Research Article

Insight into the Methods for Improving the Utilization Efficiency of Fracturing Liquid in Unconventional Reservoirs

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A large amount of fracturing fluid will be injected into the unconventional reservoirs during hydraulic fracturing. At present, the maximum amount of fracturing fluid injected into shale oil reaches 70000 m³ in Jimsar. The main function of fracturing fluid is to make fractures for traditional reconstruction of fracturing; for unconventional reservoirs, fracturing fluid is also used to increase formation energy by large-scale injection. It is of great significance to improve the utilization efficiency of large-scale hydraulic fracturing fluid for shale oil to increase production and recovery. In this study, the method of improving the utilization efficiency of the large-scale hydraulic fracturing fluids is explored by experiment, numerical simulation, and field test of Jimsar shale oil formation. This research shows that fracture complexity can effectively increase the contact area between the fracturing fluids and the formation. The water absorption rate of the fractured core is increased, which lays the foundation for improving the liquid utilization efficiency. Reasonably, well shutting before production ensures the pressure balance in the fractures, and the fluid pressure can be transmitted to the far end, which improves the fracture effectiveness, increases formation energy, and promotes imbibition and oil displacement. By using the additive of enhanced imbibition displacement, the displacement efficiency and the displacement amount of crude oil in the micro-nanopores can be greatly improved, and the utilization ratio of liquid can be further enhanced. The experiment adopted in the field proves that improving energy utilization efficiency has an important impact on production. This study has great guiding significance for the efficient development and practical production of unconventional reservoirs.

1. Introduction

Unconventional resource exploitation requires higher technologies [1, 2]. The permeability of the unconventional reservoir is usually less than 0.1 mD, and porosity is less than 10%; reservoir physical properties are poor. The characteristics of unconventional reservoirs make it necessary to adopt strengthening measures to develop them. The fracturing technology is used to improve the seepage condition of oil and gas flow in the reservoir to achieve the purpose of effective exploitation [3–6]. Since the concept of large-scale fracturing was put forward in the Wattenberg gas field in the 1980s in the United States [7], large-scale fracturing has developed and progressed continuously. Horizontal well technology combined with large-scale fracturing technology has become the main means

to form the effective production of unconventional reservoirs [8–10]. The unconventional reservoir has a very low seepage capacity. A large number of high-pressure fracturing fluids are injected into the reservoir to make the formation rock rupture, produce multilevel fractures and even connect the natural fractures, providing channels for the flow of oil and gas, greatly improve the seepage capacity of the reservoir, and increase the contact area between the reservoir and the wellbore [11, 12]. At the same time, the fracturing fluid with high liquid volume and high pressure carries a lot of energy, which can supplement the formation energy [13, 14]. Unconventional reservoirs have poor physical properties and lack natural energy, resulting in low productivity and rapid decline by natural depletion [15–18]. Supplement energy is an essential prerequisite to ensure the effective production of such reservoirs. Unconventional

reservoirs have more micro-nanopores, so they have higher capillary pressure [19–21]. And the strong imbibition induced by high capillary promotes fracturing fluid to displace crude oil [22–24]. High-pressure fracturing fluid into the formation provides fluid for imbibition and provides power for oil displacement. Fracturing fluid is an important carrier to realize the hydraulic fracturing technology. It is of great significance to improve the utilization efficiency of fracturing fluid for unconventional reservoirs to increase production.

In recent years, large-scale fracturing of unconventional reservoirs has greatly increased the amount of fracturing fluid injected. The amount of fracturing fluid for Jimsar shale oil is as high as 70000 m³. However, at present, a large amount of fracturing fluid is not fully utilized. Unconventional oil and gas reservoirs usually have poor seepage capability, resulting in a small swept range of injected fracturing fluid and a small production range of the reservoir. The conventional production technology performs fracturing fluid flow back and production soon after hydraulic fracturing. In this way, the fracturing fluid and the energy it carries are concentrated in the area near the well and cannot be fully diffused in the formation. The formation energy enhancement effect is not significant. This also makes the small pores with high capillary force unable to carry out imbibition and oil displacement and unable to increase production. How to improve the utilization efficiency of fracturing fluid needs further exploration. In order to discuss the above problem, this study selects the bottom hole core of Jimsar Lucaogou formation and Yanchang formation of Ordos Basin to carry out the imbibition experiments, establishes the double medium numerical simulation model, analyses the field test of Jimsar shale oil, puts forward the concept of fracturing fluid utilization efficiency, and explores the method of improving fracturing fluid utilization efficiency from the action of fracturing fluid.

2. Materials and Methods

2.1. Experimental Materials and Methods. This study selected the bottom cores of Lucaogou Formation in Jimsar depression and Yanchang Formation of Ordos Basin for experiments. The cores of Lucaogou Formation in Jimsar were taken from well J36 and J37 with the number of “Well name-#”, and the tight sandstone cores of Yanchang Formation in Ordos basin with the number of “C-#”. In the experiment, a triaxial press, some spontaneous imbibition devices and some imbibition bottles were used, as shown in Figure 1.

In order to qualitatively analyse the effect of fracture on core water absorption, the characteristics of water absorption of cores with or without fracture were compared. The cores with the number of “C-#” were made into standard rock samples; the control group rock samples were compressed by triaxial compression to make cracks, and the reference group samples were not processed; the rock samples were dried in an oven at 105°C to the same quality; the spontaneous imbibition tests were carried out on the samples, respectively. The characteristics of water absorption speed and capacity of spontaneous imbibition were analysed through the changes in the core's water absorption quality in the experiment.

Imbibition is an important reference factor to determine shut in time [25–28]. The cores of different depths in the J36 well were selected, and the rock samples were dried in a 105°C oven to the same quality; the spontaneous imbibition tests were carried out on the samples, respectively.

In order to select the suitable additives for imbibition in the Jimsar area, the differences of the solution containing different kinds of additives were compared. After washing the oil, the cores were dried in a 105°C oven to constant quality, and they were saturated with kerosene to stable quality; then, rock samples were immersed in imbibition bottles containing different types of additive solution, respectively; the amount of oil expelled was recorded regularly.

2.2. Establishment of the Numerical Simulation Model. After large-scale hydraulic fracturing, unconventional reservoirs form complex fracture networks, including hydraulic fractures, secondary fractures of hydraulic fractures, and numerous microfractures. A large number of microfractures can also connect the natural fractures and bedding fractures of the reservoir. Many scholars think that a dual media system is more suitable for unconventional reservoirs with a complex fracture network after hydraulic fracturing [29, 30].

The model in this study is based on the Petrel RE software and is established using a dual-medium system. Based on a well of Lucaogou Formation in Jimsar, a single fracturing section shut-in model of a horizontal well is established, as shown in Figure 2(a). The calculation of the model is mainly based on the following equations. If gravity is not considered in the flow equation, it can be expressed as

$$q = -\frac{k}{\mu} \nabla P. \quad (1)$$

The material balance equation is expressed as follows:

$$-\nabla \cdot M = \frac{\partial}{\partial t} (\phi \rho) + Q. \quad (2)$$

The flow equation in the model can be expressed as

$$\nabla \cdot [\lambda (\nabla P - \gamma \nabla z)] = \frac{\partial}{\partial t} \left(\frac{\phi}{\beta} \right) + \left(\frac{Q}{\rho} \right). \quad (3)$$

In the equation, $\lambda = k/\mu\beta$.

There are three hydraulic fractures perpendicular to the wellbore (hereinafter referred to as the primary fracture) and ten secondary fractures perpendicular to the hydraulic fracture in the dual-medium single-stage fracturing model. We use local mesh refinement and modify the porosity and permeability properties of the mesh to characterize primary and secondary fractures. The grid fracture system in the dual medium is used to the numerous microfractures in the reservoir after fracturing, as shown in Figure 2(b). The grid matrix system characterizes the reservoir matrix. The fracture and the matrix system exchange material and energy through the effects of imbibition wherein fluid expansion, viscous force, etc. occur.

(a)

(b)

(c)

FIGURE 1: Laboratory equipment: (a) triaxial press, (b) spontaneous imbibition device, and (c) imbibition bottle.

The basic parameters of the model are as follows: section length is 50 m, fracture half-length is 100 m, height is 20 m, the equivalent diversion capacity of primary fractures is $20 \mu\text{m}^2\cdot\text{cm}$ and the equivalent diversion capacity of secondary fractures is $8 \mu\text{m}^2\cdot\text{cm}$, porosity of matrix is 0.1, permeability is 0.001 mD, porosity of microfracture is 0.01, permeability is 1 mD, and permeability of microfracture near primary fracture is slightly higher. The reservoir depth is 2800 m; the original formation pressure is 36 MPa; the material balance

method is used to initialize; the rock compression coefficient is $6 \times 10^{-6} \text{ Pa}^{-1}$. We inject 1200 m^3 fracturing fluid, shut the well for 90 days, and then open the well for production.

Three types of relative permeability curves are used to characterize the permeability characteristics of primary and secondary fractures, microfractures, and matrix, respectively, because of the large difference of seepage characteristics between multistage fractures and matrix. The relative permeability curves of primary and secondary fractures adopt

FIGURE 2: Single-stage fracturing model of dual media. (a) Single-stage fracturing model. (b) Dual medium grid.

standard artificial fractures', and the relative permeability curves of microfractures refer to the literature on the relative permeability of fractures in low-permeability unconventional reservoirs [31]. The relative permeability curve of the matrix is processed by core experiments in the Jimsar area. The three types of relative permeability curves and matrix capillary force curves are shown in Figure 3. "Sw" represents water saturation. "Krw" and "Kro" represent the relative permeability of water and the relative permeability of oil, respectively. "Pc" represents capillary force.

3. Results

3.1. Analysis of the Factors Affecting the Efficiency of Liquid Utilization. Large-scale hydraulic fracturing brings a large amount of fracturing fluid and energy into the reservoir. Fracturing fluid has the function of making the reservoir rock fracture, replenishing energy for the reservoir and enhancing the ability of imbibition displacement oil. The extent to which fracturing fluid plays a role in the reservoir is its utilization efficiency, which can be reflected by the increase of reservoir yield and pressure. The higher the utilization efficiency of fracturing fluid is, the better the productivity of the reservoir is, and the higher the pressure of the reservoir is. In this part, the methods to improve the efficiency of fracturing fluid are explored from many aspects through the related laboratory experiments and numerical simulation.

3.1.1. The Complexity of Fracture Networks. Improving the complexity of the fracture network can enhance the utilization efficiency of hydraulic fracturing fluid. Simple fracture network cannot effectively transform fracturing fluids and liquid pressure into the matrix, Ghanbari et al. [32] used Figure 4(a) to sketch a simple fracture network, and its number of secondary fractures was less. The remarkable characteristic of the unconventional reservoir is low seepage capacity; most of the injected fracturing fluid can only gather in the hydraulic fractures and can not spread to the matrix. The complex fracture network is shown in Figure 4(b), has primary fractures and many secondary fractures, and even connects with the natural fractures in the reservoir [32]. Such a complex fracture network can greatly improve the seepage capacity of the reser-

voir and the contact area between the fracturing fluid and the reservoir [33]. The unconventional reservoir represented by shale has the characteristics of many micro-nanopores, ultra-low water saturation, and strong capillary force. The increase of contact area between fracturing fluid and reservoir can promote the infiltration of fracturing fluid into matrix pores, thus improving fluid utilization efficiency and increasing production after hydraulic fracturing.

In this study, the effect of fracture on core water absorption is qualitatively compared through water imbibition experiments. The C-# control group rock samples formed a visible oblique through fracture after pseudotriaxial compression experiment, as shown in Figure 5, and the cores also contained many small, invisible fractures. Some cores are compressed by the press and broken. The control group with cracked cores C-2, C-3, and C-7 and the reference group with no cracks C-10 for the water absorption experiment were selected. The water absorption experiment of some cores containing cracks is shown in Figure 6.

Figure 7 shows the imbibition characteristic curve of cores with cracks in the control group and core without cracks in the reference group. In this figure, the horizontal axis is the time, and the vertical axis is the net water absorption of the cores. The black curve is the net water absorption curve of the reference group C-10 core, and the red, green, and blue curves represent the water absorption characteristics of C-2, C-3, and C-7, respectively. The stepped water absorption curve of core C-7 is due to the low sensitivity of the balance and the high threshold of the indication change.

Comparing the above water absorption curves of cores with cracks and core without cracks, it is easy to know that the water absorption quality of core with cracks is greater than that of seamless core, and the water absorption rate of core with cracks is faster than that of seamless core, and seamless core still has a certain water absorption capacity. When the cores were immersed for 50 hours, the water absorption quality of the core with cracks was between 0.54 and approximately 0.58 g, and the water absorption quality of the core without cracks was 0.45 g. The water absorption quality of core with cracks was 0.09~0.13 g more than that of core without cracks, and the extra part accounts for at least 20% of the water absorption of core without cracks. In the first two hours of the

FIGURE 3: Relative permeability curve and matrix capillary force curve: (a) relative permeability curve and (b) matrix capillary force curve.

FIGURE 4: Comparison of simple and complex fracture network [32]: (a) simple fracture network and (b) complex fracture network.

FIGURE 5: Fractured cores and unfractured core.

water absorption experiment, the water absorption rate of the core without cracks was fast, but it was much lower than that of the core with cracks, and the water absorption quality of the core with cracks increased almost linearly at the initial stage of water absorption. The water absorption rate of the cores gradually slowed down with the experiment time, but the water

absorption rate of the core with cracks was always higher than that of the core without cracks. The core without cracks absorbed a part of the liquid with the action of imbibition. Sufficient time was required for the water absorption of the cores to reach equilibrium. The existence of fractures increased the water absorption rate and imbibition velocity of the cores, but fractured cores also need enough time for the water absorption quality to reach equilibrium. Then, the complex fracture network caused by large-scale volume fracturing will inevitably affect the utilization of fracturing fluid and its energy in the reservoir, and time is an important factor in the utilization of fracturing fluid in reservoirs with complex fracture networks.

This study also compared the production of different fracture numbers and different fracture network complexities by numerical simulation. In order to highlight the influence of hydraulic fracture on the utilization of liquid, this part adopted the single pore medium model. The fracturing segments of the same length were perforated with 2, 3, and 4 clusters, respectively, as shown in Figure 8. After the water

FIGURE 6: Water absorption experiments of fractured core.

FIGURE 7: Variation curve of cores imbibition with or without fracture.

injection, the well was closed for the same time. Then, the cumulative water production and oil production of different perforation clusters were compared, as shown in Figure 9. In the early stage of fracturing production, the cumulative production increased rapidly, and the production gradually stabilized with time. The fracturing section of the perforation 4 clusters had the best production situation, with the highest cumulative oil production, about 780 m^3 , and the lowest cumulative water production, about 280 m^3 . The fracturing section with perforation 2 clusters had the worst production situation, with the lowest cumulative oil production, about 560 m^3 , and the highest cumulative water production, about 520 m^3 . With the increase of the number of perforation clusters in the fracturing section, the cumulative water production of the fracturing section decreased, while the cumulative oil production increased. This is because the number of perforation clusters increases, the number of hydraulic fractures increases, the complexity of the reservoir fracture network increases, and the contact area between the fracturing fluid and reservoir matrix increases so that more fracturing fluid enters the matrix pores and displaces the crude oil. Increasing the complexity of the fracture network can improve the utilization efficiency of fracturing fluid and then increase the production.

3.1.2. Well Shut-in Time. Well shut-in for a specific time after hydraulic fracturing is the technical way to improve the efficiency of liquid utilization. Shut-in time after fracturing is an important factor influencing the utilization efficiency of fracturing fluid [34–36]. In this study, the dual-medium single-stage fracturing model was used to study the utilization law of fracturing fluid during shut-in after fracturing and the effect of shut-in time on the efficiency of fracturing fluid utilization.

Figure 10 shows the fluid pressure variation range of the fracturing section at different shut-in times after fracturing fluid injection. After the injection, the fracturing fluid was mainly distributed in hydraulic fractures and secondary fractures with stronger conductivity. There was a certain degree of imbalance in the distribution between the primary and secondary fracture networks; the pressure of hydraulic fractures and secondary fractures near the wellbore were higher. The fracturing fluid gradually diffused outward from the primary and secondary fractures with the shut-in time with the effects of imbibition and pressure potential difference caused by uneven fluid distribution. The seepage capacity of the microcrack is limited but higher than that of the matrix. The microcracks were filled with fracturing fluid and the pressure increased. And then, the fracturing fluid seeped into the adjacent matrix and the matrix pressure increased. In each grid, the fracturing fluid entered the microfracture slightly earlier than the matrix, and the pressure of the microfracture increased earlier than that of matrix. So at the same time step, the pressure of microfracture was higher than that of the matrix. With the passage of shut-in time, the imbalance of fluid pressure distribution in the fracturing section gradually weakened, and the pressure distribution also changed accordingly. When the well was shut-in for 2 days, the primary and secondary fracture pressures were balanced, the internal imbalance of the fractures basically disappeared, but the pressure almost did not propagate outward, and the microfractures and matrix far away from the primary and secondary fractures still maintained the initial formation pressure. When the well was shut-in for 20 days, the pressure of the primary and secondary fractures decreased significantly, and the pressure of the surrounding matrix increased. Still, most of the matrix remained unchanged, even maintaining the original pressure. When the well was shut-in for 40 days, the pressure

FIGURE 8: Fracturing model with different numbers of fracture clusters.

FIGURE 9: Comparison of cumulative production for different clusters of the same section length: (a) cumulative oil production and (b) cumulative water production.

FIGURE 10: Simulation results of pressure propagation during fracturing shut-off.

distribution in the fracturing section was balanced. Only the pressure of the edge part of the fracturing section and matrix far from the fractures were lower. When the well was shut-in for 90 days, the pressure in the fracturing section basically did not change and the pressure of the fracture network was slightly lower than that of matrix. This is because the strong imbibition caused by the strong capillary force of the unconventional oil and gas reservoir matrix makes the fracturing fluid more retained in the matrix. The diffusion and pressure

propagation of the fracturing fluid in the fracturing section have noticeable time effects, and the fracturing fluid is basically transferred to the whole fracturing section after 90 days of shut-in.

Shut-in well after fracturing provides time for the diffusion of fracturing fluid in the fracture network. After large-scale hydraulic fracturing, the reservoir has formed a complex fracture network. Firstly, the fracturing fluid fills the hydraulic fractures that have high conductivity and the secondary fractures

FIGURE 11: Comparison of cumulative production after different shut-in times: (a) cumulative water production and (b) cumulative oil production.

FIGURE 12: Spontaneous imbibition curve of J36 borehole in Jimsar.

that connect with the hydraulic fractures. Then, the fracturing fluid gradually fills the microcracks and natural fractures and gradually diffuses into the matrix. There is a great difference in the conductivity between fractures in the reservoir, and the distance between microcracks and wellbore is also different. Fracturing fluid filling fracture network has an obvious time effect; it takes a long time for the fracturing fluid to diffuse into the smaller and deeper fractures in the reservoir and then gradually seep into the rock matrix to be fully utilized.

Because of the characteristics of low porosity and low permeability in the unconventional reservoir, the diffusion speed of fracturing fluid is slow and has an obvious time effect [37, 38]. If it is produced directly without closing the well after hydraulic fracturing, or if the closing time is too

short, the fracturing fluid can not diffuse to the distal microcrack and rock matrix. A large number of fracturing fluid will be produced directly. The fracturing fluid can not play a full role in the formation, and the utilization efficiency of the fluid is low, which is manifested in the increase of water production. The paper compared the cumulative production after different shut-in times. The cumulative water production was the highest, and the cumulative oil production was the lowest when the well was produced directly without shut-in, as shown in Figure 11. With the increase of shut-in time, the cumulative water production in the fracturing section decreased and the cumulative oil production increased. This is because the shut-in time is long and more fracturing fluid can be used, thereby replacing more oil and improving the efficiency of liquid utilization. However, after a certain period of shut-in time, the cumulative water production was no longer decreased, and the cumulative oil production was no longer increased if the time increased. Therefore, the closing time is not the longer the more favorable; the reservoir has a reasonable closing time suitable for itself. The determination of closing time should refer to the diffusion and balance of reservoir pressure and consider the effect of improving production.

Closing well also provides time for the imbibition of fracturing fluid and matrix in the reservoir. The numerous micro-nanopores make shale oil reservoirs have ultrahigh capillary force, and the imbibition caused by capillary force is the main role of fracturing fluid entering into rock matrix and replacing oil [21]. It needs enough time to reach equilibrium and also has an obvious time effect. Suppose the closing time is inadequate, the contact area between fracturing fluid and reservoir will be greatly reduced because of insufficient filling of fracture network and reservoir matrix, so that the reservoir can not fully imbibe and the displacement oil will be reduced. Figure 12 is the spontaneous imbibition test

curve of core of well J36 of Jimsar shale oil. Due to the difference of physical properties and clay content among samples, the time to reach imbibition balance is different, which takes 50 hours for short and 130 hours for long. Although reasonable closing time can improve the utilization efficiency of fracturing fluid, the determination of shut-in time needs to further explore the fluid filling condition of fracture network and the imbibition characteristics of the reservoir.

3.1.3. Imbibition Additives. The reservoir has formed a complex fracture network after large-scale hydraulic fracturing. Imbibition is the main oil recovery mechanism of the fractured low-permeability reservoir. In order to improve the well shut-off effect, Bakken's tight oil reservoir was put into production by large-scale fracturing. By adding surfactant in the fracturing fluid and carrying out the "well shut off" experiment, tight oil recovery was effectively improved [39]. Surfactant solution can improve the imbibition of low-permeability core and enhance imbibition and displacement [40, 41], and the recovery of imbibition is higher than that of water injection [42], which also improves the utilization efficiency of fracturing fluid. In this study, the cores of J37 well in the Jimsar area were used to compare the influence of different additives on imbibition and oil displacement and discuss the influence of different additives on the improvement of liquid utilization efficiency. The results show that the oil displacement efficiency of the additive based on anionic surfactant is better than that of cationic surfactant and emulsion surfactant in Jimsar shale oil reservoir, as shown in Figure 13. And the oil displacement efficiency of anionic surfactant-based additives increases 5-15 percentage points. Enhancing imbibition can promote the oil-water replacement between fracturing fluid and reservoir and improve the utilization efficiency of fracturing fluid. It provides a feasible angle for improving the utilization efficiency of fracturing fluid.

3.2. Field Application. The field well closing test of Jimsar shale oil reservoir has achieved good results. Six wells with 200m spacing were tested and put into production in 2018. Their geological profile and reservoir physical properties are similar, but the fracturing process and shut-in time are different, as shown in Table 1 below. The total liquid intake, fluid intensity and shut-in time of J1-J3 wells are lower than those of the last three wells. The liquid strength of J4-J6 wells is about 30% to 50% higher than that of the first three wells, but the shut-off time is about 2 to 6 times more. After hydraulic fracturing, well J1-J3 is closed only briefly, and the shut-off time is insufficient, while the shut-off time of well J4-J6 after fracturing is between 30 and 40 days, and the shut-off time is sufficient.

Figure 14 is a comparison chart of oil pressure before and after shut-in and days of shut-in of wells J1-J6. The oil pressures of the three wells J4-J6 are higher at the beginning of the shut-in, but the wellhead pressure drop of the three wells is significant at the end of the shut-in. This is because the fracturing fluid carrying pressure at the bottom of the well spreads to the deep part of the reservoir. With the passage of shut-in time, the fracturing fluid gradually diffuses from the bottom of the well to the fracture network and the deep part

FIGURE 13: Recovery of different imbibition additives.

TABLE 1: Well J1-J6 fracturing table.

Well name	Total fluid intake (m ³)	Strength of liquid (m ³ ·m ⁻¹)	Shut-in time (d)
J1	44186.3	29.5	10
J2	29536.7	19.6	6
J3	45750.4	29.9	9
J4	56642.4	41.7	43
J5	58724.6	47.2	42
J6	70069.8	47.6	33

of the matrix. The pressure is no longer gathered at the bottom of the well but diffuses into the reservoir, so the wellhead pressure decreases greatly. In addition, after the fracturing fluid reaches the tiny fissure, the imbibition of the fracturing fluid and the matrix can promote the fracturing fluid to enter the matrix pore and make the matrix pore pressurization and reduce the wellhead pressure. The obvious decrease of wellhead pressure is the manifestation of fracturing fluid being used effectively.

Comparing with the actual production of wells J1 to J6, it is found that the production effect of three wells J4 to J6 after a long period of closing well is obviously better, as shown in Figure 15. In the early stage of production, there is little difference in the output of the six wells. With the increase of the production time, the production of the three wells J4-J6 is significantly higher. By the time of production 360 d, the cumulative oil production of these three wells J4-J6 is almost double that of three wells J1-J3. The cumulative water production of three wells J4-J6 has been lower than that of wells J1-J3. The longer the production time, the more prominent the advantages of J4-J6 wells. Sufficient shut-in time improves the utilization of fracturing fluid. It not only makes the fluid pressure spread to the far end and makes the formation energy increase effect remarkable

FIGURE 14: Different well closures of wells J1–J6.

FIGURE 15: Different well closures and developments of well J1–J6: (a) cumulative water production and (b) cumulative oil production.

but also makes the fracturing fluid fully imbibition and increases the oil well yield. Improving the utilization rate of the liquid has an important impact on productivity. This study has great significance for the efficient development and actual production of unconventional reservoirs.

4. Conclusions

- (1) The increase of the complexity of reservoir fracture network can effectively increase the contact area between fracturing fluid and reservoir, lay the foundation for the formation to absorb fracturing fluid, and improve the efficiency of fluid utilization
- (2) Reasonable shut-in after fracturing provides time for fracturing fluid and pressure to spread to the deep reservoir, improves fracture effectiveness, and also provides time for imbibition and strengthens oil displacement to increase formation energy and effective use of liquid
- (3) By using the additive of enhanced imbibition and displacement, the displacement efficiency and the displacement amount of crude oil in the micro-nanopores can be greatly improved, the displacement of oil and water can be strengthened, and the utilization ratio of liquid can be further improved

This paper proposes to make full use of the fracturing fluid of large-scale hydraulic fracturing, explores several methods to improve the utilization efficiency of the fluid, and provides multiple angles for the utilization of the fluid, which has guiding significance for production practice. Determining the reasonable well closing time and enhancing the imbibition need to be further studied.

Data Availability

The test data used to support the findings of this study are included within the article. Readers can obtain data supporting the research results from the test data table in the paper.

Disclosure

The funders had no role in the design of the study; in the collection, analyses, or interpretation of data; in the writing of the manuscript; or in the decision to publish the results.

Conflicts of Interest

The authors declare no conflict of interest.

Authors' Contributions

Conceptualization was done by Tianlu Xu and Chengmei Wu. Methodology was done by Tianlu Xu and Yingxian Lei. Software was acquired by Yingxian Lei. Validation was performed by Chengmei Wu. Investigation was conducted by Chengmei Wu. Writing—original draft preparation was

done by Yingxian Lei. Writing—review and editing was done by Tianlu Xu. Visualization was performed by Yingxian Lei and Chengmei Wu. All authors have read and agreed to the published version of the manuscript.

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