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Performance of CO_2 Foam Huff and Puff in Tight Oil Reservoirs

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The challenges associated with unconventional reservoirs are related to their intrinsic nature: extremely low porosity and permeability. Combinations of horizontal wells and multistage hydraulic fracturing techniques have been developed to overcome the production obstacles and unlock the vast amount of oil in place in such formations. However, oil production still exhibits a sharp decline within the first 2 years after the stimulation, leading to an oil recovery of less than 15%. Thus, enhanced oil recovery methods need to be investigated to further increase the production rates and the recovery. In this study, laboratory experiments and numerical simulations were conducted to evaluate the performance of the CO_2 foam huff and puff process and its impacts on oil recovery in tight oil formations. More specifically, the foam half-life was measured as a function of surfactant concentration and followed by the foam drainage ratio and its rheological properties in the subsequent tests. Reservoir simulations were conducted using the lab data and the field data collected from Cardium formation. Sensitivity analyses were finally carried out to investigate the effects of controlling variables on the CO_2 foam performance. Experimental results revealed that the optimal surfactant concentration was found to be 0.2%, which is the critical micelle concentration point. Simulation results show that CO_2 foam huff and puff can increase the oil recovery by more than 11% compared to that of the primary production. Moreover, sensitivity analyses show that the production time, injection time, and soaking time are the main effecting parameters, while the injection rate and the incremental injection rate are less important.

Keywords: hydraulic fracturing, huff and puff, Cardium, CO_2 Foam, soaking

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INTRODUCTION

Worldwide oil demand and decline in the well production rate has led to the implementation of improved oil recovery (IOR) and enhanced oil recovery (EOR) methods to sustain oil production (Golabi et al., 2012; Shabib-Asl et al., 2014; Ayoub et al., 2015; Hosseini et al., 2015a; Hosseini et al., 2015b; Shabib-Asl et al., 2015a; Shabib-Asl et al., 2015b; Dianatnasab et al., 2016; Shabib-AsL et al., 2019a; Shabib-Asl et al., 2019b). Tight oil reservoirs provide 45% of total oil production in the U.S. and 9% of world oil production (Wang et al., 2016; Shabib-Asl and Plaksina, 2019; Shabib-Asl et al., 2020), yet the oil recovery from the primary production and waterflooding of such formations is as low as 10–15%, compared to 40% from conventional reservoirs (Hosseini et al., 2015a). Due to the low injectivity in the tight oil reservoirs, gas injection is preferred as the potential EOR techniques, such as huff and puff gas injection. In this technique, gas is primarily injected into the reservoir (huff process), and then time is given for the gas to improve the physical properties of the oil (soaking time). After an optimum soaking time, the well will return to production (puff process) (Zhou et al., 2018). Using the huff and puff EOR process can activate production mechanisms such as viscosity reduction (Sayegh and Maini, 1984), oil swelling (Hoffman and Reichhardt, 2019), reservoir re-pressurization (Zhang et al., 2004), and solution gas drive (Monger et al., 1991). There are many parameters that can affect the huff and puff performance, including soaking time, injection rate, injection pressure, number of cycles, and injection fluid composition, which need to be optimized for its field application to achieve maximum oil recovery or profits.

Researchers have conducted both experimental and numerical studies on CO_2 injection performance under different conditions (Rahmanifard et al., 2014). Wan et al. (2018) used nuclear magnetic resonance (NMR) technology to investigate pore-scale recovery mechanisms of cyclic nitrogen injection and revealed that the first few cycles provided the most accessible oil (Wan et al., 2018). Santiago and Kantzas (2020) performed a huff and puff gas injection simulation for an unconventional gas condensate reservoir (Santiago and Kantzas, 2020). They discovered that the higher number of cycles yields more efficient contact between the injected fluid and reservoir oil; nevertheless, they emphasized that extra cycles do not constantly enhance oil production. Li and Sheng (2017) also reported that the incremental produced oil decreased while the number of cycles increased (Li and Sheng, 2017). On the other hand, the incremental oil produced is not a direct function of soaking time in all cases. Yu et al. (2016) reported that increasing soaking time from 0.25 to 12 h in the laboratory could increase recovery by about 7%, but expanding soaking time from 12 to 48 h only increases recovery by 1% (Yu et al., 2016). Furthermore, (Meng and Sheng, 2016) observed that the best recovery case was the one that had no soaking time. Plus, increasing the number of cycles when the soaking time was large can decrease the produced oil for a limited time owing to the increased non-productive period (Meng and Sheng, 2016). There is a notable difference in the oil production rate after the first or second cycle. Moreover, the role of the injection rate and pressure has also been investigated in numerous research studies (Monger and Coma, 1988; Monger et al., 1991; Shayegi et al., 1996; Song and Yang, 2013; Wang et al., 2013; Yu et al., 2014; Sanchez-Rivera et al., 2015; Wan et al., 2015; Sun et al., 2016; Zhang et al., 2018). Wan et al. (2018) and Kerr et al. (2020) both showed that higher injection pressure and larger slug size would lead to an increase in the recovery factor (Wan et al., 2018; Kerr et al., 2020). Field and laboratory data indicated that the larger slug size improves oil production (Monger and Coma, 1988; Monger et al., 1991; Cronin et al., 2019). Evaluation of huff and puff CO_2 injection into Texas Gulf Coast Miocene reservoirs reveals a weak correlation between slug size and incremental oil produced, but the larger slugs appear to be better. A study by Haskin and Alston, (1989) showed that the optimum soaking time was confirmed to be between 14 and 21 days, and the larger or shorter soaking time was considered uneconomical (Haskin and Alston, 1989).

The limitations associated with the gas injection are well understood so far (Farajzadeh et al., 2016; Hematpur et al., 2016; Moortgat, 2016; Zaker et al., 2020; Khan and Mandal, 2021). Gas fingering and channeling are shown to be destructive to overall operation performance (Navarro-Brull and Gómez, 2018; Yang and Hou, 2020; Zhao et al., 2020), and the mobility control methods are developed to reduce the negative effects of injection of weightless, low-viscosity fluid (Kovscek and Bertin, 2003; Li et al., 2010; Yu et al., 2012; Sabet et al., 2016). The addition of surfactant solution to the injection stream could effectively reduce surface tension between liquid and gas phases, thus forming stable bubbles and trapping the gas phase that prevents the gas phase from bypassing the oil bank (Zhao et al., 2015; Afifi et al., 2021). The CO_2 foam properties such as stability, foam quality, and rheological behavior are investigated in numerous studies (Rafati et al., 2016; Yekeen et al., 2017; AlYousef et al., 2018; Phukan et al., 2020) to increase foam half-life and the apparent viscosity. Xu et al. (2017) conducted a series of experimental tests on CO_2 foam huff and puff injection and showed the beneficial aspects of this method (Xu et al., 2017). Moreover, their findings showed that the ultimate oil recovery can provide 13% more than CO_2 injection in the case of CO_2 foam injection, and the observations suggest that the CO_2 foam was capable of increasing sweep efficiency by 16.7%. However, the fundamentals and main controlling factors of the CO_2 foam huff and puff process in the tight oil reservoirs are still not clear, and more work needs to be conducted to understand the potential field performance of such a process.

In this work, a series of experimental tests were conducted to analyze the foam stability, foam quality, and foam rheological properties, and then numerical simulation was used to model the effects of injection, soaking, and production times on the final oil recovery factor. The Taguchi method was finally conducted to optimize the performance of the CO_2 foam huff and puff in the Cardium formation.

EXPERIMENTAL

In the study, a commercial surfactant known as sodium dodecyl sulfate (SDS) (purity>99.0%) was used as the foaming agent. The rheological characteristics of CO_2 foam were identified by the capillary tube experiment and the power-law model selected to represent its behavior. An illustration of the experimental setup is shown in **Figure 1**. CO_2 gas and SDS solution mixed in the "foam generator" located in the inlet of the capillary tube. The pressure drop in the capillary tube can be carried out using the pressure transmitters installed in the inlet and outlet of the tube and then collected using a digital system. In our setup, the foam texture is visualized using a see-through window located in the outlet of the capillary tube. The foam quality, which can be controlled by the CO2/SDS solution ratio, was set to be variable in each run. In each experiment, the injection of SDS solution-CO_2 gas continues to find the steady-state pressure drop along the capillary tube. The steady-state pressure drop was recorded to calculate the foam rheological properties, which were then used in the subsequent history matching processes.

The foam stability tests were conducted on a foam column apparatus at ambient temperature, and the concept of foam

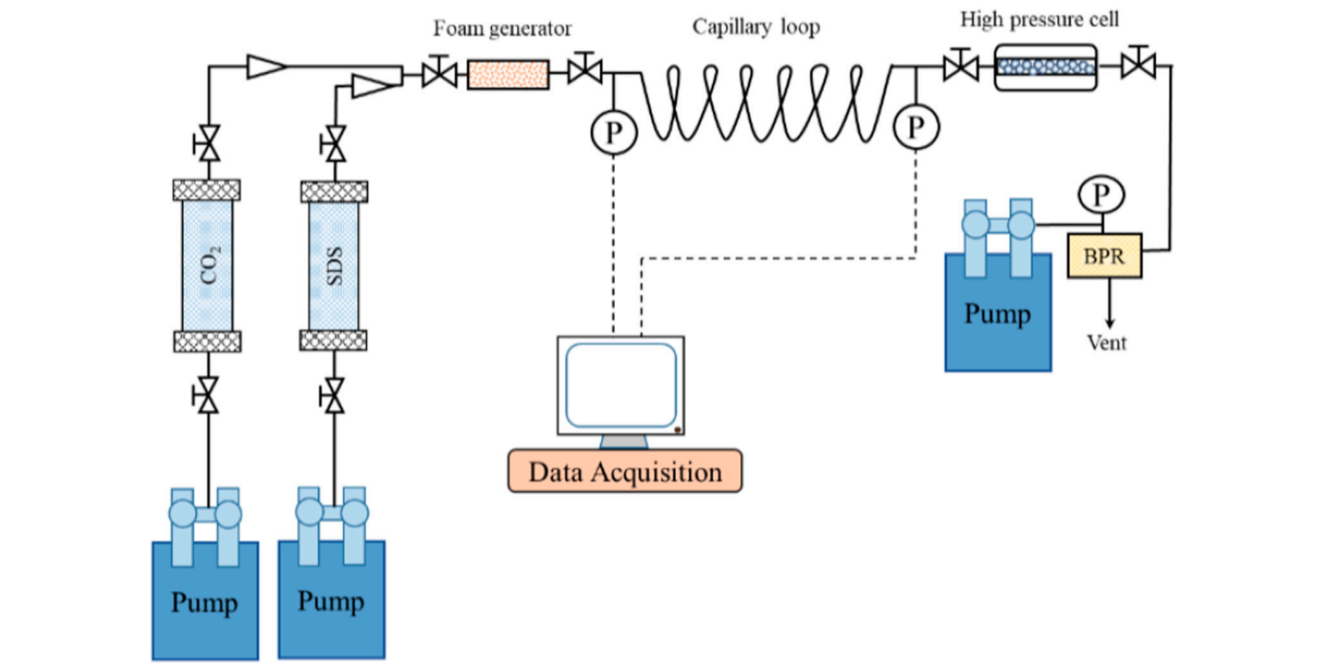

FIGURE 1 | Capillary tube setup for measurement of foam rheological parameters.

half-life was used as an indicator of foam enduring. The half-life is calculated by reading the initial foam height and stepwise measurement of foam height decline by time. The required time for the decay in foam height by 50% is recorded as its half-life. The foam stability test may have been subjected to error due to changes in environmental conditions such as temperature variation. To reduce the error in our data, the foam stability measurements were repeated three times, and the reported values on results are the arithmetic average of the listed values. After each stability test, the foaming equipment was carefully cleaned to remove any residuals.

NUMERICAL SIMULATION

Field Background

The Cardium formation was discovered in the Western Canada Sedimentary Basin and has been important in Alberta since the discovery of oil in the Pembina area in 1953. The Cardium Formation was formed around 86 million years ago in primarily marginal and shallow marine settings during the late Cretaceous period. This formation is subdivided into two parts in the Pembina field: the Pembina River and the overlaying Cardium Zone. The lower Pembina River component is an offshore shale deposit. The upper Pembina River grades into sandier lithologies that were deposited on a shallow shelf and shoreface settings. Depth to formation top for the West Pembina assessment area ranges from 1,500 m in the northeast to 2,200 m in the southwest. The bulk of horizontal drilling in the Cardium Formation has occurred in the more restricted sections of the West Pembina assessment area.

Simulation Model

The numerical model has a dimension of 2500 ft × 1200 ft × 100 ft, which is described by 50 × 30 × 10 grids in X, Y, and Z coordinates, respectively. There are eight hydraulic fracture treatments in the well with a half-length of 300 ft and a fracture spacing of 200 ft in between. The side view and top view of the reservoir model are shown in **Figure 2**. **Figure 3** represents the phase diagram, and the relative permeability curves are described in **Figure 4**. Local grid refinement has been applied to better simulate fluid flow in the fractures. Reservoir simulations and sensitivity analyses were conducted to examine the performance of the CO_2 foam huff and puff process and the effects of the main controlling variables. Local grid refinement has been applied to better simulate fluid flow in the fractures. **Table 1** shows the simulation input data, and **Table 2** represents the oil compositions.

Sensitivity Analysis

The Taguchi method is a statistical approach for enhancing experimental result quality and has been successfully applied in many engineering fields (Karna and Sahai, 2012). This experimental design procedure adjusts the design parameters, while uncontrollable factors such as noise are canceled in this manner (Phadke, 1989). **Table 3** shows the experimental design. In this work, the Taguchi method was used to effectively investigate the effects of the main variables on the performance of the CO2 foam huff and puff process, including the injection time, soaking time, production time, injection rate, and incremental injection rate.

The incremental injection rate was investigated in each cycle of some scenarios to increase the efficiency of the huff

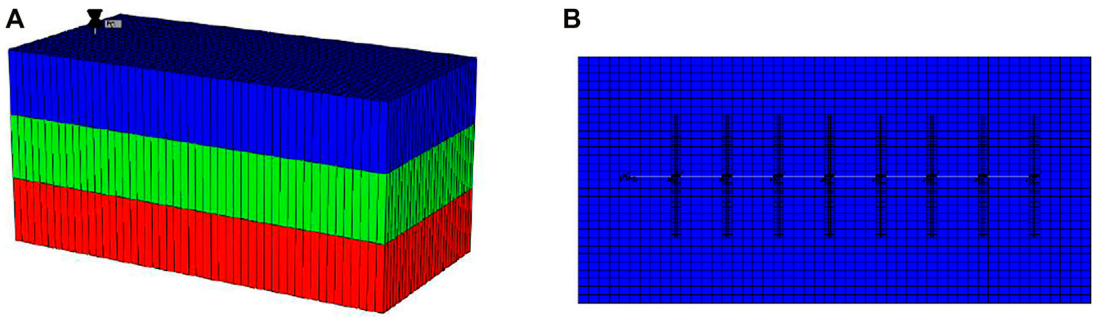

FIGURE 2 | Side view **(A)** and top view **(B)** of the simulation model.

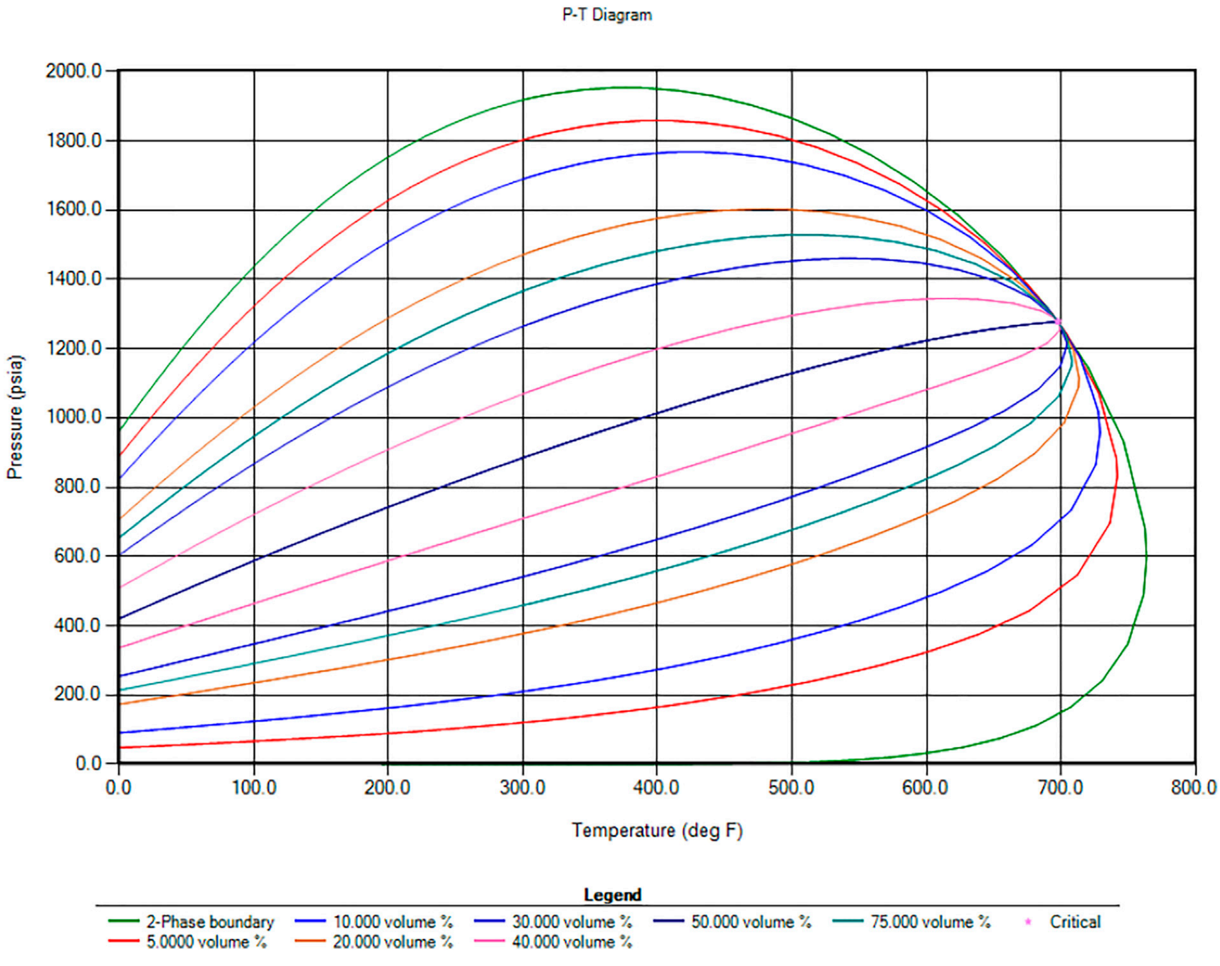

FIGURE 3 | Phase diagram of the live oil.

and puff process. As more cycles are conducted on a well, oil in the area close to the wellbore and fractures will be produced, leaving a void space growing from the wellbore and further into the formations. Such void space will then need to be filled by the injected CO_2 in the next huff period. Hence, a fixed injection rate may not be sufficient after several cycles as it cannot cover the entire drainage area and sometimes cannot reach the undeveloped oil zone. So,

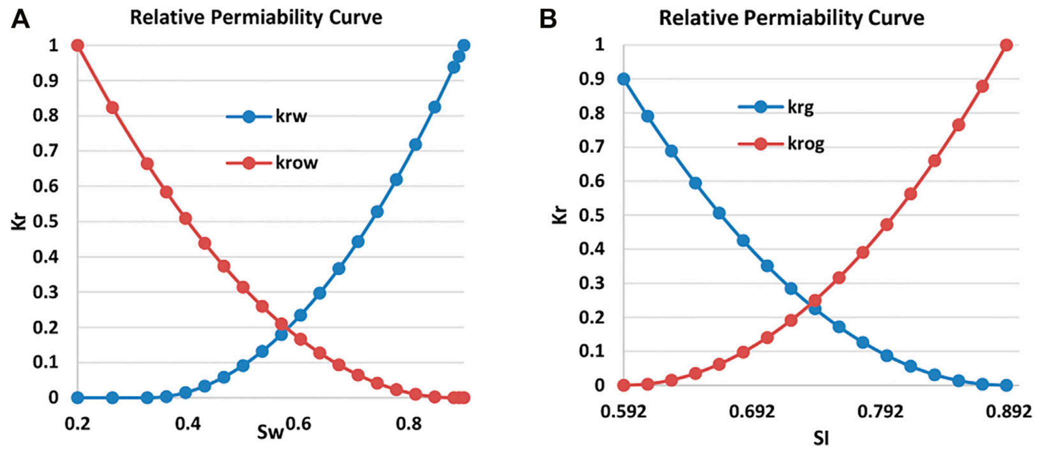

FIGURE 4 | Relative permeability curves for Cardium formation. **(B)** Gas-oil relative permeability. **(A)** Water-oil relative permeability.

TABLE 1 | Simulation input data.

Parameter	Value
Depth (m)	2000
Initial reservoir pressure (psi)	3,000
Reservoir temperature (F)	122
Initial water saturation (%)	25
Total compressibility (psi-1)	1 × 10–6
Average matrix permeability (mD)	0.01
Average matrix porosity	0.128
Fracture spacing (ft)	200
Fracture half-length (ft)	300
Fracture height (ft)	60
Number of fractures	8

TABLE 2 | Live oil compositions.

Parameter	Value (mole %)
N2	0.22
CO2	1.65
CH4	44.50
C2H6	5.85
C3H8	4.50
IC4	1.25
NC4	3.00
IC5	1.50
NC5	1.60
FC6	3.25
C7–C10	11.5
C11–C14	8.99
C15+	11.95

the incremental injection rate ratio is proposed here to overcome this problem. For instance, an incremental injection rate ratio of 1.1 means that the first cycle injection rate is 10,000 scf/d, the second cycle is 11,000 scf/d, the third cycle is 12,100 scf/d, and so on.

RESULTS AND DISCUSSIONS

Foam Stability

Experiments have been conducted to examine the foam stability at various sodium dodecyl sulfonate (SDS) concentrations. **Figure 5** shows an image of the CO_2 foam generated using the sand pack-type foam generator in this study. The milky foam with fine bubbles has been observed, indicating that the foam generator can effectively produce CO_2 when the SDS and CO_2 are simultaneously injected into the generator. The half-life of foams with different SDS concentrations is presented in **Figure 6**. It can be seen that foam stability is significantly enhanced with the increase in SDS concentration until it reaches 0.2 wt%, after which the half-life of foam almost levels off. This is because the critical micelle concentration (CMC) of SDS in deionized water under room conditions is about 0.23 wt%, and the absorption of the surfactant on the interface is almost saturated when surfactant concentration increases up to the CMC (Afifi et al., 2021). There is no noticeable enhancement for foam stability when SDS concentration is higher than 0.2 wt%. As a result, 0.2 wt% is the optimal concentration of SDS for foam stability, and the foam rheological properties are also quantified at this concentration.

The volume of liquid drained out of foam versus time has been recorded to examine the foam decay. The drainage ratio is defined as the volume of drained liquid to the total liquid used to generate foam. A slow increase in the drainage ratio means that the liquid drains slowly out of the foam, indicating a stable foam system. As shown in **Figure 7**, liquid drains faster when the drainage ratio is less than 0.6, and a straight line can well fit the drainage ratio during this period. It demonstrates that foam decays at a constant rate before 60% of the liquid is drained out of foam. Then, the change in the drainage ratio is slow. In other words, the foam system decays fast at the initial stage but can sustain at a lower rate after 60% of the liquid has drained out of the foam.

Foam Rheological Properties

The foam quality is a crucial parameter affecting the properties of CO_2 foam. It is the ratio of CO_2 volume to foam volume

TABLE 3 | Results of experimental design using the Taguchi method.

Run number	Injection time (month)	Soaking time (month)	Production time (month)	Injection rate (SCF/d)	Incremental injection rate ratio
1	1	1	1	10,000	1
2	1	2	3	20,000	1.1
3	1	3	6	30,000	1.2
4	1	4	9	40,000	1.3
5	1	5	12	50,000	1.4
6	3	1	3	30,000	1.3
7	3	2	6	40,000	1.4
8	3	3	9	50,000	1
9	3	4	12	10,000	1.1
10	3	5	1	20,000	1.2
11	6	1	6	50,000	1.1
12	6	2	9	10,000	1.2
13	6	3	12	20,000	1.3
14	6	4	1	30,000	1.4
15	6	5	3	40,000	1
16	9	1	9	20,000	1.4
17	9	2	12	30,000	1
18	9	3	1	40,000	1.1
19	9	4	3	50,000	1.2
20	9	5	6	10,000	1.3
21	12	1	12	40,000	1.2
22	12	2	1	50,000	1.3
23	12	3	3	10,000	1.4
24	12	4	6	20,000	1
25	12	5	9	30,000	1.1

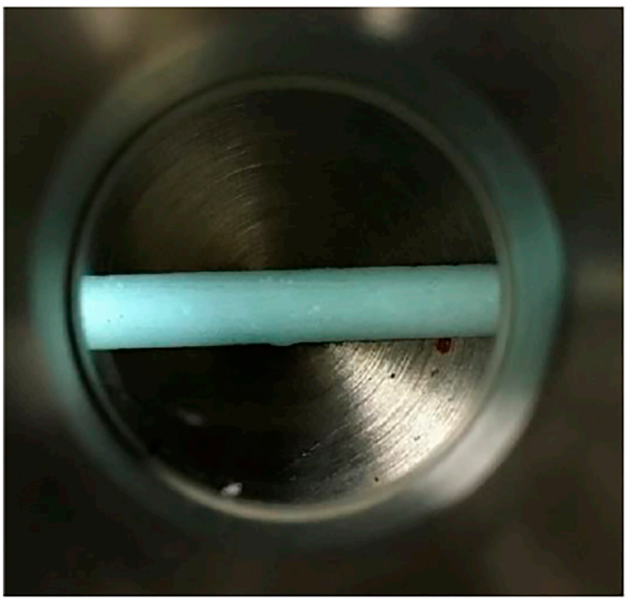

FIGURE 5 | CO_2 foam generated by the sandpack-type foam generator.

(i.e., CO_2 + SDS solution). In general, when foam quality is between 52% and 96%, the gas bubbles are in contact with each other, and as a result, an increase in viscosity will occur (Belyadi et al., 2019). In field operations, the shear rates are generally high; thus, the rheological properties of the foam are determined at three different foam qualities of 50%, 75%, and 90% based on five injection rates of 1.2, 3.0, 6.0, 9.0, and 12.0 cm^3/min corresponding to shear rates of 1091, 2728, 5,456, 8185, and 10,913 s^{-1}, respectively.

CO_2 foam is a typical non-Newtonian fluid system. The power-law model is adopted to describe the rheological properties of CO_2 foam in this study.

$$\tau_w = K\gamma_w^n \tag{1}$$

where τ_w is all shear stress, Pa; γ_w is the non-Newtonian wall shear rate, s^{-1}; n and K are the flow index and the consistency parameter of power-law modes, respectively.

As for fluid flow in the pipe, the pressure drop and wall shear stress can be described as follows:

$$\tau_w = \frac{\Delta p D}{4L} \tag{2}$$

The Newtonian wall shear rate can be determined using the flow rate and pipe diameter (Faroughi et al., 2018), as follows:

$$\gamma_{wN} = \frac{32q}{\pi D^3} = \frac{8\bar{U}}{D} \tag{3}$$

Correspondingly, the non-Newtonian wall shear rate can be quantified based on the Newtonian shear rate. The slope of the log–log plot of the flow curve (wall shear stress, τ_w, versus the magnitude of the Newtonian shear rate, $\frac{8\bar{U}}{D}$) is the flow index n.

$$\gamma_w = \gamma_{wN}\left(\frac{3n+1}{4n}\right) \tag{4}$$

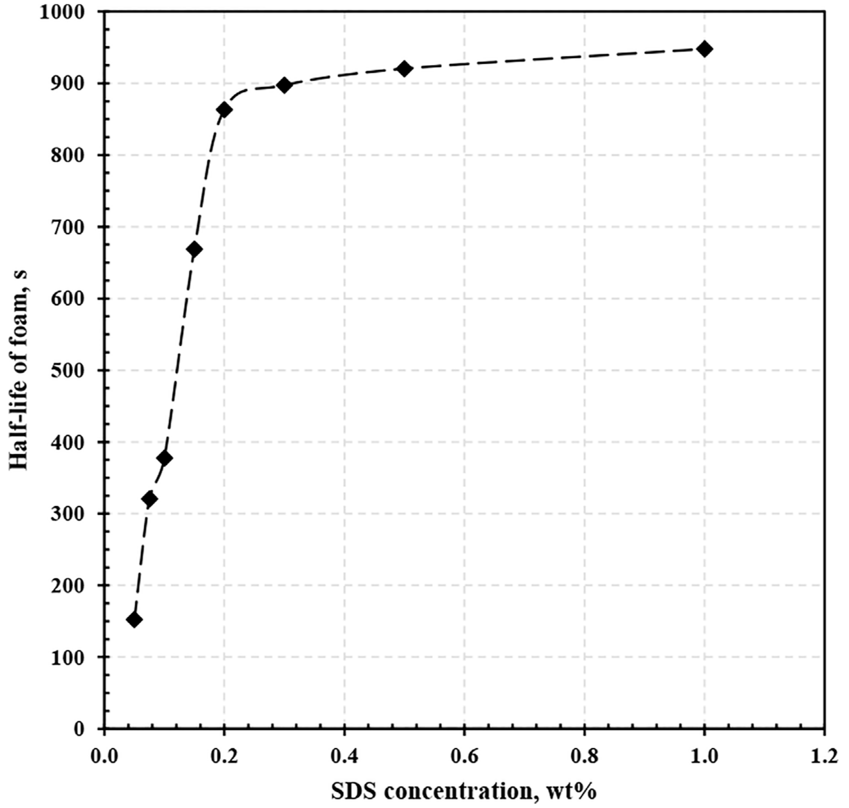

FIGURE 6 | Foam stability at different SDS concentrations.

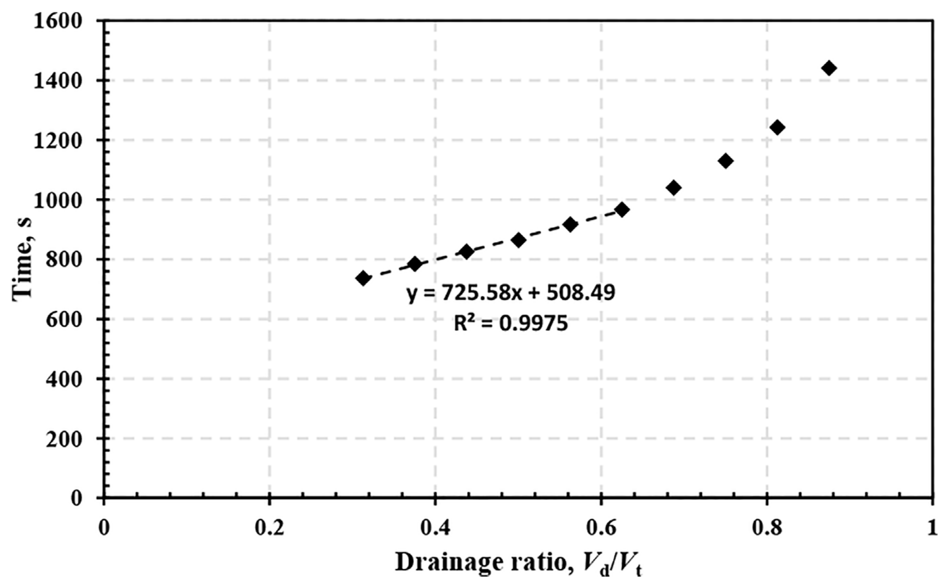

FIGURE 7 | Liquid drainage rate of foam with a SDS concentration of 0.2 wt%.

where Δp is pressure drop, Pa; D is the inner diameter of the pipe, m; L is the length of the pipe, m; γ_{wN} is the Newtonian wall shear rate, s^{-1}; q is the flow rate, m^3/s; and $\bar{U}$ is the average velocity.

The Newtonian shear rate and apparent wall shear stress for CO_2 foam with three different foam qualities are plotted in **Figure 8**. The correlations for the linear relation of log–log plots

TABLE 4 | Simulation run specification and obtained oil recovery.

Run number	Injection time (month)	Soaking time (month)	Production time (month)	Injection rate (SCF/d)	Incremental injection rate ratio	Results (recovery) (%)
1	1	1	1	10,000	1	20.3
2	1	2	3	20,000	1.1	23.7
3	1	3	6	30,000	1.2	26.4
4	1	4	9	40,000	1.3	27.5
5	1	5	12	50,000	1.4	28.3
6	3	1	3	30,000	1.3	24.5
7	3	2	6	40,000	1.4	28.7
8	3	3	9	50,000	1	29.1
9	3	4	12	10,000	1.1	28.7
10	3	5	1	20,000	1.2	24.5
11	6	1	6	50,000	1.1	27.5
12	6	2	9	10,000	1.2	28.7
13	6	3	12	20,000	1.3	31.3
14	6	4	1	30,000	1.4	26.8
15	6	5	3	40,000	1	27.9
16	9	1	9	20,000	1.4	28.7
17	9	2	12	30,000	1	29.8
18	9	3	1	40,000	1.1	26.8
19	9	4	3	50,000	1.2	27.9
20	9	5	6	10,000	1.3	28.3
21	12	1	12	40,000	1.2	29.4
22	12	2	1	50,000	1.3	25.6
23	12	3	3	10,000	1.4	27.2
24	12	4	6	20,000	1	29.1
25	12	5	9	30,000	1.1	30.2

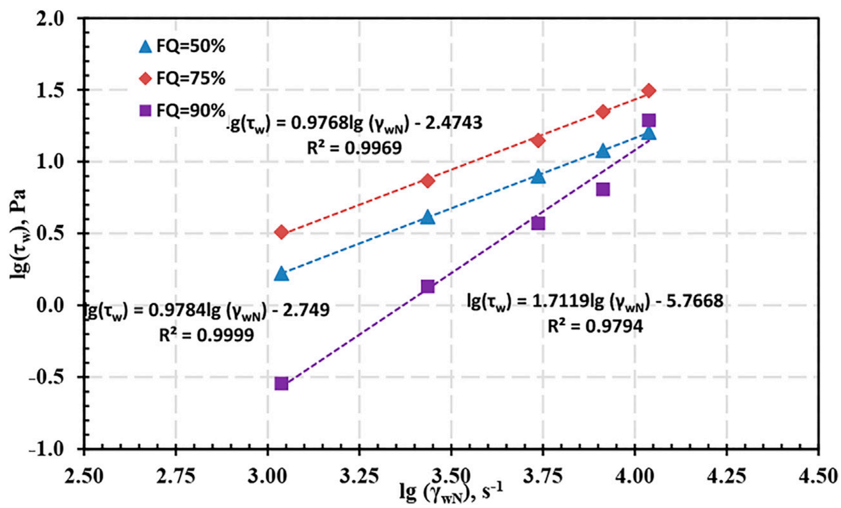

FIGURE 8 | Newtonian shear rate and apparent wall shear stress for CO_2 foam at different foam qualities.

with high R-squared values have been obtained through regression. The flow index n for foam qualities of 50%, 75%, and 90% are 0.9784, 0.9768, and 1.7119, respectively. The plots for CO_2 foam systems with foam quality of 50% and 75% are almost parallel, and the values of n are less than 1. Such CO_2 foams are shear-thinning fluids. By contrast, the CO_2 foam with a foam quality of 90% is a shear-thickening fluid because the flow index value is larger than 1. The values of K are 1.773×10^{-3}, 3.336×10^{-3}, and 2.065×10^{-3} for CO_2 foams with foam qualities of 50%, 75%, and 90%, respectively. Consequently, the apparent CO_2 foam with different foam qualities can be quantified using the power-law model. As shown in **Figure 9**, foam quality is a critical factor for the rheological properties of CO_2 foam. The flow index values for CO_2 foams with foam

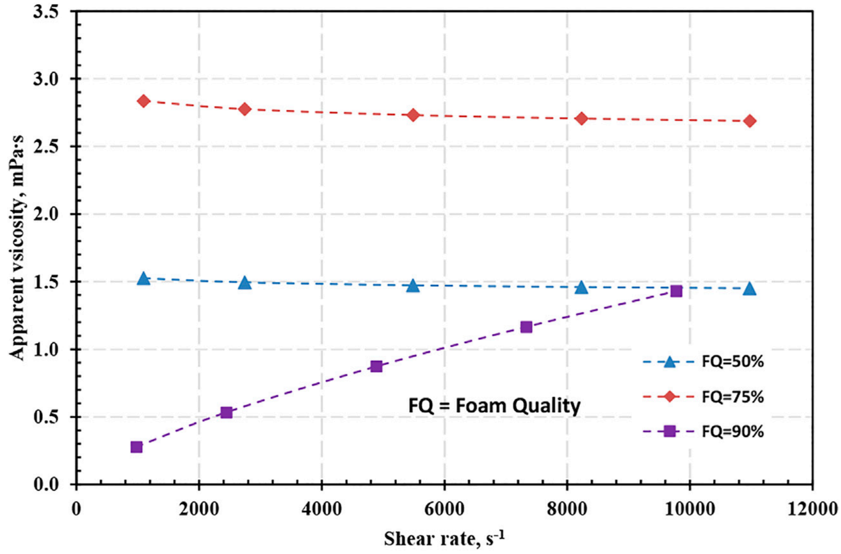

FIGURE 9 | Apparent viscosity of CO_2 foam with three foam qualities at different shear rates.

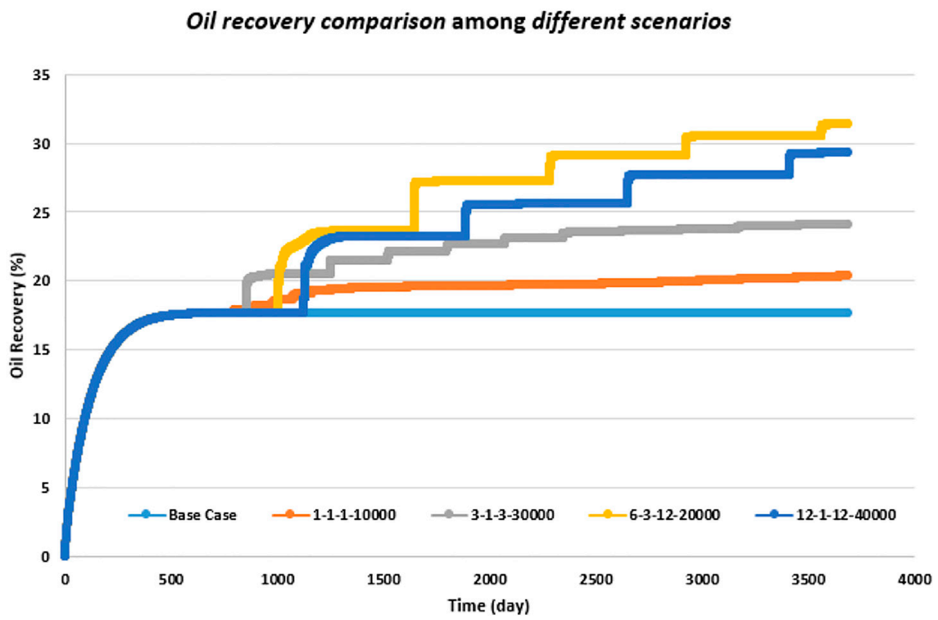

FIGURE 10 | Oil recovery comparison among different scenarios (run number 1, 6, 13, and 21 from **Table 4**).

qualities of 50% and 75% are close to but less than 1. The apparent viscosities of these two foam systems are decreased slightly with the increase in the shear rate, that is, a shear-thinning behavior. Meanwhile, the apparent viscosity of CO_2 foam with a foam quality of 90% increases with the increasing shear rate, that is, a shear-thickening behavior.

The apparent viscosity of CO_2 foam increases when the foam quality is increased from 50% to 75% due to the presence of a higher number of bubbles and regular interaction among the bubbles (Blauer et al., 1974). Nevertheless, the apparent viscosity is decreased when the foam quality is increased to 90%. That is mainly because the bubbles become denser, and thus the energy dissipation among these bubbles due to the collision and viscous friction decreases at high foam quality (Jing et al., 2017). In addition, the surfactant solution phase is transformed from the external phase into the internal phase when the CO_2 proportion is significant for high foam quality, resulting in apparent viscosity reduction and weak stability (Luo et al., 2014).

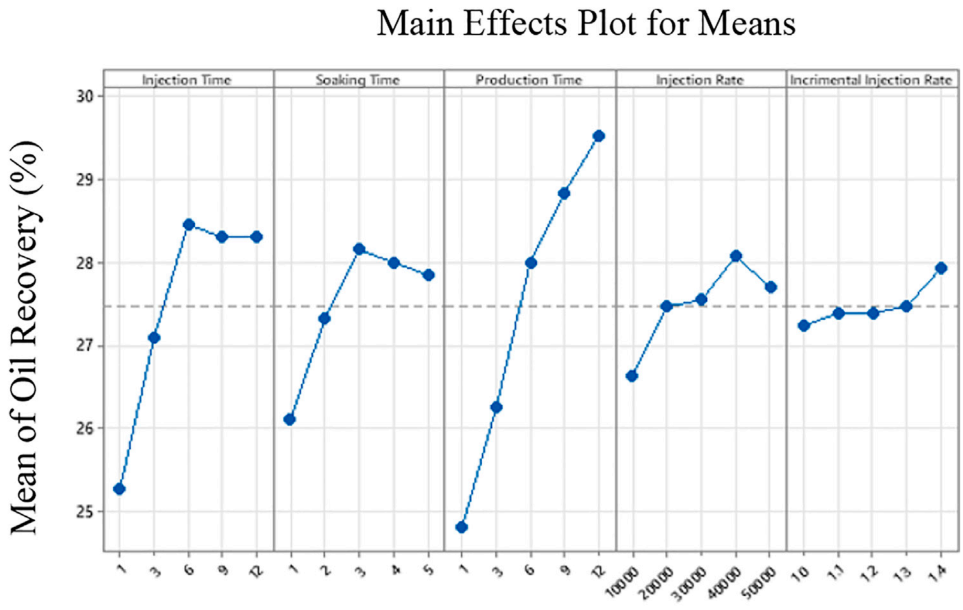

FIGURE 11 | Influence of main parameters on the oil recovery factor.

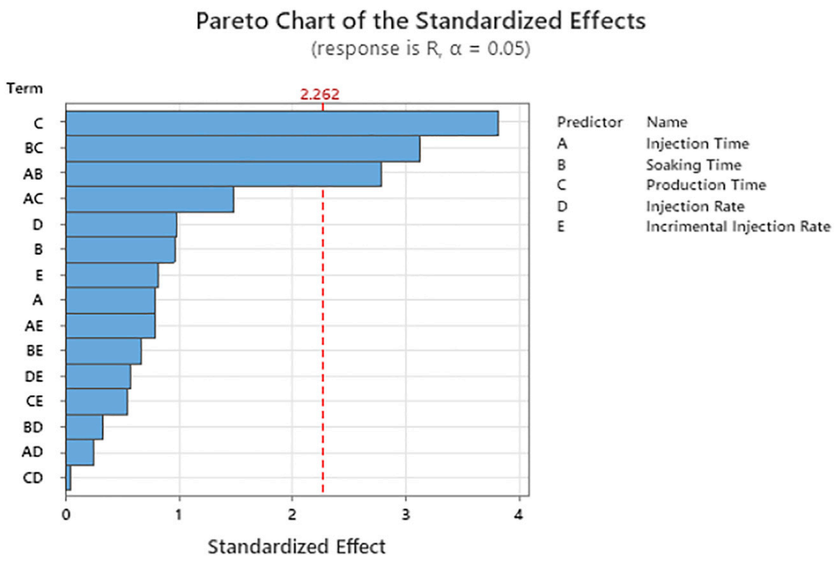

FIGURE 12 | Pareto chart of the affecting parameters.

Simulation Results

Simulation runs were conducted based on the Taguchi theorem *via* a compositional reservoir simulator, and the final recoveries are recorded in **Table 4**. The impact of injection time was determined through a series of simulations by setting the injection time to 1, 3, 6, 9, and 12 months. In this regard, the minimum oil recovery was gained in the lowest injection time, and the highest oil recovery was achieved when injection time increased. However, the optimum huff time of 6 months and more extended foam injection can inversely affect the reservoir performance. In a 1-month injection, the volume of injected fluid is small and cannot cover all the drainage area. Hence, longer huff time provides enough EOR agents to contribute to reservoir depletion. On the other hand, only a certain amount of injected fluid would change oil PVT properties, and an extra injection of the foam would result in the occupation of reservoir pores with the useless fluid; thus, the oil relative permeability is reduced as a negative parameter. **Figure 10** illustrates oil recovery

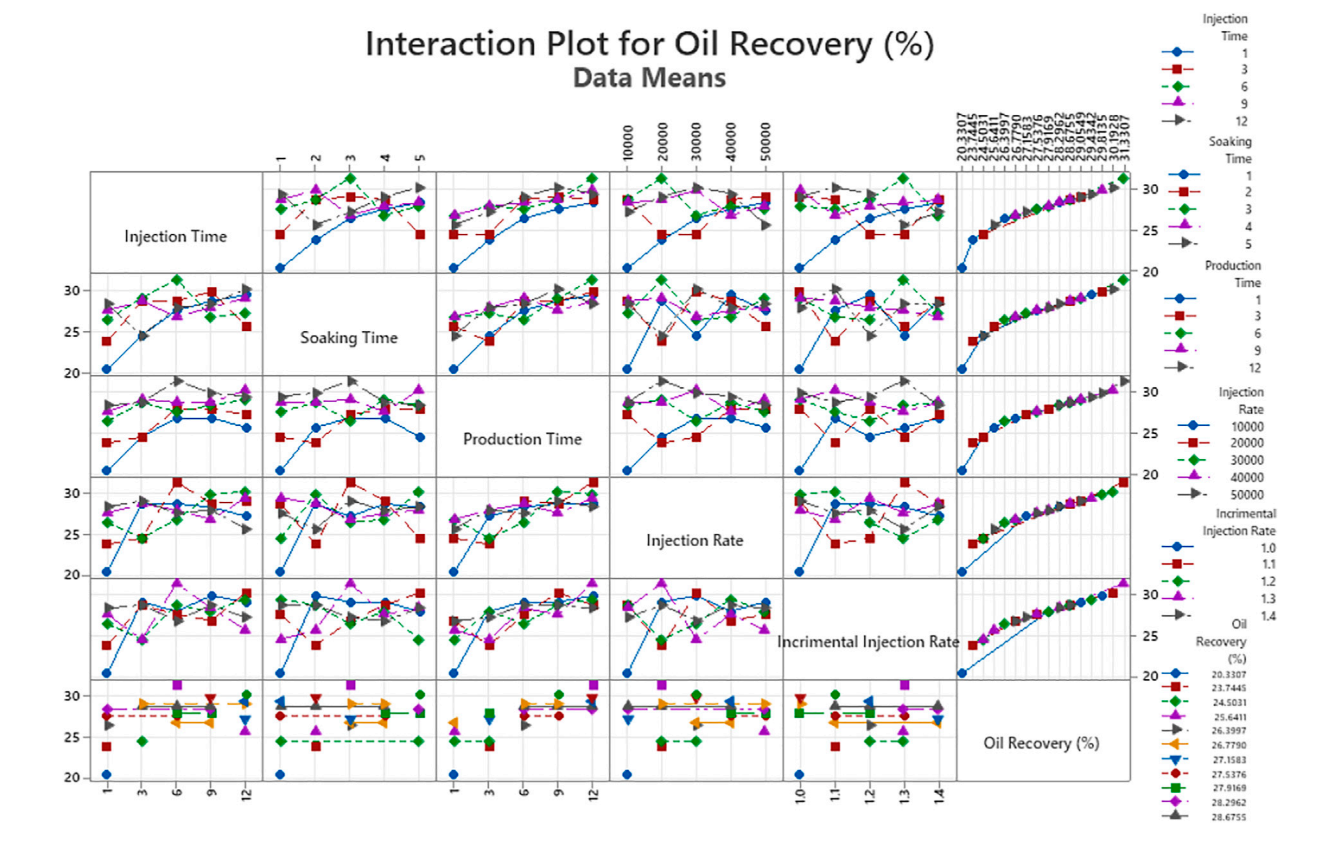

FIGURE 13 | Binary interaction of the impacting factors.

comparison among different scenarios; as is obvious in the figure, the highest oil recovery was achieved in the case of 6-month injection, 3-month soaking, and 12-month production. The results showed that longer production is the key parameter to increase oil recovery, but longer soaking time is not guaranteed for more oil recovery. The lowest oil recovery is represented by the case of 1-month injection, 1-month soaking, and 1-month production.

Sensitivity Analysis Results

Figure 11 demonstrates the influence of the main parameters on the oil recovery factor. The change in soaking time also has a considerable impact on the final amount of produced oil. The increase in soaking time from 1 to 3 months can raise the recovery factor by 6%, and the additional increase in soaking time has an inverse effect on the oil recovery. The injected gas reached the equilibrium state with the reservoir fluid at a particular time and added soaking times would not change oil viscosity and volume anymore. For a limited timeframe, extra waiting times equal shorter production time; accordingly, the oils that have enough potential to be produced would not produce appropriately due to lack of production time.

The puff process time was determined to have the most significant influence on the CO_2 foam huff and puff, and the longer production times yielded higher oil recovery. In the CO_2 foam huff and puff, the injection of the EOR agent has already increased reservoir pressure, and the reservoir fluids properties also have enhanced to some extent, based on the soaking time. Hence, the more productive time of the well increases the recovery factor. However, the reservoir performance shrinks after the 6 months of production owing to decreased reservoir pressure. The longer soaking time results in a shorter production time; thus, a lower amount of oil is produced and the reservoir pressure is maintained at higher levels. Increasing the injection rate would bring more foam to the reservoir, and the oil with a long distance from the injection well has a higher chance of getting in touch with the injected fluid and being positively altered for production. However, further increasing the injection rate would diverge oil from the well and reduce oil recovery after a specific rate. In this regard, the incremental injection rate in the subsequent huff processes has negligible oil recovery effects.

Affecting parameters on the recovery change were analyzed by the binary interaction plots. Based on the Pareto chart shown in **Figure 12**., it can be seen that the main affecting parameters of the CO_2 foam huff and puff are determined to be production time and the synergic effects of soaking time and production time (BC), followed by the synergic effects of injection time and soaking time. The letters on the vertical axis in Figure describe the affecting parameters, and the two-lettered vertical axis shows the synergism between those parameters. However, the other four main parameters are less significant, which reveals that a huff and puff process cannot be optimized based on a single parameter, and their synergic effects should be considered. The optimum value of each parameter thus can be calculated through a set of optimization algorithms to obtain the best systematic performance.

A detailed view of the interactions is given in **Figure 13**. The interaction of soaking time and production time was ranked as the second influencing factor in our study. The results showed that the final recovery is a direct function of soaking time and production time, and the higher soaking times require more production times. In this case, the optimum recovery was obtained when the soaking time was 3 months and production time was maximized. For the low soak times, the increased injection time was favorable in recovering more oils. However, in the higher soaking times, the increased injection time can reduce project efficiency.

CONCLUSION AND FUTURE WORK

In this work, CO_2 foam was first generated on the laboratory scale, and its stability and rheological properties were measured through several tests. Then the performance of huff and puff foam injection into tight oil reservoirs was investigated using a compositional model, which was optimized using the Taguchi method to reduce costs of computation. Outcomes showed the feasibility of this oil recovery method, and the combination of affecting parameters can be used to maximize the oil recovery. The final conclusions are as follows:

The foam stability increases with the increase in surfactant concentration, and then reaches a plateau after its CMC. The optimum surfactant concentration was measured to be 0.2 wt %. The foam rheological properties showed that in foam qualities of 50% and 75%, the generated foam acts as shear-thinning fluids, and the increase in foam quality changes its behavior to shear-thickening fluid.

The puff process time was determined to have the most significant influence on the CO_2 foam huff and puff, and the longer production times yielded higher oil recovery.

The simulation results showed that the production time is the most significant factor followed by the soaking time and injection time. Simulation results also demonstrated that the injection rate and incremental injection rate ratio have lower impact on the final oil recovery. Further analysis showed that combination of soaking time–production time and soaking time–injection time have higher impact than individual soaking and injection time. Using the optimum parameters, huff and puff foam injection can return 13.61% more oil than the base case.

DATA AVAILABILITY STATEMENT

The raw data supporting the conclusion of this article will be made available by the authors, without undue reservation.

AUTHOR CONTRIBUTIONS

AS-A is a Postdoctoral Research Fellow at the University of Calgary, Canada under the supervision of SC. AS-A's contribution is around 40%, SC's is around 30%, and SZ's is around 30%.

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Conflict of Interest: Author SZ was employed by the company Exceed Canada Oilfield Equipment.

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