Laboratory Studies on CO$_2$ Foam Flooding Enhanced by a Novel Amphiphilic Ter-Polymer

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Highlights:

- Evaluation of a novel amphiphilic polymer which can significantly enhance foam stability without affecting foamablity significantly

- Investigation on bulk foam behaviour by employing the agitation method

- Application of core flooding to optimize the operating parameters of CO$_2$ foam flooding enhanced by this novel polymer

Abstract

Previous research has demonstrated Hydrolysed Poly-Acrylamide (HPAM) exhibits poor thickening ability even under mild reservoir condition; furthermore, it would detrimentally affect the foamability of the foaming system. This work presents the finding of an investigation using a novel polymer named AVS which is a ter-polymer of AM, AMPS and one functional monomer and which can stabilize CO$_2$ foam under relatively high salinity and temperature without greatly compromising foamability. Core flooding experiments indicate the optimal injection method for AVS enhanced CO$_2$ foam flooding is direct injection of foam and the suitable gas/liquid ratio is determined to be around 3:1. Under these experimental conditions, tertiary oil recovery differences between foam flooding enhanced by AVS and that enhanced by HPAM are 3.7% and 6.6% for low and high permeability respectively, suggesting AVS possesses great EOR potential in the CO$_2$ foam flooding process.

Keywords: polymer enhanced foam flooding, foamability, foam stability, injection scheme, gas/liquid ratio

1. Introduction

The application of CO_2 foam might be considered as a technically feasible way to overcome the shortcomings of CO_2 flooding such as viscous fingering and gravity segregation (Wang et al., 2015; Asghari and Khalil, 2005; Sun et al., 2015). Over the past few decades, it has been widely accepted that the efficiency of foam flooding largely depends on the foam stability which indicates the capacity of the foam to propagate and sweep in reservoirs (Rohani et al., 2014; Rafati and Hamidi, 2011). However, the breakdown of foam under reservoir temperature, pressure and salinity can significantly affect the performance of foam flooding; consequently, in recent years, extensive theoretical and experimental research has been done to boost foam stability during the foam flooding process (Sun et al., 2014; Zhu et al., 2004; Singh and Mohanty, 2014; Liu et al. 2005; Shen et al., 2006; Yu et al., 2012).

Among the techniques used to improve the efficiency of foam flooding, addition of polymer into the foam system has been the focus of numerous investigations and is considered to be viable both technically and economically. By adding HPAM into the foaming agent solution, known as Polymer Enhanced Foam (PEF), the surface strength of lamella can be improved, the drainage of liquid membrane can be weakened and the gas diffusion is decelerated, all of which favour better foam stability and increase foam flooding efficiency(Zhu et al., 2004; Romero et al. 2002). Nevertheless, due to its sensitivity to salt, HPAM's thickening ability suffers in reservoirs with high salinity formation water where its molecules existed in coiled form. High temperature is another major concern if thermal breakdown of HPAM molecules is taken into consideration (Moradi-Araghi and Doe 1987). Meanwhile, the addition of HPAM may also lower the foamability of the foaming agent. Accordingly, the behaviour of

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foam thickened by HPAM would be significantly affected especially under harsh reservoir conditions.

Owing to the replacement of some amounts of acrylate units in HPAM with functional groups, the modified HPAM is able to resist high salinity or/and high temperature. N-vinylpyrrolidones (NVP), 2-acrylamido-2-methylpropane sulfonic acid (AMPS) and poly-vinylpyrrolidones (PVP) are among the most commonly used functional groups. The ter-polymer of AM, NVP and AMPS present excellent thickening ability under high salinity condition (Kulawardana et al 2012); the work done by Levitt and Pope (Levitt and Pope 2008) indicated the increased tolerance to divalent ions by using AMPS-substituted HPAM. Nevertheless, most of the group-substituted HPAM only serve as gels in conformance modification or as thickener in polymer flooding and little research has been focused on the performance of CO_2 foam flooding enhanced by these polymers. The objective of this work is to systematically study the static and dynamic behaviour of CO_2 foam thickened by a novel ter-polymer with surface activity, named AVS. In this study also, the injection method and liquid/gas ratio were investigated and optimized through the core flooding process, which demonstrated that the CO_2 foam flooding enhanced by AVS could be more practical and economical.

2. Apparatus and methodology

2.1 Materials

$CaCl_2$ and NaCl were obtained from Sigma-Aldrich Co. (USA); Sodium Alpha Olefin Sulfate (AOS C14-16) with 35% active matter was supplied by Stepan Chemical Co. (USA). HPAM with molecular weight of 25×10^6 and hydrolysis degree of 25% was provided by Beijing Hengju Chemical Co. Ltd (China); AVS which was a ter-polymer of acrylamide (AM), AMPS and one synthesized functional monomer was provided by the Research Institute of Petroleum Exploration & Development (RIPED, China). The schematic of HPAM and AVS

molecules were illustrated in Fig. 1. The analysis result of Fourier transform infrared spectroscopy (FTIR) was shown in Fig. 2. High purity grade (99.99%) CO_2 gas was supplied by BOC (Australia). Distilled water was also used to prepare brine and chemical solutions. Berea samples were cut from quarried sandstone blocks (Ohio, USA). Crude oil sample was sourced from an oil reservoir located offshore from Western Australia. Properties of the crude oil are listed in Table 1.
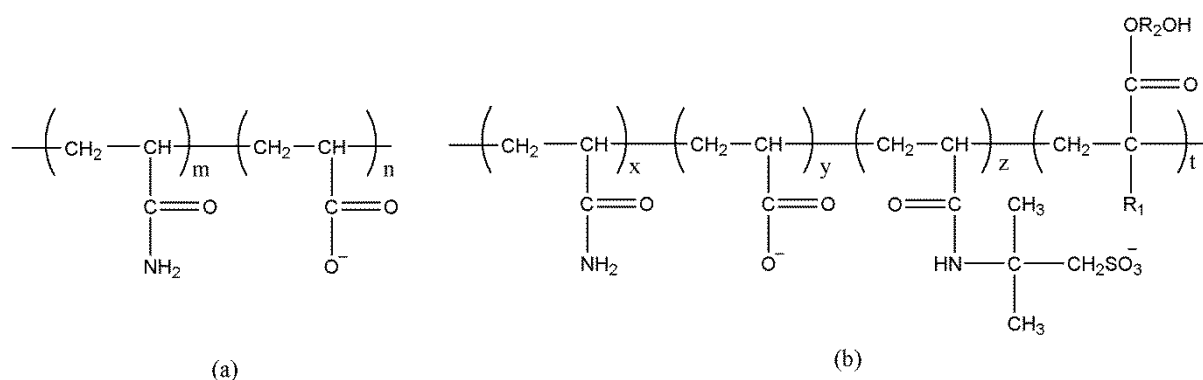

(a)　　　　　　　　　　　　　　　　(b)

FIGURE 1 Schematic of HPAM (a) and AVS (b) molecules

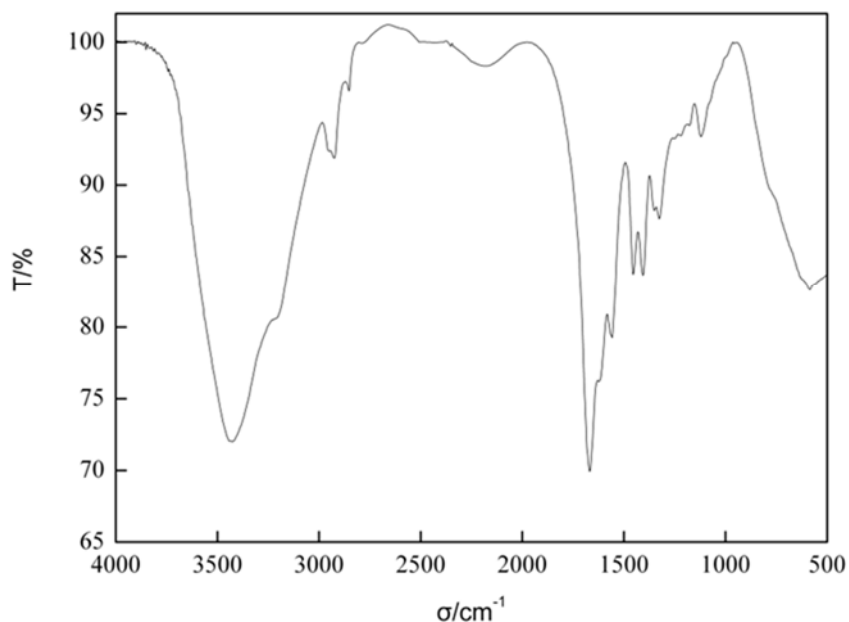**Note: R_1 and R_2 are long chain alkyl groups.**

FIGURE 2 FTIR analyses of AVS

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Note: The absorption peak at 1620 cm^{-1} can be attributed to $\upsilon_{C=O}$ of ester group. The two peaks at 1050 cm^{-1} and 1409 cm^{-1} belong to the stretching vibration of S-O and C-N, respectively. The absorption peak at 1 540 cm^{-1} is ascribed to acylamino C=O. The broad band around 3400 cm^{-1} can be attributed to υ_{O-H}. The peak at 1450 cm^{-1} belongs to the bending vibration of C—H. There is no specific absorbing peak between 1 670～1 600 cm^{-1} which can be attributed to $\upsilon_{C=C}$.

Table 1
Properties of Crude Oil

Test	Unit	Result
Density @ 15°C	Kg/L	0.9428
API gravity	°API	18.5
Asphaltenes	%mass	0.14
Arsenic	mg/kg	2.3
Kinematic Viscosity @40°C	cSt	37.26
Sulphur-Total	%mass	0.14
Total Acid Number	mg KOH/g	0.50
Water Content	%volume	0.150

2.2 Viscosity Measurement

It is widely accepted that the foam stability is closely associated with the bulk viscosity of the foaming agent/polymer solution. HPAM, which is most commonly employed as a thickener for the foaming agent, was selected as the reference in order to evaluate the thickening ability of AVS. The base solution (5000 ppm) was prepared by adding a given amount of polymer into brine and mixing them with an overhead stirrer (VELP Scientifica, Australia) at the speed of 400 rpm for 2 hours. Then the base solution was diluted into solutions with the desired concentrations. The diluted polymer solutions would be aged for 24 hours before the viscosity measurements which were conducted by employing a Brookfield DV-II + Pro viscometer (Brookfield Engineering Laboratories, Inc, USA). It is worth noting that the shear rate was 7.34 S^{-1} for all the measurements.

2.3 Surface Tension Measurement

Surface tension measurements were conducted using a JZHY-180 Tensiometer (Jinan Precision Testing Equipment Co. Ltd., China) which used the Du Nouy Ring method. Prior to

any tests, the tensiometer was carefully calibrated by adjusting the screw nuts mounted on the lever arm to maximize the measurement accuracy. Then 20 mL of investigated solution was added into the glass cup sitting on a metal stand whose height would be set to enable the platinum ring with radius of 9.55mm to slightly touch the solution, followed by increasing the torque applied on the platinum ring until the liquid membrane between the ring and gas/liquid surface collapsed. At this moment, the corresponding surface tension would be displayed on the dial. It is worth noting that every sample solution was tested five times and the average surface tension could be calculated accordingly. All the measurements were carried out at 20 °C.

2.4 Foamability and Stability Evaluation

For reliable and robust foam flooding, reasonable foamability and stability are required. In this work, agitating method was applied to investigate the two most critical parameters which could be used to predict the EOR capacity during the foam flooding process. AOS was selected as the foaming agent. Either HPAM or AVS was used as the thickener to stabilize the generated foam. A 100 mL solution of the foaming agent/thickener was added into a Warring blender and agitated at a speed of 2000 rpm for 60 seconds with continuous CO_2 gas injection. The created foam was then transferred to a graduated cylinder which was standing in a water bath whose temperature was controlled by digital thermal couple. The initial volume of the generated foam was measured as an indicator of foamability and the time period for half of the liquid drainage (i.e. the liquid dropout volume reached 50 mL) was recorded as an indicator of the stability under various test conditions. The concentration of AOS was fixed at 0.5% wt.

2.5 Core Flooding Experiment

The experimental schematic is given in Fig. 3. To begin with, the core plug was loaded into the core holder and vacuumed for 24 hours before it was fully saturated with brine. Then

crude oil was injected into the core plug until the water cut reached less than 1%. After that, the core was aged in the core holder for 24 hours. Water flooding was conducted by injecting brine again in order to establish residual oil saturation, which was followed by the CO_2 foam flooding and extended water flooding to obtain ultimate oil recovery. The system temperature and pressure were maintained at 50 °C and 2000psi respectively. The confining pressure was kept constant at 4000psi throughout the flooding process.
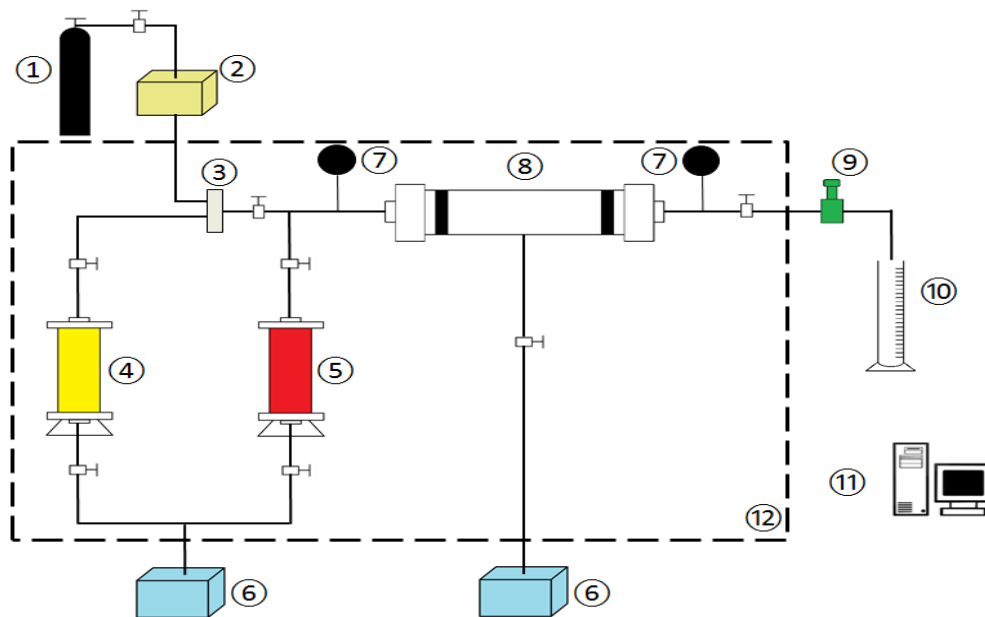

FIGURE 3 Schematic of experimental setup for core flooding experiment

1- CO2 Tank 2- Gas Mass Flow Control System 3- Foam Generator 4- Chemical Solution 5- Brine 6- Pump 7- Pressure Transducer 8- Core Holder 9- Back Pressure Regulator 10- Graduated Cylinder 11- Data Acquisition System 12- Heating System

3. Results and discussion

3.1 Viscosity of Polymer Solution

The destruction of lamellae in the foaming system can be considerably hindered through the addition of polymer, which is capable of boosting the strength of liquid membrane. The effect of polymer concentration on solution viscosity is shown in Fig. 4. Below a concentration of 750 ppm, there were no significant viscosity differences between HPAM and AVS. However,

when the concentration was above 750 ppm, viscosities of the AVS solutions were roughly twice those of the HPAM solutions with the same concentration, which indicated the outstanding thickening performance of AVS.

It is widely accepted that the temperature can greatly influence the viscosity of polymer solution. From Fig. 5, it is noticeable that the viscosity of both HPAM and AVS dropped with increasing temperature. This is because high temperature could facilitate the breakdown of molecular chains and negatively affect the interaction between polymer molecules. Nevertheless, AVS contained hydrophobic groups (functional monomer) which led to hydrophobic association; therefore, the molecules were bonded strongly in a 3D network and the impact of temperature on polymer viscosity could be mitigated. What is more, high temperature tended to boost the potential for hydrophobic association through reducing the solution polarity, which enabled AVS to resist high temperature and yield higher viscosity than the counterpart HPAM.

The effect of salinity on polymer viscosity is illustrated in Fig. 6. It was observed that the viscosity decreased with an increase in salinity. It is known that charge repulsion could induce the molecular coil swelling; yet, with the presence of salt, the swelling effect would be negatively affected by the charge screening. Accordingly, solution viscosity dropped significantly. However, the large and rigid side groups such as the methylpropane sulfonic acid group in AVS molecules could improve the rigidity of the molecular chain. Meanwhile, high salinity also favoured hydrophobic association. Therefore, AVS exhibited excellent salt tolerance capacity, which could be verified by relatively high viscosity of AVS solution under high salinity.
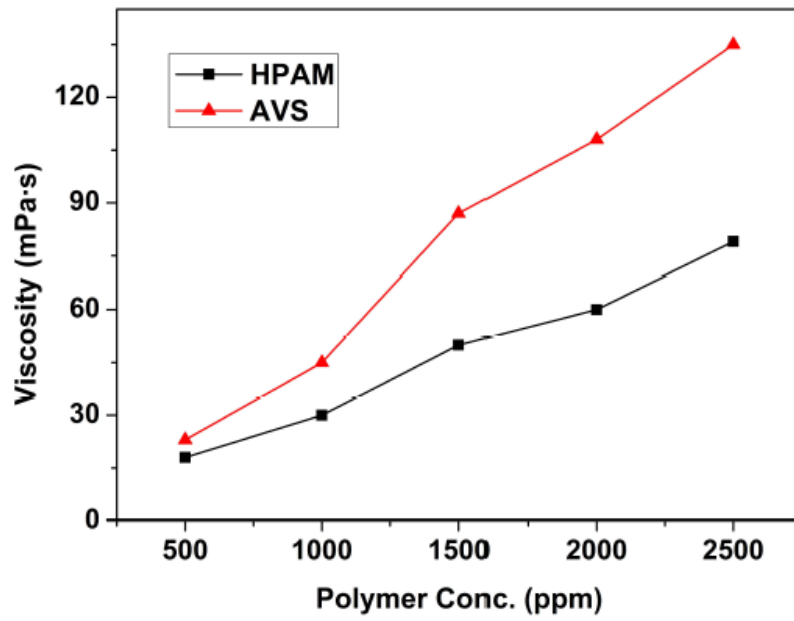
FIGURE 4 Effect of polymer concentration on solution viscosity
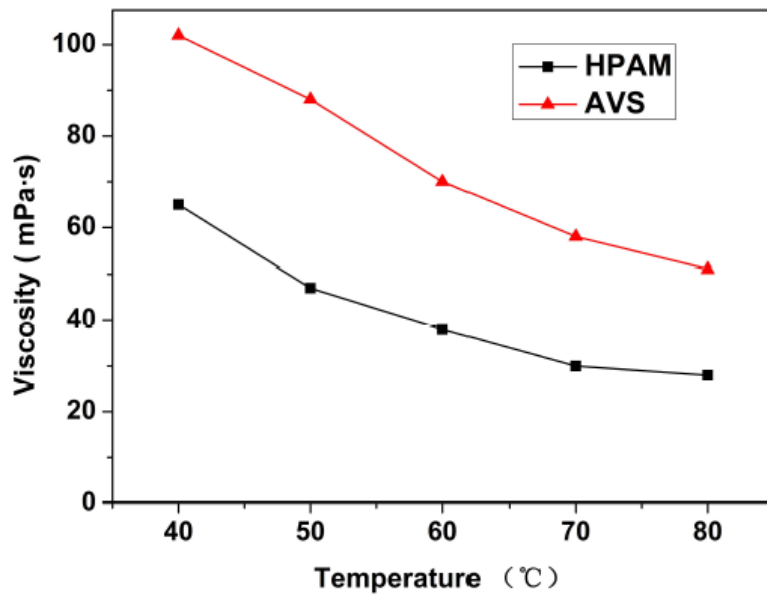
(50 °C, Nacl 10000ppm + Cacl$_2$ 100ppm, 7.34S^{-1})

FIGURE 5 Effect of temperature on solution viscosity

(Nacl 10000ppm + Cacl$_2$ 100ppm, polymer concentration 1500ppm, 7.34S^{-1})
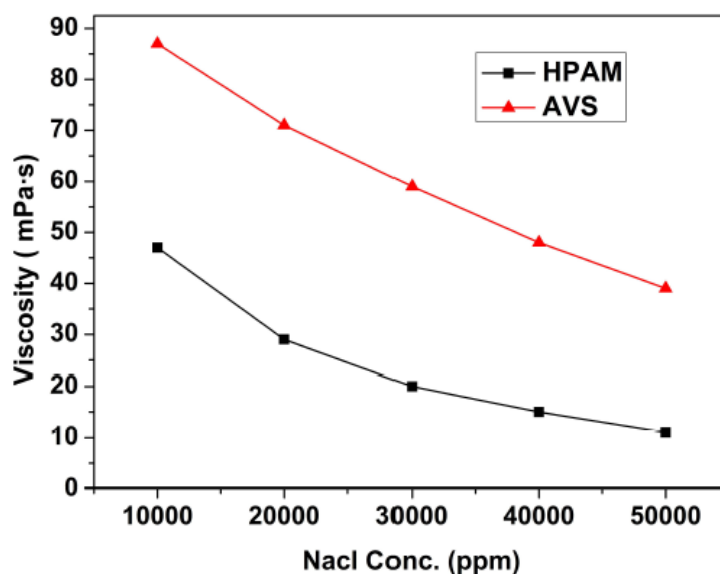
FIGURE 6 Effect of salinity on solution viscosity

(50 °C, Cacl₂ 100ppm, polymer concentration 1500ppm, 7.34S⁻¹)

3.2 Surface Tension

The surface tensions of both HPAM and AVS solution with different concentrations are summarized in Table 2. It was found that the surface tension of AVS solution declined with increasing concentration and could reach as low as 45.8 mN/m. The AVS was an amphiphilic ter-polymer which contained hydrophilic as well as hydrophobic groups in the molecular chain, so its molecules were capable of adsorbing at the surface between the gas and liquid phases just like the ordinary surfactant. With the increase in the AVS concentration, more and more AVS molecules could gather up at the interface until reaching a point where the interface could not accommodate any more molecules. That is why, as shown by the data in Table 2, above a concentration of 1500 ppm, the surface tension remained relatively stable and higher concentration only led to a thicker solution rather than favorable surface activity. As expected, due to the molecular structure limitation, HPAM molecules existed mainly in bulk solution, so it was not able to the lower surface tension and made only a limited contribution to foamability.

To further understand the dependence of foamabilty on surface tension, foaming agent/polymer solutions (AOS concentration 0.5 wt %) instead of polymers alone were utilized in the measurements. The assessment results are listed in Table 3. Interestingly, unlike the scenario of polymer solution, the surface tension of both the AOS/AVS solution and the AOS/HPAM solution appeared to be concentration-independent and the surface tension differences between them were quite small. This might have been because the foaming agent AOS imparted a lot better surface activity than its counterparts AVS or HPAM; therefore, the polymers' surface activity would be overridden by the existence of the foaming agent. The investigation results agreed with the widely accepted conclusion that the foamability barely correlated with the gas/solution surface tension. Consequently, the superior foaming ability of AOS/AVS solution, more than likely, could be attributed to the surface activity of AVS polymer, although the mechanism of how it assisted in the foamability is not yet very clear at this stage.

Table 2
Influence of concentration of polymer on the surface tension

Concentration (ppm)	Surface tension (mN·m^{-1})	
	AVS	HPAM
500	51.7	68.9
750	50.4	68.8
1 000	48.0	68.9
1 250	46.6	69.5
1 500	46.2	69.8
1 750	45.9	70.1
2 000	45.8	70.9

Table 3

The dependence of surface tension on foaming formula

Concentration (ppm)	Surface tension (mN·m⁻¹)	
	AOS/AVS	AOS/HPAM
500	29.5	30.4
750	29.6	31.2
1 000	28.8	31.5
1 250	29.3	31.0
1 500	28.9	31.3
1 750	28.6	31.1
2 000	29.0	31.5

3.3 Foamability and Foam Stability

Foamability, an indication of the ability to generate foam, relates to the initial volume of foam created by stirring up a fixed amount of foaming solution, while foam stability is strongly dependent on the fraction of the foam bubbles that stay intact over time. The foamability and stability of both AOS/HPAM and AOS/AVS were tested under different temperatures (25°C and 65°C) and salinities (10000 ppm and 50000 ppm). The results are presented in Fig. 7-10. Both foamability and stability were found to be closely associated with the polymer concentration. Foamability declined with an increase in the polymer concentration. On the one hand, due to the relatively high bulk viscosity, AOS molecules would encounter considerable resistance when they migrated from bulk solution to the gas/liquid interface, which might have greatly affect the foaming ability. On the other hand, AVS contained surface active groups which were favourable to the generation of foam; therefore, the foamability loss of AOS/AVS was less noticeable than that of the AOS/HPAM solution. It is also noted that the AOS/AVS solution was more viscous and was endowed with more capacity to reduce the possibility of bubbles in the foaming system collapsing and decaying, which led to greater stability compared to the AOS/HPAM foaming system under the same polymer concentration.

The results also demonstrated that both salinity and temperature would affect the foam behavior significantly. It is clear that the stability levels of AOS/AVS were much greater than those of AOS/HPAM at high salinity (50000 ppm NaCl + 100 ppm Cacl$_2$) or high temperature (65°C), which was primarily attributed to the effect of hydrophobic association, accordingly, AVS exhibited outstanding salinity and temperature tolerance and the foam enhanced by AVS was more robust under relatively harsh conditions.
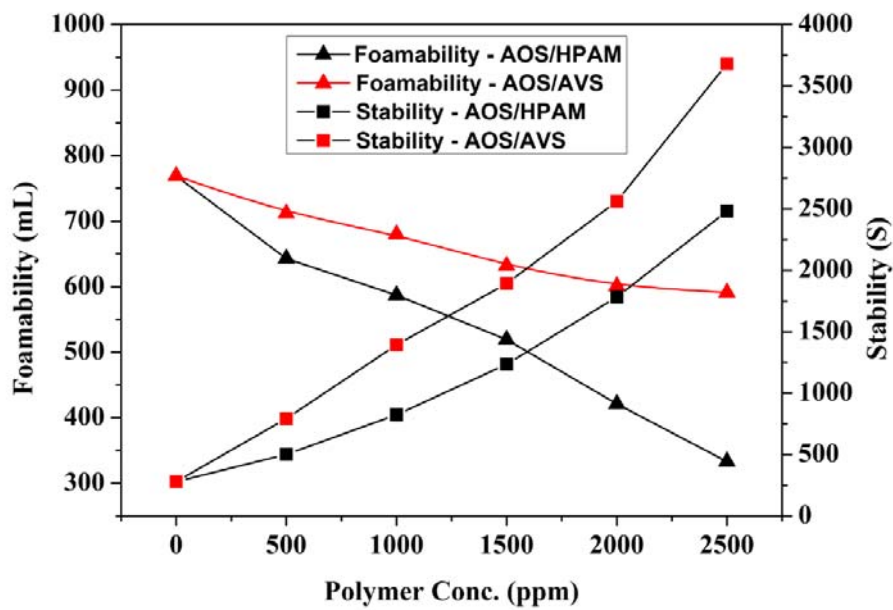

FIGURE 7 Effect of polymer concentration on foamability and stability
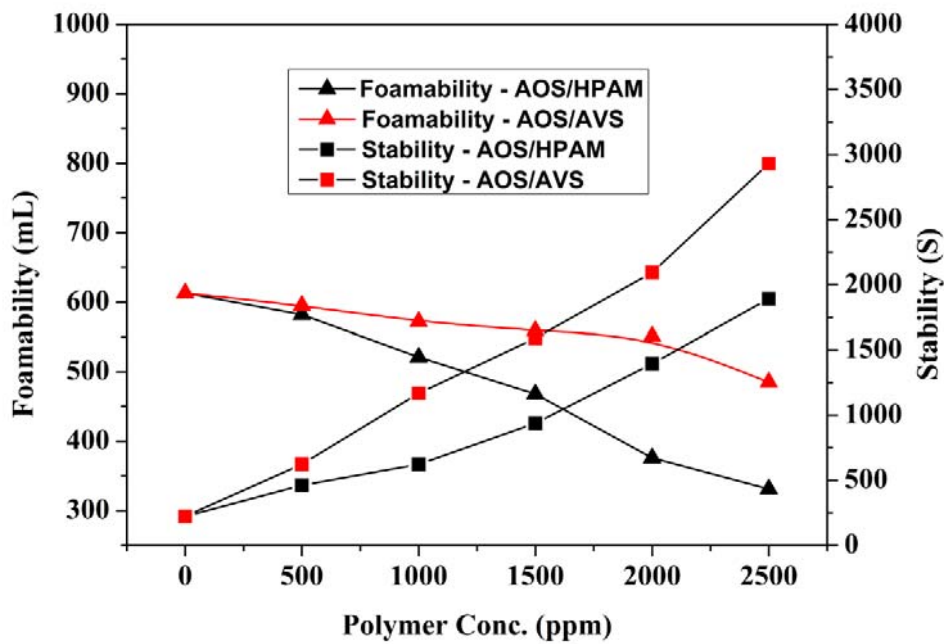
(NaCl 10000ppm + Cacl$_2$ 100ppm, 25°C)

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FIGURE 8 Effect of polymer concentration on foamability and stability

(NaCl 10000ppm + Cacl$_2$ 100ppm, 65°C)
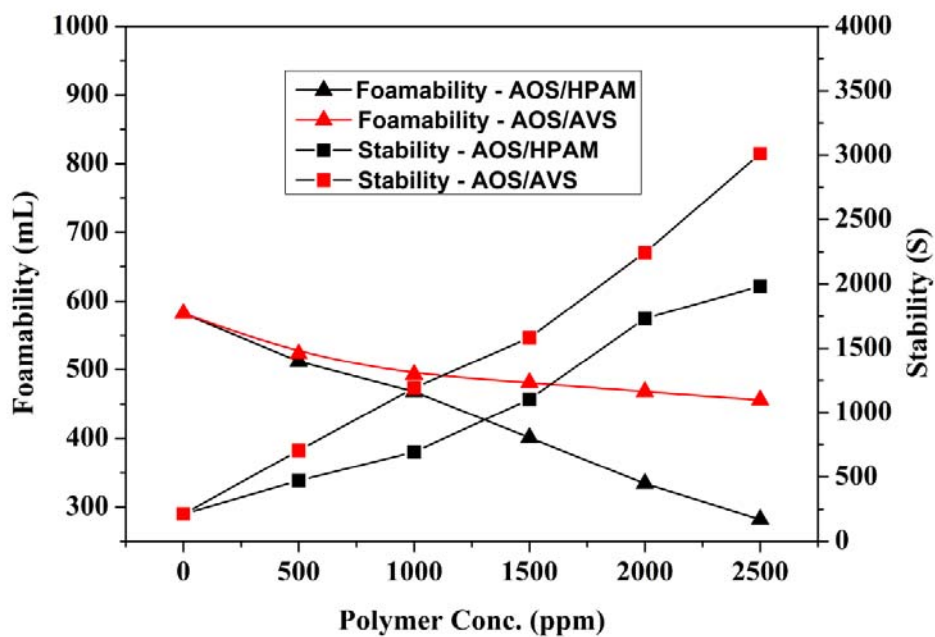

FIGURE 9 Effect of polymer concentration on foamability and stability

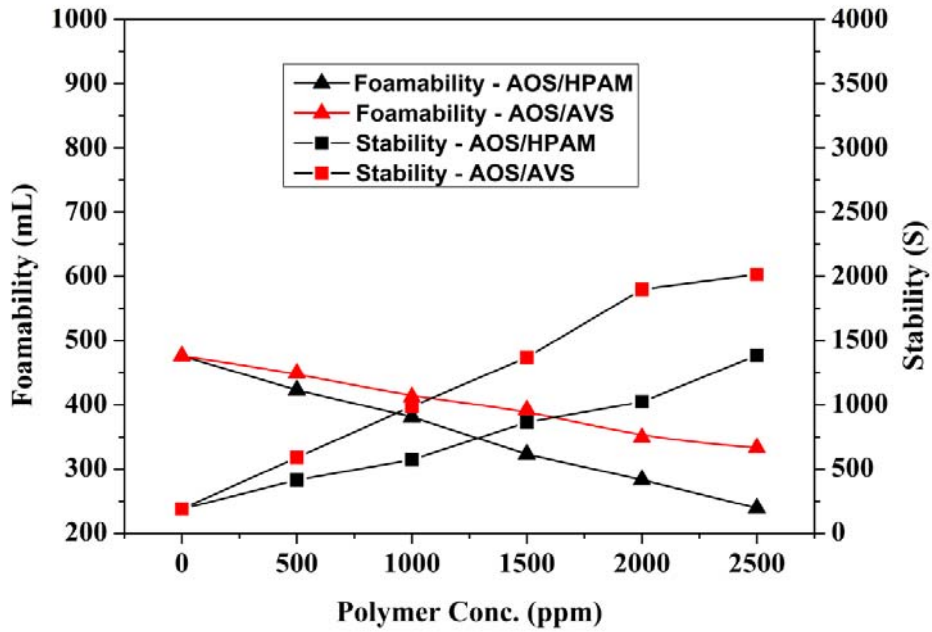**(NaCl 50000ppm + Cacl$_2$ 100ppm, 25°C)**

FIGURE 10 Effect of polymer concentration on foamability and stability

(NaCl 50000ppm + Cacl$_2$ 100ppm, 65°C)

3.4 Core Flooding Experiment

In order to evaluate the effect of the injection method on the displacement performance of AVS-enhanced CO_2 foam flooding, Runs #1, #2 and #3 were carried out through the direct injection of foam, co-injection of gas and liquid, and solution-alternating-gas (SAG) injection, respectively. It was noted that in Run #1, the creation of foam was attributed to the foam generator. In Run #3, 1.0 PV of solution and gas was alternately injected into the core plug in four cycles. The results of the runs are summarized in Table 4. The results indicated that the tertiary oil recovery factor of Run #1 was the highest (28.89%), which, very likely, was due to the excellent blocking and mobility ratio modification ability of the pre-generated CO_2 foam stabilized by AVS. Among the three injection methods, co-injection of foam recovered the least amount of oil (20.68%) after water flooding, which may suggest that only a limited amount of foam was produced because of insufficient contact between the gas and liquid phases in the relatively short core plug (8.93 cm). In this series of experiments, SAG

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performed moderately, although an increase in the number of injection cycles may result in more incremental oil.

The gas/liquid ratio is also one of the key factors in polymer enhanced CO_2 foam flooding. Run #1, #4, #5, #6 and #7 were conducted under various gas/liquid ratios to examine the effect of gas/liquid ratio on the tertiary oil recovery. The results are presented in Table 5 and Fig. 11. With gas fraction increasing, the amount of foam produced would increase too, which would enhance the displacement efficiency; It is evident that the tertiary oil recovery decreased once the gas/liquid ratio exceeded a certain value, which might indicate early gas breakthrough had occurred due to the high flowability in the gas phase, thereby, strong blocking ability could not be obtained. Apart from the influence of fluid flowability, the foam apparent viscosity could also impose huge impact on the performance of foam displacement. The dependence of foam apparent viscosity on the gas/liquid ratio (foam quality) was investigated through core flooding experiment without the presence of crude oil (foams with various gas/liquid ratio were fed into the brine-saturated core plug until steady state flow was obtained. The viscosity was then calculated based on single phase Darcy's law). The results were shown in Fig. 12. It was clear that the maximum foam apparent viscosity existed under a specific foam quality (around 72%) known as transition foam quality which was indicated by the blue dash line. Under this foam quality, the foam flooding endowed the best displacing ability. Although the existence of crude oil would affect the foam behavior somehow, according to the trend concluded from Fig. 11, the optimal gas/liquid ratio was proposed to be between 3:1 and 4:1 at which level the maximum tertiary oil recovery could be achieved.

Two sets of core flooding experiment (#8 and #9, #10 and #1) were carried out to compare the EOR potential of the AOS/AVS foaming system to that of AOS/HPAM with the direct injection of foam and a gas/liquid ratio of 3:1. Results are tabulated in Table 6. The pressure drop histories during secondary recovery (brine injection) and tertiary recovery (foam

flooding and chase waterfloods) were plotted as a function of overall injected PV in Fig. 13 and 14. It was clear that, regardless of the rock permeability and foaming formulation, the pressure drop across the core plug increased dramatically right after the introduction of polymer enhanced foams, which indicated its outstanding blocking ability. Nevertheless, compared to AOS/HPAM foam, the counterpart AOS/AVS foam endowed better blocking performance verified by its higher differential pressure over a longer period of time. This was attributed to its remarkable foam stability associated with the surface activity and thickening ability of AVS polymer. Another intriguing fact was that the steady pressure drops of AOS/AVS foam flooding in chase waterfloods phase were greater than that of AOS/HPAM foam, suggesting the brine relative permeability after foam flooding was better modified; that was, more areas in the core plug could be swept due to the greater brine permeability reduction, which explained the higher tertiary oil recovery of CO_2 foam flooding enhanced by AVS polymer.

In the lower permeability range, the tertiary recovery of the CO_2 foam flooding enhanced by AVS was 3.7% higher than that of the foam flooding enhanced by HPAM. This could be attributed to the excellent foamability, stability and blockage of the AOS/AVS foaming system under the test condition, which have already been discussed in the earlier sections of this text. When the enhanced foam collapses in the pores, the polymer can also work as a thickener to displace the residual oil. As the thickening ability of AVS was found to be much better, it was about to contribute more to the tertiary recovery. When it came to the higher permeability range, the tertiary recoveries of both experiments increased, while the recovery difference between them increased from 3.7% to 6.7%, which may suggest that high permeability was more favorable to polymer enhanced foam flooding. It should be noted, however, irrespective of the rock permeability range, the oil recovery differences between the two foaming formulae were not remarkable. This could be attributed to the limitations in the

experiments, such as, the relatively short core plugs, etc. It can be concluded that, compared to HPAM, AVS is able to enhance stability without significantly affecting foamability during the CO_2 foam flooding process. Therefore, AVS can be considered to be a promising option in the applications for polymer enhanced CO_2 foam flooding in thefuture.
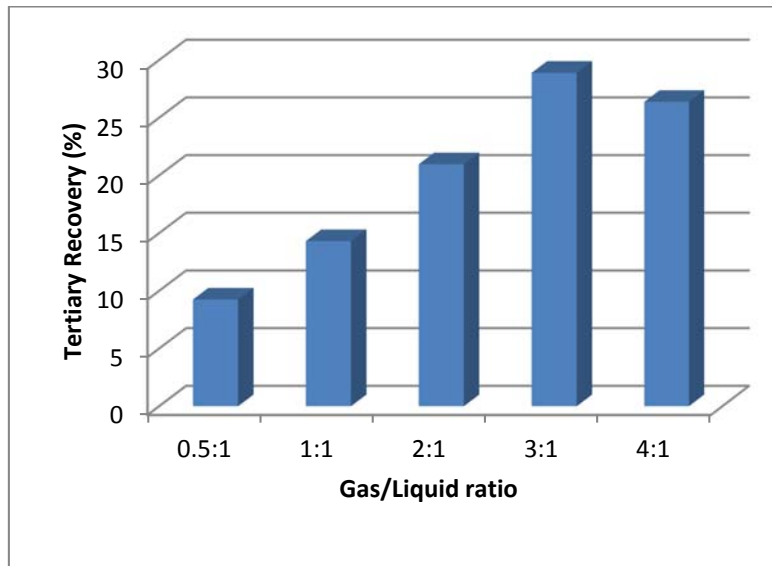

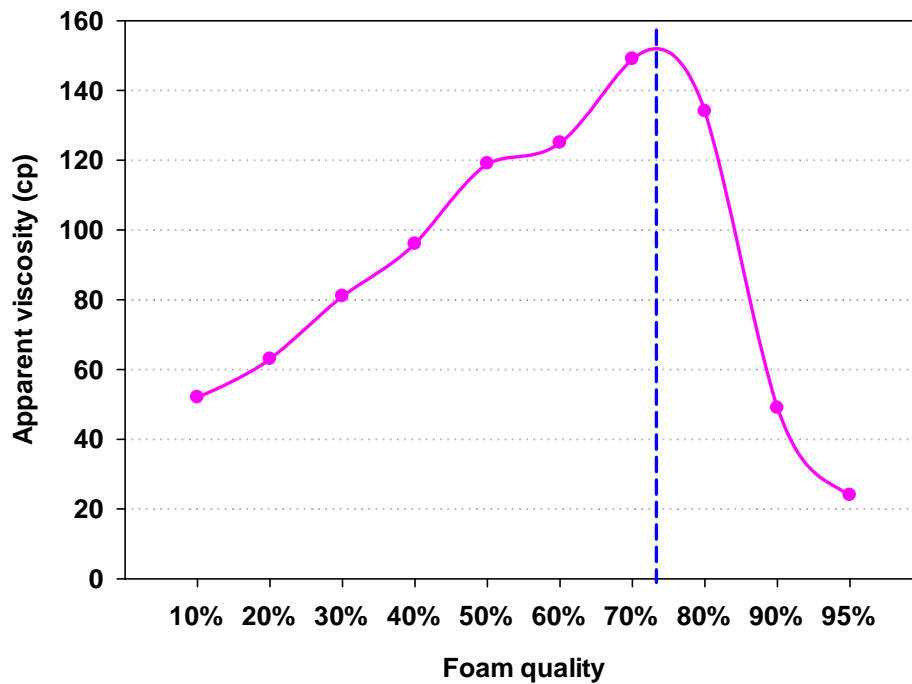**FIGURE 11 Tertiary oil recoveries under different gas/liquid ratio**

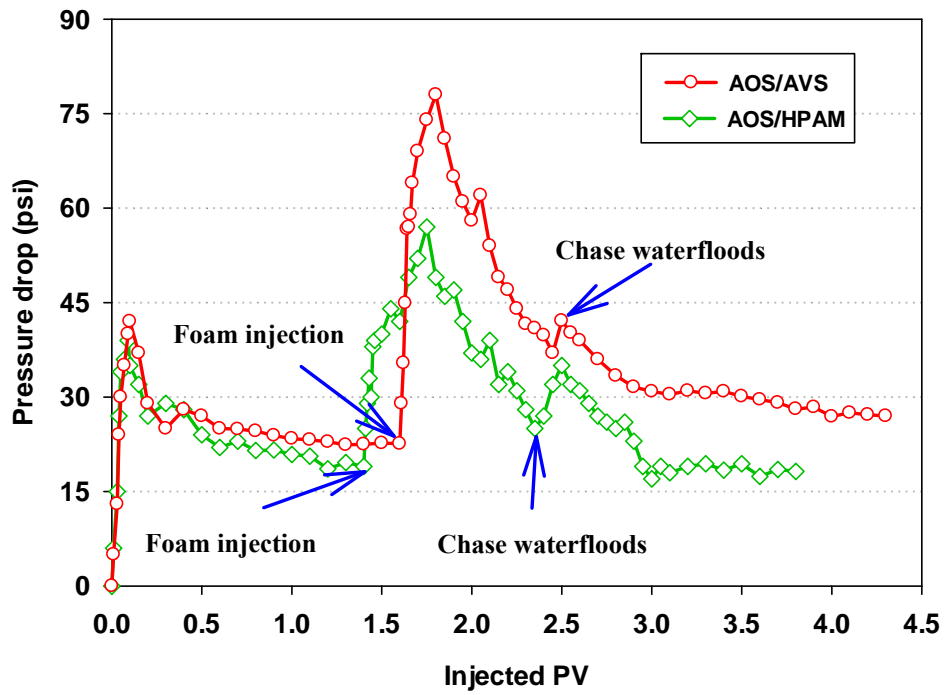**FIGURE 12 The effect of foam quality on foam apparent viscosity**

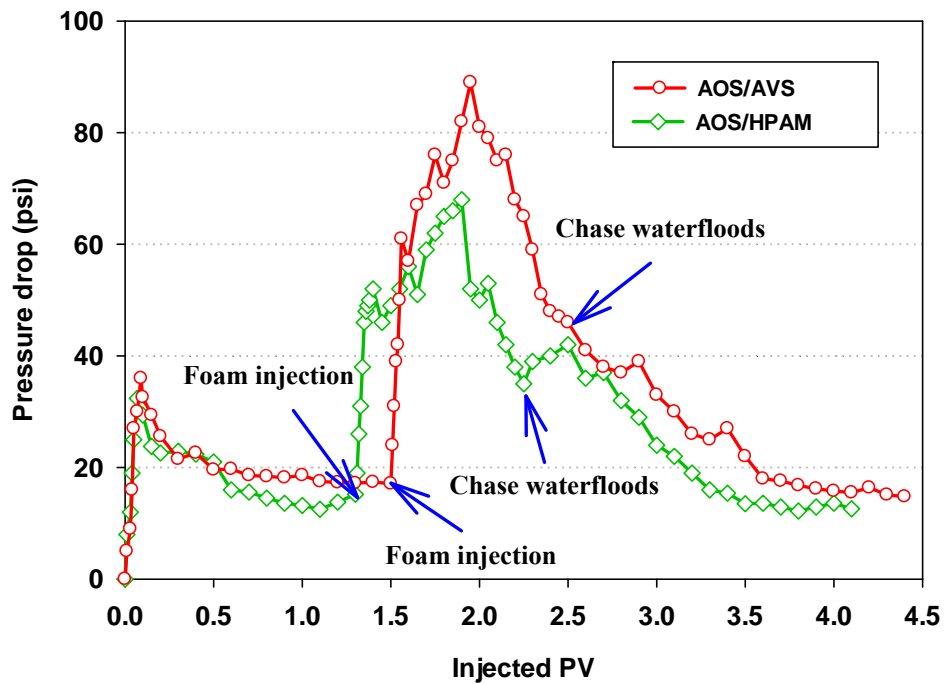**FIGURE 13 Pressure drop during core flooding process in Run #8 (AOS/HPAM) and #9 (AOS/AVS)**

FIGURE 14 Pressure drop during core flooding process in Run #10 (AOS/HPAM) and # 1 (AOS/AVS)

Table 4
The effect of injection scheme on oil recovery

Run No.	1	2	3
Formula	0.5%AOS +1500ppm AVS	0.5%AOS +1500ppm AVS	0.5%AOS +1500ppm AVS
Porosity (%)	17.45	18.24	17.95
Permeability (mD)	149.83	154.23	159.04
Gas/liquid ratio	3:1	3:1	3:1
Injection scheme	direct injection	co-injection	SAG
Slug size (PV)	1.0	1.0	1.0
Initial oil saturation (%)	67.50	69.93	70.55
Waterflood recovery (%IOIP)	38.85	38.12	39.54
Ultimate recovery (%IOIP)	67.74	58.80	62.31
Tertiary recovery (%IOIP)	28.89	20.68	22.77

Table 5
The effect of gas/liquid ratio on oil recovery

Run No.	4	5	6	1	7
Formula	0.5% AOS +1500ppm AVS	0.5% AOS +1500ppm AVS	0.5% AOS +1500ppm AVS	0.5% AOS +1500ppm AVS	0.5% AOS +1500ppm AVS
Porosity (%)	16.59	17.33	17.26	16.87	17.35
Permeability (mD)	152.78	146.24	140.98	156.25	139.64
Gas/liquid ratio	0.5:1	1:1	2:1	3:1	4:1
Injection scheme	direct injection	direct injection	direct injection	direct injection	direct injection
Slug size (PV)	1.0	1.0	1.0	1.0	1.0
Initial oil saturation (%)	64.12	64.21	68.65	67.50	68.55
Waterflood recovery (%IOIP)	36.88	39.52	39.74	38.85	36.23
Ultimate recovery (%IOIP)	46.13	53.83	60.71	67.74	62.61
Tertiary recovery (%IOIP)	9.25	14.31	20.97	28.89	26.38

Table 6
The effect of chemical formula and permeability on oil recovery

Run No.	8	9	10	1
Formula	0.5%AOS +1500ppm HPAM	0.5%AOS +1500ppm AVS	0.5%AOS +1500ppm HPAM	0.5%AOS +1500ppm AVS
Porosity (%)	14.73	15.24	17.32	17.45
Permeability (mD)	49.65	48.97	155.36	149.83
Gas/liquid ratio	3:1	3:1	3:1	3:1
Injection scheme	direct injection	direct injection	direct injection	direct injection
Slug size (PV)	1.0	1.0	1.0	1.0
Initial oil saturation (%)	60.69	62.17	69.29	67.50
Waterflood recovery (%IOIP)	32.57	33.06	39.12	38.85
Tertiary recovery (%IOIP)	20.49	24.17	22.23	28.89
Ultimate recovery (%IOIP)	52.06	57.23	61.35	67.74

4. Conclusion

1. Compared to HPAM, AVS was found to be more temperature and salt tolerant, which was validated by its noticeable thickening ability even under harsh test conditions.

2. The introduction of hydrophobic as well as hydrophilic groups enabled AVS molecules to adsorb onto the gas/liquid interface, which resulted in the reduction of surface tension.

3. The addition of AVS into the foaming system could significantly enhance foam stability without lowering foamability to any great extent.

4. As a result of its outstanding ability to improve oil recovery, direct injection of foam was selected as the appropriate injection method. The gas/liquid ratio of 3:1 was found to be optimal under test conditions.

5. Tertiary oil recovery of the CO_2 foam flooding enhanced by AVS was noticeable in the low or high permeability core plugs into which the foam was directly injected, exhibiting great potential for its application in Enhanced Oil Recovery.

Acknowledgement

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