A New Method to Estimate Formation Pore Pressure in Fractured Areas of Shale Gas Reservoir

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Abstract. The matrix of shale gas reservoir has the characteristics of low porosity and ultra-low permeability, but also develop natural and hydraulic fractures. Many field operations observed that the formation pore pressure after hydraulic fracturing is higher than the original formation pore pressure. Drilling in the fractured areas of shale gas reservoir, including natural fractures and artificial fractures, always faces greater overflow risk. The pore pressure test after fracturing also shows that the test value is higher than the formation initial pore pressure. However the conventional formation pore pressure predicting methods are difficult to obtain the accurate pore pressure in the fractured areas of shale gas reservoir.

In this paper, the causes of formation pore pressure changing and fracturing pressurization effect in the fractured zones of shale gas reservoir are analyzed. Based on the assumption of closed and constant volume material balance and the gas equation of state, the internal mechanism of the increase in pore pressure caused by fracturing operation in low-permeability shale gas formation is theoretically analyzed. A new method to predict pore pressure changing of shale gas reservoir during drilling and hydrofracturing operations is proposed. The pore connectivity of shale gas reservoir is poor, and the permeability is tens of nano-darcy. The permeability is usually between 0.01-0.20 millidarcy when natural fractures are developed. After fracturing, the permeability can be increased by 2-3 times. Based on the principle of effective stress, a pore pressure calculation model with the influence of permeability change is established by using logging data. Three influence terms are considered in the model: the first one is the overburden pressure term, the second one is the skeleton stress term, and the last one is the influence term of permeability change rate on local formation pore pressure. The proposed method shows simple principle, clear mechanism and easy to use in the field. Field applications show that this method could quickly and accurately predict dynamic formation pore pressure changing of shale gas reservoir. It offsets the shortcomings of traditional formation pore pressure calculation methods.

1. Introduction

The matrix of shale gas reservoir has the characteristics of low porosity and ultra-low permeability with natural and induced fractures developed due to hydraulic fracturing[1-2]. This caused negative impacts on drilling operation. Many field operations observed that the formation pore pressure after hydraulic fracturing is higher than the original formation pore pressure. When drilling into the fractured areas of shale gas reservoir, it is often necessary to increase the drilling fluid density to balance the formation pore pressure. For several shale gas wells in South China as examples. Four wells on the same platform were affected by hydraulic fracturing operations of adjacent wells. The drilling fluid density was increased by more than 0.15 g/cm³ compared with wells that were not affected by hydraulic fracturing. Meanwhile, gas kicks and fracturing fluid invasion were often detected.
Therefore, accurately predicting the formation pore pressure in fractured areas of shale gas reservoir is significant to drilling safety.

Commonly used methods to obtain formation pore pressure include seismic method, dc index method and well logging method. Among them, logging methods include equivalent depth method, Eaton method and effective stress ratio method. Using logging data to analyze and predict formation pore pressure is the most widely used method to determine formation pore pressure. It could ignore the effect of human factors and the result changes continuously with the well depth. Recent years, many scholars focused on increasing the accuracy of obtaining formation pore pressure from logging data[3-6]. The approaches can be categorized into resistivity data analysis, data mining of acoustic characteristics and improving compaction characteristics precision. However, all these researches cannot predict the formation pore pressure accurately in fractured areas. The field practices show that the results of pore pressure test before fracturing are significantly lower than those after fracturing [7]. The equivalent drilling fluid density calculated by Eaton method based on acoustic wave is matched well in non-fractured areas. But the result is quite different from the actual pore pressure when Eaton method is used in natural fractured zones or areas affected by adjacent well hydraulic fracturing.

Accurate estimation of formation pore pressure is significant for drilling safety. Fail to obtain accurate formation pore pressure may lead to gas kick and other downhole problems. Based on the analysis of the variations of formation pore pressure under different working conditions and the fracturing pressurization effect of shale gas reservoir, this paper proposed an accurate method to estimate formation pore pressure in fractured areas of shale gas reservoir.

2. Theoretical analysis

The matrix of shale is tight and has low permeability. It is found that the pore pressure of shale formation is closely related to the characteristics of fractures during both drilling and hydraulic fracturing operations. During hydraulic fracturing operation, a huge amount of high-pressure fluid is injected into the fractures, and the formation of induced fractures could connect more reservoir. The primary pore, natural fractures and induced fractures generated by hydraulic fracturing absorb a large amount of liquid and occupy the space of free gas in the reservoir, resulting in the increment of formation pore pressure in the fractured areas. When the stimulated reservoir volume of the adjacent well is large or the distance between two wells is close enough, the well under drilling may show significant drilling aftereffect. The drilling fluid density has to be increased to balance the consequent higher formation pore pressure. The existence of natural fractures improves the flow channel of shale gas reservoir, the positive pressure difference increases the formation energy, and the pressure difference between wellbore and formation causes the gas in the formation to flow into the wellbore[8-9].

Material balance method of constant volume is a common method for shale gas reserves prediction, which has good adaptability and accuracy [10-11]. The analysis of the effect of fracturing pressurization also adopts the material balance condition of constant volume. The stimulated reservoir is regarded as a closed system with constant volume. This assumption avoids the analysis of the shape and size of fracture network and fluid flow behaviors in the stimulated volume. It is a new and feasible approach to study the effect of fracturing pressurization. The time effect of hydraulic fracturing can be ignored compared with the producing period, so the mass flow outside the fracturing volume can be ignored. Only the interaction between the formation fluid and the fracturing fluid in the fracturing area is considered, in other words, the areas outside the fracturing volume are not connected and do not flow into stimulated reservoir volume. At the same time, because the fractures volume is less than 5% of the stimulated reservoir volume, the micro expansion effect of the fractures can be ignored. With the estimation of gas volume in the stimulated reservoir volume and combined with the gas equation of state, the influence of hydraulic fracturing operation on the original formation pore pressure can be analyzed.

The effect of fracturing pressurization in low permeability shale is analyzed as follows: (1) collect basic data such as gas content and pore pressure test results of each sublayer; (2) According to the thickness and gas content of each strata in the fracturing affected areas, the average gas content of the stimulated reservoir volume is calculated; (3) According to the estimated stimulated reservoir volume,
the volume of the gas in the formation corresponding to the surface temperature and pressure is calculated. Since the gas content is measured under the surface standard condition (0 °C, 101.325kpa), the gas volume calculated by using the gas content is the volume of the gas in shale reservoir under the standard condition; (4) Given the standard temperature, pressure, volume (from gas contained in the stimulated reservoir), bottom hole temperature, and the tested pressure before fracturing, the gas compressibility of shale gas can be obtained[12], and the real gas equation of state can be used to calculate the volume of shale gas in the formation environment; (5) The volume of fracturing fluid used in the well is calculated. Since the fracturing fluid is incompressible, it occupies the volume of shale gas in the formation. The volume of natural gas after being occupied by the fracturing fluid is calculated (under formation conditions, short-term fracturing has a significant impact on free gas; (6) Using the original formation pore pressure before fracturing and real gas equation of state, the formation pore pressure after fracturing can be estimated at different fracturing scales.

Taking the shale reservoir in Fulin China as an example. The 89 m thick stratum of Layer A-Layer B is dark carbonaceous and siliceous shale section with good gas bearing capacity. According to the gas bearing capacity and physical property, the shale section is divided into 9 sublayers. Among them, sublayer 1 to 5 is about 40 m thick, with the characteristics of high - medium carbon content (about 2.5% - 4.0% of total organic carbon), high porosity (4% - 6%) and high gas content (5-7 m3/t). The field test results are as follows: the gas content of sublayer 1-sublayer 5 is the best, ranging from 0.89 to 5.19 m3/t, with an average value of 2.99 m3/t; the ratio of free gas to adsorbed gas is 62:38. Sublayer 1 to sublayer 3 are the target layers during the initial development period. The height of fracture is 35-58 m, generally lower than 40 m, and basically within the sublayer 5. After fracturing, the simulated fracture half-length is 162-312 m, which is about 60% - 80% of the designed fracturing scale [11]. Taking a horizontal well with 1500 horizontal section as an example, the designed fractured volume Vdc (horizontal section length 1 500 m × fracture length 500 m × fracture height 70 m) is 5.25 × 107 m3, and the volume of fracturing fluid entering into the fractured volume is about 3 × 104 m3 (excluding the cumulative backflow liquid volume during initial pilot production).

The gas volume under standard condition is as follows:

\[ V_{gs} = V_{apsSgc} \]  

Where: Vgs is the gas bearing volume of closed constant volume container under standard condition, m3; Vaps is the volume of closed constant volume container, m3; Sgc is the gas bearing volume, m3/kg.

By using the gas equation of state, the free gas volume and the gas volume occupied by fracturing fluid can be obtained:

\[ V_{gfa} = V_{g fc} \times P/S \]  

\[ V_{gc} = V_{g fa} - V_{fl} \]  

Where: Vgfa is the volume of free gas under the condition of reservoir, m3; na is the proportion of free gas, na = 0.62; Vgf is the volume of gas under the condition of reservoir temperature and pressure, m3; Vgc is the volume of gas occupied by fracturing fluid, m3; Vfl is the volume of fracturing fluid excluding backflow, m3. Based on the formation pore pressure before fracturing, Vgfa and Vgc ,by applying the gas equation of state, the pore pressure after fracturing can be calculated. The results are shown in Table 1.

### Table 1 Calculation results of fracturing pressurization

| Vdc/ (104m³) | Va/ (104m³) | Vgs/ (104m³) | Vgf/ (104m³) | Vfl/ (104m³) | Pore pressure equivalent density/ (kg L⁻¹) |
|--------------|-------------|--------------|--------------|-------------|-----------------------------------------|
|              |             |              |              |             | Before fracturing | After fracturing |
| 5 250        | 80% Vdc     | 20748.0      | 51.03        | 3           | 1.37                     | 1.52            |
|              | 70% Vdc     | 18154.5      | 44.65        |             | 1.54                     |                |
|              | 60% Vdc     | 15561.0      | 38.28        |             | 1.57                     |                |
It can be seen from table 1 that under the condition of 60% - 80% of fracturing design scale, the calculated equivalent density of formation pore pressure after fracturing is between 1.52 kg / L and 1.57 kg / L, while the measured equivalent density of formation pore pressure is 1.55 kg / L. It can be seen that this method can prove the mechanism of fracturing pressurization and validate the variation of formation pore pressure before and after fracturing. When the formation pore pressure test before or after fracturing only measures partially, the pore pressure of the reservoir section without testing can be calculated conveniently and quickly. It should be pointed out that the above method is only applicable to the calculation of formation pore pressure before production period. For the situation of formation pore pressure reduction in the later stage of gas production, the on-site monitoring and analysis methods are relatively mature, and this paper will not discuss.

Pore pressure at various conditions

The pore connectivity of shale gas reservoir is poor, and the permeability is tens of nano-darcy. The permeability is usually between 0.01-0.20 millidarcy when natural fractures are developed. After fracturing, the permeability can be increased by 2-3 times. The drilling operation of a well interfered by adjacent well fracturing operation is shown in Figure 1. The drilling fluid density is increased by more than 0.10 kg/L to balance the formation pore pressure, and the permeability of the formation in the fracturing affected areas is significantly improved, shown in Figure 2. Therefore, the change of permeability can be a sensitive response term to the formation pore pressure altering. A paper had confirmed the correlation between pore pressure and permeability during shale oil and gas development[14]. In order to forecast the variation of pore pressure around the borehole trajectory in the shale gas horizontal well, a pore pressure calculation method considering permeability changing in fractured area is proposed in this paper.

![Space location](image.png)
Based on the principle of effective stress, a general pore pressure prediction model was proposed by an international petroleum corporation[15], which consider the overlying rock pressure $\sigma V$ and the skeleton stress term $\left(A \times e^{\text{pressure}} + B \times e^{\text{pressure}}\right)$. The predicted value of pore pressure is a certain value using the method, which can’t reflect pore pressure changing in fractured zones. Then a new pore pressure calculation model with the influence of permeability change is established. Three influence terms are considered in the model: the first one is the overburden pressure term, the second one is the skeleton terms.
stress term, and the last one is the influence term of permeability changing rate on local formation pore pressure. The expression is as follows:

\[ P_{pd} = e \cdot \sigma_v \left[ (A \cdot e^{b_{Ap} / V_s} + C \cdot e^{b_{Cs} du}) - (E \cdot e^{b_{Ep} / V_s} + e^{b_{Ed} du}) \right] \]

(4)

Where: \( P_{pd} \) is the pore pressure of shale gas formation, MPa; \( \sigma_v \) is the overlying rock pressure, MPa; \( V_p \) and \( V_S \) are P-wave time difference and shear time difference, \( \mu \) s/m; \( \mu \) is Poisson ratio; \( (A \cdot e^{b_{Ap} / V_s} + C \cdot e^{b_{Cs} du}) \) represents skeleton stress term; \( K'' \) is permeability changing rate, \( K'' \) is taken as km/k (ratio of formation natural permeability to matrix permeability) when analysing the formation pore pressure during drilling; \( K'' \) is taken as Kc/km (the ratio of equivalent permeability to formation permeability after hydraulic fracturing stimulation), which represents the reduction of effective stress of fracture system; \( A, b, C, d, E \) and \( f \) are regional constants, which can be obtained from the formation pressure test results before and after fracturing in the same areas. It should be noted that after sealing the lost circulation layer during drilling, the logging data may not show the true permeability of the formation and affect the accuracy of the method.

Field validations

First collect the field logging and test data, and then calculate the overburden pressure, vertical and horizontal wave velocity, Poisson's ratio and other data during the pore pressure test. The coefficients in formula (4) can be inverted, and then the pore pressure along the well trajectory under different working conditions could be obtained. For example as table 2 shows, based on the logging data includes interval transit time, formation density, borehole trajectory, and the formation pressure test data before and after fracturing, the model coefficients are calculated. The correlation coefficient of the data fitting is 95%. The input parameters and model calculation results of the inversion are shown in Table 2.

Table 2. Inversion of model parameters

| We | Interval transit time/ (\( \mu \) s · m \(^{-1} \)) | Density/ (k g · L \(^{-1} \)) | Formative permeability/mD | Poisson's ratio | Pore pressure ECD (with natural fractures) / (kg · L \(^{-1} \)) | Pore pressure ECD (after hydraulic fracturing) / (kg · L \(^{-1} \)) |
|----|---------------------------------|-----------------|------------------|----------------|---------------------------------|---------------------------------|
| 3   | 648                             | 217 .37         | 2.6              | 0.14           | 0.2 1                           | 1.25                             | 1.58                             |
| 3   | 649                             | 216 .89         | 8                | 0.12           | 0.2 1                           | 1.22                             | 1.54                             |
| 3   | 650                             | 216 .35         | 1                | 0.09           | 0.2 1                           | 1.26                             | 1.56                             |
| 3   | 651                             | 215 .77         | 3                | 0.08           | 0.2 1                           | 1.28                             | 1.58                             |
| 3   | 652                             | 215 .69         | 9                | 0.10           | 0.2 0                           | 1.22                             | 1.54                             |
| 3   | 653                             | 214 .00         | 0                | 0.11           | 0.2 0                           | 1.23                             | 1.54                             |
| 3   | 654                             | 212 .85         | 1                | 0.10           | 0.2 0                           | 1.24                             | 1.55                             |
| 3   | 655                             | 212 .31         | 0                | 0.09           | 0.2 0                           | 1.23                             | 1.54                             |

Note: in table 2 the logging data from the middle section of the tested gas layer has been taken for inversion. Permeability of the middle formation matrix K equals 0.08 mD, and the equivalent permeability Kc equals 0.4 mD after fracturing. The measured pore pressure equivalent drilling fluid
density before fracturing is 1.28 kg/L, and the pore pressure equivalent drilling fluid density after fracturing is 1.54 kg/L.

The expression of pore pressure when drilling into a natural fractured zone is:

\[ P_{pd} = \sigma_v \left[ \frac{(225 \times e^{-1.3p/35} + 81 \times e^{-2.6a})}{2} - e^{-1.3p/35} \times e^{(-k-k/k)} \right] \]

The expression after fracturing operation is:

\[ P_{pd} = \sigma_v \left[ \frac{(225 \times e^{-1.3p/35} + 81 \times e^{-2.6a})}{2} - 3 \times e^{-1.3p/35} \times e^{(0.01k/km)} \right] \]

Applying the method of obtaining pore pressure change considering the influence of permeability under different working conditions, the formation pressure of the horizontal wells of the shale reservoir in a shale gas field were analyzed (>20 wells). And the formation pore pressure before and after fracturing were obtained. The agreement between the calculated results and the measured values is above 85%, which make up for the shortage of traditional methods in predicting the shale gas reservoir pore pressure after fracturing and underestimating the pore pressure of the fractured zones. Take the typical well-X well as an example, the analysis results are shown in Figure 3.

![Fig.3 Formation pore pressure in shale fracture area under different working conditions](image)

Figure 3 shows that the calculation results of this model can reflect the distribution of pore pressure affected by drilling and fracturing. The original formation pore pressure ECD is 1.0~1.2 kg/L and the pore pressure ECD during drilling is 1.10~1.33 kg/L. The pore pressure ECD among the part affected by formation fractures is slightly larger than the original formation pressure. The pore pressure ECD should be further increased to 1.4~1.6 kg/L, considering the effect of fracturing operations.

The real drilling fluid density in this well is 1.38~1.45 kg/L. The tested formation ECD in the middle of the horizontal well is 1.33 kg/L and the calculated value is 1.24 kg/L. The test formation ECD after fracturing is 1.50 kg/L and the calculated value is 1.55 kg/L. The results validate that the proposed method could match the field data very well.

3. Conclusions

(1) Based on the assumption of closed and constant volume material balance and the gas equation of state, the internal mechanism of the increase in pore pressure caused by fracturing operation in low-permeability shale gas formation is theoretically analyzed. Taking the shale reservoir in Fulin China as an example, the calculated equivalent density of formation pore pressure after fracturing is between 1.52 kg/L and 1.57 kg/L, while the measured equivalent density of formation pore pressure is 1.55 kg/L. The principle is simple and the mechanism is clear.

(2) For shale reservoirs with low permeability, the permeability is closely related to the change of formation pore pressure. For a well section with a permeability greater than that of the matrix, the pore pressure of the formation will increase accordingly during drilling, and the pore pressure of the formation will increase significantly after fracturing. For this reason, a method for obtaining the change of the formation pore pressure considering the impact of the drilled fracture zones and the
The fracturing operation is proposed. the formation pressure changing when drilling in the natural fracture zones and after fracturing are analyzed. This method is in consistent with the actual test values. The agreement between the calculated results and the measured values is above 85%. It offsets the shortcomings of traditional formation pore pressure calculation methods.

3) The method for obtaining the change of formation pore pressure can provide a guidance for the selection of safe drilling fluid density in shale gas fractured zones. At the same time, the applicability of this method can be further explored in deep shale gas drilling.

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