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Study on Foaming Agent Foam Composite Index (*FCI*) Correlation with High Temperature and High Pressure for Unconventional Oil and Gas Reservoirs

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Abstract: In the process of unconventional oil and gas reservoir exploitation, it is difficult to reduce drilling fluid lost in natural fractures, enhance the CO_2 displacement effect and reduce foam drainage gas recovery costs. In most cases, foaming agents can solve these problems in a low-cost way in a short period of time. Foaming agent screening and evaluation is the key to this technology. However, there are few experimental tests used in the evaluation of foaming agent properties that match the actual unconventional oil or gas well conditions of high temperature and high pressure. Using the actual temperature and pressure conditions of a wellbore, the foaming capacity and half-life of two common foaming agents were systematically evaluated by using the high-temperature and high-pressure visual foam properties evaluation device (UPMX-500), in which the foaming agent's volume concentration was 3‰ in a simulated formation water with a pH of 6 and salinity of 9×10^4 mg/L. The high-temperature (40 °C, 60 °C, 80 °C, 100 °C) and high-pressure (0.1 MPa, 6.0 MPa, 8.0 MPa, 10.0 MPa) effect on the foaming capacity and half-life was analyzed. Binary linear regression of pressure and temperature was carried out, taking the foam composite index as the target and using a formula with high correlation. The results showed that the foam composite index (*FCI*) of the two foaming agents was positively correlated with pressure and temperature. The correlation of UT-7 was $FCI = 64.1196T + 735.713p - 2066.2$, the correlation of HY-3K was $FCI = 62.5523T + 7220.391p - 2415.6$, and the coefficients of determination were 0.9799 and 0.9895, respectively, with an error of less than 10%. This correlation equation can provide a reference for accurately predicting the foaming capacity of foaming agents under high-temperature and high-pressure conditions and can also be used to optimize foaming agents or to qualitatively evaluate results for the efficient exploitation of unconventional oil and gas reservoirs.

Keywords: foaming agent; properties evaluation; foam composite index; high temperature and high pressure; correlation; unconventional oil and gas reservoir

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1. Introduction

Unconventional oil and gas reservoirs are often characterized by heterogeneity and natural fractures. Drilling fluid loss and non-uniform displacement can occur easily during drilling or production. Due to low porosity and low-permeability formation, pressure supplies are insufficient and make wellbore lifting inefficient. To address the challenges related to expensive drilling, inefficient displacement, and challenging gas recovery in unconventional oil and gas production, there is a need for solutions.

Foam flooding is one of the key techniques used for enhanced oil recovery (EOR), similar to polymer flooding (chemical flooding) or asphaltene control [1–3]. However, polymer will degrade its molecular structure in severe reservoir conditions. Many researchers have carried out a lot of research. One of the first proposals from the literature was foam plugging agents as a new cost-effective method [4–7], but foam plugging agents are affected by formation factors (pressure, temperature and formation water salinity). Consequently, these factors reduce efficacy and impact the application of this technology [8]. Secondly, research has focused on how to enhance the durability of CO_2 foam with high temperature, high pressure and high salinity, so that CO_2 foam is able to control gas channeling, reduce the injected fluid fluidity, and increase the sweep area effectively [9–12]. Finally, in terms of gas production by foam drainage, Beggs et al. (1973) [13] proposed a method to increase gas well production by using a foam agent theoretically. Solesa et al. (2006) [14] summarized the development, evaluation and application of foaming agents for gas well production systemically. Heiles et al. (2013) [15] found that the pressure gradients of foaming agent solutions were lower than those of pure water and were especially effective on interfacial wave characteristics.

Foam flooding can improve displacement efficiency by improving mobility ratio, reducing water phase permeability and water coning. Therefore, foam-based enhanced oil recovery (EOR) technology has been widely considered in the petroleum engineering field. Foam's behavior during foam flooding performance is often modeled using empirical correlation and mathematical models. One example is the foam's non-Newtonian flow behavior which can be described by power-law models, and exponential models can represent the water phase permeability reduction [16–19]. In conclusion, foam flooding for improving displacement efficiency depends on foam stability, which is sensitive to reservoir conditions such as pressure, temperature and salinity [20,21].

The Ross–Miles method is the classic evaluation method for foam agents and is used widely. At present, the two parameters of foam agents—foaming capacity and stability—are usually evaluated by indoor experiments using glass instruments [22–24]. The temperature range from room temperature to 100 °C observed in indoor experiments greatly deviates from the actual temperature conditions found in gas wells, and the experimental pressure at atmospheric levels is not reflective of the true pressure within wells. Therefore, the evaluation of a foam agent's properties is often inconclusive due to the influence of pressure and temperature.

Quintero (2002) [25] summarized the applications of surfactant technology in drilling fluids. Luo et al. (2012) [4] solved the problem of mud loss in fractured limestone formations by using solid-free recoverable foam drilling fluid. Wang et al. (2016) [26] discussed the foamability and stability of the foam agent in terms of surface tension, surface viscoelasticity, intermolecular force and defoaming. Therefore, the research ideas of these researchers can provide a reference for the foam agents' properties under high temperature and high pressure.

Currently, several studies have been conducted in China to assess the performance of foam agents in high-temperature high-pressure (HTHP) environments (Guan et al., 2023) [27]. However, the evaluation process is time-consuming and costly. Prior to this, the main type of foaming agent solution was initially assessed under standard temperature and pressure using simulated formation water and the stirring method [28]. Ultimately, two foam agents with an excellent ability to produce and maintain stable foam in simulated water were selected, and the optimum volume concentration was 3‰. This research work's aim was to evaluate foam quality and the half-life of the two foam agents (UT-7 and HY-3K) under HTHP conditions. The foam quality and half-life changing trend with temperature and pressure were studied and analyzed. The foam composite index (*FCI*) rule under high temperature and high pressure were obtained by multiple linear regression. Through this research, we developed a correlation for the precise estimation of foaming capacity under different pressure and temperature conditions.

2. Experimental

2.1. Materials and Experimental Sets

Two foaming agents were studied under high pressure and high temperature using simulated formation water to enhance the reliability and credibility of the experimental results. The agents investigated were UT-7, which is a polyol complex surfactant, and HY-3K, a complex composed of sodium dodecyl benzene sulfonate and sodium alpha-olefin sulfonate. These agents are commonly employed in unconventional oil and gas wells. The formation water used in the experiments was obtained from an actual well, and more information can be found in Table 1.

Table 1. The details of materials used in experiments.

Type	Manufacturer	Chemical Composition
UT-7	Chengdu Fuji technology Co., LTD, Chengdu, China	polyol complex surfactant
HY-3K	Sichuan Hengyi Petroleum Technical Service Co., LTD, Chengdu, China	complex of sodium dodecyl benzene sulfonate and sodium alpha-olefin sulfonate
Simulated formation water	Gas well, Linfen, China	total salinity: 9×10^4 mg/L, pH = 6 (K^+: 269.4 mg/L, Na^+: 7554.26 mg/L, Ca^{2+}: 9006.8 mg/L, Mg^{2+}: 781.9 mg/L, Zn^{2+}: 4215.7 mg/L, Ba^{2+}: 393.3 mg/L, F^-: 4.3 mg/L, Cl^-: 30,456.6 mg/L, Br^-: 107.7 mg/L, $NO_3{}^-$: 47.7 mg/L, $SO_4{}^{3-}$: 66.7 mg/L, $HCO_3{}^{3-}$: 2274.6 mg/L)

The experimental status of UPMX-500 (Jiangsu Unpac Technology CO., LTD, Hai'an, China) has been brought closer to the actual production status by the Chinese Academy of Sciences. The pressure can potentially reach up to 25 MPa and the temperature for evaluation can vary between room temperature and 120 °C, as illustrated in Figures 1 and 2. The UPMX-500 device was used to evaluate the foam properties of a foaming agent, specifically its foaming capacity and foam stability [29], under high-pressure and high-temperature conditions. An automatic camera provided a photograph every second for the analysis of the foaming agent half-life.

Figure 1. UPMX-500 experimental device.

Figure 2. Automatic camera.

2.2. Methods

2.2.1. Experimental Procedures

Test procedures were developed based on the People's Republic of China oil and gas industry standard "Evaluation Procedure for Foaming agents used in drilling fluid (SY//T 5350-2009)" and the UPMX-500 experimental device operating specifications, the following test procedures were formulated:

(1) Each group was prepared with 100 mL formation water. The total salinity was 9×10^4 mg/L, the pH value was adjusted to 6, 0.3 mL pure foaming agent was added to the formation water, and then the foaming agent concentration of 3‰ was formed and added to the experimental vessel.
(2) The prepared solution was added to the experimental container (the visual container's base liquid height was 7.96 cm with an inner diameter of 4 cm) and the required temperature and pressure was set for the experiment.
(3) A stirring button was used to initiate stirring of the foaming agent solution at a speed of 3000 r/min for 3 min.
(4) After stirring, a stopwatch was set to start timing, and the foaming height was recorded. At the same time, the automatic camera was turned on to take a picture of the foam height every one second.
(5) Timing was stopped when the precipitated liquid reached 50 mL (the liquid height was at 3.98 cm), and the cumulative time represents the foam's half-life.
(6) Different test pressures and test temperatures were used and steps (1)–(5) were repeated to find the parameters of the foaming agent's properties under different test conditions.

2.2.2. Experimental Design

A total of 32 experimental sets were devised to examine how variations in pressure and temperature affect the performance indicators of a foaming agent solution (Table 2). The selection of pressures and temperatures in the experimental design was based on the wellbore flow condition (the pressure and temperatures ranges from wellhead to wellbore are 0.1~10 MPa and 40 °C~100 °C, respectively).

Table 2. Evaluation scheme of foaming agent properties under different experimental conditions.

N.O.	Foam Agent Type	Temperature (°C)	Pressure (MPa)	N.O.	Foam Agent Type	Temperature (°C)	Pressure (MPa)
1	UT-7	40	0.1	17	HY-3K	40	0.1
2			6.0	18			6.0
3			8.0	19			8.0
4			10.0	20			10.0
5		60	0.1	21		60	0.1
6			6.0	22			6.0
7			8.0	23			8.0
8			10.0	24			10.0
9		80	0.1	25		80	0.1
10			6.0	26			6.0
11			8.0	27			8.0
12			10.0	28			10.0
13		100	0.1	29		100	0.1
14			6.0	30			6.0
15			8.0	31			8.0
16			10.0	32			10.0

3. Foam Composite Index

Foam agents can be evaluated for their ability to foam under high temperature and pressure using the foam composite index (*FCI*), which takes into account two key performance parameters: foam quality and foam half-life [30]. Figure 3 is a schematic diagram of the relationship between foaming and defoaming time with foam height under experimental conditions. The highlighted region in Figure 3 provides a comprehensive representation of the system's ability to produce foam. As shown in the figure, if the foam height h and time t satisfy the curve equation $h = f(t)$, then the area of the shaded part representing the foam composite index (*FCI*) is

$$FCI = S = \int_{t_0}^{t_0+t_{1/2}} f(t)dt. \tag{1}$$

For convenience of calculation, the following mathematical equation that relates the base lengths and the height of the trapezoid to the approximation of its area S can be used:

$$FCI = S = 0.75h_{\max}t_{1/2}. \tag{2}$$

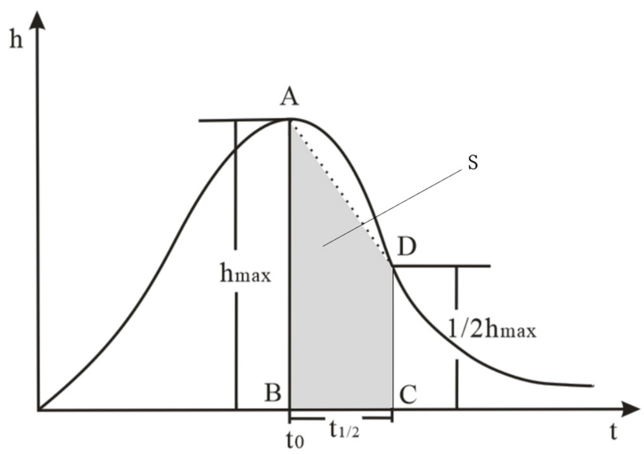


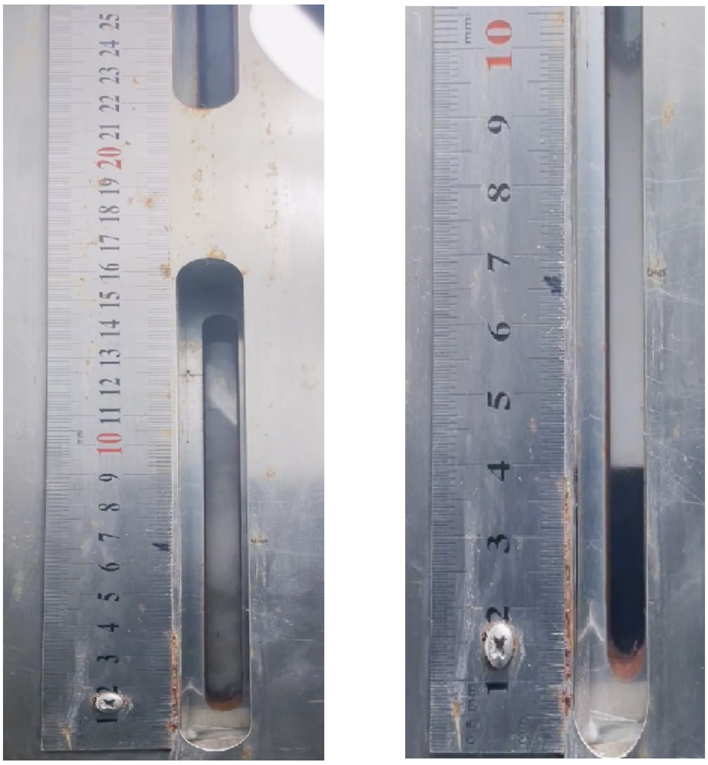
Figure 3. Relation between foaming height and time.

4. Results and Discussion

4.1. Foam Property of Two Foaming Agents under Temperature

Based on the data presented in Table 2, which outlines the number of experimental groups and steps, the foaming agents UT-7 and HY-3K were individually mixed with formation water (a total salinity of 9×10^4 mg/L and a pH of 6) at a concentration of 3‰, and their respective foaming heights and half-life were examined. The experimental test of

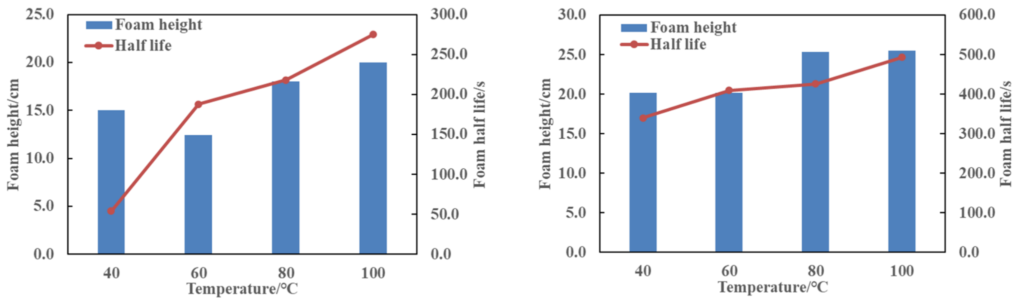
3‰ concentration UT-7 (6 MPa, 80 °C) is taken as an example, and the test process record is shown in Figure 4.



(**a**) foam height (h_{max} = 25.30 cm) (**b**) $t_{1/2}$ = 426 s liquid level equal to 3.98 cm

Figure 4. UT-7 foam agent property (Pressure = 6 MPa, Temperature = 80 °C).

Figures 5 and 6 illustrate the variation of foam height and half-life, both of which exhibit a consistent upward trend as temperature increases, but with varying levels of pressure during testing. The change trend of the foam height or half-life is prone to fluctuation points or slower growth points, so it is not necessary to accurately evaluate the foaming ability.



(**a**) 0.1 MPa (**b**) 6.0 MPa

(**c**) 8.0 MPa (**d**) 10.0 MPa

Figure 5. Effect of temperature on UT-7 foam agent properties under different pressures.

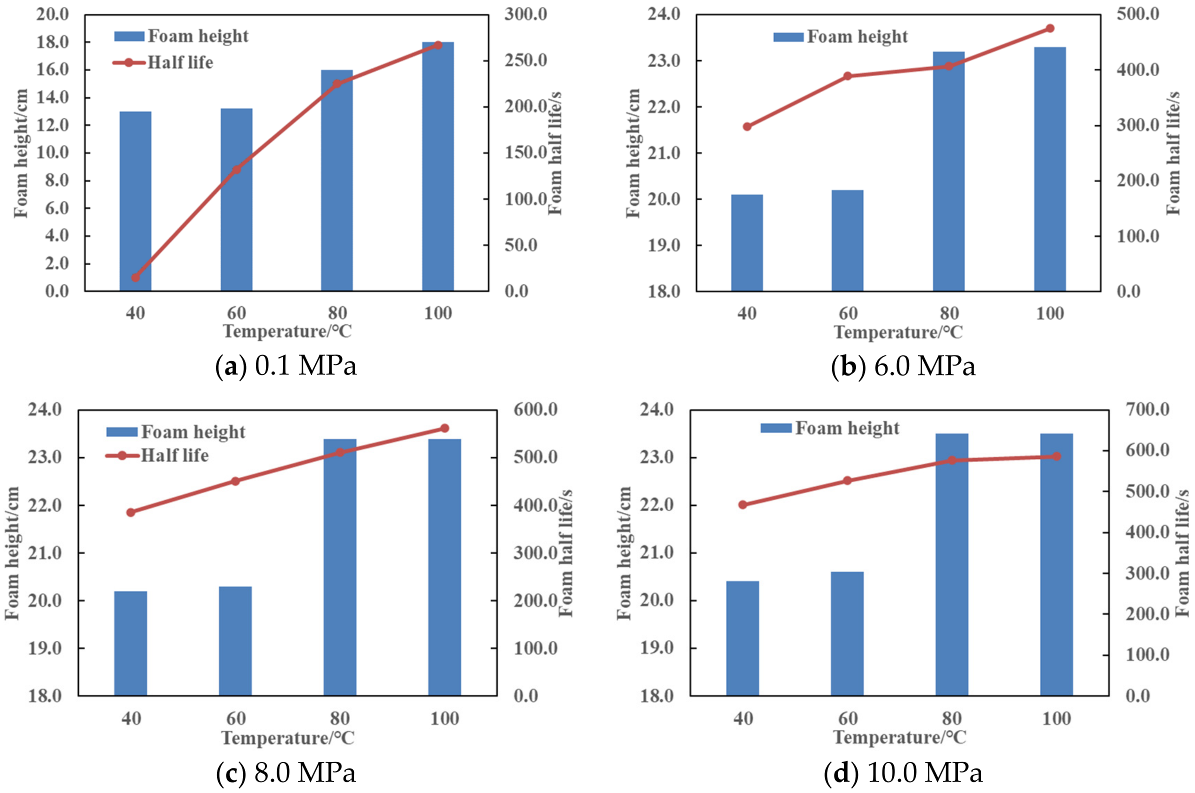


Figure 6. Effect of temperature on HY-3K foam agent properties under different pressures.

The main reason behind this phenomenon lies in the direct relationship between temperature and the molecular kinetic energy of the foaming agent, which results in an improved capacity for creating foam as the temperature increases. When the temperature reaches 80 °C, the foam height increases slowly, which may be because the foaming agent deteriorates when temperature continues to rise. The rapid increase in ambient temperature will result in a higher rate of water evaporation. The liquid layer will become less thick. The capability to form foam and the longevity of the foam will be impaired [31].

4.2. Foam Property of Two Foaming Agents under Pressure

The data in Figures 7 and 8 illustrate how foam properties change with pressure at various temperatures. The foam height and half-life changing trend demonstrate a consistent increase with the rise in pressure, signifying that it aligns with the classical foam theory where higher pressure enhances both foam formation and stability [32]. Under the well-established classical foam theory, it has been universally believed that amplifying the pressure can result in a reduction in the foam's diameter while ensuring uniformity in foam size [33]. Consequently, this increase in pressure leads to a rise in the internal friction within the liquid phase, consequently boosting both foamability and foam stability [34]. When the pressure is greater than atmospheric pressure, the foam height increases rapidly. In the high-pressure range, with the pressure from 6 MPa to 10 MPa, the foam height tends to be stable, indicating that the increase in pressure has little influence on the foaming capacity. From the perspective of half-life, an elevated pressure results in an upward trend in the half-life at various temperatures, thus enhancing the stability of the foam.

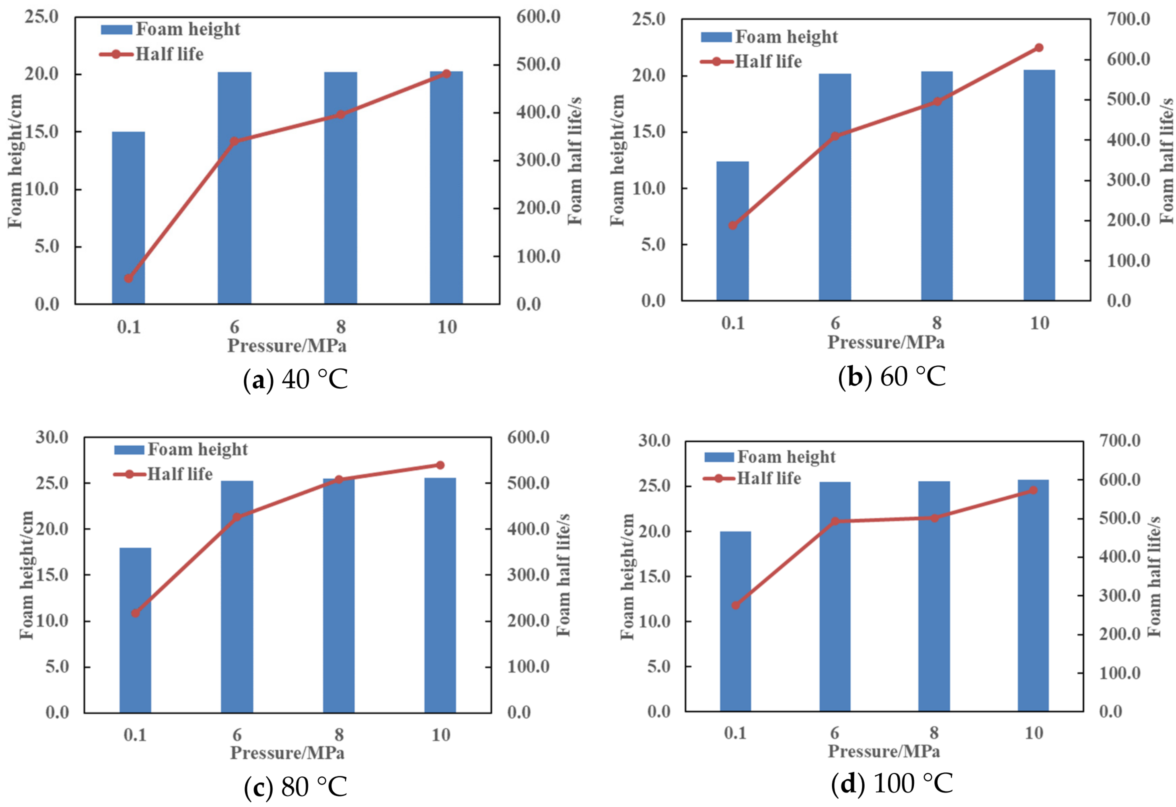


Figure 7. Effect of pressure on UT-7 foam agent properties under different temperatures.

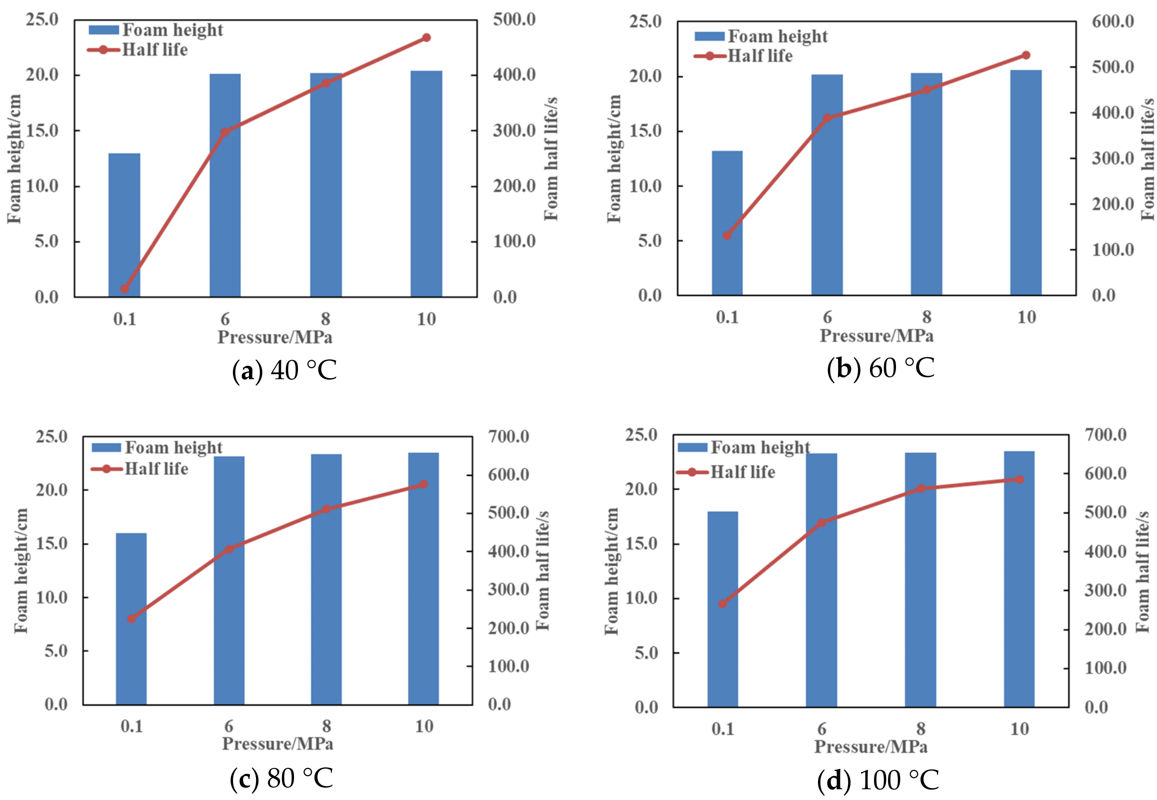


Figure 8. Effect of pressure on HY-3K foam agent properties under different temperatures.

4.3. Foam Composite Index Relationship with Temperature and Pressure

In order to further clarify the relationship between foaming capacity and pressure and temperature, the foam composite index was calculated, and the results are shown in Tables 3 and 4.

Using 32 groups of experimental data from UT-7 and HY-3K under different temperatures and pressures, sample regression analysis was conducted to establish the relationship between the temperature and pressure parameters and the foam composite index *FCI*. The regression correlation is shown using equations, and the error analysis results are shown, respectively.

The foam composite index was determined by employing Equation (2) and the findings are presented in Tables 3 and 4. The data from 32 sets of experiments on UT-7 and HY-3K, conducted at varying temperatures and pressures were analyzed. A sample regression analysis was performed to determine the correlation between the temperature and pressure parameters and the foam composite index *FCI*. Equation (3) provides the regression correlation. The results of the error analysis can be found in Tables 3 and 4.

Equation (3) reveals a positive correlation between pressure, temperature, and the foam composite index (*FCI*) of the two foaming agents, and the coefficients of determination are 0.9799 and 0.9895, respectively, with an error of less than 10%. According to the regression relationship, a greater coefficient indicates that the influence of pressure on the foaming capacity of the foaming agent is greater than that of temperature. The results of a study in the literature [35] showed that the greater the pressure, the better the liquid-carrying capacity. Therefore, the establishment of this correlation can provide a reference for accurately predicting the foaming capacity of a foaming agent under high temperature and pressure and can be also used for qualitative evaluation of the liquid-carrying capacity, plugging capacity and oil-displacement capacity of the foaming agent under different pressure and temperature conditions.

$$\begin{aligned} FCI &= 64.1196T + 735.713p - 2066.2 \quad R^2 = 0.9799 \quad UT-7 \\ FCI &= 62.5523T + 720.391p - 2415.6 \quad R^2 = 0.9895 \quad HY-3K \end{aligned} \tag{3}$$

Table 3. *FCI* of UT-7 under different experimental conditions.

Temperature (°C)	Pressure (MPa)	Foam Height (cm)	Half-Life (s)	*FCI* (cm·s)		
				Calculated Values	Predicted Values	Relative Error Values
40	0.1	15.0	54	607.50	572.16	−5.82%
40	6.0	20.2	340	5151.00	4912.86	−4.62%
40	8.0	20.2	396	5999.40	6384.29	6.42%
40	10.0	20.3	482	7338.45	7855.71	7.05%
60	0.1	12.4	188	1748.40	1854.55	6.07%
60	6.0	20.2	410	6211.50	6195.25	−0.26%
60	8.0	20.4	496	7588.80	7666.68	1.03%
60	10.0	20.5	630	9686.25	9138.11	−5.66%
80	0.1	18.0	218	2943.00	3136.94	6.59%
80	6.0	25.3	426	8083.35	7477.65	−7.49%
80	8.0	25.5	508	9715.50	8949.07	−7.89%
80	10.0	25.6	540	10,368.00	10,420.50	0.51%
100	0.1	20.0	275	4125.00	4419.33	7.14%
100	6.0	25.5	493	9428.63	8760.04	−7.09%
100	8.0	25.6	502	9638.40	10,231.46	6.15%
100	10.0	25.7	573	11,044.58	11,702.89	5.96%

Table 4. *FCI* of HY-3K under different experimental conditions.

Temperature (°C)	Pressure (MPa)	Foam Height (cm)	Half-Life (s)	*FCI* (cm·s)		
				Calculated Values	Predicted Values	Relative Error Values
40	0.1	13.0	15	146.25	158.53	8.40%
40	6.0	20.1	298	4492.35	4408.84	−1.86%
40	8.0	20.2	386	5847.90	5849.62	0.03%
40	10.0	20.4	468	7160.40	7290.40	1.82%
60	0.1	13.2	132	1306.80	1409.58	7.86%
60	6.0	20.2	389	5893.35	5659.88	−3.96%
60	8.0	20.3	451	6866.48	7100.67	3.41%
60	10.0	20.6	527	8142.15	8541.45	4.90%
80	0.1	16.0	225	2700.00	2660.62	−1.46%
80	6.0	23.2	407	7081.80	6910.93	−2.41%
80	8.0	23.4	511	8968.05	8351.71	−6.87%
80	10.0	23.5	576	10,152.00	9792.49	−3.54%
100	0.1	18.0	267	3604.50	3911.67	8.52%
100	6.0	23.3	475	8300.63	8161.98	−1.67%
100	8.0	23.4	562	9863.10	9602.76	−2.64%
100	10.0	23.5	586	10,328.25	11,043.54	6.93%

5. Conclusions

(1) A scheme to test foaming capacity under high temperature and high pressure was designed. The evaluation set, UPMX-500, was utilized to determine the foam height and half-life of the foaming agent under conditions of high temperature and pressure. The foam height and half-life demonstrated a general upward trend as the pressure and temperature increased, although the specific changes in the foam height or half-life tended to exhibit intermittent points of fluctuation or slower growth.

(2) The foam properties under high temperature and high pressure were quantitatively evaluated using the foam composite index. The foam composite index, *FCI*, of the two foaming agents is positively correlated with pressure and temperature, the coefficients of determination are 0.9799 and 0.9895, respectively, and the error is less than 10%.

(3) According to the foam composite index correlation with pressure and temperature, the influence of pressure is greater than temperature. This correlation can provide a reference for accurately predicting foaming ability and qualitative evaluation of the liquid-carrying capacity, plugging capacity and oil-displacement capacity of the foaming agent under different pressure and temperature conditions.

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

Conflicts of Interest: Authors Jianjun Wu, Wentao Ma, Yinhua Liu, Wei Qi, Kai Liu were employed by the company PetroChina Coalbed Methane Co., Ltd. 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.

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