SENSITIVITY OF OIL PRODUCTION TO PETROPHYSICAL HETEROGENEITIES

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Abstract. The multi-partner Saigup project was established to systematically investigate the relative importance of key geological heterogeneities on simulated production. In order to investigate the impact of the geostatistical variability, the petrophysical fields were drawn repeatably, and the variogram directions were rotated. The heterogeneities caused by the geostatistical variability in the petrophysical simulations and the variogram rotation were similar, and had a low impact on all the production responses except total water injected. Here they contributed about 20% of the total variability.

1 Introduction

Production from a reservoir is a complex function of many parameters. Reservoir modelling enables the prediction of reservoir performance through mathematical simulations of the flow. However, these deterministic flow simulations include significant uncertainties, due mainly to uncertainty in the original geological input in the reservoir models. Geostatistical models should aim to deal with this uncertainty.

The objective of the European Union supported Saigup project was to quantify the effects of geological variability and the associated uncertainty in faulted, prograding shallow marine reservoirs. Related, smaller scale studies are e.g. Lia et al. (1997) and Floris et al. (2001). Within Saigup, a series of geological parameters were varied systematically in order to reveal their relative importance on reservoir production. By comparing different realizations of the petrophysical fields, the stochastic variability is also quantified, c.f. Manceau et al. (2001). For a subset of the realizations the lateral petrophysical variogram anisotropy direction was rotated. This set gave information on how significant variogram direction is for the total variability in simulated production data.

2 Saigup variables

The synthetic Saigup reservoirs are a 3 x 9 km prograding shallow marine tilted fault block, comprised of four 20 m thick parasequences (Figure 1). Each parasequence contains up to six facies associations ranging from offshore through delta-front to coastal plain with channels. The facies were populated with petrophysical properties drawn from distributions taken from comparable North Sea (mainly Brent Group) reservoirs.

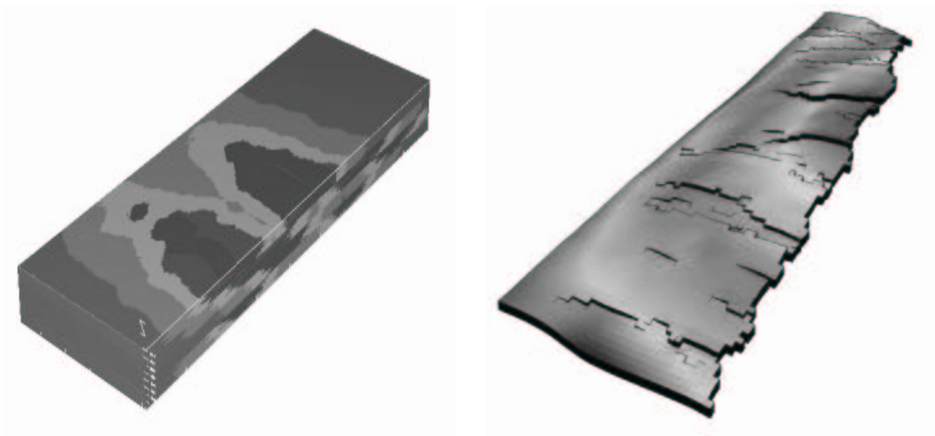

Figure 1. Facies representation of a synthetic Saigup reservoir with eastward progradation direction (left). The reservoir is then aligned under the top structure map (example with strike perpendicular fault pattern to the right). North is to the upper right edge.

Production heterogeneity was introduced by varying eight different parameters at three different levels. Seven of these are related to geology and one to production strategy. These variables included four sedimentological parameters: aggradation angle (shoreface trajectory); progradation angle relative to waterflood; delta type reflected in shoreline curvature and internal flow-barrier coverage. Structural parameters were fault permeability, fault pattern (unfaulted, compartmentalized, strike parallel and perpendicular to main flow) and fault density.

The final parameter that was varied was the well pattern. Four different well configurations (designed for each structural pattern) were run on all of the geological models. The well configurations were a combination of vertical producers and injectors. The producers were located at a high level near the crest, see Figure 2, while injectors were located at a lower level, injecting water subject to a maximum pressure of 50 bar above the initial reservoir pressure.

The first stage of the workflow was a geostatistical simulation of the sedimentology based on the chosen control levels. This produced a facies model that guided the subsequent geostatistical simulation of the petrophysical parameters.

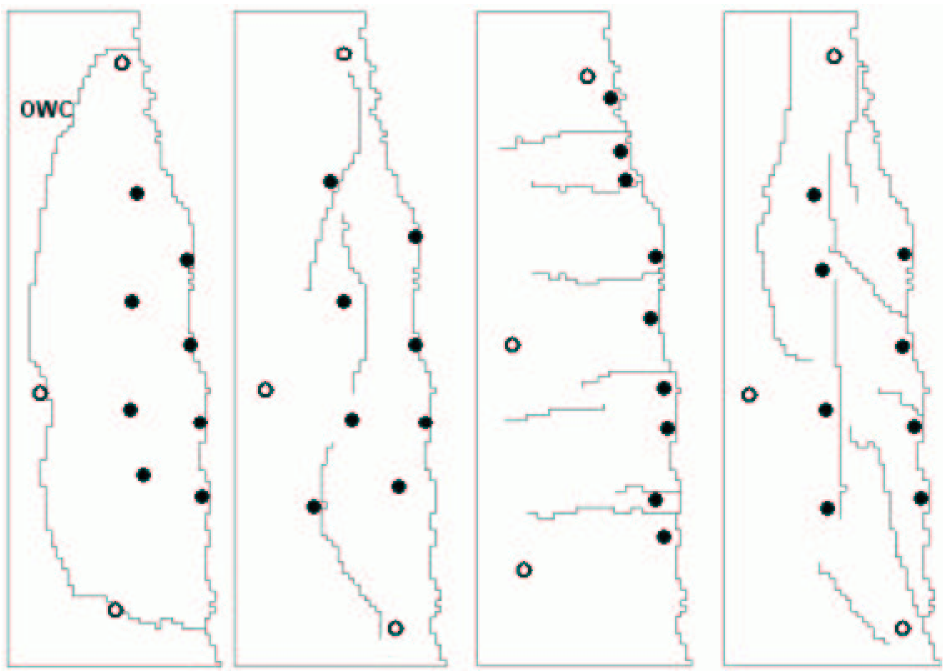

Figure 2. View of well locations designed for, from left to right, unfaulted, strike parallel, strike perpendicular and compartmentalized fault patterns. Injectors are shown as circles and producers as dots. North is to the upper edge. Only the largest faults are shown, and the owc is indicated in the unfaulted case.

The fine scale petrophysical model was then upscaled from 1.5 million geogrid cells to 96 000 flow-simulation cells. The upscaling method was a local flow preserving method with open boundaries, commonly used by the petroleum companies (Warren & Price, 1961). Relative permeability upscaling sensitivity was investigated by Stephen et al. (2003). The flow-barriers were simulated as transmissibility multipliers within the simulation grid. Finally the fault related heterogeneities were introduced and the realization was ready for flow-simulation. The flow-simulator was run for 30 years (production time) producing the final production responses.

All combinations of the 8 input key controls were run with repeated simulations on some of the combinations. In total, more than 12 000 flow simulations relevant for this analysis were run.

3 Variance components

A production response variable is a function of its explanatory variables. In the Saigup study there were originally eight key control parameters: four sedimentological, three structural and one well related explanatory variable. Also two geostatistical variables were investigated: the variogram anisotropy direction related (V) and the repeated petrophysical simulation effect (P). For simplicity, all the sedimentological, structural and well related variables are merged here into one geoscience variable G. The production response y can then be written

$$y(G, P, V) = K_0 + K(G, P, V), \tag{1}$$

where the average level is K_0 and the function $K()$ describes the variation around that average. In order to investigate the different explanatory effects by statistical analysis, this is broken down to its orthogonal effects

$$\begin{aligned} K(G, P, V) &= K_G(G) + K_P(P) + K_V(V) + K_{G,P}(G, P) + \\ &\quad K_{G,V}(G, V) + K_{P,V}(P, V) + K_{G,P,V}(G, P, V). \end{aligned} \tag{2}$$

Thereby it is possible to quantify the relationship between the variability of the different explanatory variables and the response by separating the variance components. Estimates are obtained by a standard moment method, cf. Box et al. (1978).

4 Effect from repeated stochastic simulation of petrophysics

We are interested in the relative contribution of the geostatistical variability from the petrophysics (P) in equation (2). That is the variability obtained by changing the seed in the petrophysical simulation. The relative effect of the repeated stochastic simulation depends on the main effect and all higher order combined effects,

$$E_P^r = \sqrt{\frac{||K_P||^2 + ||K_{G,P}||^2 + ||K_{P,V}||^2 + ||K_{G,P,V}||^2}{||K||^2}}. \tag{3}$$

The results for the selected responses are given in Table 1. With the exception

Table 1. Relative effect E_P^r of repeated petrophysical fields on variability in production responses.

Production response	Relative effect
Total oil production	1.1%
Discounted production	1.3%
Recovery factor	3.8%
Recovery at 20% pore volume injected	3.3%
Total water injected	15.8%

of the total water injected response, the effect is very low. This is because $||K_G||$ dominates equation (2). The reason why the water injection is more subjected to changes in the petrophysical field than the oil production, is believed to originate from the different flow characteristics of the two fluids.

5 Variogram direction effect

Reservoir properties produced by the deposition of sediment within a prograding shallow marine system will not be horizontally isotropic. Heterogeneity within the distributary channel sediments will be aligned broadly normal to the channel belt orientation. Within shallow marine deposits the greatest heterogeneity will occur perpendicular to the shoreline orientation (Kjønsvik et al., 1994); (Miall and Tyler, 1991). In the Saigup study, the variograms of the six different facies were all spherical. For the two most permeable facies associations, the variogram ranges were 800 and 250 meters for the channels, and 2000 and 1000 meters for the upper shoreface facies.

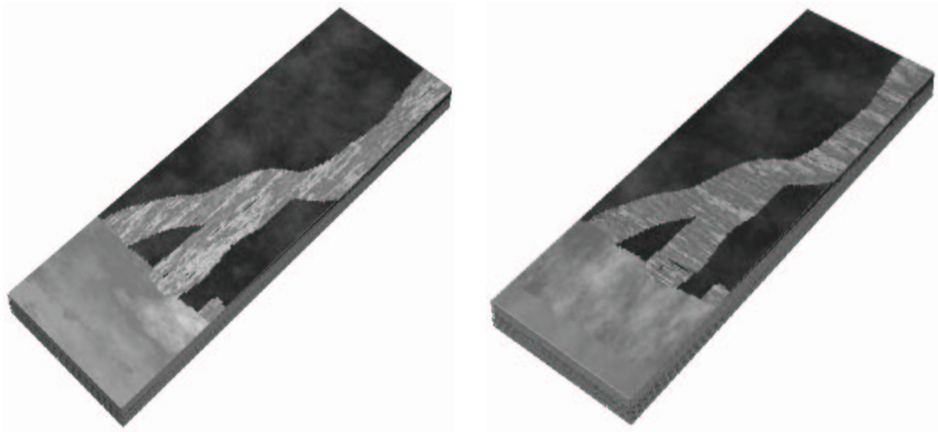

Figure 3. Rotation of variogram direction of petrophysical parameter for a southward prograding realization.

In order to investigate the importance of correct variogram anisotropy direction, a new series of repeated petrophysical simulations were made using identical facies realizations, now with 90° rotated petrophysical variograms, see Figure 3. The additional effect from rotating the variogram anisotropy direction is

$$\Delta E_V^r = \sqrt{\frac{||K_V||^2 + ||K_{G,V}||^2}{||K||^2}}, \tag{4}$$

where equations (2) and (3) give that $(E_P^r)^2 + (\Delta E_V^r)^2 = 1 - ||K_G||^2/||K||^2$. Consequently there were no difference with respect to the element K_G, and any differences in the variance components are therefore due to the other elements of equation (2). These estimates are shown in Table 2. The values are low which indicates that the variogram direction has little impact. Note also that the higher order contributions from $K_{P,V}$ and $K_{G,P,V}$ are included in equation (3). A natural conclusion is that both of the investigated geostatistical variabilities (Table 1 and Table 2) are relatively small.

Table 2. Relative effect ΔE_V^r of petrophysical variogram direction rotation on variability in production responses.

Production response	Relative effect
Total oil production	0.2%
Discounted production	0.0%
Recovery factor	0.0%
Recovery at 20% pore volume injected	0.5%
Total water injected	5.3%

Unlike other applications (such as mining) where correct anisotropy direction are important, the petroleum industry does not deal with single properties of the rock itself, but on a complex fluid flow function which is controlled by a variety of rock properties acting at different scales. Because of this, apparent errors in the orientation of the variogram direction may not be as crucial. In fact by doing so, the fingering is reduced in the model, the amount of produced water is reduced, and the sweep efficiency is increased. So it may take longer time for the fluids to get to the producer in the simulated model, but more valuable fluids will reach the producer before the water-cut becomes too high. The results suggest however that this effect is low compared to the effects of other uncertain input parameters.

6 Discussion

The effect of the stochastic variability on the computed oil production rate is illustrated in Figure 4. The rates are in accordance with the low effect seen in Table 1 and Table 2.The differences in the production curves within each reservoir are much smaller than the main features of the productions. The means and standard deviations of the cumulative production were 388 and 18 MSM3 (million standard cubic meters) for the upper and 277 and 7.5 MSM3 for the lower reservoir respectively.

The upper reservoir has an early high production rate which becomes much lower after 15 years, while the lower reservoir remains on a lower plateau for much longer. These differences are due to uncertainties in the geological model which determines most of the variability in the production response of the Saigup reservoirs. The variability from repeated geostatistical petrophysical simulations is comparable to that for the rotated variograms. This was also observed in other synthetic Saigup reservoirs. The importance of the stochastic variabilities will however be more significant if the uncertainties in the key geological parameters are reduced.

The observation that the effects of the two geostatistical variabilities considered here are quite small compared to those produced by geological variability is important. It illustrates that efforts should be focused on dealing with uncertainties in geological parameters that are key to describing the reservoirs.

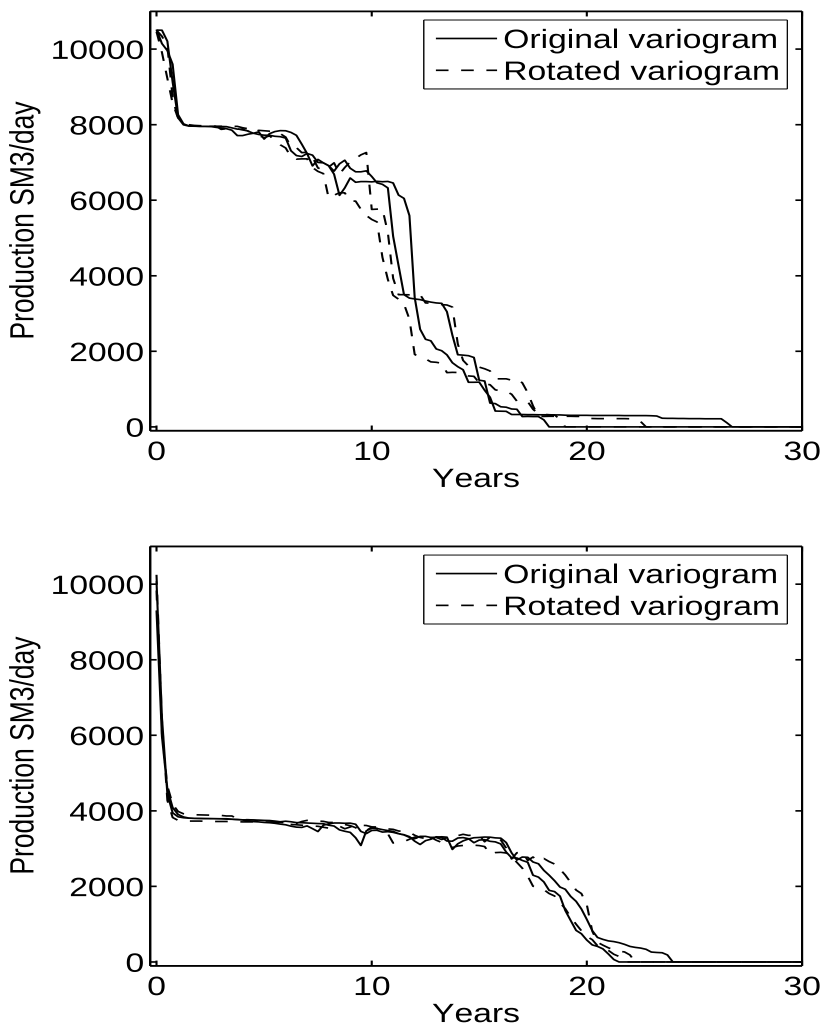

Figure 4. Four production rates observed from two reservoirs. Each line type shows the effect of repeated petrophysical stochastic simulations. The dashed curves have rotated variogram anisotropy directions compared to the solid curves.

The simulated production data indicates that if the ratio between the variogram anisotropy ranges is below 3, the actual anisotropy directions are not crucial for the cumulative response in prograding shallow marine reservoirs. Other uncertainties are far more dominant, and this variability is comparable to that of the geostatistical uncertainty originating from the repeated stochastic simulation (changing the seed).

The applicability of these results to real world reservoirs is dependent upon how representative Saigup parameter space is of the real world. Significant care was taken to ensure that the initial collection of data covered realistic geological parameter ranges and consequently we believe this has been addressed.

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