SIMULATION OF POLYMER FLOODING CONSIDERING SIZE MODEL INCREASE AND ECONOMICAL EVALUATION

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Abstract. *The water flooding is widely used because it is relatively simple and inexpensive. However, this method presents some disadvantages. Since water is usually less viscous than the oil, the water tends to arrive soon and in large quantities at the producer well, resulting in a low oil production due to the low swept efficiency. These conditions motivate the use of advanced recovery methods, and among them, polymer injection stands out. In this paper, the oil recovery by water injection alternated with polymer slug (WAP) is compared with continuous water flooding (WF). Variations on slug size, injection starting time of the polymer slug, relative permeability curves, polymer viscosity and mobile oil saturation were evaluated. Subsequently, the model was submitted to a size increase, and these results were used in economic analysis based on the net present value (NPV). The information obtained helps to understand how the oil recovery factor is influenced by changes in flooding conditions. The upsizing process doesn't present distortions when comparing different scale models. The differences in oil recovery factor and water-oil ratio were lower than 0.2%. The integration of EOR results and oil prices encourage the project viability analysis.*

Keywords: *Polymer Flooding, Oil Recovery, Simulation, Upsizing, Economic Analysis*

1 INTRODUCTION

Continuous water flooding recovery method has some disadvantages because, the greater is the difference between water and oil viscosity, water tends to arrive sooner and in large quantities in the producer wells. Polymer flooding can minimize these problems, since the polymer increases the viscosity of the water and decreases its mobility.

The first studies aiming to understand dynamic reservoir behavior are performed using laboratory models and analytical calculations. But, the advance of computer technology aligned with the development on numerical methods for solving differential equations improved the ability to solve large sets of equations describing the flow behavior (Aluhwal, 2008). Nowadays, simulators have been frequently used to predict and optimize exploitation strategies focusing on maximizing oil recovery and profit.

Studies of reservoir models at field scale needs to be preceded by an analysis in laboratory scale among another source of data information. In this sense, a comparison between different scales studies is useful to check transfer of information between models. The scale-up when it is well represented not adversely affects the results or changes the parameters behavior relative to other scale studies.

Scaling is a procedure to extrapolate the results obtained from one scale to another, usually from a small-scale laboratory observation to a large-scale process. Historical developments in the field of fluid mechanics and dynamics point to dimensionless numbers as a mean of comparison. Two succinct and apparently different methods for obtaining dimensionless numbers can be found in the general fluid flow literature (Novakovic, 2002).

Usually, a scaling process involves extrapolation from a limited amount of data to cover the global behavior. Upscaling deals with abundant data within a frame being upscaled and averages all the values within that frame to a set of representative flow parameters. This way the number of grid blocks in a model is reduced by this reduction in horizontal and vertical resolution (Novakovic, 2002).

There are two levels of upscaling. The first level of upscaling is converting a small set of laboratory measurements that needs to be interpreted at the scale of the reservoir. The laboratory measurement on core samples, perhaps a few centimeters in length and diameter, should be scaled up to geophysical cells of several meters. Another upscaling type refers to scale up the fine geological grid to the simulation grid (Islam et al., 2010).

The basic motivation behind these upscaling regimes is to create simulation models that produce flow scenarios closely correspondent to those obtained by running simulations directly on the geological models (Aarnes et al., 2007).

Aiming to classify the exploitation portfolio, simulation studies are complemented by the economic analysis.

2 ECONOMIC ANALYSIS

The implementation of oil field exploitation projects depends on the expected economic performance of each reservoir.

Many uncertainties can influence the success of exploration and production projects. The most common are related to geological aspects, recovery factor, economic variables, technological and political situation (Costa et al., 2004).

Points of uncertainty, such as fluid and rock reservoir characteristics, taxation and oil industry regulations, impact the final decision of investing or wait for a best chance in the future (Neves et al., 2004).

In situations where levels of uncertainty in oil production projects are prevailing, different economic indicators can be used to help decision making. The combination of indicators gives to the company forecasts about the economic impact, and the most sensitive variables (Neves et al., 2004).

The economic evaluation of oil projects is made through the discounted cash flow, using economic indicators among which the net present value (NPV). NPV is defined as the sum of the amounts of incoming and outgoing cash flows, discounted at a rate of return and to a certain date (Ravagnani, 2008). As shown in Moreno et al. (2005), net present value is obtained through Eq. (1):

$$NPV(t) = -Invest(t) + \int_0^t \frac{CF(t)}{(1+rate)^t} dt \tag{1}$$

where *Invest(t)* is the amount invested in exploration (Eq. (2)); *CF(t)* is the cash flow (Eq. (3)); *rate* is the discount rate; and *t* is the time of exploitation.

Investment in the exploration of a field includes Capital Expenditures, $CapEx(t_0)$, expenses with abandon, $k_{ab}CapEx\ (t_0)$, both calculated at the beginning of the exploration period; and periodic expenditures $C_{per}(t_{per})$.

$$Invest(t) = CapEx(t_0) + k_{ab}CapEx(t_0) + \sum_{k=1}^{p} C_{per}\left(t_{per}\right) \tag{2}$$

The cash flow includes the oil (c_{op}) and water (c_{wp}) production costs, water injection costs (c_{wi}) and polymer injection costs (c_{pol}), all balanced by its respective inflow rate ($Q_{op}(t)$, $Q_{wp}(t)$, $Q_{wi}(t)$, $Q_{pol}(t)$). Additionally, the *CF(t)* includes net revenue due to the oil sale (oil price, p_o) after application of income tax (*IRCS*), royalty rates (r_r), PIS/PASEP and Cofins (r_{pc}) and any special income tax (r_{pe}).

$$\begin{aligned} CF(t) &= (1 - IRCS)\left(1 - r_r - r_{pc} - r_{pe}\right)\left(p_o Q_{op}(t)\right) \\ &- \left(c_{op}Q_{op}(t) + c_{wp}Q_{wp}(t) + c_{wi}Q_{wi}(t) + c_{pol}Q_{pol}(t)\right)\left(p_o Q_{op}(t)\right) \end{aligned} \tag{3}$$

To return a maximum value, Eq. (1) may be reduced to:

$$NPV_{max} = (1 - IRCS)p_o N_p \tag{4}$$

According to Jahn et al (1998), field life cycle begins with the exploration phase, which includes the reservoirs discovery, drilling and evaluation of wildcat wells. This phase is followed by the development and production phases, where development wells are drilled, the infrastructure of production is set and the equipments, for oil and gas transportion, are installed.

Coupling simulation results for the chosen recovery strategy with economic evaluation helps to support the decision making. Based on these fundamentals, this paper try to explore the transfer of information between models from different scales, as well as integrate production and economic data for portfolio classification.

3 METHODOLOGY AND APPLICATION

Using a commercial simulator, the oil recovery methods based on continuous water flooding (WF) or water injection alternated with a polymer slug (WAP) were evaluated and compared. The studied reservoir was considered homogeneous with a permeability of 1,000 mD (1 m² = 10^9 mD) and porosity of 0.20. Porous media geometry was represented by a Cartesian grid corresponding to 20 blocks in the direction I and J, and 10 blocks in the direction K. The reservoir oil was characterized as heavy oil with 20°API (specific gravity of 0,93) and viscosity of 23.86 cp (1 Pa.s = 10^3 cp).

The polymer solution used was based on viscosity of 15 cp and concentration of 2,500 ppm. It is worth highlight that the simulator does not identify different polymer types, only their properties as inputted to the simulator file.

In this model, the wells are defined in order to represent a quarter of five-spot. The injector well has a maximum pressure of 5,000 kPa and the production well has a minimum pressure of 101 kPa (Valdivia, 2005).

The other simulated cases had modified values with respect to the polymer slug size, starting time for polymer slug injection, relative permeability curves, polymer viscosity and mobile oil saturation.

Since the studied reservoir was considered homogeneous, vector parameter upscaling was necessary. The size increase was chosen in a way that a block in field scale would have the size of 10 meters in the direction of flow (equivalent to 1 cm in a laboratory scale). With this, is possible to set the value of the increase ratio, R_L:

$$R_L = \frac{comprimento\ escala\ laboratorial}{comprimento\ escala\ de\ campo} = \frac{0.01\ m}{10\ m} = 0.001 \tag{5}$$

The relative position of the wells is maintained and the maximum flow rate of water injection, after size increase, is 612 m³/day. Total analysis time correspondent to the upsized model lasts 10 years, 9 months and 22 days. The simulation is performed considering the temperature of 24°C and pressure of 101 kPa.

The economic analysis is performed for the upsized scale model by the economic indicator NPV. Considering this approach, obtained results are more close to field case magnitude values. Also, a sensitivity analysis is performed considering a favorable and unfavorable scenario.

The study by Ravagnani (2008) served as a reference for the tax amount levied on oil, being considered 21% for income tax, 10% for royalty's rate, 9.25% for PIS / PASEP and COFINS and 4% for special income tax.

The price of oil for sale used in the calculations was $80.97/bbl (1 m³ = 6,3 bbl), and the costs were estimated at $30.00/bbl for oil production, $1/bbl for water production and water injection and $5.00/kg of polymer.

4 ANALYSIS AND DISCUSSION OF RESULTS

The results obtained with the field scale model are compared with the results on a laboratory scale model (Sanches et al., 2015). Two base cases are analyzed for oil recovery, together with an analysis of the modified parameters. Then, an economic analysis is done with the results obtained in the field scale model.

4.1 Comparison of continuous water flooding and water injection alternated with a polymer slug

This section shows the obtained results for two flow base models, i.e., continuous water flooding (WF) and water injection alternated with a polymer slug (WAP), and also, considering two models with different sizes, i.e., a laboratory scale model and an upsized model aiming represent conditions more close to field magnitude.

The base case of water injection alternated with a polymer slug is characterized by a slug size corresponding to 32% of the pore volume, equivalent to 600 min and 1.14 years for the laboratory and field scale models, respectively. Time injection of the polymer slug started after an injected water volume corresponding to 48% of the pore volume and to the production time of 900 min and 1.71 years, respectively, for laboratory and field scale models.

The water injection alternated with a polymer slug favors the oil recovery when compared with continuous water flooding. This result is due to the increased viscosity of the fluid, and this behavior is observed in the field and laboratory scale models.

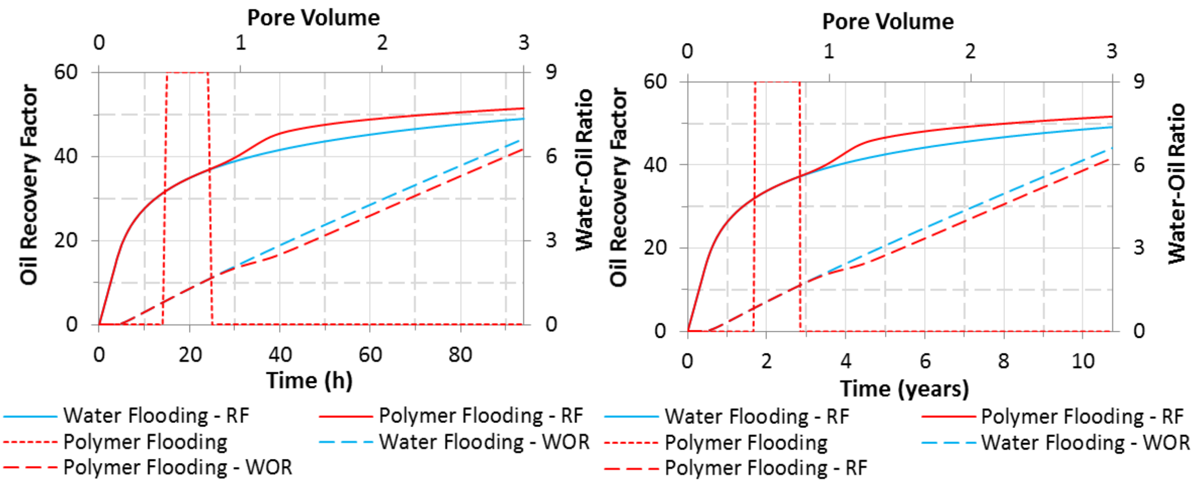

Figure 1. Oil recovery factor and the water-oil ratio for the injection of water and polymer. A) Laboratory scale; B) Field Scale

By analyzing the curve of recovery factor (Fig. 1) for the water injection alternated with a polymer slug, there is an increase in oil production caused by polymer slug injection. Another way to verify the efficiency of polymer injection is by the curve of water-oil ratio, since a higher oil production is accompanied by a reduction in water production.

Through the curves of recovery factor and water-oil ratio, it is not possible to verify any changes in the behavior due to the size increase and by comparing the final values (Table 1). Differences between the results obtained for the laboratory model and the field model were less than 0.32%, and are possibly assigned to numerical errors.

Table 1. Data for oil recovery factor and water-oil ratio

		Laboratory Scale	Field Scale	Δ
Oil Recovery Factor	Water Flooding	49.1	49.1	0.00%
	Polymer Flooding	51.5	51.6	0.19%
	ΔRF	4,89%	5.09%	
Water-Oil Ratio	Water Flooding	6.63	6.62	-0.15%
	Polymer Flooding	6.27	6.25	-0.32%
	ΔWOR	-5.43%	-5.59%	

On an oil production, pressure history must be monitored and controlled; thereby the pressure profile along the linear path between the wells (Fig. 2 and 2) was plotted for evaluation (Fig. 3).

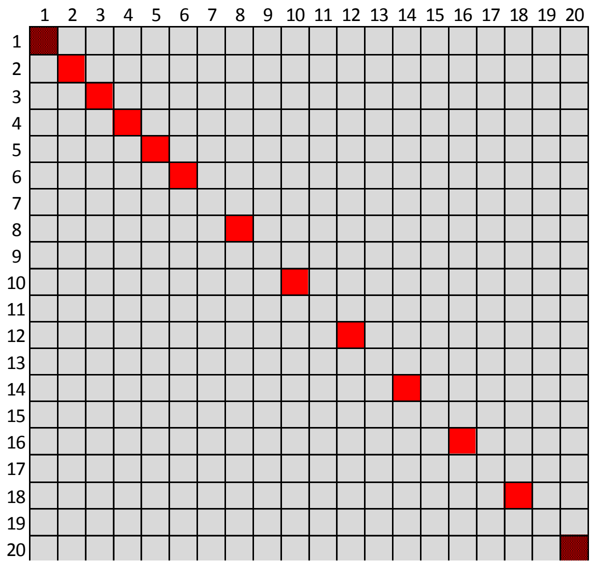

Figure 2. Pressure profile on the grid

Table 2. Description of the pressures

Cell	Description
(1 1)	Injector Well
(1 1)	Pressure 1
(2 2)	Pressure 2
(3 3)	Pressure 3
(4 4)	Pressure 4
(5 5)	Pressure 5
(6 6)	Pressure 6
(8 8)	Pressure 7
(10 10)	Pressure 8
(12 12)	Pressure 9
(14 14)	Pressure 10
(16 16)	Pressure 11
(18 18)	Pressure 12
(20 20)	Pressure 13
(20 20)	Producer Well

It was found that the behavior of the pressure history curve doesn’t change with size increase. Along the curve, it is possible to identify a first disturbance in pressure decay related to the breakthrough of connate water. The instant of breakthrough causes a pressure increase in all blocks; however in the block near the producer well this can be identified more easily. The second change in the pressure histories is caused by the injection of the polymer slug. Because the high polymer viscosity compared to water’s, polymer displacement under a constant flow rate requires a higher differential pressure. However, this increase in pressure is more intense in the block near the injector well and is smoothed along the way to the producer. The last change occurs when there is an increase in oil production due to injection of the polymer slug, this occurs more smoothly in the block near the injector and increases its intensity along the way to the producer.

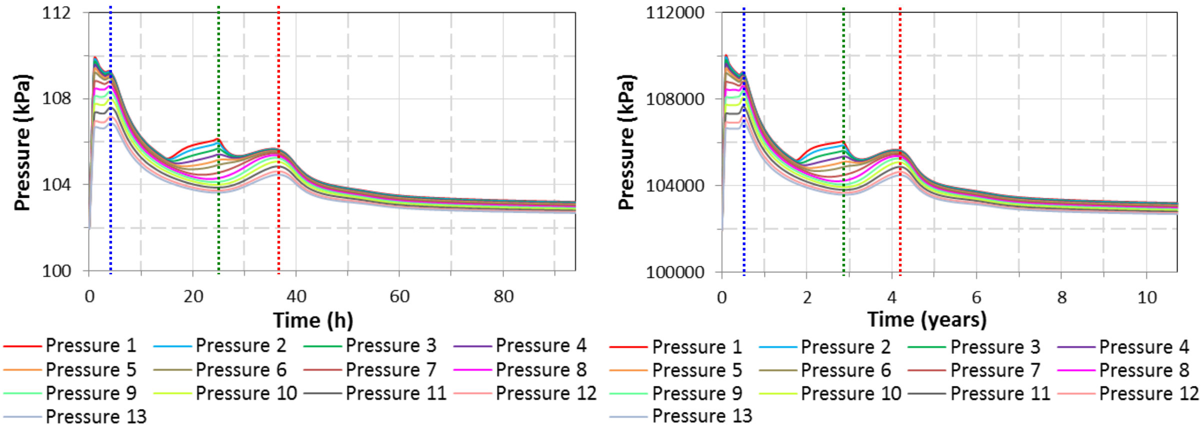

Figure 3. Pressure history along the linear path between the wells to water injection alternated with a polymer slug. A) Laboratory scale; B) Field Scale (blue: connate water BT, Green: polymer slug BT, red: incremental oil BT)

An evaluation of the ratio between the injected and produced polymer volumes can be made. The results are shown in Table 3.

Table 3. Amount of polymer retained within the reservoir

	Laboratory Scale	Field Scale
Injected Polymer	0,207 cm^3	207 m^3
Producer Polymer	0,056 cm^3	52 m^3
% producer	27,1%	25,1%

The percentage of produced polymer has a 2% variation between models, which is considered small. Thus, changes in model size do not modify the performance of the polymer flooding through the reservoir.

Complementing the investigation, a sensitivity analysis is performed searching the impact of different inputted conditions for slug size, start time of polymer injection, polymer viscosity, water relative permeability at the residual oil saturation and mobile oil saturation, on the recovery method results.

4.2 Change in polymer slug size

The amount of oil produced is influenced by the amount of injected polymer solution. Thus, the recovery was evaluated for slug size corresponding to 10%, 20%, 40% and 50% of the pore volume. The base case for water injection alternated with a polymer slug was used, where all the other properties were held constant, changing only the slug size.

In Fig. 4, it is possible check the final values of oil recovery factor and water-oil ratio regarding polymer slug size injected for each model. The zero size polymer slug corresponds to continuous water injection.

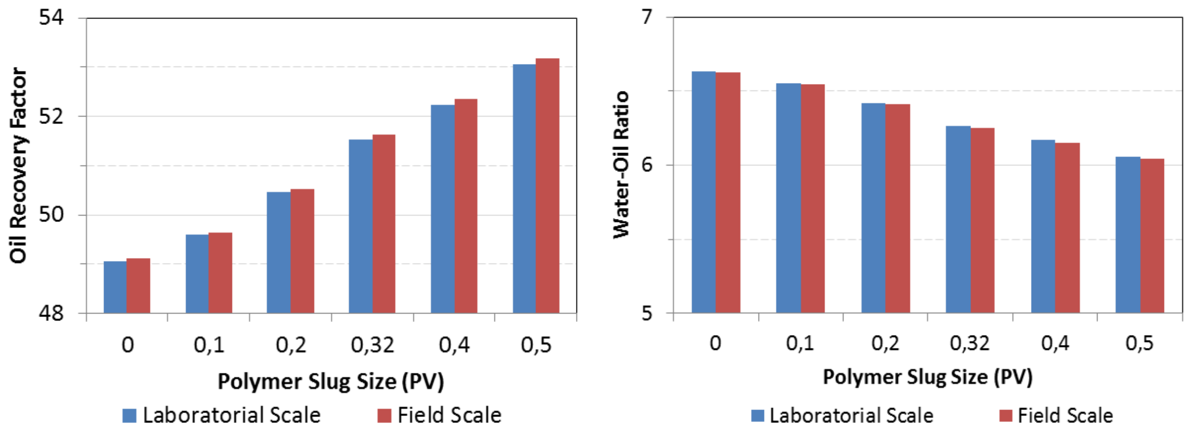

Figure 4. Analysis of polymer slug size. A) Oil recovery factor; B) Water-oil ratio.

Through Fig. 4, one can verifies that the recovery factor is proportional to the polymer slug size injected; therefore the higher is the duration of injection of the polymer solution, more polymer amount comes into contact with the oil in the reservoir, and higher is the recovery. As the slug size increases, the process will behave as a continuous polymer flooding.

Continuous polymer flooding eliminates the risk of water fingering, and consequently, provides better results compared to the continuous water flooding or water injection alternated with a polymer slug, however can be economically infeasible due to polymer cost.

Higher polymer slug sizes also return smaller water-oil ratio. However, more viscous solution requires higher injection differential pressure.

4.3 Change the injection starting time of the polymer slug

Changing on the injection starting time of the polymer solution can influence the oil recovery. Aiming to quantify the effects, simulations were carried out for the base case of water injection alternated with a polymer slug and the starting time was modified. The following cases were simulated: (1) polymer slug injection from day one (t = 0 min) and subsequently water injection; (2) polymer slug injection at the water breakthrough time (t = 92 min for the laboratory scale model, and, t = 64 days for the field scale model) measured for the base case of continuously water flooding; (3) polymer slug injection at the instant corresponding to the 95% water cut measured for the base case of continuous water flooding (t = 47 hours for a laboratory scale model, and, t = 5.4 years to the field scale model).

The recovery factor and the water-oil ratio for the studied models at different instants of polymer slug injection are shown in Fig. 5.

The anticipation of polymer slug injection results in greater oil recovery and a lower water-oil ratio production. The injection starting time of the polymer slug modifies the history of average pressure, causing a pressure increase at the instant of the slug injection.

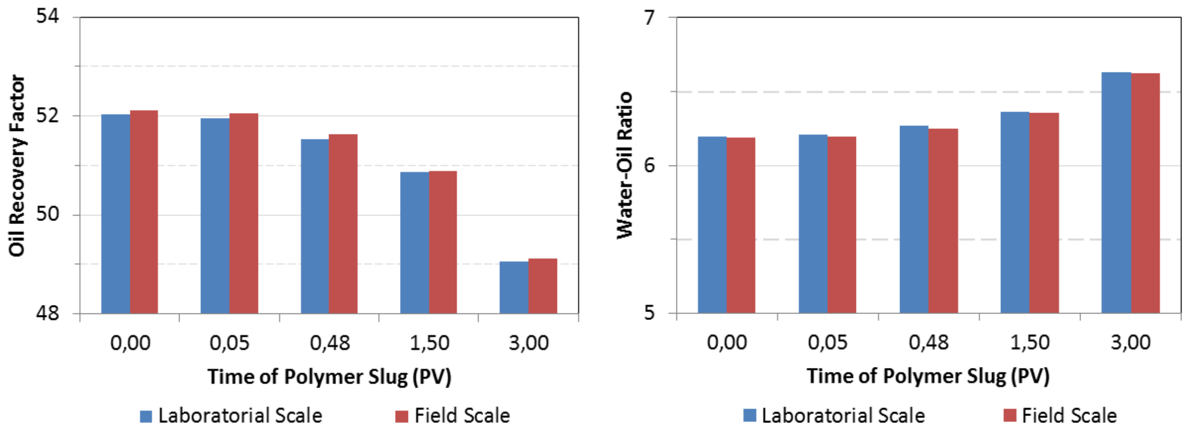

Figure 5. Analysis of the injection starting time of the polymer slug. A) Oil recovery factor; B) Water-oil ratio.

4.4 Change in polymer viscosity

High viscosity of the injected solution favors the mobility ratio. Thus, the oil recovery factor can be affected. To verify the effect of the polymer viscosity variation, simulations were performed with different viscosity values of the injected polymer solution. The base case of WAP was used considering viscosity values corresponding to 7cp, and 20cp 30cp.

The recovery factor and the water-oil ratio for each value of viscosity according to each model are shown in Fig. 6. It can be seen that the increased viscosity improves the oil recovery and decreases the water-oil ratio.

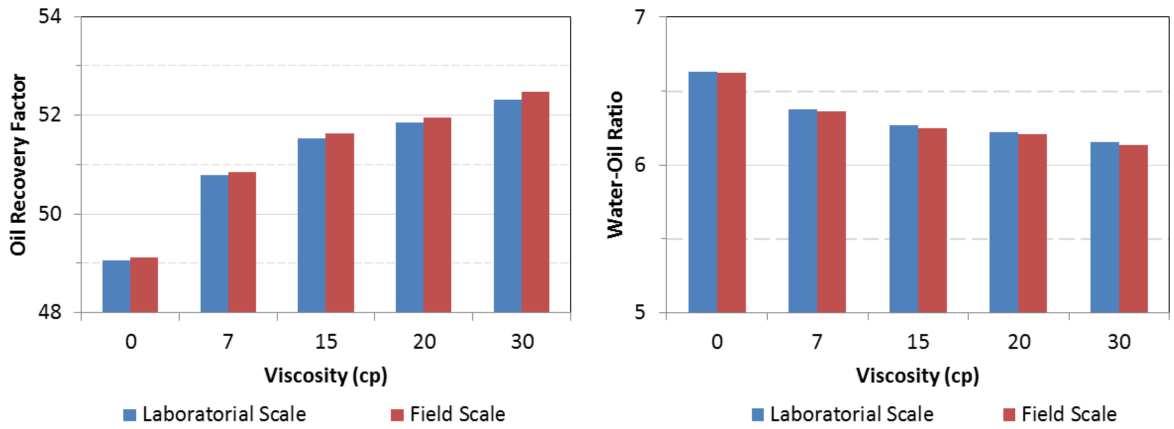

Figure 6. Analysis of polymer viscosity. A) Oil recovery factor; B) Water-oil ratio.

The increase in viscosity leads to an increased recovery factor. However, the incremental oil recovery becomes smaller when the viscosity level is higher. Thus, the increase in viscosity cannot offer a desired return. This effect occurs because higher polymer viscosities require higher differential injection pressures, which cannot always be achieved if the required pressure level can cause fractures.

4.5 Change in the water relative permeability at the residual oil saturation

The base case of water injection and water injection alternated with a polymer slug were used to verify the sensitivity of the recovery factor due to changes in terminal water permeability values. The permeability curves obey the Corey model and values of permeability at residual oil saturation (0.5, 0.65 and 0.8) were selected according to the screening criteria. Results can be seen in Fig. 7.

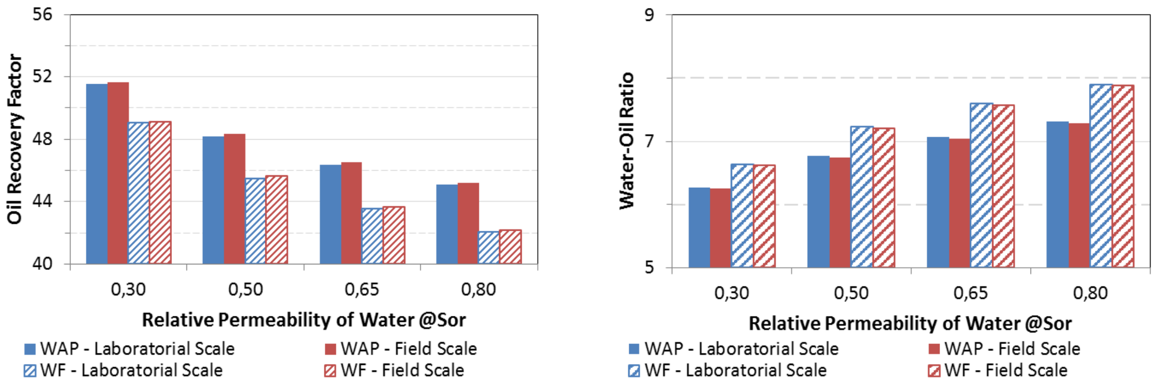

Figure 7. Analysis of water relative permeability in the residual oil saturation. A) Oil recovery factor; B) Water-oil ratio.

The increase in water relative permeability causes a decrease in recovery factor. However, for higher values of relative permeability, this decrease is smaller.

4.6 Change in mobile oil saturation

The increased amount of mobile oil favors the oil recovery. Thus, an analysis for different values of this parameter varying the initial values of water (S_{wi}) and residual oil (S_{or}) saturation was conducted. Initially, it used the WAP base case containing a mobile oil saturation corresponding to 0.5 (S_{wi} = 0.2 and S_{or} = 0.3). Then it changed to the S_{wi} values to 0.1; 0.3 and 0.4, and the S_{or} values to 0.4; 0.2 and 0.1, respectively, keeping a fixed amount of mobile oil. Finally, the amount of mobile oil was varied to 0.6 and 0.4.

The recovery factor and water-oil ratio obtained for different amounts of mobile oil and saturation combinations were observed for the different models. The results are summarized in Table 4.

The highest recovery values and smallest amounts of water-oil ratio were obtained for a mobile oil saturation corresponding to 0.6, initial water saturation specified as 0.3 and residual oil of 0.1. In Fig. 8, it can be seen the difference between the recovery factors for each amount of mobile oil.

Keeping the value of the initial water saturation constant and varying the value of the residual oil saturation, or the other way around, it is found that the recovery factor increases with increasing amount of mobile oil. However, fixing the volume of mobile oil, as smaller is the amount of residual oil saturation, higher is the volume of recovered oil. Thus, it appears that the residual oil saturation affects more the recovery than the amount of mobile oil.

Table 4. Recovery factor and water-oil ratio for different amounts of mobile oil.

Mobile Oil	S_{wi}	S_{or}	Laboratorial Scale		Field Scale	
			RF	WOR	RF	WOR
0,4	0,1	0,5	37,6	7,86	37,6	7,85
0,4	0,2	0,4	42,3	7,86	42,4	7,85
0,4	0,3	0,3	48,4	7,85	48,4	7,83
0,4	0,4	0,2	56,5	7,84	56,6	7,83
0,4	0,5	0,1	67,8	7,83	67,9	7,83
0,5	0,1	0,4	45,7	6,28	45,7	6,27
0,5	0,2	0,3	51,5	6,27	51,6	6,25
0,5	0,3	0,2	58,8	6,27	59,0	6,25
0,5	0,4	0,1	68,6	6,27	68,7	6,25
0,6	0,1	0,3	53,4	5,24	53,5	5,23
0,6	0,2	0,2	60,1	5,23	60,1	5,22
0,6	0,3	0,1	68,6	5,23	68,7	5,22

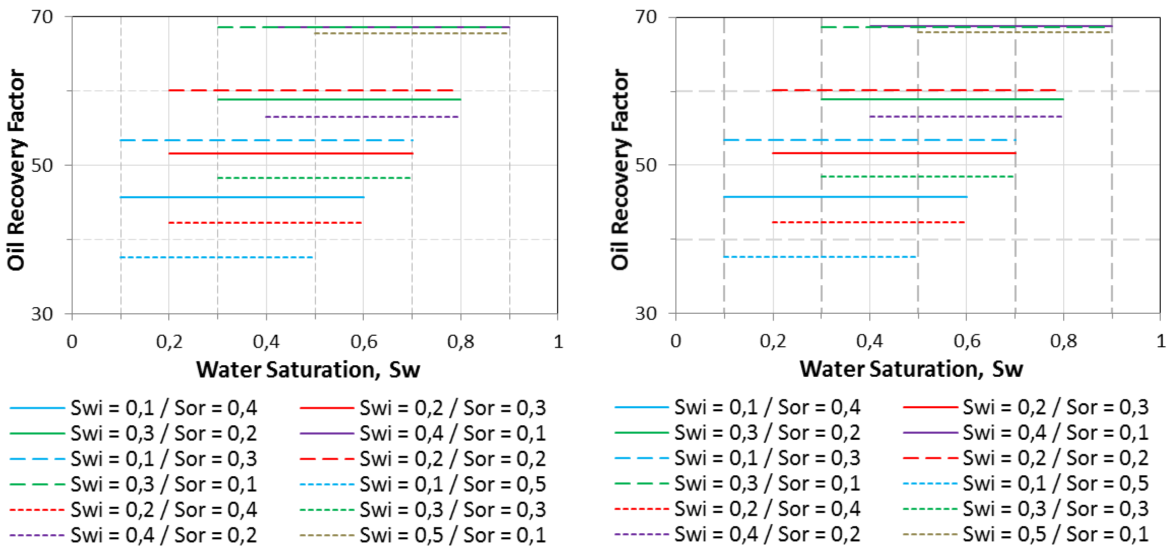

Figure 8. Oil recovery factor for different amounts of mobile oil. A) Laboratory scale; B) Field Scale

4.7 Summary of all cases

The recovery factor and water-oil ratio values obtained in all analyzes for continuous water flooding and water injection alternated with a polymer slug, in laboratory and field scale, are compiled in Table 5.

Table 5. Summary of all cases

		Laboratorial Scale		Field Scale		Difference	
		RF	WOR	RF	WOR	RF	WOR
Base Case	WF	49,1	6,63	49,1	6,62	0,0	0,01
Base Case	WAP	51,5	6,27	51,6	6,25	-0,1	0,02
Polymer Slug Size	WAP - 0% Vp	49,1	6,63	49,1	6,62	0,0	0,01
	WAP - 10% Vp	49,6	6,55	49,6	6,54	0,0	0,01
	WAP - 20% Vp	50,5	6,42	50,5	6,41	0,0	0,01
	WAP - 32% Vp	51,5	6,27	51,6	6,25	-0,1	0,02
	WAP - 40% Vp	52,2	6,17	52,4	6,15	-0,2	0,02
	WAP - 50% Vp	53,1	6,06	53,2	6,04	-0,1	0,02
Injection starting time of the polymer slug	WAP - 0 Vp	52,0	6,20	52,1	6,19	-0,1	0,01
	WAP - 0.05 Vp	51,9	6,21	52,1	6,19	-0,2	0,02
	WAP - 1.5 Vp	51,5	6,27	51,6	6,25	-0,1	0,02
	WAP - 1.5 Vp	50,9	6,36	50,9	6,36	0,0	0,00
	WAP - 3 Vp	49,1	6,63	49,1	6,62	0,0	0,01
Polymer Viscosity	WAP - 0 cp	49,1	6,63	49,1	6,62	0,0	0,01
	WAP - 7 cp	50,8	6,37	50,9	6,36	-0,1	0,01
	WAP - 15 cp	51,5	6,27	51,6	6,25	-0,1	0,02
	WAP - 20 cp	51,8	6,22	52,0	6,21	-0,2	0,01
	WAP - 30 cp	52,3	6,16	52,5	6,14	-0,2	0,02
Water relative permeability at the residual oil saturation	WF - k_{rw} = 0,3	49,1	6,63	49,1	6,62	0,0	0,01
	WF - k_{rw} = 0,5	45,5	7,23	45,6	7,21	-0,1	0,02
	WF - k_{rw} = 0,65	43,5	7,60	43,7	7,57	-0,2	0,03
	WF - k_{rw} = 0,8	42,1	7,90	42,1	7,89	0,0	0,01
	WAP - k_{rw} = 0,3	51,5	6,27	51,6	6,25	-0,1	0,02
	WAP - k_{rw} = 0,5	48,2	6,77	48,4	6,74	-0,2	0,03
	WAP - k_{rw} = 0,65	46,4	7,07	46,5	7,04	-0,1	0,03
	WAP - k_{rw} = 0,8	45,1	7,31	45,2	7,29	-0,1	0,02
Mobile oil saturation	WAP - S_{wi} = 0,1/S_{or} = 0,5	37,6	7,86	37,6	7,85	0,0	0,01
	WAP - S_{wi} = 0,2/S_{or} = 0,4	42,3	7,86	42,4	7,85	-0,1	0,01
	WAP - S_{wi} = 0,3/S_{or} = 0,3	48,4	7,85	48,4	7,83	0,0	0,02
	WAP - S_{wi} = 0,4/S_{or} = 0,2	56,5	7,84	56,6	7,83	-0,1	0,01
	WAP - S_{wi} = 0,5/S_{or} = 0,1	67,8	7,83	67,9	7,83	-0,1	0,00
	WAP - S_{wi} = 0,1/S_{or} = 0,4	45,7	6,28	45,7	6,27	0,0	0,01
	WAP - S_{wi} = 0,2/S_{or} = 0,3	51,5	6,27	51,6	6,25	-0,1	0,02
	WAP - S_{wi} = 0,3/S_{or} = 0,2	58,8	6,27	59,0	6,25	-0,2	0,02
	WAP - S_{wi} = 0,4/S_{or} = 0,1	68,6	6,27	68,7	6,25	-0,1	0,02
	WAP - S_{wi} = 0,1/S_{or} = 0,3	53,4	5,24	53,5	5,23	-0,1	0,01
	WAP - S_{wi} = 0,2/S_{or} = 0,2	60,1	5,23	60,1	5,22	0,0	0,01
	WAP - S_{wi} = 0,3/S_{or} = 0,1	68,6	5,23	68,7	5,22	-0,1	0,01

4.8 Economic analysis

The economic analysis is presented for the field scale of water injection alternated with a polymer slug base case. Using results from simulation and the economic parameters, cash flow during the production period could be calculated and then, the NPV was assessed (Fig. 9).

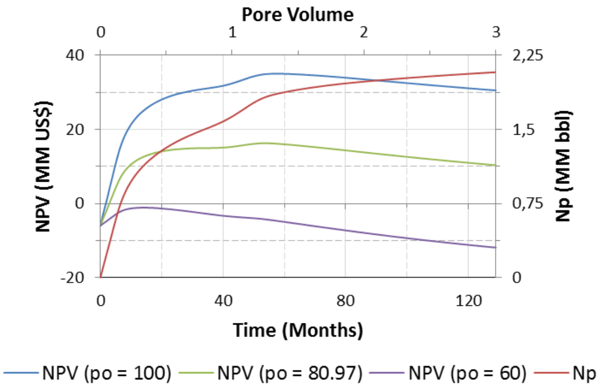

Figure 9. Net Present Value

The NPV, as a function of time, increases to a certain point and then starts to reduce. This behavior is because the exploitation time is too long and the amount of oil produced decrease over the years and, therefore, the economic return becomes lower.

The NPV for an oil price at $80.97/bbl is demonstrated in Fig. 9, as well as those calculated for a favorable estimate price ($100/bbl) and an unfavorable one ($60/bbl). One can see that very low oil price provides only negative NPV, turning the exploitation unprofitable, and, therefore, unfeasible. On the other hand, as higher is the value of oil, higher is correspondent NPV obtained during the production, and more profitable is the exploitation.

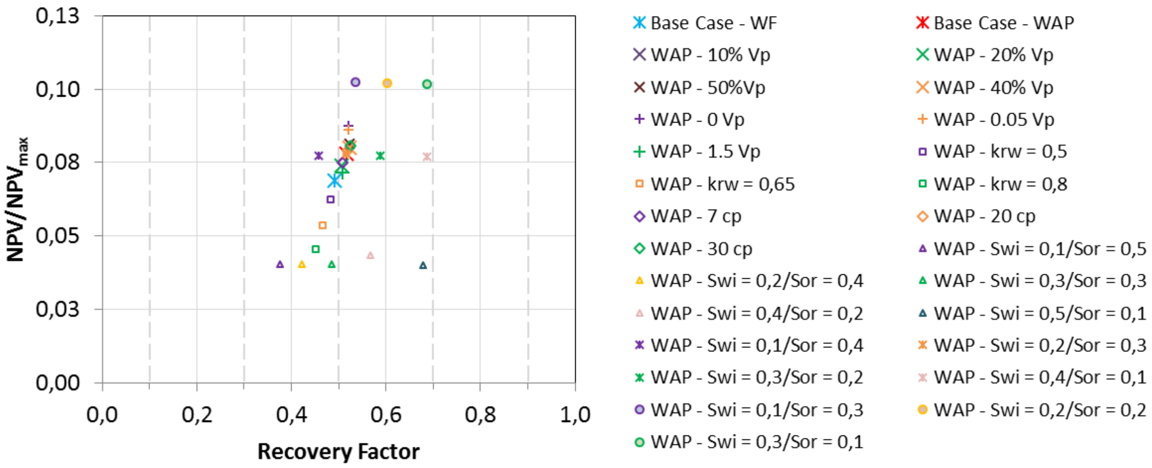

Figure 10. NPV/NPV$_{max}$ against recovery factor

Normalizing the value of NPV at the end of the simulation period by the maximum value of NPV, it is found that the higher the amount of recovered oil, the greater the value of maximum NPV. Fig. 10 shows that standard NPV values below the rate of return of 0.10 (10% annually) aren't feasible, and the negative ones result in a great financial loss.

5 CONCLUSION

Base cases were built focusing on different flow conditions, i.e., continuous water flooding (WF) or water injection alternated with a polymer slug (WAP), and different volume sizes, laboratory scale and field scale. Running the models and evaluating normalized parameters was possible to verify that the differences between results considering models with same flow conditions, but different sizes, were less than 4% for any studied case. It was possible to evaluate the transference of information from the laboratory model to the field model. The differences in oil recovery factor and water-oil ratio were lower than 0.2%. Nevertheless, the maximum difference between the produced polymers for both models was 3.9%.

Regarding the comparison between WP e WAP, for a fixed exploitation period, WAP application results in oil anticipation and reduction on the water phase volumes injected and produced. For a fixed flow rate, pressure decline is disturbed when connate water, polymer front, and incremental oil bank reach the produced.

Through sensitivity analysis on some important parameters, we can highlight that the WAP showed that larger slugs result in higher amounts of produced oil. However, the incremental oil per mass of polymer is reduced; the anticipation of polymer injection favors the anticipation of the oil production; more viscous polymer solutions reduce the mobility ratio, however, requires higher differential injection pressures; lower water relative permeability values at residual oil saturation lead to high oil production as a consequence of the small terminal mobility ratio; small values of residual oil saturation result in higher oil recovery, regardless of the mobile oil fraction.

The economic model showed how each parameter variation influences the NPV value, and how the oil price variation can make the exploitation economically viable or not. Moreover, the normalized NPV values allow identifying the cases around the return rate and the negative ones. The cases with values that surpass the return rate are characterized as profitable.

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