RECOVERY STRATEGIES FOR NATURALLY FRACTURED RESERVOIRS: A RESERVOIR SIMULATION APPROACH

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Abstract. Due to the differentiated characteristics of naturally fractured reservoirs, the forecast of the behavior of these reservoirs has been subject of frequent studies in the oil industry. This work presents a study that aims to formulate rules for selection of initial recovery strategies for naturally fractured reservoirs considering different reservoir properties, and to study an optimization process for the proposed strategies. For the accomplishment of this work, a literature review about the main aspects of naturally fractured reservoirs was made, and a methodology was proposed to evaluate, through numerical simulation, the impact of some reservoir parameters and production strategies on the production forecast. The results demonstrate that the reservoir behavior is strongly influenced by the selected strategy. Furthermore, it can be observed that the selection of the initial strategy is a function of reservoir parameters such as matrix and fracture permeability, reservoir inclination and fracture orientation. Finally, the importance and usefulness of optimization processes for increasing the production and economic performance indicators is demonstrated.

***Keywords**: Naturally Fractured Reservoirs, Production Strategy, Numerical Simulation*

1. Introduction

The significant occurrence and production of naturally fractured reservoirs around the world and their particular characteristics make necessary different approaches for the characterization and modeling when comparing with homogeneous reservoirs. Therefore, for such reservoirs, it is necessary to consider the concept of dual porosity system, where rock matrix and fracture are different and separated porous media (Aguilera, 1980; Saidi, 1987). The rock matrix presents a high capacity of fluid storage and low permeability; the fractures present a high flow capacity and a low porosity with relation to the matrix. Natural fractures are very important zones, which are searched with great interest due to their high draining capacity, and to the increase in permeability that is evidenced in these zones. Although the fractures can have a significant effect in the total permeability of the rock, generally they have little effect on the porosity, saturations and other petrophysical characteristics of the reservoir rock (Nelson, 1985). Fracture detection is the first and more important step for the evaluation of naturally fractured reservoirs. The fracture detection process can be based on laboratory studies from core analysis, as well as on results of the interpretation of well logs and, in more advanced cases, on results from pressure tests. Additional to the detection, it is important to make an evaluation of the fracture properties in the process of characterization of the reservoir, in order to help with the planning of the production and development strategy, which is the integration of the geologic, productive, modeling and economic aspects.

The objective of the present work is to formulate general rules that, based on the petrophysical properties of the reservoir, oil, and production parameters (well type, number and location, injection and production rates, among others), make possible the selection of an initial production strategy for water injection in naturally fractured reservoirs. A literature review of the concepts related to the naturally fractured reservoirs was made to achieve this objective, as well as help the understanding of the relation between the main properties of this type of reservoir and the choice of a production strategy. The generated rules simplify the decision process, since they take into consideration the characteristics of the reservoir as well as the production parameters and guide the choice of an initial production strategy for the development of these reservoirs, being able also to be used as a first approach for posterior optimization.

2. Recovery strategies for naturally fractured reservoirs

The production strategy is one of the most important factors for the oil recovery of reservoirs and is a complex process due to the multiple alternatives that can be implemented (Muñoz, 2005). The adequate choice of a production strategy improves the performance of the reservoir along its productive life. The production strategies are proposed considering definite objectives and observing the operational, economic characteristics and restrictions and the physical conformation of the porous medium. Moreover, a production strategy depends mainly on the geologic characteristics of the reservoir and the operational program that will be used in the strategy proposal. Inside the strategy proposal, the diverse changes in the external environment must be taken into account, and the project must be under continuous revision, since they can change with the acquisition of new information.

According to Putra and Schechter (1999), the reservoir pressure can be maintained, or even developed if the water injection is carried through in the perpendicular direction to the direction of higher permeability of fracture in the case of a project of injection in staggered line, and the case of horizontal wells, orienting these in the parallel direction to the fractures of higher permeability. With these types of configurations of injector wells it is possible also to delay the water breakthrough in the producing wells and to force the flow of more oil from the matrix to the producing wells.

Optimization processes applied to naturally fractured reservoirs can be considered processes that involve the characteristics of the general behavior of the reservoir and the objectives of the project as well positioning, where the main objective is to determine the best location of the wells aiming a higher performance. The parameters that can be used for this process are usually the cumulative oil, gas and water production (Np, Gp and Wp), Recovery Factor (RF), water breakthrough time and economic indicators as Net Present Value (NPV). Putra and Schechter (1999) consider two optimization methods to reach this objective, which consist of the optimization of the water injection rate and of the possibility to apply cyclic water injection. In both processes it is necessary to take into consideration the influence of the petrophysical properties of the reservoir and the different operational conditions of the wells.

3. Methodology and application

The objective of this work is to study the process of selection of recovery strategies for naturally fractured reservoirs and to establish rules that, based on the petrophysical properties of the reservoir, the oil and in the parameters of production (type, number and location of the wells, rates of injection and production, among others), make possible to speed up the process of selection of the initial recovery strategy considering water injection.

The optimization processes may present high complexity due to the diverse parameters that must be considered. Therefore, the methodology presented here offers an initial study to assist this type of decision process. For the accomplishment of this study, a methodology that consists of three steps is proposed. The objective is to analyze the effect of the reservoir and fluids properties, the implementation of different production strategies and the introduction of optimization processes.

3.1. Step I - first sensitivity analysis

In this first step, a sensitivity analysis of the impact of different properties in the recovery factor (RF) and net present value (NPV) is made. During this step, changes in different reservoir properties as fracture spacing, matrix and fracture porosity, reservoir inclination, matrix and fracture permeability, and a case with different relative permeability and capillary pressure of those presented in the base case were carried through, with the objective of determining which parameters are most critical for the general behavior of the reservoir. The economic scenario that was defined to evaluate the effect of the changes in the NPV makes reference to values used for the development of onshore projects. In this step, the model used for simulation consists in a Cartesian grid with constant properties, in both matrix and fractures. The production configuration of the model emulates an arrangement of wells in form of a quarter of five-spot, where two vertical wells, an injector and a producer, are placed in opposite corners of the grid; the used fluid for the analysis corresponds to an oil of 15 °API.

The base case used in this first step consists in a Cartesian grid of 21 x 21 x 6 (2646) blocks with dual porosity simulation model; Gilman and Kazemi shape factor; complete gravitational segregation model; fracture spacing of 10ft (3048 m) in directions X, Y, and Z; matrix porosity 20%; fracture porosity 0.01%; matrix permeability of 5 mD in directions X, Y, and Z; fracture permeability of 500 mD in directions X, Y, and Z; matrix compressibility of $2.1\text{x}10^{-5}$ kPa^{-1}; fracture compressibility $2.07\text{x}10^{-4}$ kPa^{-1}; initial reservoir pressure 20787.7 kPa; initial matrix oil saturation 0.8; initial fracture oil saturation 1.0. The model uses 15 °API oil and the simulation was proposed initially for a time of 9540 days.

The economic scenario was defined to evaluate the effect of the changes in NPV, and it makes reference to values used for economic calculations for onshore projects considering a discount rate of 13%; taxes on gross income of 45%; initial investment of 3 million dollars; investment for each well (drilling/completion) 500000 dollars; oil price 135 dollars/m^3; oil production cost 37.7 dollars/m^3; water production cost 12.6 dollars/m^3; water injection cost 1.94 dollars/m^3. The considered economic model is theoretical and it does not have the intention to reproduce values used in oil companies or in the literature; it is just a simplified model in order to take into account the speed of recovery and different costs and investments for different configurations.

Table 1 shows the properties and the values that had been used in the accomplishment of the analysis. The values in bold font indicate the values of the base case.

3.2. Step II - second sensitivity analysis

The objective of this step is to identify which of the tested elements is more important for the general behavior of the reservoir: the type of oil, the production strategies or the reservoir properties. To accomplish the task, the most critical parameters detected in Step I were used and combined with different production strategies that are tested in a simulation base case, that presents some differences with the base case used in Step I, which consists in a Cartesian grid with constant properties for the matrix and the fractures, the presence of conjugated fractures and the absence of horizontal fractures, among others.

Table 1. Properties and values used in the first sensitivity analysis.

Case	**Values**				
Fracture spacing in X direction (m)		1.6	**3.3**	8.3	16.6
Fracture spacing in Y direction (m)		1.6	**3.3**	8.3	16.6
Fracture spacing in Z direction (m)		1.6	**3.3**	8.3	16.6
Matrix permeability in X direction (mD)		1	**5**	10	100
Matrix permeability in Y direction (mD)		1	**5**	10	100
Matrix permeability in Z direction (mD)		1	**5**	10	100
Fracture permeability in X direction (mD)		100	**500**	1000	10000
Fracture permeability in Y direction (mD)		100	**500**	1000	10000
Fracture permeability in Z direction (mD)		100	**500**	1000	10000
Matrix porosity (%)		10	**20**	30	
Fracture porosity (%)		0.01	**0.1**	1	
Reservoir dipping (°)	-40	-25	**0**	25	40
Reservoir thickness (m)		50	**100**		

The production strategies proposed for this step contemplate different distributions between producing and injector wells, as well as different types of wells and different injection production arrangements. The economic scenario considered for this step also makes reference to onshore fields. This analysis was done for heavy oil (Step IIa), for light oil of 30 °API (Step IIb), and finally for a more viscous heavy oil (Step IIc). As control parameters, the recovery factor (RF), the net present value (NPV) and the cumulative water (Wp) production were used.

For this second step another base case was constructed in which, besides being able to test the effect of some parameters of the reservoir, different production strategies can be tested, and consequently define optimization processes for the proposed strategies in this step. The main characteristics of this base case include a Cartesian grid of 41 x 41 x 5 (8405) blocks; dual porosity modeling with Gilman and Kazemi shape factor; fracture spacing 3048 m in directions X and Y; absence of horizontal fractures; matrix permeability 5 mD in directions X, Y and Z; fracture permeability in X direction 10 mD; fracture permeability in Y direction 500 mD; fracture permeability in Z direction 100 mD; matrix porosity 20%; fracture porosity 0.1%; complete gravitational segregation model; properties such as compressibilities, saturations of fluids, and petrophysical properties have identical values to those used in the first base case, and the system of vertical fractures is of conjugated type, that is, two systems of orthogonal fractures where for the cases simulated in this study, one of the systems is guided in the direction of the maximum horizontal permeability and the orthogonal system to this is guided in the direction of minimum horizontal permeability. Thirteen production strategies were proposed. All the injector wells are completed in the inferior layer of the reservoir, while the producing wells are completed in the superior layer if they are horizontal, and in the two superior layers for the case of vertical producing wells.

For all the strategies tested in this step, for simplicity, the axis Y was designed as the maximum fracture permeability axis and is represented by an arrow in the bottom left corner. The proposed strategies intend to involve several configurations, there are: peripheral injection, central injection, arrangements of the inverted five-spot and five-spot types, combination of vertical and horizontal wells, use of horizontal wells in the injection and the production, and different orientations of the horizontal wells with respect to the axis of higher fracture permeability. The thirteen production strategies had been evaluated in each one of the following cases of variation of the properties of the reservoir: base case; inclination 25°; matrix permeability 1 mD.; matrix permeability 100 mD.; vertical fracture permeability 500 mD.; matrix porosity 10%; matrix porosity 30%; increased capillary pressure. For the case with increased capillary pressure, a new set of properties was considered (capillary pressure and relative permeabilities). For the conformation of the economic scenarios, the same values of Step I were used with exception of the average investment for well, which was variable for each strategy, where the horizontal wells have a cost of 1 million dollars and the vertical wells, 500000 dollars. The simulations were made for three cases with distinct types of fluid: in the first case (Step IIa), the fluid of Step I is used (15 °API), in Step IIb the used fluid is a lighter oil (30 °API), and for Step IIc a heavier fluid with a higher viscosity was used.

Figure 1 shows the thirteen production strategies used during the second sensitivity analysis.

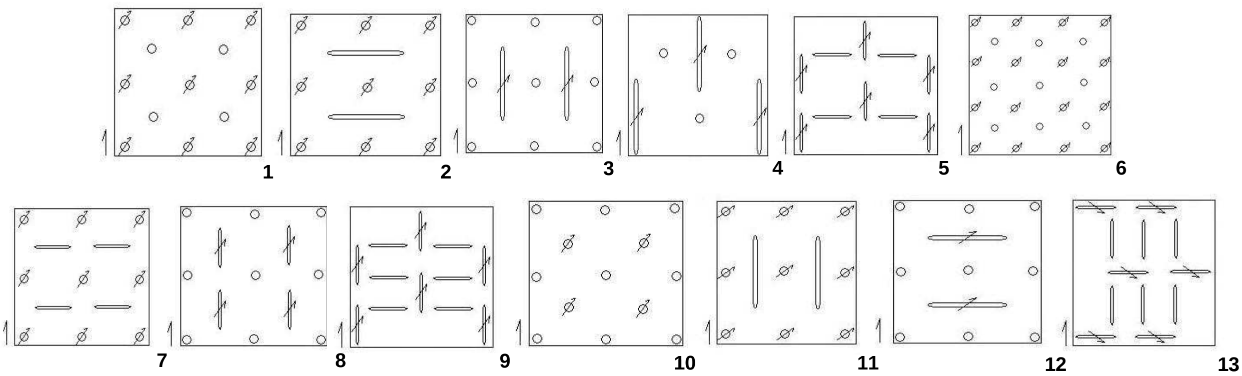

Figure 1. Production strategies used for Step II.

3.3. Step III - recovery strategy optimization analysis

In this step, the optimization processes of the best strategies identified in Step II were performed. For this, a reservoir model of real geometry was used, in which the strategies were tested and optimized one at a time, by means of an optimization process that aims, through the reduction of the water production and the delay in the breakthrough, the field NPV maximization for this step of the study. The model used in this step consists of a variable grid with variable properties for the matrix and constant properties for the fractures in the simulation blocks; it also includes conjugated fracturing and absence of horizontal fractures. In the model, light oil is used (30 °API) and the same values of capillary pressure and relative permeability of Step I are adopted. This step of study makes possible to establish the criteria for the accomplishment of optimization processes for production strategies in naturally fractured reservoirs and to formulate the criteria of choice of an initial production strategy for this type of reservoir.

For the accomplishment of Step III, a simulation model of real geometry was used, in which have been included different heterogeneities related to porosity, matrix permeability, depth and thickness of the blocks that compose the grid. It is intended with this to test the best strategies from Step II (a, b and c) and to optimize them inside a more realistic scene. The used model in this step consists in a variable grid of 51 x 28 x 6 blocks; blocks of 150 x 150 m^2 of area and variable height; dual porosity model with Gilman and Kazemi shape factor; the matrix porosity obeys a normal distribution with mean 0.2 and standard deviation 0.1, in the three directions; The matrix permeability follows a log-normal distribution with mean 30 mD and standard deviation 20 mD in the three directions; the fracture porosity is constant and has a value of 0.001 in the three directions; the fracture permeability has a value of 10 mD in direction X, of 500 mD in direction Y, and of 100 mD in direction Z; fracture spacing in X direction 1.6 m; fracture spacing in Y direction 8.3 m; the water-oil contact is located at 2033 m depth; the oil saturation in the matrix is 80% and in the fractures it is 100%; the petrophysical properties are the same ones used for the simulation models of Steps I and II. The simulations were made for a oil-water model, where the fluids present the same characteristics and properties used in Step I; the simulation time considered for the optimization step is 3720 days; the economic scenario used in this step is the same used in Steps I and II, where the investment needed for vertical wells is 500000 dollars, and for the horizontal wells there is a cost of 1 million dollars.

The strategies optimized in this step are those that showed the higher production (RF) and economic (NPV) indicators, as well as a lesser cumulative water production (Wp) in Step II. Also, Strategy 13 was tested, with the purpose of showing the effect of the horizontal injector wells orientation according to the higher fracture permeability direction with the objective to maximize the NPV. The actions that compose the optimization process consists of (1) consider the initial configuration; (2) remove wells with negative NPV; (3) relocate producing wells with early water breakthrough; (4) close producing wells at the point of maximum cumulative NPV; (5) relocate injector wells; (6) remove low expression production wells; (7) modify the injection rates and (8) modify the well spacing.

The analyses made in the three steps of the work were carried through in the flow simulator IMEX® and the economic analysis module MEC® of program UNIPAR®.

4. Results and discussion

The sensitivity analysis for the first base case (Step I) showed that the increase in fracture permeability in directions X and Y has as consequence the increase in the cumulative oil production (Np), in the RF and the NPV, explained by the increment in the reservoir draining capacity. Increases in the same indicators have been found for increments in matrix permeability and the reduction of fracture spacing, as a consequence of a higher matrix-fracture fluid transference. It was noticed that the behavior of the vertical fractured permeability was inverse to the behavior of the horizontal permeability, that is, for an increase in the vertical permeability, a reduction in RF and NPV was observed.

Another property that had great impact in the sensitivity of the model was reservoir inclination. It was observed that in the cases of positive tilt, in which the producing well is located in the superior part, the oil production was bigger and, therefore, the RF and the NPV had higher values than in the base case. For the case of changes in matrix porosity, the expected results, derived from the volume changes, were obtained for both the indicators RF and NPV. The reduction of the thickness of the reservoir to the half had the expected effect, that is, a reduction in the indicators used in this step. With the increase in the capillary pressure a significant increment in oil production and, therefore, in the RF and the NPV was achieved. These increases can be explained by the higher water imbibition capacity, that this increase in the capillary pressure allows to the matrix.

For the second sensitivity analysis (Step II), the thirteen production strategies proposed in the methodology were tested in each one of the considered cases. It was observed that, in all the cases, as shown in Figs. 2, 3 and 4 for the base case, Strategies 3, 5, 7, 8 and 9 presented the highest recovery factors, and Strategy 9 showed the highest NPV. Moreover, it was possible to establish that the highest water production was given in Strategy 12, that is the strategy that presented, in all the cases, the minor NPV, which can be explained by the orientation of the injector wells in the direction of lesser permeability, and consequently they had suffered the effect from the massive water channeling, that occurs when guiding the horizontal injector wells in the direction of lesser permeability. Among the cases that presented the highest NPV (Strategies 5, 6, 7, 8 and 9), Strategy 5 showed a lesser water production. It could also be observed that the results reflect the effects observed in Step I, since for all the tested strategies, the cases of changes in matrix porosity and reservoir inclination, the observed values were next to the values obtained for the base case; and the cases of changes in the matrix permeability and the fracture permeability, as well as the case of increased capillary pressure showed significantly distant values from the case base.

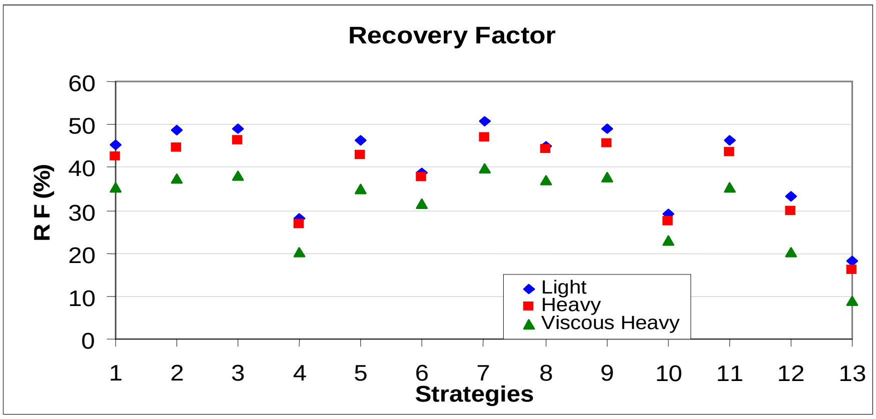

Figure 2. Recovery factor for simulations in Step II, base case.

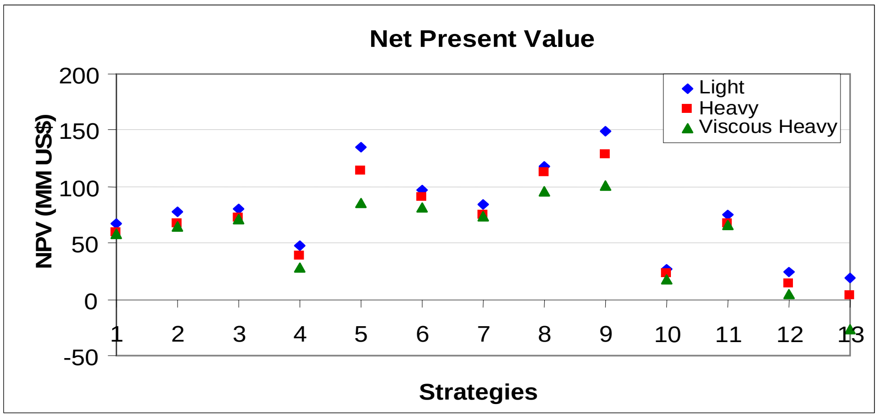

Figure 3. net present value for simulations in Step II, base case.

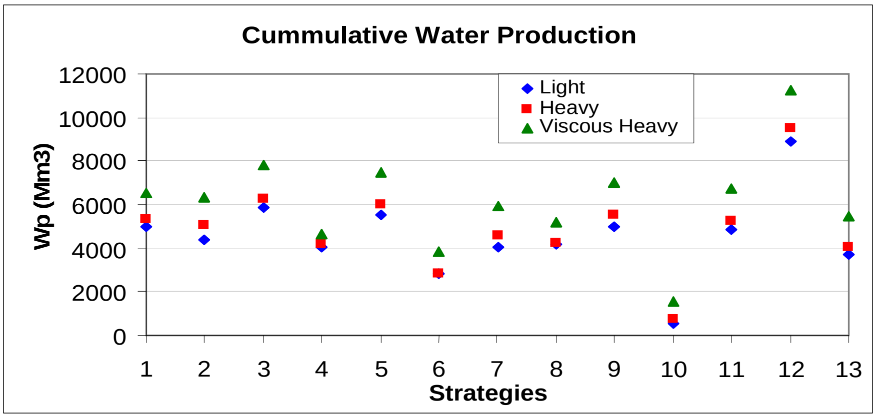

Figure 4. Cumulative water production for simulations in Step II, base case.

Comparatively with Step IIa, in Step IIb and Step IIc higher and lower values of RF are obtained respectively. This can be explained by the changes in the mobility of the phase oil, due to viscosity variations that affect the reservoir fluids production (oil and water for the cases in this study) making the cumulative water production lower for the cases studied in Step IIb and higher for the cases in Step IIc. These mobility variations also affect the NPV in each case, since this parameter is strongly influenced by the produced volumes.

Taking into consideration that in Steps IIa, IIb and IIc thirteen production strategies, different reservoir properties and three types of oil were tested, that for a specific case the tested strategies offer a higher variability than the cases tested for one specific strategy and that the oil difference only affects the level reached by the different control parameters, it can be inferred that for the results obtained from the sensitivity analysis, the configuration of the tested production strategies has more importance on the general behavior of the reservoir than the reservoir properties analyzed and the type of oil used.

In order to test the consistency of the results obtained in Step II, an optimization process was implemented and tested trying to maximize the NPV (for some selected strategies). The optimization process for Strategy 13 showed the disadvantages of guiding the injector wells in the direction of lower permeability of breaking and the producers in the direction of higher permeability. Therefore the process had to be considered for 2000 days, instead of the 3720 days that had been used in the other strategies since, at the end of the process, it was not possible to increase the oil production, nor to decrease the cumulative water production or to delay the breakthrough with respect to the base case for this strategy. Figure 5 shows the evolution of the optimization process for the strategies. The points maximized in Fig. 5 correspond to the highest NPV during the optimization process. It can be observed that the processes present few simulations, in order not to change too much the characteristics of each initial strategy.

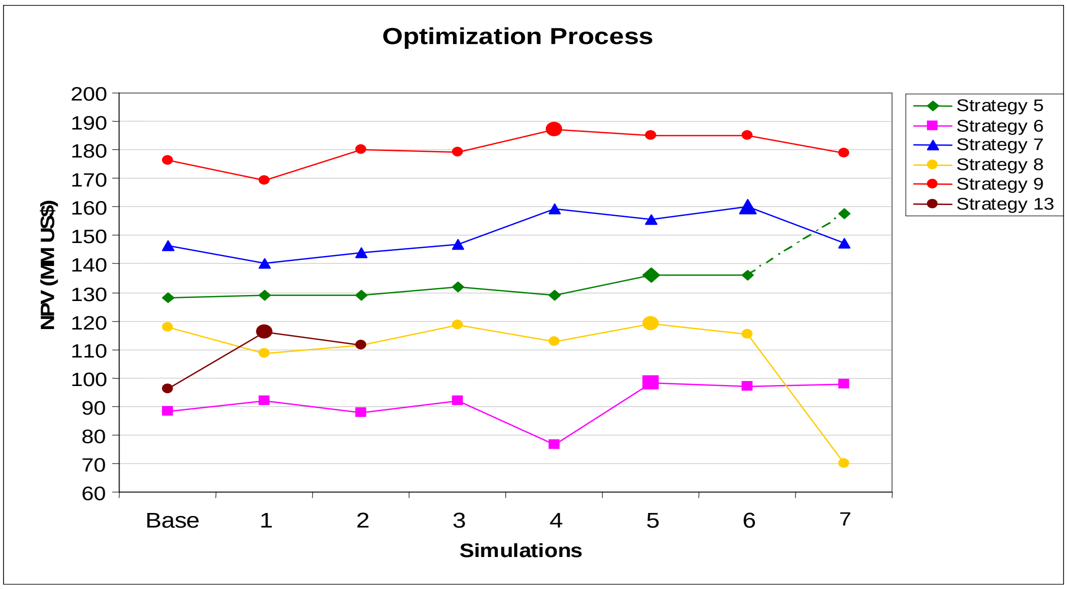

Figure 5. NPV for the strategies tested in Step III.

The optimization processes applied in Step III allowed one to observe that the strategies selected for optimization have shown similar results to those obtained in Step II, indicating that the rules obtained in that step are good initial guesses. The Strategy 9, which showed the highest values of NPV in Step II, continued presenting the higher values of this indicator, both before and after the optimization process. In Strategy 5, the optimization process also allowed the increase of NPV, but further improvement in this indicator only was possible by increasing the number of producing wells (by the addition of new wells or the reduction in well spacing) making it similar to Strategy 9. The Strategies 9, 5, and 7, that have production for horizontal wells oriented in the direction of lesser fracture permeability, have shown the highest values of NPV before and after the optimization, whereas Strategies 6 and 8, that use vertical wells, had shown lower values. Therefore, the advantages of the use of horizontal wells are also confirmed in this step. It can be observed that the optimization process allowed the delay of water breakthrough; as a result, the strategies presented a reduction in the cumulative water production at the end of the process.

Taking into consideration the results obtained during the three steps of the present study and their analyses, it is possible to formulate some rules that, in a generic way, guide the selection of an initial production strategy for the development of naturally fractured reservoirs and favor their posterior optimization. These rules are:

- Use horizontal wells for injection and production of fluids (preferentially and whenever possible), making possible to reach a bigger portion of the reservoir rock, increasing the cumulative oil production and maximizing the NPV for the project;
- Guide injector wells in the direction of higher fracture permeability and producing wells in the direction of lesser permeability, thus preventing the channeling of the injected water and, in consequence, delaying water breakthrough in the producing wells;
- New producer wells should be added in a pattern aligned with the direction of higher permeability; this allows increasing oil recovery, and NPV of the field for strategies where an only type of well is used.
- The optimization processes should aim for a reduction of water production and delay in the breakthrough time yielding higher NPV; these processes contemplate mainly the relocation of producing and injector wells, the opening and the closing of wells and the adjustment of the injection rates.

Finally, it is possible to affirm that the methodology proposed and implemented in this study allowed to identify, through sensitivity analyses, the properties of the reservoir that affect more strongly the reservoir behavior during its production through technical and economic indicators. It was also possible to determine the types of production strategies that have to be considered as more adequate to be used as initial proposals for the development of this type of reservoir, showing the strategies, wells placement, and arrangements of producers and injectors that yield better performance. And, by means of an optimization process for the studied cases, it was possible to increase its NPV. With the obtained results, general rules for the initial selection of a production strategy, and its optimization for naturally fractured reservoirs have been formulated.

5. Conclusions

- A methodology to generate generic rules for the choice of initial strategies of production for naturally fractured reservoirs was studied. This methodology involved sensitivity analyses of the properties of the reservoir and fluids, analyses of production strategies and the implementation of an optimization process.
- A sensitivity analysis of naturally fractured systems was performed in order to change characteristics of reservoir and fractures such as spacing, inclination, matrix and fracture permeabilities, observing changes in production indicators (production, Np and recovery factor, RF), and economic parameters (NPV).
- The results allowed for the observation of higher efficiency of horizontal wells in relation to vertical wells when used in the production strategy, presenting higher production and NPV.
- It was shown that the orientation of horizontal wells with respect to the fracture permeability directions is an important factor in the behavior of the production, as well as in the selection of an initial strategy for the development of projects in naturally fractured reservoirs.
- The production strategies that involve horizontal wells have a better performance when tested in different situations of configuration of the properties of naturally fractured systems, different inclinations, presence of systems of conjugated fractures and different permeabilities of matrix and fracture.
- The analysis of the results has shown that the influence of the production strategy is higher than the influence of reservoir properties and type of oil (in terms of production, Np, RF and Wp) and economic indicators (NPV).
- Optimization processes in naturally fractured reservoirs must have as one of the most important objectives the reduction of the cumulative water production and the delay in the breakthrough; in this way it is possible to increase the NPV of the project.
- The general rules formulated in this work aim to facilitate the process of selection and optimization of the production strategy, and to serve as a starting point for further studies in this area.

6. Acknowledgements

The authors thank to the Petroleum Engineering Department of the Faculty of Mechanical Engineering of UNICAMP, to CEPETRO and CNPq for their support in the realization of this work.

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