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Research Article

Numerical Simulation of Choke Size Optimization in a Shale Gas Well

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To optimize the flowback system of shale gas horizontal wells after fracturing and to maximize the production capacity of gas wells, pipe flow and flowback models of shale gas multistage fractured horizontal wells were established based on the actual geological engineering conditions and the fracture parameters inverted from automatic history matching by combining experimental and numerical simulation methods. Optimization of the maximum choke size, reasonable opening choke size, replacement stages, and choke replacement frequency were studied. The research results show that the larger the production pressure difference in the early period, the higher the initial gas production rate but the easier the migration of proppant and the higher its stress sensitivity, which increases the permeability damage and weakens the reservoir recovery ability. Thus, the fracture conductivity gets worse and the later gas production rate and liquid production rate get lower. Specifically, the research results mainly include the following: (1) The laboratory experiment results show that the effective stress exceeding 19 MPa caused a proppant breakage and embedding phenomenon, leading to difficult recovery from reservoir permeability damage. Therefore, the maximum production pressure difference corresponding to the single-well maximum choke size shall not exceed 19 MPa. (2) A small opening choke size of a shale gas well is superior to the large one, and according to the numerical simulation, the choke size of 3 mm is recommended to be the reasonable opening choke size. (3) Under the drainage and production systems of replacing the choke size from small to large, the simulation results indicate that the production effect under the drainage and production systems of increasing the choke size incrementally stage by stage with an increase in amplitude of 1 mm is much better than that under the drainage and production systems of increasing the choke size by skipping the stage. (4) When the choke size is increased stage by stage, the research results indicate that the optimal duration of each grade of choke size is 3 days, beyond which, the increase of EUR will not be remarkable. The application of the proposed fine choke system research method in Well-CN001 indicates that the influence amplitude of the reasonable choke system on the daily gas production of Well-CN001 is in the range of 65.96%–121.67% and that on single-well EUR increase amplitude in 20 years is in the range of 5.2%–22.27%. The research results provide technical support for understanding the influence of different choke systems on the productivity of shale gas wells and optimizing the reasonable drainage and production systems of shale gas wells after fracturing.

1. Introduction

Shale gas reservoirs typically require large-scale volume fracturing to be economically viable. Upwards of 10,000 cubic meters of fracturing fluid is injected into a formation, making the flowback process particularly important. The amounts of fluid filtration, conductivity of hydraulic fractures, and subsequent development of the wells are impacted. Therefore, the selection of the optimal choke size is a key part of the design of drainage and production systems, which determine whether gas well productivity can be achieved.

The drainage and production systems currently applied on site are quite different. Chokes are generally between 3 mm and 13 mm and are replaced from large to small or small to large, with varying replacement frequencies. Some scholars believe that the use of large chokes at the beginning makes the fracturing fluid flow back as soon as possible, reducing the damage from fracturing fluid to the reservoir, such as water lock damage and clay expansion. Meanwhile,

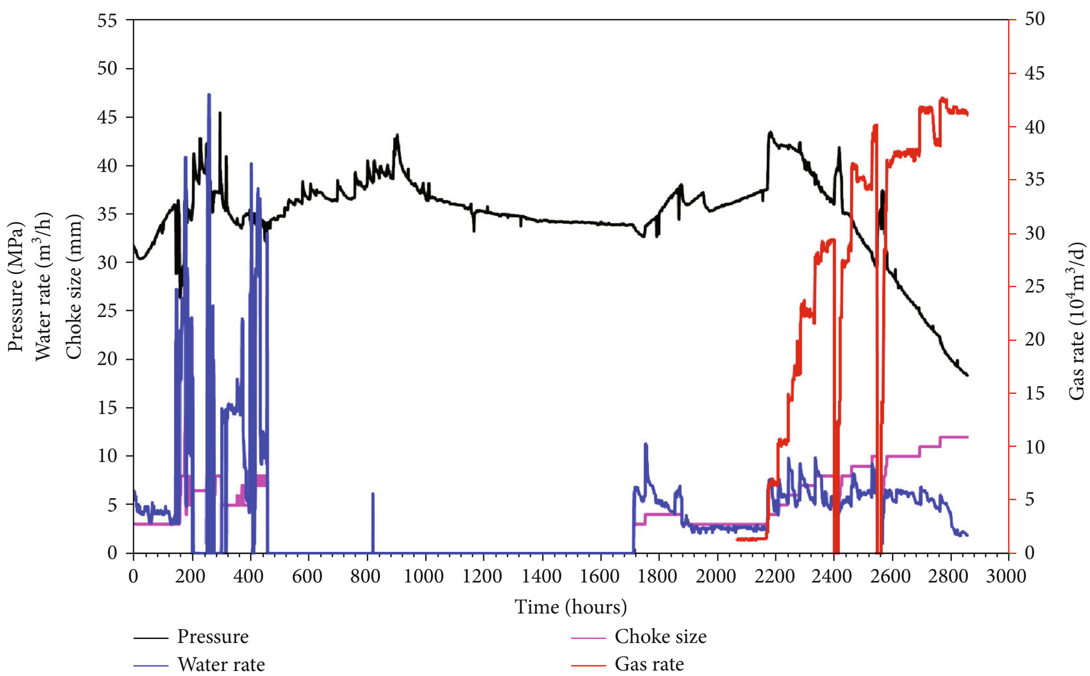

Figure 1: Well-CN001 drainage and production-test curve.

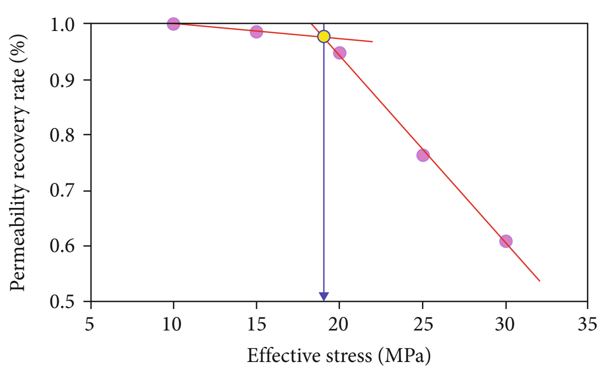

Figure 2: Permeability recovery curve under different effective stress conditions.

many scholars prefer gradually enlarging the choke, so as to prevent the embedding and reflux of proppant and improve the fracture conductivity. The advantage of adopting the choke system is usually related to the protection of fracture conductivity, which is related to stress sensitivity. Miller et al. and Quintero and Devegowda [1–2] believe that fluid production from the reservoir reduces the pore pressure and increases the net effective stress. The increase of stress leads to the decrease of fracture conductivity, including hydraulic fracture and natural fracture. Wilson et al., Lerza et al., Rojas and Lerza, and Rodriguez and Maldonado [3–6] believe that excessive production pressure difference in the early stage of shale gas well drainage and production damages fracture stress sensitivity seriously. Fractures are the main gas production channels in shale reservoirs, so the production under smaller pressure difference in the early period is quite important to protect fracture conductivity and optimize the EUR.

The choke system affects the flowback rate and production of shale gas wells. Numerical simulation and production data analysis have been used to study the postfracture choke system of shale gas wells. Liu et al. [7] studied the size selection of the blowout choke by establishing the two-dimensional filtration and fracture-forced closure model of fracturing fluid and the proppant reflux model of the shale gas well. However, in the study, the selection range of the choke size is only between 3.5 mm and 6.5 mm and only one choke size is selected without considering the change of the choke size in the same model. Han et al. [8] used numerical simulation and experimental analysis to study various backflow influencing factors, but it is mainly mechanism research and lacks the combination with the flowback system. Wijaya and Sheng [9] analyzed a large number of the flowback data of shale gas wells in a particular area but lacked theoretical support and could not accurately represent the formation. Some early studies tried to predict the impact of the choke system on final recoverable reserves; however, due to the prediction methods, there were no consistent results. Some researchers believe that the choke system can improve the EUR, while others believe that the choke system cannot significantly affect the recovery efficiency and also hurts the net present value (NPV). For example, Tripoppoom et al. [10] simulated the production situations of the Haynesville Oilfield by means of numerical simulation, which indicated that the choke system could improve the 30 years' EUR by 28%.

The choke system is considered to be better able to protect the fracture conductivity in the early stage of shale gas well, so as to reach the goal of improving gas well's EUR. In the early literatures, however, no consistent conclusion is reached on whether the choke system is really beneficial to EUR. At present, the formulation of the drainage and

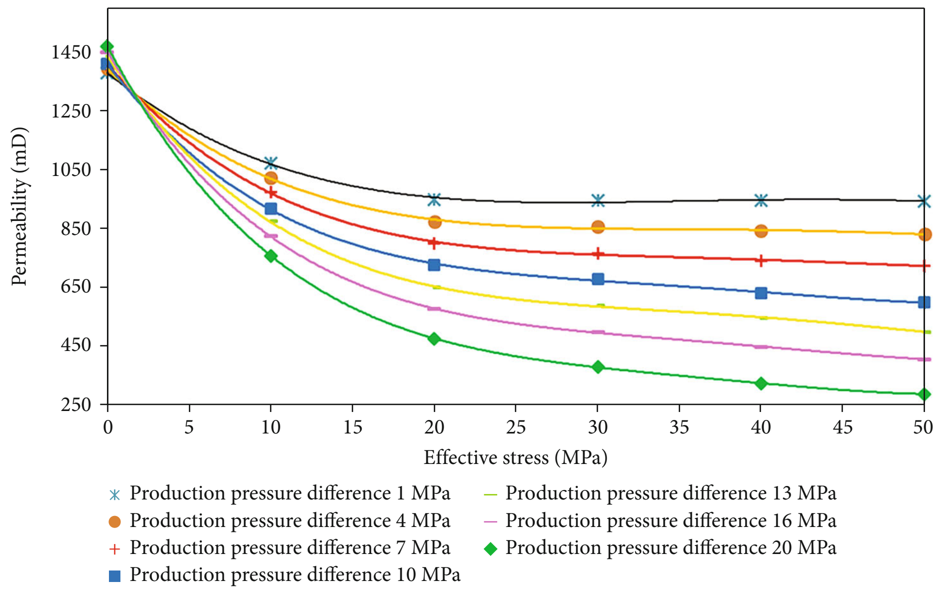

Figure 3: Permeability curve under different production pressure difference and effective stress conditions.

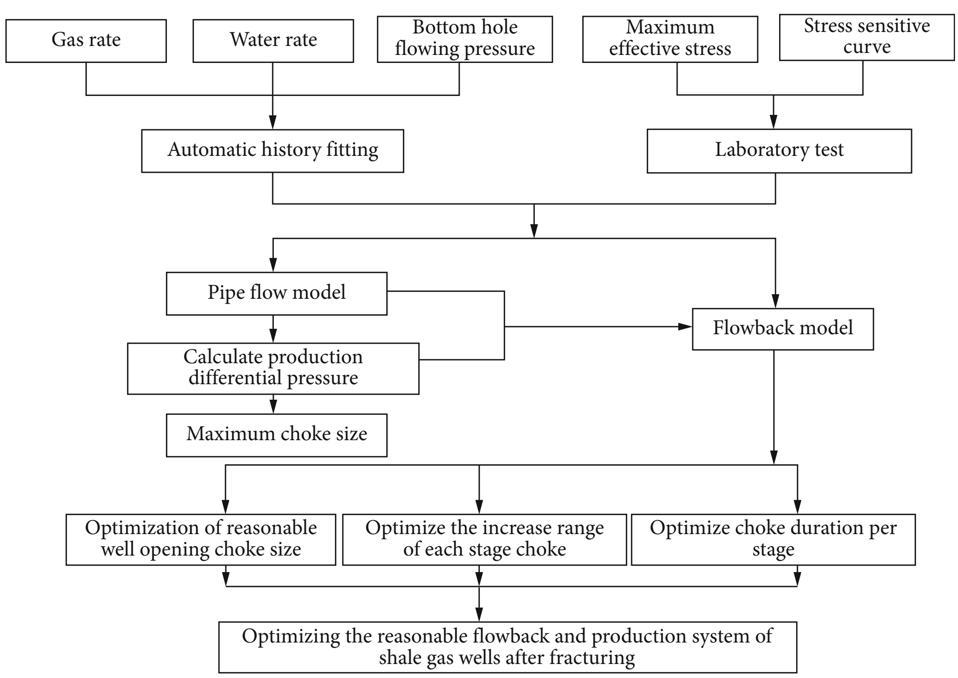

Figure 4: Workflow chart for optimizing choke system of shale gas well.

production system of shale gas well mainly depends on field experience and statistical analysis, there has been no basis for selecting the reasonable flowback control parameter and especially choke size and replacement timing, and there is lack of theoretical researches on reasonable drainage and production system. Based on literature research, the impact of the choke system on gas well EUR is unclear, highlighting the importance of this study. These studies did not conduct sufficient uncertainty analysis of their results, leading to different conclusions. The previous studies only used one reservoir model, but there are many uncertainties in the volume characteristics of the reformed reservoir, including relative permeability, capillary pressure curve, stress sensitivity, and fracture and matrix water saturation, which is considered to be the main reason for different conclusions. In this paper, a set of research methods for optimizing the choke system in the flowback stage after fracturing of a shale gas well are innovatively developed by adopting the method of combining numerical simulation and laboratory experiment. Different from the previous researches, this paper carries out numerical simulation from the perspective of mechanism and then combines the results with the production, so as to form the choke system which can be used to guide field production. It is concluded that the selection of the

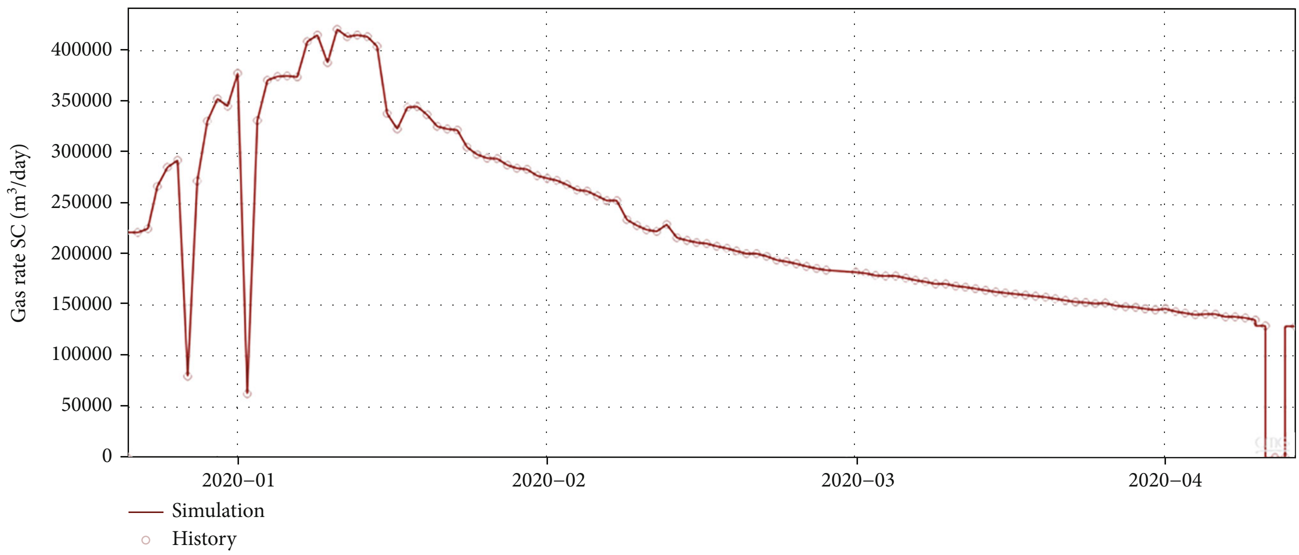

Figure 5: Daily gas production fitting diagram.

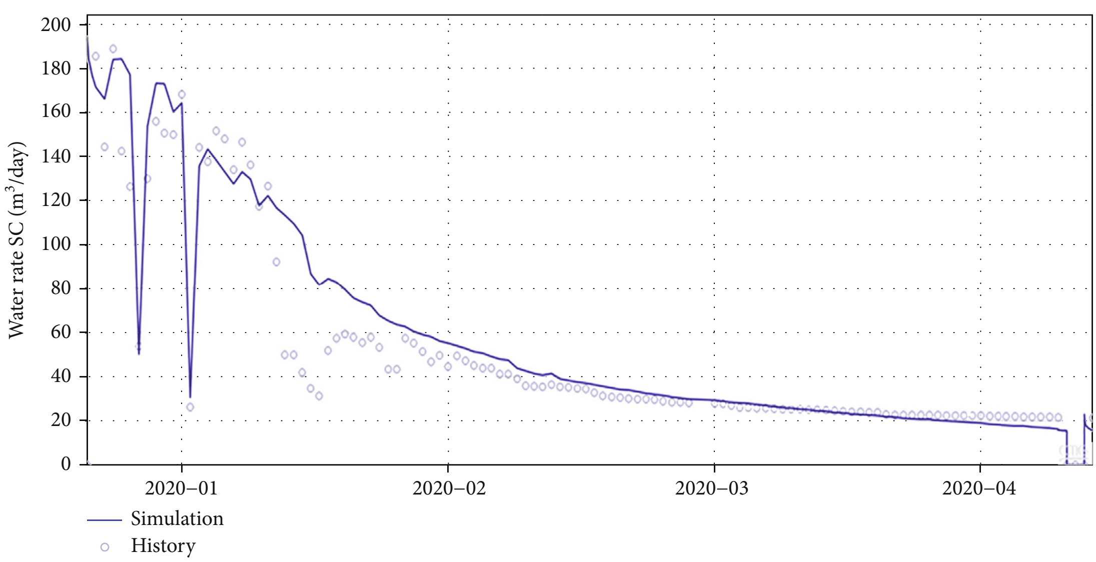

Figure 6: Daily liquid production fitting diagram.

reasonable choke size, replacement mode, replacement frequency, and increasing stages in the flowback process of shale gas wells is of important significance to the optimization of gas well drainage and production systems and lays a theoretical base for the formulation of a reasonable flowback system of a shale gas well.

2. Background

The drainage and production systems of "Well plugging–Controlled drainage–Step-by-step amplification–Adjustment and stability" are adopted in the shallow shale gas wells of southern Sichuan Basin according to experience, and then, the test production rate is obtained according to the test specification to evaluate the productivity of gas wells. However, refined drainage and production systems have not been established and the selection of on-site choke systems is still based on experience. There is no theoretical basis for the formulation of a detailed choke system such as optimal well opening choke size, maximum choke size, duration of different chokes, and increased choke ranges at each level. Additionally, a series of problems occurred in the drainage and production stages, affecting the productivity of the wells (Figure 1).

Due to the lack of theoretical support, on-site drainage and production systems are mostly determined by experience, causing the following problems. (1) During drainage and production, the well is shut due to certain reasons and the choke size is adjusted back and forth, affecting the productivity of the gas well; (2) the size of choke is too large at the start of production, resulting in the rapid decline of casing pressure and the backflow and embedding of the proppant; (3) the maximum choke size of a single well cannot be determined, and the use of too large a choke leads to

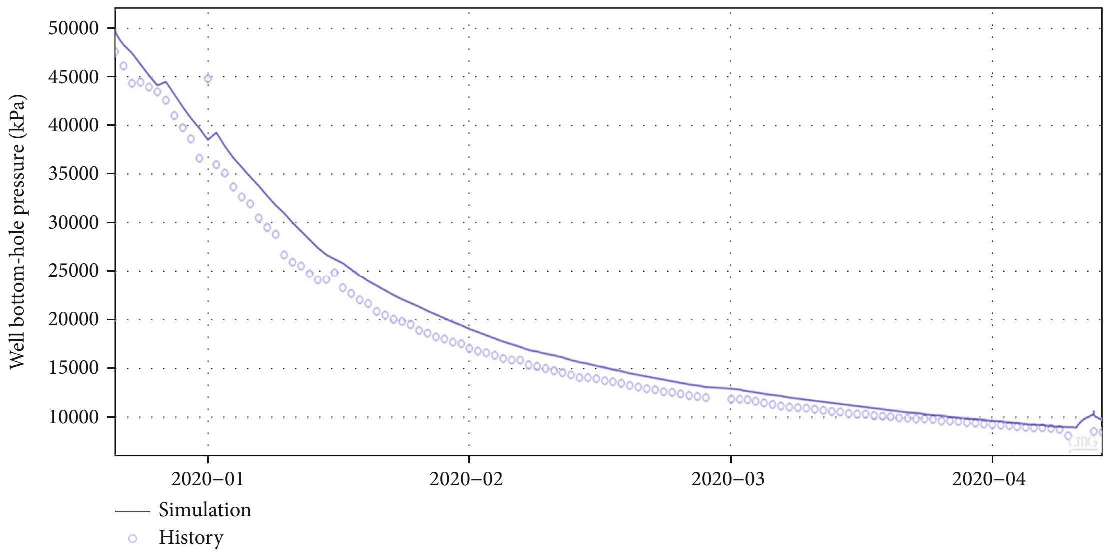

Figure 7: Bottom hole flow pressure fitting diagram.

Table 1: The inversion results of Well-CN001 fracture parameters.

Uncertain parameter	Min value	Max value	*P*50 value
Fracture height (m)	5	20	12.7
Fracture half-length (m)	70	180	85.4
Fracture conductivity (md·m)	20	70	29
Fracture water saturation	0.6	0.8	0.713
Fracture width (m)	0.07	0.1	0.09
HF efficiency	0.6	0.9	0.696

serious sand production in the gas well, affecting the conductivity of supporting fractures and the smoothness of wellbore flow channels; and (4) the duration of each level of choke is uncertain. The duration of each level is as short as a few hours and as long as more than 10 days, and it is defined only by experience.

2.1. Research on Stress Sensitivity of Hydraulic Fractures. Due to the artificial fractures in the fracturing transformation of a shale gas reservoir, the proppant will be embedded and broken and will migrate during drainage and production, creating stress sensitivity within the reservoir. With changes in the drainage and production systems and effective stress, the fracture permeability will decrease irreversibly, affecting the EUR of shale gas wells. Conducting stress sensitivity tests on artificial fractures in shale reservoirs under various production pressure differential conditions and then quantitatively evaluating the impact of artificial fractures on shale, proppant embedding, damage, migration, and permeability will provide support for determining an optimal choke system. The cores of *Longyi* $_1^1$*and Longyi* $_1^2$ layers were selected for artificial fracture experiments and stress sensitivity experiments on shale artificial fracture permeability under different pressure change modes and different production pressure differentials.

When the effective stress acting on the core decreases, pressure within the reservoir recovers. The permeability recovery rate of artificial fractures in shale was analyzed and studied when the effective stress decreased. According to the results of the indoor experiment (Figure 2), with the gradual increase and decrease of the initial effective stress, the damage of the reservoir in the initial stage gradually decreases, the recovery ability of the reservoir gradually increases, and the increase range of the recovery rate first increases and then decreases. The relationship between effective stress and permeability recovery rate has an inflection point at the effective stress of 19 MPa, i.e., the permeability recovery rate at this point is high (95%), and the maximum increase in recovery rate (18%) occurs. Then, continuing to reduce the initial effective stress, the permeability recovery rate is 98% and the recovery rate increases rapidly from 18% to 3%, i.e., the protection increase of the reservoir is not obvious. When the effective stress exceeds 19 MPa, the proppant is apparently broken and embedded and the reservoir permeability damage is difficult to recover from.

Experiments of artificial fracturing and sand laying in shale yielded permeability stress sensitivity curves of artificial fracture under different production pressure differentials. The experiments exhibited significant differences in the permeability sensitivity of artificial fractures in shale with different production pressure differentials. The greater the production pressure difference is, the greater the decline of fracture permeability will be (Figure 3). The stress sensitivity curves of different production pressure differences obtained from this research are the basis for the optimization numerical simulation of drainage and production systems based on the choke size.

2.2. Determination Method of the Optimal Choke System. Based on the experimental data, a set of detailed numerical simulation methods for choke system optimization was established in this study (Figure 4). Through a series of processes, the optimal choke system of a single well was determined.

The method is as follows.

(1) The fracture parameters of shale gas wells are inversed by automatic history fitting technology

(2) Based on the actual geological engineering parameters and inversion fracture parameters, the flowback and pipe flow models more in line with the actual production are established and the production differential pressures corresponding to different choke sizes of a single well are calculated

(3) The stress sensitivity curves under various production pressure differentials obtained from the experiments are applied to the flowback model, and different scenarios are designed to study the numerical simulation of the choke size optimization of a single well

(4) In the numerical model established by the combination of experiment and numerical simulation, the optimization of the maximum choke size, well opening choke size, choke increase range, and choke duration of each stage are performed

This method makes the numerical simulation process closer to the actual drainage and production process of shale gas wells. Thus, the simulation results are more accurate, solving the problem that the on-site drainage and production systems are formulated only by experience and providing theoretical support for guiding the formulation of on-site optimum drainage and production systems of shale gas wells.

2.3. Automatic History Fitting of Well-CN001. An early flowback model on Well-CN001 established the fracturing situation based on actual geological conditions, fracturing engineering parameters, and automatic history fitting results. After fracturing the well, the shape and volume of fractures were still unclear and it was difficult to accurately characterize fractures. Historical fitting uses production performance data to narrow the results and obtain optimal reservoir and fracture parameters. However, the conventional history fitting process is cumbersome and complex, so it is difficult to obtain representative fitting results efficiently and accurately. Automatic history fitting can solve this problem. Herein, the ability of an embedded discrete fracture (EDFM) to deal with complex fractures is used, combined with the Markov chain Monte Carlo inversion algorithm (MCMC) [10], and through artificial intelligence neural network automatic sampling machine learning, the automatic history fitting of three parameters, i.e., daily gas production, bottom hole pressure, and daily liquid production, is realized for Well-CN001 (Figures 5–7). Finally, the inversion of key fracture parameters of Well-CN001 includes effective fracture height, fracture length, conductivity, cluster effectiveness, and fracture water saturation. The inversion results of relevant fracture parameters are shown (Table 1).

2.4. Establishment of the Pipe Flow Numerical Model and Solution of Production Pressure Difference in the Shale Gas Well. The wellbore pipe flow model of the shale gas well is used to calculate the production differential pressure corresponding to different choke sizes of a single well and combine surface measures with formation flow conditions. The wellbore pipe flow model incorporates the fluid component model, inflow performance relationship model, flow correlation selection, and choke flow model. The establishment of the pipe flow model is based on the actual data of Well-CN001 (Figure 8). The depth of wellbore casing is 4,946 m, the inner diameter is 150 mm, and the outer diameter is 170 mm. The length of the completion section is 1,500 m, the number of perforation sections is 25, and the fracture parameters are inversed by automatic history fitting. The fluid components in the component model include water, methane, ethane, and carbon dioxide. The Peng–Robinson equation of the state and Pedersen viscosity calculation model are used. The IPR model adopts a trilinear transient model suitable for horizontal wells. The Baker–Jardine correlation suitable for the gas–water two-phase flow in horizontal wells is adopted as the flow correlation. The choke flow model includes a choke connecting the wellhead, a production pipeline, and a sink (Figure 9).

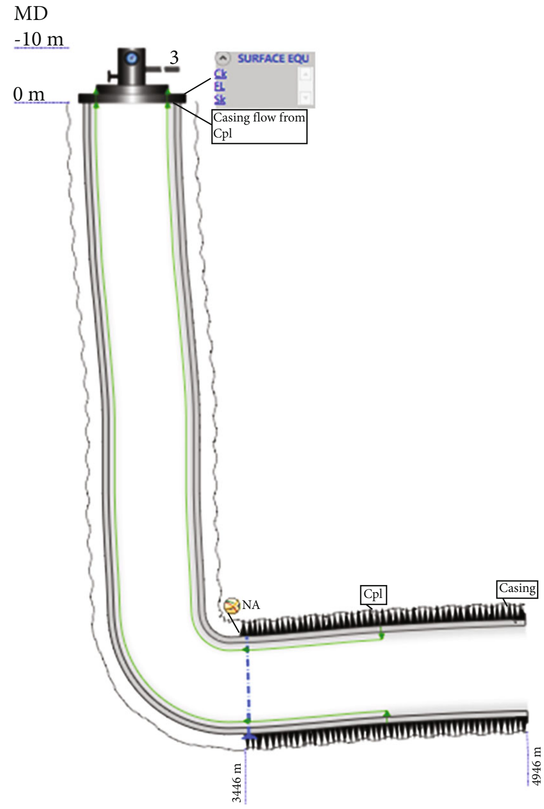

Figure 8: Schematic of Well-CN001 wellbore model.

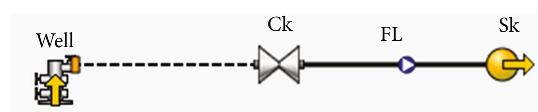

Figure 9: Schematic of Well-CN001 mouth flow model.

Herein, the optimization of the choke size in the post pressure flowback process of a shale gas well is based on

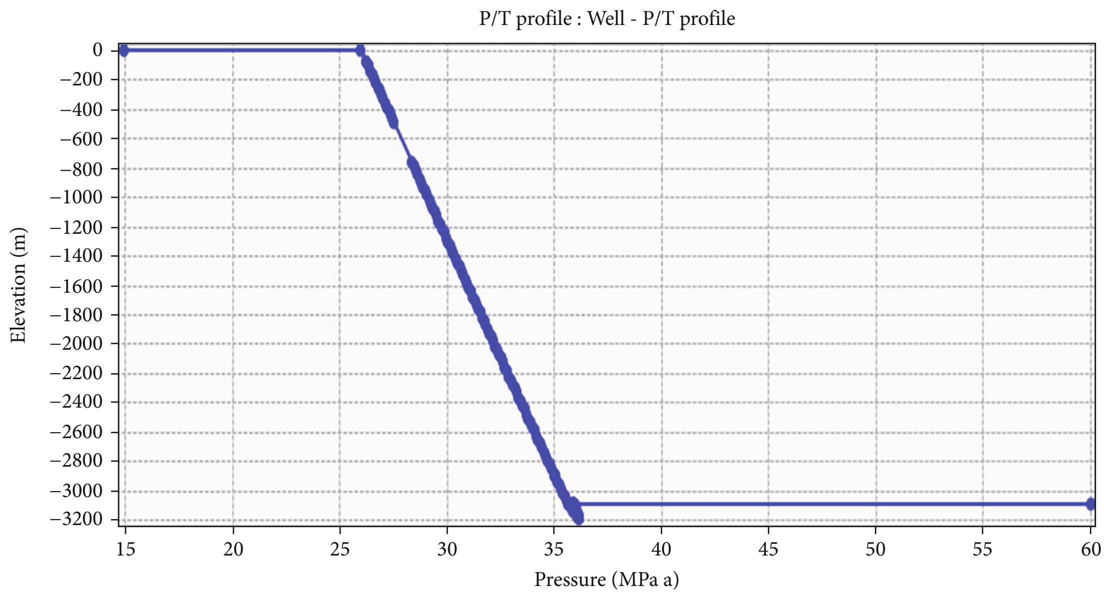

Figure 10: 12 mm choke size wellbore pressure profile.

Table 2: Production pressure difference corresponding to different choke sizes of Well-CN001.

Choke size (mm)	3	4	5	6	7	8	9	10	11	12
Production pressure difference (MPa)	1.1	3.5	4.5	9.0	12.7	16.2	19.0	21.1	23	24.0

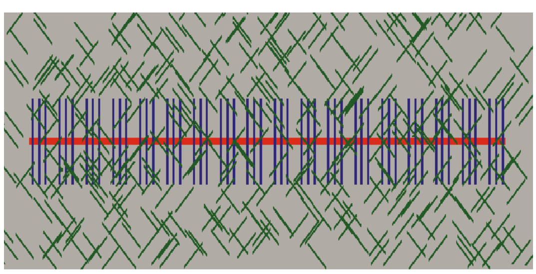

Figure 11: Schematic of numerical model of Well-CN001.

the calculation of production pressure difference corresponding to the choke size. Based on the pipe flow model established by the pipe flow calculation software, the production differential pressures corresponding to different choke sizes of Well-CN001 are determined. The size range of oil choke is 3 mm–12 mm, which is the common size of oil choke on site, and the formation pressure is 60 MPa. The wellbore pressure profile under different choke size systems is obtained through simulation, and the production differential pressure is calculated. The wellbore pressure profile calculated using a 12 mm choke size is shown (Figure 10). According to the model calculation results, the production differential pressures corresponding to different choke sizes of Well-CN001 are shown (Table 2).

2.5. Well Flowback Numerical Model. The numerical model of shale gas well flowback includes the matrix system and the fracture system (Figure 11). The establishment of the fracture system adopts the new-generation embedded discrete fracture EDFM simulation technology, which is more flexible than the local grid encryption technology. The fracture is directly embedded into the matrix grid, which can effectively reduce the number of grids and improve the calculation efficiency. The entire flowback model considers the characteristics of shale adsorption and desorption and the stress-sensitive effect of fractures, and the parameter setting is combined with the geological conditions, engineering parameters, and automatic history fitting results of actual wells. The relevant parameters of the model are shown (Table 3). The model assumes that the flow is a gas-water two-phase flow. It starts to simulate after the gas phase is stable and ignores the capillary force.

The flowback models consider the stress sensitivity under different choke sizes, i.e., the stress sensitivity curves corresponding to different production pressure differentials are designed. In the subsequent simulation study on the choke system, 41 numerical models are designed on the basis of this model and each of them sets the production pressure difference according to the choke size and then selects the corresponding stress sensitivity curve to carry out simulation calculation.

2.6. Optimization of the Maximum Choke Size. For a single well, the maximum choke size with relatively small impact on fracture conductivity is determined based on proppant reflux, embedding, and crushing. The production pressure difference corresponding to different choke sizes of Well-CN001 is calculated by the pipe flow model. According to the theory obtained from the stress sensitivity experiment of the shale artificial fracture, when the effective stress exceeds 19 MPa, the permeability damage of the artificial

Table 3: The relevant parameters of the Well-CN001 model.

Grid characteristics	pa Grid number Grid size	$263 \times 107 \times 1$ $10 \times 20 \times 20$	Fraction m
	Shale reservoir characteristics		
	Reservoir thickness	20	m
	Shale matrix porosity	0.06	Fraction
	Shale matrix permeability	0.0001	md
	Initial water saturation	30	%
	Rock compressibility coefficient	4.35×10^{-7}	Kpa
	Initial reservoir temperature	110	°C
	Formation pressure	60	MPa
	Fracture characteristics		
	Number of fracturing sections	25	
	Average section length	60	m
	Number of perforation clusters	3	
	Fracture height	12.8	m
	Fracture half-length	84.3	m
	Fracture width	0.097	m
	Fracture permeability	308.7	md
	Fracture cluster efficiency	0.702	Fraction

fracture is difficult to recover. Combined with the results of the two, the corresponding choke size of the well when the production pressure difference is about 19 MPa is the maximum choke size of the well. The maximum choke size is 9 mm (Figure 12). In the follow-up study, the choke replacement mode and replacement frequency are optimized and the maximum choke size simulated is set to 9 mm.

2.7. Optimization of the Well Opening Choke Size. Currently, the commonly used choke size of shale gas wells is between 3 mm and 13 mm. To study the influence of the well opening choke size on the early flowback process, since the maximum choke size of Well-CN001 is 9 mm, through the established shale gas well flowback numerical model, the initial choke size is between 3 mm and 9 mm, and then, the step-by-step increase range is 1 mm to the maximum choke size of 9 mm. The duration of each stage of choke is three days; 9 mm choke is used in the production stage under the total production time of 20 years and 3 months. The stress-sensitive curves corresponding to different choke sizes and different production differential pressures have been obtained through experiments. In the numerical simulation process, different choke sizes are set according to the experimental results and different stress-sensitive curves are used for the simulation calculation to improve the calculation accuracy.

The smaller the opening choke size is, the higher the initial daily gas production and peak daily gas production

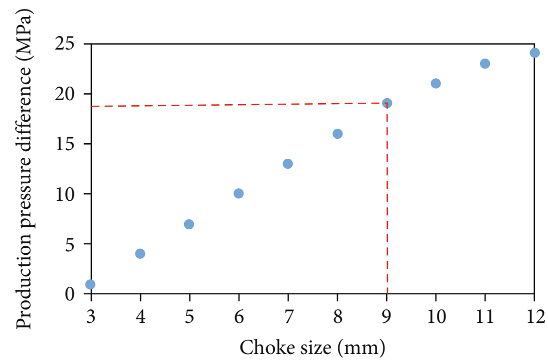

Figure 12: Maximum choke size under limited production differential pressure of Well-CN001.

within 3 months is but the daily gas production in the middle and late stages is lower (Figure 13). The initial choke size of 3 mm is 65.96% higher than the daily gas production on the 90th day of the initial choke size of 9 mm. With the increase of the opening choke size, the flowback rate and EUR in 20 years of production are lower and the reduction range gradually increases (Figure 14). The initial choke size of 3 mm is 13.19% higher than the EUR of the initial choke size of 9 mm. At the beginning, large choke flowback is adopted with the higher production pressure difference and the higher initial gas production. However, the proppant is more likely to migrate, causing high stress sensitivity and permeability damage, weakening the reservoir recovery ability and the fracture conductivity. The gas production and liquid production reduce in the later stage. Therefore, it is better to choose a small well opening choke size. The optimal well opening choke size of Well-CN001 is 3 mm (Figure 15).

2.8. Optimize the Increase Range of Each Stage Choke. The choke size and replacement stages in the early flowback process are also important factors affecting the productivity of shale gas wells. Herein, the choke size is simulated from 3 to 9 mm, the duration of each stage is five days, and the increase range of each stage is 1 mm, 2 mm, 3 mm, and 4 mm. In the simulation, different stress sensitivity curves are used under different choke sizes, 9 mm choke is used in the production stage, and the total production time is 3 months and 20 years.

Under the condition of constant choke duration, the smaller the increase of the choke size at each stage, the lower is the initial daily gas production and peak gas production in three months but the flowback rate daily gas production is larger in the middle and later stages (Figure 16). The daily gas production of each stage increased using 1 mm is 121.67% higher than that of the 90th day with an increase of 4 mm. With the increase of the size of each stage choke, the flowback rate and the EUR are lower in 20 years of production and the decrease rate increases (Figures 17–18). The increase of 1 mm per stage is 22.27% higher than the 20-year EUR with an increase of 4 mm. The smaller the increase of the choke size at each stage, the smaller the production differential pressure at the same time. This means that the permeability stress sensitivity of the shale artificial fracture is

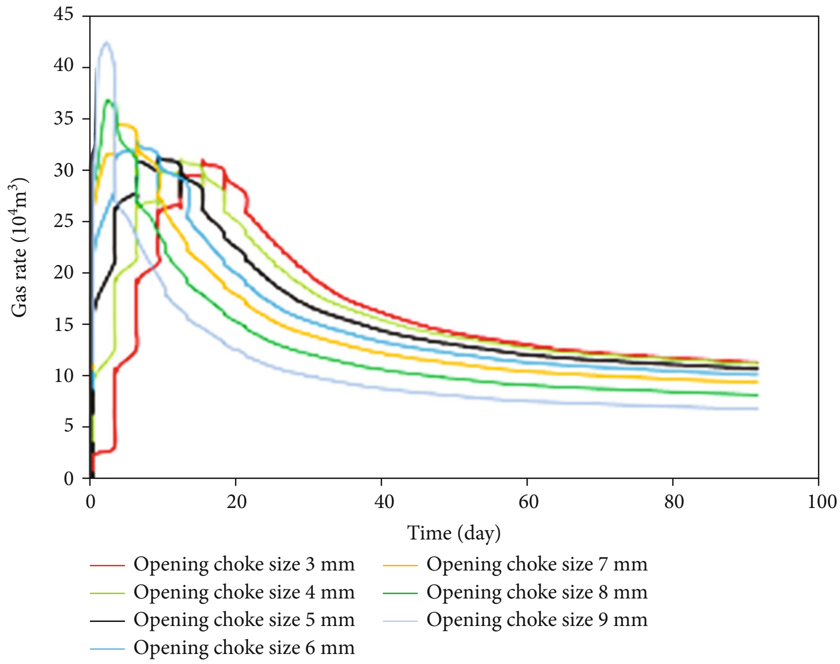

FIGURE 13: Comparison curve of daily gas production in three months with different choke replacement methods.

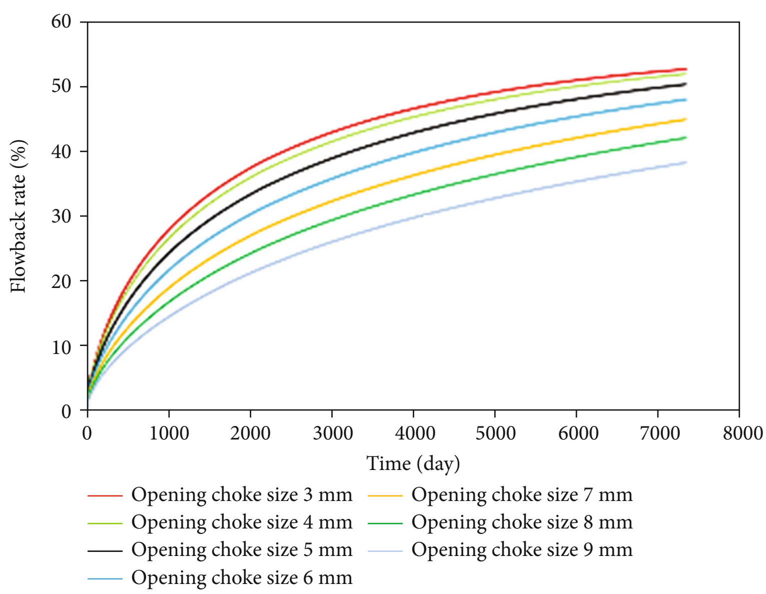

FIGURE 14: Comparison curve of 20-year flowback rate of different choke replacement methods.

weaker, providing favorable channels for later gas flow. Therefore, within the maximum choke size range, it is wise to increase the choke size by 1 mm at each stage rather than by 2 mm or larger, which is more helpful to improve the productivity of shale gas wells.

2.9. Optimize Choke Duration per Stage. The duration of each choke level is a specific research on the choke system. Through the established flowback model, the choke size is simulated from 3 to 9 mm, the increase range of each stage is 1 mm, and the duration of each stage is 1 day, 2 days, 3 days, 4 days, and 5 days. In the simulation, different stress sensitivity curves are used under different choke sizes; 9 mm choke is used in the production stage, and the total production time is 3 months and 20 years.

When the replacement stage of the choke size is 1 mm, the longer the duration of the choke size of each stage, the lower the daily gas production in the initial stage within three months, but the daily gas production is higher in the middle and later stages. When the duration is higher than three days, the increase of daily gas production decreases (Figure 19). The duration of each choke stage is five days, which is 90.19% higher than the daily gas production on the 90th day with a duration of one day. When the duration

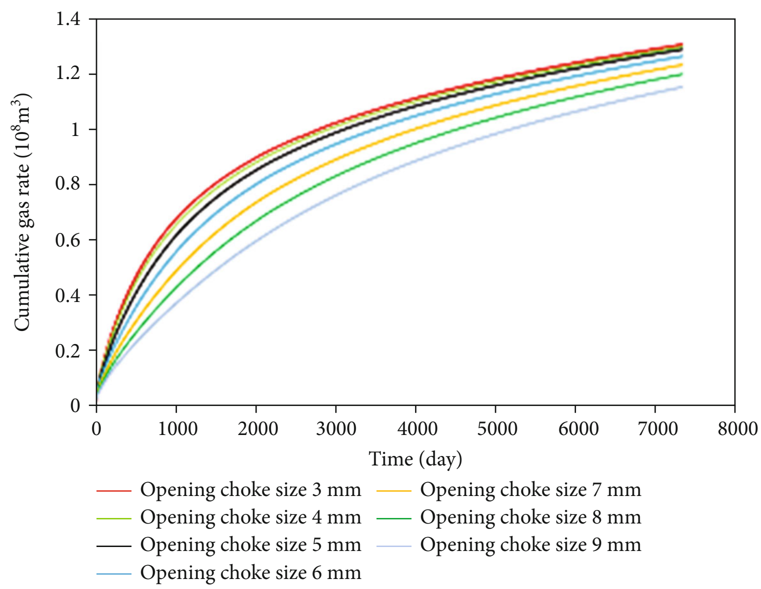

Figure 15: Comparison curve of 20-year cumulative gas production of different choke replacement methods.

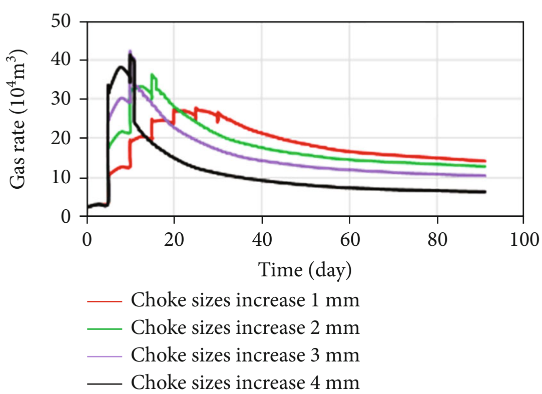

Figure 16: Comparison curve of daily gas production in three months for different choke size increase.

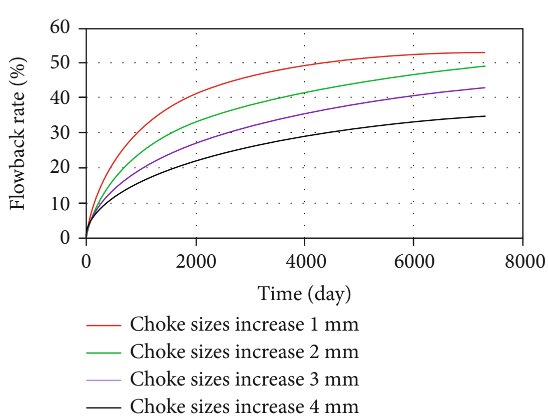

Figure 17: Comparison curve of 20-year flowback rate of different choke size increase.

of the choke size of each stage is less than three days, the 20-year flowback rate and EUR increase with the increase of duration. When the duration of the choke size at each stage

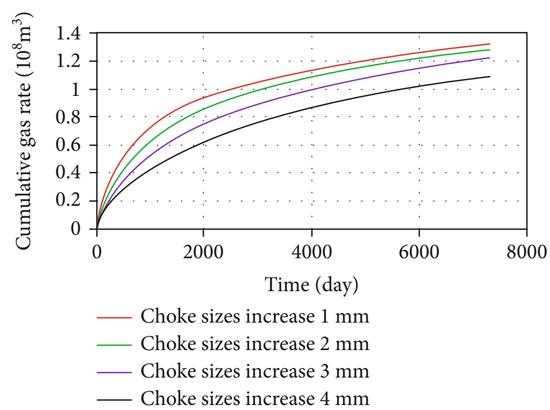

Figure 18: Comparison curve of 20-year cumulative gas production of different choke size increase.

is higher than three days, the flowback rate and EUR change slightly (Figure 20). The duration of each stage choke is five days, which is 5.2% higher than the 20-year EUR with a duration of one day. The longer the small choke size lasts, the smaller the early production differential pressure and the smaller the initial gas production is. The stress sensitivity becomes low, which can reduce the early fracture closure damage, helping to improve the fracture conductivity. Under the smaller initial reservoir damage, it is favorable to the increase of medium- and long-term cumulative gas production of a single well. With the increase of the duration of each level of choke, the time of drainage and production stage also increase. The increase of the overall drainage and production time leads to the longer retention time of the fracturing fluid in the reservoir and affects the production effect of gas wells. Therefore, it is better to keep the duration of each level of choke long. Therefore, under the condition that the choke size is increased step by step and the duration of each choke is the same, the optimal duration of each choke size is three days.

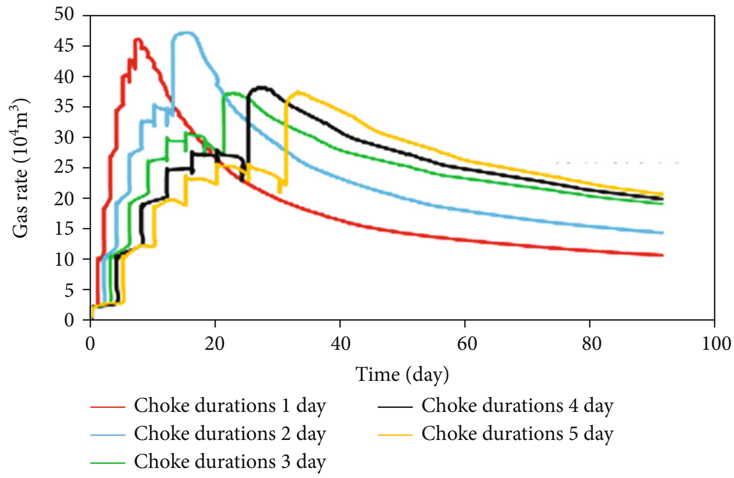

FIGURE 19: Comparison curve of daily gas production of three months with different choke durations.

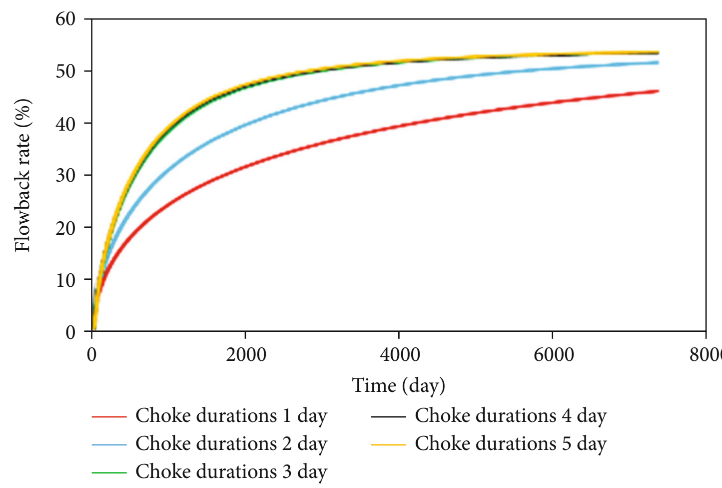

FIGURE 20: Comparison curve of 20-year flowback rate of different choke durations.

2.10. Limitation. In this paper, existing numerical simulation software are used to carry out numerical simulation analysis on the flowback of shale gas wells but they are limited in the simulation of shale imbibition and hydration and can hardly simulate shale imbibition and hydration. In the whole life cycle of a shale gas well, the variation of reservoir permeability caused by imbibition and hydration still has an influence on the result, which needs further researches.

3. Conclusion

(1) With the gradual decrease of the initial effective stress, the damage of the reservoir in the initial stage is weakened, the recovery ability of the reservoir is enhanced, and the increase range of the recovery rate initially increases and then decreases. When the effective stress exceeds 19 MPa, the proppant is apparently broken and embedded, which makes the reservoir permeability damage recovery more difficult. Therefore, the optimal maximum choke size of different shale gas wells is determined when the production differential pressure does not exceed 19 MPa

(2) Through the application of the refined choke system research method established in this paper to Well-CN001, the impact of different choke systems on the third month daily gas production of Well-CN001 is 65.96%–121.67% and the impact on the 20-year EUR of a single well is 5.2%–22.27%

(3) The higher the initial gas production is, the larger the early production pressure difference will be but the proppant is more likely to migrate and its stress sensitivity becomes high. The permeability damage increased and the reservoir recovery ability becomes lower if the fracture conductivity and the gas and liquid production decreased in the later stages. Therefore, the smaller the opening choke size of shale gas well is, the better it is. The common opening choke size can be 3 mm. Within the maximum choke size range, the increase range of the choke size at each stage is preferably 1 mm. When the choke size is

increased stage by stage, the optimal duration of each choke size is three days

Data Availability

The original contributions presented in this study are included in the article and further inquiries can be directed to the corresponding author(s).

Conflicts of Interest

The authors declare that the research was conducted in the absence of any other commercial or financial relationships that could be construed as potential conflicts of interest.

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