Journal of Natural Gas Science and Engineering 21 (2014) 425–432

Contents lists available at ScienceDirect

Journal of Natural Gas Science and Engineering

journal homepage: www.elsevier.com/locate/jngse

Prevention of fracture propagation to control drill-in fluid loss in fractured tight gas reservoir

Chengyuan Xu [a,*], Yili Kang [a], Long Tang [a], Daqi Li [b], Fei Chen [c]

[a] State Key Laboratory of Oil and Gas Reservoir Geology and Exploitation, Southwest Petroleum University, China
[b] Sinopec Research Institute of Petroleum Engineering, Sinopec, China
[c] CCDC Changqing Downhole Technology Company, China

ARTICLE INFO

Article history:
Received 21 July 2014
Received in revised form
26 August 2014
Accepted 27 August 2014
Available online

Keywords:
Fractured tight gas reservoir
Drill-in fluid loss
Formation damage
Fracture propagation pressure
Loss control material

ABSTRACT

Developed fractures are beneficial for the economic and efficient development of tight gas reservoir. But they will lead to drill-in fluid loss and induce serious formation damage. Preventing natural fractures propagation is the key to control drill-in fluid loss in the fractured reservoir. Plugging and sealing the fracture loss channel with loss control material (LCM) can improve the fracture propagation pressure (FPP) effectively. However, the main parameters that affect the improved FPP are not clear. To our best knowledge, few papers have been published on the comprehensive parametric analysis for improved FPP to select reasonable LCM and control drill-in loss in fractured tight gas reservoir. In this paper, we develop a mathematic model to analyze the parameters that affect the FPP after plugging. Laboratory experiment is conducted to select reasonable LCM based on the parametric analysis. Study results show that formation stress anisotropy, elastic modulus, fracture length, fracture pressure and plugging location are the main parameters that impact the improved FPP. According to the analysis results, maximum plugging pressure and total loss volume before sealing are proposed as the key indexes for LCM selection. Experiment results show that reasonable combination of rigid granule, fiber and elastic particle can create a synergy effect to effectively control drill-in fluid loss in fracture tight gas reservoir.

1. Introduction

Lost circulation into induced or natural fractures has been a prevalent source of formation damage, nonproductive time and associated trouble cost and events where copious amount of drill-in fluid are lost, contingency casing strings need to be run, and lost wellbores need to be redrilled or sidetracked (Kang et al., 2012; Li et al., 2011; Cai et al., 2014). The solid phase and liquid phase invasion induced by drill-in fluid loss will lead to serious formation damage (Arabloo et al., 2012). The corresponding damage mechanism includes particle plugging, sensitivity damage and water phase trapping (Bennion et al., 2000). With the global exploitation and development moving to more and more challenging natural gas reservoirs in tighter, deeper, and more depleted conditions, safe and efficient drilling put forward higher requirements on the wellbore pressure containment (WPC) which refers to the maximum pressure a wellbore can withstand before the wellbore starts to leak its fluid into the formation (Wang et al., 2008). It is of great importance to strengthen the wellbore to enhance the WPC and control drill-in fluid loss in fractured tight gas reservoir.

The DEA 13 investigation conducted in the late 1980s laid the groundwork for preventing fracture propagation and control lost circulation by investigating the difference in fracturing behavior between oil-based drilling fluid and water-based drilling fluid (Whitfill and Nance, 2008). Then Stress cage method and fracture-closure stress method are developed to strengthen the WPC. The stress cage method aims to create additional hoop stress in the near wellbore region by propping the near-wellbore fractures open with high strength LCM (Aston et al., 2004). The fracture-closure stress method attempts to generate more closure stress by deliberately widening included fractures and keep them propped open with sized LCM (Dupriest, 2005). Fracture tip isolation and fracture stability are considered essential for the above two method (Van Oort et al., 2009). The previous studies have also investigated a series of factors that weaken the WPC (Wang et al., 2011). Conductive wellbore fractures have been identified as the most important factor that lowers the WPC to its minimum (Otutu, 2011). When a wellbore is formed, the generated secondary stress

* Corresponding author. Tel./fax: +86 028 83032872.
E-mail address: chance_xcy@163.com (C. Xu).

http://dx.doi.org/10.1016/j.jngse.2014.08.021
1875-5100/

field, along with the rock strength together, plays a critical role in protecting the wellbore integrity. For homogenous, isotropic and linear elastic porous materials, the hoop stress in the near wellbore region of a vertical well is given by (Chen et al., 2008):

$$\sigma_\theta = \frac{\sigma_H + \sigma_h}{2}\left(1 + \frac{r_w^2}{r^2}\right) - \frac{\sigma_H - \sigma_h}{2}\left(1 + 3\frac{r_w^4}{r^4}\right)\cos 2\theta - p_w\frac{r_w^2}{r^2} \tag{1}$$

The hoop stress σ_θ achieves the minimum value when polar angle θ is 0° or 180°. Fracture is initiated when the minimum hoop stress reaches the formation rock tensile strength σ_t. Considering drill-in fluid in non-penetrating condition, the wellbore pressure containment P_b of the vertical well is given by (Chen et al., 2008):

$$P_b = 3\sigma_h - \sigma_H + \sigma_t - p_p \tag{2}$$

When a closed small fracture exists on the wellbore wall, the rock strength needs not to be overcome to initiate a fracture and P_b in this case is given by:

$$P_b = 3\sigma_h - \sigma_H - p_p \tag{3}$$

When the fracture propagates further from near wellbore region to far field region, near wellbore stress has little effect on the fracture propagation. In this case P_b is further reduced and given by:

$$P_b = \sigma_h + \sigma_t \tag{4}$$

When the fracture has propagated to intersect with vugs and/or natural fractures, the P_b is equal to formation pore pressure P_p. The weakening process of the WPC with the fracture propagation is shown in Fig. 1.

Form the above discussion and Fig. 1 we can conclude that fracture propagation is the most significant factor that weakens WPC and leads to drill-in fluid loss. Preventing natural fractures propagation is the key to control drill-in fluid loss and strengthen wellbore in the fractured reservoir. Plugging and sealing the fracture loss channel with LCM can improve the FPP effectively. However, the main parameters that affect the improved FPP are not clear. To our best knowledge, few papers have been published on the comprehensive parametric analysis for improved FPP to select reasonable LCM and control drill-in loss in fractured tight gas reservoir.

In this paper, we develop a mathematic model to predict the improved FPP after plugging. Parametric analysis is performed to determine the effects of different parameters on the improved FPP. Then the key indexes for selecting reasonable LCM properties are proposed according to the analysis results. Laboratory experiment is conducted to determine reasonable LCM type and concentration based on the indexes to control drill-in loss in the fractured tight gas reservoir effectively.

2. Model for fracture propagation pressure after plugging

In fractured tight gas reservoir, Plugging and sealing fracture loss channel by LCM is the most important way to prevent fracture propagation and control lost circulation. FPP is improved in the plugging and sealing process. After the fracture is sealed, I-type stress-intensity factor which quantifies the intensity of a stress singularity at a crack tip has a decisive impact on the improved FPP. It is affected by formation stress, wellbore fluid pressure and fracture pressure. In this paper, vertical stress is assumed as the maximum principal stress and vertical fracture is the main fracture type. Fig. 2 shows the mechanical model of a vertical fracture plugged at some distance from the wellbore surface. For a certain fracture, the stress-intensity factor can be determined according to the superposition principle (Fig. 3).

Note that the sign of stress is positive for tension and negative for compression. The pressure and in-situ stresses are effective pressure and stresses, which correspond to the deviations from the formation pore pressure. If one assumes a line fracture with half-length L, then the stress-intensity is given by (Yin, 1992):

$$K_I = \frac{1}{\sqrt{\pi L}}\int_{-L}^{L}\sigma(x,0)\sqrt{\frac{L+x}{L-x}}dx \tag{5}$$

For condition A and B, the stress-intensity factor with $I_f = 1$ is given by (Morita and Fuh, 2012; Tada et al., 1973):

$$k_I(\sigma_{H,h}) = \sigma_h F_\lambda(s)\sqrt{\pi(a+\Delta L)} \tag{6}$$

$$K_I(P_w) = P_w\sqrt{\pi(a+\Delta L)}\left\{1 + (1-s)\left[0.5 + 0.743(1-s)^2\right]\right\} \tag{7}$$

where$\lambda = \sigma_H/\sigma_h$, $s = (a+\Delta L)/(r_w + a + \Delta L)$, and $F_\lambda(s) = 0.5(1-\lambda)(3-s)[1+1.243(1-s)^3] + \lambda(1-s)[0.5+0.743(1-s)^2] + \lambda$.

Condition C shows the fracture pressure $P_f - P_w$ between the plugging location and the fracture tip. And the stress-intensity factor induced by this component is given by:

$$K_I(C) = \frac{1}{\sqrt{\pi L}}\int_{-L}^{L}\left(P_f - P_w\right)\sqrt{\frac{L+x}{L-x}}dx \tag{8}$$

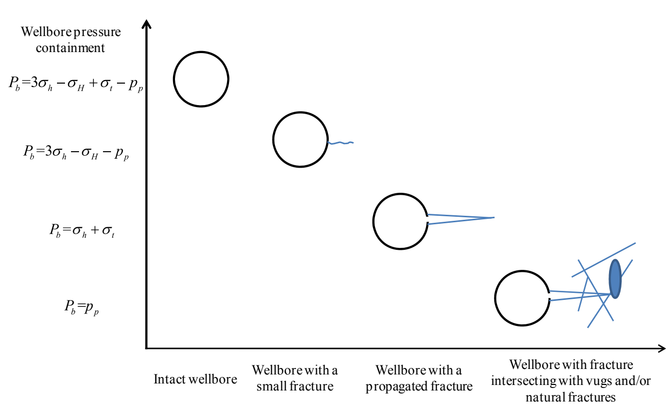

Fig. 1. WPC in different formation conditions.

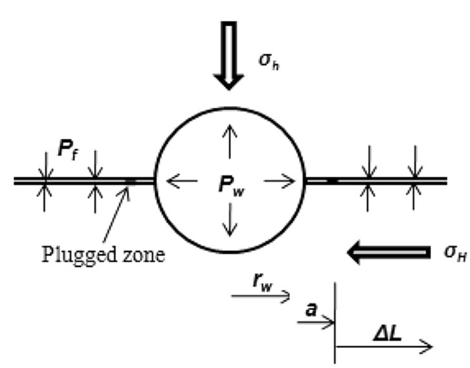

Fig. 2. The mechanical model of a fracture plugged with LCM.