Fracturing-Fluid Flowback Simulation with Consideration of Proppant Transport in Hydraulically Fractured Shale Wells

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ABSTRACT: Involving the fluid-particle hydrodynamic process and hydraulically created fracture network, fracturing-fluid flowback in hydraulically fractured shale wells is a complex transport behavior. However, there is limited research on investigating the influence of proppant transport on the fracturing-fluid flowback behavior and flowback data analysis. In this paper, a flowback model is developed to simulate the flowback behaviors of the carrying fluid and proppant from the recompacted fracture system in shale wells. The development of fluid pressure and proppant concentration profiles of the fractured shale well are presented. The fluid and proppant fluxes among the hydraulic primary fracture and the induced fracture are also calculated. The influences of proppant consideration or not, proppant density, proppant size, fracturing-fluid viscosity, and fracturing-fluid density on the flowback behavior are investigated. The simulation results are useful for fracturing-fluid optimization in the design phase. Finally, two field cases from the Longmaxi Formation, Southern Sichuan Basin, China are used for matching the actual flowback data with the model results. The results prove that the proppant transport has influence on the flowback behavior to some degree and should be considered in the flowback model for a rather elaborate flowback analysis and post-treatment fracture evaluation.

1. INTRODUCTION

Fracturing-fluid flowback is a complex process, involving fluid transport, proppant transport, fracture closure, as well as their interactions. Proppant transport has long been recognized in modelling fracture propagation during the fracturing-fluid pumping process. Two major forces control the transport of proppant particles as they are carried into the hydraulic fracture, that is, the proppant sedimentation on the bottom due to gravity and the drag force exerted by the carrying fluid cause proppant particles to migrate with the carrying fluid. Together, these two forces control the transport of proppant particles in the fracture, thus influencing their final distribution.

The earliest research on proppant transport in hydraulic fracturing operations have focused more on proppant sedimentation in hydraulic fractures but less on horizontal proppant migration. They generally assumed that proppant flow rates are equal to the carrying-fluid flow rates and proppant concentrations are constant across the fracture width. However, in actual fracturing operations, the proppant-carrying fluid has a certain concentration; at this time, due to the mutual interference between the proppant particles, proppant horizontal migration velocity will also be hindered; the interaction of multiple particles is a very complicated process. As the proppant particles flow through the fracture, surrounding particles limit the area in which they flow and thus increase their resistance to flow. By experiment, the horizontal migration velocity of proppant particles is proved not equal to the average velocity of proppant-carrying fluid in the fracture. Besides, the horizontal migration velocity of proppant particles in the...
fracture is mainly affected by the fracture wall\textsuperscript{10} and proppant concentration.\textsuperscript{11,12}

Besides experiment research, modeling and simulation of proppant transport during hydraulic fracturing treatment have also been developed. Dontsov et al.\textsuperscript{13} considered both gravity settlement as well as tip screen-out phenomena and proposed a model to characterize proppant transport. The proposed model is further utilized in two hydraulic fracture geometries: KGD and P3D. Shiozawa and McClure \textsuperscript{14} developed a three-dimensional (3D) simulator to perform proppant transport, and gravity settlement, fracture closure, and tip screen-out have been taken into consideration. A propagation simulation of hydraulic fracture was also conducted with natural fractures, and the result showed that proppant is easy to accumulate at the junctions between two kinds of fractures. Chang et al.\textsuperscript{15} presented a 3D model, coupling a hydraulic fracture propagation model, to characterize proppant transport, and several proppant transport mechanisms have been considered, including creeping, advection, dispersion, and saltation. The concentration and distribution of proppant and stimulated reservoir volume propped by proppant can be obtained. Zhang et al.\textsuperscript{16} utilized a CFD-DEM model to simulate proppant transport and distribution, and results showed that proppant with big diameters tends to accumulate next to the wellbore but that with small diameters is more likely to transfer into deeper fractures. Wang et al.\textsuperscript{17} developed a CFD-DEM model to describe proppant flow and deposition in both hydraulic fracture and fracture networks. Zeng et al.\textsuperscript{18} employed the CFD-DEM approach to the simulation of transport behavior of proppant, and the contacts of particles and particles and of particles and walls have been highlighted in this study. The representative particle model is also used. Roostaei et al.\textsuperscript{19} proposed a proppant transport model using the non-oscillatory numerical method, which assisted in generating proppant distribution with little diffusion and oscillation. Kong et al.\textsuperscript{20} proposed a 3D simulator, which coupled the transport of both fluid and proppant, fracture propagation, and the computation of fracture geometry, to describe proppant distribution at flowback and production stages in Marcellus shale reservoirs. Zhang et al.\textsuperscript{21} used the CFD-DEM method to model proppant distribution. The interaction between particles and fluids has been considered, and the phenomenon of particle collisions has also been involved.

Numerical studies of proppant transport during post-fracturing flowback periods are relatively fewer and all focus on the internal flow of hydraulic fracture. Zhu et al.\textsuperscript{22} applied the DEM-CED method to simulate stability and pillar deformation of proppant at the flowback stage after channel fracturing treatment is conducted. Qi et al.\textsuperscript{23} developed a prediction model for proppant flowback, and this model coupled both the fracture shunt model and critical rate model. Smith et al.\textsuperscript{24} conducted numerical simulation, which considered fluid rheology, fluid loss, gravity, proppant concentration, viscosity, changes in fracture geometry, and in-situ stress to model proppant flowback. Hu et al.\textsuperscript{25} proposed a mechanical model for proppant flowback before and after the fracture closure. Simulation results provided advice for controlling proppant back flow. But most existing flowback models considering a fracture-matrix flow system developed for flowback simulation and flowback data analysis for post-treatment fracture evaluation have been focusing on modeling the fluid flow.\textsuperscript{26–34} None of them has fully considered the synchronized proppant flowback and further investigated its influence on the fracture parameter interpretation.

We believe that proppant transport has been overlooked as a possible influencing factor for the fracturing-fluid flowback behavior, since there is more than one thousand cubic meters of proppant particles pumped into the target shale formation during hydraulic-fracturing operations\textsuperscript{16} and they may transport like the fluid does within the complex fracture system during the flowback process. To address this issue, a flowback model is developed for a comparative simulation to analyze the influence of proppant transport on the fracturing-fluid flowback behavior. Then, sensitivity analyses are performed to investigate the physical properties of the proppant and fluid on the fracturing-fluid retention in the course of flowback. Finally, field application for flowback data analysis is provided.

## 2. FLOWBACK MECHANISM MODEL

The post-fracturing flowback of fracturing-fluid is a hydrodynamic process coupling fluid and proppant transport in the hydraulically created fracture system. In the course of fracturing-fluid flowback, the fluid in the primary hydraulic fracture transports to the wellbore under the hydraulic pressure difference, and simultaneously the fluid in the induced fracture transports to the primary fracture as compensation under the natural convection. The proppant particle suspending in the carrying fluid enters into the hydraulic fracture system in the course of fracturing-fluid injection but cannot enter into the matrix pore due to the size scale (nanoscale matrix pore vs millimeter diameter proppant). In the course of flowback, the proppant particle in the hydraulic fracture system flows under natural convection as well as the fluid. With the drop of reservoir pressure, the fluid leaked into the matrix during the fracturing-fluid pumping process may gradually release into the fracture during the flowback process.

From the viewpoint of force, the fracturing-fluid flow in the fracture system is driven by viscous and gravity forces, simultaneously carrying suspended proppant particles. The proppant particle flow is driven by the vertical forces, including gravity and buoyancy and horizontal forces, including drag, inertia, and collision.\textsuperscript{35} Due to the high conductivity of hydraulic fractures, the fluid flow within the fracture system can be treated as Darcy’s flow. The interaction of proppant-carrying fluid and proppant flow can be coupled by the equivalent viscosity model.\textsuperscript{36} The fluid flow in the matrix is driven by viscous and gravity forces, not carrying proppant particles. Figure 1 exhibits the forced situation of fluid and proppant from a hydraulic fracture into the wellbore in the course of fracturing-fluid flowback.

## 3. MATHEMATICAL MODEL AND SOLUTION

### 3.1. Physical Assumptions

On the basis of the above-mentioned hydrodynamic flowback behavior for fracturing-fluid, following physical assumptions are made: (1) the physical flowback model is composed of four interconnected domains, i.e., $W$, $F$, $f$, and $m$ (as shown in Figure 2); (2) $f$ and $m$ form a dual-porosity media, which directly link $F$, and all $F$ connect to $W$; (3) a set of fine grids with high permeability is used to characterize $F$, which has a half-length ($l_0$), width ($w_0$), and height ($h_0$); (4) the recompaction of propped hydraulic fractures during the flowback can be described as a stress-dependent porosity change; (5) the carrying fluid flowback satisfies Darcy’s law, considering viscous and gravity forces; (6) proppant flowback considers the drag force, inertia force, and collision force; (7) proppant settlement and height change of...
proppant bed due to the closure of hydraulic fracture are not considered during the flowback process.

### 3.2. Carrying-Fluid Flowback Equations

The mass balance equation for the carrying-fluid flowback in primary fractures is expressed below

\[
\frac{\partial [(1 - cF) \rho_w]}{\partial t} = -\nabla [(1 - cF) \rho_w \nu_F^F] - q_w^{FW} + q_w^{EF} + q_w^{MF}
\]

where \( \partial [(1 - cF) \rho_w]/\partial t \) stands for the mass variation in \( F \), including the carrying-fluid density \( \rho_w \), the residual volume fraction \( (1 - cF) \), and change with flowback time \( t \), while \( \nabla [(1 - cF) \rho_w \nu_F^F] \) stands for the carrying-fluid flux term in \( F \), which is related with carrying-fluid flowback velocity \( \nu_F^F \). Due to the high conductivity of \( F \), a Darcy flow equation is used to describe the velocity below

\[
\nu_F^F = -\frac{(w_F^F)^2}{12 \times 10^9 \mu_d^{EF}} \nabla (p_F^F + 10^{-6} \gamma z)
\]

where \( \nu_F^F, p_F^F, \) and \( \mu_d^{EF} \) stand for the velocity of carrying-fluid (cm/s), the pressure \((10^{-6}\) MPa), and the equivalent viscosity of carrying-fluid \((\text{mPa} \cdot \text{s})\) in \( F \). \( w_F^F \) refers to the width of \( F \) (cm); \( \gamma \) stands for the vector unit in \( z \) direction (cm). \( \mu_d^{EF} \) could be obtained as

\[
\mu_d^{EF} = \mu_d \left( 1 - \frac{cF^F}{\epsilon_{\text{max}}} \right)^{-n}
\]

where \( \mu_d \) is the viscosity of the carrying fluid \((\text{mPa} \cdot \text{s})\), \( cF^F \) is the volume concentration of proppant in \( F \) \((\text{cm}^3/\text{cm}^3)\), \( \epsilon_{\text{max}} \) stands for the maximum volume concentration of the proppant \((\text{cm}^3/\text{cm}^3)\), and \( n \) stands for an exponent, usually from 1.0 to 2.5.

Besides, the second term in eq 1 on the right side, \( q_w^{FW} \), refers to the wellbore-fracture flux term during flowback \((g/(\text{cm}^2 \text{ s}))\). This flux term is driven by hydraulic pressure difference, which is defined by Bian et al. \[39\]

\[
q_w^{FW} = \frac{(w_F^F)^2 h_F}{12 \times 10^9 \mu_d^{EF} B_w F} (p_F^F - p_{sf})
\]

where \( h_F \) and \( l_F \) refer to the half-length (cm) and the height (cm) of \( F \). \( B_w \) stands for the formation volume factor of the carrying-fluid \((\text{m}^3/\text{m}^3)\); \( p_{sf} \) refers to the bottom-hole flowing pressure \((10^{-1}\) MPa).

Also, the third term \( q_w^{MF} \) in eq 1 refers to the flux term between \( F \) and \( f \), which is also driven by hydraulic pressure difference and derived from the Kazemi model \[40\]

\[
q_w^{MF} = \frac{\rho_f (w_f^F)^2}{12 \times 10^9 \mu_d^{MF} A} (p_f^F - p_f^f)
\]

where \( w_f^F \) refers to the width of \( f \) (cm); \( A \) stands for the single surface area of grids \((\text{cm}^2)\); \( p_f^F \) stands for the pressure in \( f \) \((10^{-1}\) MPa); \( \mu_d^{MF} \) stands for the equivalent viscosity of carrying-fluid in \( f \) \((\text{mPa} \cdot \text{s})\) and could be obtained as

\[
\mu_d^{MF} = \mu_d \left( 1 - \frac{c_f^F}{\epsilon_{\text{max}}} \right)^{-n}
\]

where \( c_f^F \) stands for the volume concentration of the proppant in \( f \) \((\text{cm}^3/\text{cm}^3)\).
Moreover, the remaining term in eq 1 on the right side, \( q^m_w \), stands for the flux term between \( F \) and \( m \) and could be referred to a previous study\(^{34} \)
\[
q^m_w = \frac{\alpha k^m_w (p^m - p^F)}{\mu_w} 
\]  
(7)
where the shape factor \( \alpha \) represents the transmission between \( F \) and \( m \), \( k^m_w \) refers to the matrix permeability (\( \mu m^2 \)), and \( p^m \) refers to the pressure in \( m \) (\( 10^{-1} \) MPa).

3.3. Proppant Flowback Equations. The conservation equation for the proppant flowback in primary fractures, which involves the carrying-fluid flux terms in eqs 4 and 5 is expressed below:
\[
\frac{\partial \left( \rho_p^F \phi^F \right)}{\partial t} = - \nabla \left( \rho_p^F \phi^F \nu^F \right) - c^{FW} q^w - c^F q^m_w 
\]  
(8)
where \( \rho_p \) stands for the density of the proppant (g/cm\(^3\)); \( c^{FW} \) and \( c^F \) stand for the concentration transport terms from \( F \) to \( W \) as well as from \( F \) to \( F \) (cm\(^3\)/cm\(^3\)); and \( \nu^F_w \) refers to the proppant flowback velocity in \( F \) (cm/s), which is decided by carrying-fluid flowback velocity\(^{31} \)
\[
\nu^F_w = k^F_{ret} \cdot \nu^F_w 
\]  
(9)
where \( k^F_{ret} \) refers to the retardation factor, which is derived from a fluid-particle flow experiment considering the drag force, inertia force, and collision forces of particle-to-particle and particle-to-wall.
\[
k^F_{ret} = 1 + \left( \frac{d_p}{\omega^F} \right)^2 - 2.02 \left( \frac{d_p}{\omega^F} \right)^2 
\]  
(10)
where \( d_p \) stands for the diameter of proppant (cm) and \( \omega^F \) stands for effective width of \( F \) (cm), which is related with the diameter and concentration of proppant by experiments, as shown below:\(^{31} \)
\[
\frac{1}{(\omega^F)^2} = 1.411 \left( \frac{1}{d_p^2} - \frac{1}{(\omega^F)^2} \right) (\nu^F)^{0.8} 
\]  
(11)

3.4. Fracture Recompaction Equations. During the fracturing-fluid flowback, with the fracturing fluid imbibing into the matrix or being recovered to the surface, the net closure stress within fracture networks increases and the fracture gradually closes.\(^{42} \) For propped hydraulic fractures, the reduction of the hydraulic fracture width is effectively restrained because of proppant support. A stress-dependent porosity equation can be applied to describe this closure phenomena.\(^{45} \)
\[
\phi^F = \phi^F_0 \exp \left( - \frac{p^F - p_{f}^F}{C_{fp} \mu_w} \right) 
\]  
(12)
where \( \phi^F_0 \) and \( \phi^F \) are the current and original porosities of propped fractures, respectively. \( C_{fp} \) is the fracture compressibility during the flowback (\( 10^{-1} \) MPa); \( P_{net} \) is the net pressure within fractures and is the same as the difference between the original pressure and the instant pressure at current. For propped fractures, the value of \( C_{fp} \) can refer to the chart of fracture compressibility inferred by Aguilera\(^{34,42} \) based on his laboratory experiments.

For our flowback model, \( I \) can be \( F \) or \( f \) and the porosity can be correlated with the width of propped fractures by using the Carman–Kozeny equation\(^{30} \)
\[
\nu^F_w = \frac{q^F}{h \mu_w} 
\]  
(13)
where \( n_l \) is the density of propped hydraulic fractures (cm\(^{-2}\)), \( \nu^F_w \) is the width of propped hydraulic fractures (cm), and \( h \) is the height of propped hydraulic fractures (cm).

4. COMPUTATIONAL METHODS

The carrying-fluid and proppant flowback equations are discretized in space and time using the finite-difference method.

We utilize the IMPES approach for dealing with nonlinear equations and the Gauss–Seidel iteration method for equations’ solution. The developed algorithm includes equation discretization, transmissibility calculation, solving equation systems, and calculation for the next time step.

Take eq 1 as an example of the solution progress.

Step one: equation discretization.

At first, the equation could be expanded as the partial difference equation of \( p^F_w \)
\[
\rho_p \phi^F (1 - \phi^F)(C_{F} + C_{w}) \frac{\partial p^F_w}{\partial t} - \rho_p \phi^F \frac{\partial \phi^F}{\partial t} = - \nabla \left( (1 - \phi^F) \rho_p \nu^F_w \right) - q^{FW} + q^{F} + q^{mF} 
\]  
(14)

We apply the forward difference method to deal with terms related to time on the left side, which is given as follows
\[
(\rho_p)^n (\phi^F)^n (1 - \phi^F)^n (C_{F} + C_{w}) \left( \frac{p^F_w^{n+1} - (p^F_w)^n}{\Delta t} \right) = (\rho_p)^n 
\]
\[
(\phi^F)^n (1 - (\phi^F)^n) \Delta t 
\]  
(15)

As for terms related to space on the right side, the central method is applied.

The flow coefficient is defined as
\[
\lambda_w = \frac{\rho_p (w^F)^2 (1 - \phi^F)}{12 \times 10^8 \mu_w} 
\]  
(16)
The first term on the right side could be discretized as
Transmissibility terms are defined as

\[ TX_{wi+1/2} = \lambda_{wi+1/2} \frac{\Delta y_j \Delta z_k}{\Delta x_{i+1/2}}, \quad TX_{wi-1/2} = \lambda_{wi-1/2} \frac{\Delta y_j \Delta z_k}{\Delta x_{i-1/2}} \]  

\[ TY_{wj+1/2} = \lambda_{wj+1/2} \frac{\Delta x_i \Delta z_k}{\Delta y_{j+1/2}}, \quad TY_{wj-1/2} = \lambda_{wj-1/2} \frac{\Delta x_i \Delta z_k}{\Delta y_{j-1/2}} \]  

Then, second order difference quotient operators are defined

\[ \Delta_x TX_{wi} \Delta p = TX_{wi+1/2}(p_{i+1} - p_i) + TX_{wi-1/2}(p_{i-1} - p_i) \]  

\[ \Delta_y TY_{wj} \Delta p = TY_{wj+1/2}(p_{j+1} - p_j) + TY_{wj-1/2}(p_{j-1} - p_j) \]  

\[ \Delta_z TZ_{wk} \Delta p = TZ_{wk+1/2}(p_{k+1} - p_k) + TZ_{wk-1/2}(p_{k-1} - p_k) \]  

So, the first term could be written as \[ \Delta T_x \Delta p^{n+1} + \Delta T_w 10^{-6} \gamma Z. \]  

Finally, the whole equation is further written as

\[ \Delta T_x \Delta p^{n+1} + \Delta T_w \times 10^{-6} \gamma \Delta Z + V_{ij} g_i^F (q_{i+1}^F + q_{i-1}^F - q_{i}^W) \]

\[ = \frac{V_{ij}}{\Delta t} ((1 - \epsilon)^F)_{i+1/2}^F (\frac{1}{\rho_i^F (1 - \epsilon)^F})^{n+1} - ((1 - \epsilon)^F)_{i-1/2}^F (\frac{1}{\rho_i^F (1 - \epsilon)^F})^{n} \]  

\[ V_{ij} = \Delta x_i \Delta y_j \Delta z_k \]  

For terms related to space on the left side, coefficients take the values of time step \( n \), namely, \( T_w = T_w^n \gamma^n \). Parameters in space are only assigned at grid points.

Linearization mainly focuses on coefficients and terms on the right side by dealing with transmissibility terms.

\[ TX_{wi+1/2}^{n+1} = \frac{\Delta y_j \Delta z_k}{\Delta x_{i+1/2}} \]  

\[ = \frac{\Delta y_j \Delta z_k}{\Delta x_{i+1/2}} (w_{i+1/2,j,k}^F)^{n+1} \times 10^{-8} (H_{ij}^F)^{n+1} \]  

Step two: Transmissibility calculation.

Fluid always flows from the high flow potential side to the low one, so flow potential in two adjacent grids should be adjudged to determine transmissibility terms on the basis of the upstream weight method.

Flow potential of grid \( i \) could be defined as

\[ \Phi_i = p_i + 10^{-6} \gamma_i Z_i \]  

(27)
Flow potential of grid \( i + 1 \) could be defined as

\[
\Phi_{i+1} = P_{i+1} + 10^{-6} h_{i+1} Z_{i+1} \tag{28}
\]

\[
\lambda_{i+1/2,j,k} = \begin{cases} 
\lambda_{i+1,j,k} > \Phi_{i+1}, & \Phi_{i+1} > \Phi_{i} \\
\lambda_{i+1,j,k} > \Phi_{i}, & \Phi_{i} > \Phi_{i+1} 
\end{cases} \tag{29}
\]

Step three: solving equation systems.

The linear equation system is formed after discretization, which can be solved by combining coefficients for each variable after coupling initial and boundary conditions. Then unknown variables are calculated.

Step four: calculation for the next time step.

Once achieving the initial values of valuables in the next time step, the \((n+2)^{th}\) time-step calculation is achieved by going back to step two.

5. NUMERICAL MODEL DESCRIPTION

Fracturing-fluid flowback is simulated with the use of a developed simulator. A hydraulically fractured horizontal well with a 1200 m horizontal wellbore and 15 fracturing stages situated in the center of a shale reservoir (1500 m \( \times \) 560 m \( \times \) 40 m) is considered. The initial reservoir pressure is 25 MPa. Each single stage creates four transverse primary fractures along the horizontal wellbore with a fracture spacing of 20 m (\( x_f = 20 \) m). And all primary hydraulic fractures (\( n_f = 60 \)) are assumed to be identical and penetrating the whole reservoir, as shown in Figure 3.

Since our simulation programming is capable of modeling only one-size solid particles, the generally accepted 40/70 proppant particle for shale fracturing, with a mean diameter of 0.3 mm is adopted. Other inputs for the basic model\(^{44,47} \) have been listed in Table 1. The proppant-carrying fluid injection of this well is simulated with a previous fracture model.\(^{53} \) The simulation results of fluid pressure and proppant concentration are input as initial conditions for our flowback simulation. The bottom-hole flowing pressure in the course of the flowback process is 15 MPa.

6. RESULTS AND DISCUSSION

6.1. Simulation Results. Figure 4 exhibits the initial distribution of proppant concentration along the fracture height before flowback. The origin of the coordinate refers to the center of \( F \), which is also the site of wellbore. The \( Z \) axis stands for the position opposite to the wellbore. The negative value of \( Z \) corresponds to the zone at the bottom of reservoir. Due to the gravity, the initial proppant concentration at the bottom of fractures is a little bit greater than that at the upper part of fractures.

Figures 5 and 6 exhibit the developments of fluid pressure and proppant concentration profiles perpendicular to and along \( F \), respectively. The origin of the coordinate refers to the center of \( F \). The \( X \) axis stands for the position along \( F \), and the \( Y \) axis refers to the position perpendicular to \( F \). All profiles with flowback time \( t_f = 3 \) (blue curves in Figures 5a,b and 6a,b) represent the initial state of our numerical model for the following flowback simulation. As shown in the blue curves, both fluid pressure and proppant concentration gather in \( F \) and they distribute in \( f \) before flowback. Specifically, the proppant concentration distribution in the 280 m primary fracture is high in the middle (near-wellbore zone) and low on both sides of the two-wing zone. The proppant concentration distribution in induced fractures shows gradient changes. The closer it is to \( F \), the higher is the regional concentration of \( f \).

Since the proppant sedimentation in hydraulic fractures has not been considered in our proposed flowback model, we focus on demonstrating the flowback simulation results in \( X \) and \( Y \) directions. As shown in Figure 5, the fluid pressure inside and next to \( F \) shows a downward trend, while the pressure far away from \( F \) increases slightly at first and decreases after 30 min. Finally, the 3 h flowback creates a funnel-shaped fluid pressure distribution.

The development of proppant concentration profiles perpendicular to and along \( F \) in the course of flowback are shown in Figure 6. The simulation result indicates that during the well flowback process, the proppant concentration inside and next to \( F \) declines while the concentration far from \( F \) inclines continually. After the 3 h flowback, the initial raised proppant-concentration region exhibits a wave-shaped concentration distribution.

Figure 7 shows the comparison of the fluid fluxes and accumulated fluid fluxes among the three media, i.e., primary fracture (\( F \)), secondary fracture (\( f \)), and matrix pore (\( m \)), during the flowback periods. Figure 6a shows that all of the fracturing-fluid fluxes of \( F-W , f-F , \) and \( f-m \) drop in the course of flowback. And the fluid flows from \( f \) to \( F \) and \( m \) all the time within the 3 h flowback. That means the matrix does not drain water but can suck up water during the flowback. After the 3 h flowback, the accumulated fluid flux of \( F-W \) which means the

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**Table 1. Inputs for the Basic Model**

| parameter, symbol | value parameter, symbol | value |
|-------------------|-------------------------|------|
| primary fracture half-length, \( l_f \) | 140 m | primary fracture width, \( w_f \) | 0.1 cm |
| primary fracture width, \( w_f \) | 1 cm | primary fracture height, \( h_f \) | 40 m |
| primary fracture height, \( h_f \) | 40 m | matrix permeability, \( k_m \) | 0.0004 mD |
| matrix permeability, \( k_m \) | 0.0004 mD | carrying-fluid density, \( \rho \) | 1000 kg/m\(^3\) |
| carrying-fluid density, \( \rho \) | 1000 kg/m\(^3\) | carrying-fluid viscosity, \( \mu \) | 1.0 mPa-s |
| carrying-fluid viscosity, \( \mu \) | 1.0 mPa-s | proppant density, \( \rho_p \) | 2000 kg/m\(^3\) |
| proppant density, \( \rho_p \) | 2000 kg/m\(^3\) | injected fluid volume, \( V_{inj} \) | 11000 m\(^3\) |
| injected fluid volume, \( V_{inj} \) | 11000 m\(^3\) | injected proppant volume, \( V_{inj} \) | 990 m\(^3\) |

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**Figure 4. Initial proppant concentration distribution in Z direction.**
total flowback volume, is 702 m$^3$, as shown in Figure 6b. Meanwhile, there are 601 and 487 m$^3$ of fluid in $f$ transporting to $F$ and $m$. Figure 8 shows the comparison of the proppant fluxes and accumulated proppant fluxes among the three media during the flowback periods. The proppant transports from $F$ to $W$, with an acceleration at first and a deceleration later. By contrast, proppant transports from $F$ to $f$ at the beginning but the transport direction reverses later with an acceleration first and then a deceleration, as shown in Figure 8a. After the 3 h flowback, the proppant flux of $F-W$ is approximately zero, which means that the proppant flowback stops. However, the fluid flowback still continues, since the fluid flux of $F-W$ is still stable.

Figure 5. Development of fracturing-fluid pressure profiles in the course of flowback. (a) Perpendicular to $F$; (b) along $F$.

Figure 6. Development of proppant concentration profiles in the course of flowback. (a) Perpendicular to $F$; (b) along $F$.

Figure 7. Comparisons of fluid fluxes and accumulated fluid fluxes of $F-W$, $f-F$, and $f-m$. (a) Fluid fluxes; (b) accumulated fluid fluxes.
at 3.3 m$^3$/min. As shown in Figure 8b, after the 3 h flowback, the accumulated proppant volume from $F$ to $W$ is 5.4 m$^3$, while the accumulated proppant flux of $f-F$ is 8.2 m$^3$.

6.2. Sensitivity Analysis. To figure out whether considering proppant is important or not, proppant density ($\rho_p$), proppant size ($d_p$), fracturing-fluid viscosity ($\mu_w$), and fracturing-fluid density ($\rho_w$) on the fracturing-fluid flowback sensitivity simulation cases were run. Each group containing four values was considered for single sensitivity variable analysis by varying one variable and keeping the others identical to the basic model. The value ranges of the four sensitivity variables are selected according to the field practice in shale fracturing, i.e., $\rho_p$, 1700–3000 kg/m$^3$; $d_p$, 0.15–0.9 mm (50–100 mesh); $\mu_w$, 1–5 mPa·s; $\rho_w$, 1000–1500 kg/m$^3$. Figure 8 exhibits simulation results.

As shown in Figure 9, the fluid flowback volumes after a 3 h flowback from case A (without considering proppant transport in $f$), case B (proppant transport neither in $F$ nor in $f$ is considered), and base case (proppant transport both in $F$ and $f$ is considered) are 702.9, 742.5, and 702 m$^3$, respectively. Among them, the base case has the lowest load recovery, which is 6.38%, while the case B has the highest load recovery, which is 6.75%. That means if modeling the fracturing-fluid flowback without considering the proppant transport and induced hydraulic fractures, the load recovery will be overestimated by 0.37%. This small proportion is because the proppant production under a low fluid flowback rate is very less and stops in 3 h.

Besides, the incline in $\rho_w$ results in growth in both the fluid flowback volume and the proppant flowback volume. On the contrary, the increase of $d_p$ makes both decrease. The increase of both $\rho_p$ and $\mu_w$ leads to a drop in the fluid flowback volume, while there is an increase in the proppant flowback volume. This means that using the low-density proppant (small $\rho_p$) and low-viscosity fracturing-fluid (small $\mu_w$) in hydraulic fracturing treatment, assists in recovering the fluid and inhibiting the proppant flowback.

6.3. Discussion. To investigate the influence of proppant transport on the fracturing-fluid flowback behavior, a comparative simulation has been performed in the foregoing content. Such a comparative analysis provides intuitive information of the influence weight of proppant transport in different media under the given reservoir and well conditions. The result shows that the influence of proppant transport on flowback is just in 3 h, because after 3 h of fracturing-fluid flowback, all proppant fluxes among wellbore, primary fractures, and induced fractures approach zero. The influence of considering the proppant transport or not on the fluid load recovery turns out not to be significant, since without considering the proppant transport (case B) and only considering the proppant transport in primary fractures (case
A) leads to overestimated fluid load recoveries by 0.37 and 0.1%, respectively.

Moreover, sensitivity simulations have been performed then to quantify the effects of competitive parameters, i.e., proppant density, proppant size, fracturing-fluid viscosity, and fracturing-fluid density on the flowback behavior. The simulation results are practical for fracturing-fluid optimization in the design stage. From the perspective of proppant loss minimization and fluid recovery maximization, low-density resin-coated ceramsite ($\rho_p = 1700$ kg/m$^3$) and low-viscosity slickwater ($\mu_w = 1$ mPa·s) are good choices.

7. FIELD APPLICATION

In this section, the flowback model is utilized for flowback water data analysis from two shale gas wells in the field in the Longmaxi Formation, Southern Sichuan Basin, China. The objective is to determine whether considering the proppant transport in the model would have an influence on the flowback history match of the 2 months flowback water transients by the proposed model with and without considering proppant transport. The good matching provides an effective hydraulic-fracture conductivity of 1.7 D·cm. The flowback water transients from our proposed model considering proppant transport match the actual flowback data better than the model without considering proppant transport. As expected, the no proppant transport model predicts higher flowback water rates with the same hydraulic-fracture conductivity of 1.7 D·cm. If adjusting the hydraulic-fracture conductivity for pursuing an equivalent matching of the proppant transport model (same as the red

7.1. Shale Gas Well X. According to the well completion report, the lateral length of well X is 1500 m and a 20-stage hydraulic fracturing treatment is conducted. Three transverse fractures are generated evenly along the horizontal wellbore in each single stage. The thickness, length, and width of the drainage area for well X are 30, 1500, and 800 m, respectively.

To construct the numerical model and alleviate the non-uniqueness problem, the estimated fracture half-length of 160 m and other properties are fixed and then only the influence of proppant transport on the fracture conductivity can be observed. The bottom-hole flowing pressure, shown in Figure 10a, was estimated from surface casing pressure measurements and is set as an input for the simulation. Figure 10b shows the reasonable history match of the 2 months flowback water transients by the proposed model with and without considering proppant transport. The good matching provides an effective hydraulic-fracture conductivity of 1.7 D·cm. The flowback water transients from our proposed model considering proppant transport match the actual flowback data better than the model without considering proppant transport. As expected, the no proppant transport model predicts higher flowback water rates with the same hydraulic-fracture conductivity of 1.7 D·cm. If adjusting the hydraulic-fracture conductivity for pursuing an equivalent matching of the proppant transport model (same as the red.

![Figure 10](https://example.com/figure10.png)

**Figure 10.** History match of flowback data for well X. (a) Bottom-hole flowing pressure; (b) flowback water transients.

![Figure 11](https://example.com/figure11.png)

**Figure 11.** History match of flowback data for well Y. (a) Bottom-hole flowing pressure; (b) flowback water transients.
curve in Figure 10b), the fracture conductivity after the adjustment turns out to be 1.3 D·cm. This means analyzing the flowback water data without considering proppant transport may underestimate the hydraulic-fracture conductivity by 0.4 D·cm.

7.2. Shale Gas Well Y. Well Y is completed with an 18-stage hydraulic fracturing treatment along the 1500 m horizontal wellbore, with four transverse fractures created evenly perpendicular to the horizontal wellbore in each fracture stage. The thickness, length, and width of the drainage area for well Y are 42, 1500, and 800 m, respectively.

Same as before, certain properties for the well are put into the numerical model for initialization, and to alleviate the non-uniqueness problem, the estimated fracture conductivity of 1.4 D·cm is fixed. Numerical simulation then is run until the simulation results match the field data. Here, for well Y, only the influence of proppant transport on the fracture half-length can be observed. Figure 11a shows the estimated bottom-hole flowing pressure, which is set as an input for flowback simulation. Figure 11b shows the good history match of the 1 month flowback water transients by the proposed model with and without considering proppant transport. This match provides an effective hydraulic-fracture half-length of 180 m. As shown, the simulated flowback water rates from the no proppant transport model exhibit a little bit higher than those considering proppant transport. If adjusting the hydraulic-fracture half-length for pursuing an equivalent matching effect of the proppant transport model (same as the red curve in Figure 11b), the fracture half-length after adjustment turns out to be 147 m. That means analyzing the flowback water data without considering proppant transport may underestimate the hydraulic-fracture half-length by 33 m.

8. CONCLUSIONS

Flowback simulation for investigating the influence of proppant transport on the fracturing-fluid flowback is presented in this paper. Through sensitivity analysis and field data matching of hydraulically fractured shale wells, the following conclusions can be drawn.

1. During the flowback, the matrix doesn’t drain fluid but can suck up fluid. The fluid in induced fractures flows to primary fractures, and the fluid in primary fractures flows to the wellbore. After the 3 h flowback, the fluid load recovery is 6.38% and the fluid flowback rate is stable at 3.3 m³/min.

2. The proppant in primary fractures has been flowing to the wellbore during the flowback, but there is a reversal of the flow direction between the primary and induced fractures. Before the induced fractures release the proppant, the proppant in primary fractures flows into the induced fractures. After the 3 h flowback, the proppant flowback stops and the accumulated proppant flowback volume is 5.4 m³.

3. Modeling the fracturing-fluid flowback only considering the proppant transport in primary fractures will lead to an overestimated fluid load recovery by 0.1%. Furthermore, without considering the proppant transport and induced hydraulic fractures, the fluid load recovery will be overestimated by 0.37%.

4. The four dominating properties, i.e., proppant density, proppant size, fracturing-fluid viscosity, and fracturing-fluid density, show different influences on the flowback of fluid and proppant. Simulation results indicate that using the low-density proppant (as low as 1700 kg/m³ resin-coated ceramic) and low-viscosity fracturing-fluid (approaching 1 mPa·s slickwater) for the hydraulic fracturing treatment helps to recover the fluid and minimize the proppant loss.

5. Field application proves that the consideration of proppant transport in the flowback model has an influence on the flowback data analysis and post-treatment fracture evaluation. Analyzing the flowback water data without considering proppant transport may underestimate the hydraulic-fracture conductivity by 0.4 D·cm or hydraulic-fracture half-length by 33 m.

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Notes
The authors declare no competing financial interest.

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