owing to multi-injection. This can increase the probability of rock tensile or shear failure.

   3) If rock was damaged during injcetion or shut-in, then the fractures can be initiated and propagated easily during next injection.

   4) Micro-seismic events show that mlti-injection can contribute to creating complex fracture network.Thisis a cheap method to create fracture network

Acknowledgments

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