COB09-1961 - ANALYSIS OF THE EFFECT OF OIL MOBILITY ON THE INJECTION RATE OPTIMIZATION FOR WATER INJECTION UNDER FRACTURING CONDITIONS

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Abstract. *It is known that injection with fracture propagation is an effective method for overcoming the problems caused by the injectivity loss due to the formation damage. In this process, a high conductivity channel is created by the continuous injection of water at a pressure equal or higher to the minimum formation propagation pressure (healing pressure), and the properties and geometrical characteristics of the fracture created are determined, primarily, by the petrohysical and geomechanical features of the reservoir rock, as well by the water properties and injection configuration. There are several methods for representing both, the injectivity loss and the fracture propagation when commercial simulators are used; in this work virtual horizontal wells are used to represent to the fracture propagation. This approach consists in the opening of wels perforations accordingly with the fracture propagation profile obtained from geomechanical simulation and the modification of the Well Index to describe the increasing conductivity of the channel open by the fracture. In the hydraulic fracturing process, it is necessary to give special attention to the operation pressure and the injection rates, since if the bottom-hole pressure of the injector well falls below healing pressure the fracture will close and the efficiency of the process will be less than expected. The scope of this study is to analyze the determination of the minimum injection rate to avoid the fracture closure in commercial flow simulators and the effects of oil density and viscosity on the horizontal virtual well representation of fracture propagation. The results indicate that, in some cases, it is necessary an increase on the injection rate from the fracture opening time to maintain the fracture propagation, and the importance of a continued feedback between flow and geomechanical simulation, in order to monitor pressures and injection rates for a satisfactory accomplishment of the water injection with fracture propagation process.*

Keywords*: Reservoir Simulation; Water Injection; Fracture Propagation Modeling*

1. INTRODUCTION

Water injection is the most used method for assisting oil recovery and maintaining the pressure of the reservoir. However, the injection process presents some disadvantages that must be analyzed carefully in order to guarantee that the process is carried out in an efficient form.

As pointed by Altoé et al (2004), injectivity loss is one of the most common problems associated to water injection processes in reservoir management. Muñoz Mazo et al (2007) showed the usefulness of water injection with fracture propagation (IFPP) to overcome the negative effects of injectivity loss in isotropic and anisotropic reservoirs with different oil densities and viscosities.

The method, as pointed by Montoya Moreno et al (2007), consists into increasing the injection pressure as long as the injectivity loss is present until it reaches values above formation fracturing pressure, creating in this way high conductivity channels inside the reservoir, using the injection pressure of the water for maintaining its opening throughout the time and to guarantee its propagation. In this way, a bigger water injection in the reservoir is expected jointly with an increase in the final recovery and consequently greater sweep efficiency for the process.

Costa (2009) and Muñoz Mazo et al (2008) showed the importance of establishing an optimal injection rate as consequence of reservoir pressure variation conditions and for different injector-producer well spacing.

Several studies in the area of hydraulic fracturing show the necessity of establishing minimum conditions of pressure in order to guarantee the fracture propagation in the porous medium, so it is necessary to relate the minimum pressure of fracture propagation with an analysis of the optimization of the injection rate. During the water injection, increments in the injection pressure are necessary to keep the constant rate, and this gradual increase in the injection pressure induces to the beginning of the fracture when the injection pressure reaches the fracturing pressure of the formation creating the fracture. A value slightly lesser of pressure than the one of fracturing is necessary for its propagation and, below this value, the fracture closes. The evolution of the injection pressure during the hydraulic fracturing process is shown in Figure 1.

The propagation and the advance of the fracture inside the reservoir, and some of the characteristics of the fracture generated in the process, mainly geometry (opening, length and height) and orientation, are determined by the laws of mass conservation in the fracture and by the petrophysical and geomechanical characteristics of the reservoir rock and the conditions of injection. All this knowledge is important for the determination of the position of the wells since, as pointed by Muñoz Mazo et al. (2006), there is the possibility that the fractures generated in the reservoir reach the producing wells, leading to a canalization of the injected water into the reservoir, diminishing the efficiency of the injection process.

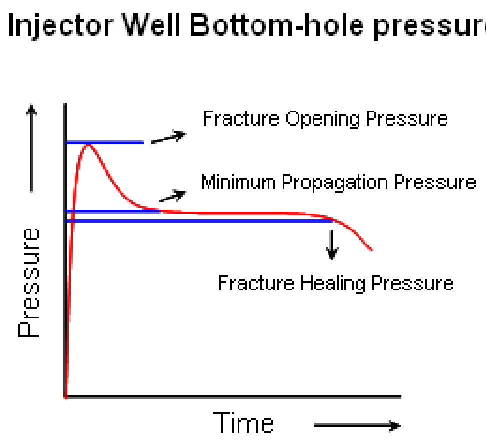

Figure 1. Injector well pressure behaviour during hydraulic fracturing

Thus, taking in consideration that the fracturing due to water injection presents a volumetric efficiency relatively low (0.05%) because of the high filtration rate, and that the fracture propagation is a slow process, that can take months or years to be accomplished, it is necessary to guarantee the continuity of the propagation by means of a rigorous control of the injection pressure, that, consequently, implies an optimization of the injection rate.

The simulation of the water injection with fracture propagation process requires the coupling of models for the injectivity loss associated with the permeability reduction as consequence of formation damage and a model of fracture propagation based on the geomechanical characteristics of the rock. The loss model is analytical and allows representing the reduction of the absolute permeability in the region near the injector well, while the fracture propagation model is derived from the use of geomechanical simulators. In this work the coupled model is used to study the effect of injection rate optimization for water injection under fracturing conditions.

The analysis presented in this work, that takes as study parameters the water injection rate and the recovery factor in terms of cumulative oil production is centered in the optimization of water injection rate from the moment in which the fracture is created aiming to keep the fracture open, and the effects of different oil types into the behaviour of the injection process.

2. INJECTIVITY LOSS AND FRACTURE PROPAGATION MODELING FOR COMMERCIAL SIMULATORS

Coupling geomechanical calculations and flow simulation is fundamental for the process modeling, nevertheless, the access to a full coupled simulator is limited the most of the times and a full coupled simulation presents a high computational consumption time, making necessary the use of analytical functions to represent the injectivity loss and the results obtained from an in-house geomechanical simulation to model the fracture propagation in time.

2.1. Injectivity loss modeling

In order to model the well impairment, the injectivity index is varied as a result of considering permeability as a time function. The permeability variation around the injector well, as consequence of formation damage, is modeled by an analytical expression, as shown by Montoya Moreno et. al. (2007):

$$k_s = \frac{k_{ij}}{\left(1+\left(n * a_i * t\right)\right)^{\frac{1}{n}}} \tag{1}$$

In Equation 1, k_s is the absolute permeability of the damaged region, k_{ij} is the original permeability of the block in which the injector well is located, n and a_i are the constants that determine the decline trend of the curve (for this case, respectively, 1.0 and 0.009).

Once the permeability variation is established, it is introduced into the simulator by the modification of the well index in each time step until the well bottom-hole pressure reaches the formation fracturing pressure. The Well Index variation, which includes properties as well block permeability, the formation damage factor (skin factor) and their combinations, is given by the Equation 2.

$$WI = \frac{2\pi hkw_{frac}}{\ln\left(\frac{r_e}{r_s}\right) + s} \tag{2}$$

2.1. Fracture propagation modeling

Commercial simulators do not offer options to model the propagation of induced fractures by water injection, this make necessary the implementation of some modifications, such as transmissibility modifiers, local refinements and equivalent well radius, to represent the fracture propagation.

Souza et al. (2005) proposed, in an attempt to overcome this difficulty, altering the block transmissibility to represent the conductivity increase caused by the fracture presence. For the purpose of this work, the fracture propagation is modeled using a virtual multilateral well as shown in the Figure 2. In this approach, the injector well perforations are open accordingly to the fracture propagation profile obtained from hydraulic fracturing simulation tools (Devloo et al. (2001)) that also estimate fracturing pressure, vertical penetration, fracture propagation pressure and fracture width and length as time functions.

The effects of fracture length on sweep efficiency are pointed by Gadde et al. (2001). Fracture propagation modifies the water displacement front, creating a preferential flow direction that, in some cases, causes the early water incoming at the producing wells.

The fracture geometry and the permeabilities of both reservoir and fracture are studied by Cinco-Ley and Samaniego (1981) by means of the Dimensionless Fracture Conductivity factor (F_{DC}), as shown in Equation (3).

$$F_{DC} = \frac{k_f w}{kL_f} \tag{3}$$

Where k_f is the fracture permeability, w is the fracture width, k is the matrix permeability and L_f is the fracture length.

Fracture conductivity can be improved by the increase of the fracture permeability and width or by the diminution of the matrix permeability or the fracture length. In this work the relationship between fracture length and matrix permeability is analyzed using the results obtained from the geomechanical simulation and their effects on the technical and economic performance of the reservoir.

The virtual horizontal well approach used in this work to represent the fracture growth is based in the analyses of Ogunsanya (2005), who considered the horizontal well as a small height fracture. In this model, the well parameters are calculated as function of the geometric characteristics of the fracture, avoiding the high time consumption of the fully coupled simulators with geomechanics (Muñoz Mazo et al, 2006).

3. METHODOLOGICAL PROPOSAL

For this study it is applied the methodology proposed by Muñoz Mazo et al (2007) where, initially, are studied, three cases:

(1) Without injectivity loss and without fracture propagation (NLNF, for No Loss, No Fracture).

(2) With injectivity loss and without fracture propagation (WLNF, for With Loss, No Fracture).

(3) With injectivity loss and fracture propagation (WLWF, for With Loss, With Fracture).

The same models are used for the different cases proposed in the work cited above for the representation of the processes of injectivity loss and fracture propagation in the commercial simulator. WLNF model aims to quantify the effect of injectivity loss in the reservoir behaviour, and WLWF model illustrates the impact of fracture propagation in the model affected by the injectivity loss model.

The simulation models that were used to obtain the results reported in this work consist in a Cartesian grid, with 51x51x10 active cells. Each block has 30x30x4 m and the main reservoir properties are shown in Table 1. The production strategy implemented for the simulations represents an inverse five-spot arrangement, with a central vertical injector well operating at a constant rate of 1200m³/day and limited by fracture pressure (35771 kPa), and four vertical producer wells, that operate at 300 m³/day each one. The simulation time is 6200 days.

Table 1. Reservoir properties

Property	Nomenclature	Value
Porosity	ϕ	25%
Horizontal Permeability	kx = ky	500 mD
Vertical Permeability	kz	200 mD
Water viscosity	μ_w	0.9 cP
Relative Permeability to oil	kro'	0.5833
Relative Permeability to water	krw'	0.3593

For the purpose of this work, which is to analyze the effect of the oil type on the sweep efficiency of the waterflooding under fracturing conditions, three different oil types are used, and their properties are shown at Table 2:

Table 2. Oil properties

Oil type	API gravity	Density (kg/m³)	Viscosity (cP)
Light	41	817.2	0.6
Intermediate	30	871.5	3.4
Heavy	21	924.8	17.1

The data used for fracture propagation are obtained from simulator PROPAG. For the development of the study, the main objective is to determine a value of water injection that, based on the conditions of the model, allows the continuity of the fracture propagation from its time of initiation, this is, a rate that keeps the bottom-hole pressure of the injector well above of the value of 34000 kPa. This value has been obtained from geomechanical simulation as the minimum value of propagation pressure. The used simulation grid is shown in Figure 2.

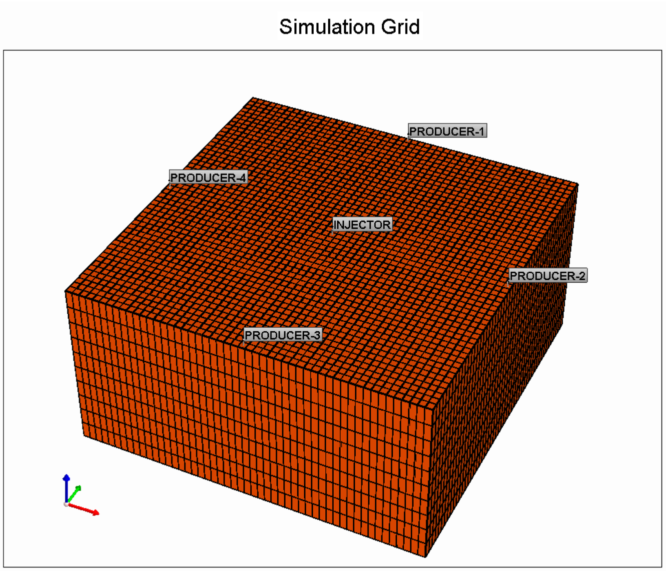

Figure 2. Simulation grid and well arrangement.

4. RESULTS AND DISCUSSION

The methodology proposed in the previous section is implemented for the three oil types. The following sections show the results obtained for every single type.

4.1. Results for intermediate oil

The simulation results of the cases NLNF and WLNF show the typical behavior for reservoirs affected by the injectivity loss, this is, a gradual reduction of the water injection rate followed by the pressurization of the reservoir. The injector well for the case considering injectivity loss reached fracturing pressure at 1830 days. From this time the modeling of virtual multilateral well with the results of propagation obtained from program PROPAG for 1200m³/day is used to simulate the fracture propagation.

The simulation of the case WLWF shows that at the moment in which the fracture starts to propagate, a fall in the bottom-hole pressure of the injector well occurs due to the elimination of flow restriction caused by the fracture. For the studied case, the pressure diminishes in an instantaneous way until a value lesser than the one established as propagation pressure, causing the closure of the fracture.

The behavior of the injector well bottom-hole pressure for the three cases is illustrated in Figure 3.

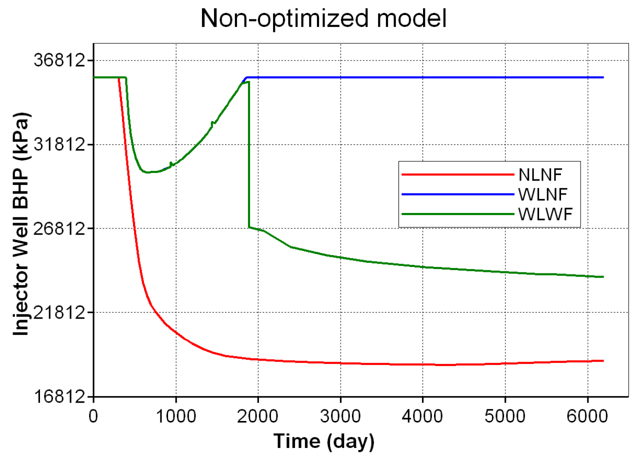

Figure 3. Pressure behavior for the non-optimized model.

The optimization process considered in this work consists in to determine an injection rate that keeps the bottom-hole pressure of the injector well above of the minimum fracture propagation pressure. For this, several simulations with the injection rate increased from the moment of initiation of the fracture are carried out. The behavior of the pressure for the simulations is shown in Figure 4.

In Figure 4, it can be observed that with an increase of the injection rate to 2200 m³/day, since the moment of the initiation of the fracture, the bottom-hole pressure of the injector well does not fall under the value of 34000 kPa, established as minimum pressure of propagation in the geomechanical simulation process.

However, with this value of injection rate an over-pressurization in the reservoir, originated by the high amount of water that is injected occurs, what causes a high final water production and a faster irruption, contributing in this way to the reduction of the efficiency of the water injection in terms of final oil recovery.

In order to control the high pressurization into the porous medium, the limitation of the injection rate by bottom-hole pressure is necessary for the injector well. In this way it is possible to guarantee the continuity of the fracture propagation preventing the exaggerated water injection, delaying the water irruption at the producer wells and diminishing the water production, with positive consequences for the final oil recovery.

Figure 5 shows the behavior of the injection rate for the simulated models (NLNF, WLNF, WLWF Optimized without control of injection rate and WLWF Optimized with injection rate control). Figure 6 presents the behavior of the pressure for the optimized model and Figure 7 illustrates the effect of the control of the injection rate on the final oil production.

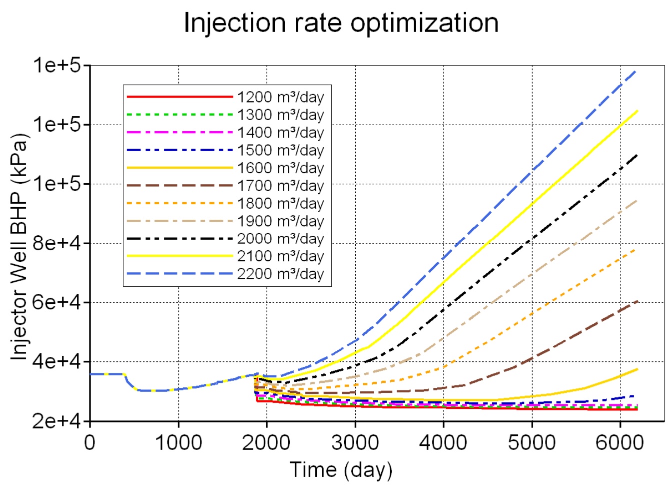

Figure 4. Pressure behavior during injection rate optimization.

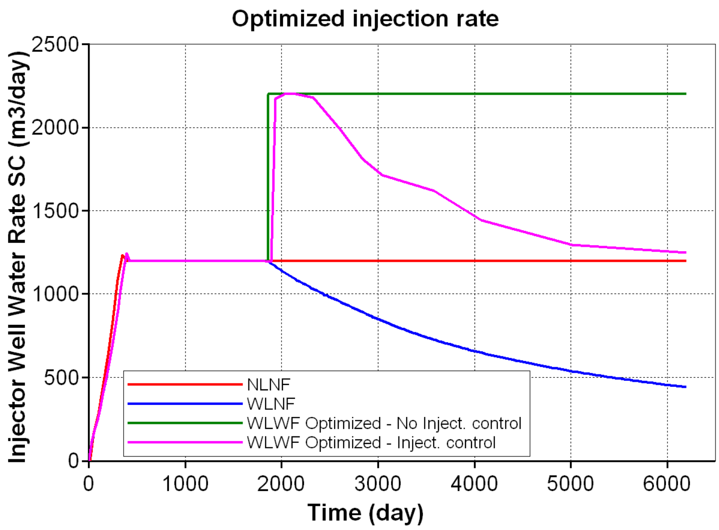

Figure 5. Injection rate behavior for the optimized model.

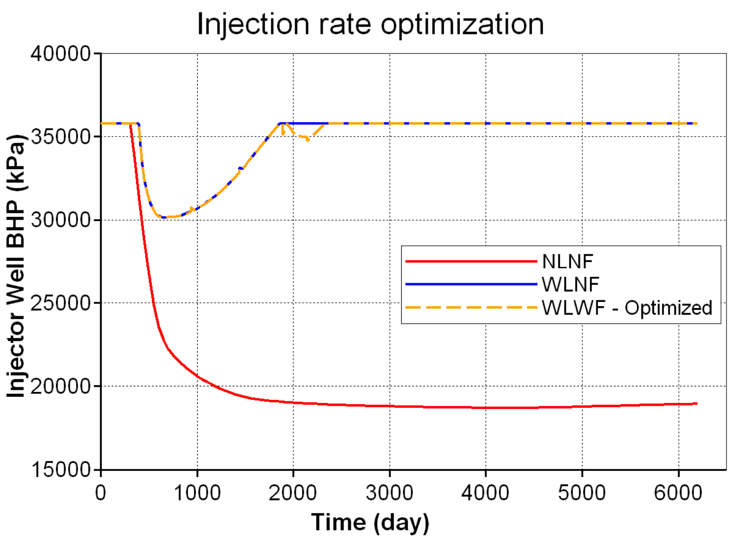

Figure 6. Pressure behavior for the optimized model.

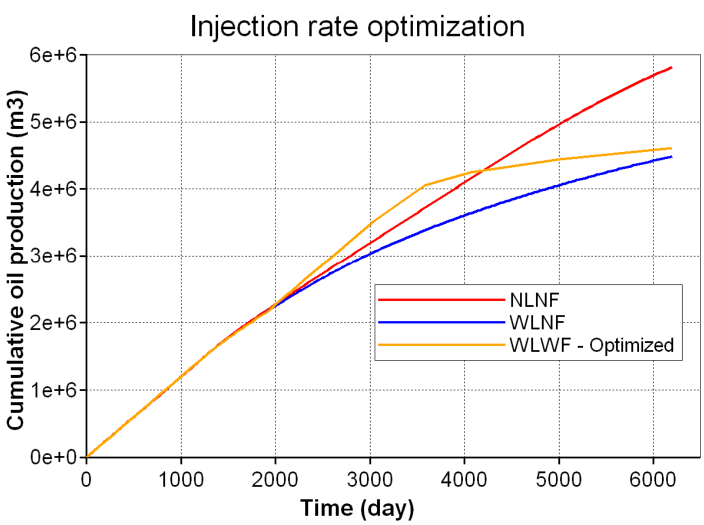

Figure 7. Oil production for the optimized model.

4.2. Results for light oil

The simulations for the cases NLNF and WLNF show, in an analogous form to the intermediate oil, the negative effect of injectivity loss. The bottom-hole pressure at the injector well for the case WLNF case reaches fracturing pressure at 2340 days, and the fracture propagation with 1200 m³/day shows an instantaneous fall of the injection well bottom-hole pressure, making necessary the increase of the injection rate to maintain the fracture open.

The injection rate optimization for this oil type gives the value of 2800 m³/day as the necessary to keep the fracture propagation. This increment on the injection rate is higher than the necessary for the intermediate oil, and the problems of an earlier water breakthrough and an over-injection, with the consequences explained in the section above, continue.

In a similar way to the case with intermediate oil, the optimized injection rate is limited by bottom-hole pressure, again with satisfactory results, as shown in Figure 9. Figures 10 and 11 show the behavior of the injector well bottom-hole pressure and the cumulative oil production, respectively, after the injection rate optimization process.

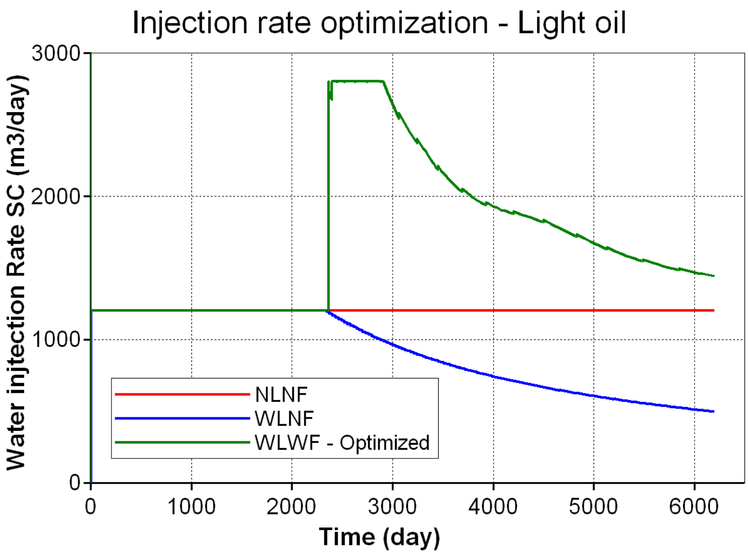

Figure 9. Injection rate behavior for optimized model – Light oil.

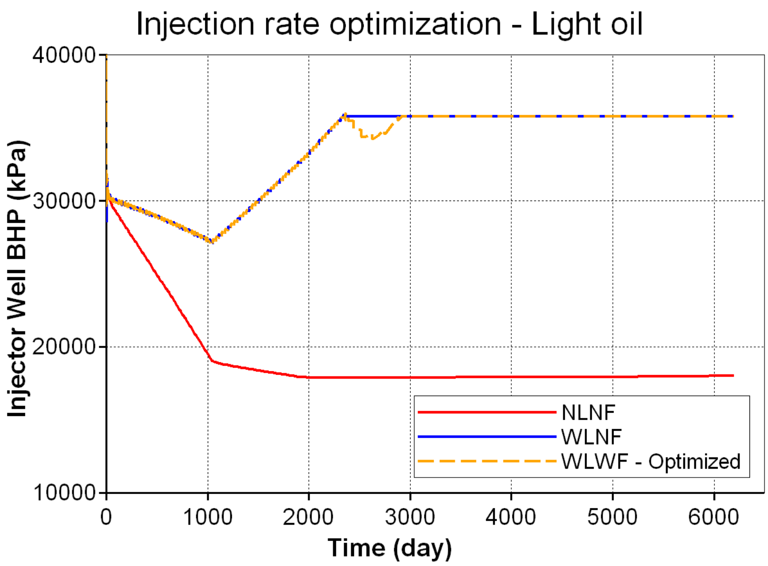

Figure 10. Injector well BHP for the optimized model – Light oil.

From Figure 11 it can be observed that the optimized fracture propagation shows a higher level of recovery of the injection conditions and better results for the final oil recovery if compared with the intermediate oil. This corroborates the results obtained by Muñoz Mazo et al (2007), who showed that the capacity of the injection with fracture propagation of overcoming the injectivity loss problem increases as the density and viscosity of oil diminishes.

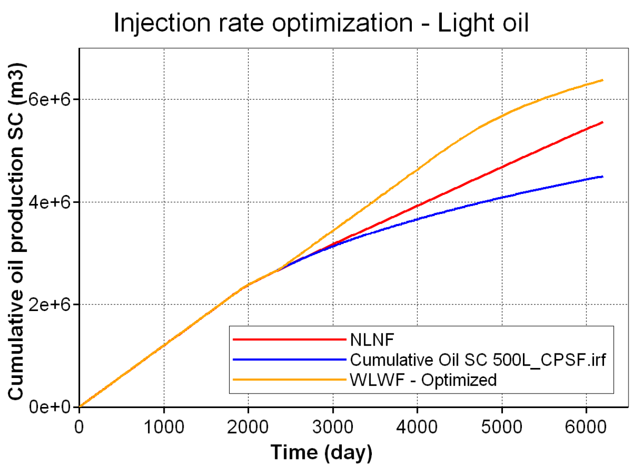

Figure 11. Cumulative oil production for the optimized model – Light oil.

4.3. Results for heavy oil

The simulation of the case NLNF for the heavy oil shows that the fracture pressure is reached at the beginning of the injection, making necessary the simulation of a case without injectivity loss and with fracture propagation (NLWF – for No Loss With Fracture) as proposed by Costa et al (2009). In this case the fracture propagation is started jointly with the water injection. The injection rate and pressure behavior for these cases is shown in Figure 12, and the cumulative oil and water productions are shown in Figure 13.

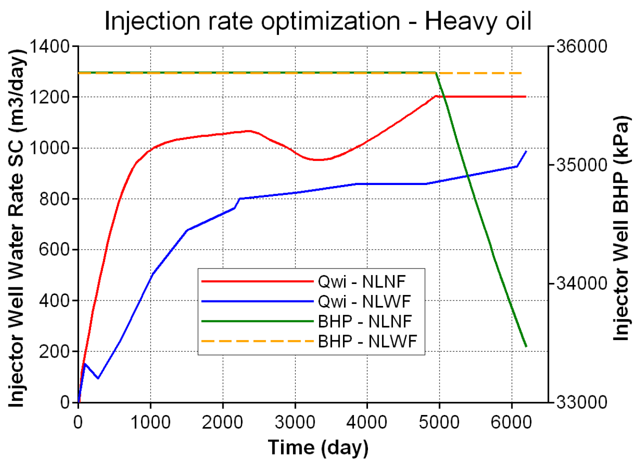

Figure 12. Behavior of injection rate and pressure for the heavy oil models.

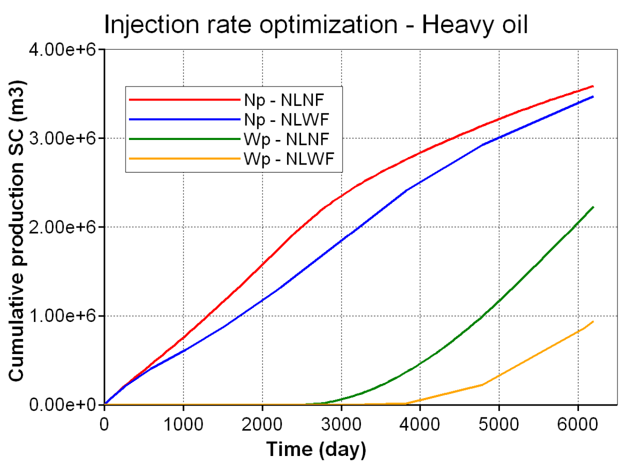

Figure 13. Cumulative productions for the heavy oil models.

The results in Figure 12 show that at the injection rate of 1200 m³/day the continuity of the fracture propagation is guaranteed and further optimization shall be done in order to increase the final oil recovery or even verify the necessity of injecting water under fracturing conditions for the project development.

Table 3 summarizes the main results obtained for the three oil types after the optimization process related with the oil mobility.

Table 3. Simulation results related to oil mobility

Oil type	Mobility ratio	Optimized injection rate	
		Injection rate increment	Final oil recovery
Light	0.4	230 %	48 %
Intermediate	2.3	183 %	30 %
Heavy	11.7	0 %	20 %

From Table 3 it can be observed that as the mobility ratio of the oil increases the injection rate proposed for this study (1200 m³/day) is able to maintain the fracture propagation, in part, by the rapid pressurization caused by the slower displacement of the injected water inside the reservoir. For more mobile fluids it is necessary to increase the injection rate, and these increases are higher as the oil viscosity decreases, leading, in the other hand, to higher recovery factors and sweep efficiencies.

5. CONCLUSIONS

- The impact of injectivity loss and the fracture propagation on the reservoir performance makes necessary the implementation of reliable tools to model the process in commercial reservoir simulators. This implies that subjects, as geomechanics and formation damage analysis, shall be coupled as better as possible.
- The results show that the water injection under fracturing conditions is a useful tool for overcoming the problem of injectivity loss, increasing the recovery efficiency. Nevertheless, sometimes it cannot to restore the reservoir performance to the level of models that do not present neither injectivity loss nor fracture propagation, even being unreliable and not necessary for determined reservoir and oil conditions.
- The results show that the process of water injection with fracture propagation can be studied as an injection rate optimization problem in order to establish the optimal conditions for fracture propagation continuity. This means that both, the applicability of the process and the behavior and characteristics of the propagated fracture, are influenced directly by the amount of water that should be/is planned to inject in the reservoir.
- Hence, the economic and technical analyses of the injection processes and water production in reservoirs have great importance because are basic tools for establishing the best form of managing water in oil fields.
- This makes necessary a detailed knowledge of the characteristics and properties of the reservoir rock and the fluids as the conditions in which injection under fracturing conditions must be enclosed in the analysis of the production strategy with the purpose of maximizing its efficiency and its economic performance.
- This study shows the importance of the process of water injection under fracturing conditions. For this process, a more detailed evaluation of the conditions in which is developed is necessary to establish the best way to incorporate the process as a possible tool of being used for water management in oil fields.

6. ACKNOWLEDGEMENTS

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