EFFECTS OF WATER INJECTION UNDER FRACTURING CONDITIONS ON THE DEVELOPMENT OF PETROLEUM RESERVOIRS

Juan Manuel Montoya Moreno
Departamento de Engenharia de Petróleo – Faculdade de Engenharia Mecânica –UNICAMP
Caixa Postal 6122 – Cep 13081-970
Campinas – SP – Brasil
moreno@dep.fem.unicamp.br

Eliana Luci Ligero
Departamento de Engenharia de Petróleo – Faculdade de Engenharia Mecânica -UNICAMP
Caixa Postal 6122 – Cep 13081-970
Campinas – SP – Brasil
eligero@dep.fem.unicamp.br

Denis José Schiozer
Departamento de Engenharia de Petróleo – Faculdade de Engenharia Mecânica - UNICAMP
Caixa Postal 6122 – Cep 13081-970
Campinas – SP - Brasil
denis@dep.fem.unicamp.br

Abstract. Waterflooding is the most frequently used method in the petroleum fields to increase oil recovery. The injected water maintains the reservoir pressure above the bubble point of fluid and displaces the oil to the producer wells. However, water injection is associated to a technical problem called injectivity loss, which occurs due to deposition of different types of solid particles in the porous media around the injector wells. Actions to avoid injectivity loss have an important economic impact, especially in offshore projects, where high oil production rates are required. One possible solution to this problem is to inject water above the fracture propagation pressure, bringing up high conductivity channels from injectors. The fracture growth from injector wells can have a significant impact on reservoir performance (sweep efficiency, oil production rates, oil/water ratio and recovery factor). However, there is a risk associated to water injection under fracturing conditions if the fractures grow up in the direction of the producer wells, resulting in recycle of water. Due to the importance of the problem and to the difficulties to model the problem, some different approaches can be applied to this problem. In this work, two alternatives are presented to model the fracture propagation in a petroleum reservoir: (1) grid refinement and transmissibility modifiers and (2) virtual horizontal wells. The impact of injectivity loss on the oil production and the net present value are studied in order to show that the problem can be modeled, representing an initial point to future research in this area.

Keywords: Waterflooding, injectivity loss, fracture propagation, hydraulic fracture, reservoir numerical simulation.

1. Introduction

Water injection has been the most used recovery method in petroleum industries due to its advantages: operational simplicity, low cost and favorable characteristics of displacement. The injected water displaces oil from porous media to producer wells and maintains the reservoir pressure above of saturation pressure, increasing the recovery process efficiently. During the injection process, large quantities of water are introduced into the reservoir, which involves many complex variables (Singh, 1982). Some important variables are the geological characteristics that influence the water injection performance, the well localization and consequently the production strategy, the fluid properties like viscosity that is related directly to the water injection efficiency, technical variables such as injection pressure, water quality and water processing systems and economic variables. Water injection has high initial investment and the project conditions for the injection are more complicated in offshore operations. According to Palsson *et al.* (2003), the operational conditions in an offshore field are complex and have narrow economic limits. The production cost of maritime fields are elevated and many water injection projects are implemented quickly to support the pressure as recovery mechanism to maintain high oil production rates. Another important characteristic of offshore fields is the average project life that is smaller than onshore projects (Singh, 1984 and Palsson *et al.,* 2003).

Either offshore or onshore operations, injector wells are associated to injectivity loss. This phenomenon influences strongly the injection project performance since it is directly related to the capacity to maintain the pressure and fluid rates in the reservoir. For example, in Gulf of Mexico, the main causes for injectivity loss are formation of scales, plugging of porous media by fine rock particles or oil droplets and introduction of bacteria due to the poor quality of the water injected (Sharma and Pang, 2000). Some works are concerned about the impact of these variables in the injectivity loss. Sharma and Pang (2000) developed an analytical model to study the injection decline caused by the injection of fines and their impact on the injector performance and to determine the parameters of injection water quality. Bedrikovetsky *et al.* (2001) developed a mathematical model with two parameters, formation damage and

filtration coefficient, to calculate the necessary information to determine the injector well impairment from laboratory tests and well history.

The injectivity loss increases the operational cost due to the continuous filtration of the injected water, which cost depends on the particle diameters in suspension, the addition of chemical agents to inhibit the formation of scales and kill bacteria and the changing parts of the injection system that generally are neither simple nor cheap.

The water injection above of fracture pressure is one process that reduces or avoids the injectivity loss due to the generation of channels with high conductivity, resulting in elevate values of injectivity. This process has been applied in different offshore or onshore fields around the world. The Valhall field, in North Sea, was submitted, during three years, to the water injection with pressure above the parting fracture in order to improve the injectivity, while its effect in the water breakthrough was minimum (Nazir *et al*., 1994). Others examples are the Dan field, also in North Sea, where water injection with fracture formation increased the oil production (Ovens, *et al*., 1997), in some fields in Oman the injection with fracture propagation was implemented in order to sustain high injectivity rates with a reduced treatment of the produced water (Noirot *et al*., 2003) and several Petrobras's wells in onshore fields (Souza *et al*., 2005). Although, the water injection with pressure above the fracture pressure can generate benefits in relation to the injectivity loss, it can unfavorably decrease the sweep efficiency since the water channels into the fractures.

The injection with fracture propagation pressure is a manner to avoid infectivity loss, but traditional reservoir numerical simulators do not consider the fracture formations during the injection process. In order to correctly model the fracture formations and its effects in the reservoir oil production, a *Black-Oil* reservoir simulator must be associated to geomechanical models, which describe the fluid flow when the rock properties are changing during the time. Different reservoir simulators describing fluid flow and geomechanical behavior are reported in the literature (Gadde and Sharma, 2001 and Noirot *et al*., 2003). However, in the absence of such simulators, conventional reservoir simulators are employed and the presence of fractures and injectivity loss are considered using, for example, mathematical models, grid refinement and transmissibility modifiers. Souza *et al.* (2005) associated a non-commercial geomechanical software to model the fracture growth and its propagation to a commercial reservoir simulator. These authors showed that the impact of injection with fracture propagation pressure can be high, depending on the injection pressure, the velocity and direction of fracture propagation, the type of well (vertical or horizontal), the injector-producer distance and the injection pattern.

The goal of this work is to study the impact of the injectivity loss in the reservoir performance and to model the water injection with fracture propagation pressure in order to avoid injectivity loss. Two alternatives were considered to model the fracture propagation: (1) the use of grid refinement and transmissibility modifiers as proposed by Souza *et al.* (2005) and (2) the use of a virtual horizontal well to represent the behavior of the fracture. In addition, a model with injectivity loss and without injection with fracture propagation pressure had its injectivity decline calculated through the variation of the formation factor damage in the injector well.

2. Application

The reservoir model was based on the model proposed by Souza *et al.* (2005) and the numerical flow model was constituted by a 27x47x1 Cartesian grid. A production strategy with direct line pattern and two vertical wells was adopted, one producer well and one injector well, both with bottom hole pressure constant and equal, respectively, to 19,500 kPa and 16,400 kPa. The maximum injected and produced liquid rates were equal to 2,000 m^3/day. The reservoir petrophysical properties were assumed as constant (Tab. 1), the net to gross ratio was equal to 1.0 and the capillary effects were neglected. The fluid properties are indicated in Tab. 2. The reservoir simulations were executed through a *Black-Oil* commercial reservoir simulator. The total time of simulation was 3,600 days.

Table 1. Reservoir properties.

Property	Value
Porosity (%)	21.8
Rock compressibility (kPa^{-1})	3.467x10^{-6}
Horizontal permeability (mD)	1345.5 [m1]
Vertical permeability (mD)	135.55
Initial pressure (kPa)	19,500
Depth (m)	2,395

Table 2. Fluid properties.

Property	Value
Temperature of reservoir (^{o}C)	91.1
Pressure of saturation (kPa)	16,609
Initial Water Saturation (%)	22.8
Initial water FVF, B_{wi} (m^3/m^3)	1.0073

3. Procedure

Four situations of the reservoir model were studied, Fig. 1.: (1) the base model without injectivity loss (Model 1), (2) the model with injectivity loss throughout the simulation time and none procedure was applied to avoid it (Model 2), (3) the model with injectivity loss during the initial two years of simulation and injection with fracture propagation pressure, which was represented by transmissibility variations in the reservoir simulation model (Model 3) and (4) the

model was similar to third model, however the fracture propagation was represented by one virtual horizontal well (Model 4). The simulation grid of the models was refined in the direction injector - producer well, except for Model 4 as indicated in Fig.1.
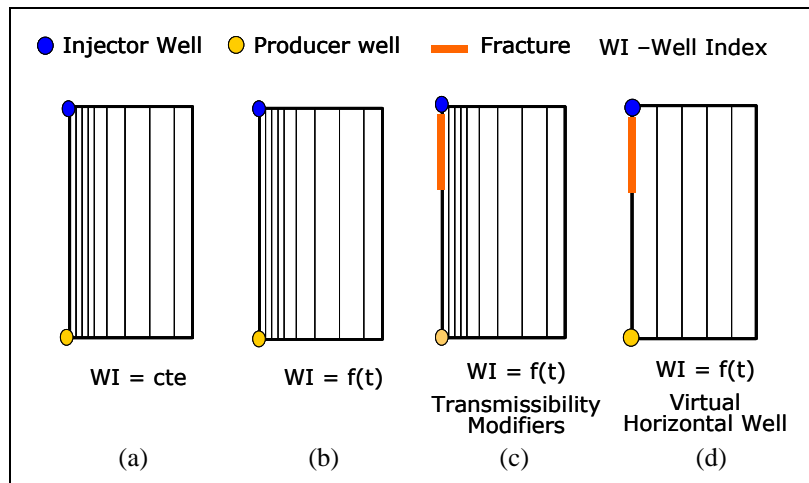

Figure 1. Simulation models: (a) Base model without injectivity loss -Model 1, (b) Model with injectivity loss - Model 2 and (c) and (d) Model with injectivity loss and injection with fracture propagation pressure – Models 3 and 4.

The reservoir parameters analyzed, for each model, were: water injection rate, cumulative oil production, produced water rate in the producer well and net present value (NPV). The NPV values were calculated using the Economic Model of UNIPAR software. Table 3 lists the economic parameters adopted for NPV calculations.

Table 3. Economic parameters.

Price, Cost and Tax	
Oil Price (US$/m^3)	125.8
Oil Production Cost (US$/m^3)	20.0
Water Injection Cost (4 US$/m^3)	4.0
Injected Water Treatment (US$/m^3)	4.0
Well Cost (US$)	6.0×10^6
Discount Rate (%)	15.0

3.1. Modeling of the Injectivity Loss

3.1.1. Injector Well without Fracture

In order to model the injectivity loss of the Model 2, the injector well index, which depends on geometric variables, fluid and the rock properties, was calculated for each value of well bore damage factor through the expression:

$$WI = \frac{2\pi\sqrt{k_x k_y}\, h}{\ln\left(r_e/r_w\right) + S} \tag{1}$$

where k_x and k_y are the well block permeability in x and y direction, respectively; h is the formation thickness; r_e is the equivalent radius, that is function of grid geometrical parameters; r_w is the well radius and S is the well bore damage factor, which was obtained through the expression presented by Craft e Hawkins (Dake, 1978):

$$S = \left(\frac{k - k_s}{k_s}\right)\ln\left(\frac{r_s}{r_w}\right) \tag{2}$$

where k is the original formation permeability, k_s is the damage zone permeability and r_s is the damage radius.

The permeability impairment was modeled by an analytical expression adjusted from experimental information that allows calculating the permeability variation during the time (Tiab, 1996). Figure 2 shows the permeability and injector well index during the time. The decline of the well index is resulting the formation damage due to the plugging of the formation by oil droplets, scale and water particles in suspension.
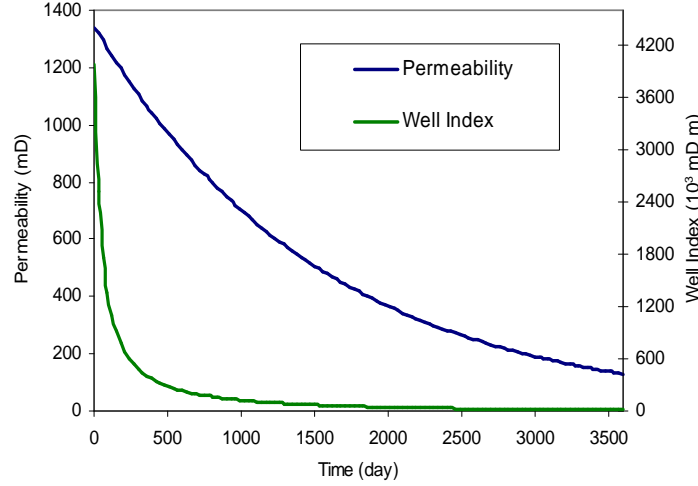

Figure 2. Injector well - Permeability and well index.

3.1.2. Injector Well with Fracture - Transmissibility Modifiers

Most of commercial reservoir simulators do not consider geomechanical modeling. Ji and Settari (2004) presented different manners to model suitably the fractures in porous media; however their proposal required modifications in the simulator code, which is impracticable with commercial simulators. As consequence, the fractures should be modeled through different simulation parameters, such as transmissibility modifiers.

In order to model the reservoir with fracture generated by water injection, the transmissibility between the blocks were modified in the direction of fracture growth according the methodology used by Souza *et al.* (2005). This procedure was employed in Model 3 and it was assumed that the fracture propagated in all reservoir thickness. The fracture length from the injector well, L_f, which varies during the simulation time, t, was obtained by the equation:

$$L_f = \frac{Q_{W_{inj}} \sqrt{t}}{\pi h C_L} \tag{3}$$

where $Q_{W_{inj}}$ is the water injection rate and C_L is overall fluid loss coefficient, that depends on the injection water quality and its filtration properties and the reservoir and fluid characteristics. This coefficient is usually obtained experimentally. The values for offshore reservoir used in this work were based on typical values presented by Souza *et al.* (2005). The fractured block dimension was considered as 0.125 m (Fig. 3). It was also considered local refinement of the simulation grid in the direction of the injector and producer wells.

The variation of the fracture length during simulation time is illustrated in Fig. 4, that represents a reservoir with injectivity loss and the continuously generation of a hydraulic fracture from two times: beginning of the simulation (t = 0) and after two years of the beginning (t = 2 years). The values of transmissibility between simulation blocks in the direction of fracture growth were modified in agreement with the fracture length.

3.1.3. Injector Well with Fracture - Virtual Horizontal Well

A proposed alternative to model the presence of induced fracture in the reservoir was to add a virtual horizontal well in order to substitute the fracture (Fig.3). The addition of a horizontal well was considered in Model 4. The well completion was in agreement with the fracture growth during all simulation time (Fig. 4) and the beginning of the fracture induction were similar to that ones employed to modify the transmissibility between the blocks (t =0 and t = 2 years). In this model, it was not necessary to refine the simulation grid in the direction of the wells.
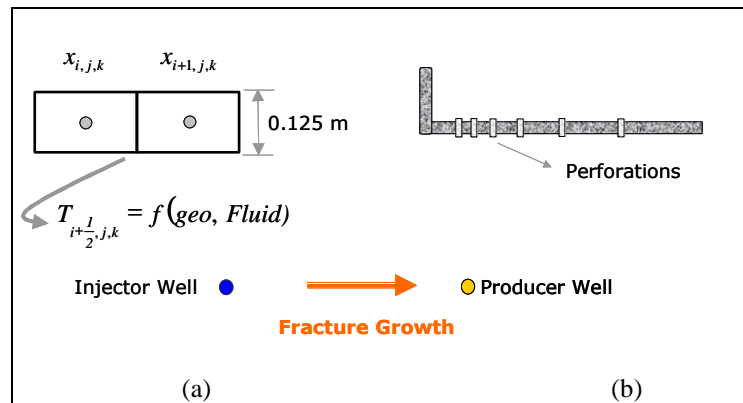
Figure 3 Representation of the fracture: (a) Transmissibility modifiers and (b) Virtual horizontal well.
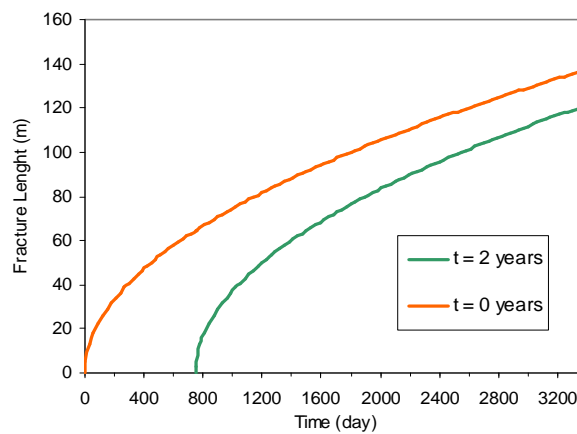

Figure 4. Fracture length during the simulation time.

4. Results

The main variables of the four proposed models were analyzed. The water injection rates of the models with injectivity loss (Model 2, 3 and 4) were compared with the model without injectivity loss (Model 1) as illustrated in Fig. 5. The water injection rate of the Model 1 (WI = const.) was not coincident to the water rate of the Model 2 (WI= f(t)) which was lower than Model 1. These two curves of the Models 1 and 2 were practically different from the beginning of the water injection. The characteristics of injection rate curve of the Model 1 were resulting of reservoir pressurization and no permeability variations around the injector well. In Models 3 and 4, the induced fracture was capable to recover the initial injectivity, increasing the water injection rate. The curves of injection rate were similar for these models in most simulation time, however the model with the virtual horizontal well injected more water than the model with transmissibility modifiers. This is an important result since it was easier to model fracture with virtual horizontal well than to model fracture through transmissibility modifiers and grid refinement. It is important to stand out that the injection rate values of the Models 3 and 4 are super estimated compared to Model 1 and 2. For the Model 4, the injected water rate was similar to the Model 3, however should be necessary an adjust process with fracture geomecanical model.

The cumulative oil productions for the proposed models are presented in Fig. 6. The virtual horizontal well (Model 4) presented a similar behavior to the Model 3 (transmissibility modifiers). The curves of the Model 2 (WI = f(t)) and Model 3 were below and above , respectively, of the curve of Model 1 (without fracture), according to the injectivity recovery presented in Fig. 5. The produced water rates of the Model 3 and Model 4 (virtual horizontal well) were greater than the produced water rate of Model 2, Fig. 7. It is important to emphasize that the induced fracture in the proposed models was in an unfavorable direction to related to the oil producer well and the water rate could be smaller in the producer well if the fracture was considered in a more favorable direction. In the development of production strategies with water injection above the formation parting pressures, this should take advantage of the fractures in relation to the injectivity and should diminish the water production by means of a good location of producing wells to diminish the impacts generated by the water production, as it was presented in the Fig. 7.

The water breakthrough in the producing well can be also observed in Fig. 7. The breakthrough for the models with fracture was lower than the Model 1(approximate difference of 400 days). However, the Model 2 was greater,

indicating that the injectivity loss delayed the water arrival time in the producer well and the oil rate was reduced in the producer well (Fig. 8), which did not agree with water injection objectives to support reservoir pressure and keep oil rates. The induced fracture was capable to maintain constant the oil rate for the Models 3 and 4 during 2,500 days.
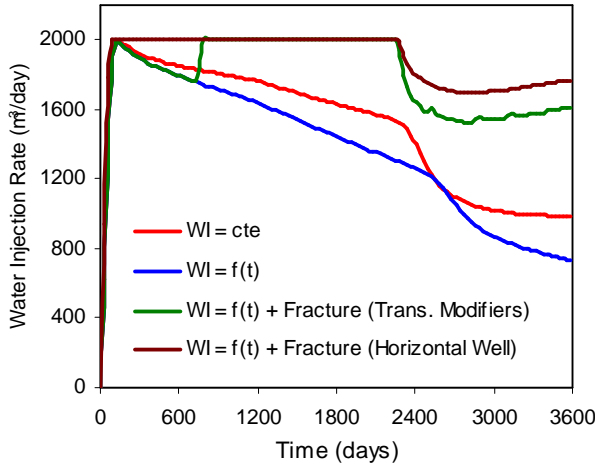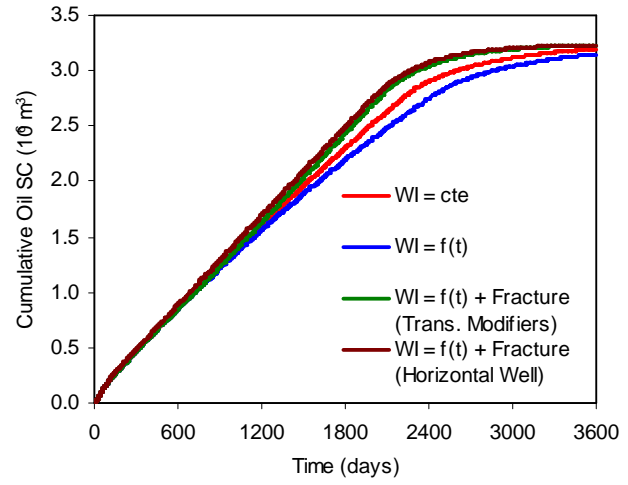

Figure 5. Water injection rate.

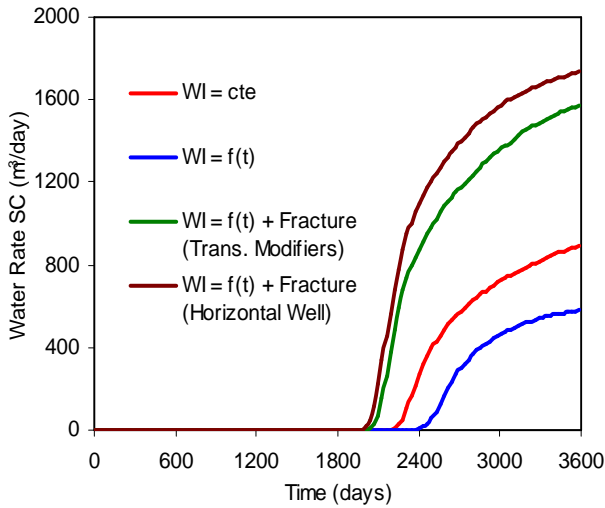Figure 6. Cumulative oil production.

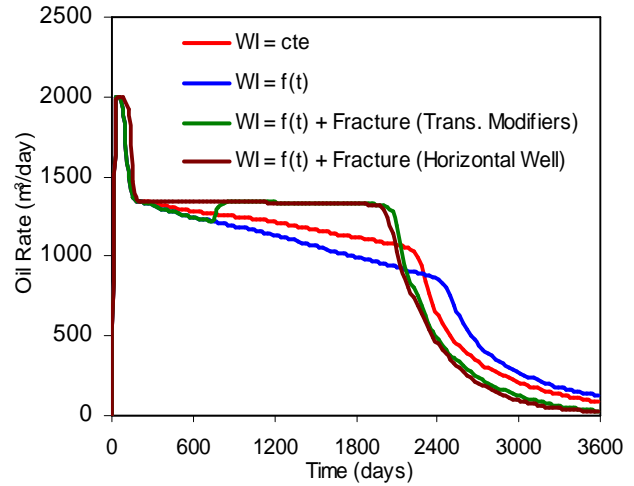Figure 7. Producer water rate.

Figure 8. Producer oil rate.

For the four investigated models, the NPV values were calculated for all simulation time (3,600 days). The maximum NPV for each model and respective N_p and W_p are reported in Tab. 4. It is important to emphasize that for Model 2 (WI = f(t)), the NPV was reported at end of the simulation time due to its low oil rate. The results of the Model 4 (virtual horizontal well) were similar to those to Model 3 (transmissibility modifiers), therefore it was not shown in Tab. 4. Figures 9 and 10 show the NPV and W_p for the models on Tab. 4. The models with fracture (Model 3 or 4) reached the maximum NPV at 2,850 days, which was the greatest one of the models. Similarly, at the end of the simulation, the models with fracture presented higher water production than the Models 1 and 2 (Fig. 10). For the total time of simulation, the NPV for the Models 1 and 3 were similar, however, the Model 3 produced almost the double of water, which represents a non-desirable situation.

Table 4. Comparison of NPV, N_p, and W_p for studied models.

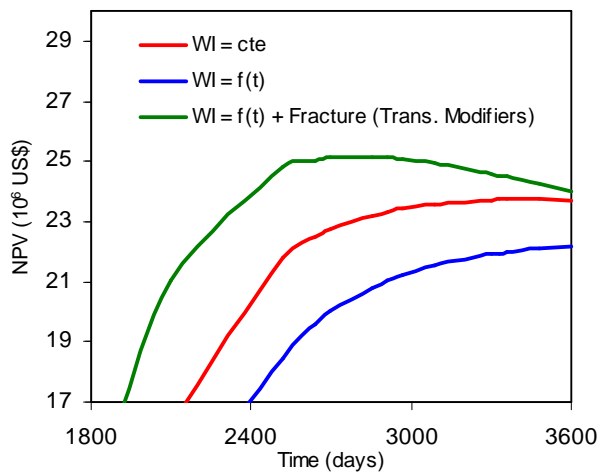| Simulation model	Time (days)[1]	NPV (US$)	N_p (10^6 m^3)	W_p (10^6m^3)
WI = constant (Model 1)	3,360	23.73	3.16	5.60
WI = f(t) (Model 2)	3,600	22.15	3.13	4.05
WI = f(t) + Fracture (Model 3 or 4)	2,850	25.17	3.17	6.52

[1]: Time for maximum NPV
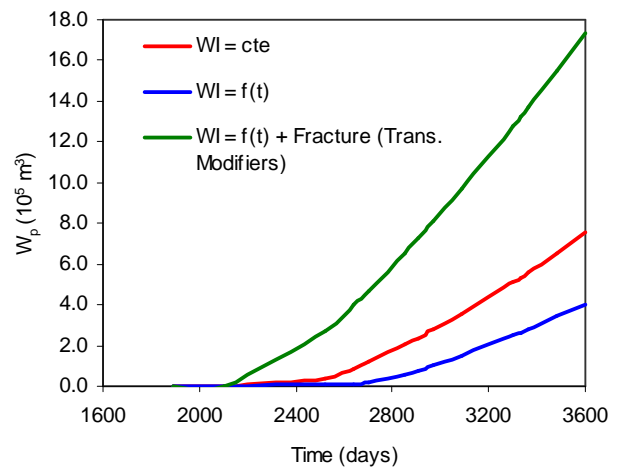
Figure 9. Net Present Value.

Figure 10. Cumulative Water Production.

5. Conclusions

This work had as goal to associated the fracture propagation to commercial reservoir simulator that did not consider geomechanical models. The fractures were modeled through different parameter: transmissibility modifiers and grid refinement and virtual horizontal well. The transmissibility modifiers and inclusion of the horizontal well presented similar results in the cumulative oil produced and injected water rate. For the studied case, the inclusion of a virtual horizontal well was considered the best option because it is simpler than grid refining and transmissibility modifiers and do not require modifications on the grid simulation. For greater scale simulation models; this represent important advantages. Although the obtained models were capable maintain the well injectivity, a better integration between the fracture geomechanical model and the reservoir simulation describing the fluid flow in porous media should be analyzed in future studies.

In order to model real situations, water quality information should be included in the models in order to have better predictions of the impact of the injectivity loss in the reservoir performance, development strategies that include different parameters of the fracture.

The effect of injectivity loss in the Net Present Values for models as time function was analyzed. The models with the injection with fracture propagation pressure, virtual horizontal wells or transmissibility modifiers, presented NPV higher than the model with injectivity loss and without fracture.

In this work, the fracture was studied only in the injector-producer well direction. However, the orientation of the fracture is an important variable to be considered in the process of reservoir water injection with fracture propagation pressure. In this work was used a simple geometry patterns between injectors and producers wells. Different patters with fracture models should be studied to determine the optimum well pattern for different field situations, optimizing the fracture sizes of and injection rates.

6. Nomenclature

C_L = fluid loss coefficient, m/day$^{1/2}$
h = formation thickness, m
k = original formation permeability, mD
k_s = damage zone permeability, mD
k_x = well block permeability in x direction, mD
k_y = well block permeability in y direction, mD
L_f = fracture length, m
NPV = net present value, US$
N_p = cumulative oil production, m^3
Q_{Winj} = water injection rate, m^3/day
r_e = equivalent radius, m
r_s = damage radius, m
r_w = well radius, m
S = damage factor
t = time, days

WI   = well index, mD m

W_p = cumulative water production, m^3

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