Numerical Modeling of Reservoir Rock Treatment Processes with Polyacrylamide

Mihaela Helstern[1], Doru Stoianovici[2], Timur Chis[3]

[1]Ph.D. Department, Oil-Gas University, Ploiesti, Romania
[2]Geological and Petroleum Engineering Department, Oil-Gas University, Ploiesti, Romania
[3]Oil and Gas Engineering Department, Oil-Gas University, Ploiesti, Romania

ABSTRACT: Increasing the quantities of crude oil extracted from depleted deposits can be achieved using tertiary exploitation methods, namely water injection and polyacrylamide plugs. The adsorption on the surface of the rocks determined the reduction of the mobility of the polymer but also the modification of the gel structure by the modification (crossing) of the polymer (of the polymer chains), which led to clogging (blocking of the pores) and increasing the possibility of fluid flow. Polyacrylamide as a polymer to improve the final recovery factor aims to achieve a good flow of crude oil. In this article, the equations of polymer flow through sands and limestones have been established.

KEYWORDS: poliacrilamides, oil and gas, modelling

I. INTRODUCTION

Increasing the quantities of crude oil extracted from depleted deposits can be achieved using tertiary exploitation methods, namely water injection and polyacrylamide plugs. The adsorption on the surface of the rocks determined the reduction of the mobility of the polymer but also the modification of the gel structure by the modification (crossing) of the polymer (of the polymer chains), which led to clogging (blocking of the pores) and increasing the possibility of fluid flow.

Polyacrylamide as a polymer to improve the final recovery factor aims to achieve a good flow of crude oil. In this article, the equations of polymer flow through sands and limestones have been established.

EOR (Enhanced Oil Recovery) methods refer to the recovery of crude oil using fluid injection and supplementing the reservoir energy with energy resources not present in the reservoir rock.

In Romania, as well as in other countries, there is a relatively large number of deposits located at shallow depths, below 1000 m, containing crude oils with high viscosity (over 1000 cP) and high density (over 900 kg/m^3), the so-called crude oils heavy, whose exploitation based on their energy is inefficient due to the reduced mobility of crude oil, resulting in recovery factors of the order of a few percent.

Due to the reduced mobility, the recovery of heavy crude oils by conventional methods is low, and in this case, we can increase the mobility through water injection.

However, water injection is usually not effective in heavy oil fields.

Water drainage has a very low recovery efficiency, and the water content of the produced fluid becomes very high, up to 90 - 99%.

The main impediment in recovering heavy crude oil is its high viscosity.

Thus, any reduction in crude oil viscosity will increase its mobility, increasing the recovery factor.

Washing with polymer solutions is a mature enhanced recovery (EOR) method that has been applied on the construction site since the 1950s. Today, the specialized literature contains a large volume of information and experience data related to the implementation of this technology, including logistics, design, reservoir properties, monitoring, and supervision.

Based on the data in the specialized literature, qualitative information, and statistics were obtained regarding the differences between the projects classified as technically successful and the cases reported as unsuccessful.

The experience gained so far can be used to plan and implement future projects involving the use of polymers.

The injection of polymer solutions is a chemical method of increasing the recovery factor; it is a well-known method (widely applied worldwide for more than half a century) with low risks and applicability for a wide range of deposit existence conditions.

It is known from practice that when water is injected into a deposit, it follows the path of minimum resistance to flow (through areas with higher permeability) toward the location of the production wells, where the pressure is lower.

If the crude oil in the reservoir has a higher viscosity than the injection water, the water will bypass it.

The result will be a low efficiency of washing the deposit and a reduced recovery.

The purpose of polymer injection is to improve the efficiency of reservoir flooding and to decrease the ratio of water-crude mobilities, with the ultimate goal of a sub-unit ratio of water-crude mobilities, at most unitary, corresponding to a piston-type displacement.

The method consists of dissolving the polymer in the injection water to increase its viscosity and improve fluid flow efficiency in the hydrocarbon reservoir.

Injection of polymer solutions can significantly increase crude oil production in the recovery process compared to conventional water injection techniques.

Secondary mining is when the mined mineral substance goes through a mining process a second time.

It does not refer to mineral substances found in deposits in the natural state in which they were formed but to waste mineral substances in anthropogenic or exploited portions of the deposits.

In rare situations, there may even be tertiary exploitations, in which the mineral substance undergoes the exploitation process a third time.

Exploitation is mixed when part of the mineral substance is exploited primarily, i.e., from the deposit, and another part is secondary (or maybe even tertiary), i.e., from deposits of mineral and energy substances resulting from an exploitation activity before the current exploitation.

Supplementing the existing energy in the field is necessary to extract as much crude oil as possible and shorten the exploitation time.

The moment when the addition of deposit energy begins represents the beginning of secondary exploitation, which can be:

- in the initial phase of exploitation, to maintain the pressure at a value close to the boiling pressure or at a value between 25%-30% lower or only to mitigate the decline of the deposit pressure,

- after a short time of operation, when the pressure has decreased, for example, by 30% compared to the initial pressure to restore the reservoir pressure, close to the initial pressure,

- After a longer time of exploitation, when the reservoir pressure has dropped a lot, the crude oil remaining in the pores must be washed or dislodged by adding additional energy from the outside.

II. MATHEMATICAL MODELING

Polymer injection is considered one of the chemical techniques for enhancing the recovery of crude oil in many fields, especially in heavy crude oil fields, due to its low cost.

As a stabilizing process, polymer injection increases water viscosity, effectively reducing the phenomenon of preferential displacement of polymer. This, in turn, leads to a significant increase in crude oil mobilization.

To combat the phenomenon of preferential displacement of the polymer, measures are taken to improve its uniform distribution and ensure that it covers the entire area of the deposit.

Figure 1 shows the polymer injection performance schematically.

Reducing the viscosity of the fingering, specifically the formed grooves leads to improved flow efficiency, a higher volume of crude oil, and, consequently, a dramatically reduced required volume of injected water and produced water.

Furthermore, the polymer is administered to close the channels the water creates in the high permeability layers and the water coming phenomenon in the borehole aquifers.

To avoid the problem of water or injected polymer mobilization in the high permeability zone, a weak gel with high resistance to fluid flow is added to the polymer for deep reservoirs, and therefore, the water flow paths or drainage problems would be controlled or blocked.

In other words, the mechanism of disproportionate permeability reduction (DPR) is considered to be reducing water permeability. On the other hand, the viscoelastic behavior of polymers is another mechanism for using polymers instead of other chemical processes.

This problem is related to the higher interfacial viscosity between crude oil and polymer than between water and crude oil. The value of shear stress is proportional to the interfacial viscosity, and subsequently, the polymer exerts a greater pulling force on the crude oil droplets, which helps push crude oil out of dead-end pores.
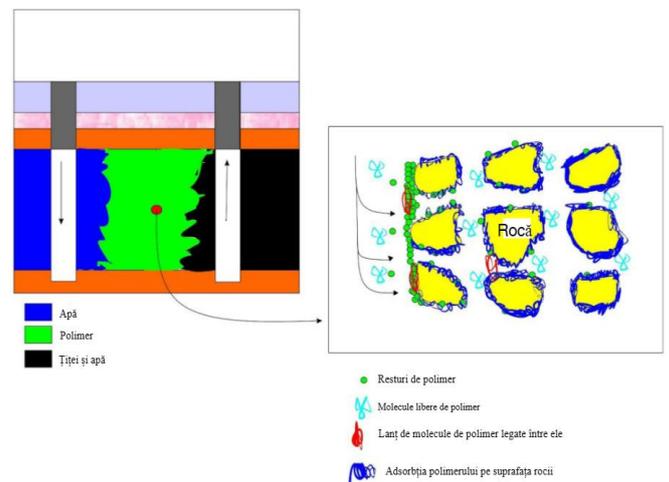
Fig. 1. Schematic representation of polymer injection performance [1]

Therefore, the rate of crude oil recovery during polymer injection (treatment) depends on the rate of polymer injection, and it should be taken into account that the economic success of polymer injection (crude oil recovery)

procedures has played a significant role in implementing this technique.

The booming economic performance of polymer flooding (injection) depends on polymer concentration, additives, and reservoir characteristics.

Liu, Tang, and Zhao [2] analytically modeled different types of rheology, such as viscoelasticity, flow law, and Newtonian rheology, to consider the profound impact of the rheology parameter on polymer injection performance.

The polymer was assumed to be a single aqueous phase, considering that no crude oil banks are formed during polymer flooding performances.

To calculate the saturation fronts by assuming segregation flow (polymer-oil fluid), AlSofi and Bluntau proposed an analytical model to simulate polymer flooding (injection) performance without considering polymer concentrations.

Based on Koval's theory, Jain and Lake [3] we proposed an analytical model to calculate the flushing efficiency in a stratified reservoir. In this theory, the polymer-crude flow was assumed to be segregated under vertical equilibrium conditions.

Seright [4] proposed a case study model to determine the optimum viscosity volume of polymer injected into layered reservoirs.

Moreover, the injection flow, which crossed between the layers and had different characteristics regarding the injection of the polymer solution, was modeled analytically.

Hall plotted the performance of injection probes in water and polymer wash processes.

Hall (1963) initially created a diagram to evaluate the steady-state flow of polymers as a single phase (radial flow) for a Newtonian fluid.

Since then, due to the widespread use of polymer flushing procedures in operational performance, the Hall diagram has been applied to investigate the performance of similar injections of polymer with water into the reservoir.

To verify the validity of this mathematical model, Buell, Kazemi, and Poettmann [5] proposed a numerical solution that uses these characteristics to be more adapted to realistic situations; these assumptions include two-phase flow in the presence of water and crude oil, slightly compressible flow, non-Newtonian rheological properties, retention/adsorption with reduced permeability, and single permeability.

However, numerous studies are widely reported to consider the profound influence of polymer washing performance.

In this subsection, we propose a mathematical model to evaluate the cross-flow effect and the saturation distribution in the pressure integral and compare it with simulated field data.

The pressure integral gives us a measure of the total pressure exerted on a fluid in a reservoir.

In the case of polymer flooding (injection), this is used to evaluate process efficiency and compare performance with simulated field data.

Calculating this pressure integral allows us to understand how the pressure is distributed in the reservoir and how it changes under different operating conditions.

It is an essential tool to optimize the polymer flooding process and ensure efficient crude oil recovery.

The results of these data clearly show that the developed model agrees with the simulated field data compared to the previous models.

In addition, the model considered some geological problems, such as high permeability channeling and segregated flow problems with preferential direction, to calculate the pressure integral.

III. MODELLING EQUATION

The proposed mathematical model of the Hall diagram and developed in this paper has the following equation:

$$\int \left(p_{wf} - p_e\right) dt = \frac{142,2 B_w \mu_w \left[\ln \frac{r_e}{r_w} + s\right]}{k_{rw} k h} W_i \qquad (1),$$

in which

p_e represents the formation pressure at the interface between the original reservoir fluid and the injected fluid, in Pa;

p_{wf} is the injection pressure in the well, in Pa;

k_{rw} is the relative permeability of water, as a fraction;

k is the absolute permeability, in m^2;

h is the formation thickness, in m;

B_w is the formation volume factor for water, as a fraction;

μ_w is the viscosity of water, in Pa* s;

r_e is the external drainage radius, in m;

r_w is the probe radius, in m;

s is the dimensionless skin factor;

W_i is the cumulative injection, in m^3.

When the wellbore injection pressure p_wf cannot be measured, the wellbore pressure that is measured by the surface equipment (p_tf) is used to propose the Hall model. The Hall diagram is therefore a graphical representation of the relationship between the applied magnetic field and the electrical voltage generated in a semiconductor material or metal.

It is used to study the electrical and magnetic properties of materials, as well as to identify their specific characteristics.

The basic principle of the Hall diagram is based on the Hall effect, which occurs when an electric current passes through a conductor placed in a magnetic field perpendicular to the direction of the current.

When the wellbore injection pressure p_{wf} annot be measured, the wellbore pressure that is measured by the surface equipment (p_{tf} is used to propose the Hall model.

The Hall diagram is therefore a graphical representation of the relationship between the applied magnetic field and the electrical voltage generated in a semiconductor material or metal.

It is used to study the electrical and magnetic properties of materials, as well as to identify their specific characteristics.

The basic principle of the Hall diagram is based on the Hall effect, which occurs when an electric current passes through a conductor placed in a magnetic field perpendicular to the direction of the current.

This effect causes a lateral electrical voltage, known as the Hall voltage, which is proportional to the strength of the magnetic field and the current density.

Thus we can state the following relationship to calculate borehole pressure measured with surface equipment:

$$\int (p_{tf}) \, dt = \frac{142,2 B_w \mu_w \left[\ln\frac{r_e}{r_w}+s\right]}{k_{rw}kh} W_i + \int \left[p_e + \Delta p_f - \rho g D\right] dt$$
(2)

in which:

D represents the depth of the deposit, in m;

ρ is the density, in kg/m^3 ;

g is the gravitational acceleration, in m/s^2.

After plotting the pressure differences at the probe head as a function of the injected volume, the pressure dropped slightly, and subsequently, the slope of the Hall plot is measured according to equation (3), which was derived from equations (1) and (2) :

$$m_H = \frac{142,2 B_w \mu_w \left[\ln\frac{r_e}{r_w}+s\right]}{k_{rw}kh}$$
(3)

Therefore, the principle of using the Hall diagram is represented by cumulative pressure versus cumulative water injection.

As can be seen in Graph 3, in the first stage of the injectivity performances, the radius of the water zone would increase with the passage of time, which schematically indicates in the ab segment.

Segment bA shows the stable injection pattern as the gas fills, and if it deviated from the straight line, it would indicate that the formation is plugged or the water phase is of poor quality in segment bD.

As shown in line B, this decrease would be caused by injection processes performed above the separation pressure and negative skin.

The out-of-zone injection performances or possible channels are indicated schematically in segment bC.
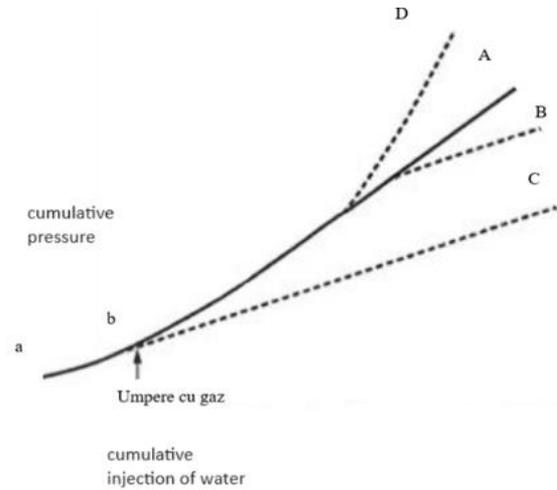
Fig.2 Diagrame Hall using

Since equation (3) is a little difficult to evaluate the injectivity performance of the polymer due to the presence of three-phase banks in the reservoir, Buell, Kazemi and Poettmann illustrated the new Hall plot by considering new assumptions regarding non-Newtonian fluids and polymer occurrence, crude oil and reservoir water.

This is derived as equation (4) to better fit polymer flooding circumstances

$$m_H = 141,2 \left\{ \begin{array}{l} \frac{B_w \mu_w \left[\ln\frac{r_{b_1}}{r_w}+s\right]}{k_{rw}k_a h} \ water \\ \frac{B_w \mu_p \left[\ln\frac{r_{b_1}}{r_{b_2}}\right]}{k_{rw}k_a h} \ polymer \\ \frac{B_t \mu_t \left[\ln\frac{r_e}{r_{b_1}}\right]}{k_{rt}kh} \ oil \end{array} \right\} (4)$$

R_f is called the permeability reduction factor, being a unitless quantity and at the same time, R_{rf} represents the residual permeability reduction factor, R_f is influenced by polymer adsorption, which leads to the reduction of rock permeability during the flow of the polymer solution in compared to water permeability.

Equation (5) defines R_f as the mobility of water prior to polymer flooding divided by the mobility of the polymer solution.

$$R_f = \frac{(kk_{rw})/\mu_w}{(k_t k_{rp})/\mu_p}$$
(5)

Due to the reduction in permeability of the polymer solution in the case of post-polymer waterflooding performances, the permeability reduction is defined as the residual permeability reduction factore R_{rf}.

Where:

$$R_{rf} = \frac{k}{k_q}$$
(6)

After rewriting Equation (4) taking into account Equations (5) and (6), it is defined as Equation 7 where r_b represents the radius of the injected fluid solution, m, which was estimated from the Buckley–Leverett equation in radial coordinates and

where f_w represents the fractional flow of water, unitless, S_w is the water saturation, unitless and k_a is the permeability value after polymer flooding, in m², $\left(\frac{\partial f_w}{\partial S_w}\right)$ is estimated from fractional flow curve.

$$m_H = 141{,}2 \begin{cases} \frac{R_{rf}B_w\mu_w\left[\ln\frac{r_{b_1}}{r_w}+s\right]}{k_{rw}kh} \ water \\ \frac{R_f B_w \mu_p\left[\ln\frac{r_{b_1}}{r_{b_2}}\right]}{k_{rw}kh} \ polymer \\ \frac{B_t\mu_t\left[\ln\frac{r_e}{r_{b_1}}\right]}{k_{rt}kh} \ oil \end{cases} \quad (7),$$

$$r_b^2 = \frac{W_i}{\pi\Phi h}\left(\frac{\partial f_w}{\partial S_w}\right)_f + r_w^2 \quad (8),$$

The change in permeability in the vertical axis is one of the significant parameters for the recovery of polymer flooding performance.

Polymer solutions will conveniently mobilize to areas of high permeability, leading to an early breakdown of the aqueous phase.

To provide the Hall plot model for the cross-flow section, the following assumptions are used in the mathematical model: steady-state flow according to Darcy's law, slightly compressible two-dimensional radial flow, heterogeneous reservoir, residual crude remains in the displacement front, and relative permeability remains constant on all layers.

According to El-Khatib's model [6], the apparent permeability, apparent porosity, saturation differences and total accumulated hydrocarbon pore volume are mathematically estimated for different layers, according to equations (1)–(6), and must be calculated before the performances of polymer flooding.

$$k_1^- = \frac{k_1\Delta V_{p1}+\cdots+k_n\Delta V_{pn}}{\overline{\Delta V_p}} \quad (9),$$

where ΔV_p is the total volume of accumulated hydrocarbon pores

$$\overline{\Delta V_{p1}} = \Delta V_{p1} + \cdots + \Delta V_n \quad (10)$$

$$\overline{\phi_1} = \frac{\phi_1\Delta V_{p1}+\cdots+\phi_n\Delta V_{pn}}{\overline{\Delta V_p}} \quad (11)$$

$$\overline{S_1} = \frac{\phi_1\Delta S_1\Delta V_{p1}+\cdots+\phi_n\Delta S_n\Delta V_{pn}}{\phi_1\Delta V_{p1}+\cdots+\phi_n\Delta V_{pn}} \quad (12)$$

Thus the permeability reduction was calculated as the flow equation:

$$k_{\overline{d1}} = \frac{k_{\overline{1}}}{\overline{\phi_1}\Delta S_1}\overline{\phi}\overline{\Delta S} \quad (13)$$

To define the cross-flow performance in real-time injectivity, $k_{\overline{d1}}$ is replaced by k in equation (11), resulting in the following equation 12.

However, the effective permeability of single-phase fluid flow in the reservoir does not change as a function of the constant value of fluid saturation. In multiphase flow (especially the polymer solution, which was considered in this example), the effective permeability changes due to the change in saturation.

To develop the saturation profile, the Buckley-Leverett displacement theory under immiscible flow conditions is used.

According to the investigations of Buell, Kazemi and Poettmann, it was assumed that the saturation factor is constant for each injectivity bank.

Thus, the saturation profile consists of three different areas:

a. two-phase immiscible flow (crude oil and water)

b. two-phase immiscible flow between crude oil and polymer.

c. displacement of crude oil by the water phase.

The saturation change profile for the water and polymer solutions and the fractional flow curves for the polymer-crude and water-crude system are defined by the following equation:

$$m_H = \frac{141{,}2}{k_{\overline{d1}}h_t} \begin{cases} \frac{R_{rf}B_w\mu_w\left[\ln\frac{r_{b_2}}{r_w}+s\right]}{k_{rw}} \ water \\ \frac{R_f B_w \mu_w\left[\ln\frac{r_{b_1}}{r_{b_2}}\right]}{k_{rw}} \ polymer \\ \frac{B_t\mu_t\left[\ln\frac{r_e}{r_{b_1}}\right]}{k_{rt}} \ oil \end{cases} \quad (14).$$

$$\left(\frac{dx}{dt}\right)_{S=constant} = v\frac{df}{dS} \quad (15)$$

$$f_w = \frac{1}{1+\frac{k_{rtw}\mu_w}{k_{rw}}\frac{\mu_w}{\mu_t}} \quad (16)$$

$$f_p = \frac{1}{1+\frac{k_{rtp}\mu_p}{k_{rp}}\frac{\mu_p}{\mu_t}} \quad (17)$$

where, k_{rtw} is the relative permeability to crude oil in the water-crude oil system and k_{rtp} is the relative permeability to crude oil in the polymer-crude oil system.

In terms of the polymer and water fractional flow curves, the polymer saturation velocity and the water saturation velocity at the polymer front are equal and are defined by the relation:

$$\left(\frac{df_w}{dS_w}\right)_{S_w=\overline{S_w}=1-S_{tr}} = \left(\frac{df_p}{dS_p}\right)_{S_p=S_{wp}} \quad (18)$$

Regarding the influence of the crude oil flow on the polymer resistance in the flow of the polymer bank, in terms of the polymer bank, the displacement of the crude oil flow is considered in Equation (18).

As a result, the polymer bank is divided into crude oil and polymer solution.

Equation (18) was derived by considering both the effects of the saturation profile and the effect of transverse flow in heterogeneous deposits.

$$m_H =$$

$$\frac{141,2}{k_{\overline{d1}} h_t} \left\{ \begin{array}{l} \dfrac{R_{rf} B_w \mu_w \left[\ln\frac{r_{b_2}}{r_w}+s\right]}{k_{rw}(1-S_{tr})} + \dfrac{B_t \mu_t \left[\ln\frac{r_{b_2}}{r_w}\right]}{k_{rt}(1-S_{tr})} \ banc\ de\ ap\check{a} \\[3mm] \dfrac{R_f B_w \mu_w \left[\ln\frac{r_{b_1}}{r_{b_2}}\right]}{k_{rw} S_{wp}} + \dfrac{B_t \mu_t \left[\ln\frac{r_{b_2}}{r_2}\right]}{k_{rt} S_{wp}} \ banc\ polimer \\[3mm] \dfrac{B_w \mu_w \left[\ln\frac{r_e}{r_{b_1}}\right]}{k_{rw} \overline{S_w}} + \dfrac{B_t \mu_t \left[\ln\frac{r_e}{r_{b_1}}\right]}{k_{rt} \overline{S_w}} \ banc\ \c{t}i\c{t}ei \end{array} \right\} \quad (19).$$

IV. EXPERIMENT ANALYSIS

In the first experiment we analyzed the effect of the filtration factor (considered to be the ratio between the time for a given volume of polymer solution to flow in a porous medium versus of the flow time of the same polymer in a normal (Engler) viscometer.

For a 500 ppm solution of partially hydrolyzed polyacrylamide in 3% NaCl salt water, a linear variation of resistance factor versus filtration factor is observed.

Thus, the time differential equation for a siliceous sandstone type structure (over 30% silicon) is of the form:

$$\frac{\partial y}{\partial t} = 0{,}5549 \frac{\partial x}{\partial t} + 2{,}3476$$

Where:
- x is the filter coefficient,
- y is the resistance factor.

Table 1. Values of the filtration factor as a function of the resistance factor (determined on a siliceous sandstone with a permeability of 250 mD and through which a partially hydrolyzed polyacrylamide with a concentration of 500 ppm and a solution of 3% salt water (NaCl) passed

Number determination	Filtration factor	Resistance factor
1	5	5
2	10	8
3	20	14
4	30	18
5	40	25
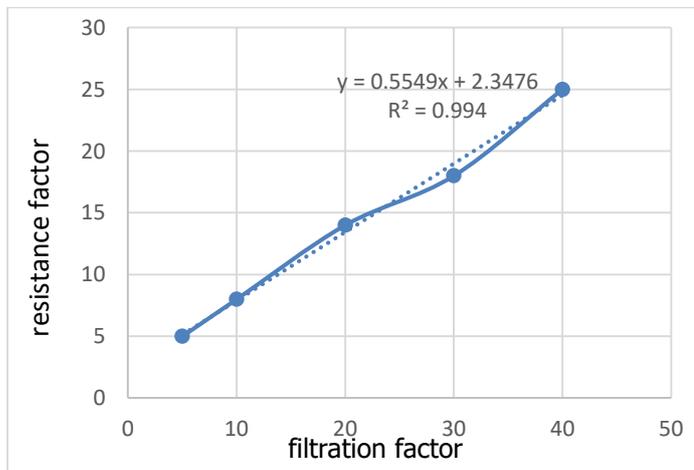
Fig 3. The resistance factor as a function of the filtering factor

Measurements in the laboratory showed us that the partially hydrolyzed polyacrylamide has molecules with a maximum size of 1 μm and that the effect of salt concentration is what gives us different viscosity values, the reduction in mobility and permeability obtained in the porous medium being given by the increase in molecular weight of the solubilized polymer.

In the second experiment we analyzed the variation of the resistance factor R as a function of the saturation in the intestinal water, the viscosity of the crude oil (cP), the average permeability of the analyzed rocks mD, the porosity, the concentration of polymer ppm and the size of the polymer plug (% of the porous volume), for various rocks.

The numerical model created to model the flow of partially hydrolyzed polyacrylamide polymer in limestone consists of the equations 20-29.

Table 2. Behavior of partially hydrolyzed polyacrylamide in limestone deposits

Rocks analysis	Resistance factor (R)	Internal water saturation, (s)	viscosity, cP, (μ)
limestone	4	0,23	0,007
limestone	5,6	0,27	1,8
limestone	12,7	0,46	2,6

Rocks analysis	Permeability, (k) mD	porosity ($\emptyset$)	Polymer concentration, ppm,	polymer leght, % whith porous rocks (c)
limestone	50	0,17	250	78
limestone	21	0,17	250	20
limestone	20	0,2	250	28

$$\frac{\partial R}{\partial t} = 0{,}0265 \frac{\partial \mu}{\partial t} + 0{,}1228 \qquad (20)$$

$$\frac{\partial R}{\partial t} = 2{,}0081 \ln\left(\frac{\partial s}{\partial t}\right) - 2{,}3134 \qquad (21)$$

$$\frac{\partial R}{\partial t} = 2{,}0671 \left(\frac{\partial k}{\partial t}\right)^2 - 37{,}97 \frac{\partial k}{\partial t} + 168{,}8 \qquad (22)$$

$$\frac{\partial R}{\partial t} = 0{,}028 \ln\left(\frac{\partial \emptyset}{\partial t}\right) + 0{,}1273 \qquad (23)$$

$$\frac{\partial R}{\partial t} = 4{,}2962 \left(\frac{\partial c}{\partial t}\right)^2 - 77{,}493 \frac{\partial c}{\partial t} + 319{,}23 \quad (24)$$

The numerical model created for modeling the flow of partially hydrolyzed polyacrylamide polymer in sands consists of the equations:

$$\frac{\partial R}{\partial t} = 0{,}0057 \left(\frac{\partial \mu}{\partial t}\right)^6 + 0{,}3188 \left(\frac{\partial \mu}{\partial t}\right)^5 - 7{,}3169 \left(\frac{\partial \mu}{\partial t}\right)^4 + 88{,}181 \left(\frac{\partial \mu}{\partial t}\right)^3 - 589{,}032 \left(\frac{\partial \mu}{\partial t}\right)^2 + 2069{,}6 \frac{\partial \mu}{\partial t} - 2990{,}5 \qquad (25)$$

$$\frac{\partial R}{\partial t} = -1{,}2518 \left(\frac{\partial s}{\partial t}\right)^6 + 69{,}109 \left(\frac{\partial s}{\partial t}\right)^5 - 1561{,}3 \left(\frac{\partial s}{\partial t}\right)^4 + 18488 \left(\frac{\partial s}{\partial t}\right)^3 - 121126 \left(\frac{\partial s}{\partial t}\right)^2 + 416742 \frac{\partial s}{\partial t} - 588928 \quad (26)$$

$$\frac{\partial R}{\partial t} = 10{,}313\left(\frac{\partial k}{\partial t}\right)^5 - 480{,}04\left(\frac{\partial k}{\partial t}\right)^4 + 8692{,}6\left(\frac{\partial k}{\partial t}\right)^3 - 76537\left(\frac{\partial k}{\partial t}\right)^2 + 328477x \frac{\partial k}{\partial t} - 551353 \quad (27)$$

$$\frac{\partial R}{\partial t} = 0{,}2711 ln \frac{\partial \emptyset}{\partial t} - 0{,}3264 \quad (28)$$

$$\frac{\partial R}{\partial t} = -0{,}2823\left(\frac{\partial c}{\partial t}\right)^2 + 8{,}0204 \frac{\partial c}{\partial t} - 26{,}167 \quad (29)$$

where: p, μ, S, k și $\emptyset$ are the pressure, viscosity, saturation, permeability and porosity of the porous medium.

Table 3. Behavior of partially hydrolyzed polyacrylamide in sands deposits

Rocks analysis	Resistance factor (R)	Internal water saturation, (s)	viscosity, cP, (μ)
Sands	6,3	0,1	5,3
Sands	6,4	0,23	9
Sands	6,5	0,24	16
Sands	7,4	0,25	23,5
Sands	7,5	0,26	31,4
Sands	7,8	0,27	40
Sands	8	0,31	62
Sands	8,1	0,36	76
Sands	8,5	0,38	77
Sands	12	0,39	78
Sands	13,7	0,47	126

Rocks analysis	Permeability, (k) mD	porosity ($\emptyset$)	Polymer concentration, ppm,	polymer leght, % whith porous rocks (c)
Sands	27	0,14	250	11
Sands	38	0,18	250	14
Sands	41	0,19	250	15
Sands	70	0,2	250	16
Sands	150	0,21	250	17
Sands	196	0,22	250	19,8
Sands	300	0,24	250	20
Sands	750	0,28	310	22,5
Sands	1030	0,29	450	24,5
Sands	2178	0,34	500	25
Sands	2300	0,37	500	33

CONCLUSIONS

In this paper we describted:

a. the choice of a numerical model is a function of the retention of the polymer in the pores of the rocks and the resistance factor,

b. it is observed that at a resistance factor of more than 6 we have the best behavior data of the polymer solution in the deposit,

c. a water plug and then a polymer plug are usually injected,

d. site conditions cannot be simulated in the laboratory, therefore it is accepted that the ratio between the injectivity of water and the water solution with polymers is equivalent to its resistance factor.

REFERENCES

1. Lotfollahi, M., et al., 2016. Mechanistic simulation of polymer injectivity in field tests. SPE J. 21, 1, 178-171, 191.
2. Liu, P., Tang, J., Li, N., Zhao, L., 2014. Research and application of a novel polymer plugging removal agent. Electron. J. Geotech. Eng. 19, 9543–9552.
3. AlSofi, A.M., Blunt, M.J., 2013. Control of numerical dispersion in streamline-based simulations of augmented waterflooding. SPE J. 18, 1, 102-101,111.
4. 1 Jain, L., Lake, L.W., 2014. Surveillance of secondary and tertiary floods: Application of Koval's theory to isothermal enhanced oil recovery displacement. In: SPE Improved Oil Recovery Symposium. Society of Petroleum Engineers.
5. Buell, R., Kazemi, H., Poettmann, F., 1990. Analyzing injectivity of polymer solutions with the Hall plot. SPE Reserv. Eng. 5, 41–46.
6. El-Khatib, N., 1985. The effect of crossflow on waterflooding of stratified reservoirs (includes associated papers 4490 and 14692 and 15043 and 15191). Soc. Petrol. Eng. J. 25 (02), 291–302.