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RESEARCH PAPER

Numerical simulation of chemical potential dominated fracturing fluid flowback in hydraulically fractured shale gas reservoirs

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Abstract: To find out the impact of chemical potential difference between the low salinity fracturing fluid and the high salinity formation water on fracturing fluid flowback, a chemical potential difference expression of fracturing fluid and formation water was deduced, on this basis, a mathematical model which considers viscous force, capillary force and osmosis pressure driven gas-water flow in matrix-fracture system was built, the flow back performance of fracturing fluid driven by chemical potential difference was simulated, and the formation water saturation and salt concentration profile with flow back time were analyzed. The results show that in the process of flow back, the water molecules in the matrix driven by the chemical potential difference continually migrated to the deeper reservoirs, while salt ions in the matrix constantly spread to the fractures. After 168 h of fracturing-fluid flow back, the migration distance of water was up to 40 cm, and the salt concentration near the fracture surface increased by 0.841%, and the cumulative flowback ratio of the gas well was only 22.1%. The cumulative flowback ratio would be 23.5%, 32.4% and 41.1% respectively, without taking into account the effect of gas absorption, chemical osmosis or capillary imbibition. The capillary imbibition and chemical osmosis seriously hindered the fracturing-fluid flow back, therefore, the two factors should be fully considered in the post-fracturing evaluation of shale gas wells.

Key words: shale; flow back; chemical potential; capillary force; desorption effect; osmosis pressure

Introduction

As an important part of unconventional resource, shale gas has become the focus of the world, and has been developed successfully in a number of basins in the United States and Canada. Slick water fracturing is one of the key shale gas reservoir stimulation technologies. In order to achieve large stimulated reservoir volume (SRV) and necessary proppant carrying capacity, large fracturing fluid volume and high pumping rate are required[1]. Fracturing practices of shale gas reservoir in China and abroad show that the fracturing fluid has low flowback ratio in general[2–3]. The flowback ratio of fracturing fluid in the United States is about 20%–40%, and only 5%–10%[4] for some shale gas wells in Fuling, China. Most researches[5–8] attribute this phenomenon to fluid spontaneous imbibition caused by capillary pressure or closure of natural fractures.

Shale is composed of sediments with high heterogeneity. It has higher clay content than conventional oil and gas reservoirs, of up to 80%[9]. Clay can work as semi-permeable membrane under subsurface condition[10], which enables osmotic migration of water molecules, namely, migration of water molecules from the low salinity side of the membrane to high salinity side. There is certain amount of formation water in shale reservoir, and due to water consumption in diagenesis and hydrocarbon generation process, the salinity of initial formation water is very high[11]. Research by Haluszczak et al[12] indicates that the salinity of formation water in shale reservoir can be as high as 28%, in contrast, the general salinity of slick water is about 0.1%, thus, the huge salinity difference between fracturing fluid and formation water surely will create huge osmotic pressure, which drives fracturing fluid to move from hydraulic fractures to matrix.

Flowback of fracturing fluids is commonly considered as an immiscible displacement process. Single-porosity or dual-porosity gas-water two-phase flow models[13–18] have been developed, and on this basis, numerical simulation of fractur-

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fracturing fluid flowback as well as fracturing parameter analysis have been conducted in previous researches. These flowback models assume water flows in fractures or flows both in fractures and matrix; sensitivity analysis considers relative permeability, stress sensitivity, capillary pressure as well as gravity. However, previous researches only took into account driven force of water molecules in physical level, didn't take into account the chemical osmosis process and its force characterization and osmotic pressure. In this paper, the concept of chemical potential difference is introduced into previous mathematical model of fracturing fluid flowback, and the driving effects of viscous force, capillary pressure and osmotic pressure are considered. Through numerical simulation, the influence of different driving forces and gas desorption on fracturing fluid flowback have been verified. This study aims to understand the control mechanism of slick water migration and retention in shale gas reservoirs, and improve the understanding on mechanism of shale gas recovery.

1. Chemical potential difference

1.1. Derivation of chemical potential difference of certain component in different solutions

For multi-component solution system, the differential of chemical potential of component B can be expressed as[19]

$$\mathrm{d}\mu_{\mathrm{B}} = -S_{\mathrm{B,\,m}}\mathrm{d}T + 10V_{\mathrm{B,\,m}}\mathrm{d}p \tag{1}$$

Under isothermal condition, the chemical potential of component B can be obtained by integration of eq. (1).

$$\int_{p^{\Theta}}^{p} \mathrm{d}\mu_{\mathrm{B}} = 10\int_{p^{\Theta}}^{p} V_{\mathrm{B,m}}\mathrm{d}p \tag{2}$$

Eq. (2) can also be expressed as

$$\mu_{\mathrm{B}}(T,p) = \mu_{\mathrm{B}}\left(T,p^{\Theta}\right) + 10\int_{p^{\Theta}}^{p} V_{\mathrm{B,\,m}}\mathrm{d}p \tag{3}$$

Assuming the solution containing B is ideal dilute solution (solution obeying Raoul's law, s, different from pure liquid, l). Its chemical potential can also be written as

$$\mu_{\mathrm{B}}(T,p,\mathrm{s}) = \mu_{\mathrm{B}}(T,p,\mathrm{l}) + RT\ln x_{\mathrm{B}} \tag{4}$$

According to eq. (4), the chemical potential difference of component B between two different concentrations under different pressure can be derived:

$$\mu_{\mathrm{B}}(T,p_1,x_1,\mathrm{s}) - \mu_{\mathrm{B}}(T,p_2,x_2,\mathrm{s}) =$$
$$\mu_{\mathrm{B}}(T,p_1,\mathrm{l}) + RT\ln x_1 - \left[\mu_{\mathrm{B}}(T,p_2,\mathrm{l}) + RT\ln x_2\right] \tag{5}$$

Combining with eq. (3),

$$\mu_{\mathrm{B}}(T,p_1,x_1,\mathrm{s}) - \mu_{\mathrm{B}}(T,p_2,x_2,\mathrm{s}) =$$
$$\left[\mu_{\mathrm{B}}\left(T,p^{\Theta},\mathrm{l}\right) + 10\int_{p^{\Theta}}^{p_1} V_{\mathrm{B,\,m}}\mathrm{d}p\right] -$$
$$\left[\mu_{\mathrm{B}}\left(T,p^{\Theta},\mathrm{l}\right) + 10\int_{p^{\Theta}}^{p_2} V_{\mathrm{B,\,m}}\mathrm{d}p\right] + RT\ln\frac{x_1}{x_2} \tag{6}$$

Simplifying eq. (6),

$$\mu_{\mathrm{B}}(T,p_1,x_1,\mathrm{s}) - \mu_{\mathrm{B}}(T,p_2,x_2,\mathrm{s}) = 10\int_{p_2}^{p_1} V_{\mathrm{B,\,m}}\mathrm{d}p + RT\ln\frac{x_1}{x_2} \tag{7}$$

Assuming that partial molar volume doesn't change with pressure, then the chemical potential difference of component B between different solutions can be expressed as

$$\mu_{\mathrm{B}}(T,p_1,x_1,\mathrm{s}) - \mu_{\mathrm{B}}(T,p_2,x_2,\mathrm{s}) = 10V_{\mathrm{B,\,m}}(p_1 - p_2) + RT\ln\frac{x_1}{x_2} \tag{8}$$

1.2. Chemical potential difference between fracturing fluid and formation water

During the process of hydraulic fracturing treatment, nearly ten thousand cubic meters of fracturing fluid is pumped into the formation in general. As the primary formation water has high salinity, chemical potential difference will occur between the primary formation water and low-salinity fracturing fluid. Assuming that fracturing fluid flows from wellbore to matrix through hydraulic fractures, and formation water exists in matrix, then the chemical potential difference between fracturing fluid and formation water is:

$$\mu_{\mathrm{w,\,f}} - \mu_{\mathrm{w,\,m}} = 10V_{\mathrm{w}}\left(p_{\mathrm{w,\,f}} - p_{\mathrm{w,\,m}}\right) + RT\ln\frac{x_{\mathrm{f}}}{x_{\mathrm{m}}} \tag{9}$$

The molar fraction of water in solution can be calculated according to salt composition and their concentrations[20].

Both chemical potential difference and pressure difference are driving force of water migration, and $(\mu_{\mathrm{w,f}} - \mu_{\mathrm{w,m}})/V_{\mathrm{w}}$ has the dimension of pressure. Therefore, eq. (9) can be simplified as

$$\frac{\mu_{\mathrm{w,\,f}} - \mu_{\mathrm{w,\,m}}}{V_{\mathrm{w}}} = 10\left(p_{\mathrm{w,\,f}} - p_{\mathrm{w,\,m}}\right) + \frac{RT}{V_{\mathrm{w}}}\ln\frac{x_{\mathrm{f}}}{x_{\mathrm{m}}} \tag{10}$$

From eq. (10), it can be concluded that the chemical potential of water is not only related to concentration, but also pressure. When ignoring salinity difference, driving force is viscous pressure difference $10(p_{\mathrm{w,f}} - p_{\mathrm{w,m}})$, which is conventional viscous pressure driving; when ignoring pressure difference, and only considering the salinity difference between formation water and fracturing fluid, the driving force becomes $(RT/V_{\mathrm{w}})\ln(x_{\mathrm{f}}/x_{\mathrm{m}})$, which is osmotic pressure.

2. Flowback mathematical model and solution

2.1. Assumptions and physical model

Assumptions: (1) shale gas reservoir is composed of matrix and hydraulic fractures; (2) matrix is considered as a homogeneous system with permeability anisotropy; (3) hydraulic fractures are vertical cracks symmetric in two wings, with height equal to the reservoir thickness; (4) isothermal flow and ignoring the influence of gravity; (5) the stress sensitivity of permeability is considered; (6) the effect of capillary pressure is considered; (7) the effect of osmotic pressure is considered; (8) the effect of gas desorption is considered; (9) in the process of fracturing fluid pumping, water enters matrix through hydraulic fractures, and in the process of flowback, gas and water flow into the horizontal wellbore through hydraulic fractures.

Based on the above assumptions, shale gas reservoir can be simplified as the combination of hydraulic fracture system and