SENSITIVITY ANALYSIS FOR POLYMER INJECTION TO IMPROVE HEAVY OIL RECOVERY – SMALL-SCALE SIMULATION STUDY

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Received: 11.09.2020 / Revised: 05.11.2020 / Accepted: 08.11.2020 / Published on line: 07.01.2021

ABSTRACT

Polymer flooding has been widely used for enhancing oil recovery, due to the growing number of successful applications around the world. The process aims to increase water viscosity and, thus, decrease the water/oil mobility ratio, thereby improving sweep efficiency. The understanding of the physical mechanisms involved in this enhanced oil recovery process allows us to forecast the application potential of polymer flooding. This work aims to assess physical phenomena associated with heavy oil recovery through polymer flooding using 1D small-scale simulation models. We evaluate the influence of different levels of adsorption, accessible pore volume, residual resistance factor, and polymer concentration on the results and compare their magnitude effect on the results. The models used in this study were built using data from previous lab work and literature. For each one of the mentioned parameters, this work compares the histories of water cut, cumulative water-oil ratio, average pressure, and oil recovery factor. Additionally, water saturation, water viscosity, and water mobility profile were determined for specific periods of the flooding process. The sensitivity analyses showed that high levels of adsorption influence the polymer loss of the advance front, delaying oil recovery. Low values of accessible pore volume lead to a slightly faster polymer breakthrough and oil recovery anticipation. A high residual resistance factor increases the average pressure and improves oil recovery. Higher polymer concentration enhances the displacement efficiency and enhances the recovery factor.

KEYWORDS

enhanced oil recovery; polymer flooding; simulation; heavy oil; sensitivity analysis

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doi:10.5419/bjpg2020-0018

1. INTRODUCTION

As global needs for sustainable projects increase, polymer-flooding for enhanced oil recovery has become an attractive opportunity. This scenario is mainly due to oil recovery anticipation and injected/produced water reduction, compared to the conventional water-flooding method.

The polymer-flooding method has been successfully applied in heavy-oil reservoirs, especially in cases where thermal methods are not suitable. For instance, some heavy-oil deposits in western Canada are so thin that thermal methods cannot be applied efficiently (Jamaloei et al., 2010). Excessive heat loss is also a challenge for deep reservoirs, opening up opportunities for polymer injection.

Viscous-oil reservoirs present several challenges for polymer-flooding. One of the main issues is the ability to design a high viscous polymer solution while avoiding injectivity problems. Seright (2010) states that reduced injectivity can limit polymer-flooding of viscous oils more than chemical costs. However, the use of horizontal wells has mitigated concerns about low injectivity of large viscous slugs, therefore, turning polymer-flooding more technically feasible and profitable.

Simulation models have a relevant role in evaluating potential production and profitability of sophisticated techniques such as polymer-flooding. A precise simulation relies on accurate laboratory data and reliable representation of its physical phenomena. Therefore, rheology experiments, single-phase and two-phase core flooding tests, are necessary to determine the properties associated with the polymer flow through porous media. Among these properties, the most important are adsorption, inaccessible pore volume, residual resistance factor, fluids viscosity, and relative permeabilities.

The comprehension of polymer behavior using simulation model can assist in the history matching process and complement the data of core flooding tests, such as the fluid displacement over the sample. Moreover, the evaluation of laboratory outcomes through numerical modeling can give insights on how accurate a field-scale reservoir simulation and its corresponding risk assessment are.

Many authors have gathered experimental studies and numerical simulations of polymer flooding, including non-Newtonian models, in oil recovery process disclosed in the open literature (Seright, 2010; Fabbri et al., 2013; Hatzignatiou et al., 2013b; Sheng, 2013; Lamas et al. 2016; Zampieri et al., 2020). This work relies on a comprehensive observation of fluids displacement into porous media with polymer injection, assessing the shock fronts, including formation water and injected solution.

We performed this work in a core-scale non-Newtonian model, relying on maintenance of the fidelity of laboratory design and understanding of the physical phenomena in 1D. The description of the model and the main equations involved are presented. We developed sensitivity analyses (SA) based on laboratory experiments. The uncertainties were based on values found in literature, aiming at determining the effects of adsorption (ADS), accessible pore volume (APV), residual resistance factor (RRF), and polymer concentration (CCP) on recovery results.

1.1 Adsorption - ADS

Adsorption is the interaction between polymer molecules and rock surface, depending on its affinities. This interaction causes polymer molecules to be bound to the rock surface mostly by physical adsorption – van der Waals forces and hydrogen bonding – that is weak and forms no chemical bonding (Sheng, 2011). Regarding polymer physical features, molecular size and average molecular weight act on adsorption. Moreover, salinity, pH, and hardness of the used solvent are related strongly to the adsorption degree as well (Sorbie, 1991).

The rock surface adsorbs some polymer molecules from the injected solution, lowering its concentration and, consequently, reducing the fluid's viscosity. On the one hand, this reduction of polymeric solution viscosity has an adverse effect on mobility ratio, thus, decreasing oil recovery potential. It is essential to consider the water permeability reduction caused by the polymer retention (Jennings et al., 1971; Carcoana, 1992; Grattoni et al., 2004), which contributes to mobility ratio's reduction.

Table 1 shows some values of adsorption level of HPAM polymer, reported in the literature at different concentrations.

Table 1. Maximum adsorption per concentration.

Source	Concentration (ppm)	Adsorption (µg/g)
Willhite and Dominguez (1977)	100 - 500	10 - 21
Osterloh and Law (1998)	500	10 - 20
Zheng et al. (1998)	250 - 1500	40 - 58
Choi (2008)	5000	76 - 382
Salazar (2009)	1750 - 2250	109.7 – 208.2
Hatzignatiou et al. (2013b)	400	1.92 - 42.41
Delamaide et al. (2013)	500 - 1000	12
Manichand and Seright (2014)	1000 - 2300	50 - 250

Sorbie (1991) stated that the level of polymer retention is one of the fundamental factors to assess the economic feasibility of polymer flooding. In a dynamic-flooding test, the total polymer loss or polymer retention comprises the mechanical entrapment, hydrodynamic retention, and adsorption. The amount of oil recovered per mass of injected polymer is related inversely to polymer retention.

Polymer adsorption is usually the major cause of polymer retention. We can restrict the retention to polymer adsorption in a simulation model. The simulator can represent polymer adsorption by adsorption isotherms, which are used to estimate, at a given temperature, the amount of adsorbed polymer related to the polymer concentration. There are different models of isotherms, such as Langmuir isotherm, Henry isotherm, Freundlich

isotherm, and Concave isotherm.

The Langmuir-type isotherm is one of the most used models to quantify polymer adsorption at the solid surface (Lake, 1989; Aluhwal, 2008; Mohammadi, 2008; Wang, 2009; Sheng, 2011). It can be represented by the following equation:

$$\hat{C}_p = \frac{a_p C_p}{1 + b_p C_p} \quad (1)$$

C_p is the polymer concentration on the liquid phase, $\hat{C}_p$ is the polymer adsorbed in the rock, and a_p and b_p are constants for a given rock-fluid system at a specific temperature.

Figure 1 shows a typical shape of Langmuir-type isotherm, where b_p determines the curvature of the isotherm and the ratio a_p/b_p controls the plateau value of the adsorption (Lake, 1989).

Figure 1. Typical shape of the Langmuir isotherm (adapted from Lake, 1989).

Adsorption is used as an instantaneous effect in the model, which results in a stripped water bank at the leading edge of the slug (Aluhwal, 2008).

1.2 Accessible Pore Volume – APV

The accessible pore volume parameter defines the effective pore volume for the polymer macromolecule flow in porous media. Dawson and Lantz (1972) were the first to report this phenomenon. Conceptually, a polymer molecule is not able to flow through the entire pore space; it only travels through the accessible portion which accelerates its arrival at the outlet face or producer well. Sorbie (1991) developed models that reflect this concept.

In fact, both the pore throats and the polymer molecule do not have absolute sizes, but a range of values. Statistically, there is a combination of molecule sizes that passes through a combination of pore throat. If the size of the molecule is equal to or bigger than the pore throat, it does not go through this pore, and this porous portion is called inaccessible pore volume (IPV) (Dawson & Lantz, 1972). The APV is commonly represented by a fraction of the total pore volume, which is defined as one minus the fraction of IPV.

The magnitude of the inaccessible pore volume depends more on polymer type and porous medium than on polymer concentration, salinity, and the remaining oil in the porous medium (Lötsch et al., 1985).

Many authors noted that, in lab tests, when no retention is observed, polymer molecules are transported through porous media more quickly than the inert chemical tracer dissolved in the injected polymer solution, because of the IPV. The dispersion of the tracer coefficient has at the same value as the water solvent (Dawson & Lantz, 1972; Lötsch et al., 1985; Lake, 1989; Sorbie, 1991).

Two explanations have been reported to explain the fact that the polymer moves faster than the tracer. One considers that large polymer molecules do not pass into small and dead-end pores, flowing only through bigger pores. Thus, polymer molecules propagate faster than the tracer substance. The second hypothesis relates to the wall-exclusion effect of the flow regime. Under this effect, polymer molecules concentrate and flow in the center of the porous channels of the reservoir

rock. This effect occurs because the streamlines away from the wall are associated with the higher velocities. Such flow behavior accelerates the polymer to move on average velocity faster than the chemical tracer through the porous media (Lake, 1989; Sorbie, 1991).

Lötsch et al. (1985) injected a bank of biopolymer solution (Scleroglucan and Xanthan) and a tracer through a sandstone-core. After polymer and tracer outlet concentrations reached their respectively injected levels, brine was pumped (post flood) to displace all mobile polymer and tracer. Then, the second bank of polymer solution containing tracer was injected, and polymer retention and inaccessible pore volume were determined using only the front part of the effluent curves, resultant of the two injection stages. Inaccessible pore volume (IPV) was measured during the second injection cycle from the difference in area between polymer breakout and tracer breakout curves.

Manichand and Seright (2014) determined IPV from Equation 2.

$$IPV = \frac{\sum [(C_{poly}/C_{polyo} * \Delta PV) - (C_{trac}/C_{traco} * \Delta PV)]}{C_{polyo} * PV / M_{rock}} \quad (2)$$

The authors also determined polymer retention (Equation 3) during the first injection cycle from the difference in area between the polymer breakout and the tracer breakout curves.

$$R = \frac{[\sum [(C_{poly}/C_{polyo} * \Delta PV) - (C_{trac}/C_{traco} * \Delta PV)] + IPV * C_{polyo} * PV / M_{rock}}{C_{polyo} * PV / M_{rock}} \quad (3)$$

R is the polymer retention in $\mu\text{g/g}$, C_{poly} is effluent polymer concentration, C_{trac} is the effluent tracer concentration, C_{polyo} is the injected polymer concentration, C_{traco} is the injected tracer concentration, PV is the pore volume, ΔPV is the pore-volume increment, and M_{rock} is the mass of the core.

Differently, low APV requires a low amount of polymer, reducing the cost of the process and presenting advantages. In contrast, too low APV may impair the recovery process (Melo, 2008).

Table 2 shows some values of IPV of HPAM polymer, described in the literature at different porous media, permeability, and salinity. Some data are a complement to that shown previously in the adsorption item (Table 1).

Table 2. IPV values from the literature.

Source	Porous Medium	k, md	Salinity, % TDS	IPV, %
Dawson and Lantz (1972)	Berea	470	1–2	22
Dawson and Lantz (1972)	Bartlesville	2090	1–2	24
Knight et al. (1974)	Berea	90 - 120	0.05	0 - 4
Willhite and Dominguez (1977)	Teflon	86	2	19
Osterloh and Law (1998)	Sandpack	2500 - 11000	1.3	~20
Choi (2008)	Berea	629 - 593	3	14-27
Pancharoen et al. (2010)	Sandpack	12600	-	~30
Hatzignatiou et al. (2013a)	Berea	758 - 842	-	7 - 15
Manichand and Seright (2014)	Sandpack	401 - 877	0.0005	~0

1.3 Residual Resistance Factor - RRF

RRF is a parameter used to indicate the decrease of water mobility after polymer flooding, relative to the water flow before the flow of the polymer solution (Carcoana, 1992).

In order to describe only the permeability reduction effect, a permeability reduction factor (R_k) is defined as the ratio between relative permeability to water (k_w) and polymer fluid (k_p):

$$R_k = \frac{k_w}{k_p} \quad (4)$$

The contribution of the mobility reduction achieved by the polymeric fluid, including viscosity increase and permeability reduction effects, is known as resistance factor (R_F). It is defined as the ratio between water (λ_w) and polymer fluid (λ_p) mobilities:

$$R_F = \frac{\lambda_w}{\lambda_p} = \frac{k_w/\mu_w}{k_p/\mu_p} \quad (5)$$

μ_w and μ_p are water and polymer fluid viscosities, respectively.

Even when applying water flooding in the porous media after a polymer slug, a residual resistance to flow still remains. The residual

resistance factor (RRF) is given by the ratio between water mobility before (λ_{w1}) and after (λ_{w2}) the flow of the polymeric slug.

$$RRF = \frac{\lambda_{w1}}{\lambda_{w2}} = \frac{k_{w1}/\mu_w}{k_{w2}/\mu_w} = \frac{k_{w1}}{k_{w2}} = \frac{P_2}{P_1} \quad (6)$$

P_1 and P_2 are the pressure drop before and after the polymer flooding respectively.

Although the resistance factor R_F is a parameter to evaluate polymer ability to sweep the oil from the reservoir, it is rarely used due to limitations to estimate polymer mobility. The R_F is a function of the permeability to the polymer, which is calculated from Darcy's equation.

The residual resistance factor is used more frequently to make comparisons between laboratory and field data, than to assess resistance factor, because it is simpler, more directly accessible, and devoid calculation simplifications (Silva et al., 2010).

Delamaide (2014) stated that in highly permeable formations, RRF can be low (close to 1); values in the 2-4 range are common, but higher values suggest that the polymer molecules may be too large for the formation. Osterloh and Law (1998) core-flood results indicate that RRF would

Figure 2. Polymer-adsorption mechanism per concentration on the rock surface (adapted from **Zhang and Seright, 2014**).

be between three-to-five at most, but possibly lower. **Zampieri (2012)** found values of RRF of 2.62 for highly permeable sandstones.

1.4 Concentration

Polymer concentration is a crucial parameter in the design of an efficient polymer flooding project. Due to the high cost of polymers, it is essential to optimize polymer injection strategies to perform the greatest oil recovery at the lowest cost for the project. The optimum concentration of the injected polymer solution has a direct impact on the optimization process, maximizing profit and cumulative oil production (**Lei et al., 2012; Sheng et al., 2015**).

Each type of polymer provides a specific increase of fluid viscosity (**Sorbie, 1991**). A higher target polymer viscosity can be reached by increasing polymer concentration. **Wang and Dong (2007)** claimed that a lower concentration of polymer solution can be strategically implemented if polymer flooding is applied at an earlier stage of the production life of a heavy-oil reservoir.

Polymer concentration increase is more effective on the incremental oil recovery because polymer concentration reduces the mobility ratio of water/oil directly by increasing the water-phase viscosity and reducing the effective permeability to water.

Zhang and Seright (2014) investigated how

polymer concentration affects retention in porous media for both dynamic and static measurements. They state that if a rock surface is first contacted with dilute HPAM solution to fill the retention, no substantial additional retention takes place when subjected to higher concentrations (Figure 2). In field applications, reduced polymer retention may be achieved by first injecting a slug of low polymer concentration.

De Bons and Braun (1995), between 1975 and 1992, reviewed twelve pilots and field applications of polymer-flooding around the world. These projects were analyzed and compared with polymer-flooding conducted in the US between 1980 and 1993. The authors stated that the average concentration of polymer injected in US projects was 460 ppm vs. 920 ppm for the polymer-flooding used abroad. The median incremental oil recovery through polymer flooding for the US was 4.9% OOIP, while the successful international incremental recovery accounted for 6 - 52% OOIP.

The Daqing Field pilot tests started in 2001 using high molecular weight and high polymer concentration in three blocks: WN block, WM block, and E N1 block. These pilot areas began with polymer flooding of 16 million molecular weight (MW) and 1000 ppm. Then, after injecting polymer of 25 million MW and about 2000 ppm, the water cut was reduced by 25 to 30%. After the positive results obtained from these pilots, a large-scale polymer flooding was applied to the E W N1 blocks

Table 3. Summary of input parameters.

Information	Parameter	Value
Formation Properties	Rock density	2.65 kg/cm ³
	Porosity (homogeneous)	28%
	Permeability (homogeneous)	5500 mD
	Core length	31.6 cm
	Cross-Sectional Area	10.75 cm ²
	Pore Volume	95.12 cm ³
Fluid Properties	Oil density	9.62 x10 ⁻⁴ kg/cm ³
	Oil viscosity	180 cP
	Water density	1.08 x10 ⁻³ kg/cm ³
	Water viscosity	1.2 cP
	Polymer solution density	1.10 x10 ⁻³ kg/cm ³
	Polymer viscosity vs Concentration	Figure 3
Rock-fluid interaction	Polymer viscosity vs. Shear rate	Figure 4
	Relative Permeability Curves	See Eq. 5 and 6
	Residual water saturation	5%
	Residual oil saturation	25%
	Polymer Adsorption – Langmuir	SA – Figure 5
	Residual Resistance Factor (RRF)	SA
Initial Conditions	Accessible pore volume	SA
	Initial pressure	101.3 kPa
	Initial temperature	22.8 °C
	Initial Oil Saturation	95%
Operational conditions	Initial water saturation	5%
	Injection rate	0.4cm ³ /min
	Polymer Concentration	SA
	Minimum pressure at producer well	101.3 kPa
	Simulation period	95% of Wcut

in January 2009. Polymer MW was 25 million, and injected concentration was 2030 ppm. Injected polymer solution was 0.61 PV. Water cut was significantly reduced and incremental oil recovery was more than 10% (Sheng, 2013).

The polymer flooding in the East Bodo heavy-oil reservoir in Canada began in May 2006. The oil viscosity was 600-2000 cP (140 API). It was expected that the polymer solution injected (1500 ppm) would result in 25 cP. However, reservoir solution viscosity was 10 cP at maximum. So later, a fresher water source with 3700 ppm of TDS was applied, and the solution viscosity of 1500 ppm reached 60 cP at the surface. Polymer concentration at the nearest producing wells was about 100 ppm. The pilot performance indicated that for polymer flooding in the heavy-oil reservoir, horizontal wells alleviated the injectivity problem (Sheng, 2013).

2. METHODOLOGY

This section describes the procedures used for

building the simulation models. We carried out the core-scale models using the CMG-STARs® commercial simulator. We generated the conceptual model with data from previous lab experiments (Zampieri & Moreno, 2013; Silveira et al., 2016).

Table 3 summarizes the main input parameters for formation properties, initial and operational conditions, fluid properties, and rock-fluid interaction of the conceptual model.

Rock properties of simulation models were based on two-phase displacement tests performed by Zampieri and Moreno (2013). The model is a synthetic core-sandstone representing the porous media by homogeneous porosity and permeability.

Figure 3 shows the polymer viscosity for different polymer concentrations of the solution at 7.848s⁻¹ of shear rate (Silveira et al., 2016) and the function used in the simulation model. The bulk viscosity vs. concentration of the polymer solution was determined through a rotational rheometer with concentric cylinders geometry by Silveira et al. (2016). The CMG-STARs simulator uses a

Figure 3. Viscosity vs concentration.

Figure 4. Viscosity vs shear rate (adapted from Silveira et al., 2016).

Figure 5. Adsorption curve – Langmuir.

multiplication variable to calculate the viscosity, taking into account the shear rate effect to model polymer viscosity dependence on concentration.

To include the non-Newtonian behavior, we implemented the viscosity data measured as a function of the shear rate in the simulation file. Figure 4 shows the rheological study from the lab

including the non-Newtonian data (shear thinning effect) for 1250 ppm of partially hydrolyzed polyacrylamide solution containing salt (Silveira et al., 2016).

The Base model considers a heavy oil with 180 cP viscosity, and connate water viscosity of 1.2 cP. We carried out the flow in one dimension and adopted relative permeability curves in the model with residual water saturation of 5% and residual oil saturation of 25%. Equations 1 and 2 show the Corey model.

$$k_{rw}(S_w) = 0.6 \left(\frac{S_w - 0.05}{1 - 0.05 - 0.25} \right)^{2.5} \quad (7)$$

$$k_{ro}(S_w) = 1.0 \left(\frac{1 - 0.25 - S_w}{1 - 0.05 - 0.25} \right)^{4.0} \quad (8)$$

We defined a stop criterion for all simulated cases with 95% of water cut.

The sensitivity analysis developed aims at determining the effects of the adsorption, the accessible pore volume, the residual resistance factor, and the polymer concentration in the model results. The modeling analyses were developed, evaluating each parameter individually, as explained below.

Adsorption: Considering the maximum adsorption values and respective uncertainty reported in the literature (Table 1), we performed the SA for 10 µg/g, 30 µg/g (P_Base), and 60 µg/g of maximum adsorption (ADS_{max}), as shown in Figure 5.

The equations below convert µg/g to kg/cm³. We used sandstone rock density ($\rho_s = 2.65 \text{ g/cm}^3$) and the porosity value ($\phi = 28\%$) for the models.

$$ADS_{Max} [\mu\text{g/g}] \times \text{Factor} = ADS_{Max} [\text{kg/cm}^3] \quad (9)$$

$$\text{Factor} = \frac{\rho_s(1 - \phi)}{\phi} 10^{-9} \quad (10)$$

Accessible Pore Volume: The APV for the Base Model (P_Base) was defined as 85%. We also evaluated the SA considering the limit values 15% higher or lower than 85%, based on literature data (Table 2).

Residual Resistance Factor: We evaluated three values of RRF, 1.0 (no resistance effect), 2.62 (Base Model), based on Zampieri (2012), and the highest value of 4.0, based on Delamaide (2014).

Concentration: We set the Base Model (P_{Base}) as 1250 ppm of the polymer concentration required to reach the target viscosity of 10 cP (at $7,481 \text{ s}^{-1}$). The SA for the injected polymer concentration were 1000 ppm and 1500 ppm, corresponding to the reference viscosity values of 7.6 and 13, respectively.

The proposed methodology aims to investigate the impacts of the above mentioned uncertain physical phenomena related to polymer flooding affect on oil recovery into porous media. Each of the mentioned parameters allows gathering information that, combined appropriately, can lead to a representative model for evaluating the polymer method.

3. RESULTS

This paper presents the sensitivity analysis for the core-scale model, seeking to evaluate the magnitude effect of different values of adsorption, accessible pore volume, residual resistance factor, and polymer concentration on displacement results. We compared each result obtained to the corresponding results obtained for water injection.

We obtained the following results for each case: (1) histories for water cut, cumulative water-oil ratio, average pressure and oil recovery; (2) profiles of water saturation, water viscosity, and water mobility at 11% and 42% of PV; (3) values of the cumulative produced water per cumulative produced oil (Wp/Np), cumulative injected water per cumulative produced oil (Wi/Np), total injected pore volume (Total PV), water and polymer breakthrough times (Bt) and total duration of the injection phase, mass of polymer injected per cumulative produced oil ($(P_{mass})_i/Np$) and recovery factor (RF).

One can notice from the results that the polymer flooding forms two self-sharpening saturation fronts. These fronts correspond to the arrival of water and polymer banks. The injected polymer solution displaces connate water and oil to the producer. Discussions related to these phenomena can be found in [Pope \(1980\)](#), [Sorbie \(1991\)](#), [Al-sofi and Blunt, \(2010\)](#), and [Rios and Moreno \(2014\)](#).

3.1 Adsorption analysis

Here, we present and discuss the effects of ADS on polymer flooding. Figure 6(a) to (d) show that all responses reached, approximately, the same final value for all adsorption levels. Adsorption interferes more in the polymer advance front before its breakthrough. Polymer breakthrough is delayed until the reservoir layer achieves the maximum adsorption level.

From the water cut and the cumulative WOR curves, Figure 6(a) and (b), one can see that the higher the adsorption rate is, the faster the water production will be. This occurs due to the stripping of the polymer from the solution causing a polymer viscosity reduction along the flow. Consequently, the connate water breakthrough is anticipated and the polymer front is delayed.

Figure 6(c) shows that the average pressure history is inversely proportional to the adsorption level until the polymer BT, due to the initial loss of the injected polymer solution viscosity. Before the polymer breakthrough, lower adsorption ensures better maintenance of reservoir pressure. After that, all models examined reach the same pressure level.

After the delayed polymer front (P_{ADS60}) achieves the producer well, all cases reach almost the same oil recovery (Figure 6(d)). The consequence is a delay in oil production, showing the importance of adsorption minimization.

Figure 6(e) to (j) shows profiles for water saturation, water phase viscosity and water phase mobility at 11% of the injected pore volume (before the water breakthrough, 28 min after the injection starts) and at 42% of injected pore volume (before the polymer breakthrough, 99 min after the injection starts).

Polymer adsorption effect tends to remove the polymer molecule from the solution. This phenomenon increases and accelerates the pushed connate water saturation, as evidenced in Figure 6(e). This initial polymer retention in the rock decreases polymer solution viscosity (Figure 6(g)), reducing mobility control (Figure 6(i)).

Figure 6. ADS analysis.

Figure 6. ADS analysis (Cont.)

Table 4 summarizes the quantitative results and shows the values at the stopping time (95% of the water cut).

The higher the adsorption is, the higher the ratio of injected and produced water per oil produced will be. The connate water breakthrough is anticipated, and the polymer front breakthrough is delayed. As a result, the ratio of the mass of polymer used per oil produced increases. The total injected pore volume and the recovery factor were quite similar for the studied cases. [Ferreira \(2019\)](#) reported experimental and field-scale simulation studies regarding retention, and our findings are aligned with those results and with the one found in classical literature, as presented in the introduction of this work.

3.2 Accessible Pore Volume analysis

We evaluate the accessible pore volume (APV) in this section. With the goal of comparing different values of APV, we set the base model (P) at 85%

and the variation range of $\pm 15\%$, 100%, and 70%, respectively.

From the water cut and the cumulative WOR (Figure 7(a) and (b), respectively), one can observe that the smaller the accessible pore volume is, the lower produced water volumes and the faster polymer breakthrough will be. Polymer solution flows only through the accessible portion maintaining the average pressure of the porous media (Figure 7(c)) and anticipating oil production (Figure 7(d)).

Figure 7 (e) to (j) shows water saturation, water phase viscosity, and water phase mobility profiles at 11% and 42% of the total PV injected. It is possible to observe that these parameters were affected slightly by the accessible pore volume, mainly in the polymer advance front.

Table 5 shows the results of APV analysis - 70%, 85% (Base Model) and 100% - for the Wp/Np, Wi/Np, total injected PV, breakthrough and end time, mass of injected polymer per recovered oil, and recovery factor.

Table 4. Results of sensitivity analysis of ADS.

Parameter	P_ADS10	P_Base	P_ADS60
Adsorption ($\mu\text{g/g}$)	10	30	60
Wp/Np	2.038	2.055	2.067
Wi/Np	3.037	3.054	3.067
Total PV	1.185	1.189	1.189
Water Bt [min]	49.76	41.76	39.57
Polymer Bt [min]	83.76	107.76	140.76
End-time [min]	281.87	282.90	282.88
(Pmass)i/Np [kg/m^3]	4.100	4.123	4.140
RF [%]	41.08	41.00	40.83

The responses evaluated were not strongly affected at the end of each simulation. [Lamas et al. \(2016\)](#) studied this parameter in a field-scale model and showed the influence on the economic aspect of a polymer flooding project. Their remarks are aligned with the outcomes observed by our group. The ratio of injected and produced water per produced oil decreases for lower values of APV, which means that one needs to inject and produce less water to recover the mobile oil. The end time and the polymer breakthrough time are delayed as a consequence of higher APV to the polymer flooding.

Figure 7. APV Analysis.

Figure 7. APV Analysis (Cont.)

3.3 Residual Resistance Factor analysis

The sensitivity analysis of the residual resistance factor presents three different values of RRF - 1.0 (no resistance effect), 2.62 (Base Model), and 4.0 (high resistance).

As observed in Figure 8(a) and (b), as RRF increases, water cut delays and cumulative WOR decreases. The higher the average pressure is, the higher the RRF (Figure 8(c)) will be, for a constant flow rate. Figure 8d shows the recovery factor behavior when the RRF changes. Higher values of RRF anticipate oil recovery as well as improve the final recovery factor.

Figure 8(e) to (j) show the profiles of water saturation, water viscosity, and water mobility. As observed, an increase in the RRF delays connate water and polymer advance front leading to viscosity increase and permeability reduction. This mobility reduction suppresses the formation of possible viscous fingers along the porous media, improving the areal sweep. The water-phase mobility stays low for high RRF until polymer breakthrough. Then, it increases after sweeping the reservoir oil efficiently.

The results determined at 95% of the water cut considering three different values of RRF are summarized in Table 6, quantifying the discussed trend.

Analyzing the results, we can observe a positive correlation between RRF and oil recovery. In this case, we can point out a tendency of reduction for both injected and produced water per produced oil. Higher RRF delays the water breakthrough, increasing the average pressure. The results

observed are in accordance with what is stated in the literature (Shi et al., 2010; Zampieri, 2012; Silveira et al., 2018). Observing the plots over distance makes the understanding clearer, accounting for inherent uncertainties under laboratory when performing a core-flooding experiment.

Table 5. Results of sensitivity analysis of APV.

Parameter	P_APV70	P_Base	P_APV100
APV level	70	85	100
Wp/Np	2.034	2.055	2.076
Wi/Np	3.033	3.054	3.076
Total PV	1.181	1.189	1.198
Water Bt [min]	43.86	41.76	40.86
Polymer Bt [min]	94.86	107.76	120.86
End-time [min]	281.00	282.90	284.86
(Pmass)i/Np [kg/m ³]	4.095	4.123	4.153
RF [%]	41.01	41.00	40.99

Table 6. Results of sensitivity analysis of RRF.

Parameter	P_RRF1.0	P_Base	P_RRF4.0
RRF level	1	2.62	4
Wp/Np	2.514	2.055	1.850
Wi/Np	3.514	3.054	2.849
Total PV	1.185	1.189	1.173
Water Bt [min]	39.57	41.76	42.76
Polymer Bt [min]	96.76	107.76	111.76
End-time [min]	281.76	282.90	279.00
(Pmass)i/Np [kg/m ³]	4.744	4.123	3.847
RF [%]	35.49	41.00	43.34

Figure 8. RRF Analysis.

Figure 8. RRF Analysis (Cont.)

3.4 Concentration analysis

Figure 9(a) to (d) shows the sequence of plots for 1000 ppm, for 1250 ppm (P_Base), and 1500 ppm of polymer injection and water injection.

A direct consequence of the increase in polymer injection concentration is the increase in solution viscosity. The higher viscosity of the injected fluid improves displacement efficiency since mobility

ratio is reduced. We can note the benefits of higher polymer concentrations in Figure 9 (a) and (b), which shows the reduced water production over time. Figure 9(c) shows that the higher the polymer concentration is, the higher the average pressure in the reservoir will be. High pressures may fracture the rock when reaching its critical values (rupture pressure). The recovery factor improved as the polymer concentration increased Figure 9d).

Figure 9. CCP Analysis.

Figure 9. CCP analysis (Cont.)

Additionally, higher CCP leads to a delay in connate water front, and an acceleration of polymer BT (Figure 9(e) and (f)). One can see that water mobility is reduced (Figure 9(i) and (j)) as viscosity increases (Figure 9g and h). Polymer concentration remarks agree with the polymer applications addressed in the introduction section. The present analysis can assist in producing data of history matching or in forecasting two-phase polymer-flooding lab tests, due to the importance of compression of water and polymer bank displacement and dispersion into porous media.

Table 7 summarizes polymer flooding trends of all three models with different polymer solution

concentrations injected.

For higher values of CCP, quantitative advantages, such as the improved oil recovery and the delayed water breakthrough time, can be seen in Table 6. However, we observe an increase in the polymer mass used in the oil recovery (Polymer mass) i/N_p .

Since high polymer concentrations can be costly, it is essential to observe the limit of the injected solution. Depending on the oil and polymer prices, it may not be economically attractive to inject concentrated polymer solutions.

Table 7. Results of sensitivity analysis of CCP.

Parameter	P_CCP1000	P_Base	P_CCP1500
CCP	1000	1250	1500
Wp/Np	2.130	2.055	1.975
Wi/Np	3.130	3.054	2.974
Total PV	1.189	1.189	1.181
Water Bt [min]	40.66	41.76	43.76
Polymer Bt [min]	115.72	107.76	105.72
End-time [min]	282.84	282.90	280.84
(Pmass)i/Np [kg/m ³]	3.380	4.123	4.818
RF [%]	40.00	41.00	41.79

4. CONCLUSIONS

The results presented in this work allow us to understand the effects of rock-fluid interaction. Since oil recovery mechanisms and many aspects of the polymer solution flow in porous media are yet to be understood, this may raise challenging technical issues.

Sensitivity analysis results show that the adsorption does not change the final results. However, before the polymer breakthrough, an increase in the amount of adsorption level strips polymer from the advance front. As a consequence, water production increases, and the polymer breakthrough delays, thus, retarding oil recovery. The average pressure is low for high levels of adsorption.

It is noteworthy that, in a field project, a high concentration of polymer solution is not guaranteed or may also not inject a large pore volume of the polymer solution. In such cases, adsorption becomes the dominant factor that may decide the economics of a polymer flooding project.

The accessible pore volume proved to have a low impact on the observed responses. We observed the differences among models' results before polymer breakthrough. Low values of accessible pore volume lead to low cumulative water-oil ratio, fast polymer breakthrough, and oil recovery anticipation. Also, the average pressure is higher. In all models, after the polymer front achieves the producer well, the results tend to stabilize at the same level for different values of accessible pore volume.

The residual Resistance Factor plays an important role in oil recovery by polymer flooding. High Residual Resistance Factor values correspond to low water cut and reduced cumulative WOR. Moreover, higher levels of Residual Resistance Factor contribute to high average pressure, anticipating the oil recovery and improving the final recovery factor.

An increase in the polymer injection concentration will increase the solution's viscosity. Higher injection fluid viscosity promotes a better displacement efficiency since the mobility ratio is reduced. Consequently, less injected water is necessary to produce oil and less water is produced over the time. Therefore, oil recovery is anticipated, and recovery factor is improved. The higher the polymer concentration is, the higher the average pressure in the reservoir will be.

ACKNOWLEDGMENTS

The authors would like to thank Computer Modeling Group (CMG), Brazilian National Agency of Petroleum Natural Gas and Biofuels (ANP), Equinor, and CAPES for supporting this research.

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