

Article

Simulation Study of the Effects of Foam Rheology on Hydraulic Fracture Proppant Placement

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Abstract: Hydraulic fracture stimulation is one of the most effective methods to recover oil and gas from unconventional resources. In recent years, foam-based fracturing fluids have been increasingly studied to address the limitations of conventional slickwater such as high water and chemical consumption, environmental concerns, and high incompatibility with water-sensitive formations. Due to the gradual breakdown of liquid foams at reservoir conditions, the combination of silica nanoparticles (SNP) and surfactants has attracted a lot of attention to improve liquid foams' characteristics, including their stability, rheology, and proppant-carrying capacity. This paper investigates and compares the effects of cationic and anionic surfactants on the fracturing performance of SNP-stabilized foams at the reservoir temperature of 90 °C. The experimental results of viscosity measurements were imported into a 3D fracture-propagation model to evaluate the effectiveness of fracturing foams in transporting and distributing proppants in the fracture system. At both ambient and elevated temperatures, cationic surfactant was experimentally found to have better synergistic effects with SNP than anionic surfactant in improving the apparent viscosity and proppant-carrying capacity of foams. The simulation results demonstrate that fracturing with cationic surfactant-SNP foam delivers greater performance with larger propped area by 4%, higher fracture conductivity by 9%, and higher cumulative gas production by 13%, compared to the anionic surfactant-SNP foam. This research work not only helps validate the interrelationship between fluid viscosity, proppant settlement rate, and fracture effectiveness, but it also emphasizes the importance of proppant placement in enhancing fracture conductivity and well productivity.

Keywords: foam rheology; hydraulic fracturing; proppant placement; simulation; nanoparticle; surfactant



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1. Introduction

Liquid foams have been increasingly studied in multiple petroleum applications, such as drilling, enhanced oil recovery, carbon sequestration, and fracture stimulation [1–10]. Since first introduced in the late 1970s [11,12] foam-based fracturing fluids have brought in many significant benefits, such as their low water and chemical consumption, fast clean-up, reduced formation damage, and high compatibility with water-sensitive formations, including shale gas reservoirs [13–18].

In recent years, several research works have been conducted to combine surfactants with nanoparticles (NP) as stabilising agents to enhance the stability and thermal resistance of foams [19–25]. With recent advancements, foam-based fracturing fluids have been further

developed to improve their application in elevated temperature and elevated pressure conditions. It has been observed that surfactant, polymers, and, especially, nanoparticles play very important roles in increasing the stability and viscosity of the fracturing foams at harsh reservoir conditions [12,17,18]. As NP adsorbs on the bubble interface, it minimizes the contact area between the fluids and increases the film strength and film elasticity. This significantly helps reduce gas diffusion, decrease liquid drainage, delay film thinning, and directly improve foam stability [26,27]. In addition, the adsorption of surfactant molecules on the SNP surface reduces the surface tension of the gas–liquid interface, which directly helps to generate and maintain stable foam bubbles [28–30]. It has been found that ionic surfactants have greater synergy with silica nanoparticles (SNP) than non-ionic surfactants in enhancing foams' properties [31]. Cationic and anionic surfactants have been commonly used with silica nanoparticles (SNP) to improve the stability of both EOR and fracturing foams [32–42]. Previous studies by [24,31] compared the effects of cationic and anionic surfactants on the stability of SNP dispersions and SNP-stabilized foams at high temperatures. As cationic surfactant molecules have an opposite electric charge with the SNP, they can form multi-adsorption layers on the SNP surface, leading to increased hydrophobization and aggregation among the SNP. As a result, the liquid foams stabilized by SNP and cationic surfactants were found to have lower drainage rate, and higher half-life but lower foamability than those stabilized by the SNP/anionic surfactant system [31].

Proppants, such as sand and ceramics, are mixed in fracturing fluids to maintain the fracture width and fracture conductivity after the treatment [43,44]. Besides stability, the rheological properties and proppant suspension capacity of fracturing fluids play essential roles in the success of the stimulation treatment. Fracturing fluids with low viscosity tend to have limited proppant-carrying capacity, which results in inadequate propped area and insufficient fracture conductivity. It is, therefore, critically important for fracturing fluids to have sufficient viscosity to effectively transport and place proppants in the fractures. The impacts of proppant distribution on the fracture dimension can be demonstrated in Figure 1, in which the evenly distributed proppants result in much greater fracture volume than the unevenly distributed ones.

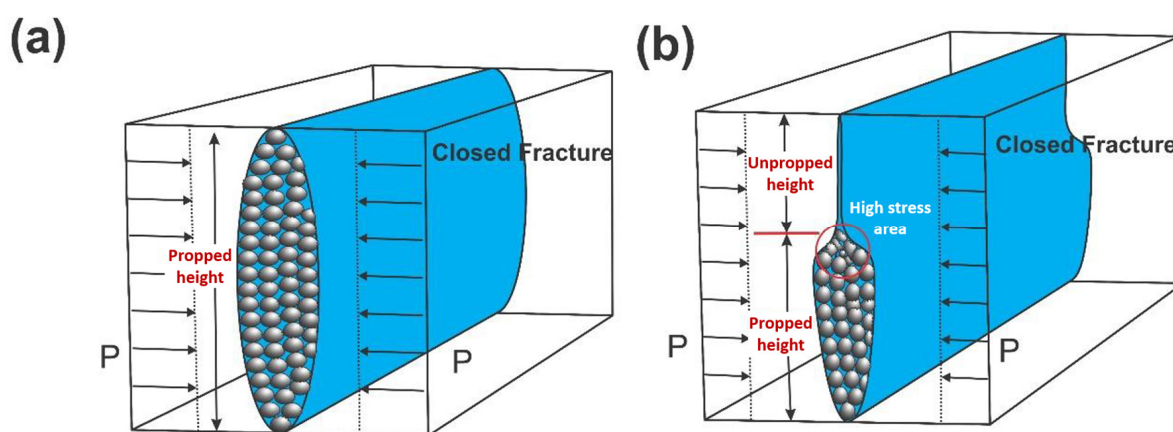


Figure 1. Schematic of fracture dimension with (a) evenly distributed proppants; (b) unevenly distributed proppants (reproduced from [45]).

In the current literature, although the stability and foamability of fracturing foams have received much attention, very few studies have been conducted to investigate the effects of different surfactant types on the rheological properties and proppant suspension capacity of SNP-stabilized fracturing foams, especially at elevated temperatures. Moreover, there has been a significant gap in the simulation of the performance of fracturing foams [12]. The simulation outputs are believed to be an excellent source to validate the experimental

results and to evaluate and compare the practical efficacy of the fracturing fluid systems. Due to the presented research gaps, this paper aims to investigate and compare the effects of cationic and anionic surfactants on the fracturing performance of SNP-stabilized foams at the reservoir temperature of 90 °C. Two foam-based fracturing fluid cases were considered: cationic CTAB/SNP foam and anionic SDBS/SNP foam. Also, a slickwater case was added as an industry benchmark for comparison. The fluid viscosity and proppant settling rate were first measured. Then, a rheological model was applied to characterise the fracturing fluids, followed by a 3D fracture-propagation simulation modeling. To evaluate and compare the fracturing performance of the fluid systems, the simulation metrics include the proppant distribution, fracture dimension, fracture conductivity, and production prediction after the treatment.

2. Rheology and Proppant Suspension Experiments

2.1. Materials

Two different surfactant types were used as foaming agents in the experiments. The cationic surfactant was Hexadecyltrimethylammonium Bromide (CTAB, >98% purity), and the anionic surfactant was Sodium Dodecylbenzene Sulfonate (SDBS, >99% purity). Both were obtained from Sigma–Aldrich, Melbourne, Australia. The critical micelle concentrations (CMC) of the surfactants were provided by the supplier, which are 0.61 mM for SDBS and 0.92 mM for CTAB at 25 °C. In addition, hydrophilic silica nanoparticles (SNP) in colloidal form were purchased from Sigma–Aldrich with a concentration of 34 wt% suspensions in water. The SNP has an average diameter of 22 nm, a molecular weight of 60.08 g/mol, and a surface area of 110–150 m²/g. All the chemicals were used without further purification. All experiments used deionised distilled water with a resistivity of 18.2 mΩ as a base fluid.

2.2. Sample Preparation

Deionized distilled water was first added with 0.05 wt% surfactant and stirred at a low speed of 50 RPM for 2 h without interruption. After that, 1.0 wt% SNP was added to the mixture and stirred for another 2 h. The surfactant–nanoparticle dispersion was then ultra-sonicated at a frequency of 40 Hz for 30 min to reach adsorption equilibrium. The dispersion appeared slightly hazy and was sealed for use in experiments. Finally, the prepared dispersion was stirred at a high speed of 2000 RPM for 2 min to produce fine foam. The produced foam was then immediately transferred into a 500 mL cylinder and ready for the next laboratory experiments. For each data point, the experiments were repeated at least three times to confirm reproducibility, and the average values were used in the manuscript to represent the stable measurement results.

2.3. Apparent Viscosity Measurement

The apparent viscosity of SDBS/SNP and CTAB/SNP foams was measured by an SR5 Rheometer (Rheometric Scientific, New Castle, DE, USA). The measurements were conducted on a cup-and-bob geometry system, with shear rates varying from 10 to 1000 s^{−1}. The produced foam was well poured into the pre-heated cup, followed by the bob element being inserted, and then the commencement of the measurements. The testing temperature inside the rheometer is generated, measured, and accurately controlled by an integrated heating system. The influence of surfactant type on the foam viscosity was studied at temperatures of 25 °C and 90 °C and atmospheric pressure.

2.4. Static Proppant Settling Measurement

Sand proppants (20/40 mesh size) with a mass amount of 1 g were evenly added to the foam column in the glass cylinder. The proppant settling velocity was then calculated by measuring the height of the initial foam column and the time taken for the proppants to settle on the bottom of the cylinder. The diameter of the measuring cylinder was more than 25 times larger than that of the proppants to minimize the effect of confining walls on the proppant-settling velocity [46].

2.5. Experimental Results and Discussions

2.5.1. Viscosity Measurement

The rheology of the fracturing fluid plays an essential role in determining the success of the fracture stimulation treatment. Figure 2 shows the studied fracturing fluids' apparent viscosity at ambient and elevated temperatures, which were obtained from the rheometer measurement. As observed in Figure 2, cationic CTAB/SNP foam had higher apparent viscosity than the anionic SDBS/SNP foam. In addition, the viscosity of foam became lower at elevated temperatures and decreased gradually as the shear rates increased.

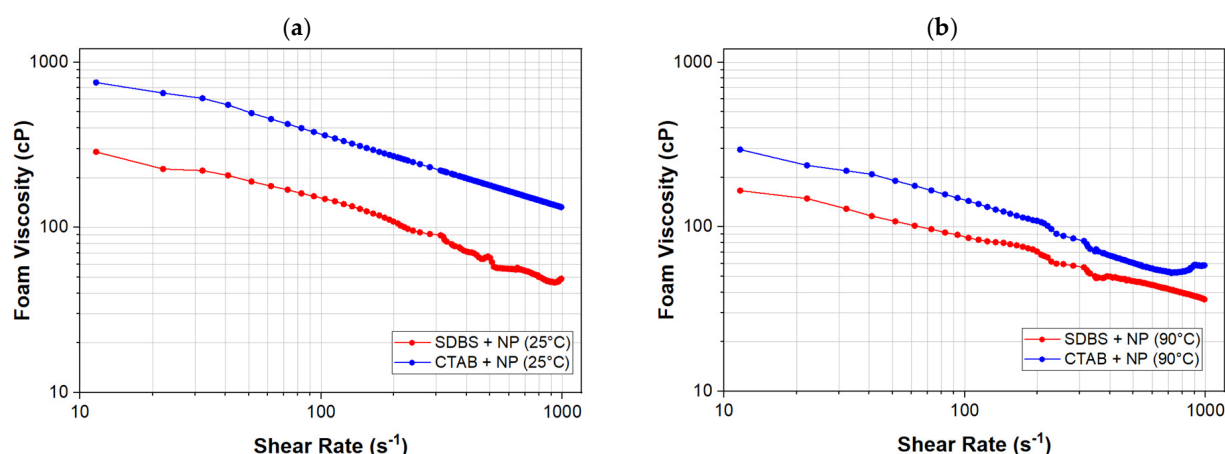


Figure 2. Apparent viscosity of foam and slickwater at (a) 25 °C and (b) 90 °C.

Based on the log–log profile of apparent viscosity (μ_{app}) versus shear rate (γ) and the power law equation (Equation (1)) [47], the rheological parameters of flow behavior index (n') and fluid consistency index (K') for each fluid were calculated and summarized in Table 1.

$$\mu_{app} = 47879K'\gamma^{(n'-1)} \quad (1)$$

Table 1. Rheological parameters of the fracturing fluids.

Parameter	Unit	SDBS/SNP Foam (90 °C)	CTAB/SNP Foam (90 °C)
Flow Behavior Index (n')	Dimensionless	0.6305	0.5565
Fluid Consistency Index (K')	$\left(\frac{\text{lb}\cdot\text{s}}{\text{ft}^2}\right)$	0.0098	0.0216

Generally, foam fluids can be classified into three main groups based on the flow behaviour index (n'). If $0 < n' < 1$, the fluid shows pseudo-plastic or shear-thinning behaviour, in which the fluid viscosity decreases with increasing shear rates. On the other hand, if $n' > 1$, the fluid shows dilatant or shear-thickening behaviour, in which the fluid viscosity increases with increasing shear rates. Lastly, if $n' = 1$, the fluid has Newtonian behaviour, in which the fluid viscosity is independent of the shear rate change. According

to Figure 2 and Table 1, it can be confirmed that all three studied fracturing fluids have shear-thinning behaviour.

The viscosity measurement data and the n' & K' parameters at 90 °C were then imported into the GOHFER 3D database. More details of the rheological characterization process are presented in Section 3.2.

2.5.2. Proppant Suspension

The settlement rate of proppants in the fractures is critical to the fracture dimension and conductivity. If the proppants settle too quickly, they tend to accumulate near the wellbore, resulting in limited fracture dimension and even formation damage. Otherwise, at a low-settling velocity, proppants are more likely to be further transported and uniformly distributed inside the fractures, helping to enhance the fracture area and increase the overall conductivity.

Figure 3 shows the proppant suspension capacity in foams at 25 °C and 90 °C. At the ambient condition, the 20-/40-mesh proppants had a settling rate of 0.024 cm/s and 0.0685 cm/s in CTAB/SNP and SDBS/SNP foams, respectively. The velocity difference can be explained by Stokes' Law theory, in which the settling velocity of proppants is greatly dependent and inversely proportional to the viscosity of the medium fluid [48]. In other words, the fluids with higher viscosity tend to have a better capability of suspending and transporting the proppants.

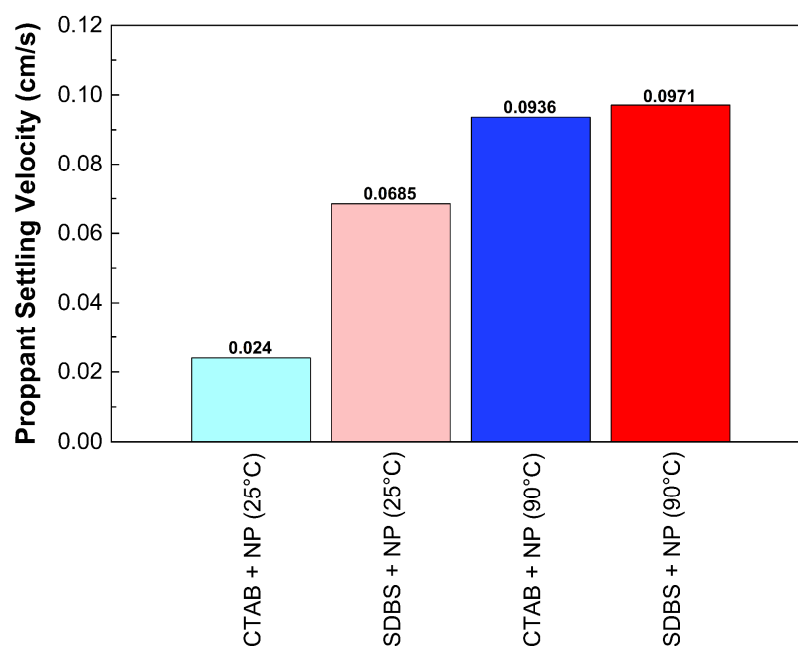


Figure 3. Proppant-settling velocity in foams at 25 °C and 90 °C.

As the temperature increased to 90 °C, the proppants settled faster at above 0.09 cm/s in both studied foams. The settling velocity of proppants in the anionic SDBS/SNP foam was much less sensitive to the temperature change than the cationic CTAB/SNP foam. Related observation can be seen in the viscosity results (Figure 2), indicating the high thermal resistance of the SDBS/SNP foam.

Simulation outputs, including the fracture dimension, fracture conductivity, and gas production, are compared between the two foam-based fluids and presented in the next section to validate the prediction.

3. Hydraulic Fracturing Simulation

Several simulations were performed on a numerical simulator (GOHFER 3D 9.4.0) developed by [49] to evaluate the practical performance of the fracturing fluids. The simulator can predict three-dimensional fracture geometry during propagation as a function of time. In addition, the fluid and solid transport models are fully coupled in the simulator.

The GOHFER 3D simulator by Barree (1983) [49] eliminates some simplified assumptions from previous models and incorporates the calculation of the fracture width. Fracture width (w) is assumed to be twice the fracture surface displacement (u), which is calculated from Poisson's ratio (ν), Young Modulus (E) (Equation (2)).

$$w = 2u = 2 \iint \left(\frac{1 - \nu^2}{\pi E} \right) P_e d\Psi dS \quad (2)$$

Effective pressure (P_e) is the distributed load at the radial deflection distance (S) and angle (Ψ). The fluid pressure determines the effective pressure in fracture (P_f), the least-principal earth stress (σ), and the pore pressure in rocks (P_p) (Equation (3)). The fluid pressure in fracture (P_f) is related to the apparent fluid viscosity and the volumetric flow rate in fracture, which is determined by the material balance equation (Barree, 1984) [47].

$$P_e = P_f - \sigma - P_p \quad (3)$$

Lastly, one of the important outputs of fracture simulation is the fracture conductivity. The absolute fracture conductivity (F) is calculated from the fracture permeability (k_f) and fracture width (w), as shown in Equation (4).

$$F = k_f w \quad (4)$$

3.1. Simulation Inputs and Outputs

The fracture simulations were conducted on a typical tight gas reservoir model. First, the well logs, diagnostic fracture injection test (DFIT) results, reservoir properties, and the perforation design were imported into the simulator. The well-log data include the measures of depth, porosity, gamma ray, bulk density, resistivity, sonic waves, and caliper logs. Figure 4 shows the DFIT results, which are used to determine the geomechanical parameters such as the breakdown pressure, shut-in pressure, and closure pressure, as well as the average permeability of the reservoir. After that, a single perforation interval was added to the model. The details of the perforation design and reservoir properties are included in Table 2. At a depth of 9400 ft, the reservoir is modeled with a temperature of 93 °C, pressure of 4339 psi, 65% gas saturation, 11% porosity, and 0.06 mD permeability. The inputs for perforation configuration and DFIT results are also included in Table 2.

Finally, the fracture treatment design was added to the simulator. Three different fracturing fluids were investigated, which are the SDBS/SNP foam, CTAB/SNP foam, and the benchmark slickwater. Table 3 demonstrates the treatment stages and parameters used in the study. The injection rate was set fixed at 30 bbl/min. Throughout the six-stage fracturing-treatment program, the clean-stage volume reduces from 15,000 to 3000 gal, while the injected amount of ceramic proppants increases from 0 to 10,000 then 28,000 lb. In order to assess the fracturing performance among the fluid systems, the key comparison metrics used are the simulation outputs of the fracture dimension, fracture conductivity, proppant distribution, and the post-frac gas production forecast.

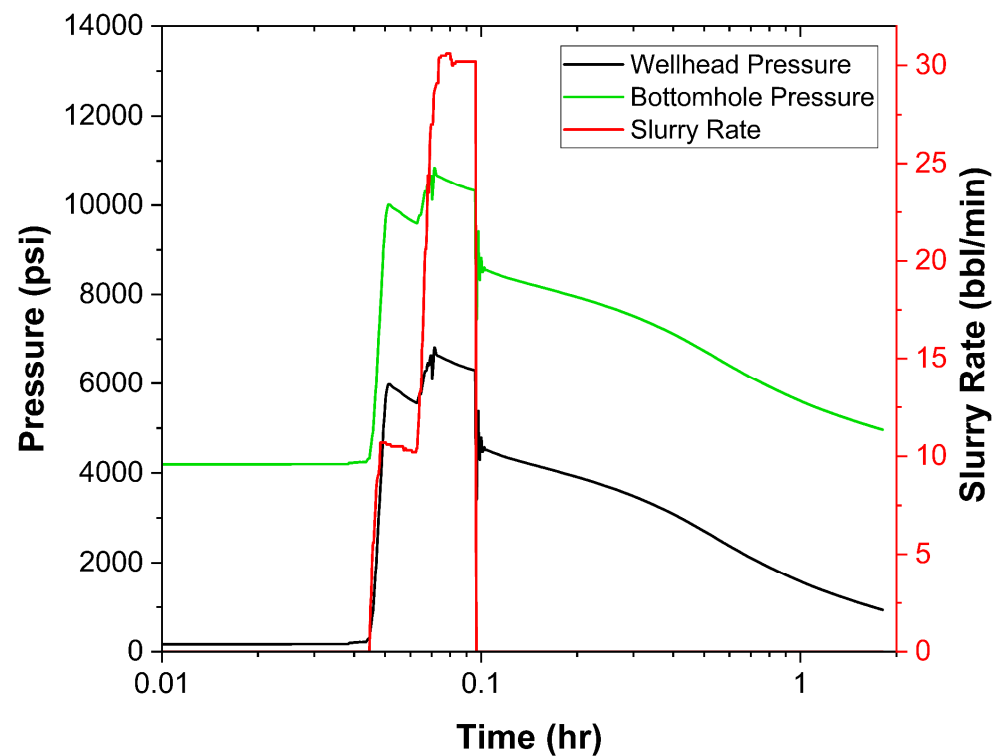


Figure 4. Diagnostic Fracture Injection Test (DFIT) data.

Table 2. Input data for reservoir properties and perforation design.

Parameters	Value
Reservoir Properties	
Reservoir depth	9410 ft
Reservoir pressure	4339 psi
Reservoir temperature	200 °F (93 °C)
Average reservoir porosity	11%
Gas saturation	65%
Water saturation (%)	35%
Perforation Design	
Perforation interval	9400–9420 ft
Number of shots	30
Perforation phasing	60°
Perforation diameter	0.4 inch
DFIT Analysis	
Breakdown pressure	10,942 psi
Instantaneous shut-in pressure	8726 psi
Fracture closure pressure	6818 psi
Average reservoir permeability	0.06 mD

Table 3. Input data for fracturing treatment.

Stage	Fluid Type	Clean Stage Volume (gal)	Proppant Amount (lb)	Proppant Type	Injection Rate (bbl/m)
1	Pad fluid	15,000	0	None	30
2	SDBS/SNP foam, CTAB/SNP foam, Slickwater	10,000	10,000	Ceramic Sand 20/40	30
3		8000	24,000	Ceramic Sand 20/40	30
4		6000	30,000	Ceramic Sand 20/40	30
5		4000	28,000	Ceramic Sand 20/40	30
6	Flush fluid	3000	0	None	30
Total		46,000	92,000		

3.2. Rheological Characterization

Before performing the simulations, the experimental viscosity results of the studied foams were imported into the fluid database of GOHFER 3D. A Carreau rheological model was used to characterize the properties of the fluids (Equations (5) and (6)). Four parameters are required in the Carreau model, which are the power law exponent (n'), fluid consistency index (K'), zero-shear fluid viscosity (μ_0), and the high-shear viscosity (μ_∞) [50]. Most of these parameters can be obtained from the laboratory plot of viscosity versus shear rate, which is demonstrated in Figure 2.

$$\mu_{app} = \mu_\infty + \frac{s_f \mu_0 - \mu_\infty}{\left(1 + \left(\frac{s_f \gamma}{\gamma_l}\right)^2\right)^{\frac{1-n'}{2}}} \quad (5)$$

$$\gamma_l = \left(\frac{\mu_0 K'}{47879}\right)^{\left(\frac{1}{n'-1}\right)} \quad (6)$$

where s_f is the sand factor, γ is the shear rate, and γ_l is the low-shear transition.

3.3. Simulation Results and Discussions

3.3.1. Proppant Distribution and Fracture Dimension

Figure 5 shows the simulation results of the proppant distribution from the three fracturing fluid cases: benchmark slickwater, SDBS/SNP foam, and CTAB/SNP foam. The simulation results show that the fracture generated by slickwater stimulation has a much smaller propped area than those generated by foam stimulation. Moreover, in the slickwater case, very high concentrations of proppants accumulate at the bottom of the fracture, indicating limited transportation and ineffective placement of proppants in the fracture. This behaviour is mainly due to the low viscosity and high leak-off rate of slickwater, both of which promote early and rapid proppant settlement in the near-wellbore region.

On the other hand, foam-based fracturing fluids result in larger propped areas with the fracture length extension and the fracture height growth. In contrast to the benchmark slickwater, liquid foams generate very uniform and homogenous proppant distributions, which can be attributed to the superior rheological properties of the nanoparticle–surfactant-stabilized foams. As the SDBS/SNP and CTAB/SNP foams have high viscosity characteristics and rigid bubble structures strengthened by nanoparticle layers, they tend to effectively suspend proppants in their bubble networks, thereby delaying the proppant settlement. According to [51], when settling through foams, proppants are exerted by two uplift forces: the drag force from the bulk foam movement and the elastic force from

the foam compressibility and lamella movement. These forces are essential to counter the gravitational force and resist the downward trend of the proppants [52]. As a result, in the foam-fracturing cases, proppants are effectively transported and uniformly placed towards the fracture tips, helping to enhance the fracture dimension and conductivity.

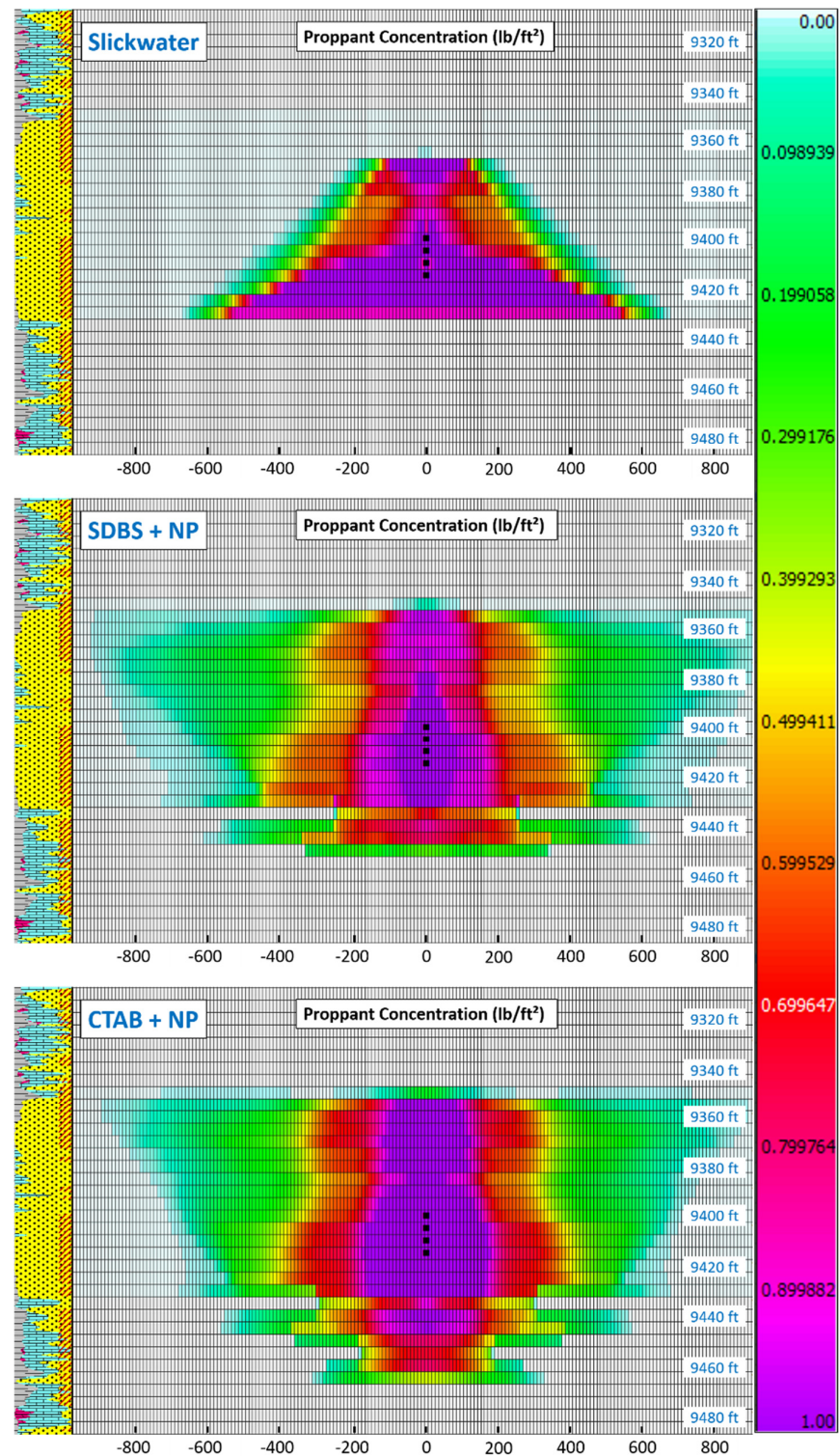


Figure 5. Concentration and distribution of proppants in fractures using slickwater and liquid foams.

The predicted fracture geometries of the SDBS/SNP and CTAB/SNP foams appear nearly identical in Figure 5. A quantitative measure, therefore, is required to evaluate the

fracturing performance of the three fluid systems. Table 4 summarizes the fracture dimensions, average fracture conductivity, and cumulative fluid lost for each simulation scenario.

Table 4. Simulation results of fracture dimension and conductivity.

Parameter	Unit	Slickwater	SDBS/SNP Foam	CTAB/SNP Foam
Fracture height	ft	70	105	120
Fracture length	ft	670	800	730
Average fracture width	inch	0.310	0.319	0.324
Propped area	ft ²	187,600	336,000	350,400
Cumulative fluid loss	gal	1198	997	961
Fracture conductivity	mD.ft	109.3	57.5	62.7

As expected from the proppant distribution results, the fracture created by the benchmark slickwater has the smallest dimensions out of the three simulation cases. While the anionic SDBS/SNP foam results in the longest fracture half-length, the cationic CTAB/SNP foam achieves the largest propped area due to its outstanding fracture height and average width. The estimated propped area of the CTAB/SNP case is 350,400 ft², which is 87% higher than the slickwater case and 4% higher than the SDBS/SNP case. Furthermore, the cumulative fluid loss is recorded as lowest in CTAB/SNP stimulation and highest in the slickwater fracturing. There seems to be a strong correlation between the fluid viscosity, its leak-off rate, and the resulting fracture dimension. It is demonstrated that fracturing fluids with higher viscosity tend to have a lower leak-off rate and produce greater height and openness for the fractures, and vice versa.

Besides the fracture dimensions, fracture conductivity is another critical parameter to evaluate fracturing performance. Based on the summary results in Table 4, the fracture conductivity of the cationic CTAB/SNP case is 62.7 mD.ft, which is 9% higher than that of the anionic SDBS/SNP case. On the other hand, the benchmark slickwater has the highest average fracture conductivity of 109.3 mD.ft. However, this high value is caused by the poor proppant transportation of the slickwater, leading to the excessive accumulation of proppants at the bottom of the fracture. Consequently, an undesirable fracture pathway with great length and very high conductivity is created, which acts as an outlier to increase the conductivity average of the whole propped area. An analogous observation can be found in [11], in which the least-stable foam generated the highest fracture conductivity due to the high accumulation of proppants in the near-wellbore area. Therefore, it is essential to note that the interpretation of fracture conductivity results alone might be misleading and not reflect the situation accurately. Instead, a comprehensive evaluation of the fracture dimensions, fracture conductivity, and leak-off behaviour is strongly required when evaluating the stimulation performance of a fracturing fluid.

3.3.2. Gas Production After Treatment

To demonstrate the impacts of the resulting fracture dimension and conductivity on productivity, simulations were conducted to predict production at the stimulated well. In GOHFER 3D 9.4.0 software, the average proppant concentration over the net pay, the closure stress, pore pressure, and reservoir properties are used to calculate the formation's effective conductivity and deliverability. A transient production model is then applied to estimate the gas flow rate at a particular time.

Figure 6 shows the cumulative gas production of the three studied cases over the first 5 years after the treatments. The benchmark slickwater case has the lowest productivity, with a total gas production of 136 MMscf. On the other hand, the CTAB/SNP foam

achieves the highest cumulative gas production of 238 MMscf, which is 13% higher than the SDBS/SNP foam case. Furthermore, Figure 7 shows the total recoverable gas production before the economic limit is reached. Over the life span of the well, the anionic SDBS/SNP and cationic CTAB/SNP foam stimulations can recover up to 2.05 and 2.24 Bscf of gas volume, compared to only 0.84 Bscf from the slickwater fracturing.

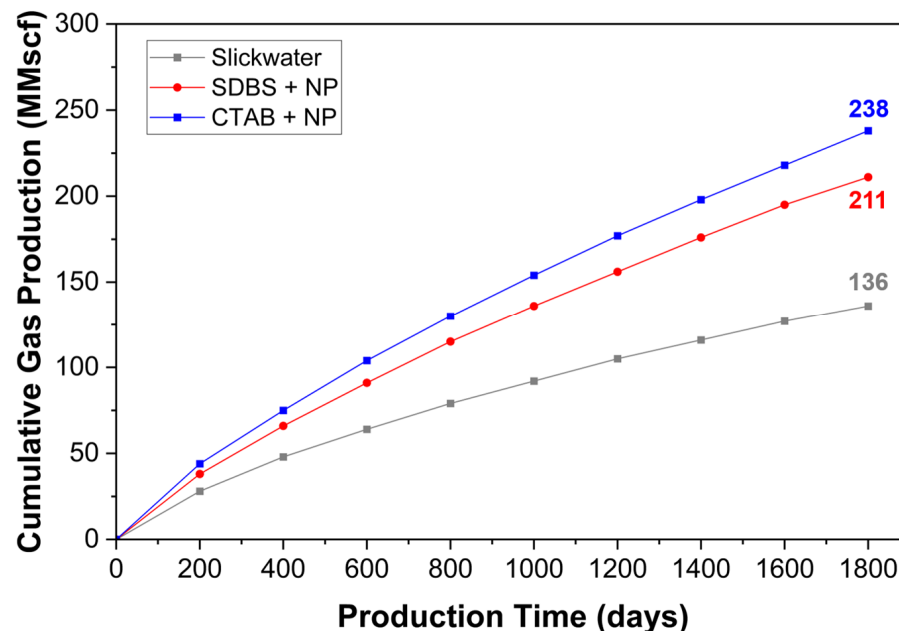


Figure 6. Cumulative gas production in the first 5-year period.

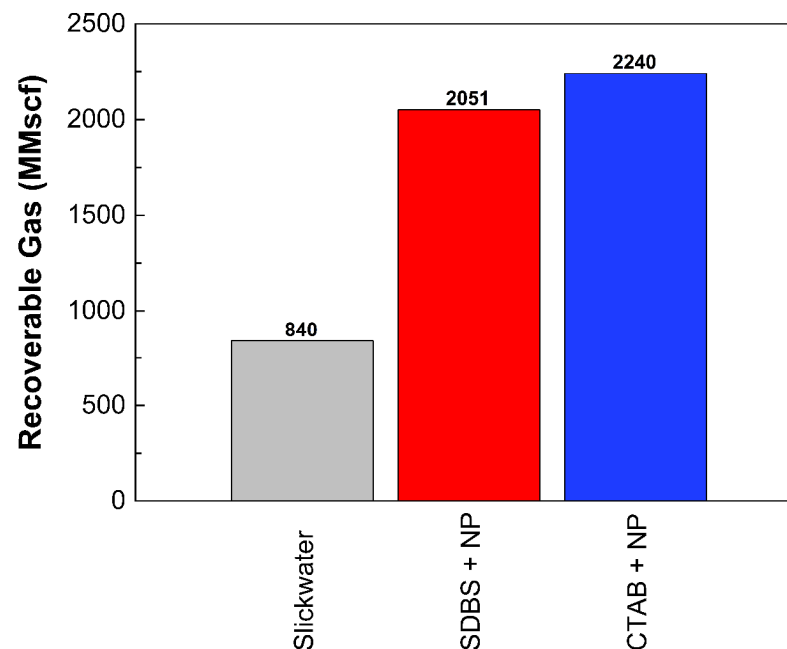


Figure 7. Total recoverable gas over the life span of the well.

It is evident that foam-based fracturing fluids can provide greater access and extract more gas volume from the reservoir than slickwater. The excellent productivity results of the foam stimulation are attributed to the large, propped area and the uniform distribution of proppants in the fractures, both of which are caused by the high viscosity and the effective proppant-carrying characteristics of the liquid foams. Nevertheless, it is important to emphasise that the performance of the fracturing fluid heavily depends on the

reservoir properties. By generating significant fracture height growth and having a slow settlement of proppants, foam-based fracturing fluids have huge advantages in expanding the propped area and enhancing the field productivity, especially on the studied reservoir with thick net pay and low permeability. However, in some other cases, foam fracturing might not be a good stimulation option as the excessive fracture height growth can cause negative consequences to the structure confinement, seal rocks, and the water aquifer. In addition, [45] reported that foam stimulation does not prevent proppant settlement in a high permeability reservoir due to the rapid closure of the fractures.

4. Conclusions

This paper aims to investigate the relationship between the foams' rheological and proppant suspension properties and their fracturing performance at elevated reservoir temperatures. Through the experimental and simulation results, the effectiveness and practicality of the nanoparticle–surfactant-stabilized fracturing foams have been highlighted. The key conclusions can be summarized as follows:

1. At both ambient and elevated temperatures, SNP has stronger synergy with cationic CTAB surfactant than anionic SDBS surfactant in enhancing liquid foams' rheological and proppant suspension properties. Because of this, CTAB/SNP foam was observed to provide 4% larger propped area, 9% higher fracture conductivity, and lower leak-off rate than the SDBS/SNP foam.
2. SNP–surfactant-stabilized foams have significantly higher apparent viscosity and proppant-carrying capacity than the benchmark slickwater. Simulation results suggest the tremendous impact of foam-based fracturing fluids on delaying proppant settlement and generating uniform distributions of proppants in the fractures.
3. The productivity of the stimulated well is controlled by the combination of the fracture dimension and the fracture conductivity. High fracture conductivity itself does not necessarily guarantee high productivity.
4. In the particular tight gas reservoir model, the highest gas production is achieved by fracturing with CTAB/SNP foam, followed by SDBS/SNP foam, and then the benchmark slickwater. The simulation modeling suggests that CTAB/SNP foam results in higher cumulative gas production than SDBS/SNP foam by 13%.
5. While surfactant–SNP-stabilized foams provide increased stability, higher mobility control, and better fracturing performance, they still have some field limitations such as their operational challenges of maintaining effective dispersions, high operating costs, especially on large scales, and, finally, the environmental, health, and safety concerns due to their high risks and toxicity. Therefore, it is crucial to factor all these considerations into the application.

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