



# Experimental evaluation of polymer-enhanced foam transportation on the foam stabilization in the porous media

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## Abstract

With the addition of polyacrylamide homopolymer (PAM) to the foam solution which is known as polymer-enhanced foam (PEF), the lamella strength in the surface could be enhanced and subsequently the membrane liquid drainage is weakened, and the diffusion of gas phase would reduce. In this comprehensive study, the comparison of different types of polymers on the property of a foaming agent is taken into the experimental evaluation. To do this, polyacrylamide homopolymer (PAM), flopaam (FA920) with the mixture of surfactants and its comparison with the utilization of only surfactants are being evaluated to generate the polymer-enhanced foam (PEF) in the porous medium. Furthermore, the performances of the foaming agent are analyzed regarding the pressure drop measurement at the displacement of the foam and the resistance factor of the gas phase ( $RF_{\text{gas}}$ ) is investigated. Consequently, polymer addition would increase the  $RF_{\text{gas}}$  regarding the more propagation of foam in the porous media which has caused more foam stabilization. The property of PEF is utterly dependent on the type of used polymer, and according to the results, the amphiphilic polymer has experienced more resistance due to more reactions with a surfactant.

**Keywords** Polymer-enhanced foam · Polyacrylamide homopolymer · Resistance factor · Foam propagation · Flopaam · Porous medium

## Introduction

The recent advancement of foam flooding in the enhanced oil recovery techniques to control the mobility ratio within the gas flooding performances was considered as one of the main issues in petroleum industries (Davarpanah 2018; Davarpanah et al. 2018a). Therefore, regarding the capability of foaming agent to reduce the gas flow in the porous media, foam flooding is considered as one of the applicable techniques to obtain more oil volume (Chen and Zhao 2015; Farajzadeh et al. 2013; Fisher et al. 1990; Guo and Aryana 2016; Hou et al. 2018; Jeong and Corapcioglu 2003).

The utilization of foaming agent in the reservoir would be performed as a collapsing agent when it has contact with oil droplets and surfactants. In addition, the foaming agent reduces the amount of interfacial tension between water and oil (Davarpanah et al. 2018b; Pang et al. 2018; Taylor 2018). During the process of foam injection in the fracture reservoirs, foaming agents are firstly injected into the layers that have high permeability. Since then, with the increase of foaming agent in the high permeable layers, the propagation of foam in high permeable zones would sequentially rise and the foaming agent entered into the low permeable layers (Liu et al. 2017; Manan et al. 2015; Singh and Mohanty 2017; Sun et al. 2015; Wang and Li 2016; Wei et al. 2018a; Cox 2015). Therefore, the sweep efficiency has increased, and subsequently, the oil recovery factor has risen gradually. Another chemical EOR method which considerably influenced the oil recovery enhancement especially heavy oil reservoirs is related to the simultaneous injection of surfactant–polymer (henceforth, it is called as SP flooding) in combination with water which is flooded into the reservoir (Aramideh et al. 2018; Zaccagnino et al. 2018; Wang et al. 2018). The procedure of efficient displacement

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in this technique entails the following steps. Firstly, the surfactants have the potential ability to react with crude oil and the formation brine to generate in situ microemulsion (Davaranah 2018; Guo and Aryana 2016, 2018; Liu et al. 2017; Telmadarreie and Trivedi 2016; Wei et al. 2018b; Wu et al. 2018). Therefore, the capillary number reached the maximum value, and the remained oil would be easily mobilized according to the capillary desaturation curve (CDC). In the second phase, the polymer particles have modified the mobility ratio within the displacing phase thickening and alleviated the impact of permeability alteration which profoundly enhances the total sweep efficiency (Davaranah and Mirshekari 2018; Jakobsen et al. 2018; Razmjoo et al. 2017).

On the other hand, the considerable influence of polymer particles presence in the injected fluids would assist the reduction of surfactant adsorption on the reservoir rocks. To grasp the importance of minimum miscibility pressure (MMP), a vast majority of laboratory experimental evaluations are widely reported in the literature to investigate the principles of these methods to provide such measurements for calculating the oil recovery factor. That is to say that the administration of empirical correlations and equations of state is also possible for MMP calculations as well. In those regions which are un-sweep and clear enough (those regions which are not severely affected by upward gas mobilization, especially in the gas injection procedures and downward water mobilization in the time of water flooding), the injected fluid would be increased dramatically (Falls et al. 1989; Farajzadeh et al. 2012, 2013; Kamali et al. 2015; Xu et al. 2015; Zeng et al. 2016; Zhang et al. 2015). According to the administered techniques to improve the efficiency of foam flooding, adding the polymer particles in the foam solution would be considered as the preferable technique regarding technical and economical purposes. In the higher concentrations of surfactant agent, the combination of surfactant and polymer was created in the bulk area. To measure the value of pressure drop and the saturation of liquid phase in the porous medium, most of the experiments could be done on the natural sandstones or in the sandpacks due to the imposing of several injection circumstances such as pressure, the quality of foam, flow rate.

Furthermore, the resistance factor is considered as the pressure drop ratio in the both absence and presence of a foaming agent which considerably demonstrates the ability of the foam to propagate and generate in the porous media. On the contrary, the presence of foaming agent in the porous media has proposed the gas relative permeability reduction while the water relative permeability has not fundamentally changed (Bureiko et al. 2015; Chassenieux et al. 2011; Kovscek and Radke 1993; Rossen 1996; Üzümlü et al. 2010). In fact, according to the previous investigations, it is explained that the proposed resistance is caused by the presence of lamellae in the porous media. Therefore, the reduction of gas relative

permeability would be of significance in numerous operational performances when the gas is injected directly as the forms of nitrogen gas and hydrocarbon gas for several EOR operational performances (Singh and Mohanty 2017; Sun et al. 2015, 2016; Wang and Li 2016; Cox 2015; Xu et al. 2015).

To enhance the stability of foam, Langevin and Monroy (2010) proposed experimental investigations that polymers are used to increase elastic and viscous properties of the interface. Polymers might form stabilized complexes with surfactant molecules. Therefore, the stability of foam would increase due to the steric effects and neutral hydrosoluble polymer would not change the interfacial surface tension (Langevin and Monroy 2010). One of the major steps to provide a stable aqueous foam is to increase the viscosity of the aqueous phase. Sett et al. (2013) proposed that the addition of hydrosoluble polymers was a key parameter to increase the aqueous viscosity. The increase in aqueous viscosity was considered as a negative impact to decrease the foamability and foam texture (Sett et al. 2013). According to the Kristen et al. (2010) investigations, the simultaneous utilization of surfactant and polyelectrolytes with the same ionicity, there is not any complex formation and the surfactants are settled in the interface. Therefore, the polymer particles only decreased the electrostatic interaction. In addition, it is operated as the viscosifying agent for the aqueous part. On the contrary, at the lower concentrations of surfactant, the complex molecules of surfactant/polymer have been formed. Hence, in the earlier times, the surfactant has not covered the interface and caused diminishment of the foamability before the denser surfactant formation at the interface. However, addition of polymer particles to the surfactant has led to the foam stability in the bulk and the high charge of polymer would cause the flat adsorption on the surfactant (Kristen et al. 2010). Gochev (2015) proposed that the higher foam stability is obtained by the hydrophobically modified inulin (which is a type of polymer) regarding the formation of larger polymer loops in the aqueous phase which might cause the stability of foams (Gochev 2015). Stocco et al. (2011) suggested the utilization of chemically modified nanoparticles to raise the foams' long-term shelf life. They proposed that by the overcoming of energy barriers by the nanoparticles, they are adsorbed at the interface of water and air. Therefore, the interfacial moduli have significantly enhanced which causes the foaming agent to be stabilized (Stocco et al. 2011). Resistance factor is defined as the ratio of pressure drop in the presence and absence of foam to depict the foam ability to propagate and generate in the porous medium. Therefore, the gas resistance factor (which is a dimensionless parameter) is calculated by the following equation:

$$RF_{\text{gas}} = \frac{\Delta P_{\text{foam}}}{\Delta P_{\text{gas without foam}}} \quad (1)$$

where  $\Delta P_{\text{foam}}$  is the pressure drop value measured during the foam propagation and  $\Delta P_{\text{gas without foam}}$  is the pressure drop

value in the flow of gas phase in the sandpacks (flow rate is constant). To determine  $\Delta P_{\text{gas without foam}}$ , it is supposed that water permeability and gas permeability were equal.

Although there are numerous studies widely reported in the literature about the significant influences of chemical EOR techniques like foam, surfactant, polymer and the simultaneous co-injection of these chemicals in the enhancement of sweep efficiency, the objective of this extensive study is to investigate the performances of two types of polymers [amphiphilic polymer (B192) and nonionic hydrosoluble polymer (PAM)] to operate as the propagation and generation of a stabilized foaming agent in the porous medium. Therefore, the value of the resistance factor for the gas phase has been explicitly illustrated for each injectivity scenario, and after its comparison, the optimum scenario was being selected which would have practical performances.

## Materials and methods

### Fluids and materials

The properties of fluids and materials which were used in this experiment are explained in more detail in Table 1.

**Coreflooding experiment:** The provided core samples which are used in this experimental evaluation are extracted from one of the sandstone reservoirs in the Pazanan oil field of Iran with the approximate length of 8.24 cm and outer diameter of 4.1. The properties of porous media that are used in this experiment are the calibrated sand from Pazanan field of Iran with the  $\text{SiO}_2$  composition of 96.5% and the average particle size of 140  $\mu\text{m}$ .

### Experimental setup

The schematic of the experimental setup which was used in this experiment is depicted in Fig. 1. As can be seen, the porous medium has been put in a cylindrical column with the internal diameter of 0.05 m and the length of 0.5 m. To measure the value of pressure difference in the core plug system, a pressure drop transmitter was used for the equipped sandpack. Furthermore, to inject the liquid fluid in the constant flow rate, a volumetric pump and a gas mass flow controller were used to impose the gas. To calculate the total volume of nitrogen and carbon in the case of quantification of polymer adsorption which was a concerning issue, a densimeter was used properly.

### Experimental investigation procedure

After packing the sand under the vibration, the core is saturated and vacuumed by the brine, and the porosity was calculated by the weighing methods. To determine the permeability of the brine, it is injected at different flow rates in the specific pressure in which the permeability is calculated according to the Darcy's law.

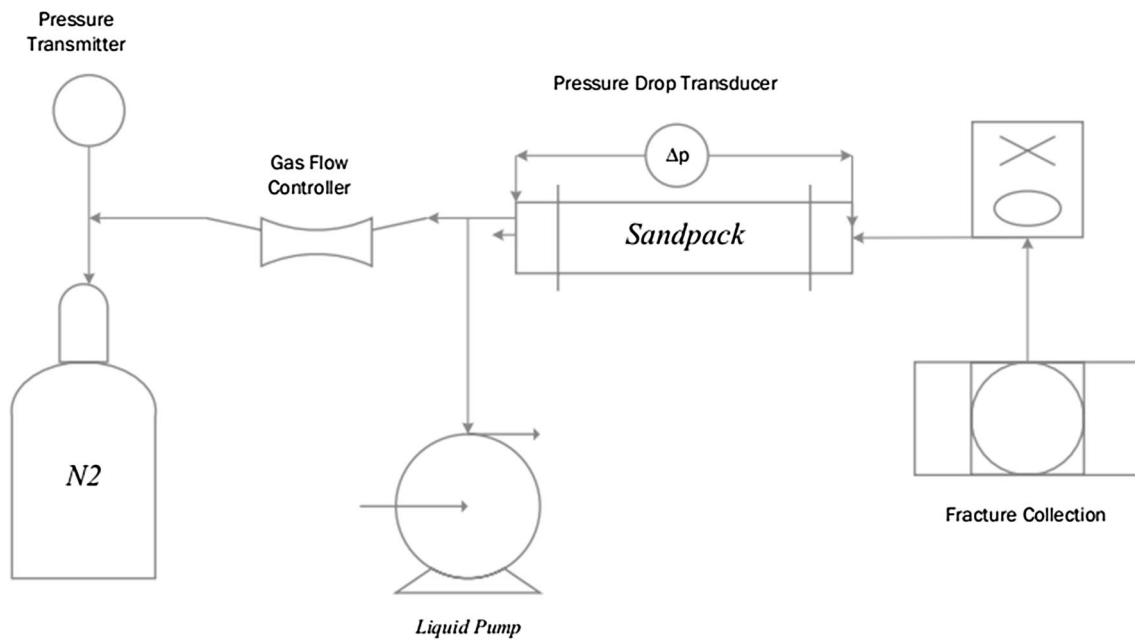
### Co-injection experiments

In this part of the experiment, eight different injectivity scenarios were performed with the simultaneous injection of liquid ( $Q_w = 25 \text{ mL/h}$ ) at different compositions and gas ( $Q_g = 190 \text{ mL/h}$ ). On the other hand, the liquid recovery and pressure difference were continuously measured in the horizontal position in all steps of the experiment, and the temperature in this room is  $22 \pm 1 \text{ }^\circ\text{C}$ . Then, as can be seen in Table 2, the following steps are done sequentially

**Table 1** Properties of fluids and materials

Row	Material	Properties
1	Gases	The utilized gas in this experiment is the purified nitrogen with the purity of 99.8%. Carbon dioxide was utilized to saturate the samples, and nitrogen was used for flooding performances
2	Brine	The prepared brine is deionized and degasified with the KCL content of 2% w/w, the purity of 98%, and pH of 6.4
3	Surfactant	It is sodium laureth sulfate (which is called CS-330) and anionic and provided by the interfacial tension and the brine. The interfacial tension ( $\sigma$ ) and critical micellar concentration (CMC) were measured from the pendant drop method ( $\sigma = 30.14 \times 10^{-3} \text{ N/m}$ and $\text{CMC} = 365 \text{ mg/L}$ ). During the flooding experiments, the concentration of surfactant is set about four times of CMC when the surfactant is utilized alone or in the association of polymer particles
4	PAM (polyacrylamide homopolymer), and FA920 (Flopaam)	In this experimental evaluation, two types of polymers were used to compare their differences on the result of the experiments. The solution of polymer is put in the brine with the concentration of 205 ppm to provide the constant viscosity of 1.25 mPa.s
5	B192 (associative polymer)	B192 is contained the modified anionic acrylamide copolymer which is included in the cationic hydrophobic parts. The solution of polymer is put in the brine with the concentration of 310 ppm to provide the constant viscosity of 1.25 mPa.s. CAC (critical aggregation concentration) for this experiment was equal to 205 ppm





**Fig. 1** Schematic of experimental setup

**Table 2** Sequential steps to provide an extensive comparison between each of the injectivity scenarios

Injection scenarios	Description
1	Simultaneous injection of gas and brine and gas which is considered as the baseline experiment
2	Simultaneous injection of PAM solution and gas. To do this, three pore volumes of PAM solution are first injected into the sandpack to complete the procedure of polymer adsorption before commencing the simultaneous injectivity of liquid and gas
3	Simultaneous injection of an FA920 solution (0 PV) and gas. Gas and polymer are simultaneously injected into the sandpack which is only saturated with brine, and there is not any adsorption of the polymer
4	Simultaneous injection of an FA920 solution (1 PV) and gas. To start the experiment, one pore volume of FA920 is injected into the sandpack before the simultaneous injection of liquid and gas
5	Simultaneous injection of an FA920 solution (3 PV) and gas. To start the experiment, three pore volumes of FA920 are injected into the sandpack before the simultaneous injection of liquid and gas
6	Simultaneous injection of surfactant solution and gas. To start the experiment, three pore volumes of surfactant are injected to the sandpack to complete the adsorption procedure of surfactant and subsequently considered as a relay agent in the foam generation before the simultaneous injection of liquid and gas
7	Simultaneous injection of surfactant, PAM solution and gas. To start the experiment, three pore volumes of surfactant and three pore volumes of surfactant PAM are injected into the sandpack to complete the adsorption procedure of surfactant and polymer before the simultaneous injection of liquid and gas
8	Simultaneous injection of FA920 solution and gas. To start the experiment, three pore volumes of surfactant and three pore volumes of FA920 are injected into the sandpack to complete the adsorption procedure of surfactant and polymer before the simultaneous injection of liquid and gas

to provide an extensive comparison between each of the injectivity scenarios.

These different injectivity scenarios are explicitly explained in Table 3.

The petrophysical characteristics of liquid solutions are reported statistically in Table 4. Other properties of the core samples are statistically described in Table 5.

## Results and discussion

### Polymer adsorption

According to the experimental investigation procedure, the concentrations of polymer and the tracer front with the



**Table 3** Summary of injection scenarios

Inj. scenario no.	Gas	PAM	Surf.	B192	Initial PV
1	X <sub>3</sub>	–	–	–	0
2	X <sub>3</sub>	X <sub>3</sub>	–	–	3
3	X <sub>3</sub>	–	–	–	0
4	X <sub>3</sub>	–	–	X <sub>3</sub>	1
5	X <sub>3</sub>	–	–	X <sub>3</sub>	3
6	X <sub>3</sub>	–	X <sub>3</sub>	X <sub>3</sub>	0
7	X <sub>3</sub>	X <sub>3</sub>	X <sub>3</sub>	–	3
8	X <sub>3</sub>	–	X <sub>3</sub>	X <sub>3</sub>	3

**Table 4** Petrophysical characteristics of liquid solutions

Inj. scenario no.	Polymer	C <sub>Pol</sub> (g/L)	C <sub>Surf</sub> (g/L)	μ <sub>w</sub> (Pa.s)	σ (N/m)
1	–	–	0	1.05 * 10 <sup>-3</sup>	65 * 10 <sup>-3</sup>
2	PAM	0.205	0	1.32 * 10 <sup>-3</sup>	65 * 10 <sup>-3</sup>
3	B192	0.32	0	1.32 * 10 <sup>-3</sup>	59.3 * 10 <sup>-3</sup>
4	B192	0.32	0	1.32 * 10 <sup>-3</sup>	59.3 * 10 <sup>-3</sup>
5	B192	0.32	0	1.32 * 10 <sup>-3</sup>	59.3 * 10 <sup>-3</sup>
6	–	–	1.45	1.05 * 10 <sup>-3</sup>	30.5 * 10 <sup>-3</sup>
7	PAM	0.205	1.45	1.32 * 10 <sup>-3</sup>	30.5 * 10 <sup>-3</sup>
8	B192	0.32	1.45	1.32 * 10 <sup>-3</sup>	30.5 * 10 <sup>-3</sup>

**Table 5** Experimental data for each scenario

Inj. scenario no.	Φ	K <sub>w</sub> (m <sup>2</sup> )	S <sub>w</sub> (g/L)	RF <sub>gas</sub>
1	0.42	7 * 10 <sup>-12</sup>	0.91	165
2	0.42	7 * 10 <sup>-12</sup>	0.91	165
3	0.42	7 * 10 <sup>-12</sup>	0.75	375
4	0.42	7 * 10 <sup>-12</sup>	0.64	465
5	0.42	7 * 10 <sup>-12</sup>	0.53	535
6	0.41	6.7 * 10 <sup>-12</sup>	0.26	685
7	0.40	6.6 * 10 <sup>-12</sup>	0.26	935
8	0.40	6.8 * 10 <sup>-12</sup>	0.26	1155

non-adsorbing property were compared which is plotted in Fig. 2. As can be seen in Fig. 2, the dimensionless parameter of C/C0 (C is the polymer concentration) is plotted versus the injection of the polymer solution. Therefore, it is elaborated that the polymer adsorption quantity could deduce by the differentiation of the plotted curve due to the concept of solid-phase density, initial polymer concentration and the value of pore volume.

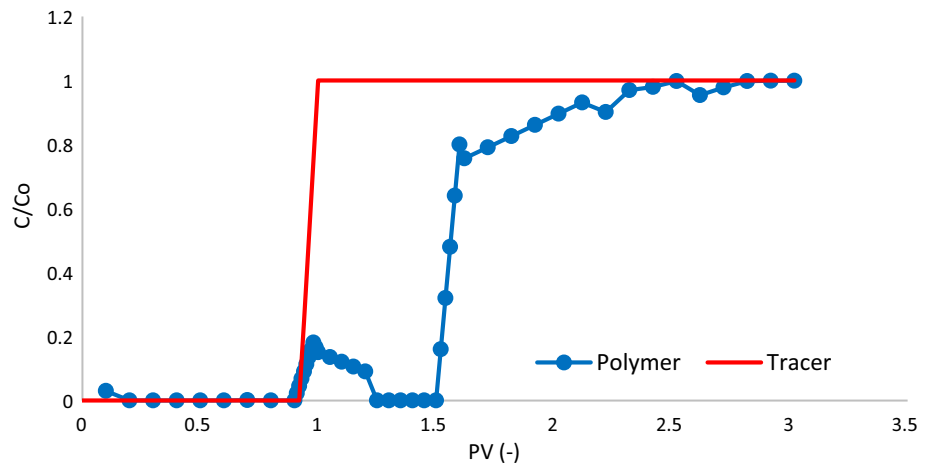
### Scenarios # 1 and # 2

Injectivity scenarios 1 and 2 were considered in the same part because of their similar procedure; however, the only different thing was the viscosity alteration. That is to say that, the viscosity of brine phase is about 1 mPa.s and 1.3 mPa.s for the solution of polymer phase. As it is evident in Fig. 3, the gas resistant factor (henceforth,  $RF_{gas}$ ) is plotted for both experiments versus the pore volume injection of both gas and liquid phase. Moreover, the breakthrough of the gas phase happens early in the 0.05 of pore volume injection, and subsequently, the pressure drop has reached a plateau after the breakthrough occurrence. At the end of these two experiments, the saturation of water measured is about 0.91. As these are classical injectivity scenarios of water and gas injection in a saturated porous medium of a horizontal core sample, the lower viscosity alteration of the polymer solution and brine (1 mPa.s for brine and 1.3 mPa.s for polymer solution) does not considerably influence the whole procedure of two-phase flow behavior which is mostly controlled by the gravity differentiation. Therefore, the viscosity differentiation between liquid and gas phase would lead to the lower rate of sweep efficiency and subsequently lower value of  $RF_{gas}$  because there is not any surfactant in the system to improve the stability of the lamellae property of the liquid phase. Consequently, after the breakthrough time, due to the increase in pore volume,  $RF_{gas}$  had been approximately constant for both brine and PAM injection.

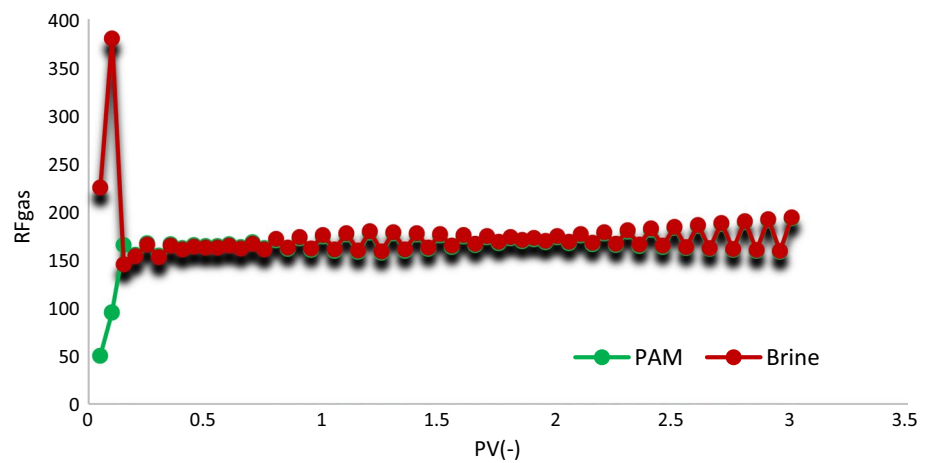
### Scenarios # 3, # 4 and # 5

As can be seen in Table 1, injectivity scenarios 3–5 are differentiated on the volume of polymer injected into the core samples before the commencing of gas–liquid injection. The schematic of experimental evaluations for different polymer solutions is explicitly depicted in Fig. 4 which shows that due to the increase of polymer solution, the  $RF_{gas}$  has increased dramatically ( $300 < RF_{gas} < 550$ ). According to the results of this experiment, when there isn't any polymer injection into the core, the value of  $RF_{gas}$  was decreased gradually up to the point of 0.85 PV and after this point it has increased slightly to reach its maximum value of about 370 and the breakthrough of gas phase happens about 0.1 PV. The reason for this decrease is elaborated as the adsorption of the polymer during the displacement of gas with pure water in the 0.85 PV, and subsequently, the decrease of pressure drop is related to the decrease of water saturation. Therefore, in this step, the measured  $RF_{gas}$  is very close to this value when there was no foam in the system. Since then, the completion of polymer adsorption allows the free polymer molecules to stabilize the foaming agent kinetically from the rapid formation of coalescence bubbles regarding the decrease of film drainage. B192 is considered as the

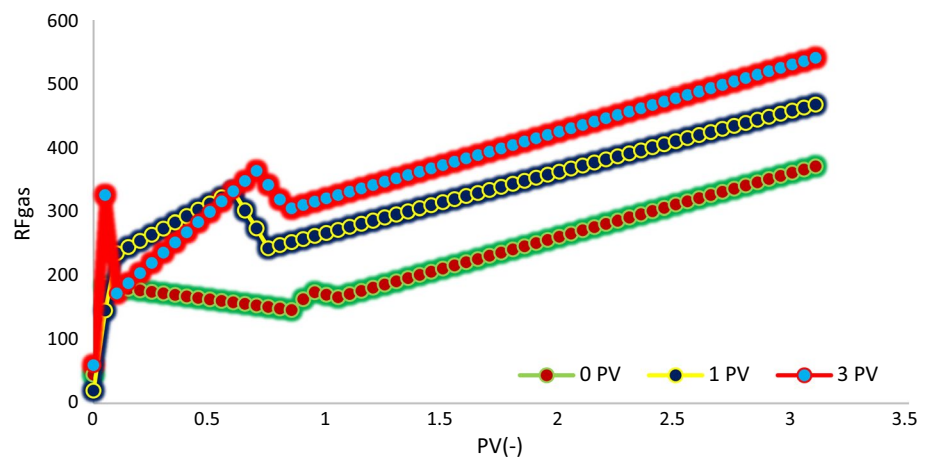
**Fig. 2** Polymer concentration versus the pore volume injection



**Fig. 3** Gas resistance factor versus the pore volume injection



**Fig. 4** Gas resistance factor versus the different pore volume injections of the polymer solution



associative polymer with the hydrophobic groups that have lower interfacial tension than pure water and the lamellae fluid would be stabilized to enhance the generation of weak foam. Moreover, the increase in pressure at the outlet of the core samples was not related only to the foam generation and

it might be concerned about the possible polymer formation which is extensively reported in the literature in the porous media (Chassenieux et al. 2011). It is noted that the final saturation of water after the injection of 3 PV of beforehand polymer was decreased. As is evident, the overall sweep



efficiency of the core sample after the adsorption of the polymer solution is considered effective. Moreover, the completion of polymer adsorption leads to the more stabilization and generation of weaker foaming agent due to the mobilization of more polymer molecules. Consequently, the  $RF_{\text{gas}}$  has a direct relation with the volume of polymer injection that has the maximum  $RF_{\text{gas}}$  for the 3 PV injection of polymer rather than 1 PV and 0 PV of polymer. The  $RF_{\text{gas}}$  for each scenario was about 550, 450, 300, respectively.

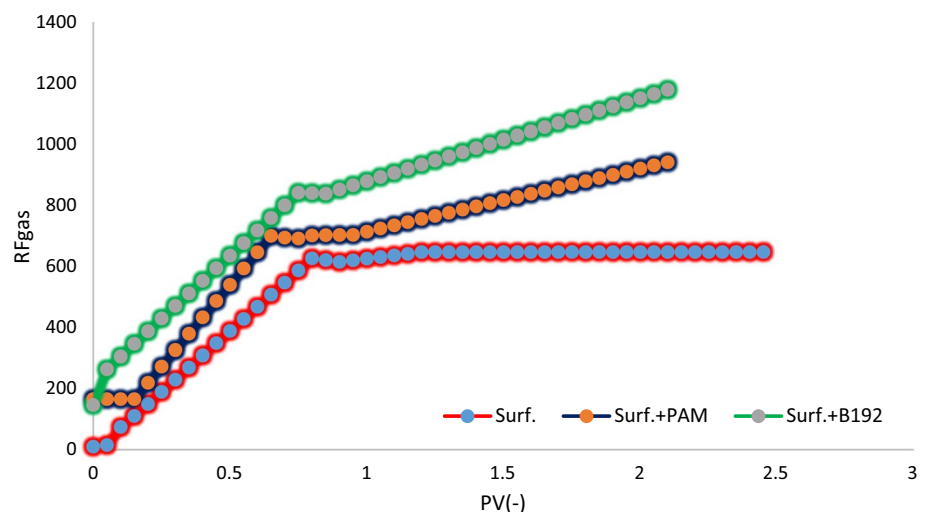
### Inj. Scenarios # 6, # 7 and # 8

The utilization of surfactants provides different injectivity scenarios of 6–8. In scenario # 6, where the uses of surfactant with the PAM solution for scenario # 7, and surfactant with an B192 solution for scenario # 8 to compare each scenario on the gas resistance factor. The evaluations of the experimental procedure are schematically shown in Fig. 5. The first part of the experiment is related to the propagation and generation of the foaming agent before the occurrence of foaming breakthrough of 0.7 PV. According to the visual observation for the displacement of foam, there was a rapid increase in the displacement front that had caused the final saturation of water which was about 0.2 for the proposed experiments in this section. The next part of the co-injection process differed a little for each experiment. In respect of the way, in the case of surfactant injection alone in the system, the  $RF_{\text{gas}}$  has reached a plateau after the breakthrough which is the result of instantaneous local equilibrium. Next, when the surfactant was mixed with the PAM solution, the  $RF_{\text{gas}}$  has experienced a gradual increase after the breakthrough, and it was stabilized on the last period of injectivity procedure (after 2 PV). In the case of B192 co-injection with a surfactant, however, the  $RF_{\text{gas}}$  was increased continuously with the mixture of surfactant and PAM, and there was not witnessed any stabilization after 2 PV of injectivity. To explain this phenomenon in

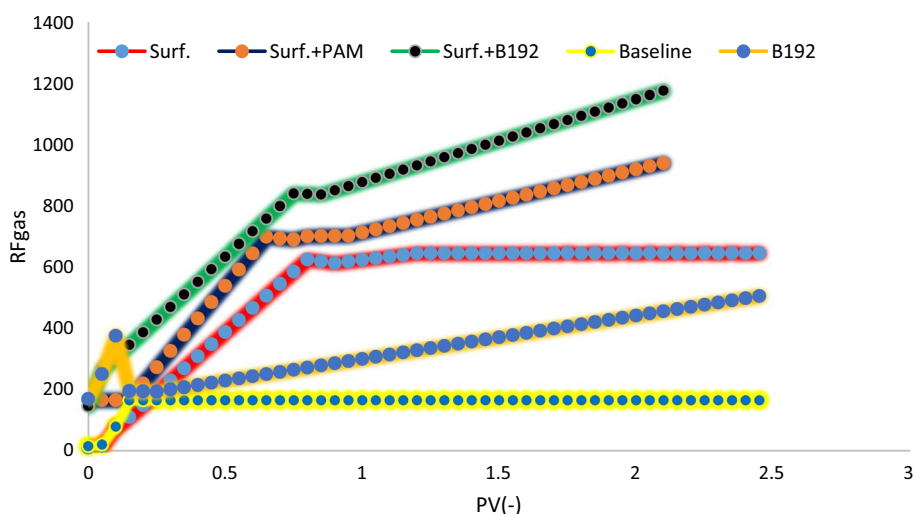
more reasonable detail, according to the previous research of Kovscek and Radke (1993) and Rossen (1996), the issue of snap-off is considered as a dominant process of lamellae generation to elaborate the steady-state fluid flow of the foaming agent in the homogeneous porous medium. In the displacement of foaming agent, the lamellae property led to a stretch phenomenon when it flowed in the pore structures, and it witnessed a compress forms when passed among the pore throats. The continuous alteration of surfactant concentration in the interfaces part and the Marangoni effect regarding the dissipation contribution subsequently lead to the pressure drop enhancement in the system.

Therefore, the total process of these three experiments is summarized in the following statements. At the first stages of the injection, the surfactant molecules were in the direct contact with the liquid/gas film in the bulk when the polymer molecules exist. By passing the injection time, some of the micelles surfactant molecules were replaced with the molecules of amphiphilic polymer. Due to the regular exchange of the film by transporting from the pore body and pore throat regarding the formation of the available region for the adsorption of surfactant and polymer, this replacement process is very slow. Due to the more adsorption of polymer molecules in the interface of gas/liquid at the longer times which is caused by the considerable enhancement of film viscoelasticity the pressure drop have risen. On the other hand, the rise of the viscosity of the liquid phase which is caused by the polymer hydrophilic sections was another reason for pressure drop rise. As can be seen in Fig. 6, the  $RF_{\text{gas}}$  has been increased gradually due to the regular alteration of liquid lamellae while it has reached the equilibrium state. Consequently, the gas resistance factor pattern differed for each injectivity scenario, and according to Fig. 6, the maximum value of  $RF_{\text{gas}}$  was different after the injection of 2 PV.  $RF_{\text{gas}}$  in the case of surfactant alone is lower than the  $RF_{\text{gas}}$

**Fig. 5** Gas resistance factor versus the pore volume injection for different scenarios



**Fig. 6** Gas resistant factor versus pore volume injection for different injectivity scenarios



for the case of surfactant + PAM that is lower than  $RF_{\text{gas}}$  for the case of surfactant + B192.

## Conclusion

Regarding the advancement of chemical flooding on the petroleum industries, especially the flow of foaming agent in the porous medium, in this paper, the simultaneous utilization of foaming agent with different types of polymer is taken into consideration. To do this, the co-injection of liquid and gas is performed in the saturated porous media. The propagation and the generation of the foaming agent are experimentally evaluated to measure the resistance factor of the gas phase. When no surfactant is present in the system, the PAM solution and brine do not have any effective action on the propagation and generation of the foaming agent, and it could be neglected; however, the amphiphilic polymer could stabilize the lamellae fluid which has led to the generation of weak foam. On the other hand, in the presence of a surfactant, the produced foam is stronger, and in the absence of polymer solution, the weaker foaming agent is produced. When the PAM solution is added to the surfactant, the lamellae fluid is being more stabilized due to the enhancement of film viscosity. Therefore,  $RF_{\text{gas}}$  has more value than the case of the only surfactant in the system. Furthermore, according to the results of this comprehensive study, surfactant/amphiphilic polymer reactions due to the complicated exchanging processes is occurred between the surfactant molecules in the micelles interfaces and polymer/surfactant molecules in the bulk system. Hence, these exchanges performances are considered as the impact of stretch/compression of lamellae within the transportation phenomenon. Consequently, the main purpose of this extensive investigation is to propose a polymer-enhanced foam stabilization in the presence of oleic phase. As it is evident, the maximum value of  $RF_{\text{gas}}$  versus

pore volume injection is related to the simultaneous injection of surfactant + B192 and surfactant + PAM, and it was about 1100 and 900, respectively. Since then, the utilization of surfactant and B192 alone is in the following steps of  $RF_{\text{gas}}$  with 600 and 450, respectively. Moreover, it is elaborated that the polymer adsorption quantity could deduce by the differentiation of solid-phase density, initial polymer concentration and the value of pore volume.

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## Compliance with ethical standards

**Conflict of interest** The authors declare that they have no conflict of interest.

## Abbreviations

EOR	Enhanced oil recovery
PEF	Polymer-enhanced foam
PAM	Polyacrylamide homopolymer
FA920*	Flopaam
B192*	Associative polymer
CMC	Critical micellar concentration
CAC	Critical aggregation concentration
$RF_{\text{gas}}$	Gas resistance factor

\*The properties of these fluids are explained in more detail in Fluids and materials section



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