COB09-1874 - PRODUCTION STRATEGY SELECTION FOR A DEEPWATER OILFIELD UNDER ECONOMIC AND GEOLOGICAL UNCERTAINTIES

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Abstract. *This work presents a case study for valuation and decision-making for the definition of the production strategy for a synthetic offshore deep water oilfield and 28ºAPI oil representing gas solution drive model with water injection, without gas cap. The main objective of this paper is to test the methodology for different geological scenarios in order to verify the influence of the several types of uncertainties on the production strategy. Several alternatives of production strategies are proposed for a base case regarding different configurations and number of wells, besides different limits of injection and production rates, as well as, completion layers. It is chosen the best alternative considering technical and economic indicators: the Net Present Value (NPV), used as the main indicator in the investment analysis, and the recovery factor (RF) It is also proposed other performance tests of production strategy in this work, changing the injection/production flow rate limits and changing the wells opening schedule. Thirty images of different geological models are analyzed considering both NPV and RF, aiming to identify representative geological models in order to characterize the uncertain variables of the projects and select significant differences of the parameters for tesingt the robustness of the production strategy selected. Sensitivity analyses are also performed considering three economic scenarios.*

Keywords*:* Reservoir Simulation; Production Strategy; Uncertainty Analysis

1. INTRODUCTION

After the exploration and appraisal phases comes the field development phase. The field development planning is one of the most important steps of the development and management phases of the oilfield (Schiozer and Mezzomo, 2003). This step determines if a project presents or not technical and/or economic feasibility, becoming much critical in the case of offshore oilfields which demand high investments and low flexibility for later changes.

The definition of the production strategy depends on the stage of development of the field and relies in the knowledge of the reservoir experts. In the initial stage, the planning is based on the definition of a great number of parameters, such as, the recovery method, the number, type and position of wells, besides the production/injection patterns, operational conditions, among others (Mezzomo, 2005). When the field is already in production phase, the management is the most important activity, being necessary the continuous monitoring of the production in order to obtain data to understand the reservoir behavior, enabling, in this way, to control and interfere in the wells efficiently.

In this phase, it is also necessary to analyze the selected strategy, by evaluating the necessity of some possible alteration due to the changes in the economic scenario, geological model review and technological advances which permits the increase in recovery.

The reservoir simulation is largely employed to understand the variables that influence the reservoir performance, providing means to define the best exploitation strategy, regarding the operational and economic constraints, such as production capacity of platforms and investments, respectively.

This study aims to verify if the process of production strategy selection is well investigated based on the graphic analysis of the technical-economic indicators utilized as objective function: NPV and RF for different geological scenarios. Initially, the production strategy is defined for a base case (Ravagnani et al, 2008) and later it is tested for the different geological images. Then, tests of performance are proposed by changing the operational conditions.

2. METHODOLOGY

Base Case

The base case study is based on the selection of a production strategy for a deep offshore reservoir containing 28º API oil. According to the characteristics of the reservoir, the recovery method considered is water injection. The injection and production wells are of the horizontal type. The model is divided into 10 layers. The horizon of production is 19 years. Simulation of different geological models is carried out in order to verify the robustness of the strategy production selected in the base case.

Different completion layers combined are tested, as shown in Table 1, for the base case, in order to assure the adequate drainage for the reservoir.

Table1: Combination of completion layers

Production wells	Injection wells
K=1	K=10
K=1	K=9
K=2	K=10
K=2	K=9

In the planning of the initial production strategy, three configurations of horizontal wells are proposed: 5-spot, inverted 5-spot and peripheral injection. The spacing between wells for the 5-spot and inverted 5-spot configurations is constant and defined accordingly to the field dimensions and well drainage radius.

The simulations are carried out varying the total number of wells according to their configuration, as can be seen in Table 2.

Table 2: Number of wells

Configuration	Total number of wells	Number of production wells	Number of injection wells
5-spot	13 to 23	9 to 12	4 to 11
Inverted 5-spot	13 to 23	4 to 11	9 to 12
Peripheral injection	13 to 26	7 to 16	6 to 10

The operational parameters considered are: production and injection flow rates. The flow rate limits are:

- Flow rate limit of production wells: 1000 to 2000 m^3/day
- Flow rate limit of injection wells: 1000 to 2000 m^3/day

It is assumed that all the wells are perforated during the first 2 years and, after this period, they start operating simultaneously. The parameters for economic analysis are shown in Table 3.

Table 3: Fiscal and economic parameters

Variable	Value
Oil price (US$/$m^3$)	314.4
Oil production cost (US$/$m^3$)	31.4
Water production cost (US$/$m^3$)	3.1
Water injection cost (US$/$m^3$)	3.1
Corporate Tax (%)	34.0
Special taxes on gross revenue (%)	9.25
Royalties (%)	10.0
Depreciation (years)	10.0
Discount rate (% a.a.)	10.0
Initial investment (US$ millions)	150.0
Well costs (US$ millions)	40.0
Costs of abandonment (US$ millions)	15.0
Offshore oilfield	Ultra deep
Investments in platform (US$ millions)	479.6 – 967.7

The total investment for each strategy is established as function of the number of wells, initial investment and liquid production capacity of the platform. Higher capacities of the platform are associated to higher costs.

The best strategy for the base case is submitted to tests in other geological scenarios as will be explained as follows.

Geological Scenarios

Thirty images regarding geological uncertainties are analyzed. Each model has the same probability of occurrence. It is considered as uncertain petrophysic parameters: porosity, absolute horizontal permeability, and net to gross, as shown in Table 4. The top map is the same for the thirty images.

Some representative models among the thirty images, which represent the variability of the reservoir, are selected to be tested with another strategy which presents potential of improvement, as well as, in the performance tests in order to optimize NPV and RF indicators.

Table 4: Geological Uncertainties

Image	Porosity	Permeability (mD)	Net to Gross (Mean)*
1	0.146 - 0.298	470 - 3510	0.675
2	0.125 - 0.318	40 - 3910	0.667
3	0.145 – 0.298	440- 3510	0.697
4	0.141 -0.303	370 - 3600	0.679
5	0.140 - 0.302	350 - 3580	0.699
6	0.143 - 0.309	410 - 3730	0.690
7	0.136 - 0.316	260 - 3860	0.667
8	0.141 - 0.304	370 - 3630	0.674
9	0.142 - 0.302	380 - 3580	0.682
10	0.136 - 0.304	260 - 3620	0.685
11	0.126 - 0.311	60 - 3770	0.690
12	0.143 - 0.306	400 - 3660	0.683
13	0.141 - 0.305	370 - 3640	0.679
14	0.130 - 0.310	140 - 3740	0.679
15	0.146 - 0.309	470 - 3720	0.664
16	0.14 - 0.314	340 - 3820	0.669
17	0.14 - 0.306	340 - 3660	0.677
18	0.14 - 0.307	350 - 3690	0.699
19	0.141 - 0.303	360 - 3600	0.672
20	0.146 - 0.312	460 - 3780	0.682
21	0.135 - 0.304	250 - 3620	0.677
22	0.140 - 0.300	350 - 3550	0.692
23	0.135 - 0.321	240 - 3970	0.683
24	0.133 - 0.299	200 - 3520	0.670
25	0.141 - 0.313	370 - 3800	0.668
26	0.146 - 0.302	470 - 3590	0.690
27	0.138 - 0.319	310 - 3930	0.666
28	0.143 - 0.314	410 - 3820	0.695
29	0.144 - 0.306	420 - 3670	0.664
30	0.143 - 0.314	410 - 3820	0.695

* Net to gross varies from 5% to 95%

Performance Tests

The best alternatives of the base case are submitted to performance tests in order to optimize NPV and RF through the change of the operational conditions. This step consists on testing other flow rates limits of injection and production wells considering that it is allowed an increase in investments, as will be seen in next section. After these tests of flow rates, additional performance tests are made considering other well opening schedule, (schedule 2), as described below:

- schedule 1 (Base Case): production and injection wells are opened simultaneously 2 years after the start date of the project;
- schedule 2: production wells alternated with injection wells are opened every 2 months from the beginning of the project.

For schedule 2, it is considered the procedure suggested by Mezzomo (2001) and Santos (2002) in the optimization process, which consists of simulating the reservoir with only all the production wells entering in operation simultaneously. Later, the individual NPV of each well is calculated. The decreasing order of NPV becomes into the initial order of operation entering for the same wells. A similar procedure for injection wells is adopted. As injection wells do not generate revenues directly, and since they have the same initial cost, the best injection well is that one which presents the more negative NPV, indicating that it injected the higher volume than the other ones.

Sensitivity Analysis

Sensitivity analysis is carried out considering two other economic scenarios. It is assumed a variation of 40% in the base case scenario as follows:

- low oil price (188.7 US$/ m^3) and
- high oil price (440.3 US$/ m^3).

It is considered a variation of 20% in Capital Expenditures (CAPEX) and 40% in Operating Expenses (OPEX) for both scenarios.

3. RESULTS AND DISCUSSION

Figure 1 shows the indicators resulted from the strategies tested in the development planning phase.

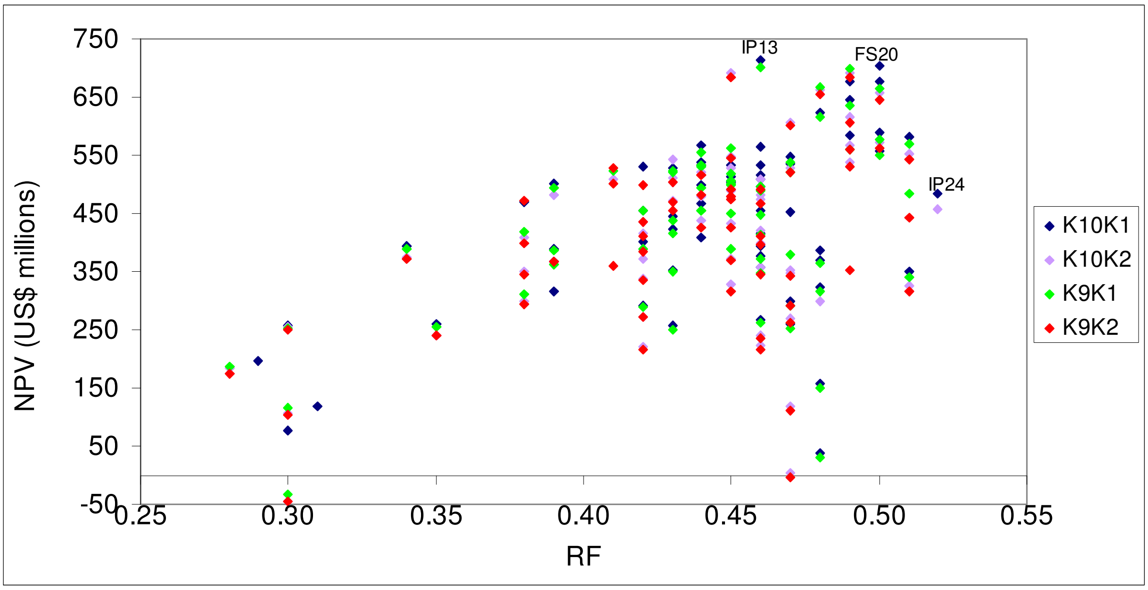

Figure 1: NPV x RF of strategies tested in the development plan definition

As can be observed from Figure 1, injection and production wells completed on the first (K=1) and last (K=10) layers of the reservoir, respectively, presents the best results for both indicators. Based on the NPV indicator the strategy to be selected would be IP13 (peripheral injection with 7 production and 6 injection wells). If the decision maker would desire to maximize RF, the strategy selected would be the IP24 (peripheral injection – 14 production and 10 injection wells). But selecting IP24 strategy, the company would lost a great part of the profits due to the low NPV value as compared to IP13. Then, this alternative will be discarded from the analyses.

On the other hand, if the decision maker would prefer to choose a strategy that attains a condition of compromise between return and production, the strategy selected would be one with 20 wells disposed in 5-spot (five-spot – 10 production and 10 injection wells). Another motivation for choosing this strategy would be that in higher price scenarios it probably would be more lucrative than the IP13 due to the higher oil production.

The characteristics and indicators of the best strategies are presented in Table 5.

Table 5: Characteristics of the best strategies in the development planning phase

Configuration	Total number of wells	Limit of production well flow rate (m^3/d)	Limit of injection well flow rate (m^3/d)	NPV (US$ millions)	RF
Peripheral injection	13 (7p6i)	2000	2000	**713**	0.46
Peripheral injection	24 (14p10i)	2000	2000	484	**0.52**
5-spot	20 (10p10i)	2000	2000	704	0.50

From the several combinations of flow rates proposed initially, the most appropriate is 2000 m^3/day for injection and production wells. The best alternative of strategy regarding NPV presented in Table 5 is analyzed for other geological models in order to verify its performance in 30 scenarios of geological uncertainties.

As strategy IP13 is the best one for the base case image, from the economic point of view, this strategy is tested for another 29 images in order to analyze if it is the appropriate one for other geological scenarios. Figure 2 presents the results of the NPV and RF indicators for the different geologic scenarios.

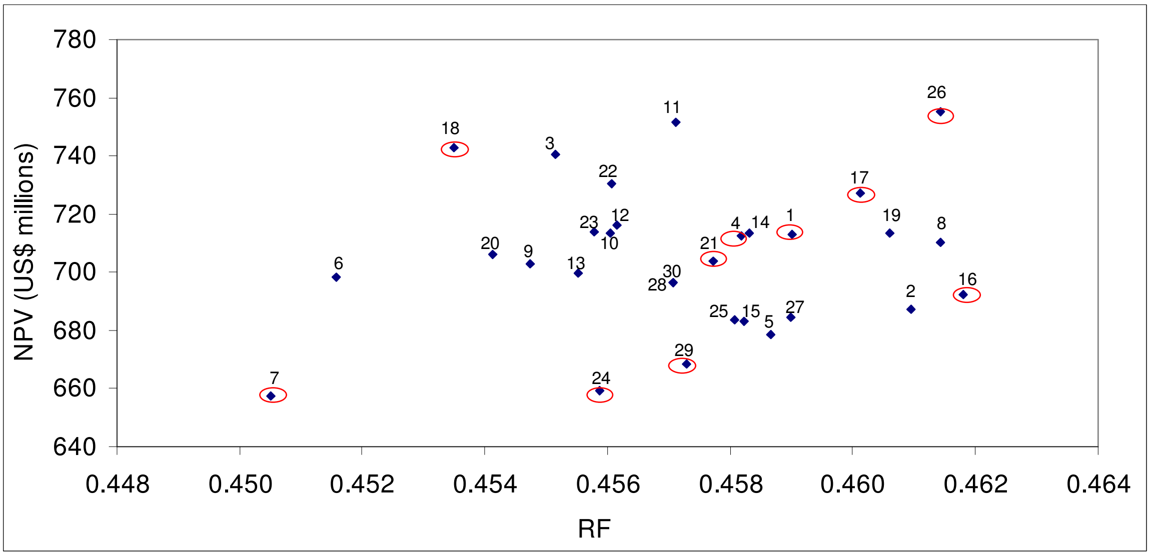

Figure 2: NPV x RF for different geologic scenarios

The numbers close to the points in Fig. 2 represent the images previously presented in Table 4. The ten strategies surrounded by red circles in Fig. 2 are selected as the representative models of the images, which will be tested for the other qualified strategy (5-spot). The IP24 strategy will not be tested for the different geological scenarios due to its very low NPV.

Table 6 shows the results of the simulations of each image regarding the RF and NPV indicators for the IP13 strategy.

Table 6: Technical-economic indicators of IP13 for all the images

Image	RF	NPV (US$ millions)	Image	RF	NPV (US$ millions)
1	0.4590	713	16	0.4618	692
2	0.4609	687	17	0.4601	727
3	0.4552	741	18	0.4535	743
4	0.4582	713	19	0.4606	713
5	0.4587	678	20	0.4541	706
6	0.4516	698	21	0.4577	704
7	0.4505	657	22	0.4561	731
8	0.4614	710	23	0.4558	714
9	0.4547	703	24	0.4559	659

10	0.4560	713	25	0.4581	683
11	0.4571	751	26	0.4614	755
12	0.4562	716	27	0.4590	684
13	0.4555	700	28	0.4571	696
14	0.4583	713	29	0.4573	669
15	0.4582	683	30	0.4571	696

As said previously, ten images were selected to test the FS20 strategy to compare its behavior with the IP13 strategy in other geological scenarios, as can be seen in Figures 3 and 4 for the NPV and RF indicators, respectively.

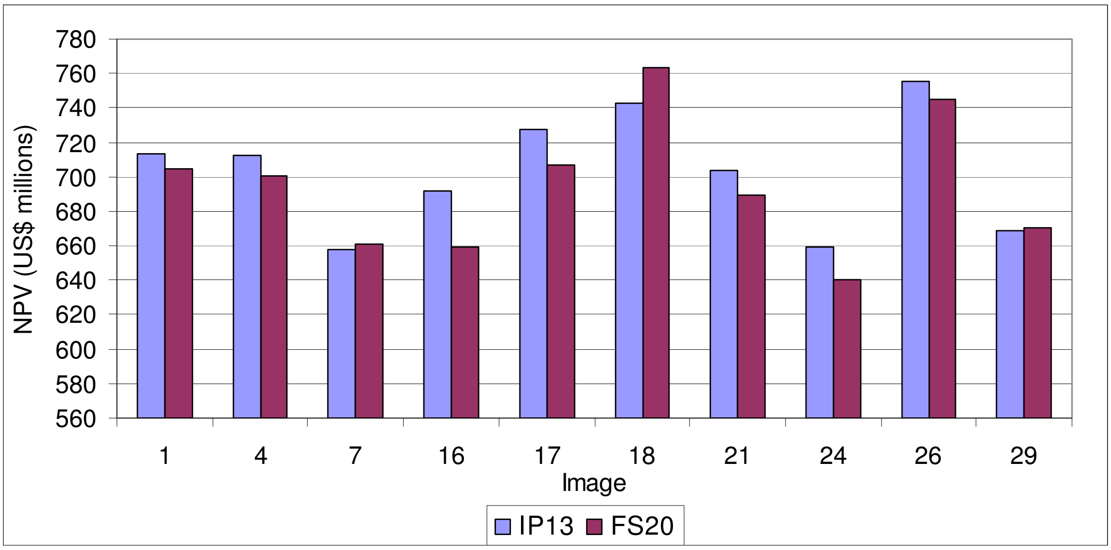

Figure 3: NPV of different strategies for different images

Considering the NPV indicator, Fig. 3 shows that IP13 is better than FS20 in the most part of the scenarios, for the base case oil price, although the best result represented by Image 18 has been FS20.

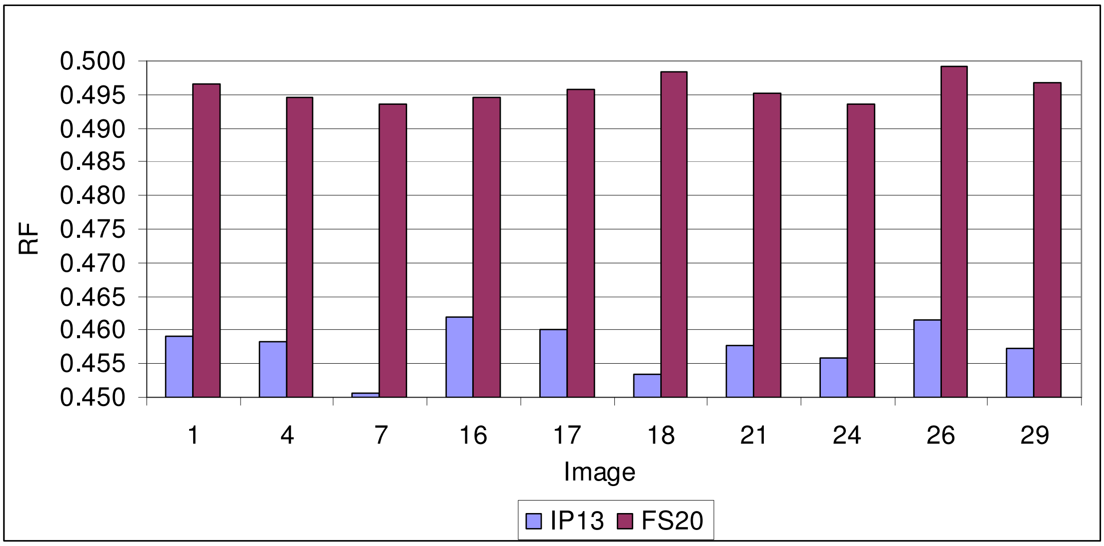

Figure 4: RF of different strategies for different images

Figure 4 shows that FS20 is much better for all the geological scenarios when RF is considered. Assuming that there is the possibility of increasing investments in capacity of injection and production flow rates, performance tests are carried out for both strategies varying the limits of production and injection flow rates for the different images. The ranges of flow rate limits of the wells are shown in Table 7.

Table 7: Range of wells flow rate limits

Strategy	Range of limit of production well flow rate (m^3/d)	Range of limit of injection flow well rate (m^3/d)
IP13	2000 to 4000	2000 to 5000
FS20	1900 to 4000	1900 to 3000

The best flow rate limits for injection and production wells for the performance tests, as well as, the base case are shown in Table 8.

Table 8: Best flow rate limits for injection and production wells

Strategy	Limit of production well flow rate (m^3/d)	Limit of injection well flow rate (m^3/d)
IP13 – Base flow rate	2000	2000
IP13 – Flow rate 1	2900	3500
IP13 – Flow rate 2	3500	4000
FS20 – Base flow rate	2000	2000
FS20 – Flow rate 1	2100	2100

Figure 5 shows the results for RF indicator for the strategies optimized from the rate limits presented in Table 8.

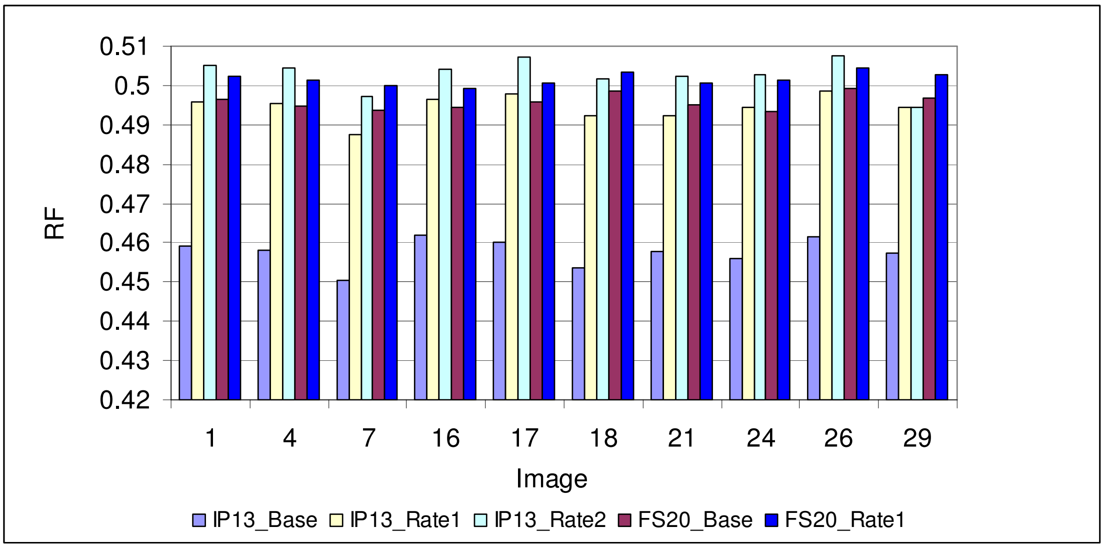

Figure 5: RF from the flow rate tests for different geological scenarios

From the Figure 5, it is possible to note that there is not much improvement in RF for the optimization of the FS20 strategy, indicating that it is already optimized. On the other hand, there is a significant increase in the recovery factor with the change of the limits of production and injection flow rates of the IP13 strategy, allowing reaching the best recovery factors for the most of the scenarios. But, even with this possibility to attain higher recovery factors when IP13 is optimized with flow rate 2; for images 7, 18 and 29 its RF is below the RF obtained for optimized strategy FS20 with flow rate 1, indicating these images are favorable for this strategy.

Figure 6 presents the results of the performance tests for the NPV indicator for the different geological scenarios.

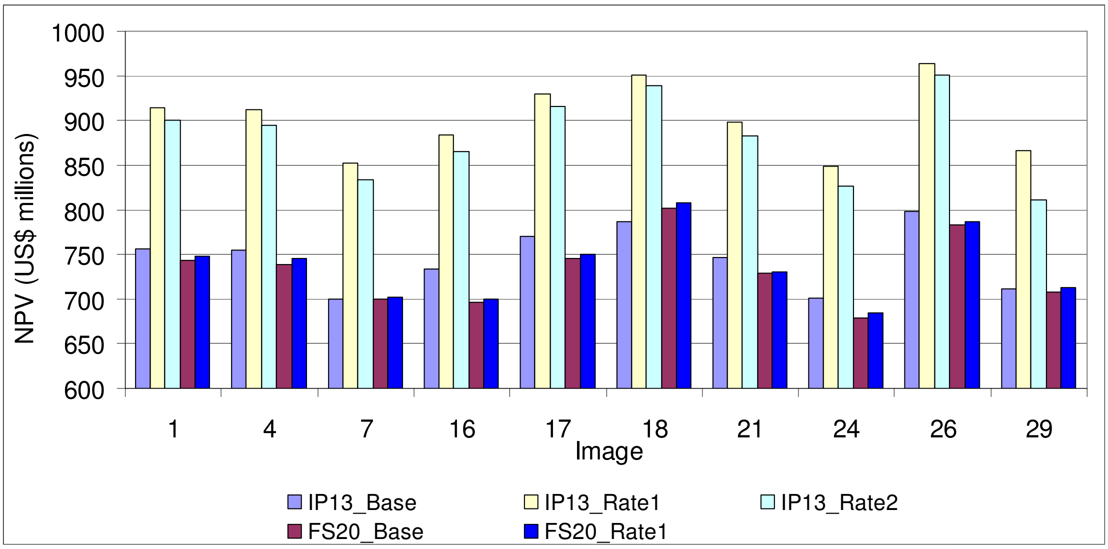

Figure 6: NPV from the flow rate tests for different geological scenarios

It is noted in Figure 6, that the optimization of the limits of production and injection flow rates of the IP13 strategy is successful. On the other hand, there is almost no improvement in NPV for the new well flow rate limits of FS20 strategy.

After the tests of flow rates, additional tests are made considering well opening schedule 2 as cited in the methodology section. The new schedule test is made for the following strategies cited below, due to their best performances:

- IP13 base case;
- IP13 with flow rate 1;
- FS20 base case

Figure 7 shows the effect of schedule 2 on RF indicator for the different images. For comparison, the same strategies with scheduling 1 are showed in this figure.

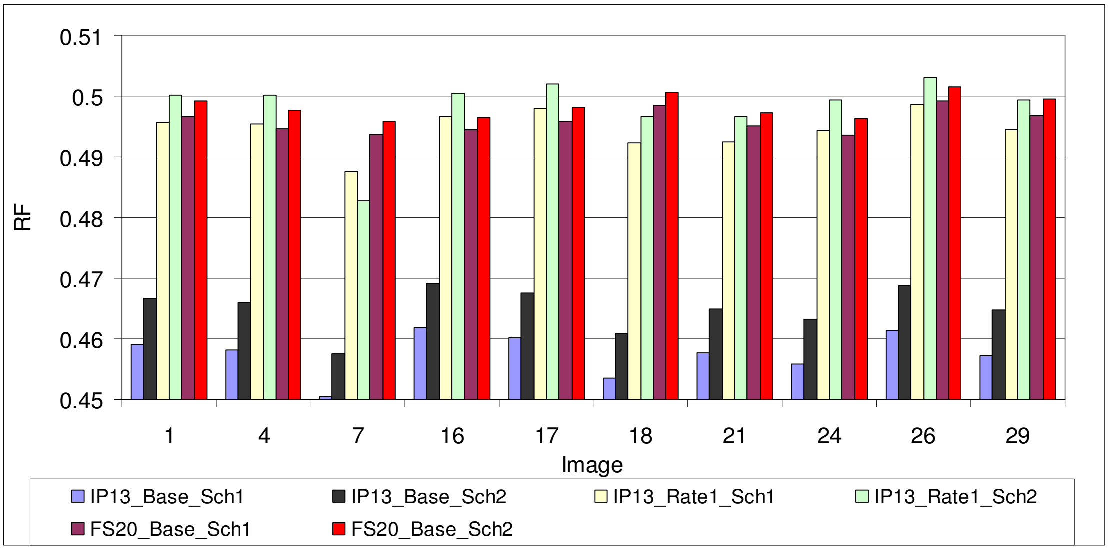

Figure 7: RF from the schedule tests for different geological scenarios

It is noted in Fig. 7 that schedule 2 is favorable for IP13 strategy-base case; because there is a substantial increase in RF. Except image 7, the IP13-rate 1 also has a better performance with schedule 2 than with schedule 1. There is also an increase in RF for the FS20 strategy-base case for all the images when schedule 2 is considered, indicating this schedule is favorable for this strategy when RF is considered.

Figure 8 presents the results of NPV indicator for the different images when schedule 2 is taking into account.

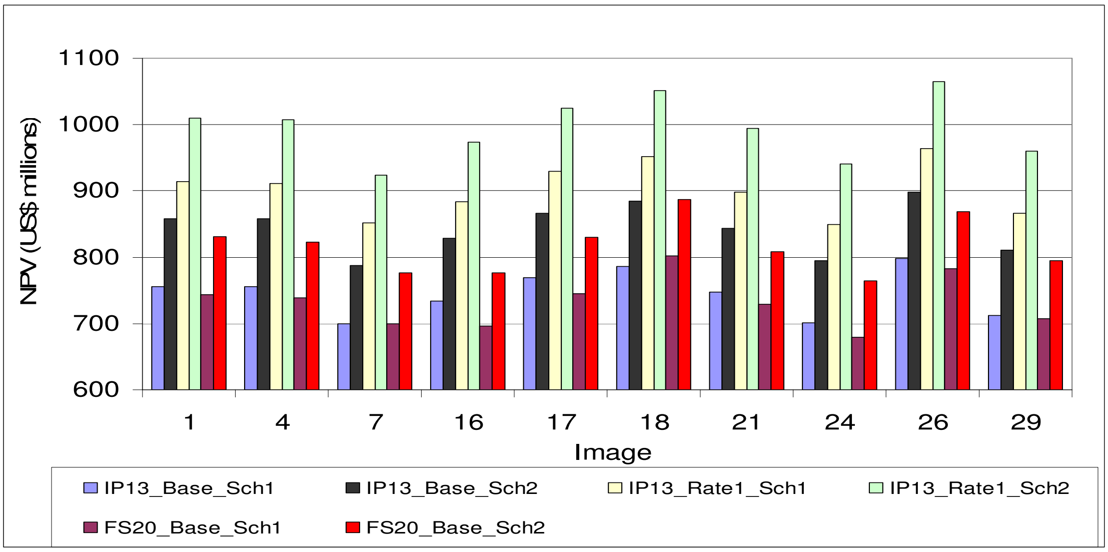

Figure 8: NPV from the schedule tests for different geological scenarios

From the economic point of view, the schedule 2 is better for all the proposed strategies, as can be seen in Figure 8. Despite, the increase in RF indicator for FS20 strategy presented previously in Fig. 7 is not much substantial with schedule 2, this schedule is favorable for the same strategy because it anticipates revenue, increasing in this way, the NPV substantially. Therefore it can be said that with schedule 2 it is obtained a remarkable increase in NPV for all the strategies and geological scenarios, as can be observed in Figure 8.

The bests alternatives presented in Fig.8 are tested in other economic scenarios: a pessimistic and an optimistic scenario. Figure 9 shows the results of these tests for the strategies with schedule 2: FS20, IP13 and IP13 with flow rate optimized for the low, medium (base case) and high price scenarios.

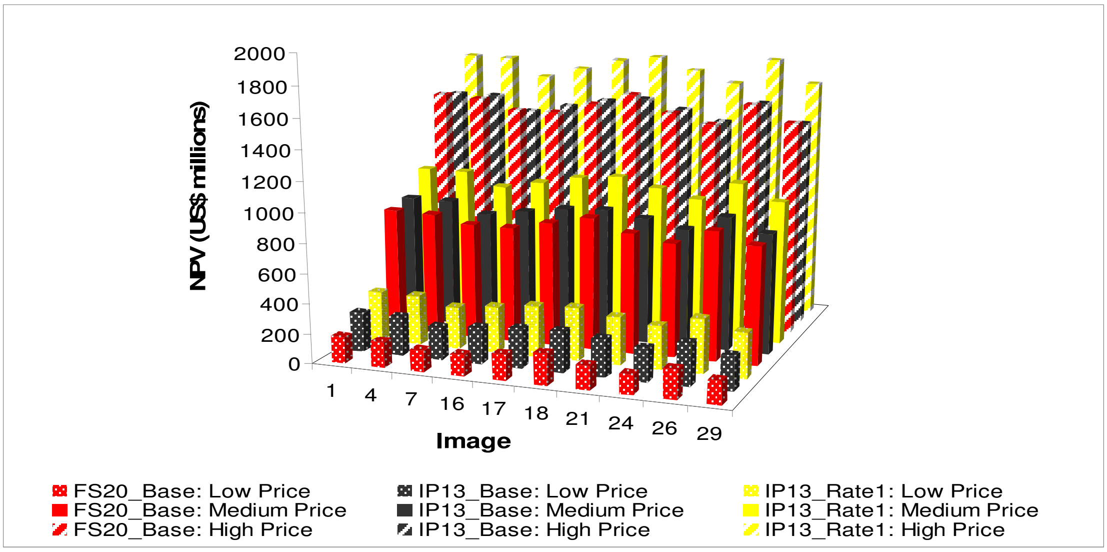

Figure 9: NPV of different geological images for 3 economic scenarios

As illustrated in Fig. 9, the best strategy for the 3 economic scenarios is the IP13 with flow rate optimized (IP13_Rate1). Otherwise, comparing the two strategies in the base case, which have the same flow rates per well, it can be noted that, in high price scenarios, the strategy which produces more oil, with higher number of wells (FS20_Base) becomes better than the IP13_Base strategy as showed in this figure. Therefore, in case of operational restrictions on well flow rates, for example, if it is not possible to achieve the higher flow rates per well obtained from the optimization process (IP13_Rate1), higher oil prices are necessary to ensure the viability of FS20 strategy. In contrast, in case without operational restrictions, with the optimization process, as already said, the strategy IP13 with flow rate 1 is the best alternative for any scenario, because it obtains the same level of recovery of FS20 strategy, with lower investment in wells and similar or a little higher investment in platform capacities, obtaining in this way, higher NPV.

4. CONCLUSIONS

- It was presented in this work a problem of decision making concerning the selection of production strategies for an oil field based on the definition and optimization of the production strategy with the consideration of different geological scenarios in order to test the robustness of the strategy selected.
- It is possible to observe that flow rates and wells opening schedule influences the technical and economic results strongly.
- For the base economic scenario considered, the best alternative when the NPV indicator is analysed is the strategy with lower number of wells (IP13), although this strategy obtains lower recovery (RF). The strategy with higher number of wells (FS20) obtained a higher RF but a little lower NPV. Then this strategy was also selected to be tested in other geological scenarios besides other performance tests in order to improve its indicators.
- Even though IP13 strategy resulted in a lower recovery factor in the base case, it presented the best NPV and its optimization process was more successful, mainly in the flow rates tests, than strategy FS20, for all the geological scenarios. This indicates that the latter strategy was already optimized with its maximum indicators values, not improving much in the performance tests.
- For all oil price scenarios, the best alternative to be selected is the IP13 strategy after the process of optimization of flow rates (IP13_Rate1) and wells opening schedule (Sch2), which allowed to obtain the same level of production of strategies with high number of wells, when the flow rates are optimized resulting in much higher NPV.
- In case of operational restrictions, that is, if it is not possible to achieve the higher flow rates per well obtained from the optimization process (IP13_Rate1), it is important to take into account the future oil price scenario aiming to choose between a lower amount of wells (IP13_Base, for low and medium oil prices) or an alternative with a larger amount of wells (FS20_Base, for high oil price scenarios), in order to maximize both the oil recovery and the economic profitability along the productive life of the project.

5. ACKNOWLEDGEMENTS

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