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EVALUATION OF ALTERNATE WATER-POLYMER INJECTION PARAMETERS USING NUMERICAL SIMULATION

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ABSTRACT

Finding an efficient injection strategy using polymers to reduce water-oil mobility ratio and improve sweep efficiency relies on many parameters. To overcome the disadvantages (injectivity loss and high costs) of injecting a continuous polymer bank, an alternative is to alternate water-polymer injection cycles, combining the benefits of water flooding (better injectivity) and polymer flooding (better sweep). A common approach is the injection of a continuous polymer bank after a period of water injection. In this case, parameters of the polymer bank (i.e. duration and starting date of the bank) are control variables and must optimized for the strategy. This work (1) evaluates the impact of alternate water-polymer injection parameters and (2) analyzes the viability of using alternate water-polymer cycles to improve the performance of the polymer flooding strategy, previously optimized for continuous injection bank. We analyze the cycle period, starting date of the cycle, and initial injected fluid using net present value (NPV) and other indicators (cumulative oil and water productions and cost of polymer injection). We apply the study to two reservoir models based on offshore heavy oil fields. The results show that cycle parameters can impact strategy performance significantly and that proper evaluation can benefit production. We observed that reducing the cycle period helped maintain injection flow at higher levels, avoiding the reduction of oil production by pressure depletion. We also noted that the cycle must start in the first years after the beginning of injection. It is important to identify the most influential parameters to set injection levels to support beneficial effects of both methods, and adjust the optimum amount of polymer to be injected.

KEYWORDS

polymer flooding; EOR; numerical simulation; economic evaluation

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1. INTRODUCTION

Polymer flooding is a chemical enhanced oil recovery (EOR) technique that involves adding polymer to water, increasing its viscosity **(Lake, 1989)**. Polymer flooding reduces the water-oil mobility ratio to improve sweep efficiency **(Needham & Doe, 1987; Miglicco, 1986; Sorbie, 1991)**. Developing a polymer-flooding project is complex, involving many variables and it is influenced by reservoir conditions beyond the sweep efficiency improvement.

The two main groups of variables **(Gaspar et al., 2016)** to be evaluated when selecting a production strategy are: project variables (G1, related to field development, i.e. number and location of wells, platform capacity and schedule of well drilling) and control variables (G2, related to field management). With polymer flooding, a common approach is to inject a continuous polymer bank following a period of water injection. In this case, parameters of the polymer bank (e.g. duration and starting date of the bank) are also control variables and must be optimized for efficiency. Possible disadvantages related to this approach are injectivity loss and high costs due to longer periods of polymer injection.

Recent works have demonstrated the importance of defining the injection fluid in the beginning of field development **(Lamas & Schiozer, 2016; Botechia et al., 2016)**, as it can affect other choices in the production strategy. Besides project variables **(Gaspar et al., 2016)**, such as number and location of wells, polymer specificities (for instance, polymer solution concentration and bank size) must be considered to maximize the potential. The costs of this improved oil recovery should also be considered (chemicals, logistics, and potential platform alterations).

Botechia et al. (2016) presented a methodology for production strategy selection considering polymer flooding. The authors considered the injection of a continuous polymer bank, optimizing the polymer injection starting date and bank size. However, alternate water-polymer injection cycles can also be an effective means to the injection strategy **(Zampieri & Moreno, 2013)**. Polymer flooding could potentially lose injectivity **(Seright et al., 2009; Li & Delshad, 2014; Luo et al., 2016)**, which can be lessened by using alternate cycles.

In this paper we (1) evaluate the impact of selected parameters of alternate water-polymer injection in heavy oil reservoir simulation models and (2) compare the performance of alternate water-polymer cycles for cases previously optimized for continuous injection of polymer bank, using numerical simulation and economic analysis. We analyze the cycle period, starting date of the cycle, and initial injected fluid. We use NPV (Net Present Value) as the objective function, as we include polymer costs in the analysis, but we also assess other indicators such as cumulative oil and water production.

2. MODELING ALTERNATE WATER-POLYMER INJECTION

Figure 1 shows the alternate injection scheme used in this study.

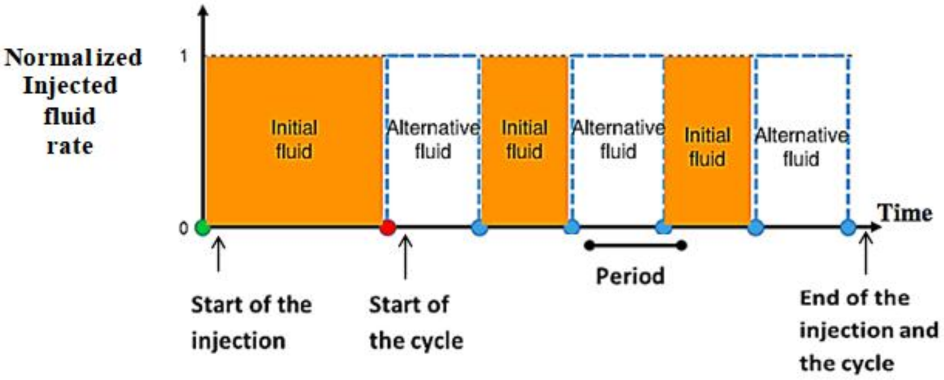


Figure 1. Alternate water-polymer injection modeling. Injected fluids alternate between zero (not being injected) and 1 (being injected) in the vertical axis.

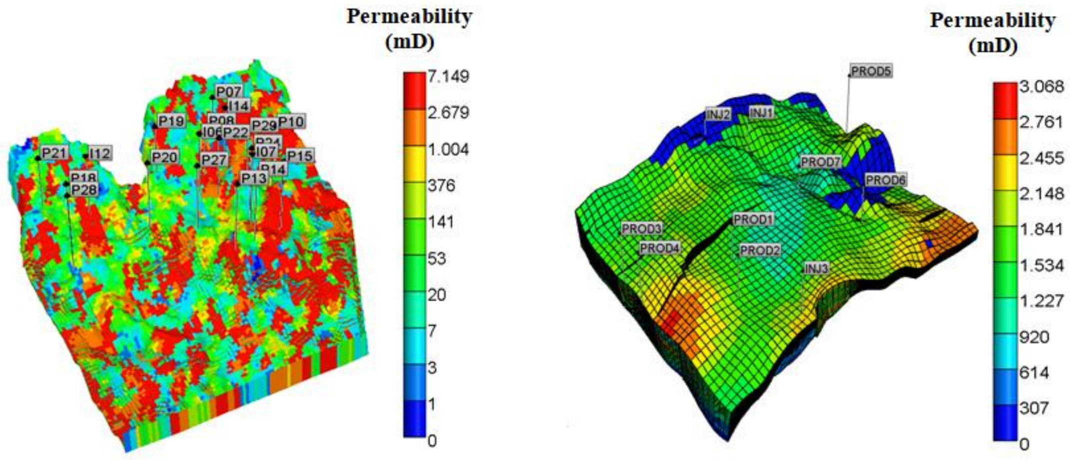


Figure 2. Alternate water-polymer injection modeling. Injected fluids alternate between zero (not being injected) and 1 (being injected) in the vertical axis.

We test two initial fluids, water and polymer. The horizontal axis shows the start of injection of the "initial fluid" (either water or polymer), the "start of the cycle," and the "period" of the cycle. At a pre-determined date, the cycle begins by replacing the "initial fluid" by the other fluid, called the "alternative fluid," represented by the blue dashed line. At the end of a period, the alternative fluid is replaced totally by the initial fluid. The periods of injection remain the same until the end of injection. The injected fluids alternate between zero (not being injected) and 1 (being injected) in the vertical axis, replacing each other. Thus, the three parameters of the alternating injection used in this work are: the "Initial Fluid," "Cycle Start Date," and "Period."

3. METHODOLOGY

Using a tree of cases, we assess the impact of varying the three parameters of alternating injection (initial fluid, cycle start date, and period) in a specific production strategy. We assign various values to the evaluated parameters to assess the impact on the alternating injection strategy. The methodology consists of the following steps:

1. Select values for each parameter;
2. Create scenarios including combinations of all values for all selected parameters;
3. Simulate all generated scenarios;
4. Evaluate results.

First, we analyze the general impact of alternate injection cycle parameters. Then, we compare the best and worst cases with the base cases (without cycles), assessing whether alternate injection cycles maximize NPV for each model.

3.1 Application

3.1.1 Reservoir simulation case

We use two simulation models for this study, and both are representative of offshore heavy oil fields. Figure 2 shows permeability maps and well locations, while Table 1 shows the main characteristics for both models. Table 2 presents the economic parameters used in this work. The cost of polymer also includes, besides chemicals costs, the logistics and possible adaptations to the platform.

The production strategies for both models were optimized for polymer flooding. Some of the optimized variables relate to the polymer bank (size and starting date of polymer injection). Thus, the injection strategies always begin with water injection, followed by polymer bank injection.

The target viscosity of the polymer solution is 10 cP at 1500 ppm. Figure 3 shows the behavior of the viscosity with concentration.

3.1.2 Parameters of alternate water-polymer injection model

In this work, we tested two initial fluids (water and polymer), 10 different cycle dates (start dates from 2014 to 2032) and 4 cycle periods (0.5, 1, 2 and 5 years). Simulation starts in 2010.

Table 1. Main characteristics of models.

Parameter	Model 1	Model 2
Av. Permeability (mD)	1501	1650
Av. Porosity	0.22	0.20
Av. Depth (m)	2350	3066
Temperature (°C)	78	81
Average Pressure (kPa)	23668	31783
Oil Viscosity (cP)	174	70
°API	15	17
Grid blocks (I, j, k)	104 x 102 x 10	37 x 48 x 19
Av. Grid Block Size (m)	100 x 100 x 100	120 x 180 x 5
Reservoir Dimensions (m)	10400 x 10200	4440 x 3840
Number of Wells	15 producers, 4 injectors	7 producers, 3 injectors

Table 2. Economic parameters.

Market Values	Discount Rate (%)	9
	Oil Price (USD/bbl)	75
Taxes	Special Taxes on G. Revenue (%)	9.25
	Corporate Taxes (%)	34
	Royalties (%)	10
Costs	Oil Production (USD/bbl)	10
	Water Production (USD/bbl)	1
	Water Injection (USD/bbl)	1
Investment	Initial Investment (USD Millions)	1000
	Wells (USD Millions)	100
Polymer cost	Polymer injection cost (USD/kg)	8

4. RESULTS

4.1 Model 1

Figure 4 shows the results for NPV (blue circles) and cumulative produced oil (orange circles) for all simulation runs for Model 1, considering different cycle periods (Figure 4a) and different starting dates (Figure 4b), with initial injections of water. Figure 5 shows the same parameters, but with initial injections of polymer. Increased cycle periods tended to decrease NPV and Np, so

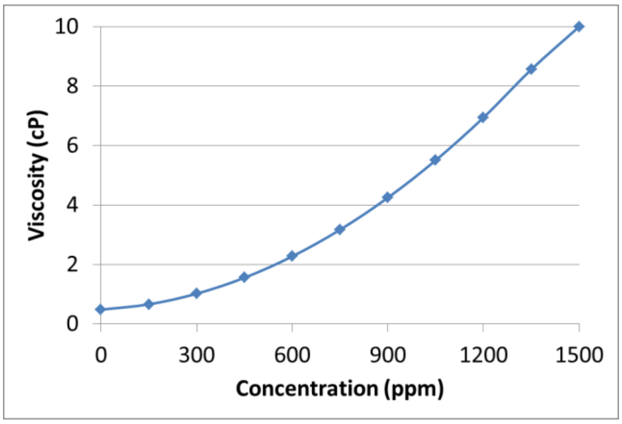
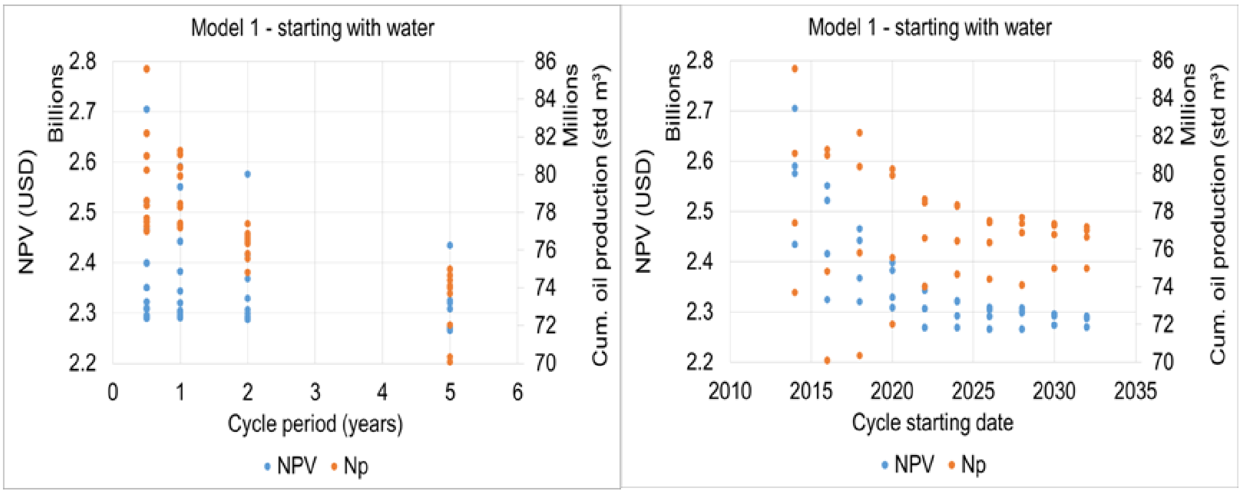


Figure 3. Concentration of polymer solution vs. viscosity.



(a) **(b)**

Figure 4. Results for NPV and Np for (a) different cycle periods (each point represents a cycle period and a start date) and (b) different cycle start date (each point represents a cycle start date and a period) for Model 1, with initial injection of water.

(a) **(b)**

Figure 5. Results for NPV and Np for (a) different cycle periods (each point represents a cycle period and start date) and (b) different cycle start date (each point represents of cycle start date and period) for Model 1, with initial injection of polymer.

reduced cycle period times were beneficial for these objective functions. Prolonged polymer injection times resulted in losses for this case. Starting the cycle later also resulted in reduced NPV and Np. The best options are to start soon and use short cycle periods.

The cycle starting in 2014 with an initial polymer injection and periods of 6 months showed the highest NPV (the simulation starts in 2010). The worst case, for NPV, started in 2020, also with an initial polymer injection and cycles of 5 years. Table 3 shows the results for the base case (without cycles), and best and worst cases (with cycles) for Model 1. We list results for NPV, cumulative oil and water production, mass of injected polymer, and time of max NPV. Table 4 shows the variation in relation to the base case for the same indicators.

While the water produced and costs for injected polymer were higher for the best case, the NPV increased significantly due to increased oil production. Note that the indicators refer to the time of maximum NPV. Thus, when using cycles, oil production increased substantially with longer production time when compared with the base case. On the other hand, the worst case showed significantly decreased NPV and oil production.

Table 3. Results for best, worst, and base cases (Model 1).

Cases for Model 1	NPV (10^6 USD)	Np (10^6 m³)	Wp (10^6 m³)	Mass of poly. injected (10^6 kg)	Time of max. NPV (Years)
Cycles - Best Case	2794	87	225	165	40
Base case (no cycle)	2517	76	139	184	32
Cycles - Worst Case	2190	68	142	145	31

Table 4. Variation in indicators for best and worst cases, in relation to the base case (Model 1).

Cases for Model 1	NPV Variation (%)	Np Variation (%)	Wp variation (%)	Mass of poly. injected variation (%)	Dif. in time of max. NPV (years)
Cycles - Best Case	11	15	38	-10	8
Cycles - Worst Case	-13	-11	2	-21	-1

The best case showed oil production above the base case for the majority of the simulation time as well as prolonging the production time (Figure 6). The worst case exhibited opposite behavior.

The significant improvement, in the best case, was due to the better injectivity and maintained pressure obtained with cycles (Figure 7). Despite abrupt drops and increases in injectivity during the changeover between polymer and water, the average pressure in the long term was higher when compared with the base case. The base case showed a sharp increase in injectivity only at the end of the polymer slug when water was injected again, in 2036. The worst case showed reduced injectivity in the long term.

Thus, as injection cycle parameters affected the strategy significantly, the starting date and cycle duration must be optimized to add value to a production strategy.

4.2 Model 2

For Model 2, the initial fluid affected general results. Figure 8 shows the results for NPV (blue circles) and cumulative oil production (orange points) for all simulation runs, considering different cycle periods (Figure 8a) and different starting dates (Figure 8b), and establishing water as the initial fluid. Figure 9 shows the same parameters, but with initial polymer injection.

Cases with initial water injections showed little difference for the different cycle lengths with similar values for NPV and Np for different periods. The earliest start dates achieved the best NPVs. After 2024, the strategies have similar values, indicating that field production was interrupted (production wells shutdown when they reach an uneconomic value for water cut).

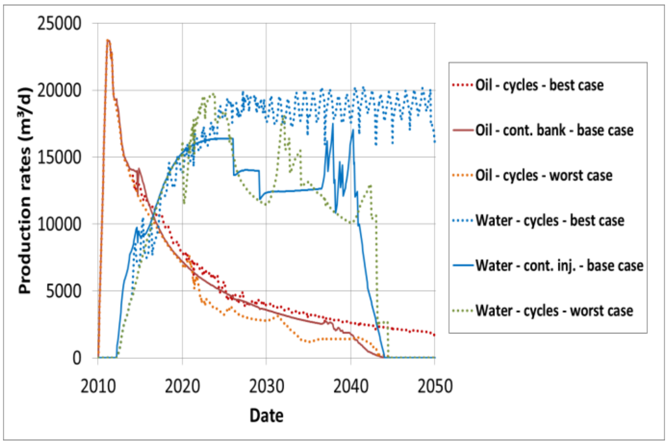


Figure 6. Oil and water rates for best, worst, and base cases (Model 1).

For cases with initial polymer injection, the shortest cycles achieved the highest NPV. As with initial water injections, the earliest cycle start dates achieved highest NPV. Note that oil production increases when the cycle start was delayed (Figure 9b). Therefore, NPV and Np did not correlate in this case.

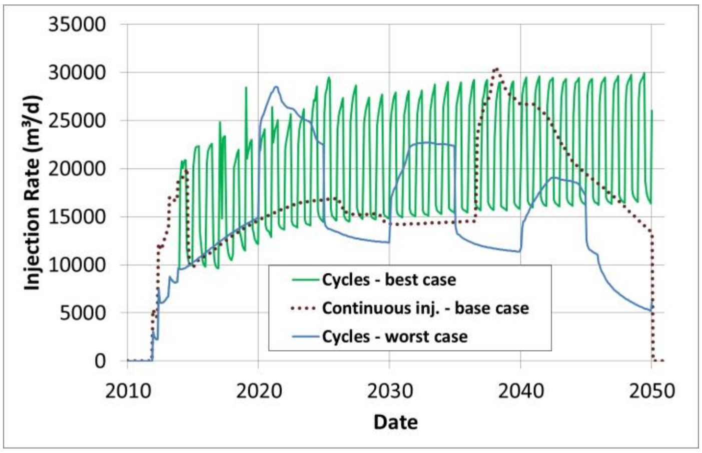


Figure 7. Injection rates for best, worst, and base cases (Model 1).

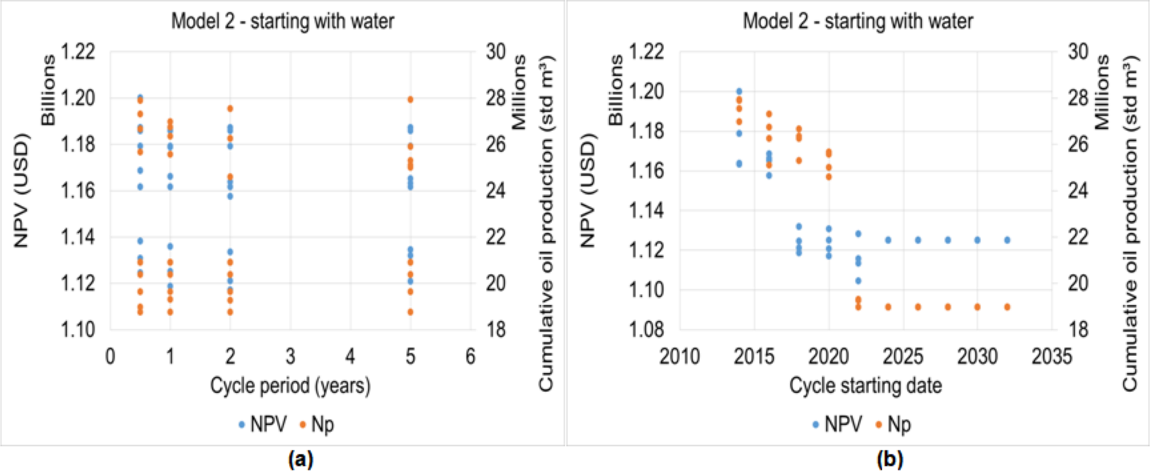


Figure 8. Results for NPV and Np for (a) different cycle periods (each point represents a cycle period and a start date) and (b) different cycle start date (each point represents a cycle start date and a period) for Model 2, with initial injection of water.

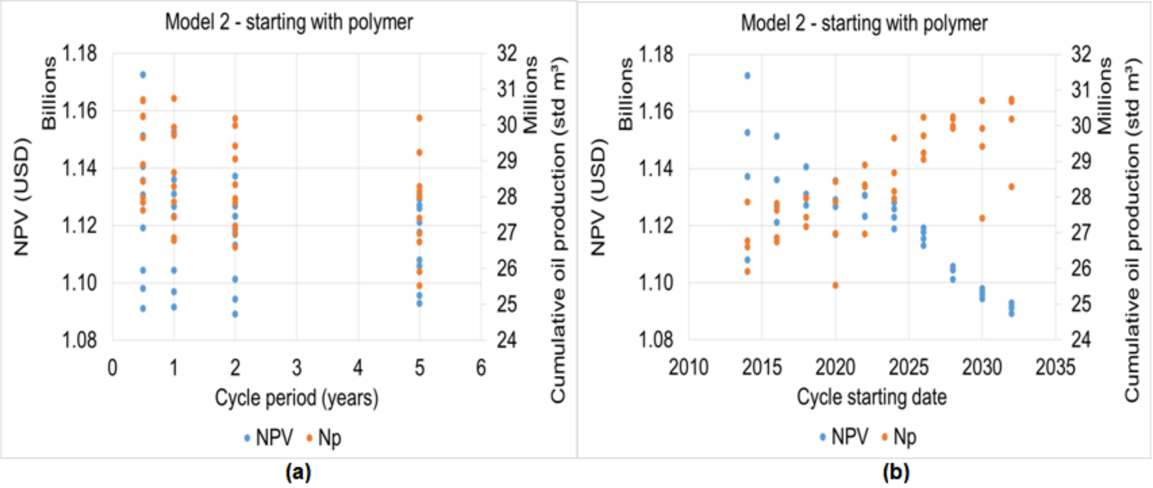


Figure 9. Results for NPV and Np for (a) different cycle periods (each point represents a cycle period and a start date) and (b) different cycle start date (each point represents a cycle start date and a period) for Model 2, with initial injection of polymer.

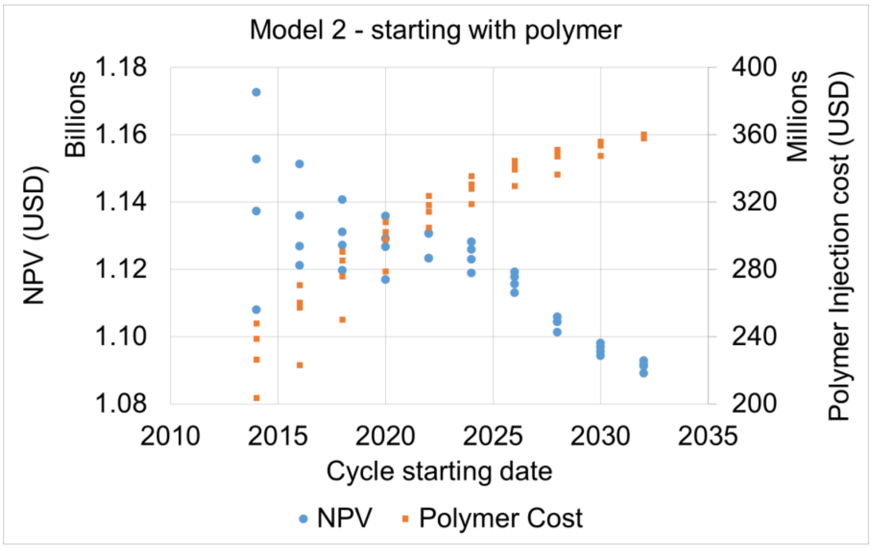


Figure 10. NPV and cost of polymer injection at different cycle start dates. Each point represents a simulation run for a determined start date. Blue points represent NPV, while orange points represent polymer injection cost.

NPV did not improve with increased Np because the cost for polymer injection increased as the beginning of the cycle was delayed, since it was initially injecting polymer and the fluid changed to water only when the cycles began. Therefore, longer polymer injection times increased the amounts of polymer so much that the incremental oil produced was insufficient to cover these costs. Figure 10 shows the NPV and the cost of polymer injection according to the start of the cycle.

These results show that using only production indicators may be insufficient to assess polymer injection parameters. Potential increases in oil production may involve further costs that must be assessed.

We obtained the best results starting the cycle in 2014 with a cycle period of 6 months, with initial water injection. The worst results were for the case starting the cycles in 2030 with a 2-year cycle length, beginning with initial polymer injection. Table 5 shows the following results for Model 2: NPV, cumulative oil and water production, the amounts and costs of injected polymer and time of max NPV. Table 6 shows the results for the same indicators in relation to the base case.

Table 5. Results for the best, worst, and base cases (Model 2).

Cases for Model 2	NPV (10^6 USD)	Np (10^6 m³)	Wp (10^6 m³)	Mass of poly. Inj. (10^6 kg)	Cost of Poly. Inj. (10^6 USD)	Time of max. NPV (Years)
Cycles - Best Case	1200	28	118	87	216	29
Base case (no cycle)	1140	29	76	112	333	31
Cycles - Worst Case	1089	29	78	118	360	30

Table 6. Variations for best and worst cases, compared to the base case (Model 2).

Cases for Model 2	NPV Variation (%)	Np Variation (%)	Wp variation (%)	Mass of poly. inj. var. (%)	Cost of Poly. inj. var. (%)	Dif. in time of max. NPV (years)
Cycles - Best	5	-3	55	-22	-35	-2
Cycles - Worst	-4	3	3	5	8	-1

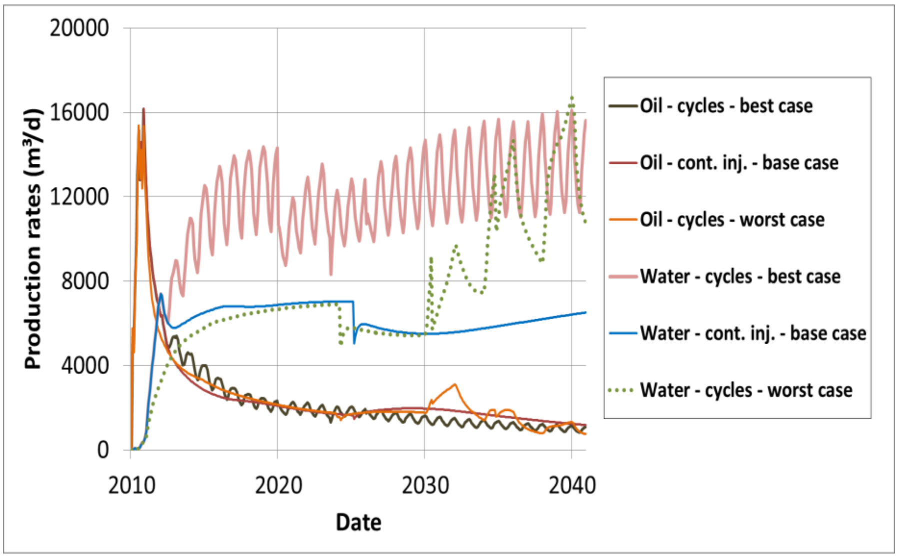


Figure 11. Oil and water rates for best, worst, and base cases (Model 2).

Note that cumulative oil production for the case with the highest NPV was less than that for the base case. However, the bulk of production happened sooner, which positively influenced NPV. Figure 11 shows the highest oil production rate for the period between 2012 and 2018 for the best case. A reduction of 35% for polymer flooding costs, over the base case (Table 6), contributed significantly to improving NPV. Also, note that the indicators refer to time of maximum NPV, which was two years earlier for the best case than for the base case.

The worst case, despite similar oil production to the base case, presented lower NPV, largely due to higher injection costs. Thus, in this example, the main benefit of alternating cycles is the option to control the amount of injected polymer to lower costs.

5. CONCLUSIONS

In this work, we varied parameters of polymer-water injection cycle parameters and found they affected economic and production indicators significantly. Alternate water-polymer injection can benefit a production strategy, bringing better economic return than the injection of a continuous polymer bank, but the parameters must be evaluated properly for each case to find the best start date and cycle length, otherwise the performance of the strategy can be unsuccessful.

In the cases tested, the best options were shorter cycles with early start dates. This configuration provided the better injectivity of water flooding with the better fluid displacement of polymer. We were also able to adjust the amounts of injected polymer to improve financial return.

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NOMENCLATURE

EOR	Enhanced oil recovery
Np	Cumulative oil produced
NPV	Net present value
Wp	Cumulative water produced

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