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Research article

Flowback patterns of fractured shale gas wells

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Abstract

Shale gas reservoirs generally need to be fractured massively to reach the industrial production, however, the flowback ratio of fractured shale gas wells is low. In view of this issue, the effects of natural fracture spacing, fracture conductivity, fracturing scale, pressure coefficient and shut-in time on the flowback ratio were examined by means of numerical simulation and experiments jointly, and the causes of flowback difficulty of shale gas wells were analyzed. The results show that the flowback ratio increases with the increase of natural fracture spacing, fracture conductivity and pressure coefficient and decreases with the increase of fracturing scale and shut-in time. From the perspective of microscopic mechanism, when water enters micro-cracks of the matrix through the capillary self-absorbing effect, the original hydrogen bonds between the particles are replaced by the hydroxyl group, namely, hydration effect, giving rise to the growth of new micro-cracks and propagation of main fractures, and complex fracture networks, so a large proportion of water cannot flow back, resulting in a low flowback ratio. For shale gas well fracturing generally has small fracture space, low fracture conductivity and big fracturing volume, a large proportion of the injected water will be held in the very complex fracture network with a big specific area, and unable to flow back. It is concluded that the flowback ratio of fractured shale gas wells is affected by several factors, so it is not necessary to seek high flowback ratio deliberately, and shale gas wells with low flowback ratio, instead, usually have high production.

Keywords: Shale gas well; Flowback; Reservoir simulation; Fracture spacing; Fracturing volume; Pressure coefficient; Self-absorbing hydration

Shale gas reservoirs feature high brittleness, low permeability, and rich natural micro-cracks, etc. [1,2]. Through massive hydraulic fracturing with "high injection rate, high liquid volume, high sand volume, low viscosity and low sand ratio", complex fracture networks can be created in these reservoirs to enlarge the contact area between fracture plane and shale matrix, thus realizing industrial recovery of shale gas [3–5]. The development practice of American Barnett shale indicates that hydraulic fracturing with fresh water not only can greatly reduce operation cost, but also increase ultimate recovery of shale gas [6]. But different from conventional low-permeable gas reservoirs, the flowback ratio of shale gas reservoirs after fracturing is lower (generally 10%–40%) [7,8], a large amount of water remaining in formations would inevitably have serious effect on gas migration in matrix and fracture system. Hence, it is very important to know the distribution of water in shale gas reservoirs for mastering flowback pattern.

1. Establishment of a mathematical model

As the flow pattern of shale gas is very complex, current numerical simulation of shale gas is mainly based on filtration theory of CBM, i.e., using matrix-fracture dual-porosity model, considering some other factors (such as desorption, diffusion and stress sensibility of gas). The basic parameters of this model are as follows: gas reservoir volume is

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1400 m × 1000 m × 50 m, grid number is 383 × 205 × 10, matrix permeability is 0.0001 mD, matrix porosity is 5%, flow conductivity of primary fractures is 2−5 D·cm, flow conductivity of secondary fractures is 0.5 D·cm, initial formation pressure is 30 MPa, the number of fracturing stages is 12, fracturing cluster number is 25, fracturing scale is 10000−25000 m^3, Langmuir pressure is 4.5 MPa, Langmuir volume is 2.3 m^3/t, horizontal section length is 1000 m, fracture half length is 200 m, cluster spacing is 40 m, secondary fracture spacing values are 20 m, 40 m and 80 m respectively, and initial water saturation of formation is 25%.

1.1. Treatment of fracture network

The fracture network formed in shale gas reservoirs after fracturing is very complex. It must be simplified in simulation because of the limit of computer memory and the solution convergence. In the model, there are primary fractures and secondary fractures (natural fractures), according to the equivalent conductivity theory, the scales and attributes of the primary fractures and secondary fractures were set to assure the same migration capability of the fractures for gas phase and liquid phase. The primary fractures are perpendicular to the horizontal wellbore direction, and the secondary fractures are parallel to that (Fig. 1).

1.2. Treatment of flow patterns

As the permeability of shale matrix is extremely low, no gas flowing happens in matrix, but only adsorbing, desorbing and diffusing occurs with the change of pressure and gas molecule concentration. The desorbed gas flows into fractures following Darcy's Law, and finally into the bottom hole.

1.3. Initiation of the model

According to fracturing scale, the initial water saturation and formation pressure of the model were pre-treated through injecting water via the injection wells to change the required formation water saturation and pressure (Fig. 2).

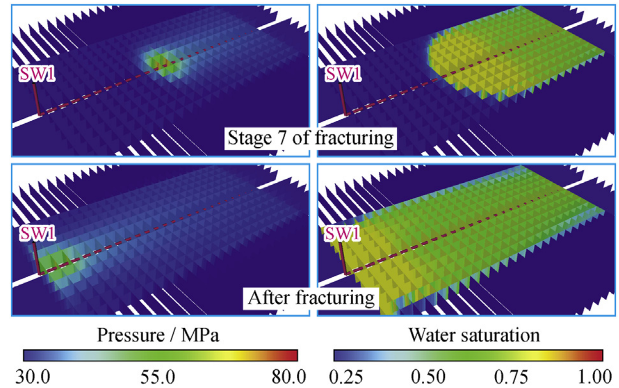


Fig. 2. Distribution of initial water saturation and formation pressure.

2. Analysis of factors influencing flowback patterns

The flowback of shale gas is inversely proportional to its productivity after fracturing. During fracturing, a part of fracturing fluid (slick water) exists in induced primary fractures and secondary fractures, and another part filters into shale matrix. After fracturing, driven by pressure difference, the slick water enters well bores along fractures. During this process, fracture spacing, fracture conductivity, fracturing scale, formation pressure and shut-in time have stronger effect on the flowback.

2.1. Conductivity

“Conductivity ratio” is defined as the ratio of primary fracture conductivity to secondary fracture conductivity. In this simulation, the conductivity of secondary fractures is kept constant at 0.5 D·cm. Fig. 3 shows the changes of five-year flowback ratio versus conductivity ratio at various fracture spacing values. It can be seen that the flowback ratio increases with the increase of fracture spacing and fracture conductivity ratio. As the conductivity of secondary fractures is constant, the increase of flowback ratio means the increase of primary fracture conductivity, and the slick water in the primary fractures flows back more easily. The bigger the secondary

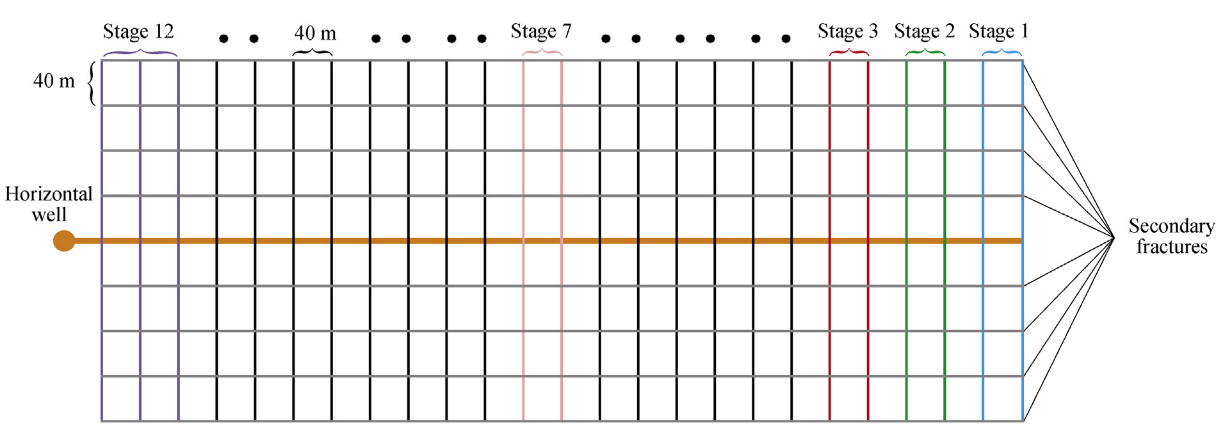


Fig. 1. Sketch map of fracture network.

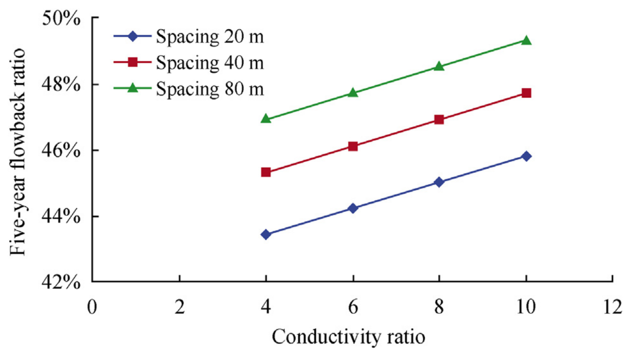


Fig. 3. Effect of conductivity ratio on flowback ratio.

fracture spacing, the lower the natural fracture density is, and the less slick water exists in secondary fractures and filters into formation through secondary fractures. More slick water existed in the primary fractures makes flowback easier. It can be deduced that the higher the shale reservoir brittleness, the richer the natural fractures (i.e., the more developed fracture network formed after fracturing), the lower the flowback ratio is, but the production is generally higher.

2.2. Fracturing scale

According to the statistics of current fracturing scale of shale gas wells in China and other countries [9—13], the scale of single cluster is usually between 400 m^3 and 1000 m^3. Therefore, for horizontal wells with 12 stages and 25 clusters, the fracturing scale is between 10000 m^3 and 25000 m^3. It can be seen from Fig. 4 that the bigger the fracturing scale, the larger the absorbed water volume in single cluster, the lower the flowback ratio is. This is because the bigger the absorbed water volume in single cluster, the more the slick water exists in the secondary fractures and filters into the matrix, but the conductivity of the secondary fractures and the matrix is poorer, thus the water is hard to flow back. When the absorbed water volume in single cluster is kept constant, the effect of various fracturing scales on flowback ratio simulated shows similar pattern to that in Fig. 4. This is mainly because the bigger the fracturing scale, the more the fracturing stages and clusters, the more developed the fracture network, the lower the flowback ratio and the higher the production will be.

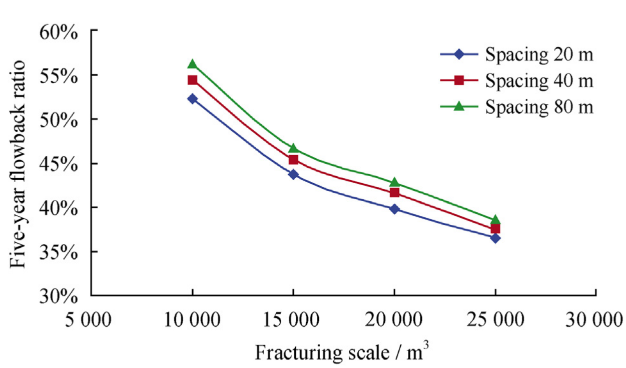


Fig. 4. Effect of fracturing scale on flowback ratio.

2.3. Pressure coefficient

Both flowback ratio and productivity are sensitive to formation pressure. Under the same conditions, the higher the formation pressure, the bigger the pressure difference between the matrix and fractures during flowback, the bigger the flowback energy provided by the formation, the higher the flowback ratio will be (Fig. 5). During production, the higher the formation pressure, the larger the adsorbed gas volume will be on one hand, the bigger the production pressure difference is, the higher the productivity will be on the other hand. It can be seen from Fig. 5 that flowback ratio is proportional to pressure coefficient. Studies show that the higher the pressure coefficient, the better the development effect of the shale reservoirs will be. The pressure coefficient of the U.S. shale gas reservoirs higher in productivity is generally high (pressure coefficient of Haynesville, Eagle Ford and Marcellus shale gas reservoirs is 2.0, 1.33 and 0.93—1.56, respectively) [14,15].

2.4. Shut-in time

After fracturing, shale gas wells generally undergo three stages: flowback, shut-in and commissioning. The shut-in period (10—30 days) after flowback generally is set aside for the laying of gas pipelines, and its length has certain influence on subsequent production. It can be seen from Fig. 6 that, given the same fracture spacing, the longer the shut-in time, the lower the flowback ratio is, and the lower the production of the shale gas well is. During shut-in time, the slick water in the primary fractures further filters to secondary fractures and matrix, the longer the shut-in time, and the bigger the loss volume, the lower the flowback ratio will be. Therefore, for the shale gas reservoirs that can be commercially produced, the shut-in time after flowback should be minimized. If possible, pipeline should be laid ahead of time to allow direct production after fracturing without shut-in operation.

3. Mechanism of shale imbibition hydration

The imbibition feature of shale can be regarded as one of the mechanisms causing low flowback ratio after fracturing.

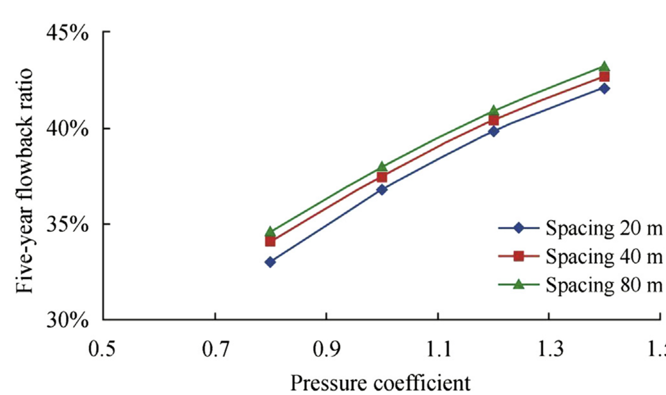


Fig. 5. Effect of pressure coefficient on flowback ratio.

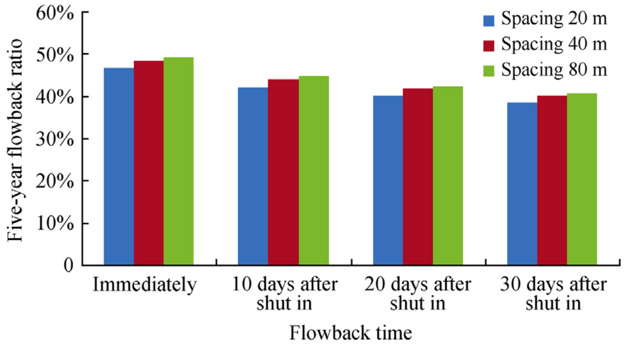


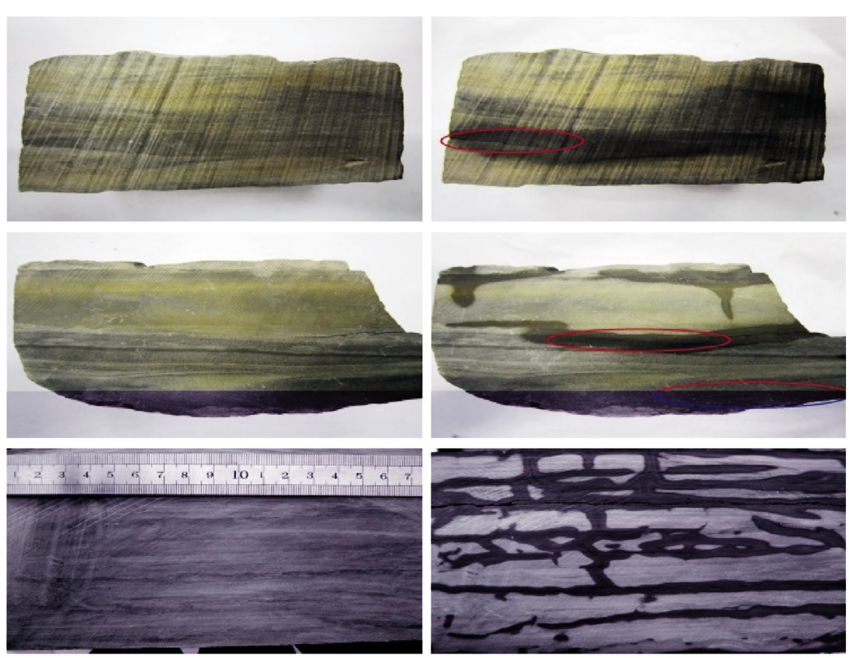
Fig. 6. Effect of shut-in time on flowback ratio.

As water content in the fracturing fluid for shale gas reservoirs is generally higher than 90% [16], the flowback ratio is closely related to existing state of water in shale. Three shale outcrop samples were put into a container with 5 mm water respectively, after 24 h, the capillary imbibition effect observed is shown in Fig. 7.

Hard and brittle shale is an aggregation of mineral particles in mutual cementation. There are weak bonding points or planes between mineral particles or between mineral particles and cement, and hydration makes these places become initial microscopic damage points or planes. As a large quantity of micro-cracks are generated in shale by dehydration in diagenesis, the water firstly enters bigger micro-cracks, then finer micro-cracks connected with the bigger ones, under the action of capillary force, water imbibition occurs, generating inter-connected crack networks. Water molecules are absorbed in between mineral particles, reacting with hydroxyl on the surface of these particles, and replacing previous hydrogen bonds, this is the so-called hydration effect (stress corrosion effect). This effect reduces the cohesive force between particles, leading to hydration shattering of the minerals or cement, and microscopic damage at last. During fracturing, stress at the tip of micro-cracks increases, and new micro-cracks will generate and larger cracks will be enlarged due to the tensile stress on particles, which will result in macro-damage [17,18]. Therefore, because of the imbibition controlled by capillary force, water is pushed to the far end from wells through the primary fractures. The more complex the fracture network is, the bigger the fracturing scale is, the longer the time water remains in the formation, the harder the flowback and the lower the flowback ratio will be. It can be concluded that there are two main reasons behind the reverse relationship of the single well productivity and flowback ratio: ① the complexity of fracture network, and ② imbibition of shale. The more complex the fracture network, the bigger the contact area between the injected water and the formation, the stronger the imbibition by capillary force, the lower the flowback ratio and the higher the single well productivity will be. Otherwise, the simpler the fracture network, the higher the flowback ratio, the lower the single well productivity will be.

4. Conclusions and suggestions

1) Flowback ratio increases with the increase of fracture conductivity, fracture spacing and pressure coefficient, but decreases with the increase of fracturing scale and shut-in time.
2) The capillary imbibition in micro-cracks leads to cohesion reduction between matrix particles, and thus facilitates the formation of complex fracture networks of



a. Initial shale samples b. Samples after 24 h of water imbibition

Fig. 7. Capillary imbibition effect of shale.

confluent and connected fractures, which makes it hard for a large proportion of water held in the fracture network to flow back, and leads to low flowback ratio in the end.

3) Flowback ratio of shale gas wells after fracturing is affected by several factors, but deliberately seeking high flowback ratio is not necessary. The spontaneous imbibition of fracturing fluid in shale can greatly increase the complexity of the fracture network, enlarge the contact area between reservoir and well bore, making it easier for adsorbed gas to desorb. Therefore, the production of shale gas wells with low flowback ratio is usually higher.

Fund project

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