THE INFLUENCE OF PRODUCTION SYSTEM CONSTRAINTS ON THE RESERVOIR STRATEGY OPTIMIZATION

Tasso C. B. de Magalhães
Schlumberger Information Solutions. Rio de Janeiro – RJ, Brazil.
tassocbm@gmail.com

Rogério F. Martini
DEP-FEM-UNICAMP. P.O. Box 6122, Campinas - SP, Brazil. 13083-970
rogeriom@dep.fem.unicamp.br

Denis J. Schiozer
DEP-FEM-UNICAMP. P.O. Box 6122, Campinas - SP, Brazil. 13083-970
denis@dep.fem.unicamp.br

Abstract. *The production unit capacity can be limited by many parameters, such as maximum rate of liquid, water treatment facilities and number of wells. Most works concerning production strategy optimization consider only the reservoir, which often results in an oversimplified process where operational constraints of the production system are overlooked. However, restrictions imposed by treatment facilities have direct influence on the production and consequently on reservoir profits. This work presents an offshore field where the adopted constraints were the amount of liquid produced and the available capacity for gas lift operation, analyzed separately. In the first case, a model with no liquid restriction and two others with the liquid flow rate restricted by the treatment capacity of the production unit were simulated. Regarding the gas lifting, four cases were analyzed: one in which pressure losses were not considered dynamically during simulation and three cases where pressure losses were considered dynamically using gas-lift option (with different amounts of gas available) in the simulator. An integrated analysis combining economic and technical parameters was made; many differences were observed in a variety of parameters, such as the Net Present Value and fluid production, showing that oversimplifying the problem can lead to sub-optimal strategies. This work clearly demonstrates that it is essential to perform an integrated study of the reservoir behavior and the production system during optimization, especially in offshore environments.*

Keywords*: Production Contraints, Reservoir Simulation, Production Strategies*

1. Introduction

Despite the great influence of production system restrictions on reservoir performance, they are often neglected due to the higher complexity involved when these limitations are taken into account during the optimization of drainage strategies. Yet, some works have shown the importance of simulating and optimizing both the drainage strategy and the production system behavior, especially since the reservoir, which is initially a static system, becomes dynamic after the start of production (Yang *et al.*, 2002, 2003). The impact of production constraints is even higher in offshore systems due to the high costs involved; therefore, it is essential to establish the dimension and capacity of the production system in the designing phase, to avoid extra costs with plant modifications or reduction of the reservoir production due to limitations in the production unit.

The present work studies the impact of liquid treatment capacity on the reservoir drainage strategy; it also analyzes the influence of the amount of gas available for continuous gas lift operation (GLC), which is the most common artificial lifting method used in Brazilian offshore reservoirs. These constraints are studied separately in order to better identify their influence on drainage strategies and reservoir performance.

2. Methodology

The methodology initially proposed by Nakajima (2003) was modified before being applied to this work, since it did not take into account the existence of operating restrictions of the production system. The procedure adopted here consisted of running reservoir simulations followed by an economic assessment of the results. By analyzing the performance of each well, it is possible to determine which ones must be altered and in what manner. In this work, the producer wells are classified according to their:

(1) present value (PV),
(2) cumulative oil production (Np),
(3) average oil flow rate ($Q_o$med)
(4) cumulative water production (Wp),
(5) cumulative gas production (Gp) and
(6) quality map index (Cruz, 2000, Nakajima and Schiozer, 2003).

In the list above, PV is a parameter which indicates the economic performance of the well, measuring the income obtained from oil sales against drilling investment and production costs. A list of prior producers is compiled based on their classification and, according to the priority level which is assigned to the parameters described above, the wells are divided into primary and secondary; primary wells are placed on top of the priority list.

The changes to the simulation model are then made by the user/engineer and a new simulation is run, followed by another analysis of the wells and the field; reservoir data for each optimization loop is stored in order to allow one to analyze if the modifications are beneficial to the whole field; this is important since the changes can improve the performance of a few wells and yet, have a deleterious effect on the overall performance (e.g., reduce field Net Present Value or field Np); this procedure is carried on iteratively until a stop criterion is met. This methodology allows reservoir engineers to make use of a comprehensive databank of suggestions for well modifications, as well as use their own experience to decide for other changes, if that is the case.

Figure 1 shows the methodology used in this work, with the modifications to the original procedure depicted in red.

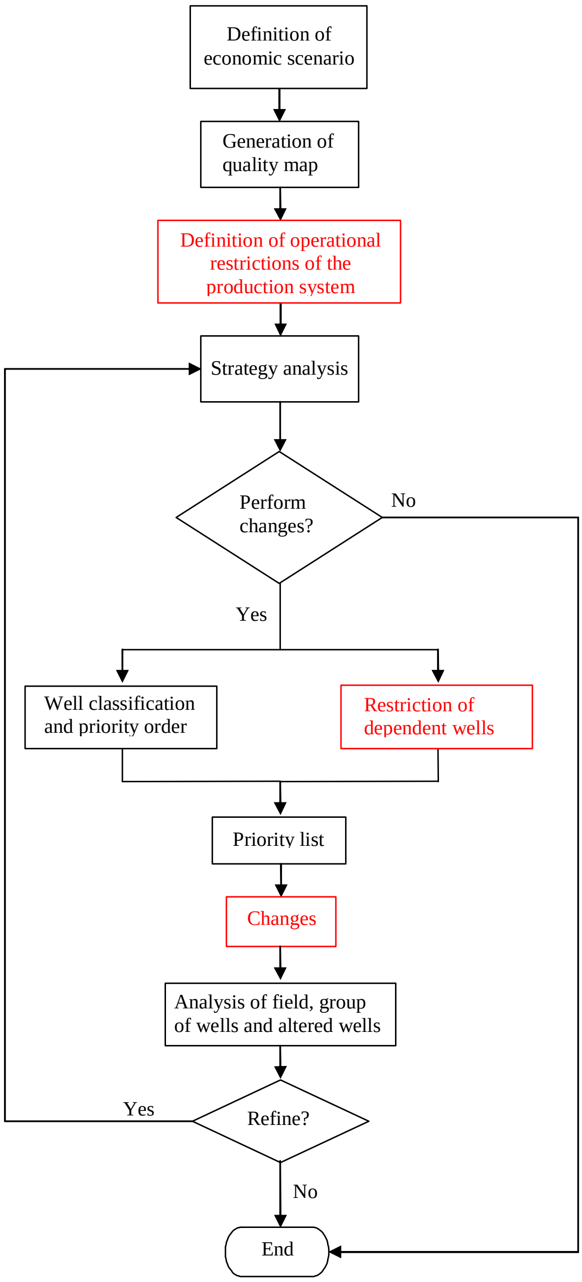

Figure 1. Methodology applied in this work

Since the objective of this work is to study the impact of operating constraints on the production strategy and on the optimization / refinement process, two operating constraints were analyzed separately: a limitation on the production unit capacity for liquid treatment (early results presented by Magalhães and Schiozer, 2004) and the use of gas-lift to elevate the fluids from the reservoir to the production unit.

Modifications made in some wells may affect the performance of others throughout the reservoir, thus not all wells should be altered at the same time. Only the distance between them was considered in the restriction of dependent wells stage, i.e. the neighborhood concept was adopted (Moreno and Schiozer, 2002); this concept may not be strictly correct for reservoirs with strong heterogeneities, therefore its use was very conservative, that is, simultaneous modifications were made only in wells which were quite distant and, therefore, independent.

Regarding the changes made to wells, the differences between the alternatives adopted here and those of Nakajima (2003) concern mostly the conversion to horizontal wells and the increase of the oil flow rate of single wells. Those changes did not apply to this work since all wells considered here were horizontal and the oil flow rate of single wells was subordinate to that of the group of wells. Some suggestions were also added to the list, therefore the changes considered during the refinement process were:

- Cancellation of well allocation
- Change of completion layer
- Change of well schedule (start of operation of producers or injectors)
- Change of well position
- Conversion from producer to injector
- Abandonment of producer (well is shut)
- Addition of extra producers or injectors
- Abandonment of injector (well is shut)
- Reduce water injection limit (maximal water flow rate)

2.1. Analysis of the impact of production system constraints on drainage strategies

The process was divided in six steps:

1) Define the constraint to be studied
In this step, the system constraint is defined, along with its limits and the adopted simplifications.

2) Refine the drainage strategy
The procedure outlined in Fig. 1 is followed; priority was given to wells with lower PV, i.e., wells with worse economic performance.

3) Compare final strategies for each case
The final strategies for each case (different liquid flow rate constraints or different amounts of available gas for GLC) are compared, with emphasis on the differences in behavior, the number and positioning of wells.

4) Analysis of the refinement process
Again, emphasis was given to the differences found for each case, however in this step the whole refinement process was analyzed, instead of just the final strategy.

5) Apply the constraint to the strategy previously defined without considering it
Depending on the reservoir size and the number of wells, the optimization of a drainage strategy considering the production system limitations can be difficult; therefore, it is not uncommon to optimize strategies without taking into account these restrictions. The impact of such simplification was analyzed in this step, by defining strategies without considering the production system constraints and then applying such constraints to the strategy.

6) Sensitivity analysis
The influence of the economic scenario was analyzed by varying the oil sales price. A normalized field Net Present Value (NPV) was adopted to make possible the comparison between the results for different scenarios; the normalization process is described in Eq. (1).

$$NPV_{norm} = \frac{(NPV_{simulation}) - (NPV_{\min imum})}{(NPV_{\max imum}) - (NPV_{\min imum})} \tag{1}$$

3. Case studies and results

The reservoir shown in Fig. 2 was modified from a real offshore field; permeability channels were added to the model; the range of horizontal permeability is from 0 to 2000 mD and the range of vertical permeability is from 0 to 200 mD.

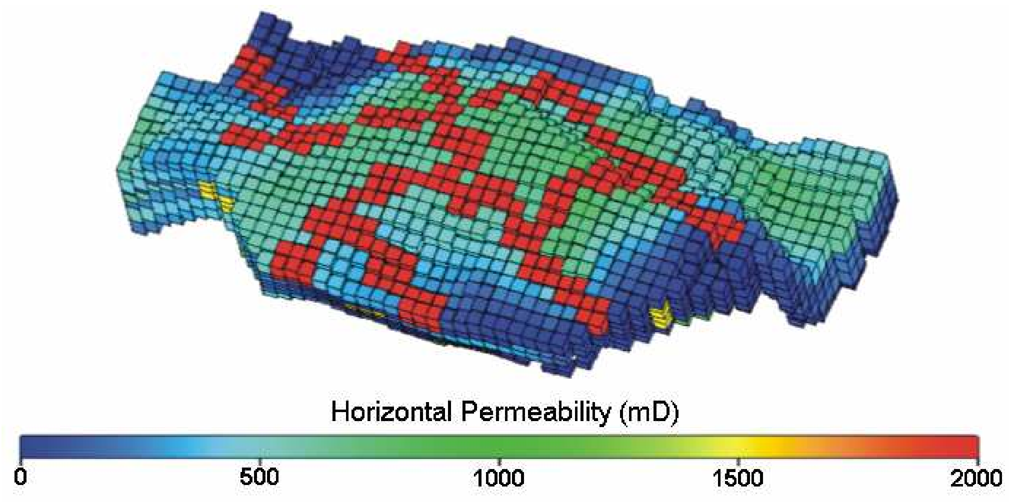

Figure 2. Model based on an offshore reservoir; permeability channels were added to the original model

A light oil of 28°API and viscosity of around 1 cP was used in the simulations involving restriction of liquid capacity, and an intermediate oil of 22°API and viscosity of approximately 9 cP; pressure variation during the simulation was in the range of 207 to 442 x10^5 Pa.

3.1. Restrictions analyzed and economic scenario

Following the procedure outlined in section 2.1, in Step No. 1 the cases to be studied were defined; for the restrictions of maximum liquid capacity, the same values presented by Magalhães and Schiozer (2004) were adopted: no restriction (simulated with the use of a platform with capacity for 20,000m^3/day), maximum of 10,000m^3/day and maximum of 15,000m^3/day. For the gas lift study, four restrictions were analyzed: unlimited amount of gas available for GLC, gas-lift limited to 1,200,000m^3/day, gas-lift limited to 800,000m^3/day and a simplified case where the pressure drops were estimated only in the beginning of the simulation.

A summary of the studied cases is shown in Tab. 1, where the CAPEX values are related to the platform capacity; the economic scenarios analyzed (in Step No. 6 of the procedure mentioned above) involved the oil prices already presented in Tab. 1, where US$ 113.20/m^3 was considered low, US$ 157.23/m^3 was considered intermediate and a further value of US$ 201.26/m^3 (US$ 32/bbl) was adopted for the high sales price.

Table 1. Summary of case studies

Case	Restriction	Oil price	CAPEX	Well cost	Oil type
1A	Maximum liquid flow rate: 10,000 m^3/day	US$ 113.21/m^3 (US$ 18/bbl)	US$ 155 millions	US$ 11.5 millions	Light
1B	Maximum liquid flow rate: 15,000 m^3/day	US$ 113.21/m^3 (US$ 18/bbl)	US$ 195 millions	US$ 11.5 millions	Light
1C	No limit for liquid flow rate	US$ 113.21/m^3 (US$ 18/bbl)	US$ 235 millions	US$ 11.5 millions	Light
2A	Unlimited gas flow rate	US$ 157.23/m^3 (US$ 25/bbl)	US$ 245 millions	US$ 11.5 millions	Intermediate
2B	Maximum gas flow rate: 1,200,000 m^3/day	US$ 157.23/m^3 (US$ 25/bbl)	US$ 245 millions	US$ 11.5 millions	Intermediate
2C	Maximum gas flow rate: 800,000 m^3/day	US$ 157.23/m^3 (US$ 25/bbl)	US$ 245 millions	US$ 11.5 millions	Intermediate
2D	Simplified treatment of pressure drop	US$ 157.23/m^3 (US$ 25/bbl)	US$ 245 millions	US$ 11.5 millions	Intermediate

3.2. Restriction on the maximum production capacity of liquid

Results obtained in Step No. 2 of the procedure mentioned previously were initially presented by Magalhães and Schiozer (2004); Figure 3 reproduces those results; however, since the analysis concerning Step No. 3 was thoroughly discussed in the same work, it will not be repeated here.

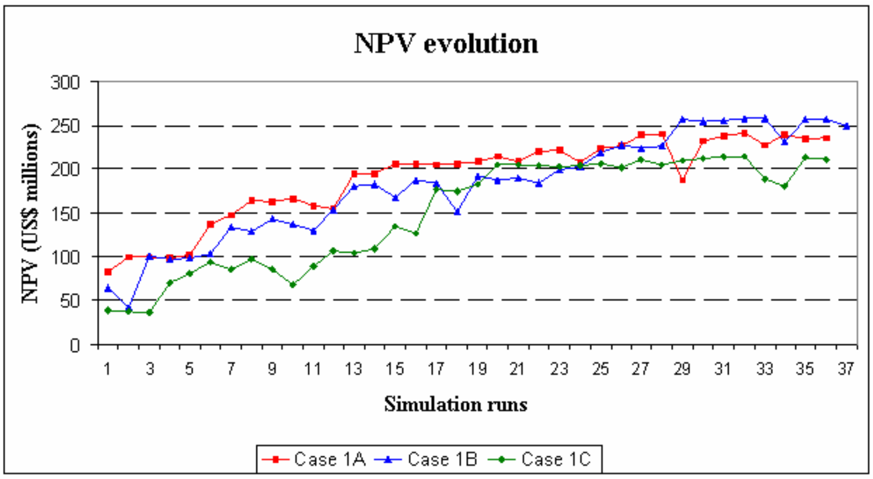

Figure 3. NPV evolution during strategy refinement process – light oil (Magalhães and Schiozer, 2004)

In Step No. 4, it was observed that the addition of new injectors in Case 1C, which had the objective of preventing a drastic reduction in reservoir pressure, increased the production of oil, but not enough to compensate the additional costs; therefore, there was a reduction in field NPV; this problem was not observed in Cases 1A and 1B, where the lower limit of maximum oil flow rate allowed for a better control of the reservoir pressure without the need for extra injectors.

In Case 1C, the final strategy was obtained without taking into account any production constraints; Figure 4 shows the impact that applying those constraints to this final strategy would have on the field economic performance, measured by its NPV (Step No. 5 of the procedure set in section 2.1). Case 1A-C refers to Case 1C when the restriction of 10,000 m^3/day is applied to it and Case 1B-C refers to Case 1C when the restriction of 15,000 m^3/day is applied. Clearly, not taking into consideration production constraints during the refinement process resulted in strategies with inferior performance for this reservoir.

The sensitivity analysis concerning the economic scenario was made in Step No. 6, generating Fig. 5 for Case 1A. It was observed that the NPV was more sensitive to variations in the oil production (Np) for higher prices of oil, as can be seen in runs 20-21 of Fig. 5. Similar behavior was observed for cases 1B and 1C.

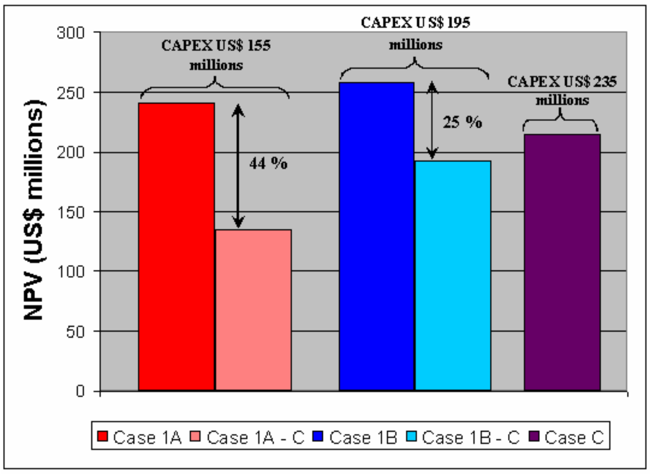

Figure 4. Comparative analysis between NPV of the cases refined with and without production constraints

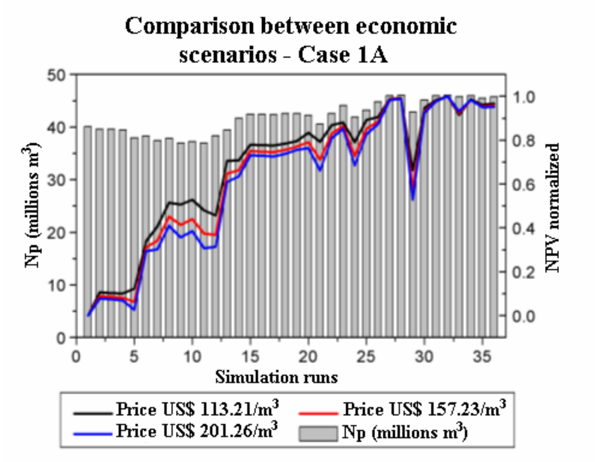

Figure 5. Comparison between economic scenarios for Case 1A

3.3. Restriction on the available capacity for gas lift operation

Figure 6 shows the results obtained in Step No. 2, namely the NPV evolution for the cases tested with gas-lift; the different number of simulations for each case is due to the stop criterion, which consisted of the refinement process not being able of improving the field NPV for four consecutive runs. Therefore, the total number of simulation runs for each case was: 47 (Case 2A), 43 (Case 2B), 42 (Case 2C) and 39 (Case 2D).

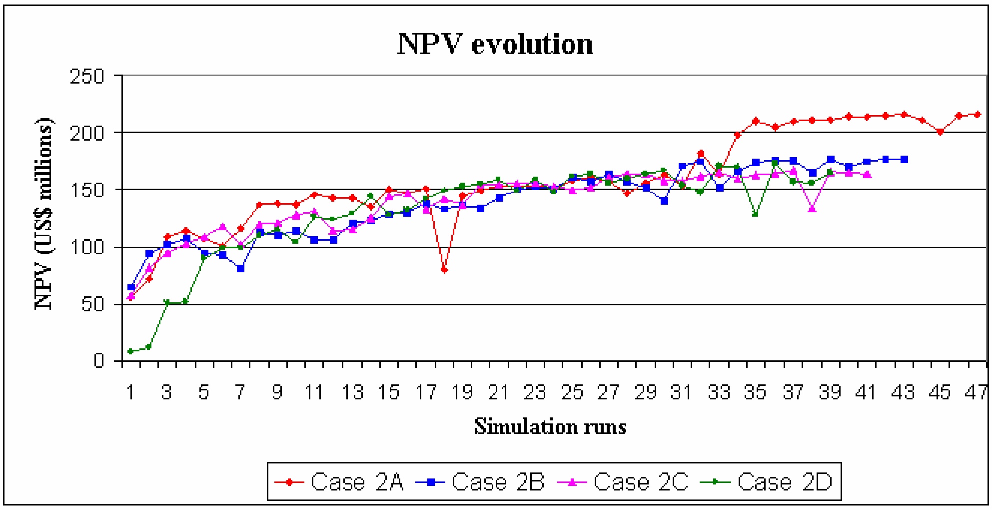

Figure 6. NPV evolution during strategy refinement process – gas-lift

Figure 7 presents a correlation between N_P and NPV for each run of the four case studies. It can be observed that cases 2A and 2D show higher NPV for higher N_P, whereas in cases 2B and 2C higher Net Present Values were achieved for intermediate values of N_P. It can be seen from Fig. 8 that the highest NPV showed no correlation with the lowest values of W_P for Case 2A, unlike the behavior observed in cases 2B, 2C and 2D.

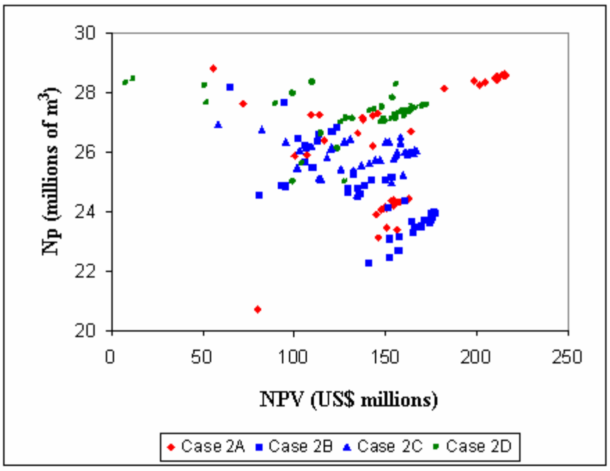

Figure 7. Correlation between NPV and N_P – gas-lift

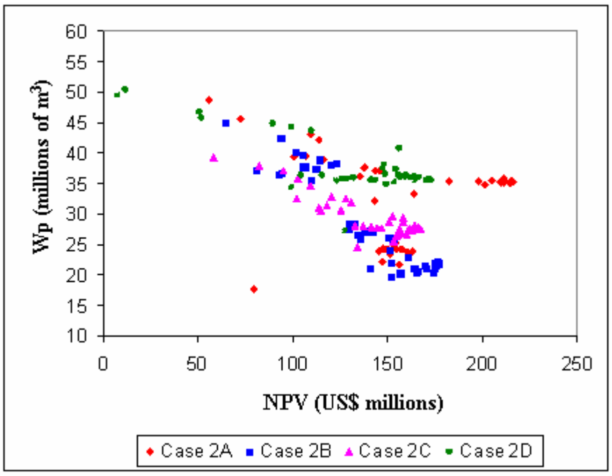

Figure 8. Correlation between NPV and W_P – gas-lift

The final strategies obtained in each case are shown in Figures 9 to 12 (Step No.3); it can be seen that there is a concentration of producers in the central region of the reservoir. Further details of the analysis made in this step, including well flow rates and bottom hole pressure values can be found in Magalhães (2005).

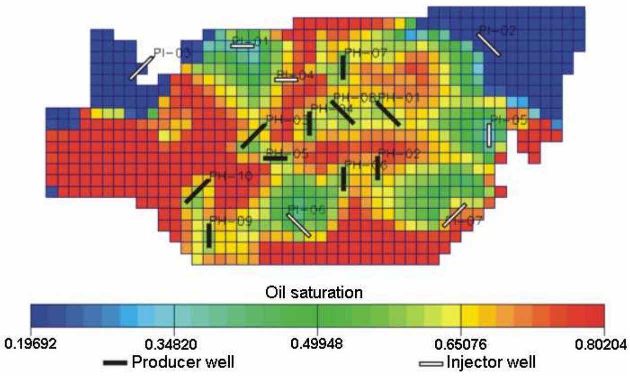

Figure 9. Final strategy – Case 2A

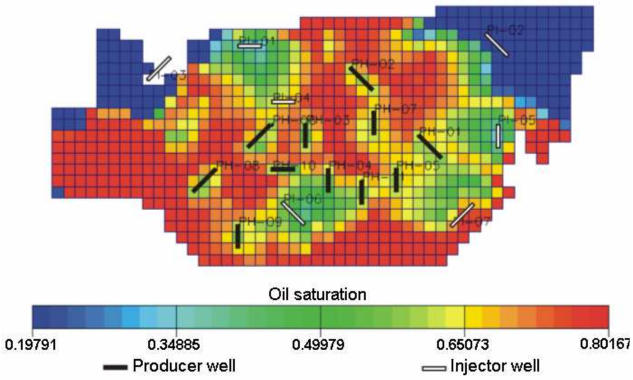

Figure 10. Final strategy – Case 2B

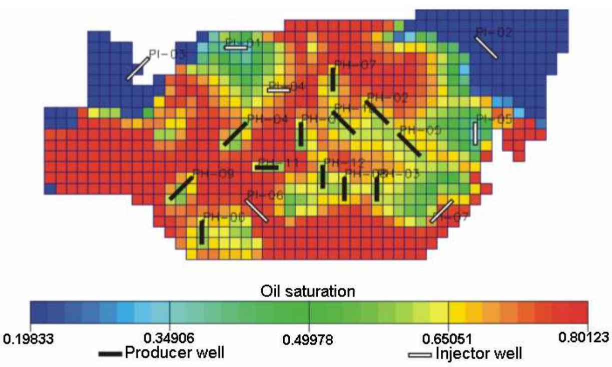

Figure 11. Final strategy – Case 2C

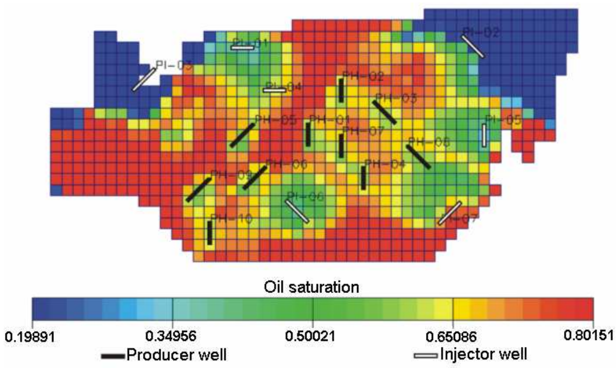

Figure 12. Final strategy – Case 2D

The initial modifications during the refinement process were the removal of producers with low PV and injectors with poor injectivity (Step No. 4); however, this reduction was different for the cases with limitation of gas (2B and 2C) and the other two (cases 2A and 2D). The addition of injectors did not favor an increase in field NPV, and attempts to drain further the areas in Figures 9 to 12 with high remaining oil saturation were not successful (the field NPV was reduced due to the additional costs).

In Case 2D, the final strategy was obtained by simplifying the pressure drop treatment, i.e., they were not calculated dynamically during the refinement process; Figure 13 shows the impact that applying the dynamic calculation of the pressure drops would have on the final strategy set in Case 2D, measured here by the NPV (Step No. 5 of the procedure set in section 2.1). Case 2A-D refers to Case 2D when the condition of “unlimited gas flow rate” is applied to it; Case 2B-D refers to Case 2D when the restriction “maximum gas flow rate = 1,200,000 m^3/day” is applied and Case 2C-D refers to Case 2D when the restriction “maximum gas flow rate = 800,000 m^3/day” is enforced. Although the difference is not as large as the one observed for the restriction on liquid flow rate, the results still indicate that not taking into consideration production constraints during the refinement process will result in strategies with inferior performance.

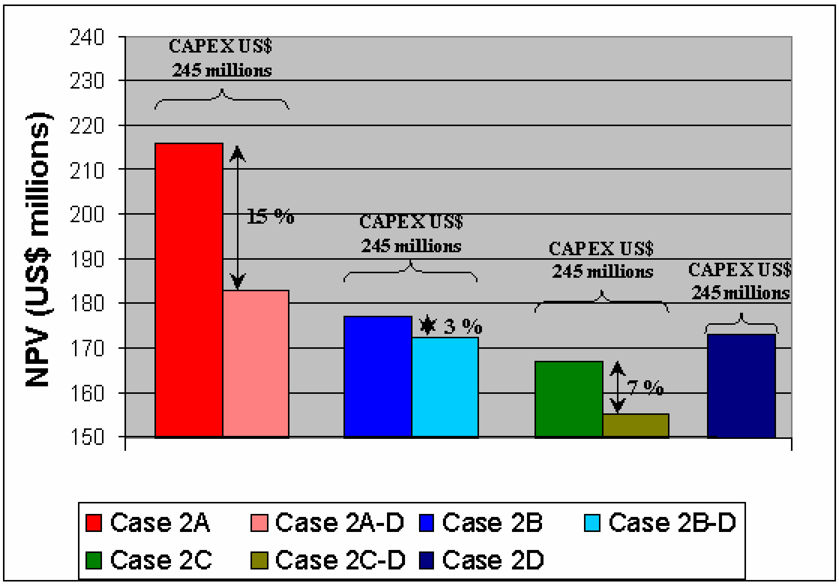

Figure 13. Comparative analysis between NPV of the cases refined with and without production constraints – gas-lift

The sensitivity analysis concerning the economic scenario was made in Step No. 6; it was observed that the overall shape of the NPV curves was the same and the strategies with highest field NPV were coincident. The curves are shown only for Case 2A, in Fig. 14, since the other cases showed similar profiles.

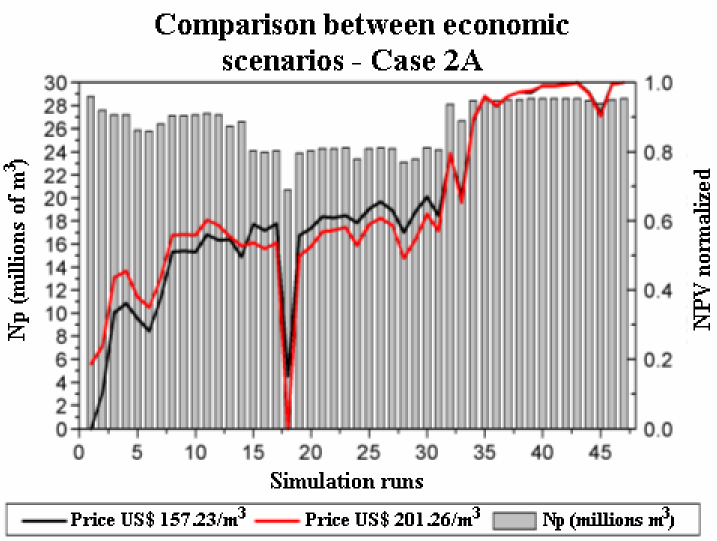

Figure 14. Comparison between economic scenarios for Case 2A

4. Concluding remarks

To obtain the best performance out of a drainage strategy, it is important to take into account production restrictions during the refinement/optimization process, not afterwards.

Restrictions on the maximum liquid flow rate have influence on the final strategy, both in the number of wells and in their position in the field; the configuration of the injection system is also affected by such restrictions, e.g., the injectors operational conditions and location relative to the producers.

The limitation of gas available for gas-lift operation affected the final strategy obtained, especially the number and position of wells. No correlation was found between the ratio of producers and injectors as far as gas-lift restrictions are concerned.

5. Acknowledgements

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7. Responsibility notice

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