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Imbibition inducing tensile fractures and its influence on in-situ stress analyses: A case study of shale gas drilling

Liu Yang [a,*], Hongkui Ge [a], Yinghao Shen [a], Junjing Zhang [b], Wei Yan [a], Shan Wu [a], Xianglu Tang [a]

[a] State Key Laboratory of Petroleum Resources and Prospecting, China University of Petroleum, Beijing 102249, China
[b] Petroleum Engineering Department, Texas A&M University, College Station, TX 77843, USA

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ABSTRACT

For conventional oil and gas reservoirs, the orientation and magnitude of in-situ stress can be estimated by analyzing wellbore failures such as borehole breakouts and drilling induced fractures (DIF) using Zoback's stress polygon model. According to this model, DIFs are most likely induced by the high mud weight, wellbore cooling, high stress difference, or pressure surge. A large number of DIFs have been identified by imaging logging in shallow well sections of shale gas well QY1 in the Sichuan Basin of China. However, all possible explanations of standard DIFs do not work well, suggesting the limitations of this model when applied to shale formations. Other mechanisms influence the formation of DIFs in this shale gas well that are not covered in this model. In this paper, the orientation and magnitude of the in-situ stress in the study area are constrained following the general procedure outlined by Zoback's stress polygon model. The DIF distribution in the QY1 wellbore and its relationship with organic matter are then analyzed. A new mechanism was introduced to explain the DIFs in the organic-rich section. The results show that the maximum horizontal stress (SHmax) in the study area trends N95°E±9°. The calculated in-situ stress magnitudes are consistent with a strike/reverse faulting stress regime (SHmax > Sv ≈ Shmin). In addition, the DIFs are concentrated in the organic-rich interval. For organic-rich shale, strong water imbibition is common, which is related to super-dry gas shale due to the water displacement of kerogen-transformed hydrocarbons, high capillary pressure due to micro-nano meter pore diameters, and the water-sensitive clay mineralogy. This spontaneous water intake generates the effective internal stress around the wellbore, producing DIFs in the shale gas well. The introduction of this new mechanism allows the Zoback's stress polygon model to constrain the in-situ stress in the study area. Therefore, this mechanism should be considered during estimation of the in-situ stress in gas shale formation when using Zoback's stress polygon model.

1. Introduction

Horizontal drilling and multistage fracturing technologies have been applied to maximize the effectiveness and minimize the cost of shale gas exploration. Understanding the current state of crust stress could assist in the optimization of the borehole trajectories, drilling fluid weight and multistage fracture design, thereby enhancing the efficiency of shale gas exploration. In southwest China, the Sichuan Basin (a forerunner zone in China) has a variety of marine shale formations. The Qianjiang shale play in the Sichuan Basin is in the initial stage of shale gas exploration, and accurate knowledge of the stress state at depth is of interest for engineering applications.

Wellbore breakouts and DIFs are common phenomena during drilling, and can be identified by imaging logging. These images could provide significant information regarding the crustal stress field, which has become an important method for full stress tensor calculation. According to wellbore failures, the in-situ orientation is well determined, and the magnitude of the horizontal principal stress is constrained by constructing a geomechanical model based on the frictional strength of the crust (Trautwein-Bruns et al., 2010). The stress polygon model provided by Zoback is a classical model of in-situ stress calculations based on borehole failures (Zoback et al., 2003). However, limitations are noted when constraining the in-

* Corresponding author.
E-mail address: shidayangliu@126.com (L. Yang).

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situ stress. Estimating the SHmax accurately is difficult (Zoback et al., 2003), and large fluctuations in SHmax values are found (Wiprut et al., 2000). As proposed by Brudy et al. (1997), the value of SHmax tends to be a lower-bound estimate because DIFs might occur without excess mud weight or cool mud. Morita et al. (1990) found that borehole breakdown could not occur until the tangential stress is equal to the tensile strength of the rock, suggesting the limitations of conventional theories predicting the DIFs. The conventional theories should account for the effect of various parameters that affect the propagation of DIFs such as drilling fluid properties, formation permeability, and possible pore pressure build-up caused in drilling lowly permeable or impermeable formations (Fuh et al., 1992; Oort and Razavi, 2014). The QY1 shale gas well in southeast Chongqing developed a large number of DIFs in the organic-rich well section (as identified by imaging logging). An obvious limitation of this model is noted when estimating in-situ stress based on the DIFs. In this paper, the authors constrained the in-situ stress using Zoback's stress polygon model and analyzed its limitations in organic-rich shale. Based on a comprehensive analysis of the distribution of DIFs, the influence of the spontaneous water imbibition on the development of DIFs at the organic-rich section is considered when modifying the model.

2. Determination of the in-situ stress according to Zoback's stress polygon model

2.1. QY1 wellbore

QY1 is an exploration well targeting the shale formation in southeast Chongqing. It was drilled in 2012 with technical casing perforation, and the lower Sullivan Longmaxi Group and Upper Ordovician Wufeng Group marine shale were encountered. The shale formations are dark-colored, silty shale and are carbonized. The borehole diameter decreases from 12 to 1/4 inches in the upper 300 m to 8.5 inches at the final depth of 880 m. The maximum inclination angle is 11.19°. Core samples (74.8 m) were cored as depth intervals over 727–801.8 m. The borehole section was from 570 to 853.7 m. In addition to the standard logs, a simultaneous acoustic imager and a cross-multiple array acoustic log that provides the azimuth of the fast shear wave and the horizontal shear wave velocity anisotropy were included (Fig. 1). Moreover, the high-resolution Formation MicroScanner Image (FMI) provided detailed information on wellbore failures and natural fractures (Fig. 2). Packers were used, and a mini-frac test was performed to obtain a direct measurement of the minimum horizontal stress (Shmin) at a depth of 780–790 m.

2.2. Borehole failure distribution

Although the dual caliper curves indicate a slight borehole enlargement, no obvious breakouts were noted throughout the imaged intervals. The shale formation at the bottom QY1 well section developed a large number of DIFs (Fig. 2). The stress state tends to be a strike-slip/reverse faulting regime when numerous DIFs occur (Zoback et al., 2003). The direction of SHmax (N95°E±9°) is acquired in vertical wellbores depending on these stress-induced wellbore fractures.

2.3. Determination of the fracture closure pressure (Pc)

The surface pressure was measured during the mini-frac test, and the bottom-hole pressure can be calculated from the surface pressure when considering the fluid pressure. The mini-frac data of QY1 were analyzed using the Minifrac module of the fracturing software to acquire the instantaneous shut-in pressure (ISIP) and closure stress (Pc) (Fig.3). The mini-frac program is based on Nolte's equations, and the fundamental method is discussed by Nolte (1979), Castillio (1987) and Meyer and Hagel (1988). $\triangle P = P - ISIP$.

The results of the mini-frac test are shown in Table 1. This mini-frac test revealed that the fracture closure pressure is approximately 20.5 MPa. According to Eq. (8), the overburden stress (S_v) at the depth of 780–790 m is approximately 20.8 MPa, which tends to be slightly larger than the Pc. The fracture closure pressure is a better measure of the Shmin at depth. The fracture closure stress is approximately equal to the overburden stress. The errors cannot be eliminated completely in the values for the Pc and S_v. Therefore, hydraulic fracturing is possible in the horizontal plane. Considering the large numbers of DIFs at the bottom of the well section, the in-situ stress state tends to be SHmax > Sv ≈ Shmin.

2.4. Rock mechanical and frictional properties

Rock mechanical properties such as the tensile and compressive strength, elastic modulus, Poisson's ratio, Biot coefficient and fault friction coefficient provide the basis of the in-situ stress calculation and wellbore stability analysis. These data are derived from lab tests and logs to constrain the geomechanical model of the study area.

The tensile strength of the rock has to be exceeded to initiate a fracture. By contrast, DIFs are initiated easily when small flaws in the borehole wall can be used as starting points for the development of fractures, because no tensile strength has to be overcome at these points. If small flaws contribute to the development of fractures in the borehole wall, then no tensile strength is noted. Shale develops a large number of joints, fractures and many discontinuous surfaces. Therefore, the tensile strength of the rock is assumed to be small and can even be neglected for the analysis of DIFs.

No tool is currently available to directly obtain the unconfined compressive strength (UCS) in boreholes. The UCS can be acquired from well logging. The accurate acquisition of UCS is significant for wellbore breakout prediction. Several empirical correlations based on well images could be adopted to determine the UCS in shale:

Lal (1999) proposed the following formula based on shale in the Gulf of Mexico:

$$UCS = 10(304.8/\Delta t_P - 1) \quad (1)$$

where Δt_P is the P-wave interval transit time in μs/ft.

Horsrud (2001) presented the following correlation for shale in the North Sea:

$$UCS = 0.77(304.8/\Delta t_P)^{2.93} \quad (2)$$

The following equation is from the Schlumberger Company for siliceous shale.

$$UCS = 3.8069E_s \quad (3)$$

where E_s is the static Young's modulus in GPa.

Fig. 4 shows that Eq. (3) well matches the UCS measurements for QY1 core samples. Eq. (3) can be implemented with empirical correlations to predict the UCS for the research area. The marine shale in southeast Chongqing has a higher UCS than that in North America, which may be related to the old age of the formation.

The Biot coefficient α (ranging between 0 and 1) is required to calculate the effective stresses. Warpinski and Teufel (1992) showed that the values of samples rich in micro-cracks are also near 1. Zimmerman (1999) and Wang (2000) showed that the Biot coefficient is likely to be less than 1.0 for rocks with low matrix compressibility or low porosity. Nevertheless, a Biot coefficient of 1 is used in this study area.