Fracture Characterization Using Flowback Water Transients from Hydraulically Fractured Shale Gas Wells

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ABSTRACT: Fracture characterization is necessary to evaluate fracturing operations and forecast well performance. However, it is challenging to quantitatively characterize the complex fracture network in shale gas reservoirs because of the unknown density and reactivation of natural fractures. The flowback water transients can provide useful information about the complexity of the fracture network after the fracturing operations. In this paper, a mathematical model for modeling fracturing fluid flowback of hydraulically fractured shale gas wells is established. This proposed model characterizes the flow of water and gas in a hydraulic fracture-induced natural fracture–shale matrix system. Hydraulic, capillary, and osmotic convections; gas adsorption; and natural fracture closure are considered in this model. Flowback simulation of a hydraulically fractured shale gas well is conducted using the developed numerical simulator, and the water/gas transients between hydraulic fractures, natural fractures, and matrix are obtained. Finally, two field cases from the Longmaxi Formation, Southern Sichuan Basin, China, are used for comparison of the flowback data with the model results. The good match of the two water transients provides a group of fracture network parameters, that is, the effective length and conductivity of main hydraulic fractures and the density of induced natural fractures. The proposed model for describing the flowback process and its meaningful relationship with the fracture–network complexity provides an alternative approach for post-stimulation evaluation.

1. INTRODUCTION

In recent decades, shale gas development in North America has become very successful, which is mainly attributed to the technological advancement of multistage hydraulic fracturing of horizontal wells. Fracture characterization is necessary to evaluate fracturing operations and forecast well performance. The most common methods for fracture characterization are rate-transient analysis (RTA), pressure-transient analysis (PTA), micro-seismic analysis, and tracer test. Many researchers used RTA and PTA to characterize the fracture network.14−17 because production data are available for almost every well. Micro-seismic monitoring is also broadly used in the field to characterize the fracture network during and after the hydraulic fracturing operations.8−11 Tracer test is another method commonly used to characterize the fracture network.12−16 Each of these three methods has its strengths and limitations. No one method is solid enough to be applicable to all wells, especially when dealing with field data.

In the past, the flowback data obtained during the post-stimulation routine practice for well clean-up are usually ignored. The flowback models are limited to single-phase water flow in a dual-porosity medium without considering induced natural fractures, gas-phase permeability, and fracture closure effects. However, flowback is a multi-phase problem, without analytical solutions. Numerical simulation and matching seem to be the only way to deal with this problem.

In 2006, Crafton and Gunderson17 analyzed the data of water flowback rate and pressure with high frequency to obtain fracture length before and after gas breakthrough; later in 2010, a two-dimensional simulator was developed for modeling gas/water two-phase flow during the flowback.18 In 2012, Clarkson19 extended the multi-phase RTA method to shale gas reservoirs and developed a single water-phase analytical model for the flowback process; other effects, including various fracture geometries, the flow of free gas, pressure-dependent relative permeability and porosity, communications between fracture stages and between wells, fracture closure, and the use of nitrogen-energized fracturing fluid, have been included in later studies.20−23 Clarkson and Williams-Kovacs24 also proposed the analytical method for tight oil reservoirs; the salinity modeling and additional constrain on relative permeability curve were considered later.25 In 2016, Clarkson and Qanbari26 included dynamic drainage area27 into the proposed semianalytical model for modeling flowback, and fracture propagation was considered.28 Abbasi et al.29 divided the whole flowback process into water-dominant period, water decreasing and gas increasing period, and gas dominant period, and pointed out that the
carefully measured rate and pressure data in the flowback stage supplement production data analysis for more accurate fracture characterization. In 2013, Alkouh \textsuperscript{30} developed a three-dimensional gas–water two-phase flow model for shale reservoirs and pointed out that analyzing the combined data of flowback, shut-in and production provides proper flow regime identification. In 2014, Ezulike and Dehghanpour developed a flowback analysis model (FAM) for two-phase flow; the FAM model can be applied to the comprehensive analysis of flowback and production records;\textsuperscript{31−33} later in 2016, Ezulike et al.\textsuperscript{34} included fracture closure in the two-phase flow model for obtaining effective fracture pore volume. In 2016, Zolfaghari et al.\textsuperscript{35} proposed a model for describing salt transport during water flowback and to characterize fracture network through a salinity profile. In 2017, Jia et al.\textsuperscript{36} introduced complex fracture network to gas–water two-phase flowback in shale gas reservoirs. In 2018, Zhang and Emami-Meybodi\textsuperscript{37} developed a gas–water two-phase flow semi-analytical model for analyzing flowback and long-term production data; fracture closure can be quantified with the use of this model.

In 2014, Adefidipe et al.\textsuperscript{38} proposed a mathematical model to characterize instant gas breakthrough and to obtain fracture parameters by matching gas–water two-phase flowback data. In 2014, Bertoncello et al.\textsuperscript{39} provided well management suggestion through shut-in and flowback simulation. In 2014, Almuhih et al.\textsuperscript{40} investigated various effects on water flowback. In 2016, Fakcharoenphol et al.\textsuperscript{41} simulated fracturing fluid flowback to investigate how shut-in affects gas produced and water recovery. In 2016, Wang and Pan\textsuperscript{42} proposed a chemical potential dominant flowback model in shale gas reservoirs.

Although many flowback models\textsuperscript{17−42} have been published, few of them coupled the transient fluid flow modeling with important phenomena occurring in the shale gas reservoir, such as mechanical fracture closure, thermal transfer, and chemical—potential equilibrium. Because of the limitation of the flowback models, the results from flowback data analysis cannot provide fracture network parameters. In this study, an integrated hydro-mechanical—chemical model (HMC) developed by Wang et al.\textsuperscript{33} is used to simulate fracturing fluid flowing back after the hydraulic fracturing treatment. Two field cases from the Longmaxi Formation, Southern Sichuan Basin, China, are investigated with the HMC model-based flowback history matching method. The proposed method aims to provide an alternative approach for post-stimulation evaluation.

2. PHYSICAL MODEL AND ASSUMPTIONS

The proposed physical model for loaded fracturing fluid recovery from a multi-stage hydraulically fractured well in shale gas reservoirs is shown in Figure 1. In this model, the fractured shale gas reservoir is subdivided into grid blocks in shale matrix (m), induced natural fractures (f), and hydraulic fractures (F). In this model, the hydraulic fractures are ideally set to propped planar fractures and can be characterized by length ($l_f$), width ($w_f$), and height ($h_f$). The fracturing fluids flow directly between F and the horizontal wellbore. The grid blocks for characterizing f overlie those for m, and the flows of both fracturing fluid and gas occur between the two layers. According to Gilman and Kazemi\textsuperscript{44} and Yan et al.\textsuperscript{45}, the shape factor ($\alpha_f$) can be converted to natural fracture density ($n_f$). The horizontal wellbore is embedded in F, while the discrete organic matter is in the inorganic matrix grid, with both regarded as the sink source terms.

To be specific, in m, clay acts as the surface membrane, so hydraulic convection, osmotic convection, and capillary imbibition contribute to the flow of water.\textsuperscript{46} As the reservoir pressure decreases during the flowback, the adsorption layer of the organic matrix desorbs the shale gas. Langmuir equation is used to characterize gas desorption, which is assumed to be an instantaneous equilibrium process in the modeling.\textsuperscript{47,48} there is no clay contained in $f$, so we do not consider osmotic pressure as the driven force for water and salt ion transport,\textsuperscript{49} and the transport of both water and salt ions in $f$ is driven by hydraulic pressure and capillary force; the gas transport in both $f$ and m is induced by hydraulic convection.\textsuperscript{50} The capillary force is ignored in F because hydraulic fractures are designed to be high-conductivity propped fractures.\textsuperscript{51} Hydraulic pressure acts as the only driven force for both water flow and gas flow in F.
Gas transport is regarded as the high-velocity non-Darcy flow.52 We assume sodium chloride (NaCl) to be the only dissolved mineral in fracturing fluids and formation brine. Therefore, advection contributes to the flow of NaCl in F, f, and m.53,54 Dispersion and other transport mechanisms have not been included in this model for the description of salt ion transport.

In the process of fracturing fluid flowback, water flows into the horizontal wellbore from F under the hydraulic pressure difference. Hydraulic, osmotic, and capillary forces induce water flow of NaCl in F, f, owback process is implemented, the reservoir pressure difference between the current pressure in a given grid cell, P_{cell}, and the initial reservoir pressure, p_i, and d_i stands for the compressibility coefficient due to the natural fracture closure (10^{-1} MPa). For induced natural fractures, the porosity can be converted form permeability using Carman–Kozeny equation58

\[
\frac{k^f}{k^m} = \frac{n_i w b_1^3}{12 \tau (n_i w)^2}
\]

where \(n_i\) represents the quantity of natural fractures contained in per unit area, that is, fracture density; \(\tau\) stands for tortuosity; \(w\) and \(b_1\) represent natural fracture height and aperture, respectively, \(w\) is unity for continuous fractures.

In eq 5, \(q_{fm}^m\) stands for the water/gas flux between f and m (g/cm^3-s), which can be calculated by the following equation

\[
q_{fm}^m = \frac{\alpha_f q_f^m k_f^m}{\eta_f^m} \left( p_f^m - P_{sw} \right)
\]

where \(p_f^m\) stands for the fluid pressure in f (10^{-1} MPa), \(\alpha_f\) stands for the shape factor between F and m (cm^2), and the calculation equation can be referred to a previous study.43

Also, \(q_{Fw}^F\) stands for the fluid flux between F and the horizontal wellbore (g/cm^3-s), which can be calculated by the following equation

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q_{Fw}^F = \frac{\alpha_f q_f^m k_f^m}{\eta_f^m} \left( p_f^m - P_{sw} \right)
\]

where \(P_{sw}\) stands for bottom-hole pressure (10^{-1} MPa), \(B_i\) stands for the formation volume factor for water or gas (nondimensional), \(\alpha_f\) stands for the shape factor between F and the horizontal wellbore (cm^2), and has been proposed by Bian et al.55

Induced natural fracture

\[
\frac{\partial (\rho_f q_f^m S_{fl}^m)}{\partial t} = -\nabla (\rho_f v_f^m) + q_{Fw}^F - q_{fm}^m
\]

where \(q_f^m\) and \(S_{fl}^m\) represent the porosity (nondimensional) and water/gas saturation (nondimensional) in f, respectively; Darcy law is used to obtain \(x_f^m\) water/gas flow velocity (cm/s)

\[
v_f^m = -\frac{k^f k^m}{\eta_f^m} \nabla (p_f^m + p_{cl}^m)
\]

where \(k^f\) stands for the permeability of f (\(\mu\)m^2); \(k_{di, f}\) and \(p_{cl}^m\) and \(p_{cl}^m\) represent the water/gas relative permeability (nondimensional), water/gas pressure (10^{-1} MPa), and capillary force (10^{-1} MPa) in f, respectively. During the hydraulic fracturing treatment, the permeability of the induced fracture near the surface of the hydraulic fracture can be expressed by an exponential function in a simple form varying with pressure57

\[
k^f / k^m = 10^{4\rho_{sw}} = 10^{4(p_{sw} - p_f^m)}
\]

where \(\rho_{sw}\) refers to the initial permeability of the induced fracture (\(\mu\)m^2); \(P_{sw}\) refers to the net pressure (10^{-1} MPa) which is equal to the difference between the current pressure in a given grid cell, \(P_{cell}\), and the initial reservoir pressure, \(p_i\), and \(d_i\) stands for the compressibility coefficient due to the natural fracture closure (10^{-1} MPa).

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\]
considered for water phase, is the osmotic pressure in m (10⁻⁴ MPa). The drainage area controlled by well W can be characterized by the length of 1500 m, the lateral length of well W is 1200 m and it is completed with a horizontal wellbore in each stage. In addition, the fracture half-length is 180 m. The fractures are transversely and evenly generated along the lateral length of well W in each stage. Langmuir’s pressure, \( p_l \) and rock density, \( \rho_r \) are 5 MPa and 2560 kg/m³, respectively.

**5. RESULTS AND DISCUSSION**

5.1. Flowback Simulation. Flowback simulation has been conducted using the numerical model described above. The water fluxes from hydraulic fractures to the wellbore (F–W), from induced natural fractures to hydraulic fractures (f–F) and the matrix (f–m) during flowback are shown in Figure 2a, while the accumulated water fluxes of the three directions aforementioned are exhibited in Figure 2b. The quick declines of the loaded water flowback rates in all directions can be observed in Figure 2a, with the water flux of f–m showing a more significant decreasing trend. The loaded water recovery volume from F to W is 1411 m³ in total, so a recovery ratio of 12.9% can be obtained. It is worth mentioning that 63 m³ water flowed from f to m in addition to the majority of water flowed into F from f. Figure 3 compares the gas rates and cumulative gas fluxes of the three directions in the flowback stage. At the beginning, there is much gas flowing from F to W, and the gaps between the gas fluxes of the three directions in the flowback stage are noticeable. Then, as the reservoir pressure decreases, shale gas is produced through desorption from the well. The quick declines of the loaded water flowback rates in all directions can be observed in Figure 2a, with the water flux of f–m showing a more significant decreasing trend. The loaded water recovery volume from F to W is 1411 m³ in total, so a recovery ratio of 12.9% can be obtained. It is worth mentioning that 63 m³ water flowed from f to m in addition to the majority of water flowed into F from f. Figure 3 compares the gas rates and cumulative gas fluxes of the three directions in the flowback stage. At the beginning, there is much gas flowing from F to W, and the gaps between the gas fluxes of the three directions in the flowback stage are noticeable. Then, as the reservoir pressure decreases, shale gas is produced through desorption from the well.

**Table 1. Basic Reservoir, Fluid, and Fracture Properties of Well W**

| Property | Value |
|----------|-------|
| Initial reservoir pressure, \( p_i \) | 25 MPa |
| Reservoir temperature, \( T \) | 334 K |
| Natural fracture density, \( n_f \) | 5 |
| Water density, \( \rho_w \) | 1000 kg/m³ |
| Water viscosity, \( \eta_w \) | 0.8 mPa-s |
| Water compressibility, \( c_m \) | 5 × 10⁻⁴ MPa⁻¹ |
| Membrane efficiency, \( \lambda \) | 0.03 |
| Tortuosity, \( \tau \) | 1 |
| Langmuir’s pressure, \( p_l \) | 5.8 MPa |
| Rock density, \( \rho_r \) | 2560 kg/m³ |
| Gas compressibility, \( c_g \) | 0.03 MPa⁻¹ |
| Gas viscosity, \( \eta_g \) | 0.058 mPa-s |

Initial porosity, \( \phi_i \), and initial water saturation, \( S_{w_i} \), are 0.35, 0.015, 0.05, 0.12 MPa⁻¹, respectively.

- Initial water saturation, \( S_{w_i} \), is 0.2, 0.2, 0.6.
- Initial gas saturation, \( S_{g_i} \), is 100 nd, 10 000 nd, 100 nd.
- Initial oil saturation, \( S_{o_i} \), is 4.4 × 10⁻⁴ MPa⁻¹.

**Table 2. Relative Permeability Data**

| Water Saturation | Main Hydraulic Fracture | Induced Natural Fracture | Matrix |
|------------------|-------------------------|--------------------------|--------|
| \( k_{xg} \)     | \( k_{wx} \)            | \( k_{yg} \)              | \( k_{yw} \) |
| 0.105            | 0.8823                  | 0                        | 0.630  |
| 0.15             | 0.778                   | 0.048                    | 0.630  |
| 0.2              | 0.73                    | 0.099                    | 0.551  |
| 0.3              | 0.631                   | 0.202                    | 0.415  |
| 0.4              | 0.532                   | 0.301                    | 0.303  |
| 0.5              | 0.434                   | 0.408                    | 0.199  |
| 0.6              | 0.336                   | 0.510                    | 0.121  |
| 0.7              | 0.238                   | 0.613                    | 0.062  |
| 0.8              | 0.139                   | 0.724                    | 0.023  |
| 0.9              | 0.041                   | 0.818                    | 0.006  |
| 0.92             | 0                      | 0.839                    | 0      |

**Table 3. Capillary Pressure Data**

| Water Saturation | Capillary Pressure, MPa | Water Saturation | Capillary Pressure, MPa |
|------------------|-------------------------|------------------|-------------------------|
| 0.18             | 3.37                    | 0.6              | 7.0                     |
| 0.2              | 3.19                    | 0.63             | 5.65                    |
| 0.3              | 2.28                    | 0.65             | 4.75                    |
| 0.4              | 1.33                    | 0.68             | 3.4                     |
| 0.5              | 0.81                    | 0.7              | 2.7                     |
| 0.6              | 0.48                    | 0.75             | 1.5                     |
| 0.7              | 0.28                    | 0.8              | 0.52                    |
| 0.8              | 0.14                    | 0.85             | 0.15                    |
| 0.9              | 0.04                    | 0.87             | 0.04                    |
| 0.92             | 0                      | 0.92             | 0                       |

In eq 11, \( m_g \) is the mass of shale gas absorbed by the organic matrix under formation condition (g/cm³) and is described by Silin and Kneafsey's60 derived from the Langmuir isotherm:

\[
m_g = \rho_g S_k V_l \frac{p_g^m}{p_g^m + p_l}
\]

where \( \rho_g \) and \( S_k \) represent the density (g/cm³) and volume fraction of source rock, respectively, \( p_g^m \) stands for the density of shale gas at the standard condition (g/cm³), and \( V_l \) and \( p_l \) stand for the Langmuir’s volume (cm³/g) and the Langmuir’s pressure (10⁻¹ MPa), respectively.

4. NUMERICAL SIMULATION MODEL

The simulated well W in this section is based on a multi-stage hydraulically fractured well in Marcellus Shale.51,62–66 The lateral length of well W is 1200 m and it is completed with a 15-stage and 4-cluster per stage hydraulic fracturing treatment. The fractures are transversely and evenly generated along the horizontal wellbore in each stage. In addition, the fracture half-length is designed to be 180 m. The drainage area controlled by well W can be characterized by the length of 1500 m, the width of 600 m, and the thickness of 42 m. Basic information from this field case is given in Table 1.51,62–66

In this model, the gas–water relative permeability and capillary pressure curves are set according to Perapont et al.’s data60 (shown in Tables 2 and 3). The whole simulation procedure includes injection for 2 h, shut-in for 5 days, and flowback for 5 days. Water (10 934 m³) is pumped into the shale formation. The bottom-hole flowing pressures for injection and flowback are set to 55 and 5 MPa, respectively.
matrix, and the production peak is overlapping that of f–F at the late flowback time.

5.2. Sensitivity Analysis. To investigate the impacts of natural fracture closure coefficient ($d_f$), natural fracture density ($n_f$), hydraulic fracture length ($l_F$), hydraulic fracture conductivity ($F_c$), and Langmuir’s pressure ($p_L$) on fracturing fluid flowback, we simulated five groups of cases for sensitivity analysis. Only a variable is changed in each group of simulation cases, with the remaining identical to those in the base case. The comparisons among water production rate, accumulated water recovery volume, gas production rate, and accumulated gas production volume caused by various values of each parameter are shown in Figures 4–13, and the simulation results are listed in Table 4.

The increase in hydraulic fracture conductivity ($F_c$) shows a monotonically increasing trend in water production rate and accumulated water recovery volume but a monotonically decreasing trend in gas production rate and accumulated gas production volume, as shown in Figures 4 and 5. These changing trends can also be observed in the sensitivity simulation cases of hydraulic fracture length ($l_F$), but much less significant, as shown in Figures 6 and 7.

On the other hand, the rise in natural fracture closure coefficient ($d_f$) from 0 to 0.12 MPa$^{-1}$ shows opposite trends, with all the simulation results suffering losses, as shown in Figures 8 and 9. However, there are growths in both the two rates and two accumulated production volumes when increasing the natural fracture density ($n_f$), as shown in Figures 10 and 11.

It is worth mentioning that the increase of Langmuir’s pressure ($p_L$) from 4.5 to 10 MPa$^{31,67}$ causes extraordinary minor inclines in both the rates and accumulated production volumes for gas and water, but the curves almost coincide with each other in a relatively short simulation time period because of these week disparities, as shown in Figures 12 and 13. Because of the incline of Langmuir’s pressure ($p_L$), there is more shale gas produced through desorption, increasing the

Figure 2. Comparisons of (a) water fluxes and (b) accumulated water fluxes of W–F, f–F, and f–m.

Figure 3. Comparisons of (a) gas fluxes and (b) accumulated gas fluxes of W–F, f–F, and m–f.

Figure 4. Comparison of water production rate and accumulated water recovery volume affected by various $F_c$. 
energy in shale formation. Therefore, the extra positive force contributes to the growths of both the water production rate and accumulated water recovery volume. The accumulated water recovery volume increases by 0.0356%, and the accumulated gas production volume rises by 0.1542% when running the sensitivity simulation case of $p_L = 10$ MPa. The gaps are estimated to enlarge and be more noticeable in a much longer duration.

The results indicate that the hydraulic fracture conductivity ($F_c$) increasing from 2 to 3 D·cm causes positive effect on the loaded water recovery, but it remarkably decreases the gas production. The increase from 320 to 400 of hydraulic fracture length ($l_F$) leads to a rise in water flowback recovery but a
slight drop in gas production. The decline of closure coefficient in induced natural fractures \(d_i\) from 0.12 to 0 contributes to the significant rises in both water flowback recovery and gas production. An impractical increase by 1.8% of loaded water recovery can be calculated in the case with \(d_i = 0\), that is, without accounting for the natural fracture closure. With the natural fracture density \(n_f\) decreasing from 25 to 1, both the water flowback recovery and the gas production suffer losses. The increase of Langmuir’s pressure \(p_L\) from 4.5 to 10 MPa causes extraordinary minor inclines in both water load recovery and gas production.

### 6. FIELD APPLICATION

In this section, the numerical simulator based on HMC model\(^43\) is applied for analyzing the flowback water data from two actual shale gas wells in the Longmaxi Formation, Southern Sichuan Basin, China. The HMC model\(^43\) can simulate the complex fracture network, natural fracture dilation, and chemical potential equilibrium, which have not been coupled in previous flowback models. The flowback data analysis and history matching using the HMC model can provide extra information, such as the induced fracture density, which is useful for fracture characterization and post-stimulation evaluation in shale gas reservoirs.

Basic reservoir and fluid properties of the two shale gas wells (well WY and YY) are given in Table 5 according to the field geological report; gas–water relative permeability and capillary pressure curves of shale matrix are set based on field core tests, while those of induced natural fractures are set according to the reference paper.\(^66\)

According to the well completion reports, the lateral length of well WY is 1500 m and a 20-stage, 4-cluster per stage hydraulic fracturing treatment was conducted. With a designed half-length of 180 m, the fractures are created evenly in all individual stages. The drainage area controlled by well WY is 1500 m \(\times\) 800 m \(\times\) 30 m (length \(\times\) width \(\times\) thickness), while well YY is completed with a 20-stage hydraulic fracturing treatment along the 1500 m horizontal wellbore, with five transverse fractures created evenly perpendicular to the horizontal wellbore in each fracture stage. The thickness, length, and width of the drainage area for well YY are 42, 1500, and 800 m, respectively.

We input the certain parameters of each well into the simulator, that is, the basic reservoir, fluid, and fracture properties in Table 5 and the information for the two wells, adjusted the unknown parameters when conducting history matching, that is, effective hydraulic fracture half-length, effective hydraulic fracture conductivity, and density of induced natural fractures, and ran the simulation for the two wells, respectively, until both the curve of water/gas rate versus flowback time and the curve of cumulative water/gas production volume versus time generated by the numerical model match well with the authentic curves of water/gas rate.
versus flowback time and cumulative water/gas production volume versus time from the field data. The bottom-hole flowing pressures of well WY and well YY, shown in Figures 14 and 15, were estimated from surface casing pressure measurements and are set as the input for simulation. The good matching of water and gas transients (Figures 16 and 17) and cumulative water/gas production volume (Figures 18 and 19) provides two groups of fracture network parameter combinations, that is, the effective hydraulic fracture half-length of 160 m, the effective hydraulic fracture conductivity of 1 D·cm, and the density of induced natural fractures of 7 m$^{-2}$ for well WY, while the effective hydraulic fracture half-length of 180 m, the effective hydraulic fracture conductivity of 1.4 D·cm, and the density of induced natural fractures of 11 m$^{-2}$ for well YY.

There is a 61 day recording history for well WY. The first month is the flowback period for well WY because water predominates in the produced fluid, while the gas rates are extraordinarily low. On the contrary, in the second half of the recording history for well WY, gas started to breakthrough in the flowing system, showing a straightly upward trend in the first 2 days and then declining to a relatively stable level, at 1.4  × 10$^6$ m$^3$/d. Finally, there are some fluctuations in water and gas rates because of the changing trends in bottom-hole flowing pressure. The daily gas production rate is estimated to

Table 5. Basic Reservoir, Fluid, and Fracture Properties for Wells WY and YY

| Property                        | Value                      |
|---------------------------------|----------------------------|
| Initial reservoir pressure, $p_i$ | 62 MPa                     |
| Reservoir temperature, $T$      | 372 K                      |
| Water density, $\rho_w$         | 1000 kg/m$^3$              |
| Water viscosity, $\eta_w$       | 0.2 mPa·s                  |
| Water compressibility, $c_w$    | $5.8 \times 10^{-4}$ MPa$^{-1}$ |
| Tortuosity, $\tau$              | 1.1                        |
| Langmuir’s pressure, $p_L$      | 6 MPa                      |
| Rock density, $\rho_r$          | 2600 kg/m$^3$              |
| Gas compressibility, $c_g$      | 0.03 MPa$^{-1}$            |
| Gas viscosity, $\eta_g$         | 0.058 mPa·s                |

initial porosity, $\phi_i$, $\phi^e$, $\phi^m$ 0.35, 0.015, 0.05
induced natural fracture closure coefficient, $d_i$ 0.27 MPa$^{-1}$
initial water saturation, $S_{wi,F}^0$, $S_{wi,f}^0$, $S_{wi,m}^0$ 0.3, 0.3, 0.3
irreducible water saturation, $S_{wi,F}^{irr}$, $S_{wi,f}^{irr}$, $S_{wi,m}^{irr}$ 0.1, 0.3, 0.62
initial permeability, $k_{i,F}$ 1800 nd, 300 nd
rock compressibility, $c_r$ 2.82  × 10$^{-4}$ MPa$^{-1}$
volume proportion of source rock, $S_L$ 0.12
ideal gas constant, $R$ 8.314 J/(mol·K)
Langmuir’s volume, $V_L$ 2.5  × 10$^{-3}$ m$^3$/kg
gas density at standard condition, $\rho_{gsc}$ 0.7714 kg/m$^3$
partial molar volume of water, $V_w$ 18.02  × 10$^{-3}$ m$^3$/mol
maintain at around 1.4 × 10⁶ m³/d in the future, and the cumulative gas production volume will also rise considerably, while the water recovery volume is going to reach a plateau. According to the summary of hydraulic fracturing treatment, 39.8% of loaded water is recovered, indicating that most of the fracturing fluid was trapped in the induced natural fractures and then flowed back to the surface when opening the well, while a small fraction of water imbibed into the shale matrix because of the long-term contact with the induced natural fracture face, to displace shale gas in the matrix.

On the other hand, Figure 17 shows a 26-day of water and gas production history for well YY. Water is the dominant flowing fluid before the 13th day, when there was a dramatic increase in the gas rate. During the latter 13 days, despite some fluctuation, water rate shows a downward trend, while gas shows an upward trend. According to the summary of hydraulic fracturing treatment, the ratio of loaded water recovered volume is 14.1%. Although the loaded water will continue to flow back at approximately 100 m³/d, the gas rate is predicted to increase continuously and be much higher than 1.5 × 10⁶ m³/d in the future because the recovered fracture network parameter combination is credible and considerable coupling the upward trend in the curve of gas rate versus time.

It is interesting to note that the histories of both the two wells experienced three flowing periods, that is, water-dominant period, gas breaking through and water production period, and gas-dominant period.

7. CONCLUSIONS
In this paper, numerical investigation of fracturing fluid flowback in a hydraulically fractured shale gas well is conducted using the proposed model. Field data matching of flowback water transients from the Longmaxi Formation, Southern Sichuan Basin, China, is investigated for fracture characterization. Our main conclusions are given below.

(1) During the 5-day flowback period, water flowed into the shale matrix from induced natural fractures, and there is no flowback water from the matrix because of the strong capillarity and chemical osmosis. Main hydraulic fractures contribute to 45% of recovered fracturing fluid, while induced natural fractures account for 55% of total.

(2) The five dominating phenomena, that is, natural fracture closure coefficient, natural fracture density, hydraulic fracture length, hydraulic fracture conductivity, and Langmuir’s pressure, show various influences on water load recovery and gas production volume. The hydraulic fracture conductivity predominates in water recovery and gas produced, followed by the natural fracture density. The influences of the hydraulic fracture length and the natural fracture closure are relatively weak, while Langmuir’s pressure shows the minimum effect.

(3) Flowback data can provide quantitative information for fracture characterization. With the proposed flowback model, the matching of simulated water and gas transients with the field collection gives a group of fracture parameter combination, that is, the effective hydraulic fracture half-length, the effective hydraulic fracture conductivity, and the density of induced natural fractures.

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Notes
The authors declare no competing financial interest.

■ ACKNOWLEDGMENTS

The authors would like to acknowledge the Foundation of State Key Laboratory of Shale Oil and Gas Enrichment Mechanisms and Effective Development (nos. P16063 and 2016ZX05061003) and the National Natural Science Foundation of China (no. U1762210) for their financial support.

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