

Article

Study of the Synergistic Flowback Technology of Fracturing-Fluid Self-Flow and CO₂ Gas Lift in Shale Reservoirs of the Lianggaoshan Formation, Sichuan Basin

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Abstract

Severe fracturing-fluid retention and low post-fracturing flowback efficiency are common in the Lianggaoshan shale reservoirs of the Sichuan Basin. Liquid loading may also occur during late production. To address these problems, this study investigates a synergistic flowback technology that combines natural fracturing-fluid flowback with CO₂ gas lift. First, based on the complex fracture network characteristics of the Lianggaoshan shale reservoir, the interaction mechanisms between hydraulic fractures and natural fractures were investigated. An energy model for fracturing-fluid flowback under natural flowback conditions was established, revealing that reservoir gas expansion energy, hydromechanical energy, and rock elastic energy are the primary driving forces for fracturing-fluid flowback. Furthermore, considering fracture closure behavior, fluid leakoff, and wellbore flow dynamics, a calculation model for the natural flowback of fracturing fluid was developed, and a staged pressure-controlled flowback strategy was proposed. Subsequently, to address the decline in liquid unloading capacity caused by formation-energy depletion during the late stage of natural flowback, a gas-lift-assisted flowback multiphase flow model for the wellbore was established. The effects of the gas injection pressure, gas injection rate, and wellhead pressure on liquid unloading efficiency were systematically investigated. The results indicate that the liquid unloading rate increases with an increasing gas injection pressure and gas injection rate; however, a pronounced diminishing marginal effect is observed. For the Well H1 reference case, the central recommended gas injection pressure was 12 MPa, the gas injection rate was 8×10^4 – 10×10^4 m³/d, and the wellhead backpressure was maintained below 0.5 MPa. Furthermore, the CO₂-assisted flowback mechanisms were evaluated by distinguishing between the effects explicitly represented in the model and the potential reservoir-scale physicochemical effects. The reduction in wellbore mixture density and bottomhole flowing pressure was simulated directly, whereas CO₂–oil mass transfer, viscosity reduction, mineral dissolution, and changes in water-blocking behavior were interpreted with reference to published experimental studies. Based on these mechanisms, a three-stage synergistic optimized flowback scheme, consisting of “CO₂ soaking–natural flowback–CO₂ gas lift,” was established. A sequence of stagewise quasi-steady PIPESIM calculations was subsequently performed over the 30-day operating schedule. Under the adopted simulation conditions, the recommended soaking period is 5–7 days. The operation should be switched to gas lift when the wellhead pressure falls below 1.5 MPa or when daily liquid production declines continuously by more than 20%. Under the synergistic scheme, the 30-day cumulative flowback volume was predicted to reach 3492 m³. This value was substantially higher than those obtained by conventional natural flowback and standalone gas-lift processes. Moreover, the flowback curve exhibits a distinct “secondary



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surge” characteristic. These findings provide a theoretical basis and technical support for efficient fracturing-fluid flowback and stable long-term production in the Lianggaoshan Formation. They may also be applicable to other shale oil reservoirs with low porosity and ultra-low permeability.

Keywords: Lianggaoshan formation; shale oil; fracturing-fluid flowback; CO₂ gas lift; natural flowback; synergistic optimization

1. Introduction

The Lianggaoshan shale formation in the Sichuan Basin contains abundant oil and gas resources and has become a key target for unconventional hydrocarbon exploration and development. Because of their low porosity and ultra-low permeability, shale reservoirs generally require hydraulic fracturing to create conductive pathways and improve hydrocarbon deliverability. However, solid-particle sedimentation in CO₂-based fracturing fluids, filtration and leakoff of the injected fluid into the formation, and fracture propagation controlled by geological and fluid properties may result in nonuniform particle distribution, fracturing-fluid retention, and complex fracture geometries [1–3]. These subsurface effects can aggravate water-blocking damage and reduce flowback efficiency, thereby limiting reservoir productivity. Conventional natural flowback is limited by the rapid depletion of reservoir energy, and liquid loading in the wellbore is prone to occur during the later production stage, leading to relatively low overall flowback efficiency. Therefore, it is of great importance to clarify the energy evolution mechanisms governing fracturing-fluid flowback within complex fracture networks and to introduce artificial lift intervention at an appropriate stage. A synergistic flowback model that combines natural flowback with CO₂ gas lift can address these limitations. The model uses the energy-enhancement, liquid-unloading, and viscosity-reduction effects of CO₂ to improve flow in the wellbore and near-wellbore region. This approach can increase flowback efficiency and support stable production from individual shale wells. This approach possesses significant theoretical value and practical engineering implications. The research presented in this paper mainly focuses on the following aspects: (1) the mechanism of fracturing-fluid flowback under natural flowback conditions in the Lianggaoshan Formation, including clarification of the energy mechanisms governing flowback within complex fracture networks and the proposal of a staged pressure-control strategy; (2) the mechanism of gas-lift-assisted flowback, with emphasis on the effects of gas injection parameters on the tubing-casing pressure balance point and liquid unloading efficiency; and (3) the synergistic optimization of natural flowback and CO₂ gas lift, including investigation of the reservoir stimulation effects of CO₂ and the establishment of a three-stage scheme of “shut-in soaking–natural flowback–gas lift” to maximize fracturing fluid flowback efficiency.

Extensive studies have been conducted on the mechanisms and controlling factors of fracturing-fluid flowback in shale and tight reservoirs. Regarding the microscopic occurrence mechanisms, Xia H B et al. revealed through basement pore network and fracture level-set models that fracturing fluid in the rock matrix mainly exists in three forms: water-phase saturation, corner water, and water films. The flowback rate exhibits a slow–rapid–gentle trend, while retained fluid within fractures is primarily distributed in dead-end matrix pores [4]. From a molecular-scale perspective, Sun Jing attributed the strong retention of fracturing fluid in inorganic pores to van der Waals forces and hydrogen bonding. In contrast, fluid retained in organic pores was found to be more readily recovered [5].

In terms of fracture network characteristics and flowback dynamics, fracture connectivity directly determines liquid unloading efficiency. Wu et al. demonstrated that connecting secondary fractures can increase the flowback rate from 38% to 72% [6]. Wang et al. reported that natural fractures are highly stress-sensitive because they lack proppant support. Their closure therefore becomes a major cause of fracturing-fluid retention and may exert a stronger influence than capillary imbibition [7]. Liu et al. additionally found that reductions in fracture volume and uneven proppant distribution decrease water recovery efficiency and promote matrix water imbibition, whereas prolonging the shut-in period does not improve long-term gas production [8]. A flow–geomechanics coupled simulator developed by Liu et al. further revealed that matrix imbibition dominates water loss, while complex fracture geometries and natural fractures promote both fluid imbibition and retention. In addition, fracture closure and stress-coupling effects were found to be highly significant. Reservoir stress sensitivity and hydration effects are also important influencing factors. Chang Yilin found that increasing net stress leads to reductions in both permeability and flowback efficiency [9]. Chen et al. demonstrated that preferential water saturation within 2–50 nm pores aggravates the stress sensitivity of both the matrix and natural fractures and recommended that fracturing-fluid retention should be controlled below 0.5 PV [10]. Gou Xiaoyan further reported that hydration can increase shale porosity, induce microfracture generation, and consequently enhance imbibition and flowback capacity [11].

In addition, the geochemical characteristics of flowback fluids provide an important basis for identifying different flowback stages. Tian et al. classified the flowback process into three stages dominated by fracturing fluid, mixed water, and formation water according to the temporal evolution of chemical and isotopic characteristics [12]. Keimowitz et al. further warned that the acids contained in fracturing fluids may dissolve carbonates and sulfides and release trace elements, thereby posing potential long-term environmental contamination risks [13]. Moreover, flowback behavior exhibits distinct characteristics among different reservoir types. For shale gas wells, the relationship between the gas–water ratio and cumulative gas production presents a “V-shaped” trend, in which the fluid absorption capacity and fracture generation capacity of the reservoir are considered the key controlling factors [14].

In terms of flowback optimization methods and engineering technologies, the appropriate determination of shut-in timing and production plays a critical role. Zhang Tao et al. demonstrated that prolonging the shut-in period reduces both flowback efficiency and long-term gas production, whereas a high production pressure drawdown can increase cumulative gas production but may easily result in liquid loading at the bottom of hydraulic fractures [15]. Chen et al. further indicated that, with increasing permeability within the stimulated fracture network region, the optimal shut-in duration correspondingly decreases, and the two exhibit an approximately hyperbolic functional relationship [16]. Based on dynamic inversion and numerical simulation models, preliminary optimization methods for the “fracturing–shut-in–production” process parameters have been established. Liu Xiaoqiang et al. introduced dynamic relative permeability and developed a gas–water two-phase productivity model based on fracturing-fluid flowback [17]. Zhang et al. further proposed a two-phase flow model during the flowback period and established a workflow for evaluating fracture half-length, reservoir permeability, and permeability modulus [18]. Precise control of the flowback pressure differential is equally important. An appropriate pressure-control strategy can maintain a high flowback velocity and prevent the premature transition into an inefficient low-pressure liquid unloading stage [19]. Qu et al. proposed an integrated model incorporating the wellhead pressure, the critical proppant flowback velocity, and the proppant settling velocity to optimize flowback timing and choke size selection. Their results indicated that low-density fracturing fluids and smaller proppant

particle sizes are more favorable for improving flowback efficiency [20]. To address the difficulties associated with flowback in deep, low-pressure wells, Guo Xinyue developed a non-damaging gas-lift-assisted flowback technology based on downhole packers and adjacent-well gas sources [21]. CO₂-assisted flowback technology has attracted extensive attention because of its advantages in reservoir energization and viscosity reduction. Kong et al. found that CO₂ injection could increase the flowback volume by 88–97% compared with conventional water-based fracturing fluids [22]. Shen further proposed a gas-lift optimization method based on multiphase dynamic inversion and reservoir–wellbore coupling. A two-stage strategy, involving first maximizing oil production and subsequently minimizing gas injection volume, was introduced to solve the mismatch between fluid supply capacity and lifting performance in high-water-cut wells [23]. In addition, studies on the effective reutilization of flowback fluids [24], fracture-parameter identification and fracture-characteristic evaluation based on flowback and production data [25,26], and post-fracturing flowback-cleanup mechanisms [27] have provided multidimensional support for flowback analysis and process optimization.

2. Mechanism of Fracturing-Fluid Flowback Under Natural Flowback Conditions

2.1. Mechanical Mechanisms of Complex Fracture Networks in the Lianggaoshan Shale Reservoir

During hydraulic fracturing of the Lianggaoshan shale reservoir, the injection of high-pressure fluid generates microfractures within the deep formation and activates pre-existing natural fractures. After shut-in, formation pressure becomes the primary driving force for the early-stage flowback of fracturing fluid. Influenced by the development of bedding weak planes, hydraulic fracture propagation exhibits significant anisotropy and is prone to deflection and branching, thereby forming a complex fracture network through fracture crossing, deflection and branching, as illustrated in Figure 1.

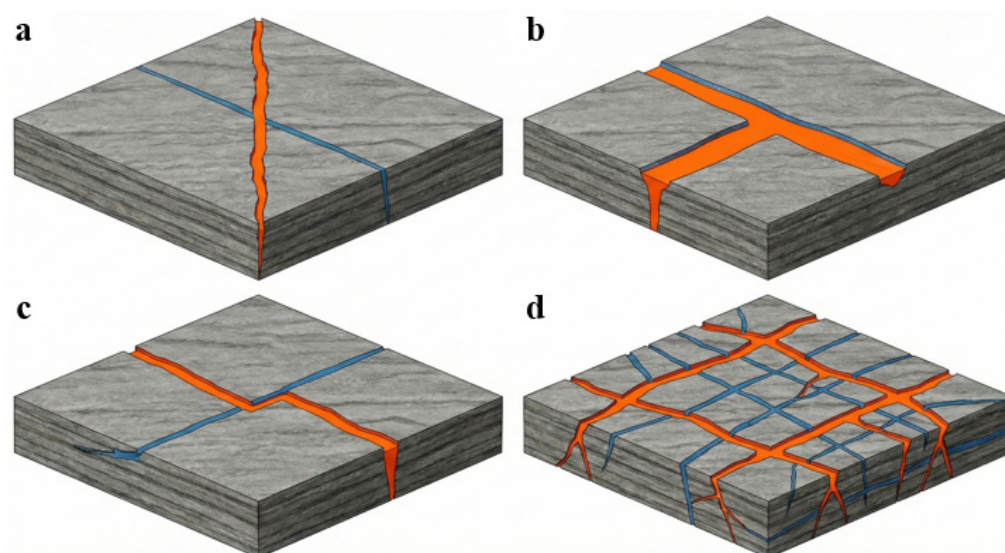


Figure 1. Schematic diagram of the interaction patterns between hydraulic fractures (blue regions) and natural fractures/bedding weak planes (orange regions): (a) direct crossing; (b) deflection and propagation along a pre-existing weak plane; (c) combined crossing, deflection, and branching; and (d) formation of a complex interconnected fracture network through repeated crossing, deflection, and branching.

Under stress boundary conditions, the stress acting on the formation units at the fracture network boundary can be expressed as follows:

$$\begin{cases} \Delta\sigma_n = P_{net} = P_{frac} - \sigma_n^{remote} \\ \Delta\sigma_s = \sigma_s^{local} - \sigma_s^{remote} \end{cases} \quad (1)$$

where

P_{frac} = fluid pressure within the fracture network, Pa;

P_{net} = net pressure within the fracture network, Pa;

σ_n^{remote} = normal stress on the fracture boundary under far-field stress conditions, Pa;

σ_s^{local} = shear stress acting on the fracture network boundary exerted by the reservoir near-field stress, Pa;

σ_s^{remote} = shear stress acting on the fracture network boundary exerted by the reservoir far-field stress, Pa.

According to the maximum circumferential stress criterion, a hydraulic fracture initiates along the direction in which the circumferential stress at the crack tip reaches a local maximum. Neglecting the higher-order terms $o(r^{-1/2})$, the leading-order stress components at any point in the near-tip region of a mixed-mode I/II crack, as illustrated in Figure 2, are expressed as follows:

$$\begin{Bmatrix} \sigma_{xx} \\ \sigma_{yy} \\ \sigma_{xy} \end{Bmatrix} = \frac{K_1}{\sqrt{2\pi r}} \begin{Bmatrix} \cos \frac{\theta}{2} \left(1 - \sin \frac{\theta}{2} \sin \frac{3\theta}{2} \right) \\ \cos \frac{\theta}{2} \left(1 + \sin \frac{\theta}{2} \sin \frac{3\theta}{2} \right) \\ \cos \frac{\theta}{2} \sin \frac{\theta}{2} \sin \frac{3\theta}{2} \end{Bmatrix} + \frac{K_2}{\sqrt{2\pi r}} \begin{Bmatrix} \sin \frac{\theta}{2} \left(-2 - \cos \frac{\theta}{2} \cos \frac{3\theta}{2} \right) \\ \sin \frac{\theta}{2} \cos \frac{\theta}{2} \cos \frac{3\theta}{2} \\ \cos \frac{\theta}{2} \left(1 - \sin \frac{\theta}{2} \sin \frac{3\theta}{2} \right) \end{Bmatrix} \quad (2)$$

where

σ_{xx} , σ_{yy} , and σ_{xy} = three principal stresses at the fracture tip within the fracture network, MPa;

r and θ = polar radius and polar angle of any point in the polar coordinate system at the fracture tip, respectively.

K_1 and K_2 are the mode-I and mode-II stress intensity factors, respectively, $\text{MPa} \cdot \text{m}^{1/2}$.

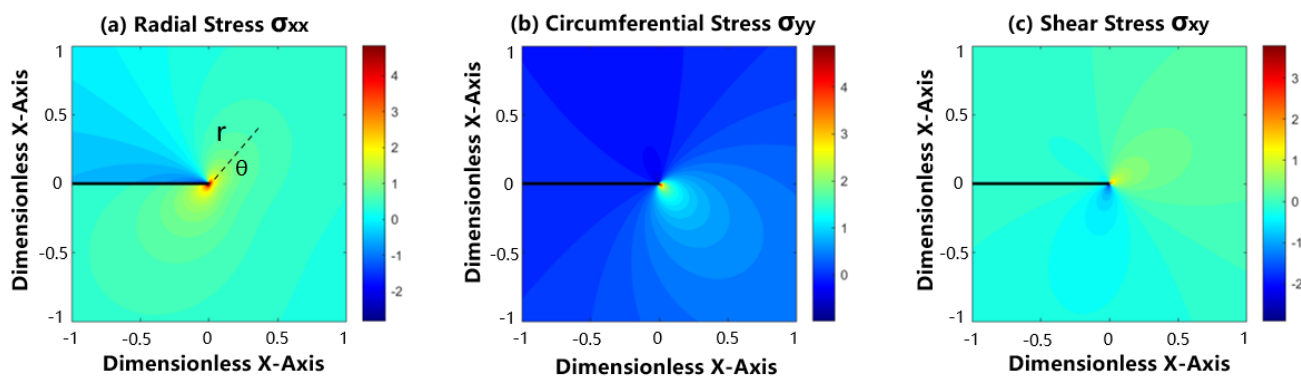


Figure 2. Contour map of the stress field distribution at the fracture tip under mixed-mode I/II loading.

To determine the crack propagation direction, the Cartesian stress components in Equation (2) are transformed into the local polar components at the crack tip. According to the maximum circumferential stress criterion, the propagation angle θ_0 must satisfy the stationary and local-maximum conditions:

$$\left. \frac{\partial \sigma_{\theta\theta}}{\partial \theta} \right|_{\theta=\theta_0} = 0, \quad \left. \frac{\partial^2 \sigma_{\theta\theta}}{\partial \theta^2} \right|_{\theta=\theta_0} < 0 \quad (3)$$

For the leading-order mixed-mode I/II crack-tip stress field, the stationary condition is equivalent to requiring the shear stress on the prospective propagation plane to vanish, i.e., $\tau_{r\theta}(\theta_0) = 0$ substitution of Equation (2) gives

$$K_1 \sin \theta_0 + K_2 (3 \cos \theta_0 - 1) = 0$$

By introducing $t = \tan\left(\frac{\theta_0}{2}\right)$, the above equation can be rewritten as

$$2K_2 t^2 - K_1 t - K_2 = 0$$

Therefore, the crack propagation angle is obtained as follows:

$$\theta_0 = \arctan\left(\frac{K_1 \pm \sqrt{K_1^2 + 8K_2^2}}{4K_2}\right) \quad (4)$$

2.2. Mechanisms Driving Fracturing-Fluid Flowback

Fracturing-fluid flowback refers to the process in which the injected fluid is lifted to the surface by reservoir stress while overcoming flow resistance. During this process, the initial formation energy and hydraulic-fracturing injection energy are redistributed into energy losses and recoverable flowback energy, as schematically illustrated in Figure 3.

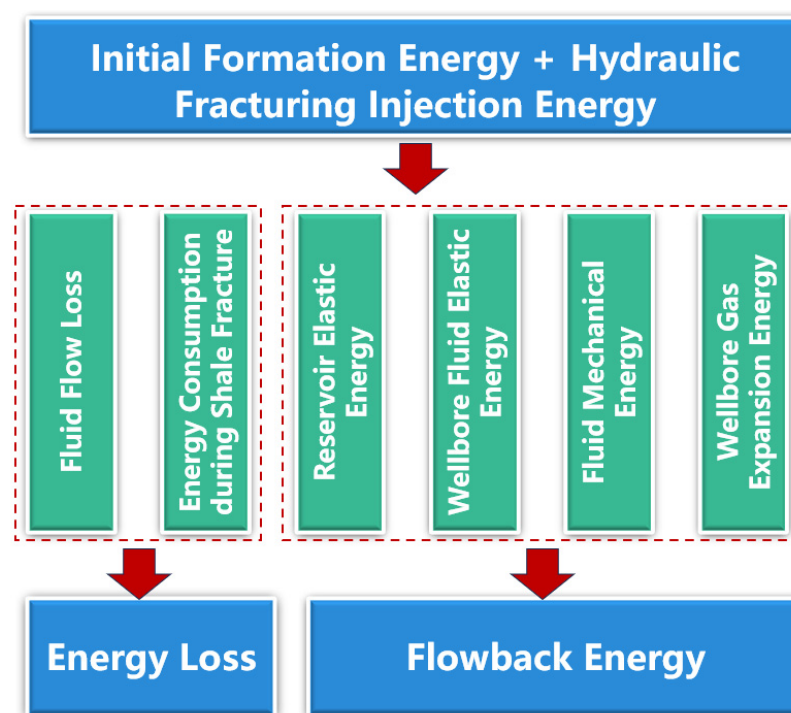


Figure 3. Energy components during fracturing-fluid flowback.

Its primary driving force originates from the release of energy stored during the hydraulic fracturing process, which mainly consists of the following three components.

(1) Reservoir Gas Expansion Energy

The energy released by the isothermal expansion of the unit gas volume in fractures is given by

$$U_g = RT(\ln p_1 - \ln p_2) = RT \ln \frac{p_1}{p_2} \quad (5)$$

where U_g is the expansion energy contained in the unit gas, J/mol; R is the universal gas constant, 8.3144 J/(mol·K); and T is the temperature of isothermal expansion, K.

(2) Fracturing-Fluid Elastic Energy and Hydromechanical Energy

The elastic potential energy of the fracturing fluid is defined as follows:

$$U_{we} = \frac{1}{2} \frac{p_{wf}^2}{E_w} \quad (6)$$

where U_{we} is the elastic potential energy per unit volume of the fracturing fluid, J/m³, and p_{wf} is the fluid pressure within the fracture, Pa. Due to the low compressibility of water in the Lianggaoshan shale oil reservoir, the fracturing fluid is typically assumed to be an incompressible fluid; consequently, the elastic energy of fracturing is frequently neglected in engineering applications.

Its hydraulic mechanical energy comprises gravitational potential energy, kinetic energy, and pressure energy:

$$U_{wh} = U_{wg} + U_{wm} + U_{wp} = gz + \frac{v^2}{2} + \frac{p_{wf}}{\rho} \quad (7)$$

where U_{wh} , U_{wg} , U_{wm} , and U_{wp} are the hydraulic mechanical energy, gravitational potential energy, kinetic energy, and pressure energy per unit volume of the fracturing fluid, respectively, J/m; g is the gravitational acceleration, m/s²; z is the relative elevation of the fracturing fluid with respect to the reference plane, m; v is the flow velocity of the fracturing fluid, m/s; and ρ is the density of the fracturing fluid, kg/m³.

(3) Elastic Energy of the Lianggaoshan Formation Shale Reservoir

Under compressive loading, the rock undergoes elastic rebound, and the elastic potential energy released per unit volume of rock is expressed as follows:

$$U_{re} = \frac{1}{2} \frac{[(\sigma_1^2 + \sigma_2^2 + \sigma_3^2) - 2\nu(\sigma_1\sigma_2 + \sigma_1\sigma_3 + \sigma_2\sigma_3)]}{E} \quad (8)$$

where U_{re} is the elastic potential energy of the Lianggaoshan shale reservoir rock per unit volume, J/m³; σ_1 , σ_2 , and σ_3 are the principal stresses in the three principal directions of the Lianggaoshan shale reservoir, Pa; ν is the Poisson's ratio of the shale reservoir rock; and E is the Young's modulus of the shale reservoir rock, Pa.

2.3. Energy Variation During Natural Flowback of Fracturing Fluids

To establish an engineering-scale energy balance for the early natural-flowback stage, the fracture network is treated as an isothermal control volume within each calculation interval. After shut-in, the confined fracture fluid is assumed to be near the formation temperature, and the surrounding rock acts as a thermal reservoir because of the large rock–fluid contact area and short pressure-update interval. Thus, heat transfer is not solved explicitly; instead, the average fracture-fluid temperature is maintained at the reservoir temperature. The control volume is open to mass exchange, with wellbore production and matrix leakoff included in the subsequent volume-balance equations, while compositional enthalpy transport is neglected. The retained energy terms are the gas expansion energy, fluid hydromechanical energy, and elastic energy released by the reservoir rock. This isothermal assumption applies only to the fracture-scale natural-flowback energy balance; the non-isothermal wellbore temperature profile is calculated separately in Section 3.2.2. Throughout the entire flowback process, the difference between the initial injected energy

at the surface and the final residual energy in the formation is defined as the total work driving fracturing-fluid flowback (E):

$$E = W_g + W_w + W_r \quad (9)$$

where W_g , W_w , and W_r represent the work associated with gas expansion in the wellbore during the flowback process, the hydraulic mechanical work of the fluid, and the elastic energy work of the reservoir rock, respectively, J.

According to the thermodynamic equation of state and the law of energy conservation, the three driving work terms can be expressed as follows:

(1) Work Done by Gas Expansion Energy W_g

$$W_g = 12194 \times \frac{G_p}{T_s} RT_i \ln \frac{p_{wf}}{p_0} + \left(0.1203 \times \frac{p_{wfi} V_{gi}}{T_i} - 12194 \times \frac{G_p}{T_s} \right) RT_i \ln \frac{p_{wfi}}{p_{wf}} \quad (10)$$

Here, the coefficient 12,194 is the rounded engineering conversion coefficient derived from p_s/R , where $p_s = 0.101325 \text{ MPa} = 101,325 \text{ Pa}$. Together with the term G_p/T_s , it converts the gas volume measured under standard conditions into the corresponding molar amount. The coefficient 0.1203 is the rounded value of $1/R$, where $R = 8.3144 \text{ J}/(\text{mol} \cdot \text{K})$. Therefore, Equation (9) is evaluated using pressure in Pa, volume in m^3 , temperature in K, and work in J and is applicable to isothermal gas expansion under the ideal-gas approximation at the adopted standard conditions of $p_s = 0.101325 \text{ MPa}$ and $T_s = 288.71 \text{ K}$.

(2) Work Done by Hydraulic Mechanical Energy W_w

Taking the average height of the reservoir fractures as the reference datum for hydraulic calculations, the variation in gravitational potential energy is neglected:

$$W_w = V_{wi} \left(\frac{v_i^2 - v^2}{2} + \frac{p_{wfi} - p_{wf}}{\rho} \right) + W_p \left(\frac{v^2}{2} + \frac{p_{wf}}{\rho} \right) \quad (11)$$

(3) Work Done by Rock Elastic Energy W_r

During the flowback stage, the elastic expansion of the rock causes the fractures to gradually close, and the work performed on the fluid within the fractures can be expressed as

$$W_r = V_{fi} \int c_f p_{wf} dp_e \quad (12)$$

where p_{wfi} and p_{wf} are the initial and current fluid pressures, respectively, Pa; V_{gi} , V_{wi} and V_{fi} are the initial gas, fluid, and fracture volumes, respectively; V_{fi} and v are the initial and current velocities, respectively; ρ is the fracturing-fluid density; and c_f is the rock compressibility coefficient.

The flow behavior and flow-rate distribution during the flowback process are expressed as follows:

Driven by the energy release described above, the fracturing fluid flows through the fracture network toward the wellbore. Each fracture branch is idealized as a locally parallel-plate channel (Figure 4), and the laminar-flow relationship is applied when the fracture Reynolds number, $Re_f = \frac{\rho u D_h}{\mu}$, remains within the viscous-dominated regime, where $D_h \approx 2w$ is the hydraulic diameter of a fracture with aperture w . This approximation is supported by the small fracture aperture, the controlled pressure drawdown, and the division of the total flow rate among multiple fracture branches, which limit the velocity and inertial contribution within an individual fracture. The resulting relationship is therefore used to reproduce the network-scale pressure–flowback trend. Roughness-induced and

inertial non-Darcy effects that may occur during short periods of high-rate flowback are not explicitly resolved. This assumption applies only to fracture flow, whereas gas–liquid flow in the wellbore is calculated separately using the multiphase-flow model described in Section 3.2. Applying fluid mass conservation, the flow rate q is given by

$$q = -\frac{w^3 h}{12u} \frac{dp}{dx} \quad (13)$$

$$\frac{\partial q(x, t)}{\partial x} - q_L(x, t) = \frac{\partial A(x, t)}{\partial t} \quad (14)$$

where w , h , and A are the fracture width, height, and cross-sectional area, respectively, and q_L is the fracturing-fluid leakoff rate.

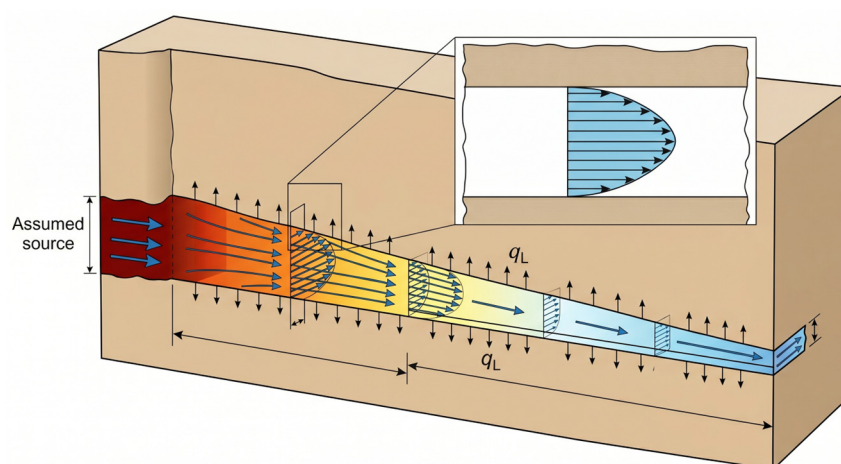


Figure 4. Fluid flow distribution in a single fracture.

According to Kirchhoff's second law and Bernoulli's equation, the total fluid injection rate Q_{Tot} is the sum of the flow rates in individual branch fractures Q_i , and the bottomhole pressure must overcome the perforation friction and wellbore friction:

$$p_0 = p_{w,i} + p_{pf,i} + p_{cf,i} (i = 1, 2, 3, \dots, m) \quad (15)$$

where the pressure drop models for the perforation friction $p_{pf,i}$ and the wellbore friction $p_{cf,i}$ are as follows:

$$p_{pf,i} = \frac{0.2369 \rho_s}{n_{p,i}^2 d_{p,i}^4 C_{d,i}^2} Q_i^2 \quad (16)$$

$$p_{cf,i} = C_{cf} \sum_{j=1}^i (x_i - x_j) Q_{w,j} \quad (17)$$

where $d_{p,i}$, $n_{p,i}$, and $C_{p,i}$ are the perforation diameter, the number of perforations, and the perforation correction coefficient, respectively; C_{cf} is the friction coefficient; and x_i is the fracture spacing.

2.4. Development of the Fracturing-Fluid Flowback Model

The flowback calculation is initialized at pump shutdown, after the principal hydraulic-fracture growth stage has been completed. The fracture-network planform and fracture length are prescribed at this time and remain fixed during flowback, whereas the fracture aperture decreases as a result of pressure-dependent closure and fluid leakoff. Accordingly, no new crack initiation, branching, or extension is calculated after shut-in. The model therefore predicts flowback from a prescribed stimulated fracture network rather than the

hydraulic-fracture growth process itself. Based on volume conservation during forced closure, the reduction in fracture volume is equal to the sum of the leakoff volume and cumulative flowback volume:

$$\Delta V_f = \Delta V_{ls} + \Delta V_{out} \quad (18)$$

After the surface pumping unit stops, the reduction in fracture volume, the cumulative flowback volume after flowback time t and the filtrate volume of the fracturing fluid after flowback time t are given, respectively, by

$$\Delta V_f = \Delta V(t_1, t) = \frac{\pi}{4} H_f L_f (W_p - W) \quad (19)$$

$$V_{ls}(t_1, t) = \pi C L_f H_p \sqrt{t_{inj}} G(t_1, t) \quad (20)$$

$$\Delta V_{out} = \frac{1}{2} c' V_{out} = \frac{1}{2} \sum_0^t c'(t) q(t) dt \quad (21)$$

Finally, the wellhead pressure expression at the beginning of the flowback stage is obtained as follows:

$$\frac{\pi}{4} H_f L_f (W_p - W) = \pi C L_f H_p \sqrt{t_{inj}} G(t_1, t) + \frac{1}{2} \sum_0^t c' q(t) dt \quad (22)$$

where

ΔV_f = reduction in fracture volume, m³;

ΔV_{ls} = filtrate volume of the fracturing fluid after flowback time, m³;

V_{out} = cumulative flowback volume after flowback time t , m³;

ΔV_{out} = cumulative flowback volume after the flowback period, m³;

t_p = pumping time of the fracturing fluid, min;

t = flowback time of the fracturing fluid, min;

W_p = fracture width at the start of flowback, m;

W = fracture width after flowback time t , m;

H_f = fracture height, m;

L_f = prescribed fracture length at pump shutdown, m;

C = overall leakoff coefficient of the fracturing fluid, m/min^{0.5};

β_s = ratio of the pressure inside the fracture to the bottomhole pressure, dimensionless;

P_{ISIP} = wellhead pressure after pump shutdown, MPa;

c' = effective compressibility of the fracturing fluid, dimensionless.

2.5. Solution Method for the Flowback Model

Because the fracture length is held constant during flowback, the time-dependent leakoff history is evaluated using the Carter leakoff formulation and the Nolte G-function. The leakoff volume over the considered time interval is therefore given by Equation (19): where

$$G(t_1, t) = \frac{4}{\pi} [g(t) - g(t_1)] \quad (23)$$

$$g(t) = \frac{2}{3} \left[(1 + t_D)^{\frac{3}{2}} - t_D^{\frac{3}{2}} \right] + \frac{1}{2} \left[(1 + t_D) \sin^{-1}(1 + t_D)^{\frac{1}{2}} + t_D^{\frac{1}{2}} \right] \quad (24)$$

$$t_D = \frac{t - t_{inj}}{t_{inj}} \quad (25)$$

Substituting Equation (24) into Equation (23) yields the following:

$$g(t) = \frac{2}{3} \left[\left(1 + \frac{t-t_{inj}}{t_{inj}} \right)^{\frac{3}{2}} - \left(\frac{t-t_{inj}}{t_{inj}} \right)^{\frac{3}{2}} \right] + \frac{1}{2} \left[\left(1 + \frac{t-t_{inj}}{t_{inj}} \right) \sin^{-1} \left(1 + \frac{t-t_{inj}}{t_{inj}} \right)^{\frac{1}{2}} + \left(\frac{t-t_{inj}}{t_{inj}} \right)^{\frac{1}{2}} \right] \quad (26)$$

Substituting Equation (25) into Equation (22) gives the following:

$$G(t_1, t) = \frac{4}{\pi} \left\{ \begin{aligned} & \frac{2}{3} \left[\left(1 + \frac{t-t_{inj}}{t_{inj}} \right)^{\frac{3}{2}} - \left(\frac{t-t_{inj}}{t_{inj}} \right)^{\frac{3}{2}} \right] \\ & + \frac{1}{2} \left[\left(1 + \frac{t-t_{inj}}{t_{inj}} \right) \sin^{-1} \left(1 + \frac{t-t_{inj}}{t_{inj}} \right)^{\frac{1}{2}} + \left(\frac{t-t_{inj}}{t_{inj}} \right)^{\frac{1}{2}} \right] \\ & - \frac{2}{3} \left[\left(1 + \frac{t_1-t_{inj}}{t_{inj}} \right)^{\frac{3}{2}} - \left(\frac{t_1-t_{inj}}{t_{inj}} \right)^{\frac{3}{2}} \right] \\ & + \frac{1}{2} \left[\left(1 + \frac{t_1-t_{inj}}{t_{inj}} \right) \sin^{-1} \left(1 + \frac{t_1-t_{inj}}{t_{inj}} \right)^{\frac{1}{2}} + \left(\frac{t_1-t_{inj}}{t_{inj}} \right)^{\frac{1}{2}} \right] \end{aligned} \right\} \quad (27)$$

Finally, the following expression is obtained:

$$P_w(t_1) = P_w(t) - \frac{3E}{2\pi(1-\gamma^2)L_f H_w^2 \beta_s} \left[\frac{1}{2} c' q t + \pi C L_f H_p \sqrt{t_{inj}} G(t_1, t) \right] \quad (28)$$

where

$P_w(t)$ = bottomhole pressure after flowback time t , MPa;

E = Young's modulus, MPa;

γ = Poisson's ratio of the reservoir shale, dimensionless;

L_f = fracture length in the reservoir, m;

H_w = designed fracture height, m.

2.6. Calculation of Flowback Volume

The flowback of the fracturing fluid in the wellbore and the wellhead choke is considered a one-dimensional flow, which remains relatively stable throughout the entire flowback process. Therefore, according to Bernoulli's equation, the flow velocity of the fracturing fluid in the choke can be expressed as

$$v = 7.44 \times 10^4 \rho^{-0.5} \left[1 + 0.5 \left(1 - \frac{r^2}{R^2} \right) + \xi \right]^{-0.5} [P(t) - 0.1]^{0.5} \quad (29)$$

From the above velocity equation, the flowback rate $q(t)$ and the cumulative flowback volume V_{out} can be obtained as follows:

$$q(t) = 7.44 \times 10^4 \frac{\pi}{4} r^2 \rho^{-0.5} \left[1 + 0.5 \left(1 - \frac{r^2}{R^2} \right) + \xi \right]^{-0.5} [P(t) - 0.1]^{0.5} \quad (30)$$

$$V_{out} = \int_0^t 186 \times 10^4 \pi r^2 \rho^{-0.5} \left[1 + 0.5 \left(1 - \frac{r^2}{R^2} \right) + \xi \right]^{-0.5} [P(t) - 0.1]^{0.5} dt \quad (31)$$

where

ρ = density of the fracturing fluid, kg/m³;

ξ = choke loss coefficient, dimensionless;

r = choke radius, m;

R = wellbore radius, m;

$P(t)$ = wellhead pressure at time t during the flowback process, MPa.

As can be seen from the cumulative flowback volume expression, the nonlinear function involved is the wellhead pressure. To improve the overall calculation accuracy,

the composite trapezoidal rule is applied to discretize the cumulative flowback equation for computing V_{out} during the flowback process, yielding

$$V_{out}^n = \frac{\Delta t_o}{2} \left[(p(t_o) - 0.1)^{0.5} + (p^n - 0.1)^{0.5} + 2 \sum_{i=1}^{n-1} (p^i - 0.1)^{0.5} \right] N \quad (32)$$

in which

$$N = 1.86 \times 10^4 \pi r^2 \rho^{-0.5} \left[1 + 0.5 \left(1 - \frac{r^2}{R^2} \right) + \xi \right]^{-0.5} \quad (33)$$

where

$P(t_0)$ = wellhead pressure at the start of flowback, MPa;

Δt_0 = time step, min;

n = index corresponding to time t_n .

The wellhead pressure at each time step is obtained by iteratively solving the pressure model with the Newton–Simpson method. The resulting pressure sequence is then used to characterize the temporal variation in wellhead pressure during flowback.

3. Study on Mechanisms and Parameters of Gas-Lift Flowback for Fracturing Fluids

3.1. Basic Simulation Parameters, Numerical Settings, and Boundary Conditions

The 30-day simulation period was selected as a practical first-month engineering evaluation window rather than the physical endpoint of flowback. It covers the complete sequence of CO₂ soaking, controlled natural flowback, transition to CO₂ gas lift, and the subsequent stabilization of gas-lift-assisted unloading. For Well H1, gas lift was initiated on day 16, allowing approximately two weeks to evaluate its sustained effect and providing a consistent basis for comparing different flowback strategies. To improve the reproducibility of the calculations, the wellbore geometry, reservoir and fluid properties, operating boundaries, and numerical-control settings used in the gas-lift start-up calculation and the stagewise quasi-steady PIPESIM calculations are summarized in Table 1. Unless otherwise stated, the same wellbore and fluid-property settings were used in all cases. The comparison shown in Figure 5 used identical initial and boundary conditions, and the only difference was the presence or absence of the gas-lift valve.

Table 1. Basic parameters and boundary conditions used in the simulations.

Parameter Category	Parameter	Symbol	Value	Unit
Wellbore geometry	Measured well depth	H	5250	m
	Tubing inner diameter	Dt	62	mm
	Casing inner diameter	Dc	108.62	mm
Gas-lift system	Gas-lift valve installation depth	Hv	2000	m
Reservoir condition	Initial formation pressure	$P_{r,0}$	26.6	MPa
	Formation temperature	Tr	170.93	°C
	Productivity index	J	10.0	m ³ ·d ^{−1} ·MPa ^{−1}
Fluid property	Crude oil density	ρ_o	896.7	kg·m ^{−3}
	Crude oil viscosity	μ_o	5.67	mPa·s
	Gas–oil ratio	R _p	1000	m ³ ·m ^{−3}
	Water cut	f _w	90	%
	Gas relative density	γ_g	1.52	-
Surface boundary	Wellhead pressure	p _{wh}	6.0	MPa
Gas injection boundary	Gas injection pressure	P _{inj}	12.0	MPa
	Gas injection rate	Q _{inj}	8.0 × 10 ⁴	m ³ ·d ^{−1}

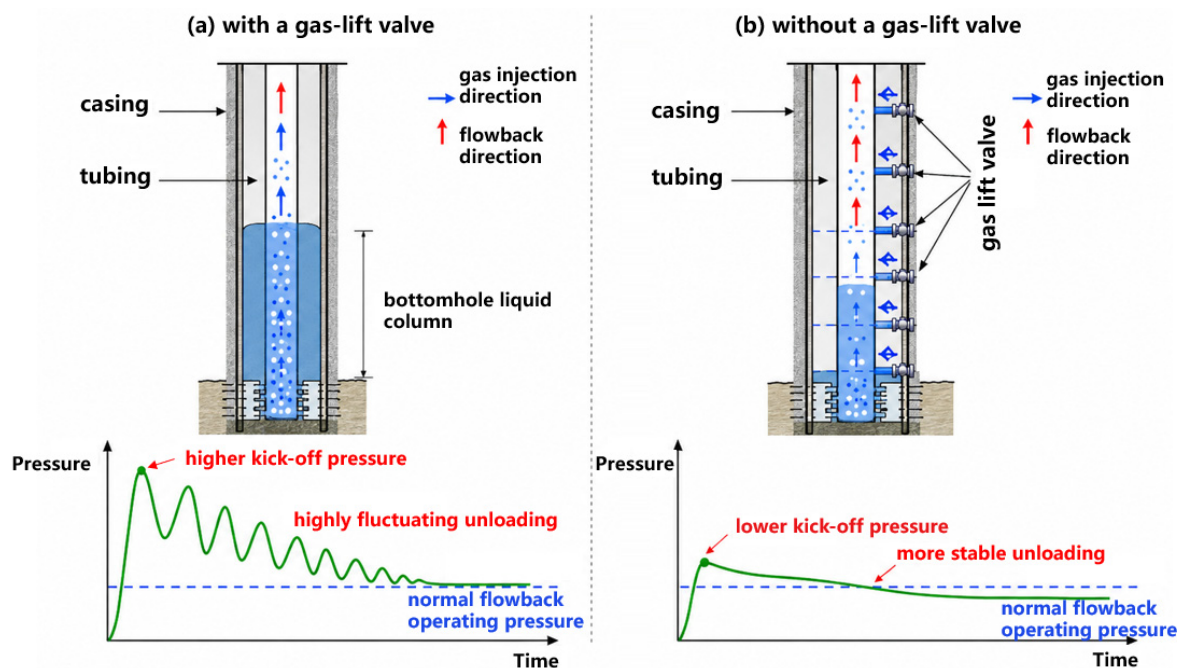


Figure 5. Comparison of the gas-lift kick-off process with and without a gas-lift valve.

For the Well H1 reference case, the treatment fluid was represented as a water-based CO₂-energized system rather than an oil-based fluid. The aqueous phase served as the carrier for proppant and treatment additives, whereas CO₂ was treated as the energizing gas phase. The present model does not resolve individual additive concentrations or shear-dependent rheology; instead, the aqueous phase is treated as an incompressible bulk liquid. The production-fluid model uses a water cut of 90%, a crude oil density of 896.7 kg/m³, and a crude oil viscosity of 5.67 mPa·s. Accordingly, the viscosity-reduction mechanism discussed below refers to CO₂–oil mass transfer and the associated reduction in crude oil viscosity, rather than direct thinning of the aqueous fracturing-fluid phase.

The initial tubing and annulus pressure profiles were established from the hydrostatic equilibrium using the specified fluid properties and wellbore temperature profile. The lower boundary was defined by the reservoir inflow relationship, with an initial reservoir pressure of 26.6 MPa and a productivity index of 10.0 m³·d^{−1}·MPa^{−1}. The upper production boundary was specified by the wellhead pressure. At the annulus inlet, the CO₂ injection rate was imposed, while 12 MPa was treated as the available surface injection-pressure constraint. The gas-lift valve at a measured depth of 2000 m provided hydraulic communication between the annulus and tubing when the local annulus pressure exceeded the tubing pressure and the valve-opening differential.

The full-cycle calculation was implemented as a sequence of stagewise operating states rather than as a fully coupled hydraulic-fracture propagation simulation. The reservoir pressure, water cut, gas–oil ratio, and operating conditions were updated at each calculation interval, and the converged solution from the preceding state was used to initialize the subsequent state. Wellbore geometry, tubing and casing dimensions, and the basic fluid-property model remained unchanged unless they were explicitly varied in the sensitivity analysis.

The Lianggaoshan shale oil reservoir is characterized by low natural energy. During the late stage of natural flowback of the fracturing fluid, problems such as declining wellhead pressure, increasing wellbore liquid holdup, and insufficient liquid unloading capacity frequently occur. If solely relying on natural flow, the fracturing fluid trapped in distal microfractures cannot be discharged in a timely manner. If swabbing or pump-

assisted lifting is adopted, it requires the tubing string to be tripped again, leading to a long operation period and the risk of secondary formation damage. Therefore, introducing gas-lift flowback after the depletion of natural flow energy is an important technical measure to improve the fracturing-fluid flowback rate and shorten the liquid drainage period. Figure 5 visually presents the two operating conditions with and without the use of a gas-lift valve. Figure 5 compares gas-lift kick-off with and without a gas-lift valve. Installing the valve reduces the required kick-off pressure and stabilizes the unloading process.

3.2. Calculation of Gas-Lift-Related Parameters

3.2.1. Multiphase Flow in the Wellbore

Gas-lift flowback injects high-pressure gas into the annulus. The injected gas reduces the density of the mixed fluid in the tubing and lowers the bottomhole flowing pressure. This creates a favorable pressure gradient for lifting the fracturing fluid. The tubing–casing equilibrium point is a key parameter in gas-lift design, defined as the depth at which the pressure in the tubing equals the pressure in the tubing–casing annulus. A greater gas-lift injection depth is more conducive to reducing the bottomhole flowing pressure and mobilizing the deeply trapped fluid. For each discretized wellbore segment, the local multiphase pressure gradient can be expressed as follows:

$$\frac{\Delta p_l}{\Delta h_l} = \rho g + \frac{\varepsilon V_l^2 M^2}{1.234 D^5 \rho_l} + \frac{\rho_l \Delta \left(\frac{V_{hl}^{-1}}{2} \right)}{\Delta h} \quad (34)$$

where

Δh_l = height difference, m;

Δp_l = fluid pressure differential across the height difference, MPa;

ρ_l = mixed fluid density, kg/m³;

ε = local effective friction factor of the gas–liquid mixture, dimensionless;

V_l = liquid unloading rate, m³/s;

M = gas–liquid ratio, kg/m³;

D = pipe diameter, m;

V_{hl} = mixed fluid velocity, m/s.

In Equation (33), ε denotes the dimensionless local effective friction factor rather than a constant resistance parameter. It is updated for each wellbore segment according to the adopted multiphase-flow model and the local pressure, temperature, fluid properties, and phase fractions, and the resulting segmental pressure drops are accumulated to determine the bottomhole flowing pressure.

3.2.2. Temperature Parameters

During the gas-lift flowback of the fracturing fluid, the temperature of the fluid inside the wellbore is not constant. As the fluid is lifted from the bottom to the wellhead, formation heat is also carried out by the fluid. The formation temperature decreases toward the wellhead, while the fluid density, viscosity, and gas–liquid phase volume are temperature sensitive. Therefore, a steady-state heat-transfer model is used to calculate the wellbore temperature profile. The model accounts for wellbore heat transfer, changes in multiphase-fluid properties, and wellbore geometry. The temperature profile obtained from Equations (34) and (35) was transferred to the pressure–volume–temperature (PVT) calculation for each discretized wellbore segment. Consequently, the phase densities, viscosities, gas compressibility factors, and phase volume fractions used in the pressure-drop calculation were updated according to the local pressure and temperature. The density

values listed in the parameter tables were therefore used only as reference-state inputs for initializing the fluid-property model:

$$T_{jzl} = T_{jdl} - g_T \left(Z - A \left(1 - e^{-\frac{Z}{A}} \right) \right) \quad (35)$$

$$A = C_0 w_t^{C_1} \rho_{hj}^{C_2} R_g^{C_3} P_{jk}^{C_4} \rho_{fp}^{C_5} \rho_q^{C_6} \quad (36)$$

where

T_{jdl} = bottomhole fluid temperature, °C;

T_{jzl} = fluid temperature at depth Z in the well, °C;

R_g = tubing inner diameter, mm;

P_{jk} = wellhead pressure, Pa;

ρ_{hj} = mixed fluid density in the wellbore, kg/m³;

ρ_{fp} = flowback fluid density, kg/m³;

ρ_q = gas relative density;

$C_0, C_1, C_2, C_3, C_4, C_5, C_6$ are dimensionless coefficients, and their values are listed in Table 2 below.

Table 2. Parameter values.

C_0	C_1	C_2	C_3	C_4	C_5	C_6
$e^{-5.065}$	0.4882	2.915	0.3476	0.2219	0.2519	4.724

3.2.3. Gas Pressure Parameters

Since only injection gas is present in the wellbore annulus, the annulus contains a single-phase fluid, and the injection pressure is therefore the single-phase gas pressure. The single-phase gas pressure is calculated using the average deviation factor method:

$$P_q(x) = P_{zq} e^{h_{jk} P} \left(\frac{\rho_q g x T_{bz}}{P_{bz} T_x Z_x} \right) \quad (37)$$

where

h_{jk} = depth measured from the wellhead, m;

g = gravitational acceleration, 9.8 m/s²;

T_{bz} = gas temperature in the injection well under standard conditions, K;

P_{bz} = gas pressure under standard conditions, MPa;

ρ_q = gas density under standard conditions, kg/m³;

T_x = average temperature of the segment of interest, °C;

Z_x = gas compressibility factor at the average temperature and pressure, dimensionless;

P_{zq} = pressure at the gas injection point, MPa;

P_q = gas pressure at depth x , MPa.

From Equation (36), the annulus pressure P_{hk} at various well depths can be obtained.

The tubing–casing equilibrium point is determined starting from the wellhead. At depth l_i , the tubing pressure P_{jt} is compared with the annulus pressure P_{hk} . When $P_{jt} > P_{hk}$, the depth of the equilibrium point Y_x is calculated as follows:

$$Y_x = Y_{x-1} + \frac{(Y_x - Y_{x-1})(P_{jt-1} - P_{hk-1})}{P_{hk} - P_{jt} - P_{hk-1} + P_{jt-1}} \quad (38)$$

where $Y_x = Y_{x-1} + \Delta Y$, and ΔY is the calculation step length.

It follows from the above formulas that the depth of the tubing–casing equilibrium point is influenced by the gas injection rate, gas injection pressure, wellhead pressure, gas injection density, and other factors.

3.3. Calculation of Fracturing-Fluid Flowback

During the flowback of fracturing fluid, the fluids above and below the gas injection point are different, and the relationship between the fluid flow velocity in the wellbore and the bottomhole pressure is given by

$$v = 7.5 \times 10^4 \rho^{-0.5} \left[1 + 0.5 \left(1 + \frac{r^2}{R^2} \right) + \varphi \right]^{-0.5} [P(t) - 0.1]^{0.5} \quad (39)$$

Because both pressure and temperature vary along the wellbore, the density term in Equation (38) was not evaluated using constant liquid- and gas-phase densities. Above the gas injection point, the tubing contains a gas–liquid mixture, whereas the section below the injection point remains liquid dominated. The equivalent density of the fluid column is therefore calculated as follows:

$$\rho_l = \frac{1}{H_{js}} \left\{ \int_0^{H_{zq}} \left[(1 - G(z)) \rho_{fpl}(p(z), T(z)) + G(z) \rho_{zrg}(p(z), T(z)) \right] dz + \int_{H_{zq}}^{H_{js}} \rho_{fpl}(p(z), T(z)) dz \right\}$$

where ρ_l is the depth-averaged density of the fluid column in the tubing, kg/m³; $\rho_{fpl}(p, T)$ is the local density of the flowback liquid, kg/m³; $\rho_{zrg}(p, T)$ is the local density of the injected gas, kg/m³; H_{js} is the total well depth, m; H_{zq} is the gas injection depth, m; and $G(z)$ is the local gas volumetric fraction above the gas injection point.

For the water-dominated flowback liquid, the local liquid density is evaluated from the pressure- and temperature-dependent water and oil densities:

$$\rho_{fpl}(p, T) = f_w \rho_w(p, T) + (1 - f_w) \rho_o(p, T)$$

where f_w is the local water volume fraction. The injected-gas density is calculated from the real-gas relationship:

$$\rho_{zrg}(p, T) = \frac{p M_g}{Z(p, T) R T}$$

where M_g is the gas molar mass, $Z(p, T)$ is the gas compressibility factor, and R is the universal gas constant. Thus, the thermal expansion of both the liquid and gas phases, together with the temperature-induced variation in gas holdup, is included in the hydrostatic-pressure calculation.

3.4. Determination of Gas Injection-Point Depth

The tubing–casing equilibrium point was determined by marching downward from the wellhead using discretized wellbore segments. For each segment, the temperature $T(z)$ obtained from Equations (34) and (35), together with the current segment pressure, was used to update ρ_{fpl} , ρ_{zrg} , and the local gas volumetric fraction. The tubing and annulus pressure profiles were then accumulated using Equations (33) and (36), respectively, and the depth at which the tubing pressure equaled the annulus pressure was interpolated using Equation (37). A prescribed working-pressure differential was subsequently applied above the equilibrium point to determine the final gas injection depth.

For Well H1, the thermal boundary varied from 15 °C at the wellhead to 170.93 °C at a depth of 5250 m. A preliminary sensitivity calculation was conducted by fixing the PVT-calculation temperature at 15 °C while retaining the local pressure dependence and all other operating parameters. Compared with the isothermal case, the coupled

pressure–temperature calculation decreased the depth-averaged tubing-fluid density by approximately 5.5%, reduced the calculated hydrostatic pressure at 5250 m by approximately 1.8 MPa, and shifted the tubing–casing equilibrium point from approximately 2000 m to 2160 m. These results indicate that the accumulated effect of fluid thermal expansion cannot be neglected in the gas-lift calculation. Therefore, all subsequent calculations were performed using pressure- and temperature-dependent phase properties.

3.5. Analysis of the Effect of Gas Injection on Fracturing-Fluid Flowback

Figure 6 shows the variation in the fracturing-fluid flowback rate with wellhead pressure under different gas injection rates. The flowback rate exhibits an approximately linear decreasing trend with increasing wellhead pressure. This phenomenon arises because a higher wellhead pressure reduces the pressure differential between the wellhead and the bottomhole. According to Darcy’s law, a decrease in the pressure differential across the tubing string leads to a reduction in fluid flow velocity, i.e., a decline in the fracturing-fluid flowback rate. At a high gas injection rate ($12 \times 10^4 \text{ m}^3/\text{d}$), the slope of the curve is smaller, indicating that increasing the gas injection rate can, to some extent, mitigate the impact of rising wellhead pressure. When the wellhead pressure exceeds 1.5 MPa, further increases in the gas injection rate result in a noticeably slower growth in the flowback rate.

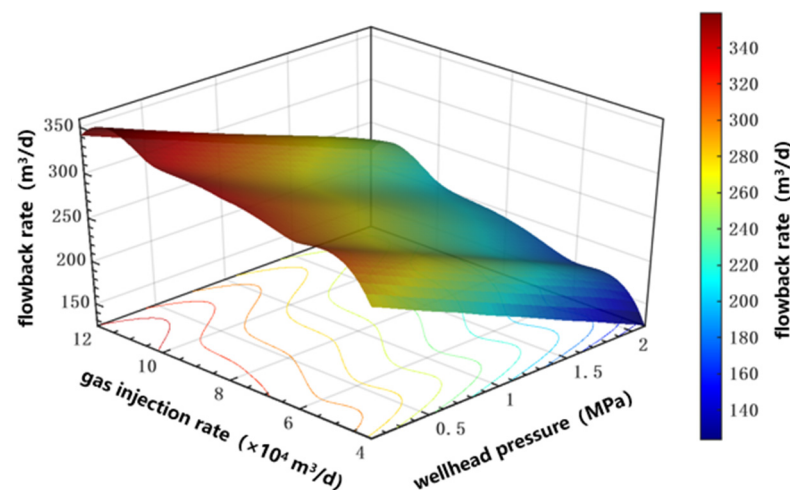


Figure 6. Variation in flowback rate with wellhead pressure under different gas injection rates.

Figure 7 shows the variation in the flowback rate with the gas injection rate under different wellhead pressures. At a low wellhead pressure (0.1 MPa), the most pronounced change in the flowback rate occurs earlier, and the peak flowback rate is significantly higher than that under higher wellhead pressures (1–2 MPa). Consequently, as the wellhead pressure increases, the gas injection rate required to achieve the same flowback rate also rises substantially. This indicates that under higher wellhead pressures, the effectiveness of the gas-lift flowback of fracturing fluid is markedly reduced. For the case studied in this paper, it is recommended that the wellhead pressure be controlled at a relatively low level (0.5 MPa) for optimal results.

Figure 8 illustrates the variation in the fracturing fluid flowback rate with gas injection pressure under different gas injection rates. Overall, the flowback rate increases continuously with increasing gas injection pressure. However, when the gas injection pressure exceeds 12 MPa, the growth rate of the flowback rate curves under different gas injection rates declines significantly. At injection pressures of 7–12 MPa, the flowback rate increases markedly. Higher injection pressure shifts the tubing–casing equilibrium point and the gas injection point downward. This extends the effective gas-lift length and reduces the

hydrostatic pressure in the tubing. Above 12 MPa, the incremental benefit of further pressure increase diminishes. At low injection rates, increasing pressure alone produces only a limited improvement; therefore, a sufficiently high injection rate is required to realize the full benefit of gas injection. For the target well, the recommended injection pressure is 12 MPa.

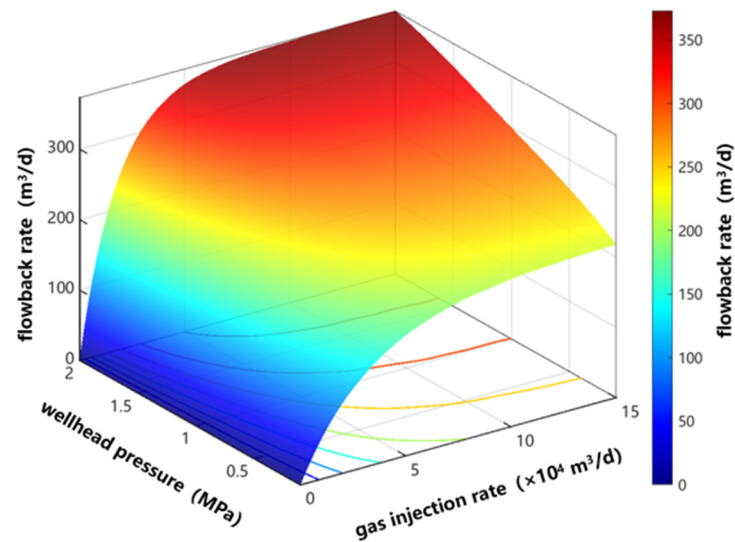


Figure 7. Variation of flowback rate with gas injection rate at different wellhead pressures.

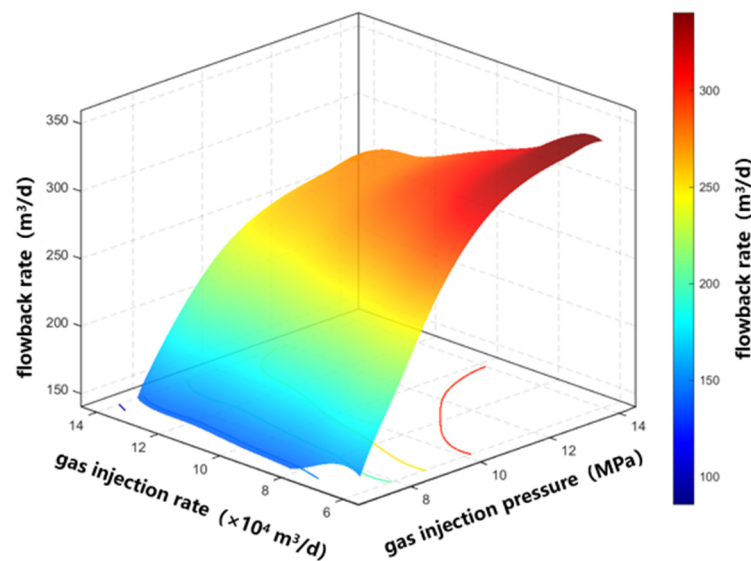


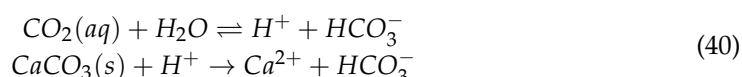
Figure 8. Variation in flowback rate with gas injection pressure under different gas injection rates.

Based on the comprehensive simulation results, the recommended operating conditions for Well H1 are a gas injection pressure of 12 MPa, a gas injection rate of 8×10^4 – 10×10^4 m³/d, and a wellhead backpressure below 0.5 MPa. The incremental improvement in the flowback rate becomes limited when the injection rate exceeds 8×10^4 m³/d. Therefore, 10×10^4 m³/d is treated as a simulation-based operating upper bound rather than a universal erosion threshold. For engineering screening, API RP 14E defines the erosional velocity as $v_e = 1.22C/\sqrt{\rho_m}$, where v_e is expressed in m/s, ρ_m is the local gas–liquid mixture density in kg/m³, and $C = 100$ is commonly adopted for continuous solids-free service. Because the present model does not resolve the gas-lift valve port geometry or the concentration and size distribution of entrained solids, a unique valve-scale critical velocity cannot be determined from the available inputs. Before field

implementation, the maximum local velocities at the gas-lift valve outlet and tubing outlet should be extracted from the PIPESIM profile and checked against the API RP 14E screening value and the allowable limits specified by the valve manufacturer. A dedicated particle-erosion assessment is required when a proppant or sand is present.

4. Synergistic Optimization of Natural Flow and Gas Lift for Fracturing Fluids

The CO₂-assisted scheme involves both wellbore-scale hydraulic effects and reservoir-scale physicochemical interactions. The reductions in wellbore mixture density, hydrostatic pressure gradient, and bottomhole flowing pressure are explicitly calculated in the gas-lift model. In the aqueous phase, dissolved CO₂ promotes calcite dissolution through



Under surface-reaction-controlled conditions, the calcite dissolution flux may be approximated as follows:

$$r_{\text{cal}} = k_{\text{H}}(T)a_{\text{H}^+} + k_{\text{CO}_2}(T)a_{\text{CO}_2(\text{aq})} \quad (41)$$

For calcite exposed on both fracture walls, the corresponding aperture increment can be estimated by

$$\Delta b(t) = 2f_{\text{cal}} \frac{M_{\text{cal}}}{\rho_{\text{cal}}} \int_0^t r_{\text{cal}}(\tau) d\tau \quad (42)$$

The viscosity-reduction effect discussed in this study refers to CO₂ dissolution and mass transfer into the crude oil phase, which can reduce crude oil viscosity and improve oil-phase mobility [28]. Calcite dissolution is supported by established CO₂–brine–carbonate reactions and published experimental studies [29], although its contribution depends on reservoir mineralogy, brine composition, and the reactive surface area. In the present model, mitigation of water blocking is primarily attributed to the reduction in bottomhole flowing pressure and the enhanced removal of retained aqueous fluid. Possible changes in pore structure and wettability are considered supplementary reservoir-dependent effects [30,31].

4.1. Model Scope and PIPESIM Implementation

Based on the equations presented earlier, simulation experiments of CO₂ injection into the formation to assist fracturing-fluid flowback were conducted using the simulation software with the input parameters listed in Tables 3 and 4. As this is a CO₂ gas-lift simulation, the injected fluid was defined as CO₂, with the CO₂ mole fraction set to 1 and the mole fractions of hydrogen sulfide, nitrogen, and hydrogen all set to zero.

The prescribed fracture network at pump shutdown was coupled to the PIPESIM workflow through the reservoir inflow relationship and the effective fracture parameters of the flowback model. PIPESIM was used to calculate the stagewise wellbore pressure and temperature profiles, multiphase-flow behavior, gas-lift valve operation, and liquid-unloading performance; it did not generate or update the fracture path. Thus, the fracture model supplies the initial post-treatment deliverability conditions, whereas PIPESIM evaluates the subsequent wellbore and gas-lift response.

CO₂ gas lift was selected because it can be introduced through the installed gas-lift valve without pulling the tubing, tolerates a high gas fraction better than an electric submersible pump, and avoids placing moving downhole equipment in the early flowback containing proppant and suspended solids. Electric submersible pumps may be competitive after the solids content and gas fraction decline, whereas plunger lift is more suitable for

intermittent liquid loading after a stable gas supply has developed. Swabbing and pump-assisted lifting remain contingency options but require additional intervention. Thus, the comparison supports the selected early-flowback workflow.

Table 3. Basic parameters of CO₂ gas.

Parameter	Value	Unit	Remarks
Pressure (standard conditions)	0.101325	MPa	Standard atmospheric pressure (≈ 1 atm)
Temperature (standard conditions)	15.556	°C	Corresponding to 60 °F (standard temperature)
Mole fraction	100	%	The mixture contains only CO ₂ ; the mole numbers of other components (water, methane, etc.) are zero
Molecular weight	42.46928	g/mol	Theoretical value is 44.01; discrepancy arises from model differences
Density	1.86906	kg/m ³	Calculated value under standard conditions
Viscosity	44.0098	μPa·s	Gas-phase dynamic viscosity

Table 4. Thermodynamic and transport properties.

Parameter	Value	Unit	Remarks
Molar enthalpy	−2777.428	J/mol	Calculated value under standard conditions
Molar entropy	11.45132	J/(mol·K)	Calculated value under standard conditions
Molar Gibbs free energy	−381.564	J/mol	Calculated value under standard conditions
Specific heat at constant volume	36.82658	J/(mol·K)	To be confirmed whether it is specific heat at constant pressure
Thermal conductivity	20.0111377	W/(m·K)	Gas-phase thermal conductivity

The final simulation diagram is shown in Figure 9, consisting of the tubing fluid, tubing, production casing, surface casing, gas-lift valve, annular fluid, and cement sheath.

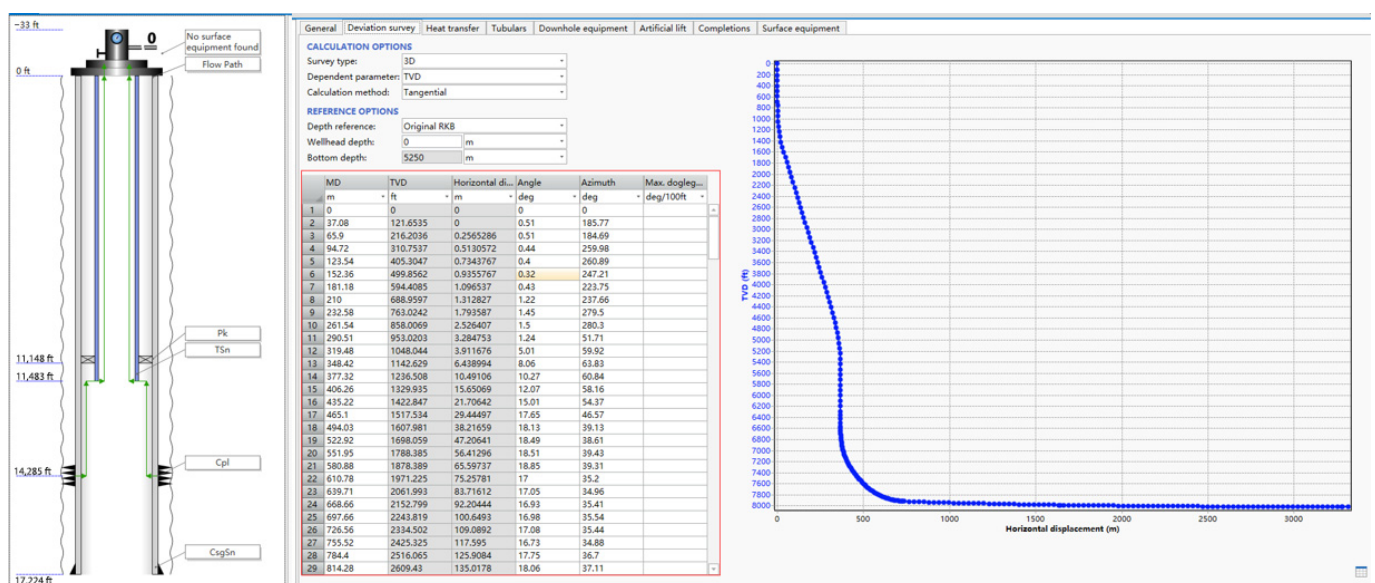


Figure 9. Wellbore configuration model.

4.2. Synergistic Optimization of Key Parameters

The reservoir temperature used in the soaking analysis was derived from the geothermal profile of Well H1. According to Table 5, the artificial bottomhole depth is 5250 m, the wellhead reference temperature is 15 °C, and the formation-temperature gradient is 2.97 °C/100 m. The bottomhole formation temperature was therefore calculated as follows:

$$T_r = T_{wh} + \frac{G_T H}{100} = 15 + \frac{2.97 \times 5250}{100} = 170.93 \text{ } ^\circ\text{C} \quad (43)$$

where T_r is the bottomhole formation temperature, T_{wh} is the wellhead reference temperature, G_T is the formation-temperature gradient, and H is the artificial bottomhole depth. The calculated temperature of 170.93 °C was adopted as the reservoir thermal boundary condition for Well H1.

Table 5. Simulation parameters for Well H1.

Parameter	Value	Parameter	Value
Tubing inner diameter (mm)	62	Borehole diameter (mm)	431.8
Tubing wall thickness (mm)	7	Artificial bottom hole (m)	5250
Tubing steel grade	N80	Bottomhole temperature (°C)	170.93
Surface casing inner diameter (mm)	339.73	Wellhead pressure (MPa)	6
Surface casing wall thickness (mm)	10.36	Wellhead temperature (°C)	15
Surface casing setting depth (m)	567.47	Formation-temperature gradient (°C/100 m)	2.97
Production casing inner diameter (mm)	108.62	Pressure gradient (MPa/m)	0.00506
Production casing wall thickness (mm)	9.19	Gas specific gravity (air = 1)	0.5756
Production casing setting depth (m)	5250	Gas compressibility factor, Z	0.5756
Casing steel grade	P110	Gas injection temperature (°C)	15

The present PIPESIM workflow evaluates the soaking stage through an engineering scheduling approach, while CO₂ diffusion, CO₂–oil compositional equilibration, and mineral-reaction kinetics are represented through their overall effects on the subsequent flowback performance. Accordingly, the 5–7-day duration is defined as a case-specific operating window for Well H1 rather than a universal equilibrium time. Within the adopted 30-day schedule, gas lift was initiated on day 16, leaving approximately 9–11 days for controlled natural flowback after a 5–7-day soaking period. By comparison, extending the soaking period to 10 days would leave only about 6 days for natural flowback and would reduce the effective production period by 3–5 days. The lower bound of 5 days provides sufficient time for CO₂–reservoir-fluid contact and pressure redistribution, whereas the upper bound of 7 days maintains an adequate natural-flowback interval while limiting the adverse effects associated with prolonged aqueous-phase imbibition and stress-sensitive fracture closure. Therefore, 5–7 days is recommended as a preliminary engineering range for Well H1, subject to further calibration using pressure-transient data, produced-fluid composition, or dedicated high-temperature and high-pressure soaking experiments.

During early flowback, a 4 mm choke is recommended, and the wellhead-pressure drawdown is limited to 0.3 MPa/h. Pressure and sand concentration should be sampled at least once per minute and evaluated over a rolling 30 min window. Pressure fluctuation is defined as $100 \times (P_{\max} - P_{\min})/P_{\text{mean}}$ within that window. Expansion to a 6 mm choke is permitted only when the fluctuation is below 5% and sand concentration is below 0.03% for two consecutive windows (60 min). The same 60 min stability test is repeated before expansion from 6 to 8 mm; any pressure rebound, sand increase, or drawdown above 0.3 MPa/h requires a return to the preceding choke size.

For the gas-lift stage, the gas injection pressure is set to 12 MPa and the gas injection rate is controlled within 8×10^4 – 10×10^4 m³/d. This range corresponds to the high-benefit

region identified by the numerical simulations, whereas increasing the injection rate to $12 \times 10^4 \text{ m}^3/\text{d}$ provides only a limited additional improvement in the flowback rate and increases compression demand. As discussed in Section 3.5, the selected range represents an operating optimum rather than a quantified erosion limit. Equipment integrity should therefore be verified separately using the local mixture velocity and density, gas-lift valve geometry, material properties, and entrained-solids loading.

Figure 10 presents the combined effects of the CO_2 injection pressure and injection rate on the performance of the gas-lift stage. The horizontal axis represents the CO_2 injection rate, the vertical axis represents the surface injection pressure, and the color scale denotes the comprehensive economic benefit score used for parameter screening. The central operating point of 12 MPa and $8 \times 10^4 \text{ m}^3/\text{d}$ yields a score of approximately 95. When the injection pressure is decreased to 10 MPa or increased to 14 MPa while maintaining the reference injection rate, the score decreases to approximately 61 and 71, respectively, corresponding to reductions of about 36% and 25%. At an injection pressure of 12 MPa, decreasing or increasing the injection rate by 20% results in scores of approximately 81 at $6.4 \times 10^4 \text{ m}^3/\text{d}$ and 85 at $9.6 \times 10^4 \text{ m}^3/\text{d}$, representing reductions of approximately 15% and 11%, respectively. Thus, the score remains above 80 under a $\pm 20\%$ injection-rate deviation, whereas a $\pm 2 \text{ MPa}$ pressure deviation causes a more pronounced performance loss, indicating greater sensitivity to injection pressure. The curved contours in Figure 10 demonstrate that the decline outside the high-benefit region is nonlinear and asymmetric rather than linear. An insufficient injection pressure or gas rate rapidly reduces the effective gas-lift depth and liquid-unloading capacity, whereas increases beyond the central operating point provide diminishing flowback benefits while increasing compression demand and equipment loading. Therefore, 12 MPa and 8×10^4 – $10 \times 10^4 \text{ m}^3/\text{d}$ should be regarded as a robust engineering operating window rather than a single rigid operating point.

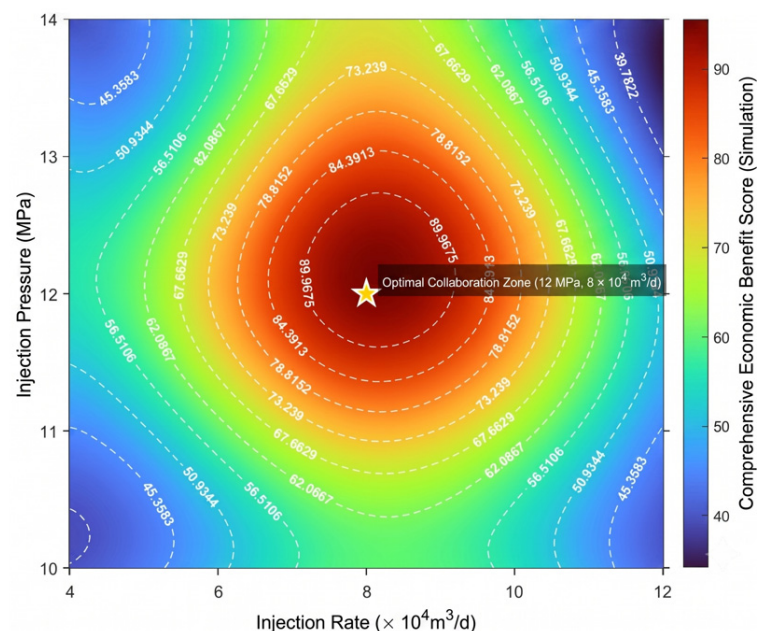


Figure 10. Comprehensive simulation-based evaluation of the CO_2 injection pressure and injection rate during the gas-lift stage.

4.3. Implementation Procedures and Performance at Different Stages of Synergistic Flowback

Based on the above research, a synergistic optimization flowback theory coupling natural flow with CO_2 gas lift is established, integrating the strong water sensitivity of the shale oil reservoir, the effects of CO_2 injection on fracturing fluid, and the critical lifting pressure revealed by multiphase flow numerical simulation. Guided by this theory, a

full-cycle synergistic optimization implementation workflow for fracturing fluid flowback in Well H1 of the Lianggaoshan shale oil reservoir is formulated (Figure 11).

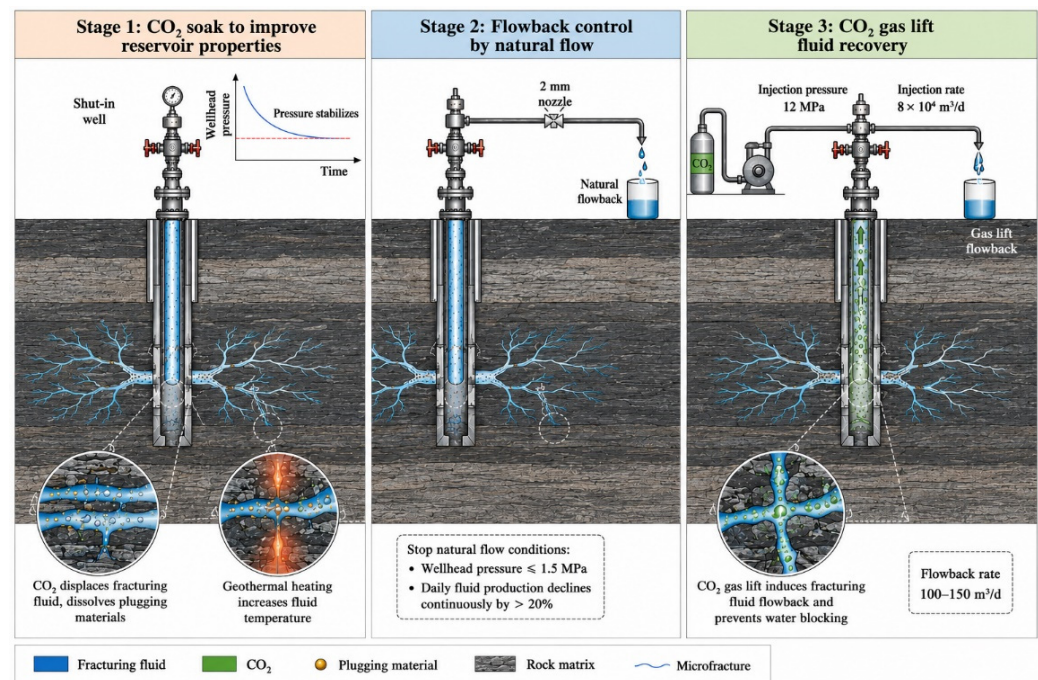


Figure 11. Implementation workflow of the synergistic scheme.

Stage 1: CO₂ soaking to improve reservoir properties. During the fracturing treatment, a water-based CO₂-energized fracturing fluid is used, with the aqueous phase serving as the carrier fluid and CO₂ as the energizing gas phase. Immediately after treatment, the well is shut in to maintain pressure and promote CO₂ contact with the reservoir fluid. CO₂ may redistribute the retained aqueous fluid and improve oil-phase mobility through CO₂–oil mass transfer and the associated reduction in crude oil viscosity. However, the effectiveness of this process is constrained by capillary imbibition, water saturation, clay hydration, and stress-sensitive fracture closure. Therefore, the shut-in period should be controlled to enhance CO₂ contact while avoiding excessive water-blocking damage in the near-wellbore region. The subsequent stage commences once the wellhead pressure stabilizes.

Stage 2: Controlled natural flowback of fracturing fluid. After soaking, the well is opened for natural flow through a 4 mm choke, and the pressure drawdown rate is strictly controlled. The objective is to remove high-concentration fracturing fluid from the wellbore and near-wellbore reservoir while limiting proppant mobilization and preserving the effective conductivity of the primary hydraulic fractures. To maintain unloading efficiency, natural flow is terminated and gas-lift flowback is initiated when the wellhead pressure drops to 1.5 MPa or the daily flowback rate declines continuously by more than 20%.

Stage 3: CO₂ gas-lift unloading. At this stage, the CO₂ originally co-injected in Stage 1 is largely depleted, and additional CO₂ must be injected to sustain the required lifting pressure differential. The surface gas injection system is activated, and CO₂ is injected through the gas-lift valve into the Lianggaoshan shale reservoir at an injection pressure of 12 MPa and an injection rate of 8×10^4 m³/d. The injected CO₂ lowers the bottomhole flowing pressure and creates a favorable lifting differential, thereby promoting the removal of retained aqueous fluid from distal fracture regions; this hydraulic unloading effect constitutes the primary basis for the water-blocking mitigation discussed in this study. Comparative simulations of water injection and CO₂ injection at the same injection rate

indicate that a fracturing fluid flowback rate of 100–150 m³/d can be sustained during this phase.

4.4. Prediction and Evaluation of the Full-Cycle Performance of Synergistic Optimization

A full-cycle prediction of the synergistic scheme was performed using PIPESIM, and the results are presented in Figure 12. The near-zero cumulative flowback during the first approximately 8–9 days represents the scheduled CO₂ soaking and pressure-stabilization period rather than ineffective operating time. This interval includes the recommended 5–7-day soaking stage and the subsequent controlled transition to natural flowback. During this period, sustained CO₂–reservoir-fluid contact promotes CO₂–oil mass transfer, redistribution of the retained aqueous fluid, and pressure equilibration within the near-wellbore fracture system. These processes provide more favorable fluid-mobility and pressure conditions for the subsequent natural-flowback and gas-lift stages.

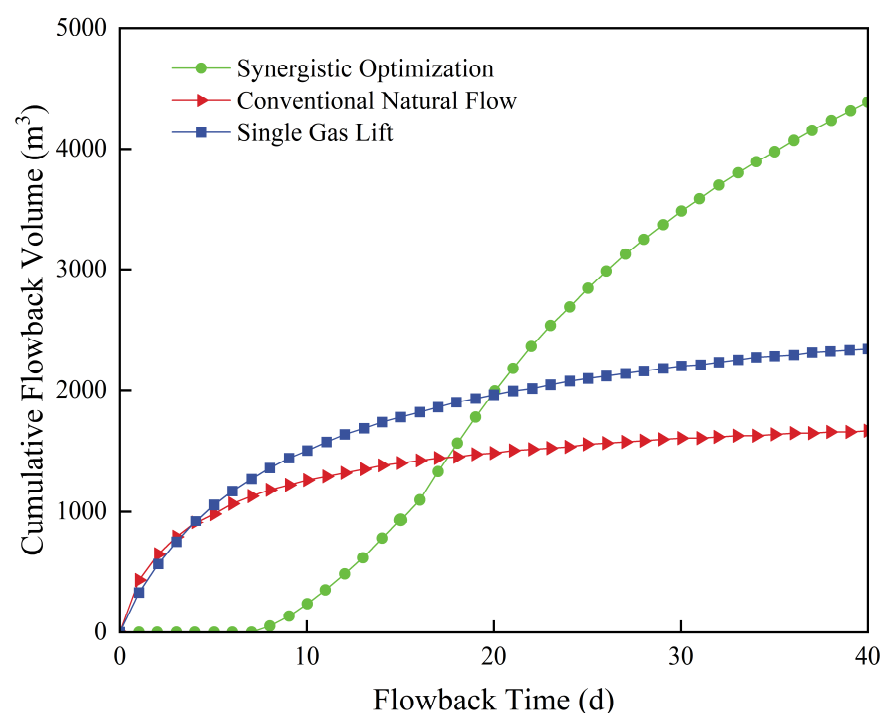


Figure 12. Comparison of cumulative flowback volumes under different flowback strategies. The initial near-zero-production interval of the synergistic scheme represents the scheduled CO₂ soaking and pressure-stabilization period.

From an engineering-economic perspective, the initial production delay represents an early-time investment in reservoir conditioning and flowback stability. Controlled soaking and pressure stabilization can reduce the risk of rapid pressure depletion, premature fracture closure, proppant mobilization, and early liquid loading, thereby helping preserve fracture conductivity and reducing the need for subsequent remedial intervention. After gas lift is introduced on day 16, the synergistic scheme exhibits a pronounced increase in the cumulative-flowback slope, whereas the conventional natural-flow curve gradually flattens because of formation-energy depletion. Over the 30-day evaluation period, the cumulative flowback volume of the synergistic scheme reaches 3492 m³, indicating that the delayed production response is compensated by stronger sustained liquid unloading and greater cumulative fluid recovery. Therefore, the initial soaking period should be regarded as an integral reservoir-conditioning stage that supports the long-term performance of the full-cycle flowback process.

4.5. Sensitivity Analysis and Applicability of the Three-Stage Workflow

To evaluate whether the proposed optimization workflow is controlled by the specific properties of Well H1, a one-factor-at-a-time sensitivity analysis was performed using the H1 model as the reference case. The investigated parameters included the initial matrix permeability, effective fracture half-length, fracture conductivity, crude oil viscosity, water cut, CO₂ mole fraction, and formation stress sensitivity. Formation stress sensitivity was represented by the permeability-retention ratio R_k , defined as the ratio of the remaining matrix permeability to the initial permeability at the maximum modeled pressure drawdown. Values of $R_k = 1.0, 0.7$, and 0.4 were used to represent negligible, moderate, and strong stress sensitivity, respectively. For each case, the corresponding C_k was calculated from

$$C_k = -\frac{\ln R_k}{p_{r,0} - p_{r,\min}} \quad (44)$$

where $p_{r,\min}$ is the minimum average reservoir pressure reached during the considered flowback period. These permeability-retention ratios represent bounded engineering scenarios rather than core-calibrated parameters for Well H1 and should be updated when stress-dependent permeability measurements become available. All parameters other than the target variable were maintained at their reference values. For each case, the switching time between natural flowback and CO₂ gas lift was reoptimized rather than fixed at the value obtained for Well H1. The fracture-conductivity multiplier continued to represent the combined hydraulic effects of the residual propped width, proppant-pack permeability, and closure-induced conductivity damage.

The sensitivity results indicate that reservoir properties affect different CO₂ control variables rather than shifting all injection parameters in the same direction. Higher permeability improves formation-to-wellbore deliverability and prolongs natural flowback, whereas lower permeability advances gas-lift intervention; however, a higher gas injection rate cannot fully compensate for poor reservoir conductivity. Higher porosity increases pore fluid storage and the volume of retained fluid contacted by CO₂, tending to increase the required cumulative CO₂ volume or soaking duration, but it has a weaker direct effect on the minimum injection pressure. A higher initial reservoir pressure provides a stronger natural drive and delays gas-lift initiation, whereas a lower reservoir pressure requires earlier assistance and a greater reduction in the wellbore hydrostatic head. The minimum surface injection pressure remains governed primarily by the annulus–tubing pressure balance, valve-opening differential, and target injection depth and is therefore not expected to vary monotonically with reservoir pressure. Because porosity and the initial reservoir pressure were not independently varied in Table 6, these trends are interpreted mechanistically rather than reported as separately calibrated optima.

Variations in effective fracture half-length affected both the retained-fluid volume and the pressure-transmission distance, thereby changing the optimal switching time without altering the preferred stage sequence. Increasing crude oil viscosity or the water cut reduced fluid mobility and increased the relative contribution of the gas-lift stage. A lower CO₂ mole fraction weakened the reduction in wellbore mixture density and the potential contribution of CO₂–oil mass transfer, requiring earlier or more intensive gas-lift assistance. These results demonstrate that the transferable component of the proposed methodology is the adaptive sequence of CO₂ soaking, controlled natural flowback, and conditional CO₂ gas lift. The specific values of the soaking duration, switching pressure, injection pressure, and injection rate obtained for Well H1 should therefore be recalibrated before application to another well.

Table 6. Probability distributions and parameter ranges used in the uncertainty analysis.

Sensitivity Parameter	Distribution	Low Level	Baseline Level	High Level
Initial matrix permeability, k/k_0	Triangular	0.3	1.0	3.0
Effective fracture half-length, $L_f/L_{f,0}$	Triangular	0.5	1.0	1.5
Fracture conductivity, $C_f/C_{f,0}$	Triangular	0.5	1.0	2.0
Crude oil viscosity, $\mu_o/\mu_{o,0}$	Triangular	0.5	1.0	2.0
Water cut	Triangular	70%	90%	95%
CO ₂ mole fraction	Triangular	80%	90%	100%

Note: The probability distributions represent bounded engineering priors derived from the available reservoir information. They should be updated when sufficient field measurements or multiwell statistical data become available. Additional formation stress-sensitivity scenarios were evaluated using permeability-retention ratios of $R_k = 1.0, 0.7$, and 0.4 , representing negligible, moderate, and strong stress sensitivity, respectively. Initial porosity and reservoir pressure were not treated as independent uncertainty variables because calibrated variation ranges were unavailable; their mechanistic effects on CO₂ soaking and gas-lift requirements are discussed below.

4.6. External Benchmark Comparison and Model Evaluation

Because absolute flowback volumes are strongly affected by the injected-fluid volume, prescribed fracture geometry, reservoir properties, and wellbore configuration, the model was evaluated by comparing the normalized flowback-enhancement trend with a published CO₂-assisted flowback benchmark rather than by claiming point-to-point validation of the absolute volume. According to Figure 12, the predicted 30-day cumulative flowback volumes under the synergistic scheme, conventional natural flowback, and standalone gas lift are 3492, approximately 1600, and approximately 2200 m³, respectively. Therefore, the synergistic scheme increases the cumulative flowback volume by approximately 118% relative to conventional natural flowback and by approximately 59% relative to standalone gas lift. The quantitative comparison between the proposed synergistic scheme, the conventional operating strategies, and the published CO₂-assisted flowback benchmark is summarized in Table 7.

Table 7. Comparison of the present model with a published CO₂-assisted flowback benchmark.

Comparison Case	Cumulative Flowback or Benchmark Result	Relative Improvement
Synergistic scheme versus conventional natural flowback	3492 m ³ versus approximately 1600 m ³	Approximately 118%
Synergistic scheme versus standalone gas lift	3492 m ³ versus approximately 2200 m ³	Approximately 59%
CO ₂ injection versus water-based fracturing fluid reported by Kong et al. [22]	Published benchmark	88–97%

Kong et al. [22] reported that CO₂ injection increased fracturing-fluid recovery by 88–97% compared with water-based fracturing fluids at injection rates of 5.0×10^3 – 1.5×10^4 m³/d. The present model reproduces the same enhancement trend and predicts an improvement of a comparable order of magnitude. The somewhat greater enhancement relative to conventional natural flowback is mainly attributed to the combined effects of CO₂ soaking, controlled natural flowback, and continuous CO₂ gas-lift unloading, whereas the published benchmark primarily evaluates CO₂ injection relative to a water-based fracturing-fluid system. This comparison supports the physical consistency and order of magnitude of the enhancement trend. Field observations from the Wufeng–Longmaxi Formation in the Changning block show that high flowback rates are associated with water-saturation heterogeneity, faults, and natural-fracture development. In particular, unidirectional linear fractures may promote inter-well frac-hit, indicating that fracture connectivity and well spacing should be considered when evaluating flowback behavior [32]. Published flowback

data from deep shale wells in the Luzhou block further indicate that shale-well flowback generally evolves from an early pressure-supported stage to a later stage characterized by declining liquid-unloading capacity [33]. These observations are consistent with the geological, fracture-related, and production-related controlling factors considered in the present sensitivity analysis and support the transferability of the proposed workflow at the mechanism and decision-logic levels. However, they do not constitute a direct multiwell history match for the Lianggaoshan Formation. Therefore, the H1-specific soaking duration, switching threshold, injection pressure, and injection rate should be recalibrated using local reservoir, fracture, fluid, wellbore, and flowback data before field application.

Energy-based physics-informed neural formulations, such as the deep-energy method proposed by Samaniego et al. [34], provide a variational framework for solving coupled partial differential equations and may facilitate repeated parameter inversion and assimilation of pressure and flowback measurements. However, the deep-energy method is primarily a forward and inverse partial-differential-equation solution framework and does not by itself replace probabilistic uncertainty propagation. In the present study, input uncertainty is quantified through variance decomposition of the stagewise PIPESIM-based workflow. The reliability of a future deep-energy implementation would still depend on the consistency of the governing energy functional and the stability of the numerical integration and training procedures [35]. A coupled reservoir–fracture–wellbore deep-energy model combined with data-driven parameter updating will be investigated when sufficient spatial pressure, fracture-diagnostic, and flowback data become available.

4.7. CO₂ Corrosion, Well Integrity, Environmental Protection, and Operational Safety

Wet CO₂ can form carbonic acid and cause internal corrosion of carbon-steel tubing, casing, valves, and surface lines. Before field deployment, the corrosion design should combine the produced-water chemistry, CO₂ partial pressure, temperature, velocity, and expected exposure time. Recommended controls include dehydration where practicable, continuous corrosion-inhibitor injection, corrosion allowance, compatible internal coatings, and a corrosion-resistant alloy trim (for example, 13Cr or a qualified higher alloy) at the gas-lift valve and other high-risk locations. Coupons or electrical-resistance probes, iron-count monitoring, annular-pressure surveillance, and periodic wall-thickness inspection should be included. Final material selection must be confirmed by CO₂–brine compatibility and erosion–corrosion tests under the actual H1 fluid composition and operating envelope.

The CO₂ supply should be documented and conditioned to control water and corrosive impurities, with metering of injected, produced, recycled, vented, and retained CO₂. Leakage risk should be managed through cement-bond and pressure-integrity verification, continuous annular and surface-gas monitoring, automatic shutdown, the pressure-relief capacity, and an emergency response plan. Injection pressure must remain below the approved formation and well-integrity limits. Baseline seismicity, pressure response, and event-rate monitoring should be used to define traffic-light thresholds where faults may be present. Because retained CO₂ was not quantified in this study, the process is not claimed as a carbon-storage or emissions-reduction result.

5. Conclusions

1. The natural-flowback mechanism and the corresponding stepwise pressure-control strategy were clarified. Early flowback is driven by reservoir-gas expansion, fluid hydromechanical energy, and rock elastic energy. A 4 mm initial choke, combined with controlled pressure drawdown and sand-concentration monitoring, is recommended to limit premature fracture closure and proppant mobilization while preserving effective fracture conductivity.

2. The key operating parameters of CO₂ gas-lift flowback were optimized. The flowback efficiency in the gas-lift stage is highly dependent on the stability of the multiphase flow regime in the wellbore and the proper control of the tubing–casing equilibrium point. Considering both the fluid lifting efficiency and the tubing string erosion safety, the optimal gas injection pressure for the target well is recommended to be 12 MPa, and the reasonable gas injection rate ranges from 8×10^4 to 10×10^4 m³/d. In addition, high wellhead backpressure can significantly weaken the gas-lift effect; therefore, the wellhead backpressure should be controlled below 0.5 MPa during field operations.
3. A three-stage full-cycle synergistic scheme consisting of “CO₂ soaking–natural flowback–CO₂ gas lift” was established. Under the adopted simulation conditions, a shut-in period of 5–7 days is recommended as an engineering compromise between sufficient CO₂–oil contact and the potential adverse effects of aqueous-phase imbibition and stress-sensitive fracture closure. When the wellhead pressure decreases to 1.5 MPa or the daily flowback rate declines continuously by more than 20%, the operation should be switched from natural flowback to CO₂ gas lift. The recommended shut-in period is model-based and requires reservoir-specific experimental verification before direct field application.
4. Under the prescribed pump-shutdown fracture geometry and the stated stagewise numerical settings, the synergistic workflow yielded an estimated 30-day cumulative flowback volume of 3492 m³. The introduction of CO₂ gas lift on day 16 produced a secondary increase in the simulated flowback rate by reducing the wellbore hydrostatic pressure and bottomhole flowing pressure. The sensitivity and external benchmark comparisons support the relative performance trend of the proposed workflow, whereas the absolute cumulative volume remains conditional on the prescribed fracture geometry, stress-dependent permeability, reservoir properties, numerical settings, and field-specific calibration.

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Conflicts of Interest: The authors declare no conflict of interest.

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