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Economical evaluation of oil recovery by applying polymer flooding

Avaliação econômica da recuperação de óleo pela aplicação da injeção polimérica

Evaluación económica de la recuperación de petróleo por la aplicación de la inyección polimérica

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Abstract
Chemical oil recovery methods are based on mainly three different products, polymers that increase the aqueous phase viscosity, surfactants that reduce interfacial tension between oil and aqueous phases, and alkalis that produce in-situ surfactants when combined with the oil phase acids. Chemical oil recovery methods are often used after waterflooding. Based on this context, this research aims to study the application and comparison of both waterflooding, and Polymer flooding based on a rough economic analysis, such as Net Pay Value (NPV) criteria. To do so, this study used a semisynthetic reservoir model, using characteristics and values like those found in a Brazilian northeast basin. Polymer flooding (PF) was studied at different concentrations, injection rates and sequences through numerical reservoir simulation and was compared to the most profitable scenarios of continuous water flooding (WF). The NPV analysis considered two different prices of barrel of oil, considering the oscillation of international prices. Results showed that polymer flooding improves the amounts of oil recovery at the three used concentrations when compared to WF and that the highest profit was obtained when the lowest PF concentration was injected continuously from the beginning of the reservoir´s productive life. Nevertheless, WF obtained a low difference in terms of NPV when compared to PF´s, but it achieved its highest value one year before PF, leading to a frequent decision regarding to choose between the higher delayed profit or a lower but faster income.
Keywords: Reservoir simulation; Polymer flooding; Improved oil recovery; NPV; CEOR.

Resumo
Os métodos químicos de recuperação de óleo são baseados principalmente em três produtos diferentes, polímeros que aumentam a viscosidade da fase aquosa, surfactantes que reduzem a tensão interfacial entre o óleo e as fases aquosas, e álcalis que produzem surfactantes in situ quando combinados com os ácidos da fase oleosa. Métodos químicos de recuperação de óleo são frequentemente usados após a injeção de água. Com base nesse contexto, esta pesquisa tem como objetivo estudar a aplicação e comparação tanto da injeção de água quanto da injeção polimérica com base em uma análise econômica aproximada, como os critérios do Valor Presente Líquido (VPL). Por tanto, este estudo utilizou um modelo de reservatório semissintético, utilizando características e valores semelhantes aos encontrados em uma bacia do nordeste brasileiro. A injeção polimérica foi estudada em diferentes concentrações, velocidades de injeção e sequências através da simulação numérica de reservatórios e comparado com os cenários mais rentáveis da injeção contínua de água. A análise do VPL considerou dois preços distintos do barril de petróleo, considerando a oscilação dos preços internacionais. Os resultados mostraram que a injeção polimérica melhora a recuperação de óleo nas três concentrações utilizadas quando comparada a injeção contínua de água e que o maior lucro foi obtido quando a injeção polimérica com menor concentração aconteceu continuamente desde o início da vida produtiva do reservatório. No entanto, a injeção contínua de água obteve uma baixa diferença em termos de VPL quando comparado à injeção polimérica, mas atingiu seu maior valor um ano antes da injeção polimérica levando a uma decisão frequente de escolher entre o maior lucro, porém atrasado ou um rendimento menor mais rápido.
Palavras-chave: Simulação de reservatórios; Injeção polimérica; Recuperação melhorada de Petróleo; VPL; CEOR.

Resumen
Los métodos de recuperación química de petróleo se basan principalmente en tres productos diferentes, polímeros que aumentan la viscosidad de la fase acuosa, tensoactivos que reducen la tensión interfacial entre el petróleo y las fases

acuosas, y alcalinos que producen tensoactivos in situ cuando se combinan con los ácidos de la fase oleosa. Los métodos químicos de recuperación de petróleo se utilizan a menudo después de la inyección de agua. esta investigación tiene como objetivo estudiar la aplicación y comparación de las inyecciones de agua y de polímeros con base a un análisis económico aproximado, como los criterios do Valor Actual Neto (VAN). Por lo cual, este estudio utilizo un modelo de reservorio semisintético, utilizando características y valores semejantes a los encontrados en una cuenca del nordeste brasilero. La inyección polimérica fui estudiada em diferentes concentraciones, velocidades de inyección y secuencias a través de la simulación numérica de reservorios, posteriormente comparado con los escenarios más rentables de la inyección continua de agua. El análisis del VAN consideró dos precios distintos del barril de petróleo, tomando en cuenta la oscilación internacional de precios. Los resultados mostraron que la inyección polimérica mejoró la recuperación de petróleo con las tres concentraciones utilizadas comparada con la inyección continua de agua y que el mejor lucro fue obtenido cuando la inyección polimérica con menor concentración fue realizada de manera continua desde el inicio de la vida productiva del reservorio. Sin embargo, la inyección continua de agua obtuvo una diferencia pequeña con relación al VAN comparada con la inyección polimérica, que consiguió su mayor valor un año antes que el de la inyección polimérica, llevando a tomar una decisión entre un lucro mayor retardado, o un rendimiento menor más rápido.
Palabras clave: Simulación de reservorios; Inyección polimérica; Recuperación mejorade de petróleo; VAN; CEOR.

1. Introduction

Oil recovery methods get into scene whenever production needs to be maintained and improved to keep up having economic profits. Among the various methods, chemical flooding includes mainly polymers, surfactants and alkali that look after enhancing fluids displacement and lowering interfacial tensions to get to produce additional volumes of hydrocarbons from within the reservoir, (Chang, 1978; Liu, 2013; Lu et al., 2018; Sheng, 2011). Regarding polymers, they are mainly used to create piston-like displacement behavior of the injected fluid, as they increase the viscosity of aqueous phase and manage to reduce the mobility ratio (de Melo et al., 2002; Chatterji and Borchardt, 1980; Needham and Peter, 1987). On the correct choice of the reservoir, followed by the specification and design of the polymer bank to be injected, depend on the technical and economic success of the process (Alusta et al., 2015; de Melo et al., 2002; Sorbie et al., 1987; Sorbie, 1991). China possesses the largest field scale project of polymer flooding (PF), known as Daqing field where chemical recovery started in 1996, having its production rate increased (Liu, 2013; Renqing, 2013; Fulin, 2006; Wang, 2003; Chang et al, 2006). In Brazil, de Melo et al., (2002) presented results from laboratory studies, carried out on cores, that showed positive results regarding PF, which led out to develop pilot projects in some specific areas as Canto do Amaro field.

This economical evaluation is based on the polymer project for mobility control conducted by Petrobras (de Melo et al., 2002, de Melo et al., 2005), as so, the chronological sequence for the implementation of that pilot is briefly described as follows:

1.1 Reservoir/pilot area selection

To achieve a successful polymer project some criteria must be considered. Initially the Canto de Amaro (CAM) field, located in Rio Grande do Norte, was selected as candidate based on screening criteria (see Table 1), therefore, screening criteria identified the potential candidate evaluating factors such as reservoir temperature, mobile oil saturation, brine salinity, water-oil mobility ratio, and reservoir fluid and rock. Beside all these factors, the polymer stability at reservoir conditions, the microbial degradation, the thermal, mechanical and chemical sensitivity were evaluated (de Melo et al., 2002, de Melo et al., 2005).

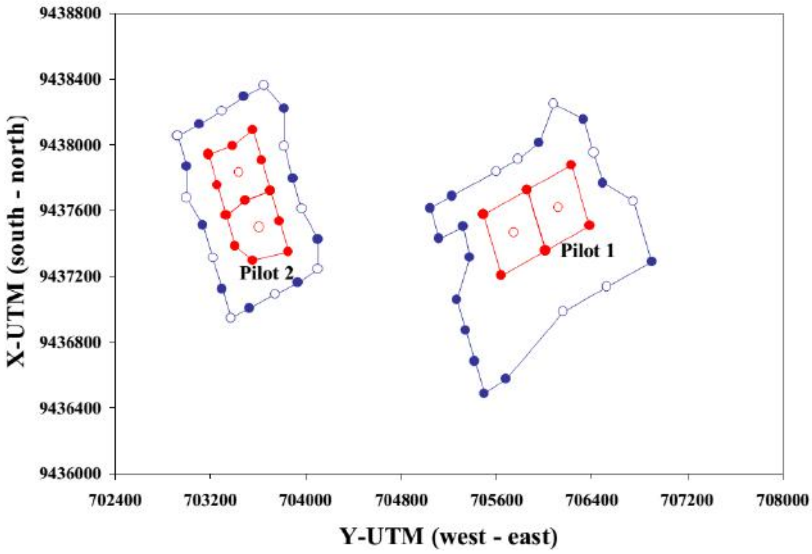
Table 1 - Reservoir characteristic.

PARAMETER	REFERENCE	CAM
Temperature (°C)	< 80°	56°
Salinity(ppm)	< 10000	500
Oil viscosity (cP)	< 100	7
°API	-	38.8
Oil saturation (%)	> 20	39
Permeability(mD)	> 100	250
Mobility ratio	> 1	5.5
Rock	Sand	Sand
Heterogeneity	Low	Low
Clay content (%)	Low	Low
Gas cap	Absent	Absent
Water drive	Absent	Absent
Natural fracture	Absent	Absent

Source: Authors.

After the reservoir was classified as candidate according to Table 1, the pilot area considering the technical information (porosity, thickness, water saturation, area, etc.) was chosen. Figure 1 shows the pilot area from CAM.

Figure 1 - Pilot area in Canto do Amaro (CAM) field.



Source: de Melo et al. (2002).

1.2 Water injection analysis

The choice of the injection water is fundamental in a polymer flooding process to avoid chemical degradation, as a result of the presence of chemical additives (corrosion inhibitors, suspended solid and biocides, etc.), or by the hydrolysis under acidic or basic conditions, etc. (Van Quy, 1983; Chang et al, 2006; Yue et al, 2015). That is why, polymers used in oil recovery projects are polyelectrolytes (with negative charge) to avoid the adsorption on the rock, preventing polymer instability and consequently their viscosity reduction.

1.3 Laboratory tests (polymer selection)

The technical and economic success of the process depends on the correct choice of the polymer to be injected in a specific reservoir (Chang et al, 2006, Braconnier et al., 2014). In this case, polyacrylamide in solid form was selected to be evaluated under different laboratory tests, like:

- Solubility tests: Used to determine if the polymer will or will not dissolve in a specific water and the time that will take to became completely diluted.
- Rheological behavior: Using the Brookfield viscosimeter, the viscosity-shear rate relationships of polymer solution was determined to understand the rheological behavior of the polymer solution under reservoir flow conditions.
- Filterability tests: To check up the polymer solution quality, these tests were performed using membranes representing the sand face of the borehole.
- Static adsorption test: Used to provide a preliminary screening of polymer, where the polymer solution is put in contact with an unconsolidated sand rock sample, after the reaction time, the final polymer concentration is measured and compared with the initial value, the difference equals the adsorbed polymer on the rock.
- Displacement test in porous media: these tests were conducted under reservoir conditions and define the interaction between polymer solution and reservoir rock, in order to determine parameters as residual resistance factor, maximum adsorption, residual adsorption and inaccessible pore volume as a function of the permeability. The API RP 63 methodology was used to perform the flow tests.

1.4 Design of the polymer slug

The polymer slug was designed using laboratory data and characteristic of the pilot area following the next steps: Polymer selection, polymer specification, polymer injection concentration and polymer slug volume.

1.5 Implementation and evaluation

Considering all the above-mentioned points (one to four), results regarding the evaluation of those projects concluded that there was a production increase, although the injected cumulative volume of polymer was small (about 16% of a PV), de Melo et al., (2005). However, economic analysis regarding such studies is not yet available. Despite the water flooding process and after 30 years of production, Canto do Amaro field is having a declining production stage, heading to consider alternative oil recovery methods such as PF among others.

This work aimed to model a reservoir from the northeast Brazilian region, using average values of properties obtained from published information and modeling the injection of polymer flooding at different scenarios. Results obtained from that study meant to be analyzed through an economic tool, such as Net Pay Value, to foresee whether this type of chemical oil recovery method would be interesting to be applied from the profitable point of view.

2. Methodology

2.1 Materials and Methods

For modeling and simulating oil and reservoir properties and their behavior this study used the Computer Modelling Group (CMG) commercial simulator and its corresponding modules. For computing profits/losses, a rough economic analysis used the NPV (Net Present Volume) criteria.

Table 2 (a) values show the characteristics of a light oil. Reservoir properties were modeled using a 3D Cartesian grid (20x20x12) for a reservoir size of 194x194x12 m, and the corresponding values are detailed in Table 2 (b).

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Table 2 - General Information.

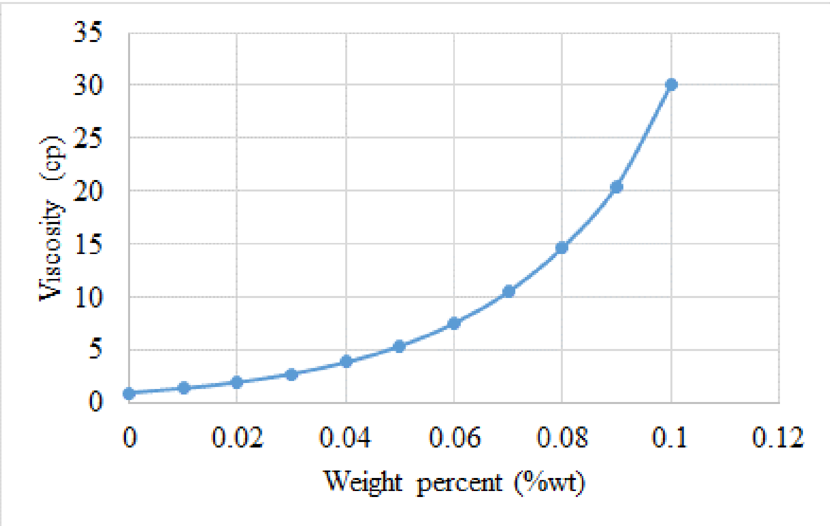
Oil composition (a)			
N2	0,0005	iC5-C6	0,1419
C1-C2	0,0032	C7-C11	0,7140
C3-C4	0,0154	C12+	0,1250
Reservoir characteristics (b)			
Parameter	**Value**	**Parameter**	**Value**
Porosity (%)	28	Oil saturation (%)	> 50
Average Horizontal Permeability (md)	630	Water saturation (%)	29
Average Vertical Permeability(md)	63	Reservoir top depth (m)	528
Reservoir pressure (psi) @528 m	693	Heterogeneity	low
Initial reservoir temperature (°F)	122	Rock type	sand

Source: Authors.

It is important to highlight that the lack of water influx or the presence of a gas cap besides a low volume of dissolved gas within the oil, results on a very low primary energy of the reservoir, which is a characteristic of the studied field.

The molecular weight and critical pressure of the polymer used along the study were $1x10^7$ (lb/lb mol) and 300 °F respectively, and the behavior of the polymer solution´s viscosity is represented on Figure 2. The high molecular weight of polymer is a characteristic of synthetic polymers such as hydrolyzed polyacrylamide (HPAM), widely used for different purposes for the oil industry, like EOR and drilling fluids (Zhang et al, 2015).

Figure 2 - Polymeric solution´s viscosity.



Source: Authors.

The curve on Figure 2 represents the increase of the polymer solution´s viscosity with concentration of the chemical product in weight percent.

Chemical recovery methods are mainly used after a previous water flooding, that was the reason why the base case used for comparison was represented by a continuous injection of water from the very beginning of the productive life of the reservoir.

The analysis of the economic profit used the Net Present Value criteria (NPV), which represents the difference between the present value of cash inflows and outflows. NPV is used in capital budgeting to analyze the profitability of a project. Mathematically, NPV is represented by equation (1).

$$\mathrm{NPV} = \sum_{t=1}^{n} \frac{Net\ period\ cash\ flow}{(1+\mathrm{i})^{\mathrm{t}}} \tag{1}$$

Where i is the rate of return and t is the number of time periods.

Regarding equation (1), positive results encourage investments while negative ones represent a net loss. As the price of the barrel of oil has not kept a certain stability during last 5 years, two prices were considered in order to span both low and high prices and evaluate their impact on the obtained results. Water and polymer prices were kept constant as variations in market would be minimal.

For the present paper, the net cash inflow and outflow considered the yearly amounts of produced oil, injected and produced water, as well as the corresponding prices per volume or mass unit of oil, injected water, water treatment and polymer. After introducing those considerations, the NPV analysis turned out to be represented, in this case, through equation (2). Other type of expenses was not considered as the equipment for polymer flooding is not that different from water flooding, except for the tanks used to mix and prepare the polymer solution.

$$\mathrm{NPV} = \sum_{t=1}^{15} \frac{(Np \times \$Oil) - \left(W_{inj} \times \$W\right) - \left(M_{pol} \times \$W\right) - \left(W_p \times \$W_{Treat}\right)}{(1+\mathrm{i})^{\mathrm{t}}} \tag{2}$$

Where the Net period cash flow = inflow – outflow, Inflow = cumulative oil production (Np) x price of oil ($Oil), Outflow = [cumulative water injected (W_{inj}) x price of water ($W)] + [amount of polymer (M_{pol}) x price of polymer ($Pol)] + [cumulative water produced (Wp) x price of water treatment (W_{Treat})], n = 15 years and i = 0.13.

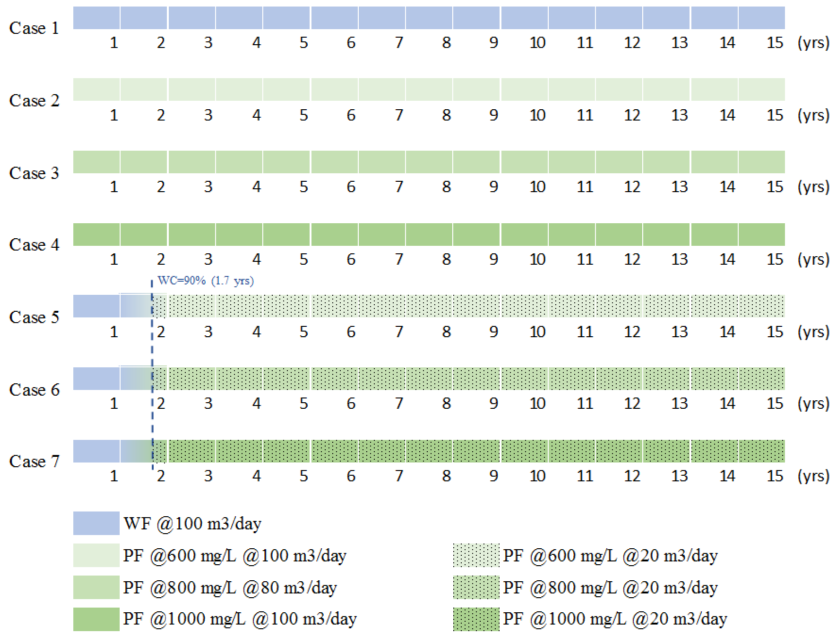
The values used to calculate the NPV results of this work through equation (2) were: Oil price ($us) per Barrel = 50.00-100.00; Injection water price ($us) per Barrel = 15.14; Water treatment price ($us) per Barrel = 5.71 and Polymers price ($us) per kilogram = 1.29.

It is important to emphasize that the prices showed previously are merely average values, which help to create a general sense of an economic analysis regarding polymer flooding, as there is a wide variety of products and prices mainly depending on suppliers, specifications and locations.

Next in line of the acquisition of the data, came the modeling of the fluid and the physical representation of the reservoir, as well as the adjustment of all the parameters in order to start the modeling process. After checking up on consistent behavior of the reservoir, a sequence of simulations was followed, looking forward to obtaining the higher results in terms of NPV, from both water flooding and polymer flooding, at different concentrations.

The criteria to build up this study was based on a sequence of steps. Every step after the initial analysis was based on the best results obtained on the previous one. It started by creating four cases, case one for water flooding (WF) and the remaining corresponding to polymer flooding (PF) at three different concentrations (600, 800 and 1000 mg/L) corresponding to 7, 14 and 30 cp, approximately, according to Figure 2. Polymer injection was analyzed starting at two different moments, the first one was from the beginning of the productive life of the reservoir, and the second one was after a water flooding process in which the water cut value achieved 90%, following the sequences displayed on Figure 3.

Figure 3 - Cumulative oil production for all cases.



Source: Authors.

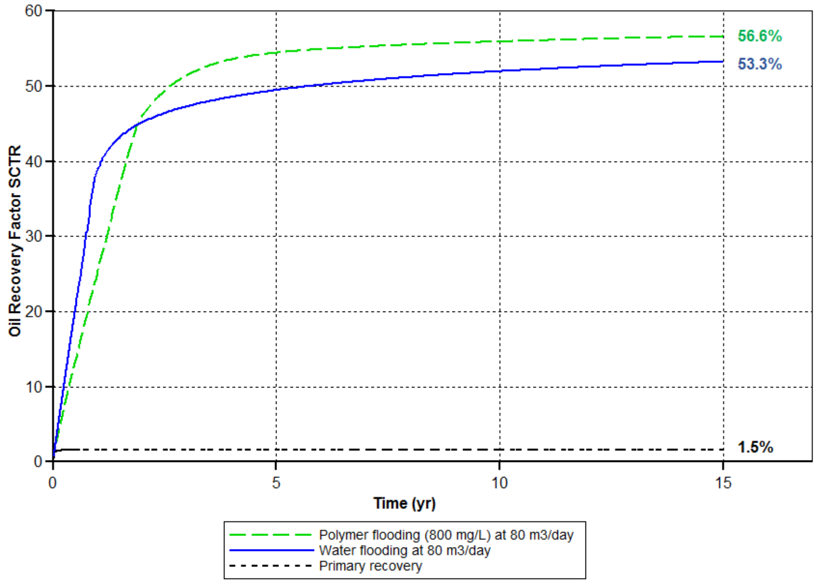
Figure 3 shows that cases 1 to 4 represent water and polymer flooding at different concentrations being injected continuously from the beginning (day 0), until completing 15 years. Each of cases 1 to 4 were simulated at different injection rates (from 20 to 160 m3/day) and the data obtained was analyzed through NPV criteria, equation 2, in order to find out which injection rate showed the most profitable results. Regarding cases 5 to 7, they were created after finding the water flooding injection rate with the highest NPV value. In those cases, water flooding was injected from day 0 until water cut was equal to 90%, at that point polymer flooding at different concentrations would start. For cases 5 to 7, water flooding remained at a constant injection rate and polymer flooding was modeled at different rates (from 20 to 160 m3/day) to find the most profitable one, same as cases 1 to 4.

Closure of the study involved a comparison between the results obtained, analyzing the behavior of the polymer flooding within the reservoir, looking forward to better understand this type of chemical oil recovery method, and picking up the better results in terms of NPV values.

3. Results and Discussion

The initial background of the study was to verify if there would be an improvement in terms of cumulative oil production of the reservoir using polymer flooding as a recovery process. Considering the low natural energy of the reservoir, as early mentioned, water flooding was used as a parameter of comparison (Yue et al, 2015), as that conventional recovery method was used on the fields from where data was acquired (de Melo et al., 2002, de Melo et al., 2005). Figure 4 represents the recovery factor from primary, water and polymer flooding oil recovery versus time, being the last two at continuous injection rates of 80 m3/day each, for comparison purposes.

Figure 4 - Oil recovery factor.

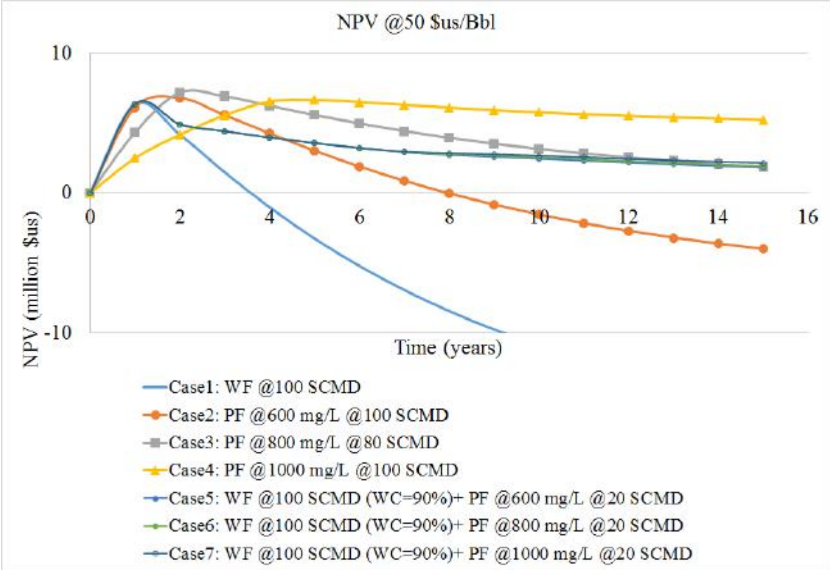


Source: Authors.

Figure 4 shows how primary energy from the reservoir would not be enough to produce significant recovery factor values, in this case it achieved about 1.54% in 15 years. Water flooding on the other hand, improved the oil production, showing approximately 53.3%, 51.8 percentage points above the primary recovery curve. Polymer flooding, when injected from the beginning at the intermediate concentration of 800 mg/L, demonstrated to be superior in terms of recovery factor, achieving 56.6%, 55.1 and 3.3 percentage points above primary recovery and water flooding respectively.

As polymer flooding improved the oil recovery factor, next in line was to analyze and compare the results obtained by using the injection sequences for cases 1 to 7 showed in Figure 3. Results obtained by modeling the above-mentioned cases and using the NPV criteria through equation 2 are shown on Figure 5.

Figure 5 - Injection rates that showed the highest NPV.



Source: Authors.

Figure 5 shows the NPV values versus time, where each curve represents the injection rate with the highest NPV value for cases 1 to 7 assuming US$ 50 per oil barrel. Initially all curves show NPV values increasing with time until they reach a maximum point, that is the highest NPV obtained by each case. Such behavior means that incomes are higher than outcomes, so the oil recovery processes are profitable according to NPV criteria. From the moment curves start to decline, it means that outcomes are higher than incomes, turning oil recovery processes unattractive from the profitable point of view. Under those considerations and using both proposed oil prices (US$ 50 and US$ 100/Bbl), a resume of the values obtained for cases 1 to 7 is presented on Table 3.

Table 3 - NPV results for all cases.

		Case number						
		1	2	3	4	5	6	7
	Injected fluid	WF	PF	PF	PF	WF+PF	WF+PF	WF+PF
	Polymer concentration (mg/L)	0	600	800	1000	0-600	0-800	0-1000
	Injection rate (SCMD)	100	100	80	100	20	20	20
Oil price @ US$ 50/Bbl	NPV (MM US$)	6.4	6.8	7.1	6.6	6.4	6.4	6.4
	Time (years)	1	2	2	5	1	1	1
	Cumulative oil production, Np (SCM)	34.6	44.3	40.9	45.2	34.6	34.6	34.6
Oil price @ US$ 100/Bbl	NPV (MM US$)	15.8	18.4	18.3	16.8	15.8	15.8	15.8
	Time (years)	1	2	3	6	1	1	1
	Cumulative oil production, Np (SCM)	34.6	44.3	45.7	47.3	34.6	34.6	34.6

Source: Authors.

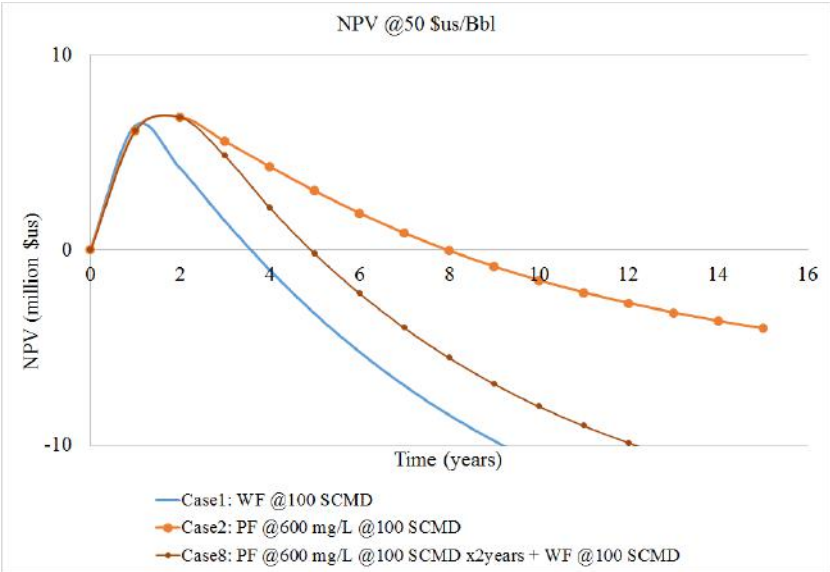
Table 3 shows a comparison of the highest NPV values obtained by all 7 cases studied in this work. It shows that when oil price is assumed at US$ 50/Bbl, the highest NPV value was 7.1 MM US$, obtained within 2 years by Case 3, which is polymer flooding at a concentration of 800 mg/L, injected from the beginning (year 0) at 80 SCMD and that produced 40.9 SCM by that time. For oil price assumed at US$ 100/Bbl, the highest NPV value was 18.4 MM US$, obtained within 2 years by Case 2, which is polymer flooding at a concentration of 600 mg/L, injected from the beginning (year 0) at 100 SCMD and that produced 44.3 SCM by that time.

About cases 5 to 7, they represent water flooding injected from the beginning, year 0, at 100 SCMD, until water cut value achieved a 90% value, which happened at about 1.7 years, followed by polymer flooding at different concentrations. Table 3 shows that those cases, 5 to 7, obtained the same NPV, time and Np values as water flooding (Case 1), which means that they did not overcome profits obtained by the injection of just water, as was previously observed on Figure 5.

Therefore, and within the values used in this work, polymer flooding was economically more profitable than water flooding when injected from the beginning (year 0) of the productive life of the reservoir at the lower and intermediate concentrations, as the higher concentration achieved lower NPV values and took considerably more time to do so.

Looking forward to decreasing the polymer expenses, the next step of the study was to simulate the reduction of the injection time of polymers. As an example, case 2 (polymer at 600 mg/L and at a rate of 100 SCMD) was injected for 2 years, as that was the time that showed the highest NPV during continued injection, followed by just water at 100 SCMD. Injection of polymer from the beginning, year 0, for 2 years and followed by water injection was called Case 8, and its NPV results are shown in Figure 6.

Figure 6 - NPV results of polymer flooding for 2 years followed by water flooding.

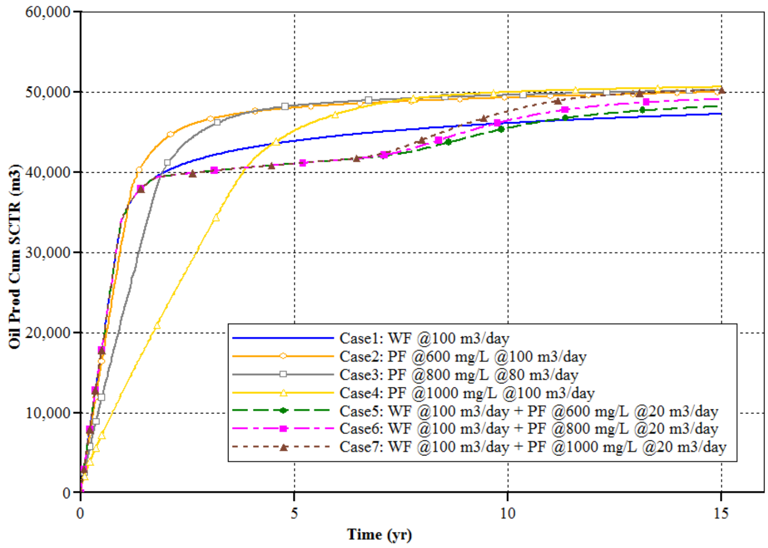


Source: Authors.

Figure 6 shows the NPV results of case 8, as well as those corresponding to case 1 and case 2 in order to compare them. It is observed that reducing the size of the polymer bank does not necessarily improve the profits. The highest NPV results of case 8 was the same as case 2 but shows lower values during the declining period. However, any values during declining are not economically attractive from the profitable point of view.

In order to complete the analysis regarding polymer flooding, results representing cumulative oil production of cases 1 to 7 are presented on Figure 7.

Figure 7 - Cumulative oil production.

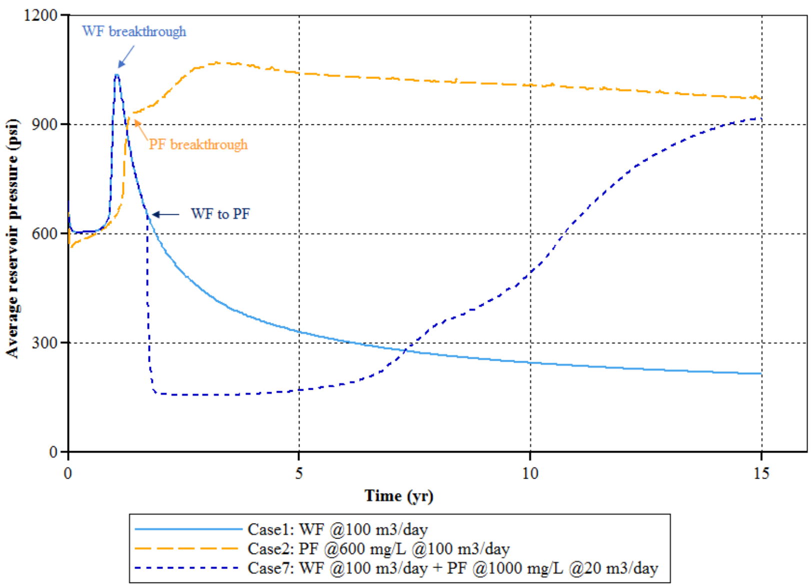


Source: Authors.

Figure 7 shows the curves that represent cumulative oil production obtained by polymer flooding at different concentrations injected from the beginning, year 0, and after water flooding. It is observed that after 15 years, for all practical purposes, polymer flooding produced more oil than water flooding. Also, the curves representing the lower polymer concentration (case 2: 600 mg/L) injected since year 0 manages to produce oil faster, this is due to a higher mobility rate, as the polymer solution´s viscosity is lower compared to cases 3 and 4.

Additionally, it is known that polymer flooding´s most noticeable contribution to oil recovery is its capacity to reduce mobility ratio, due to polymer´s viscosity. Nevertheless, it also offers the benefit of increasing the pressure within the reservoir, as previously mentioned by Moe Soe Let et al., 2012. The behavior of the average pressure of this study is presented on Figure 8.

Figure 8 - Average reservoir pressure.



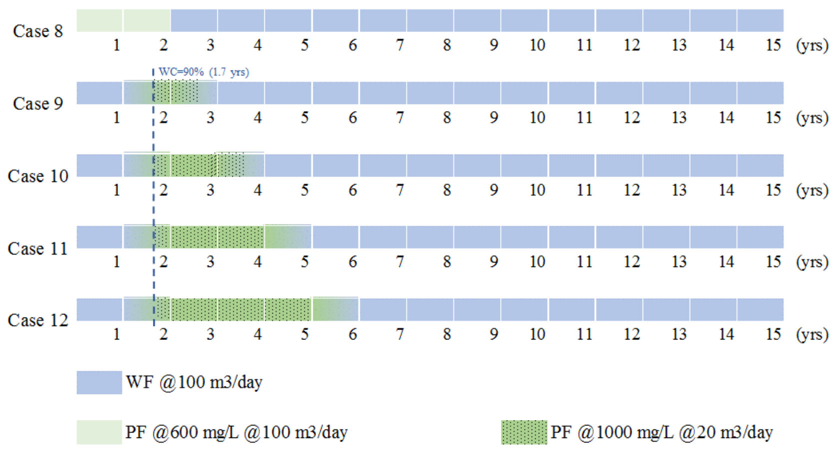
Source: Authors.

Figure 8 shows the average pressure for cases 1, 2 and 7, as examples. Initial reservoir pressure was 689 psi, so it can be observed that during water flooding there was an initial loss, which is a normal behavior due to production of fluids, afterwards came a certain stability at about 603 psi as the bank of oil was formed and produced (fill-up), and then it rose rapidly as soon as the breakthrough occurred, forming a peak at about 1040 psi. However, the declining of the pressure was sudden, as water seemed to flow easily within the reservoir, rapidly increasing the values of water production rate and water cut accordingly. Regarding case 7, the initial behavior was just the same as case 1, until water cut achieved a 90% value, then polymer at 1000 mg/L started to be injected at a low rate of 20 m3/day, causing pressure to drop even more compared to water flooding. It stood stable for about three years and started to raise again, probably that was the time the injected polymer took to displace itself within the reservoir and fill it up until forming a new bank of oil. Pressure continued to increase until it reached over 900 psi and started to decline once again.

Average pressure for case 2 on Figure 8, on the other hand, showed to have a bigger loss at the beginning, but started to increase rapidly until breakthrough came to happen. Breakthrough influenced on the behavior of the curve, but did not stop pressure from getting higher values, until it reached about 1080 psi. Differently from water flooding, the declining of the pressure for was not sharp but in a very smooth fashion, continuing to be high during the simulated time.

The effort of diminishing the polymer expenses was also considered after a previous use of waterflooding. As Table 3 shows, the NPV values for cases 5, 6 and 7, despite the difference in concentration, showed the same behavior. It was studied then a variation of case 7, polymer at 1000 mg/L and at a rate of 20 m3/d, injecting polymer injection from 1 to 4 years (cases 9 to 12), as that was the time that showed the highest NPV during continued injection, followed again by waterflooding. The explained sequence is presented in Figure 9.

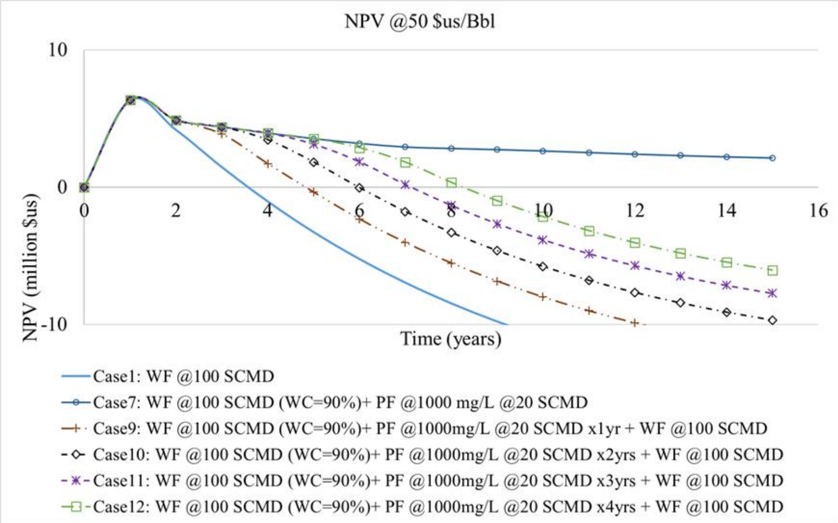
Figure 9 - Injection sequence.



Source: Authors.

Results from the explained analysis are displayed on Figure 10.

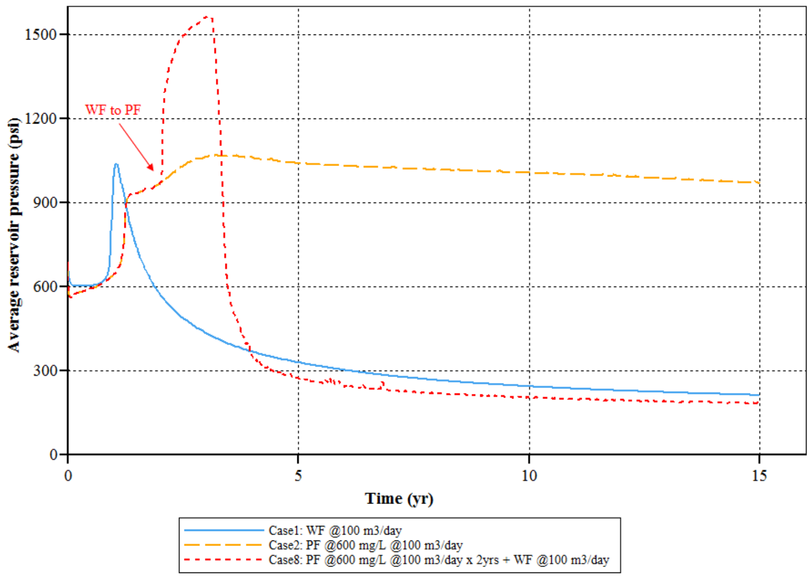
Figure 10 - NPV (WF + PF + WF).



Source: Authors.

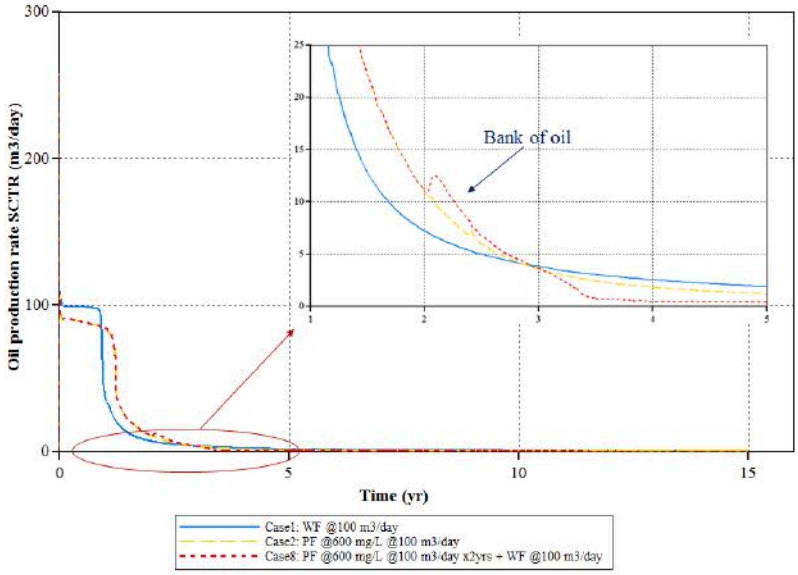
Figure 10 shows that despite diminishing the period of polymer injection, the NPV values previously obtained were not exceeded. Although every value of the curve during the declining period represents a net loss, it should be noticed that as the polymer injection time diminished the declining tendency was increased. Such behavior can be explained with the assistance of the average pressure curves. Figure 11 and Figure 13 display the comparison of the average pressure of the reservoir during polymer injection in a continued fashion and during a limited period.

Figure 11 - Average reservoir pressure (PF + WF).



Source: Authors.

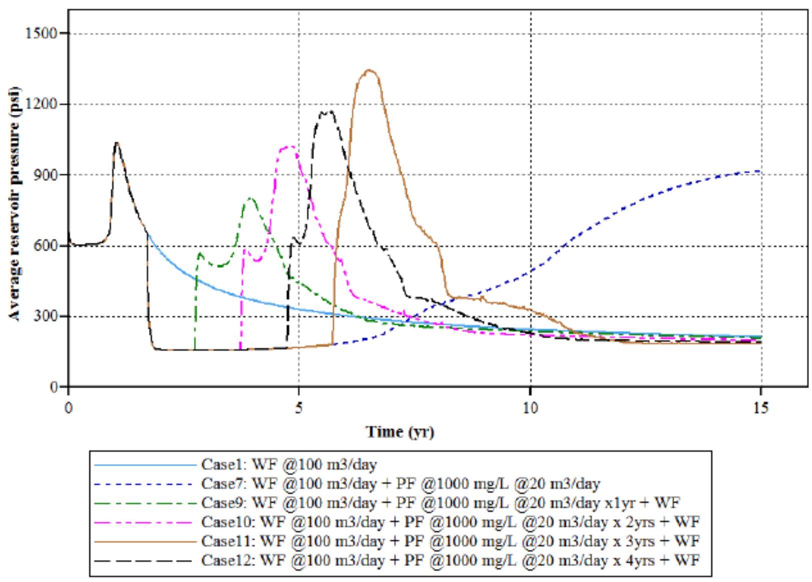
Figure 12 - Oil production rate (PF + WF).



Source: Authors.

As observed on Figure 11, the curve representing the polymer being injected from the beginning for a period of 2 years, initially showed the same behavior as continuous injection. But when the fluid changed from polymer to water, the pressure showed a clear augmentation forming a peak. Such peak of pressure, originated an increment of the oil production rate when compared to continuous polymer flooding, forming a bank of oil although it was almost imperceptible, as showed on Figure 12. Nevertheless, the water production rate was also higher than during polymer´s injection, as water has a lower viscosity and a higher injectivity than polymer´s (Figure 12), and apparently, the incomes due to an extra volume of oil were not able to overcome the expenses due to water treatment, which would explain the increased declining tendency mentioned on the paragraph above.

Figure 13 - Average reservoir pressure (WF + PF + WF).

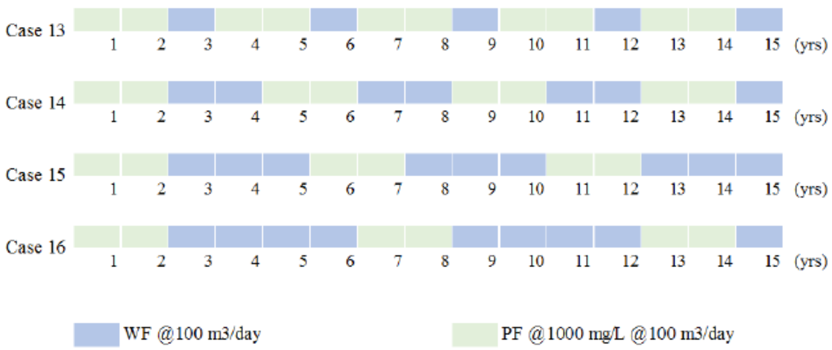


Source: Authors.

Figure 13 refers to water injection, followed by polymer flooding for a limited period followed again by water flooding. As continuous polymer flooding under such conditions, case 7, did not show any NPV values higher than initial water flooding´s, there was not a period of time that could be used as a reference, so 4 different periods were simulated and analyzed, going from 1 to 4 years. The behavior is, for practical purposes, the same as when injecting polymer from the beginning. Meaning that there was also an augmentation of pressure when the injected fluid changed from polymer to water, and the longer the period of polymer injection the higher the peak of pressure that was formed when changing fluids. The peaks of pressure assist the formation of oil banks, temporarily reducing the water cut values, however, the injection of water also generates a higher amount of produced water. Once again, the behavior of the NPV curves show that the incomes from the produced oil did not overcome the expenses of the process, provoking that the NPV curves decline more easily as the period of polymer injection went shorter (Figure 13).

In order to fulfill the purposes of this paper, one more injection sequence was simulated, that being the alternation between polymer and water flooding within the reservoir. Based on the previous results obtained. Only the results of polymer flooding from the beginning were took into consideration, as being injected after water did not show improvements in terms of NPV. And using once again the time of the highest value of NPV as a parameter of reference, the sequence of alternate injection is displayed on Figure 14.

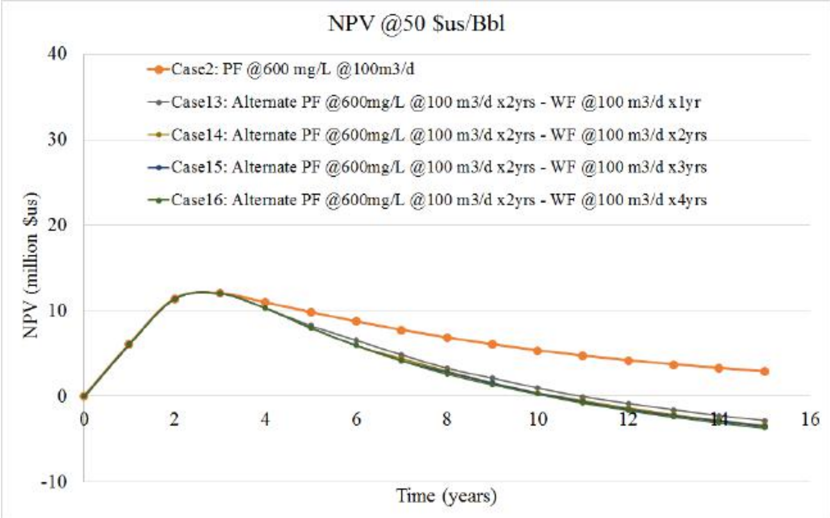
Figure 14 - Sequence of alternate injection.



Source: Authors.

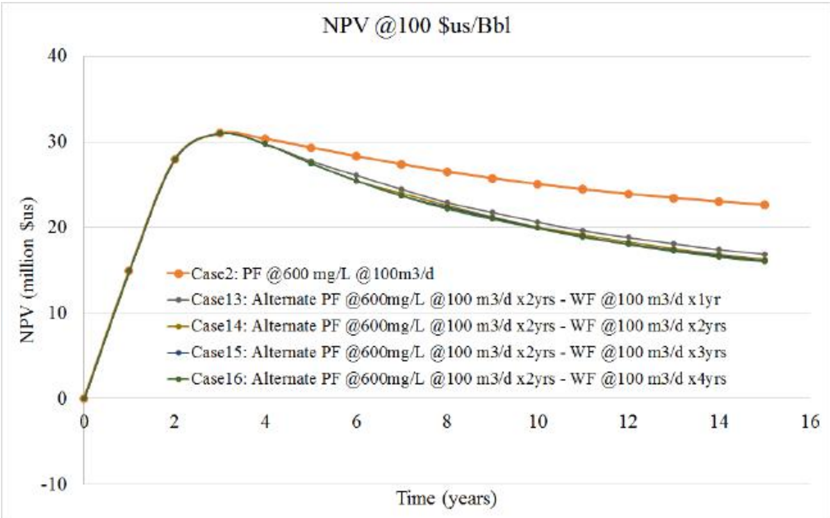
Figure 14 shows the possibilities that were studied, keeping the period of polymer flooding constant and varying the periods of WF from 1 to 4 years. Under those considerations, 4 more cases were created, numbered in sequence from case 13 to 16. As also detailed on Figure 14, the first fluid to be injected was always polymers. So, after simulating and using the corresponding values required by equation (2), the NPV values regarding the alternated injection are shown on Figure 15 and Figure 16.

Figure 15 - NPV for alternate injection (@US$ 50/Bbl).



Source: Authors.

Figure 16 - NPV for alternate injection (@US$ 100/Bbl).



Source: Authors.

Figure 15 and Figure 16 show the curves representing the NPV values corresponding to cases 2 and 13 to 16 during 15 years of alternate injection process between polymer and water flooding. As observed, there was almost no difference on the behavior of all of the curves, just a slight superiority of case 15 during the declining phase, that as mentioned before, did not represent an improvement, as any point during declination would represent a negative NPV value and no profit but a net loss.

4. Conclusion

The results showed that, under the considerations of this paper, even though polymer flooding got to produce more oil than water flooding after 15 years, polymer injection would only improve the NPV values when injected from the very beginning of the reservoir´s productive life. Furthermore, it should be considered if the additional profits due to polymer flooding are high enough to start a project.

In addition, reducing the time of polymers injection still improved the oil production, but not the highest NPV positive values. Continuous polymer injection did improve the NPV curves during the declining period, however, all those values are negative and do not offer any financial appeal for investment purposes. Polymer flooding, after water flooding, also did not improve the NPV values, neither being injected continuously nor for just a limited period, although it did get to produce more oil after 15 years.

Summing up, although the improvements regarding polymer flooding are usually focused on the reduction of the mobility ratio, it also delivers benefits regarding the maintenance of pressure within the reservoir, under controlled circumstances. When it comes to oil recovery methods, the additional amounts of hydrocarbons produced, when compared to conventional methods, does not guarantee to achieve the economic expectations.

It is recommended to carry out a study and analyze the injection of aqueous chemical solutions (polymer, alkali and surfactant) both separate and combined fashions, from the beginning of the reservoir´s productive life and after a water flooding process (when water cut reached a 90% value).

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