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APPLICATION OF HYDRAULIC FRACTURING AS STIMULATION TECHNIQUE FOR NATURALLY FRACTURED RESERVOIRS

Deyvid J. Debastiani[1], Fernando B. Tezza[2], Marcio A. S. Pinto[3]

Abstract

Naturally fractured reservoirs (NFR) are geological formations that have been in the spotlight due to their huge flow capacity. In other words, an impressive volume of oil may be extracted from these formations. In practice, all sedimentary rocks may present some natural fractures (NF) as result of in-situ geological stresses. However, naturally fractured reservoirs represent only reservoir systems that possess natural fractures capable of significantly influencing the flow in the porous media. In the past, ignoring the presence of natural fractures was commonly used as way of facilitating reservoir models due to the high heterogeneities found in this type of formation. In this context, Barenblatt et al. (1960) and Warren and Root (1963) presented the concept of dual-porosity systems, in which the rock matrix and the natural fractures was represented as two distinct and separated porous media. The matrix has high porosity and represents reservoir storage capacity, while all flow occurs in the fractures due to its high permeability. Mazo (2005) also availed himself of the concept of dual-porosity systems. The author verified that the orientation of the natural fractures has a direct impact on the production strategy applied to NFR. Besides, the sensitive analysis carried out on the reservoir parameters showed that the matrix permeability is one of the variables that most restrain the reservoir productivity. That is because the low permeability of the matrix traps the oil into the rock, hence reducing the flow from the matrix to the natural fractures. Through numerical simulation of reservoirs, this paper evaluates the response of a NFR with low permeability matrix subject to hydraulic fracturing stimulation. In order to accomplish this analysis, three different simulation models are created and each of them is subjected to hydraulic fracturing. Both short and long-term production data are investigated, and the non-stimulated and the stimulated scenarios are compared through net present value (NPV) analysis. The results show that the employment of hydraulic fracturing improves communication between the matrix and the natural fractures, resulting in increased cumulative oil production for all the considered cases, whereof the simulation model with low density of natural fractures exhibited the best results.

1. Introduction

Nelson (2001) proposed that NFR may be classified based on porosity and permeability contribution from both systems, matrix and fracture. In Type 1 reservoirs, the fractures system provides all storage and flow capacity of the reservoir. Concerning Type 2 reservoirs, the matrix system represents the storage capacity due to its medium porosity and low permeability, while the fractures provide the essential permeability for productivity. Type 3 reservoirs have high porosity matrix and may be produced without fractures, hence fractures represent additional permeability for production. When the matrix has high permeability and porosity (i.e. Type M reservoirs), the fractures represent barriers to the flow, which negatively influence the reservoir production.

Regarding the modelling of fractured formations, the work of Warren and Root (1963) suggests that the rock matrix and the natural fractures are represented as two distinct and separated porous media. The main assumptions made by the authors are: the matrix system must be considered as a homogeneous and isotropic media, and modelled as a set of rectangular parallelepiped; the fractures have constant width and spacing, and are parallel to the axis of main permeability; the flow is monophasic and occurs restrictedly between the matrix and fractures systems, meaning that there is no flow inside the matrix. Grounded on these assumptions, the authors developed the governing equations for

[1] Bachelor Candidate, Petroleum Engineering – University of the State of Santa Catarina (UDESC)
[2] Bachelor Candidate, Petroleum Engineering – University of the State of Santa Catarina (UDESC)
[3] Ph.D, Petroleum Engineer – Polytechnic School of the University of São Paulo (USP)

flow in the dual porosity model. It is important to highlight the presence of the shape factor in the dual porosity models, which is responsible for controlling the flow between the two systems.

Kazemi et al. (1976) improved the dual porosity monophasic model proposed by Warren and Root (1963). The authors expanded the previous monophasic model for multiphase flow (immiscible flow of oil, water and gas), and solved the dual porosity model for three dimensions numerically. The flow mechanism that rules the monophasic model is the fluid expansion, however the mechanisms of imbibition and gravitational segregation also must be considered in the multiphase model. Later on, Gilman and Kazemi (1983) updated the preceding work by means of accounting for the relative fracture permeability, aiming to improve the mobility behavior between the phases. The new shape factor was named as shape factor of Gilman and Kazemi.

Blaskovich et al. (1983) and Hill and Thomas (1985) extended the dual porosity model to the dual permeability model. This new approach allows for flow not only in the fractures, but also within and between matrix blocks, which was not considered in the dual porosity model. The dual permeability model shows better performance when vertical flow is an important feature of the reservoir.

The natural fractures preexisting in the reservoir have an important influence on hydraulic fracturing treatment. According to Weng (2014), the interaction between hydraulic fractures (HF) and natural fractures may result in a few distinct scenarios, such as crossing with an offset or direct crossing, and imprisonment of the HF by the NF. If the crossing happened with an offset, the HF will change its propagation direction. Direct crossing events occur when the HF directly propagates through the NF without change of direction. In the imprisonment scenario, the NF acts as a barrier preventing the HF of continue propagating in the reservoir.

The selection of a proper production strategy is of vital importance for a petroleum field. Nevertheless, it may be a tough task due to the huge amount of variables that must be simultaneously analyzed. The factors that most influence the selection of the production strategy are the rock and fluid properties, the rock-fluid interaction, and the economic and operational constrains. Mazo (2005) developed a methodology aiming to create rules that can be used as a guide for selecting the initial production strategy. He grounded his strategy theory on petrophysical properties and production parameters. Also, by analyzing the recovery factor and the NPV, the author observed that the production strategy played a greater influence on the reservoir production, compared to the reservoir properties. In addition, the author showed that the production strategy optimization can significantly delay the water cut (WCUT), and hence, decrease the water production.

Sampaio et al. (2015) presented a fast genetic algorithm (FGA), which aims the maximization of the NPV by adjusting the flow rate of the wells and the aperture of the valves. The algorithm was created based on the evolution and natural selection theories, and employs the evolutionary concept by applying the selection, reproduction, and mutation processes. The genes analyzed on their work are the apertures of the valves, the flowrate of fluids, and the WCUT values. Initially, the FGA creates a random initial data population, which is simulated in a black-oil simulator to provide the production data. The NPV of each simulation is stored and ordered by the Sigma Scaling operator, prioritizing the most significant values. Uniform Stochastic Sampling performs the parenting relationship between the genes, and the Uniform Crossover operator executes the crossover of the individuals. Finally, the mutation operator is applied on each iteration, randomly changing the features of the population until all of them are tested. The optimization strategy was employed in a heterogeneous reservoir model based on Namorado's Field, Brazil, simultaneously accounting for short-term and long-term production periods.

Through numerical simulation of reservoirs, this paper evaluates the response of a NFR with low permeability matrix subjected to hydraulic fracturing stimulation. The employment of this stimulation technique aims to improve the connection between the matrix and the fractures systems. Ultimately, the goal of this study is to maximize the NPV of the field, taking into account the hydraulic fracturing operation costs. Technical parameters such as oil and water production, as well as water injection are also evaluated.

2. Methodology

The methodology of this work aims to analyze the impact of hydraulic fracturing on the production of NFR, according to the flowchart shown in Figure 1. The first step of the methodology consists in building the reservoir employing the dual permeability model, as well as the definition of the petrophysical proprieties and the reservoir's initial conditions. The next step is the application of the production strategy, based on the results of Mazo (2005). In order to make this study wider, three simulation models that represent reservoirs with low, medium and high density of natural fractures were built, which are respectively identified by the S100, S50 and S10 codes. The letter "S" denotes the spacing and the values indicate the distance in feet between each natural fracture. Two distinct scenarios were applied for each model: a non-stimulated scenario and a scenario subjected to hydraulic fracturing, totalizing six simulation models. Furthermore, the values of WCUT were optimized for short-term (seven years) and long-term (thirty years) production utilizing the fast genetic algorithm proposed by Sampaio et al. (2015). The study is validated with the evaluation of the production technical parameters, along with the comparison between the two scenarios proposed utilizing the optimum NPV as a reference.

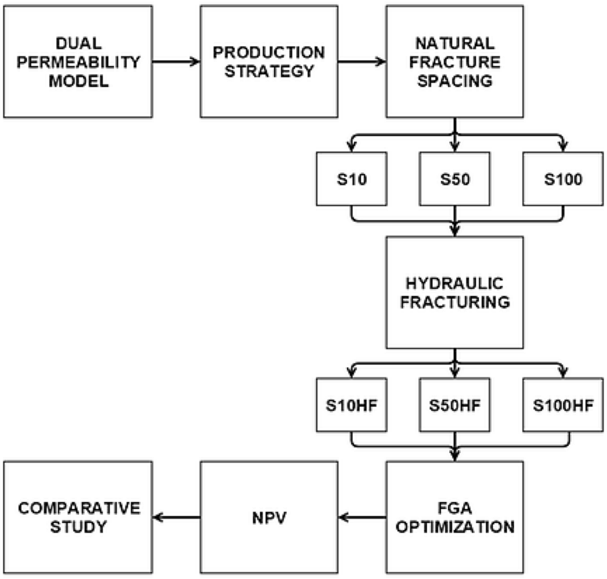

Figure 1. Flowchart of the methodology.

3. Application

The first item of this section corresponds to the initial stage of the methodology, in which the physical features and the initial conditions of the reservoir are defined. In the second item it is described in detail, the production strategy and the hydraulic fracturing stimulation. Lastly, the economic scenario utilized to calculate the NPV is presented.

3.1. General Characteristics

The characteristics common to the six simulation models are described in the following items:

- Cartesian mesh of 41 x 41 x 5 blocks (total of 8405 blocks);
- Blocks dimensions: 100 ft. x 100 ft. x 50 ft.;
- Simulation model of dual permeability with shape factor of Gilman and Kazemi;
- Naturally fractured reservoir Type 2, based on the classification proposed by Nelson (2001);
- Spacing of natural fractures:
  - Direction *i*: 10 ft., 50 ft., 100 ft.;
  - Direction *j*: 10 ft., 50 ft., 100 ft.;
  - Direction *k*: 0 ft. This value implies that there are not fractures perpendicular to the *k* direction - i.e. there are no horizontal fractures.
- Matrix porosity of 20 %; Natural fracture porosity of 0.01 %;
- Matrix permeability in the direction *i*, *j*, *k* of 1 mD;
- Permeability natural fractures:
  - Direction *i*: 10 mD;
  - Direction *j*: 500 mD;
  - Direction *k*: 100 mD.
- Initial pressure of the reservoir: 3600 psi;
- Matrix compressibility: $4 \cdot 10^{-6}$ psi^{-1};
- Fracture compressibility: $4 \cdot 10^{-6}$ psi^{-1};
- Only water and oil saturate the porous media, thus:
  - Oil initial saturation in the matrix: 0.8;
  - Oil initial saturation in the fracture: 1.0.
- Oil density: 45 lbm/ft^3.

3.2. Production Strategy and Hydraulic Fracturing Characteristics

The production strategy was chosen based on the results of the study done by Mazo (2005). According to the author, the utilization of horizontal wells significantly improves the production of RFN. However, the principal permeability direction of the natural fractures must be carefully observed to avoid water canalization. In Figure 2 it is possible to observe the distribution of producer wells and injector wells conforming to the principal permeability direction of the natural fractures, which is indicated by the arrow in the lower left-hand corner.

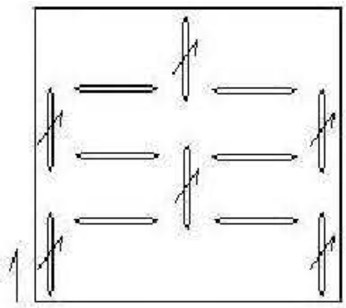

Figure 2. Production strategy involving horizontal producer wells and horizontal injection wells.

The production strategy consists of 12 wells in total, being 6 injector wells, 6 producer wells, where each of them presents a 1000 ft. length in the horizontal section. The operational parameters are summarized in the Table 1. The short-term production corresponds to 7 years, from January of 2000 to January of 2007, while the long-term production extends until 2030. The non-stimulated simulation model can be observed in Figure 3a.

Table 1. Operational parameters of the wells.

	Production wells	Injector wells
Layer of completion	1	5
Bottom hole pressure (psi)	1500 (min.)	3700 (max.)
Total surface liquid rate (bbl/d)	3000	-

The hydraulic fracturing technique was applied in the six producer wells since the first day of production. The hydraulic fractures were created by utilizing the Local Grid Refinement tool (available in the black-oil simulator), with 11 refined blocks in the *i* direction, 3 in the *j* direction and 1 in the *k* direction. Each well received three transverse fractures measuring 800 ft. in length (each wing), 1 ft. in width and a permeability of 500 mD. The fractures have a spacing of 400 ft. in between each other, and extend from the first to the last reservoir layer (Figure 3b). The interaction between the NF and the HF occur only by direct crossing, according to the description provided by Weng (2014). The simulation model that is subject to hydraulic fracturing has the same operational parameters that the non-stimulated model.

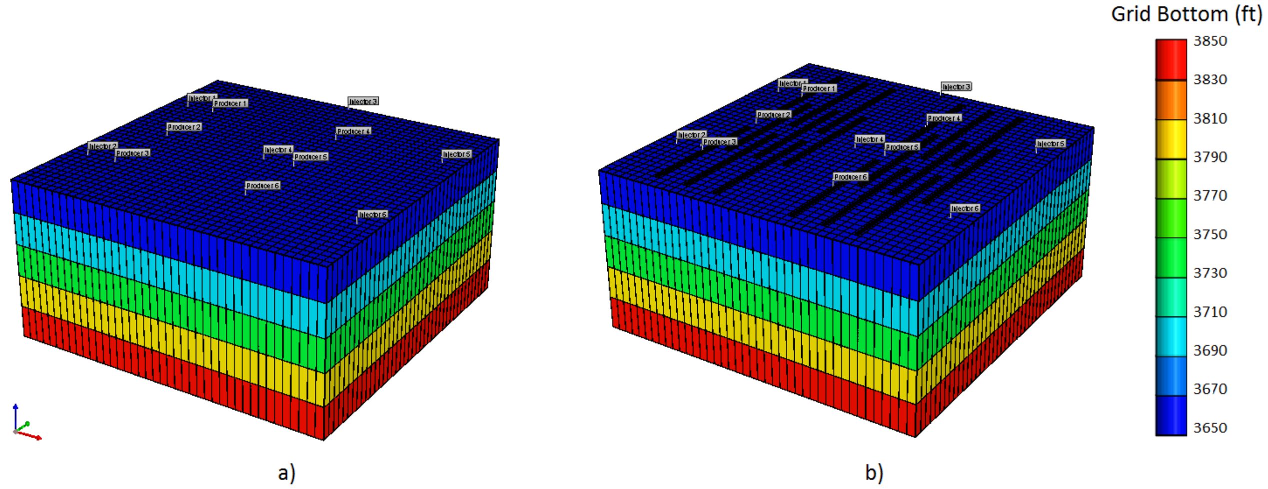

Figure 3. a) Non-stimulated simulation model and b) simulation model subjected to hydraulic fracturing.

3.3 Economic Scenarios

The Table 2 indicates the economic scenario utilized for the NPV calculations, conforming to the government taxes and operational costs applied to an onshore petroleum rig.

Table 2. Government taxes and operational costs.

Variable	Value
Royalties (%)	10.0
PIS/Cofins (%)	9.25
Social Contribution (%)	9.00
Income tax (%)	25.0
Discount tax (%)	8.00
Oil price (US$/bbl)	60.0
Oil production cost (US$/m^3)	75.5
Water production cost (US$/m^3)	7.55
Water injection cost (US$/m^3)	6.30
Horizontal well cost (10^3 US$/m)	61.2
Investment in exploration (MMUS$)	0.50
Hydraulic fracturing cost (MMUS$)	0.025

4. Results and Discussions

According to the short-term production data presented in Figure 4, it is possible to observe that the oil production is directly proportional to the density of natural fractures, i.e. the smaller the spacing between each fracture, the greater the productivity of the reservoir. This result agrees with the naturally fractured reservoir model Type 2 proposed by Nelson (2001), in which, the matrix represents the reservoir storage capacity, and the fractures provide the essential permeability for productivity.

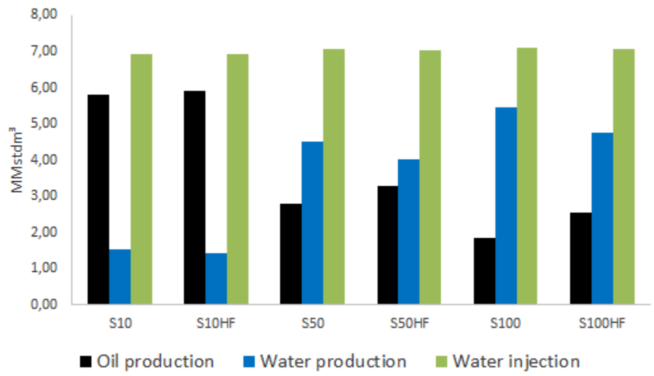

Figure 4. Results of oil production, water production and water injection for the short-term period (7 years).

Nevertheless, it can be noticed that the water production increases when the density of fractures decreases. Due to the low permeability of the matrix, most of the oil displaced by the water comes from the natural fractures, while only a small portion comes from the matrix. Therefore, the injection process becomes compromised when the water reaches the producer wells, since the water will follow a preferred flow path through the natural fractures. In a general way, the distribution of the wells proposed by Mazo (2005) avoids the water canalization because the wells are distributed conforming to the principal permeability direction of the natural fractures. However, that production strategy is not suitable for NFR with low density of fractures, because the low permeability of the matrix prevents the water from properly sweep the porous media. The water saturation distribution presented in Figure 5 shows the lack of efficiency of the injection process.

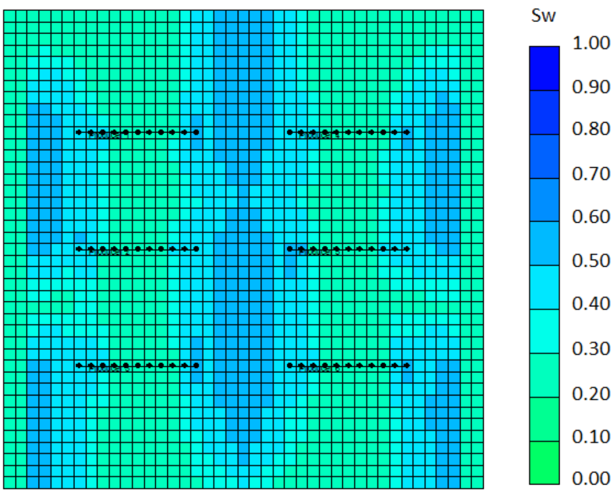

Figure 5. Water saturation for the first layer of the reservoir at the end of the seventh year of production (S100 model).

The employment of hydraulic fracturing stimulation increased the oil production in the three simulation models, among which the model S100HF stands out with an improvement of 37.25% in the cumulative oil production. The water production was reduced in all cases subjected to hydraulic fracturing treatment, and once again the model S100HF had the best result, which presented a reduction of 12.67% on water production. The cumulative water injection remained approximately constant for the three analyzed cases. Based on the previous results, it can be inferred that the hydraulic fracturing improved the connection between the matrix and the natural fractures of the reservoir. The hydraulic fractures created by the stimulation exposes regions of the reservoir previously inaccessible to the phenomenon of imbibition, leading to a more efficient secondary recovery with water injection.

The general improvement of the production data can be also verified through the results of the NPV, which are exhibited in Figure 6. As expected, the reservoir model with high density of natural fractures has the greatest NPV among the considered cases, since it has the greatest cumulative oil production. In that case, the hydraulic fracturing stimulation does not significantly affect the revenue of the field. Nevertheless, the stimulation becomes more significant for the reservoir models with medium and low density of natural fractures. It is important to highlight this, without stimulation, the exploitation of model S100 is economically unfeasible.

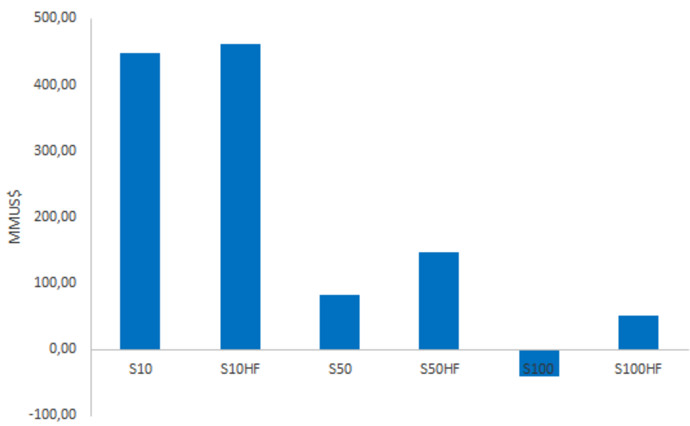

Figure 6. Results of the NPV for the short-term production (7 years).

The cumulative oil and water productions of the long-term production follow the same trend as the short-term production, i.e. they are dependent of the density of natural fractures (Figure 7). As can be noticed in Figure 5, the injected water production still did not reach the producer wells at the end of the seventh year, which explains the reason why this parameter remains constant for the short-term production. However, the same parameter does not remain constant for the long-term production, and presents greater values for models with low density of fractures subjected to hydraulic fracturing. As previously said, the hydraulic fracturing stimulation significantly increases the secondary recovery with water injection for models S50 and S100, causing the water to reach places previously inaccessible.

Therefore, models S50HF and S100HF require greater volume of injected water compared to the non-stimulated models.

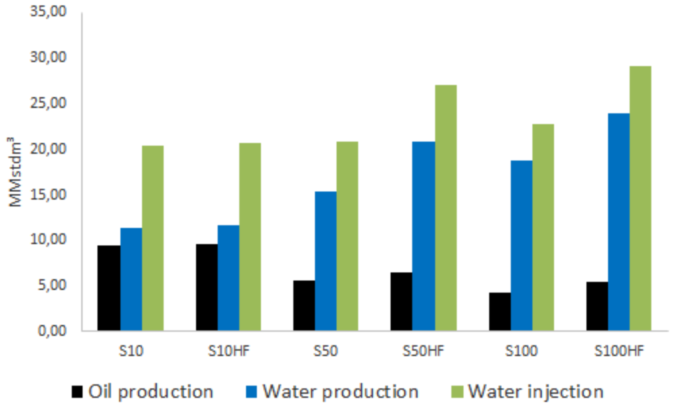

Figure 7. Results of oil production, water production and water injection for the long-term period (30 years).

Even with higher costs concerning water production and injection, the models subjected to hydraulic fracturing, present an increase to the NPV results regarding the non-stimulated models, which can be verified in Figure 8. The model S100HF had the greatest increase on VPL, from 33.44 to 103.6 MMUS$.

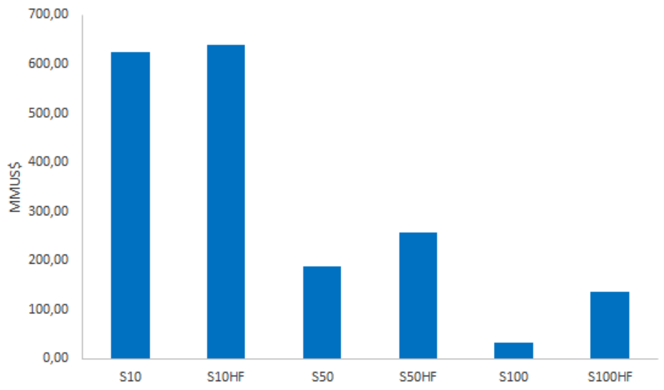

Figure 8. Results of the NPV for the long-term production (30 years).

Figure 9 shows the increase percentage in NPV obtained by the models subjected to hydraulic fracturing, for both short and long-term production.

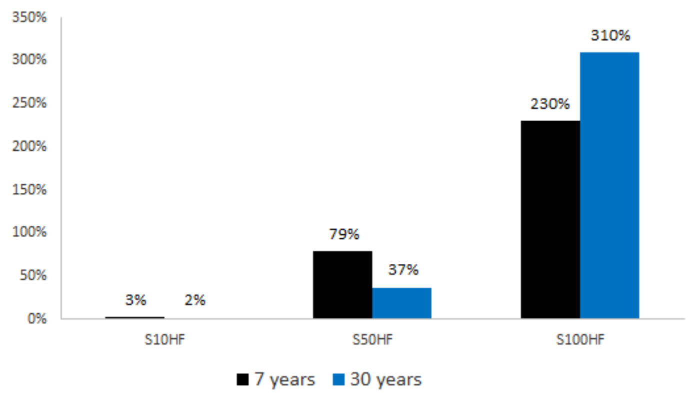

Figure 9. Percentage increase in NPV obtained by the models subjected to stimulation.

5. Conclusions

The production strategy proposed by Mazo (2005) significantly increases the productivity of naturally fractured reservoirs. However, geological formations with a low permeability matrix do not properly respond to water injection, making it necessary to study the technical and economical viability of other recovery or stimulation techniques.

Through the analysis of operational and economical parameters, it was found that hydraulic fracturing stimulation improves communication between the matrix and the natural fractures, resulting in increased cumulative production. Compared to the non-stimulated S100 case, the S100HF model showed an increase of 37.25% in the cumulative oil production, and a decrease of 12.67% in the cumulative water production for short-term production. For this same period, the S100 scenario would be economically unfeasible to be exploited, because it presented a negative NPV. However, the application of hydraulic fracturing caused an increase of 230% in NPV, making the reservoir capable of production. Even with a significant increase in cumulative water production for long-term production, the S100HF model exhibited the highest percentage increase of NPV of all the analyzed cases, about 310% in comparison with the non-stimulated S100 model. Although economic viability has been certified for the three stimulated scenarios analyzed, the use of hydraulic fracturing should focus on the most critical cases, such as formations with low density of fractures, as this type of stimulation can have serious operational and environmental risks.

The methodology proposed in this paper idealize interaction between hydraulic fractures and natural fractures as a direct crossing, since the program used for building the simulation model does not include other types of interaction. However, it is known that the growth of hydraulic fractures is strongly influenced by the natural fractures. Therefore, it is suggested for future studies to include the geomechanical effects from the interaction between the two types of fracture.

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