

Research Article

Conformance Control for Tight Oil Cyclic Gas Injection Using Foam

Falin Wei,¹ Song Zhang,¹ Yilin Xi,² Zhouyuan Zhu ,² Chunming Xiong,¹ Chuanzhen Zang,³ and Junjian Li ²

¹Research Institute of Petroleum Exploration & Development of PetroChina, Beijing, China

²China University of Petroleum (Beijing), China

³Xinjiang Oilfield Company of PetroChina, Karamay, China

Correspondence should be addressed to Zhouyuan Zhu; zhuzy02@cup.edu.cn

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Cyclic gas injection has been proven to be an effective enhanced oil recovery (EOR) technique for tight oil reservoirs. During such processes, we expect recovery mechanisms such as oil swelling, oil viscosity reduction, vaporization, and pressure support, which highly relies on the successful conformance control of the injected gas. In this work, we present the numerical simulation study of using foam for improving the conformance control of cyclic gas injection in tight oil reservoir. We focus on improving two categories of conformance control problems using foam, making the injection profile for single well more evenly distributed and mitigating the gas breakthrough to adjacent wells through the connected hydraulic fractures in a multiwell setting. The simulation results show that foam has shown major impact in improving the gas conformance control in both cases. Typical recovery factor improvements are estimated to be up to 1% for lean gas injection in this tight oil reservoir. In conclusion, we have demonstrated the great potential of using foam to improve the conformance in tight oil cyclic gas injection process.

1. Introduction

Tight oil reservoirs are typically developed using horizontal wells completed with multistage hydraulic fracturing, which are produced using primary recovery as the most dominant recovery method. In this case, the recovery factors for tight oil reservoirs are typically relatively low. For example, the recovery factors of the Mahu tight oil reservoirs in Xinjiang Oilfield, PetroChina, are typically 15%-20%. This leaves large amount of unrecovered oil resources in the reservoir, considering the total volume of tight oil resources globally. Thus, there is an urgent need to explore possible EOR techniques for tight oil reservoirs.

Cyclic gas injection or gas huff and puff has been proposed to enhance the oil recovery in tight oil reservoirs [1-4]. It is implemented through injecting certain type of gas into the multistage hydraulically fractured horizontal well, soaked for some time, and produced back from the

same well. The injected gas could be hydrocarbon gas (lean or rich), carbon dioxide, or even nitrogen. And the process can be miscible or immiscible, depending on the reservoir pressure and the composition of the injected gas and the oil. The primary recovery mechanisms for such process are oil swelling, oil viscosity reduction, vaporization, and pressure support [5]. It is documented that several hundred wells have been converted to cyclic gas injection up to date in the Eagle Ford Shale play in the United States with pleasant performance reported. In recent years, due to the increasing level of greenhouse gas emission and global warming, CO₂ geologic sequestration has been proposed by various researchers. CO₂ wettability of seal and reservoir rocks and the implications for CO₂ sequestration have been studied [6]. The effect of wettability heterogeneity and reservoir temperature on CO₂ storage efficiency in deep saline aquifers has also been studied [7]. Researchers also studied the impact of injected water salinity and reservoir wettability

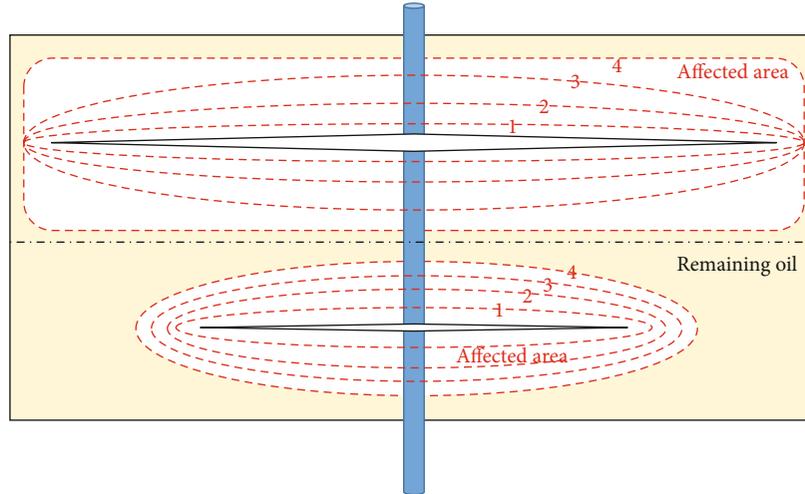


FIGURE 1: Preferential depletion for the more conductive long fracture, with much remaining oil unrecovered around the short and less conductive fracture, in a single well setting. Numbers 1-4 demonstrate the different numbers of cycles in cyclic gas injection process.

and heterogeneity on CO_2 storage efficiency in saline aquifers [8, 9]. The influence of injection well configuration and rock wettability on CO_2 sequestration has also been studied [10].

During any gas injection process, conformance of the injected gas is always an important issue for the success of such process. This is because gas is highly mobile as compared to the water and oil in the reservoir so that the adverse mobility ratio can lead to poor sweep and insufficient contact of the injected gas with the oil. On one hand, the injection/production profile for a single multistage fractured horizontal well is always unevenly distributed. This is due to the fact that each hydraulic fracture never grows to the same geometric size, shape, and conductivity, whether in a “plug and perf” or “open hole” setting. Such phenomenon has been well documented in reservoir studies implementing Production Logging Tool (PLT) surveys. This causes the reservoir volume around certain fractures to be preferentially drained in primary production and stimulated in cyclic gas injection process and vice versa. On the other hand, premature gas breakthrough to adjacent wells through the connected hydraulic fractures may happen in a multiwell setting. In the Bakken formation in the United States, it is reported that gas injected in a well under cyclic gas injection has broken through to the adjacent wells through the extended and connected hydraulic fractures between wells, i.e., “fracture hits.” In recent cyclic nitrogen injection field trials in the Mahu tight oil reservoirs in China, similar premature breakthrough to adjacent wells has been clearly observed. This causes the loss of the injected gas, insufficient contact of the injected gas with the oil, and the reservoir pressure to be inadequately raised in the injection period of the process. For both cases, the conformance issue could jeopardize the success of the tight oil cyclic gas injection process.

Foam has been demonstrated as an effective mobility control or conformance improvement agent for gas injection process in conventional oil reservoirs [11–13]. In a recent continuous gas injection field trial in a low permeability oil

reservoir in Texas, foam has been proven to be effective in diverting the injected gas to sweep the previously poorly swept region of the reservoir [14]. Based on this, we propose the use of foam to improve the conformance control in cyclic gas injection processes in tight oil reservoirs.

In this work, we present the numerical simulation study of using foam for improving the conformance control of cyclic gas injection in tight oil reservoir. We set up two categories of simulation problems: single well and multiwell cyclic gas injection processes. We test the effects of implementing gas injection with and without foam. We demonstrate that foam can help to make the injection profile for single well to be more evenly distributed and help to mitigate the amount of gas breakthrough to adjacent wells through the connected hydraulic fractures in a multiwell setting. The simulation results show that foam has shown major impact in improving the gas conformance control in both cases.

2. Methodology

2.1. Foam Improvement Mechanisms. We here demonstrate the foam improvement mechanisms for the two basic types of conformance control problems in tight oil cyclic gas injection process.

The first type is to make the injection profile for single well more evenly distributed for a single hydraulically fractured horizontal well. Figure 1 shows that preferential depletion occurs for the more conductive long fracture, with much remaining oil unrecovered around the short and less conductive fracture, in a single well setting. This remaining oil is an obvious target for enhanced oil recovery, if more gas can be directed into the short and less conductive fracture by using foam. We introduce the concept of oil exchange ratio for cyclic gas injection, which is defined as the incremental oil recovery divided by the amount of gas injected for each cycle. It measures the efficiency of a cyclic gas injection process, in which the injected gas causes certain amount of incremental oil to be recovered. Figure 2 shows

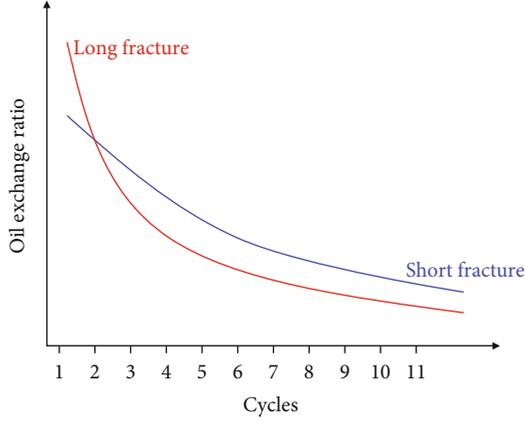


FIGURE 2: Oil exchange ratio for the long fracture and the short fracture for different cycles of the cyclic gas injection process in the tight oil reservoir.

the oil exchange ratio for the long fracture and the short fracture for different cycles of the cyclic gas injection process in tight oil reservoir. It can be seen that the oil exchange ratio for the long fracture decreases faster than that of the short fracture. This is due to the fact that the oil within the reservoir volume near the long fracture depletes faster as shown in Figure 1, because more gas has been injected into the long fracture. Using foam as profile control agent to divert the injected gas into the short fracture makes better use of the gas, since the short fracture has higher oil exchange ratio in the late cycles. In return, we would expect higher oil production rate and recovery.

The second type is to mitigate the gas breakthrough to adjacent wells through the connected hydraulic fractures in a multiwell setting. Figure 3 shows the potential gas breakthrough or channeling to adjacent producer due to connected hydraulic fractures in the cyclic gas injection process for hydraulically fractured horizontal wells in the tight oil reservoir. As gas breaks through to the adjacent well, the injected gas will be lost and has no effect on the recovery process. The reservoir pressure also cannot be raised due to such connected fracture. Using foam to block the gas flow in the connected fracture can efficiently reduce the amount of gas breaks through to the adjacent well. It also helps to raise the reservoir pressure to higher levels. In this way, more gas will be efficiently utilized for the cyclic gas injection process with more oil recovered.

2.2. Simulation Model Setup. The reservoir simulator we used in this study is CMG GEM [15]. We have developed a compositional fluid model for this simulation study, which is shown in Table 1. We use the standard Peng-Robinson equation of state for the flash calculation.

Over the years, the foam simulation model has two major categories: the mechanistic model and the empirical model. A mechanistic foam model allows direct simulation of foam creation, propagation, and coalescence, which can be observed in laboratory experiments [16, 17]. The empirical model, on the other hand, appears to be more appropriate for foam scoping studies and field pilot history matching

[15]. We have used the empirical model in CMG GEM to simulate the field scale tight oil foam-assisted cyclic gas injection problem. The basic assumption in this approach is that foam creation and coalescence occur rapidly relative to flow. Foam effects on gas mobility and sweep efficiency are handled via modified gas relative permeability curves, i.e., introducing a gas relative permeability or mobility reduction factor. Such factor and its corresponding terms are defined as follows [15]:

$$\begin{aligned}
 FM &= \frac{1}{1 + FM_{MOB} \times F_{Surf} \times F_{S_{oil}} \times F_{Cap} \times F_{GCP} \times F_{OMF} \times F_{Salt}} \\
 F_{Surf} &= \left(\frac{W_{Surf}}{FMSURF} \right)^{EPSURF} \\
 F_{S_{oil}} &= \left(\frac{FMOIL - S_{oil}}{FMOIL - FLOIL} \right)^{EPOIL} \\
 F_{Cap} &= \left(\frac{FMCAP}{N_C} \right)^{EPCAP} \\
 F_{GCP} &= \left(\frac{FMGCP - N_C}{FMGCP} \right)^{EPGCP} \\
 F_{OMF} &= \left(\frac{FMOMF - X_{oil}}{FMOMF} \right)^{EPOMF} \\
 F_{Salt} &= \left(\frac{W_{Salt} - FLSALT}{FMSALT - FLSALT} \right)^{EPSALT}
 \end{aligned} \tag{1}$$

where FM is the gas mobility reduction factor, FM_{MOB} is the reference foam mobility reduction factor, W_{Surf} is the surfactant mole fraction in the water phase, FMSURF is critical mole fraction of surfactant component in the water phase, EPSURF is the exponent for surfactant contribution to FM calculation, S_{oil} is the oil saturation, FMOIL and FLOIL are the critical oil saturation and lower oil saturation values, EPOIL is the exponent for oil saturation contribution to FM calculation, N_C is the capillary number, FMCAP is the reference rheology capillary number, EPCAP is the exponent for capillary number contribution to FM calculation, FMGCP is the critical generation capillary number, EPGCP is the exponent for generation capillary number contribution to FM calculation, X_{oil} is the mole fraction of a certain component in the oil phase, FMOMF is the critical oil mole fraction for a certain component, EPOMF is the exponent for the contribution of the a certain oil phase component to FM calculation, W_{Salt} is the salt mole fraction in the water phase, FMSALT and FLSALT are critical salt mole fraction the and lower salt mole fraction, and EPSALT is the exponent for salt contribution to FM calculation. The corresponding values for these parameters in our simulation study are defined in Table 2.

Figure 4 further shows the relative permeability curves implemented in this study. Gas relative permeability k_{rg}

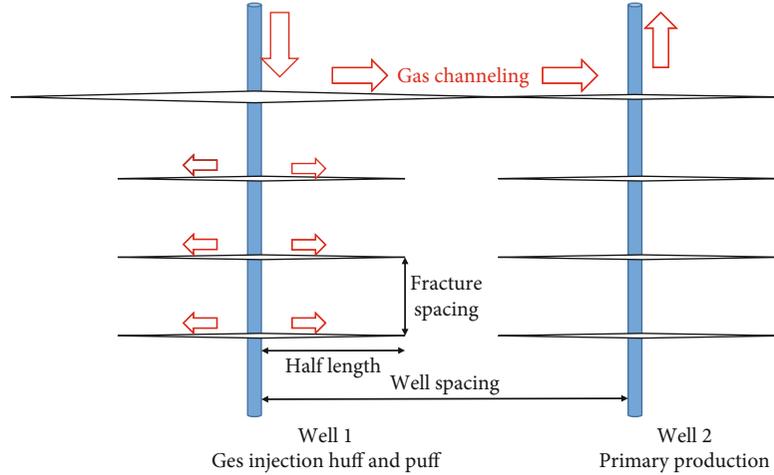


FIGURE 3: Gas breakthrough to adjacent producer due to connected hydraulic fractures in the cyclic gas injection process for hydraulically fractured horizontal wells in the tight oil reservoir.

TABLE 1: Compositional model for the simulation study.

Component name	Initial mole fraction	Critical temperature (K)	Critical pressure (bar)	Acentric factor	Molecular weight (g/mole)
C1	0.5	190.6	46.0421	0.0130	16.04
C2-4	0.03	369.8	42.4957	0.1524	44.10
C5-7	0.07	507.4	30.1239	0.3007	86.18
C8-12	0.2	617.7	20.9641	0.4885	142.29
C13-18	0.15	705.6	13.7903	0.6500	206.00
C19+	0.05	766.7	11.1660	0.8500	282.00

TABLE 2: Parameters for the empirical foam model for the simulation study.

Parameter name	Value	Parameter name	Value	Parameter name	Value
FMMOB	1000.0	FLOIL	0.2	EPGCP	0.5
FMSURF	0.00005	EPOIL	1.0	EPOMF	3
EPSURF	1.0	FMCAP	2.0e-4	FLSALT	1.0e-3
FMOIL	1.0	EPCAP	0.5	FMSALT	2.0e-3
S_{oil}	0.545	FMGCP	2.0e-4	EPSALT	-3.0

values are reduced by a factor of 0.1 in the case of strong foam as compared to the case of no foam.

The reservoir models are designed to be a generic thin box-shaped tight oil reservoir with Cartesian grid blocks. “Plug and perf” well completions are assumed in this study. We implement planar-shaped hydraulic fractures at the locations of each fracture cluster (perforation), perpendicular to the hydraulic well trajectory. Logarithmic local grid refinements are used to refine the grids around the planar hydraulic fractures. We assume single porosity reservoir in this simulation study, typically with homogeneous permeability of 0.1 mD and porosity of 0.12. For the hydraulic fractures, we assume they are equally spaced according to the corresponding fracture spacing. And we set the permeability of the inner most line of grid blocks to such high values that the product of this permeability and the width of the inner

most grid block equals the specified conductivity of the hydraulic fracture. The detailed reservoir parameters for each simulation case will be presented in the later section.

3. Results

3.1. Single Well with Two Hydraulic Fractures. We first present the case of single well with only two hydraulic fractures to demonstrate the capability of foam to create a more evenly distributed injection profile for a single hydraulically fractured horizontal well. The reservoir is 400 m wide, 80 m long, and 10.5 m thick. We discretize the reservoir using Cartesian grid ($100 \times 20 \times 1$), with local grid refinements around the hydraulic fractures. We implement such fine grid blocks so that the typically observed numerical dispersion error in simulating gas injection process will be controlled

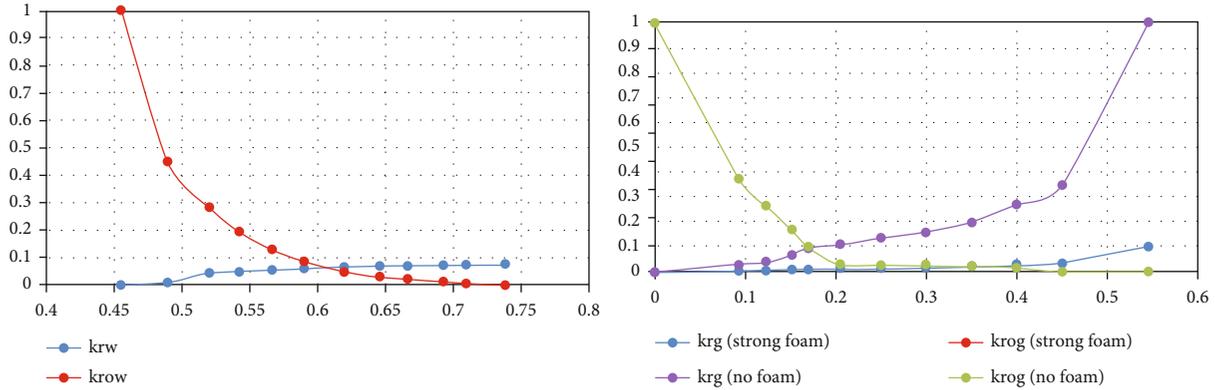


FIGURE 4: Relative permeability curves implemented in this simulation study, with gas relative permeability k_{rg} values reduced by a factor of 0.1 in the case of strong foam as compared to the case of no foam.

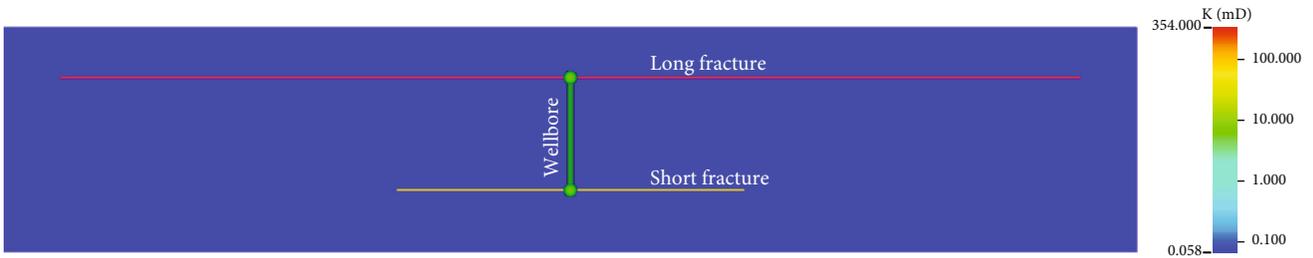


FIGURE 5: Permeability distribution for the simulation case of single well with two hydraulic fractures. The long fracture has half-length of 180 m and fracture conductivity of 240 mD-m. The short fracture has half-length of 60 m and fracture conductivity of 80 mD-m.

within a certain level. In this way, the simulation accuracy is guaranteed. Figure 5 shows the permeability distribution for the simulation case of single well with only two hydraulic fractures. The long fracture has half-length of 180 m and fracture conductivity of 240 mD-m. The short fracture has half-length of 60 m and fracture conductivity of 80 mD-m. The oil compositional model is described in Table 1. We inject a lean gas in the cyclic gas injection process with 100% C1. The initial reservoir temperature is 70°C, and the initial reservoir pressure is 25.5 MPa. The other simulation settings are the same as described in the previous section.

We start the process at the time of 2019-01-01 with 6 years of primary production, followed by 2 cycles of cyclic gas injection without foam. During primary production and the producing back period of cyclic gas injection, we set the single well maximum liquid rate to be 45 m³/day and minimum bottom hole pressure to be 10 MPa. In each cycle, we inject gas for 2 months at a rate of 20000 m³/day, directly followed by 10 months of producing back. Beginning at the 3rd cycle, we either continue with pure cyclic gas injection without foam or start the foam-assisted cyclic gas injection process by coinjecting the surfactant solution with the gas. In both cases, the amount of gas injected is the same, which is 20000 m³/day for 2 months. In the foam case, within each cycle, we inject an extra stream of surfactant solution with the rate of 5 m³/day and surfactant mole fraction of 0.3% for 1 month. We continue the process for a total of 9 cycles.

Figure 6 shows the results of total cumulative oil production for the entire well with and without foam, cumulative oil production from the long fracture with and without foam, and cumulative oil production from the short fracture with and without foam. It can be clearly seen that the cumulative oil production for the entire well has been increased for the foam case. And the major contribution for this increase comes from the short hydraulic fracture. For the long hydraulic fracture, the oil production actually decreases slightly. Figure 7 further shows the cumulative gas injection into the long fracture with and without foam and cumulative gas injection into the short fracture with and without foam. As envisioned previously in the mechanism sector, we observe increased gas injection into the short fracture with lower fracture conductivity and shorter fracture half-length, and vice versa. Figure 8 shows the average reservoir pressure for the cases with foam and without foam. The extra stream of injected surfactant solution in the case of foam injection does not cause the reservoir pressure to increase to a large extent. Figure 9 further shows the pressure at the end of gas injection during the 9th cycle, for the case with and without foam. It can be seen that more high pressure gradient exists around the short hydraulic fracture in the foam case as compared to the case without foam. This also indicates that more gas is injected into the short hydraulic fracture with the aid of foam. Thus, by injecting foam, we successfully improve the injection profile for this single well problem so that the gas injection amount is more

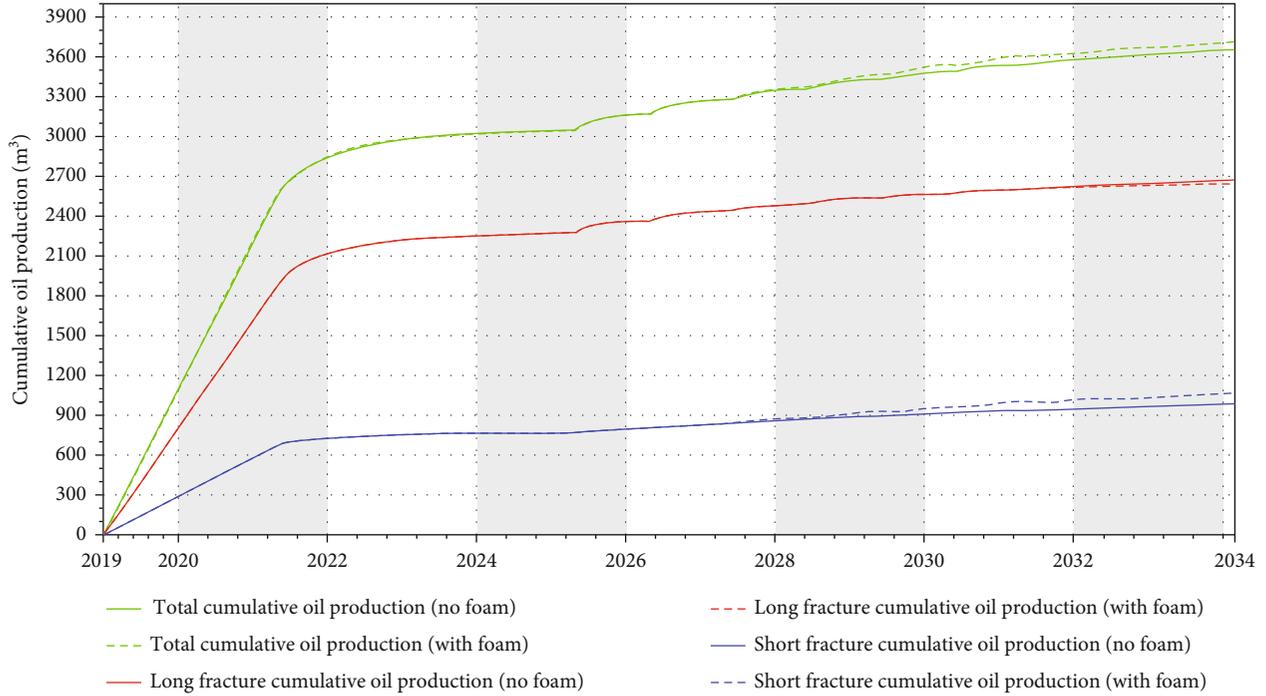


FIGURE 6: Total cumulative oil production for the entire well with and without foam, cumulative oil production from the long hydraulic fracture with and without foam, and cumulative oil production from the short hydraulic fracture with and without foam.

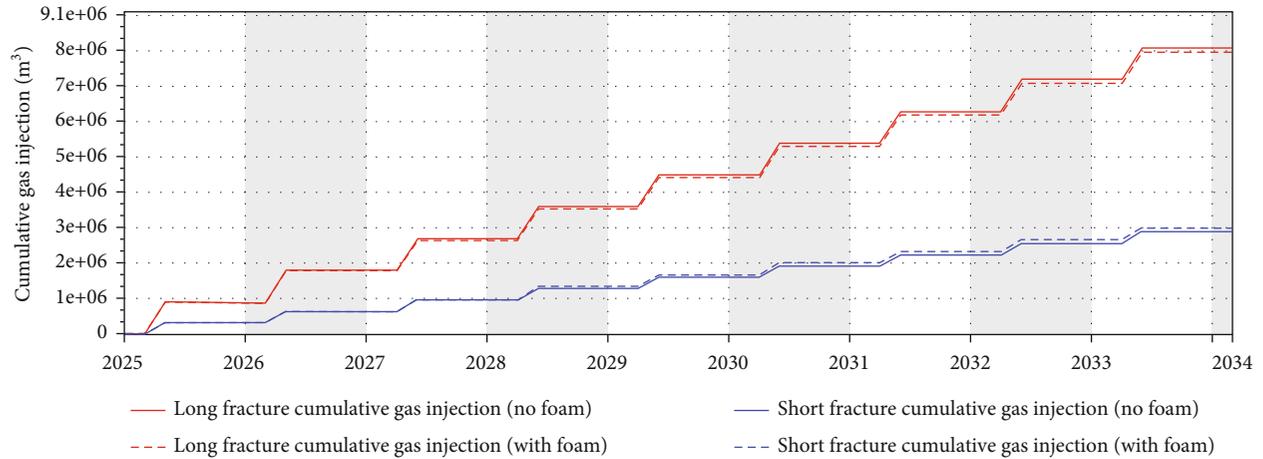


FIGURE 7: Cumulative gas injection into the long hydraulic fracture with and without foam and cumulative gas injection into the short hydraulic fracture with and without foam.

evenly distributed among different hydraulic fractures. In this case, the oil recovery factor for primary depletion stage is 17.2%. The ultimate recovery factor for the case with pure cyclic gas injection is 20.6%. And the ultimate recovery factor for the case with foam-assisted cyclic gas injection is 21.0%.

3.2. Single Well with Multiple Fractures. Second, we present the case for a single well with multiple hydraulic fractures. This case is also intended to demonstrate such more evenly distributed injection profile for a single horizontal well. The reservoir is 400 m wide, 960 m long, and 10.5 m thick.

We also discretize the reservoir using Cartesian grid ($100 \times 240 \times 1$), with local grid refinements around the hydraulic fractures. The grid block sizes are small so that the numerical dispersion is not significant. Figure 10 shows the permeability distribution for the simulation case of single well with multiple hydraulic fractures. The long fractures have half-length of 180 m and conductivity of 240 mD-m. The short fractures have half-length of 60 m and conductivity of 80 mD-m. Again, we inject the lean gas which is 100% C1. The initial reservoir temperature is 70°C, and the initial reservoir pressure is 25.5 MPa. The other simulation settings are the same as described previously.

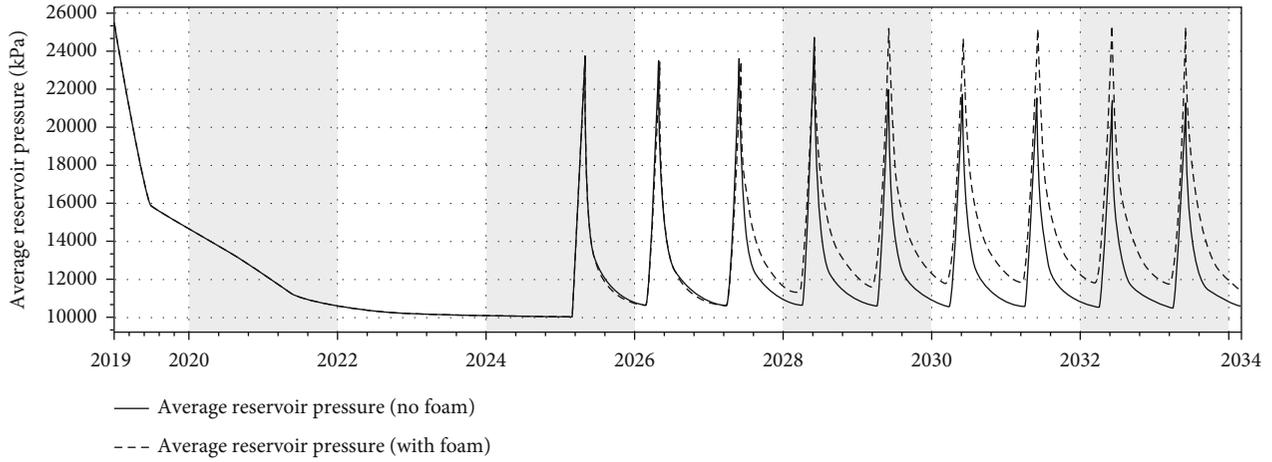
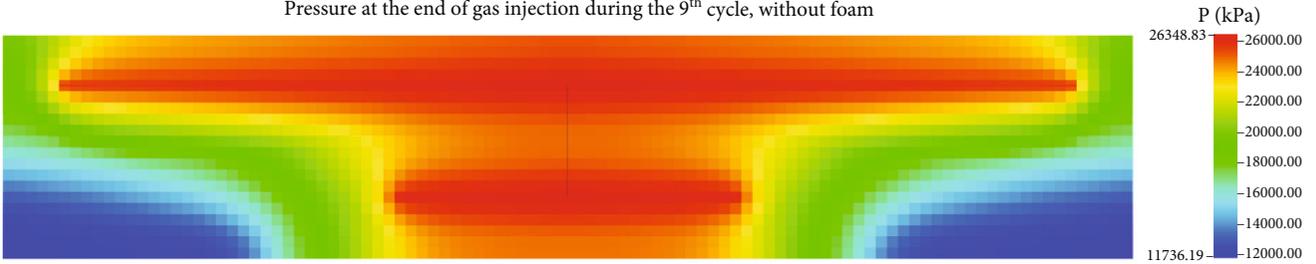


FIGURE 8: Average reservoir pressure for the cases with foam and without foam.

Pressure at the end of gas injection during the 9th cycle, without foam



Pressure at the end of gas injection during the 9th cycle, with foam

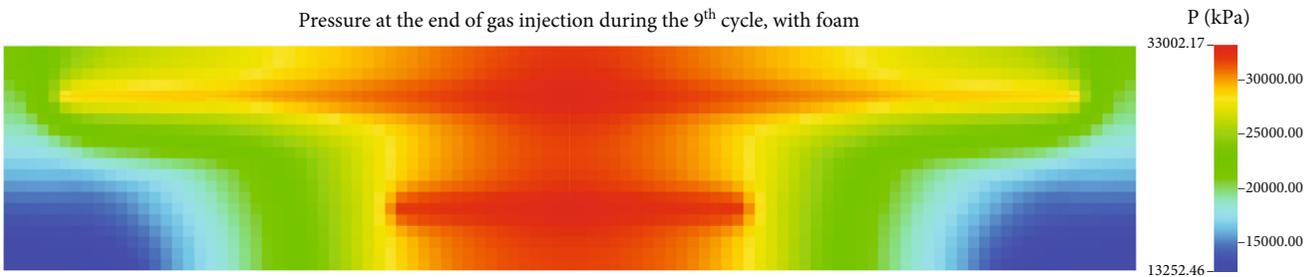


FIGURE 9: Pressure at the end of gas injection during the 9th cycle (2033-06-01), for the simulation case with and without foam.

We again start the process with 6 years of primary production, followed by 2 cycles of cyclic gas injection without foam. During primary production and the producing back period of cyclic gas injection, we set the single well maximum liquid rate to be 45 m³/day and minimum bottom hole pressure to be 10 MPa. In each cycle, we inject gas for 2 months at a rate of 240000 m³/day, directly followed by 10 months of producing back. Beginning at the 3rd cycle, we either continue with pure cyclic gas injection without foam or start the foam-assisted cyclic gas injection process by coinjecting the surfactant solutions. In both cases, the amount of gas injected is the same, which is 240000 m³/day for 2 months. In the foam case, within each cycle, we inject an extra stream of surfactant solution with the rate of 60 m³/day and surfactant mole fraction of 0.3% for 1 month. We continue the process for a total of 4 cycles. We

extend the production time period a few months longer for the case with foam, so that its average reservoir pressure drops to the similar level as the case without foam.

Figure 11 shows the cumulative oil production for the entire well with and without foam. Figure 12 shows the average reservoir pressure for the cases with foam and without foam. Figure 13 shows the cumulative oil production from the short hydraulic fractures with and without foam. Figure 14 shows the cumulative oil production from the long hydraulic fractures with and without foam. By extending the production time period, we let the average reservoir pressure for the foam case to drop to the similar level as the case without foam. It can be seen that the cumulative oil production for the entire well has been increased for the foam case. And the major contribution for this increase comes from the short hydraulic fracture. The oil production from the

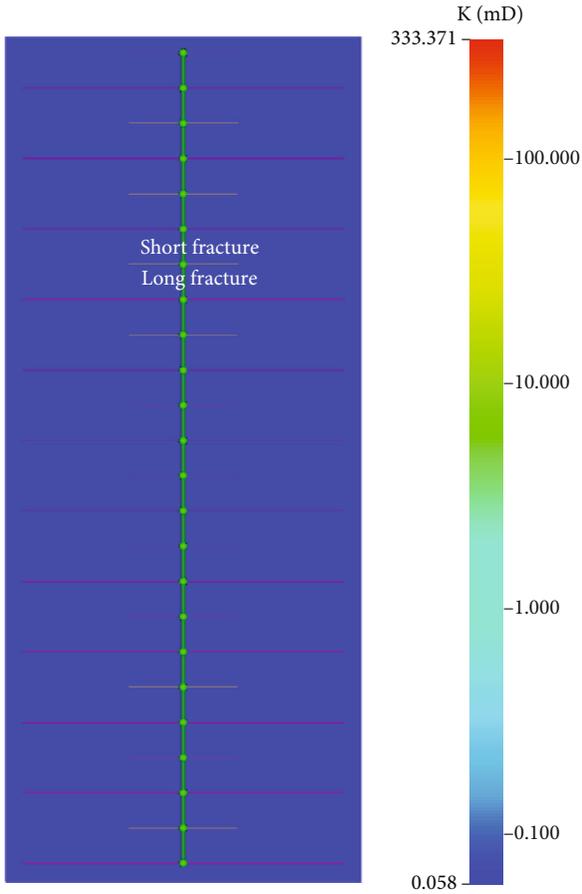


FIGURE 10: Permeability distribution for the simulation case of single well with multiple hydraulic fractures. The long fractures have half-length of 180 m and fracture conductivity of 240 mD·m. The short fractures have half-length of 60 m and fracture conductivity of 80 mD·m.

long hydraulic fractures actually decreases slightly. Figure 15 further shows the cumulative gas injection into the long and short hydraulic fractures with and without foam. We again observe increased gas injection into the short fractures with lower fracture conductivity and shorter fracture half-length, and vice versa. By injecting foam, we improve the injection profile for the multiple fracture single well problem so that the gas injection is more evenly distributed among different hydraulic fractures in cyclic gas injection process. In this case, the oil recovery factor for primary depletion stage is 17.3%. The ultimate recovery factor for the case with pure cyclic gas injection is 18.8%. And the ultimate recovery factor for the case with foam-assisted cyclic gas injection is 19.0%.

3.3. Dual Well with Connected Fracture. Third, we present the case for dual well with connected hydraulic fracture between the wells. This case is intended to show that foam can mitigate the gas breakthrough to adjacent wells through the connected hydraulic fractures in a multiwell setting. The reservoir is 800 m wide, 160 m long, and 10.5 m thick. We also discretize the reservoir using Cartesian grid

($200 \times 40 \times 1$), with local grid refinements around the hydraulic fractures. The grid block sizes are small enough so that the numerical dispersion is controlled within a certain level. Figure 16 shows the permeability distribution for the simulation case of dual well with connected fracture. The single long fractures has a total length of 600 m and conductivity of 240 mD·m. The short fractures have half-length of 100 m and conductivity of 80 mD·m. Again, we inject the lean gas which is 100% C1. The initial reservoir temperature is 70°C, and the initial reservoir pressure is 25.5 MPa. The other simulation settings are the same as described previously.

In our simulation, we have Producer 1 produced with cyclic gas injection in the late period, while Producer 2 is under primary depletion for the entire simulation. The Producer 1 starts with 6 years of primary production, followed by 2 cycles of cyclic gas injection without foam. During primary production and the producing back period of cyclic gas injection, we set the single well maximum liquid rate to be 45 m³/day and minimum bottom hole pressure to be 10 MPa. In each cycle, we inject gas for 2 months at a rate of 40000 m³/day, directly followed by 10 months of producing back. Beginning at the 3rd cycle, we either continue with pure cyclic gas injection without foam or start the foam-assisted cyclic gas injection process by coinjecting the surfactant solutions. In both cases, the amount of gas injected is the same, which is 40000 m³/day for 2 months. In the foam case, within each cycle, we inject an extra stream of surfactant solution with the rate of 10 m³/day and surfactant mole fraction of 0.3% for 1 month. We continue the process for a total of 7 cycles.

Figure 17 shows the cumulative gas production for Producer 2 from the long fracture and the short fractures, with and without foam. It can be seen that due to the existence of the long fracture which connects the Producer 1 and Producer 2, large amount of gas injected into the Producer 1 gets produced back to surface from the Producer 2 by traveling through the long fracture. This gas recycling is ineffective for the cyclic gas injection EOR process. With the aid of foam, we are able to create flow resistance within the long fracture that hinders the flow of gas from Producer 1 to Producer 2 through the high conductivity long fracture. In this way, the gas production for Producer 2 from the perforation connecting to the long fracture is much reduced. Figure 18 further shows the bottom hole pressure for Producer 1 with and without foam. Through the use of foam, the injected gas is better contained within the reservoir volume around Producer 1. Thus, the bottom hole pressure can be raised to a higher value, which is of great importance to the success of cyclic gas injection process since high reservoir pressure is the key driving force for compaction drive and solution gas drive during the producing back period. Figure 19 shows the F_{Surf} distribution for the simulation case with foam. It shows the area where foam-induced flow resistance exists. It can be seen that the long fracture has been partially filled with surfactant, thus creating major flow resistance inside. Finally, Figure 20 shows the field cumulative oil production for the simulation cases with foam and without foam. In this case, the oil recovery factor for the primary depletion stage is 16.1%. The ultimate recovery factor for the case with pure

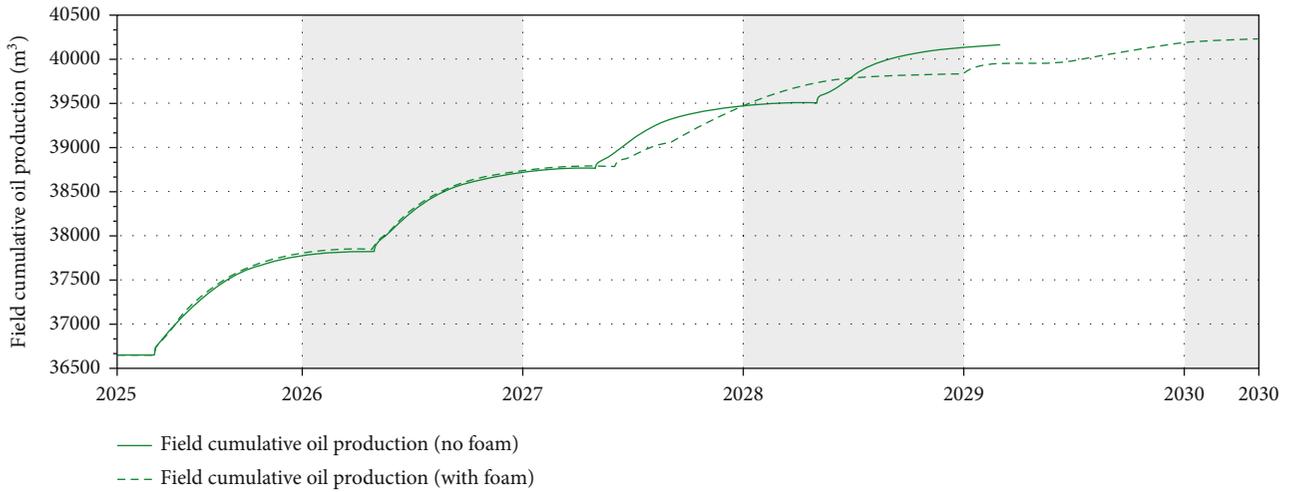


FIGURE 11: Cumulative oil production for the entire well with and without foam.

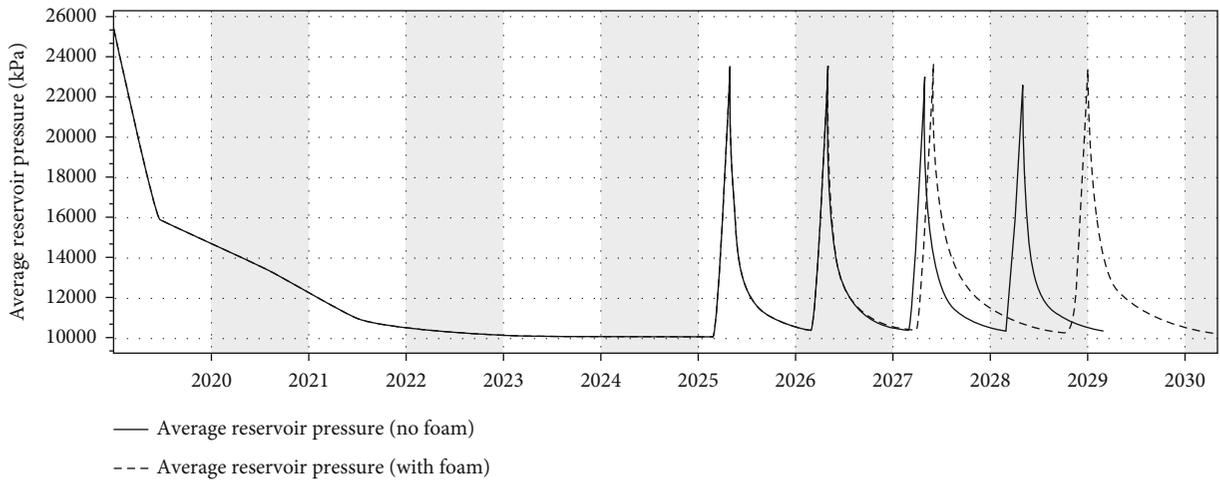


FIGURE 12: Average reservoir pressure for the cases with foam and without foam.

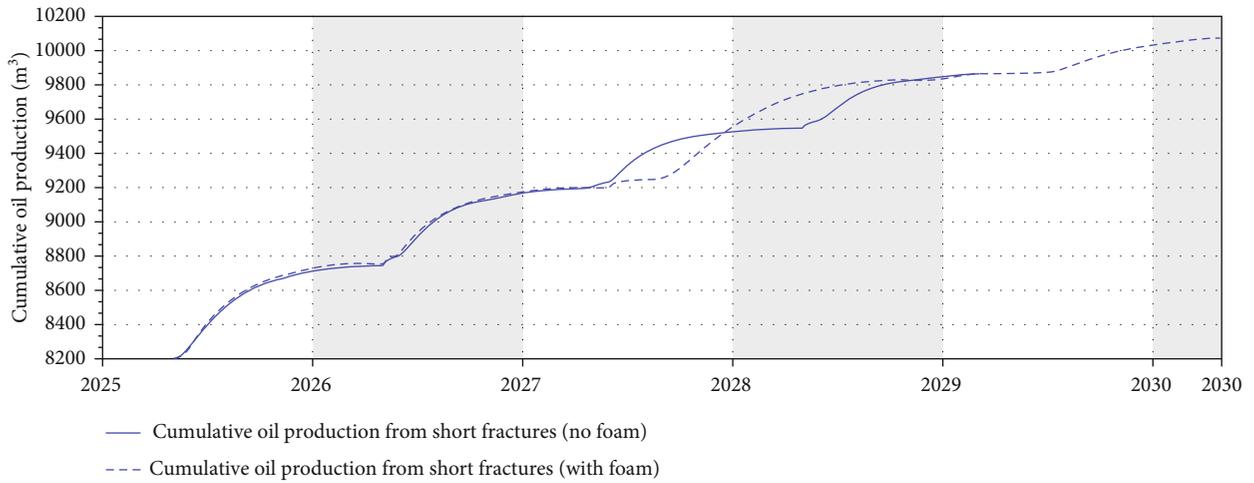


FIGURE 13: Cumulative oil production from the short hydraulic fractures with and without foam.

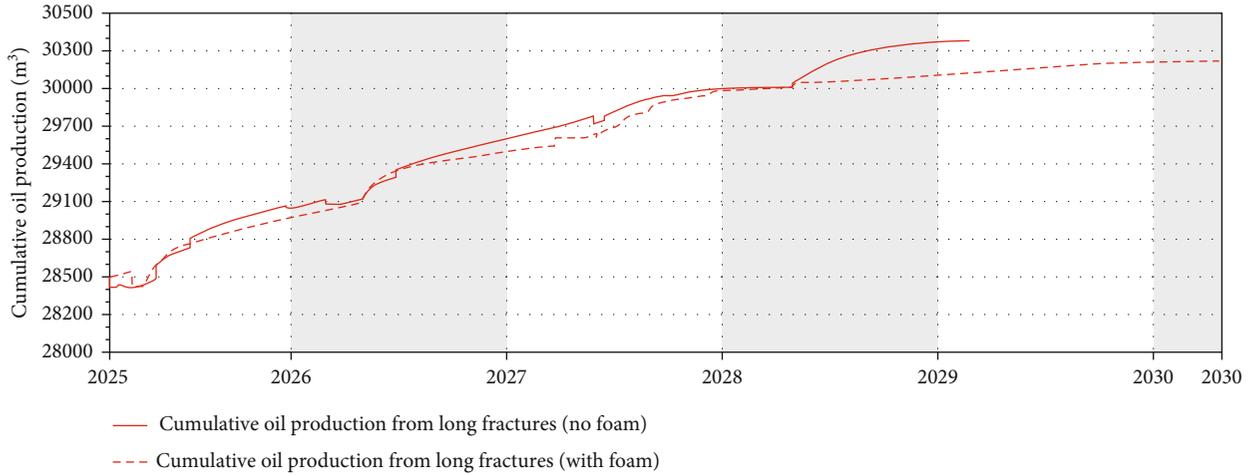


FIGURE 14: Cumulative oil production from the long hydraulic fractures with and without foam.

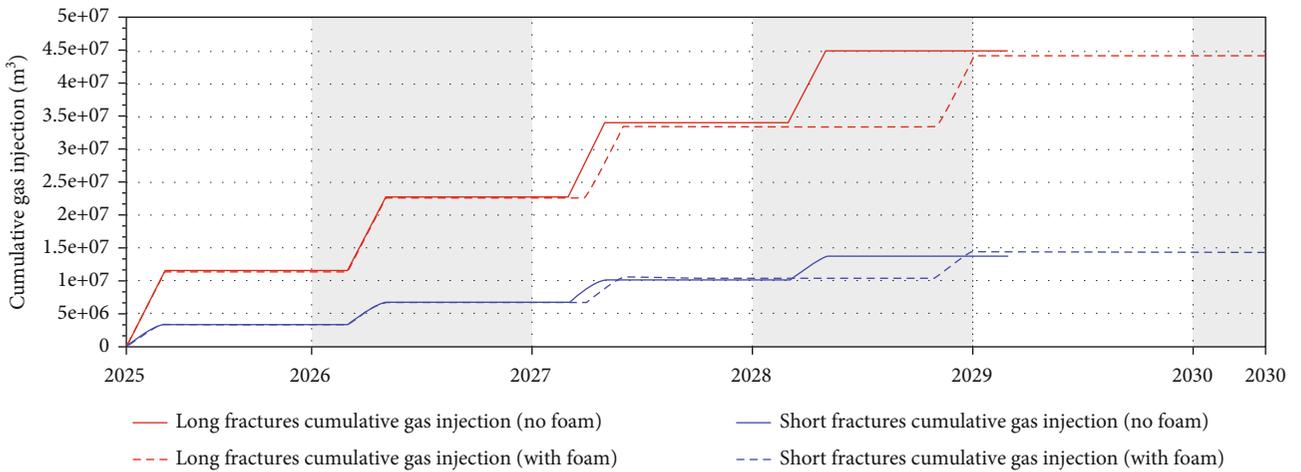


FIGURE 15: Cumulative gas injection into the hydraulic long fractures with and without foam and cumulative gas injection into the short hydraulic fractures with and without foam.

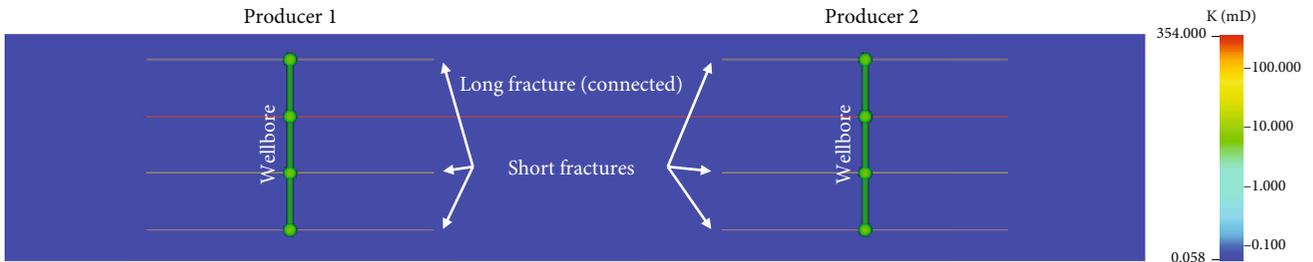


FIGURE 16: Permeability distribution for the simulation case of dual well with connected hydraulic fracture. The long fractures have total length of 600 m and fracture conductivity of 240 mD-m. The short fractures have half-length of 100 m and fracture conductivity of 80 mD-m.

cyclic gas injection is 19.3%. And the ultimate recovery factor for the case with foam-assisted cyclic gas injection is 19.6%. Foam-assisted cyclic gas injection process has achieved higher cumulative oil production than the case without foam.

4. Discussion

We have demonstrated through our simulation studies that foam can improve the performance of cyclic gas injection process in tight oil reservoirs through the two mechanisms

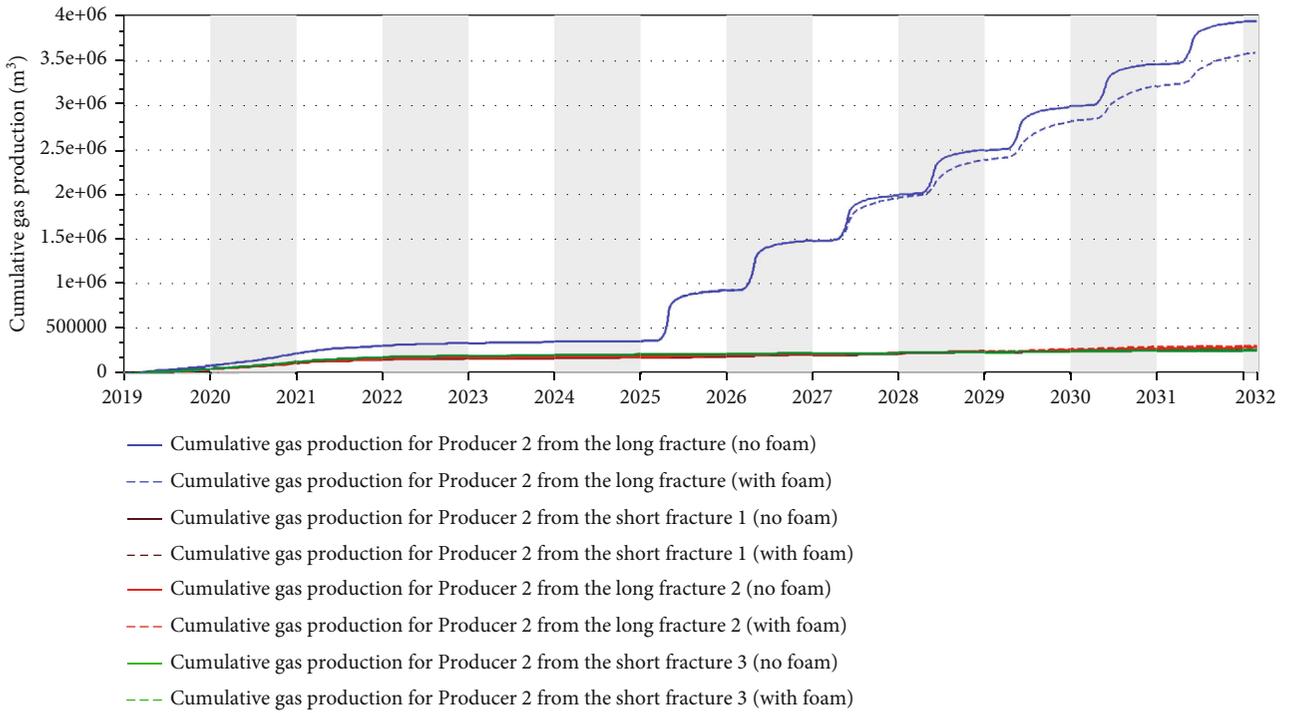


FIGURE 17: Cumulative gas production for Producer 2 from the long fracture and the short fractures, with and without foam.

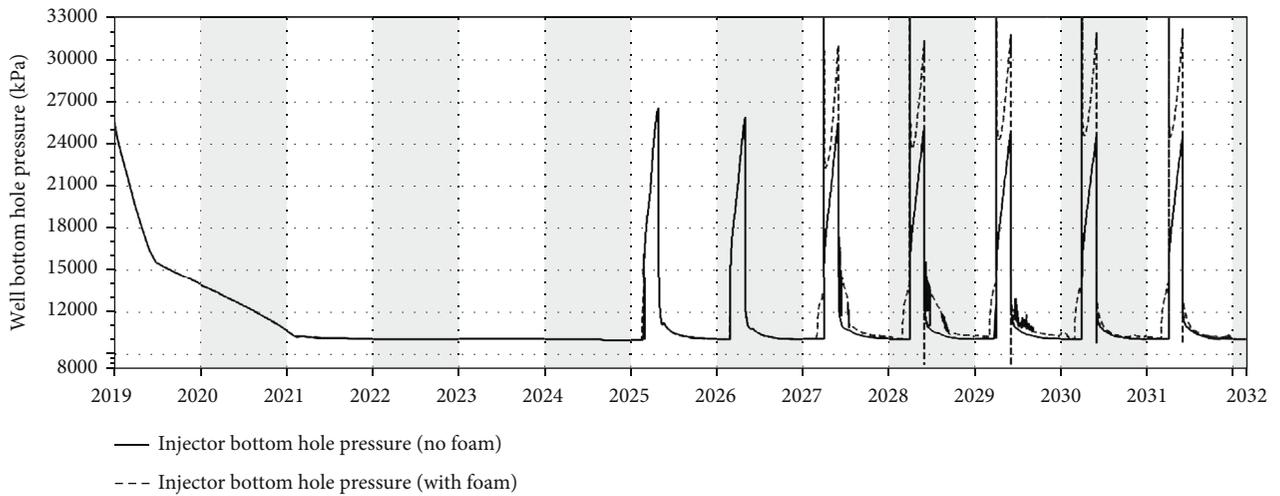


FIGURE 18: Bottom hole pressure for Producer 1 with and without foam.

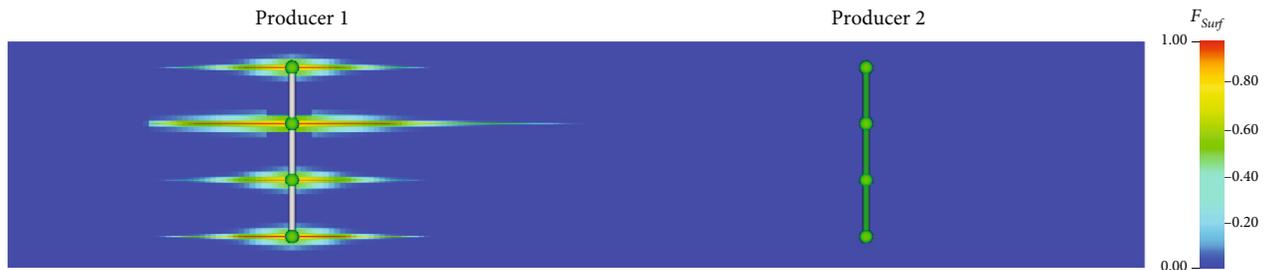


FIGURE 19: F_{Surf} distribution for the simulation case with foam showing the area where foam-induced flow resistance exists.

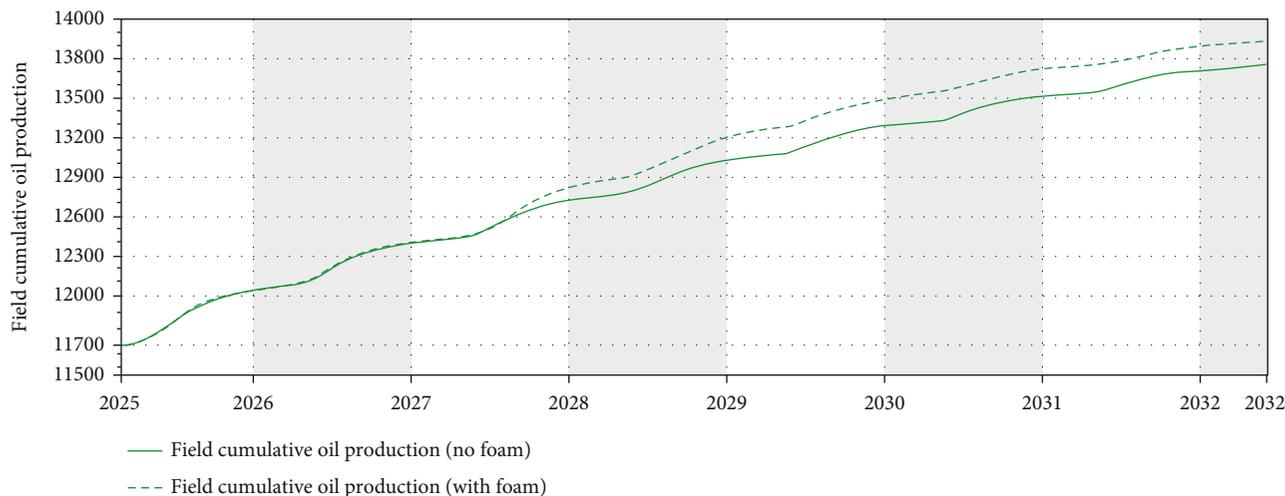


FIGURE 20: Field cumulative oil production for the simulation cases with foam and without foam.

discussed in this work. Further work includes and is not limited to laboratory experiments to screen the suitable surfactants for tight oil foaming purposes, large-scale 3D laboratory experiment to test the performance of the process, and single well or multiwell field pilots to demonstrate the actual performance of foam-assisted cyclic gas injection process.

5. Conclusion

In this work, we explore the use of foam for improving the conformance control and sweep of cyclic gas injection process. We conduct numerical simulation for the currently producing for a generic tight oil reservoir. We show the effect of foam in improving the conformance of cyclic gas injection for basic categories of conformance control problems, i.e., making the injection profile for single well more evenly distributed and mitigating the gas breakthrough to adjacent wells through the connected hydraulic fractures in a multiwell setting. The simulation results show that foam has demonstrated clear improvement in the gas conformance control in both cases. Incremental recovery factors are estimated to be up to 1% for lean gas injection in this tight oil reservoir. In conclusion, through the numerical simulation of the foam-assisted cyclic gas injection for the tight oil reservoir in this study, we have demonstrated the great potential of using foam to improve the conformance in tight oil cyclic gas injection process.

Data Availability

The data used to support the findings of this study are available from the corresponding author upon request.

Conflicts of Interest

The authors declare that they have no conflicts of interest.

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