Combined effects of structural, stratigraphic and well controls on production variability in faulted shallow-marine reservoirs

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ABSTRACT: Several key parameters that describe a prograding shallow-marine reservoir are investigated for their relative importance on hydrocarbon production variability. Sedimentological parameters are aggradation angle, progradation direction relative to the waterflood, continuity of cemented surfaces and shoreline curvature. Structural parameters are the fault pattern, the density (throw) of the faults and the fault-rock permeability. The last component investigated is the effect of well placements. Having three distinct levels for all sedimentological and structural parameters in addition to a non-faulted case gives a dataset of 2268 reservoir models. Four different sets of well locations produce 9072 production datasets.

The variability of the production data is decomposed into its explanatory factors in order to see the relative importance of the chosen parameters. The production data include the total production, the discounted production and the recovery factor. The sedimentological parameters dominate both the production and the discounted production variability, especially the aggradation angle and progradation direction, whereas the fault pattern is equally significant for the recovery factor. Continuity of sedimentological barriers were found to contribute less than expected to the production variability for these reservoir models, and the well placements also showed a low effect.

KEYWORDS: *uncertainty, sedimentology, faults, production, recovery*

INTRODUCTION

In the petroleum industry, advances in the both the technology and understanding of reservoirs have resulted in recovery factors higher than expected in the forecasts made only a few decades ago. The production from a reservoir is a complex function of many parameters, and involves several different disciplines. Geophysics, sedimentology, structural geology, petroleum engineering and computer technology all contribute to the increased understanding of the reservoir, and of how the oil, water and gas phases flow in it. Primary research is generally done within each discipline, but it is the sum of the increased knowledge that brings the industry forward. In order to investigate the relative importance on production uncertainty of parameters from different disciplines, it is necessary to have a multidisciplinary study (e.g. Lia *et al.* 1997; Floris *et al.* 2001). Such an investigation is the objective of the SAIGUP project in general (Manzocchi *et al.* 2008*a*), in which the sensitivity to production of a number of sedimentological, structural and reservoir engineering aspects is assessed within a suite of synthetic reservoir models. In this article, the relative effects of four sedimentological parameters, three fault-related parameters and one reservoir management parameter (well locations) are analysed. The selection of sedimentological parameters used in the models is discussed by Howell *et al.* (2008), of structural parameters by Manzocchi *et al.* (2008*c*) and of well configurations (for practical reasons including only vertical wells) by Matthews *et al.* (2008). The objectives of the modelling were to address differences in production behaviour, given an approximately constant reservoir volume. Addressing volumetric uncertainty due to structural characteristics was therefore not an objective of the work, and the different structural cases were generated deterministically with a constant bulk-rock volume above a constant and deterministic oil–water contact. Since the facies realizations were generated stochastically, all variability in STOIIP is a function of sedimentological model characteristics.

The effects of the different parameters were found from decomposing the production data into its variance components, originating from each of the parameters in the study. Further analyses of aspects of the production results are given by Carter & Matthews (2008) and Manzocchi *et al.* (2008*b, c*). Upscaling sensitivities are covered by Stephen *et al.* (2008), while the stochastic variability (in the sense of Manceau *et al.* 2001) is covered by Skorstad *et al.* (2005), who discuss the effect of uncertainty in the petrophysical parameters.

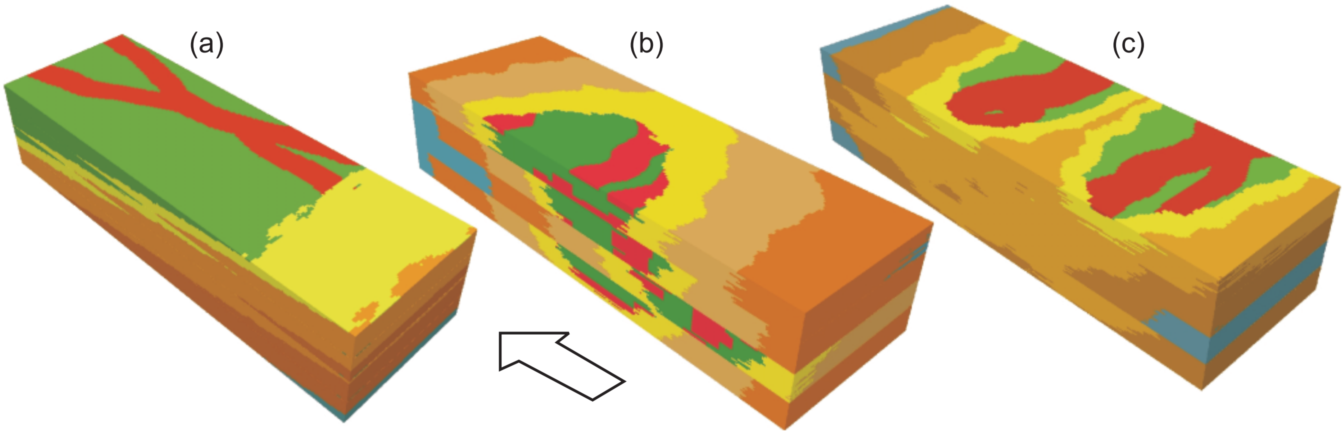

Fig. 1. Levels of the shoreline curvature, aggradation angle and progradation direction. The arrow points north and the principal waterflood direction is to the east. (**a**) Low curvature, low aggradation angle model with waterflood direction perpendicular to progradation direction. (**b**) Moderate curvature, high aggradation angle model with progradation in the same direction as the waterflood. (**c**) High curvature, moderate aggradation angle model with progradation and waterflood directions opposite to each other.

SAIGUP SYNTHETIC RESERVOIRS

The synthetic reservoirs studied in this article all consist of four 20 m thick zones with six different facies associations; distributary channel, coastal plain, upper shoreface, lower shoreface, offshore transition zone and offshore. In each facies association, the petrophysical parameters (horizontal and vertical permeability, porosity and clay content) were simulated with value distributions taken from a real case North Sea reservoir. Details are given in Howell *et al.* (2008). The reservoir models are all laterally restricted to a 3 km × 9 km area, while total formation thickness is 80 m. The main structure is an anticline bounded by a major fault to the east. Production in all scenarios is from vertical wells close to the eastern crest, while pressure support is maintained by injecting water close to the southern, western and northern edges of the reservoirs, implying a predominant waterflood towards the eastern crest.

The data used in this analysis are generated from 81 distinct sedimentological facies realizations, 28 distinct fault scenarios and four distinct well patterns. Before the structural context is added to the sedimentological model, upscaling is carried out from an $80 \times 240 \times 80$ cell resolution, at which the sedimentological modelling was performed, to the $40 \times 120 \times 20$ cell resolution used for the production simulation modelling. This means that the lateral resolution is reduced by a factor of two in both directions, and the vertical resolution is reduced by a factor of four. The upscaling method chosen is a rate-preserving method, after Warren & Price (1961), but with open boundaries. This choice gives a slightly higher upscaled permeability than the closed boundary case, and was chosen due to the expected high local vertical heterogeneity from barriers and the prograding system itself. The flow simulator is run for all combinations of the three sets of variables, producing a total of $81 \times 28 \times 4 = 9072$ different production responses.

The sedimentological models are formed by having three different levels on four parameters assumed to have high importance for the variability in the production. The rationale for choosing these four parameters is discussed in Howell *et al.* (2008). They are the shoreline curvature (of the prograding system), the aggradation angle (of the prograding system), the progradation direction relative to the waterflood direction and the continuity of cemented barriers. The three former parameters are shown in Figure 1. The barriers have coverage levels of 10%, 50% and 90%, and are located between the zones, and also as clinoforms within the zones, following the lobe shapes of the two curved cases. All the sedimentological scenarios are based on real datasets from modern systems and ancient, outcropping examples, as discussed in Howell *et al.* (2008). The variability of the oil in place for the different reservoir models is shown in Figure 2. The span is due both to different facies and petrophysical simulations, since the difference in bulk rock volume between the different structural fault patterns is negligible.

The three assumed key fault parameters are given in three different levels, but set to ensure a constant bulk rock volume. The parameters are fault structural pattern, fault density/throw and fault permeability. In addition there is an unfaulted case, which consequently has no density and permeability levels. The fault transmissibility multipliers are determined from fault-rock permeabilities governed by shale gouge ratio (SGR; Yielding *et al.* 1997), and fault-rock thickness governed by fault throw. The three fault permeability cases considered range up to 1.5 orders of magnitude fault permeability below the base-case correlation of Manzocchi *et al.* (1999). Hence, fault rocks with 20% SGR, for example, have fault permeabilities of between 0.01 mD and 0.4 mD. Further details are given in Manzocchi *et al.* (2008*c*).

The four different sets of well locations were designed to fit the three different fault structural patterns, and the unfaulted

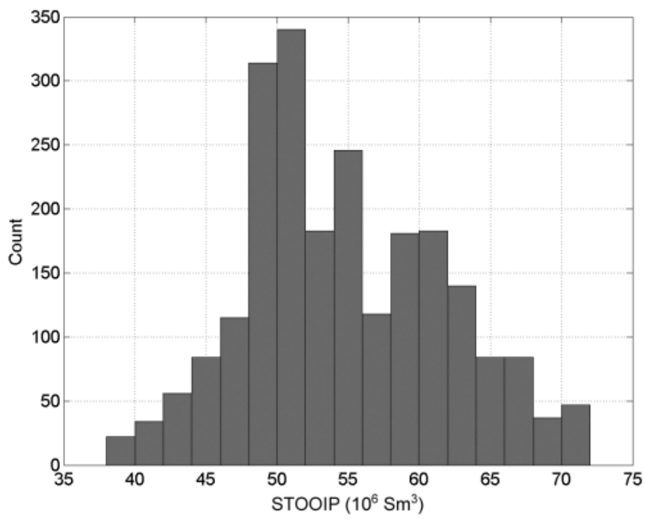

Fig. 2. Distribution of oil in place in the 2268 synthetic reservoir models. The volumes are shown in 10^6 standard m^3.

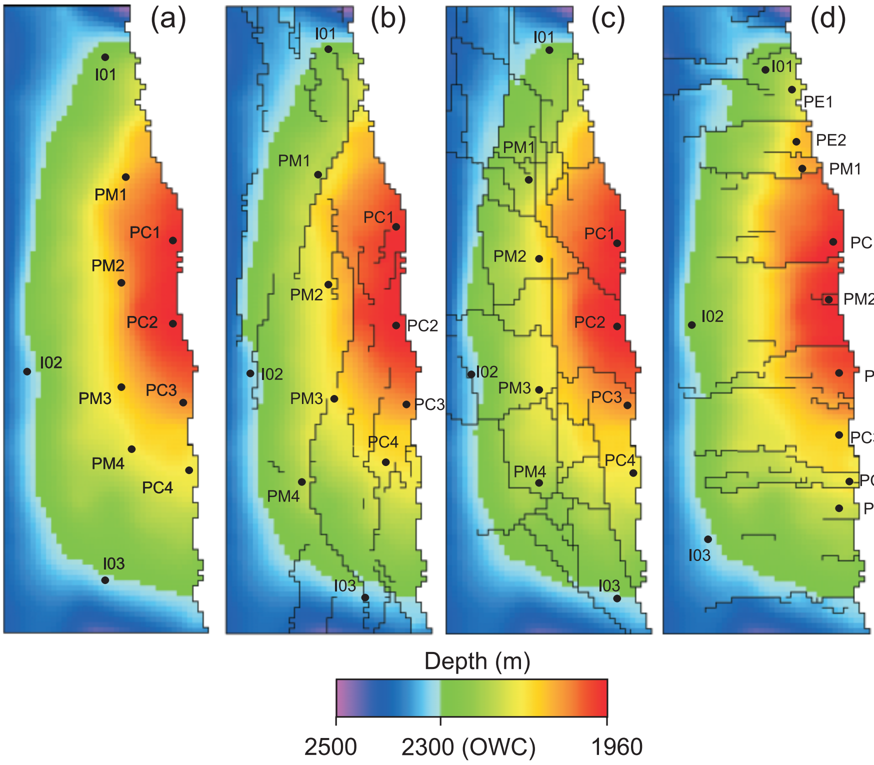

Fig. 3. The four different structural patterns and the well locations designed around them: (**a**) unfaulted model; (**b**) strike-parallel fault model; (**c**) compartmentalized fault model; (**d**) strike-perpendicular fault model.

case. These are shown in Figure 3. A reservoir with a fault scenario not corresponding to its wells will therefore be expected to produce less optimally compared to its corresponding well pattern. Further details about the well controls are given in Matthews *et al.* (2008).

DECOMPOSITION OF PRODUCTION DATA

The four sedimentological parameters under study are given a common notation S, the three fault parameters the notation F, and the well locations the notation W. A production response P will be related to the explanatory variables through the flow equations through an unknown function f,

$$P = \mu + f(S,F,W) \tag{1}$$

where the mean level of the production response is μ. The variability of the production response is decomposed into its variance components through a restricted maximum likelihood method (see, for example, Corbeil & Searle (1976) and Box *et al.* (1978, pp. 581–582)). Such a breakdown of the unknown function f into its orthogonal effects yields a decomposed equation that is useful for investigating the relative sizes of the variability in the production data:

$$f(S,F,W) = f_S(S) + f_F(F) + f_W(W) + f_{S,F}(S,F) + f_{S,W}(S,W) + f_{F,W}(F,W) + f_{S,F,W}(S,F,W) \tag{2}$$

where the three first elements are main effects of sedimentological parameters, fault parameters and well locations, respectively, the next three are the second-order effects between two of the parameter groups, and the last is a third-order effect of all three parameter groups. The main effect of a parameter is the decrease in variance when that parameter is kept constant. When two parameters are kept constant, the decrease in variance is typically larger than the sum of the two main effects of those parameters. The additional decrease is the second-order effect and can be understood as an interaction effect quantifying the synergy of the two parameters. Note also that if all but one parameter is kept constant, the observed variance is the sum of its main and all interaction effects that include this parameter. This implies that the overall variance due to one parameter is generally higher than the main effect of that parameter.

Consider Figure 4. The rationale behind decomposing the variance of the production data is to detect the relative importance the different parameters have on the variability seen in the production data. The knowledge of the importance of the different parameters also indicates where it could be worthwhile

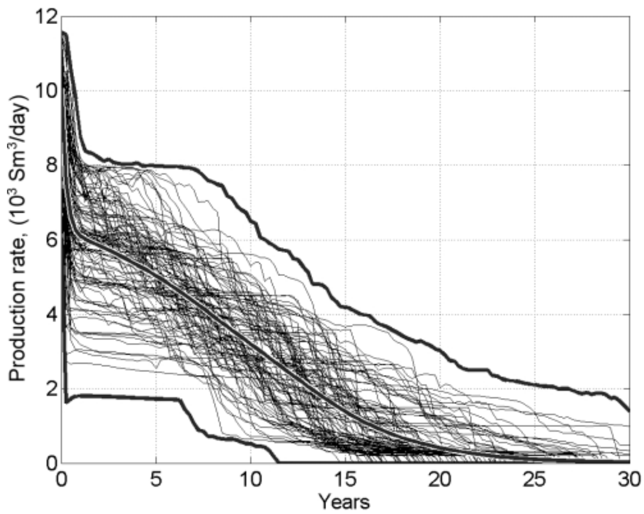

Fig. 4. Production from 9072 SAIGUP model runs (2268 reservoirs × 4 well sets). Thin lines are 100 samples; the thick lines are the pointwise maximum, average and minimum production, respectively.

to invest more effort in the reservoir characterization of a prospect.

PRODUCTION DATA

This paper focuses on three different production responses: the total oil production, the discounted production and the recovery factor. The discounted production is the weighted sum of all productions in the reservoir lifetime where the weight each year is reduced by 10%, which represents a realistic choice of discounting factor on an investment. This accounts for a response that gives information of the ‘net present value’ of the reservoir. This also means that the early production is the most important. For instance, the first six years count for 49% of the total weight of a thirty-year production scheme.

RESULTS

The decompositions of the variability are presented in normalized standard deviations. This means that the sum of the squared values on the effects in the figures will always be one. This measure is used since this study is primarily interested in the relative sizes of the different variables.

Total oil production

Figure 5 shows how much variability in total oil production there is in the different production scenarios. The span goes from 12×10^6 standard m^3 (Sm^3) of oil to approximately three times this amount. In order to make a decision about possible production of the reservoir is it important to reduce that span to ensure a profitable investment. Figure 5 demonstrates that the sedimentological parameters are the most important ones for the cumulative oil production. This is, of course, a consequence of the high correlation with oil in place, which, as discussed above, is almost totally dependent on the sedimentology in the SAIGUP reservoirs.

A measure of the causes for variability in the total oil production provides a possibility for the decision makers to understand the variability better. The price in reducing this variability can thereby be estimated better, and efforts to narrow the variability could be put primarily into those parameters that have the largest impacts. It quantifies how a more accurate determination of, for example, the faults in the reservoir, will contribute to reducing the variability in the oil production.

In Figure 6 the different sedimentological parameters are shown. The same method used to separate the disciplinary effects was also employed on the sedimentological parameters. It is seen that the aggradation angle and progradation direction have the largest influence. The uncertainty in the main effects is also seen to be large. This means that, for instance, for the aggradation angle it is uncertain whether the high effect of aggradation is non-correlated with the other parameters (a main effect), or is an effect that shows mainly as an interaction effect with progradation (A,P) and/or curvature (A,C). Note also that the relative effect of the barriers is extremely low. The rightmost column includes all other stochastic elements, e.g. the proportions of the different facies.

For the structural parameters, Figure 7 shows that the fault pattern is the most influential variable, whereas the model used for fault-rock permeability has a very low importance for the total oil production. Naturally, the different effects are a consequence of the different level chosen for the variables so, for example, the fault permeability effect would be higher if one of the permeability levels was zero, as in cases examined by Lia

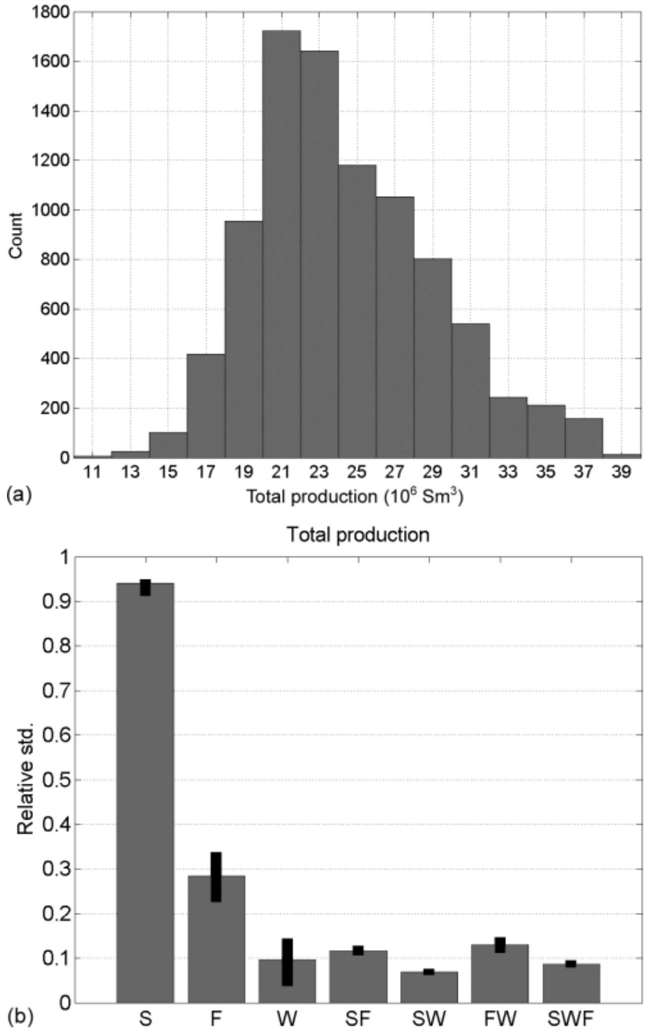

Fig. 5. (**a**) Variability in total oil production (in 10^6 Sm^3); (**b**) decomposed into explanatory disciplinary variables. Uncertainty (80% confidence interval) in estimate of disciplinary effect is shown as a black line. Disciplinary effects are sedimentology (S), faults (F), well locations (W) and their interaction effects.

et al. (1997). Indeed, Manzocchi *et al.* (2008*c*) show that fault permeability becomes an important control on production (particularly in combination with the fault pattern) at lower permeability levels than considered in this paper.

Discounted production

The discounted production is given in Figure 8. The sedimentological parameters remain the most influential ones, but the well effects have shown a slight increase. This is due to the importance of having an efficient well location design in order to get a rapid production. When the wells are not optimally located relative to faults, it will take much longer before the wells produce the oil on the other side of the faults. The discounted production will be dependent on this, whereas the total production will not – as long as the production time is long enough to eventually produce that oil.

The situation for the discounted production as seen in Figure 9 has several similarities with the total production (Fig. 6). One is that the barrier levels do not contribute much in the variability. The progradation effects are also quite unchanged, while the aggradation effect shows a reduction in the main effect. Notice, however, that it is the residuals that are the

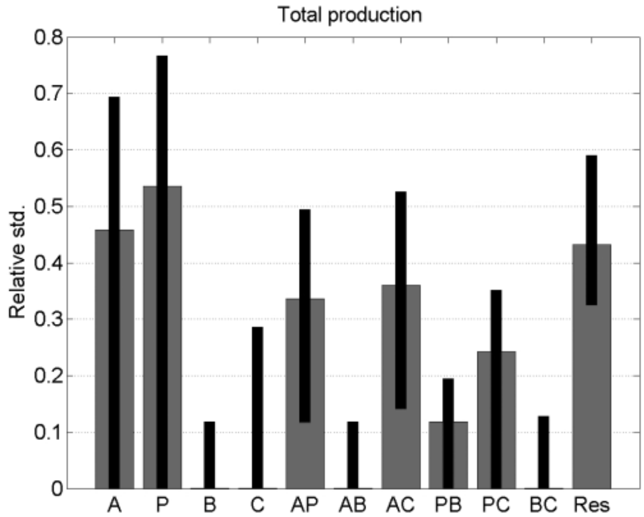

Fig. 6. Effects of sedimentological parameters on total oil production. Uncertainty (80% confidence interval) in estimate of disciplinary effect is shown as a black line. Sedimentological effects are aggradation (A), progradation (P), barriers (B), curvature (C), their two-way interaction effects and residuals (Res).

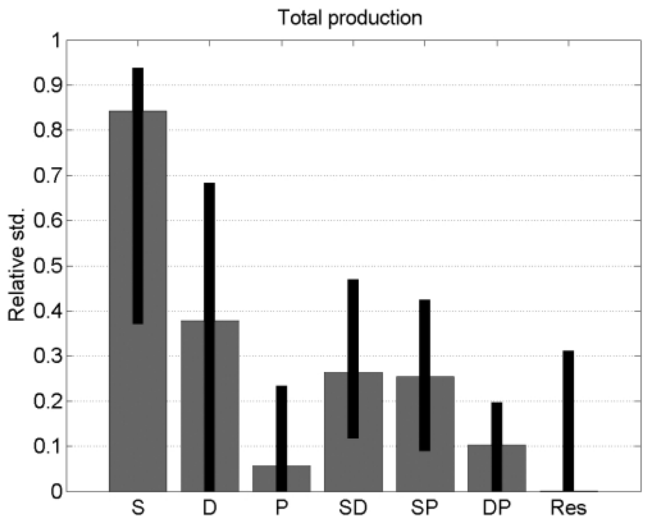

Fig. 7. Effects of structural parameters on variability in total oil production. Fault effects are structural pattern (S), density of faults (D) and permeability through faults (P), two-way interactions and residuals.

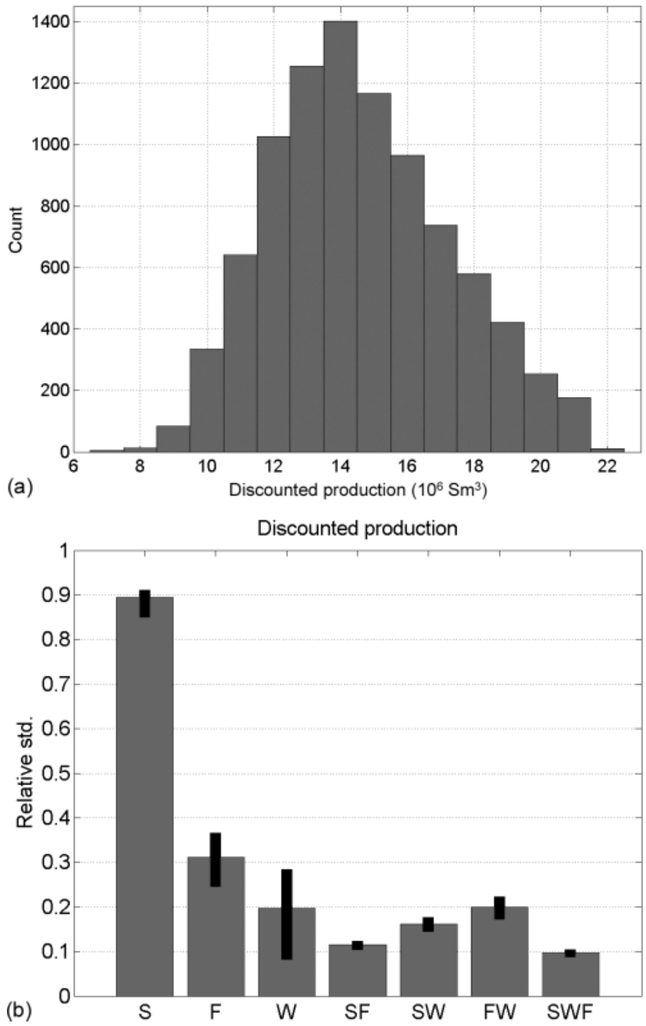

Fig. 8. (**a**) Variability in discounted production (in 10^6 Sm^3); (**b**) decomposed into explanatory disciplinary variables. Uncertainty (80% confidence interval) in estimate of disciplinary effect is shown as a black line. Disciplinary effects are sedimentology (S), faults (F), well locations (W) and their interaction effects.

highest. This residual effect is caused primarily by third-order effects and the heterogeneity effect in the stochastic modelling of facies. The effect of the stochastic modelling of the petrophysical parameters was found by Skorstad *et al.* (2005) to be low for the chosen petrophysical distributions. For wider petrophysical distributions than used here, the petrophysical uncertainty would be more important. This high residual variability level means that the total variability in the discounted production is as much due to the higher-order interactions and uncertainty in the stochastic facies distribution as from any of the four sedimentological parameters and their second-order interactions, focused on in this study.

A detailed look at the fault-related parameters for the discounted oil production in Figure 10 shows a significant difference with the total production shown in Figure 7. The most obvious observation is that the three different parameters are of approximately equal importance. The structural pattern is not as dominant, and the fault-rock permeability now plays a part. A high fault-rock permeability will ensure more rapid across-fault flow, which means that the oil reaches the producers early. This is important for the discounted production, while this effect is not as important in the total production since a delayed production contributes equally to total production as an early one. Also, the interaction effects between the different structural parameters are generally low, indicating that for the discounted production, the uncertainty is primarily a main effect of the different structural parameters investigated here.

Recovery factor

For the recovery factor, Figure 11 shows that the three fault-related parameters have about the same influence on the variability as the four sedimentological parameters. Another interesting aspect is that the interaction effect between the faults parameters and the wells is higher than the main effect of the wells.

Analysing the relatively high interaction between faults and wells seen in Figure 11 reveals that it is caused by the interaction between the structural pattern and the wells. If the recoveries based on the different structural patterns and well designs are shown in a matrix (Table 1), an interesting

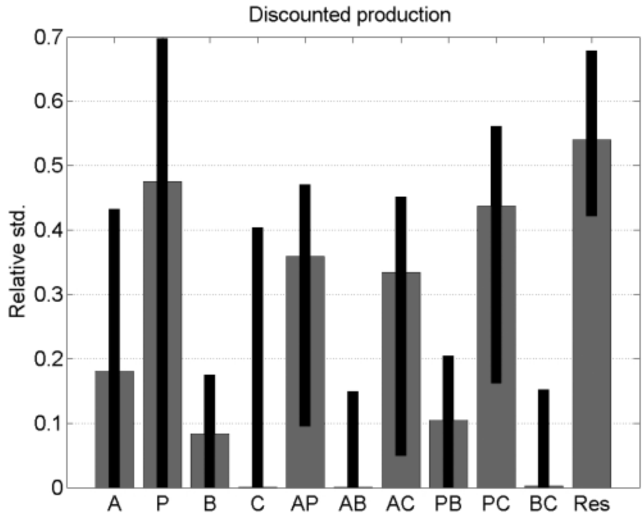

Fig. 9. Effects of sedimentological parameters on variability in discounted oil production. Sedimentological effects are aggradation (A), progradation (P), barriers (B), curvature (C), their two-way interaction effects and residuals (Res).

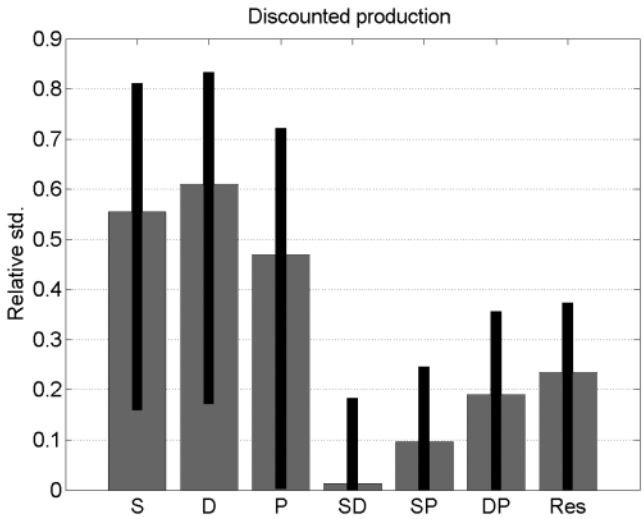

Fig. 10. Effects of structural parameters on variability in discounted oil production. Fault effects are structural pattern, density of faults and permeability through faults, two-way interactions and residuals.

behaviour appears. Each row shows the recoveries from the four well location sets while the columns from left to right represent the well locations designed to the strike-parallel, compartmentalized, strike-perpendicular and unfaulted structural pattern. Therefore, it is expected that the highest recoveries should be found on the diagonal element of each row. But it is only for the strike-perpendicular fault pattern where there is a significant difference between the well locations. In that case the well pattern designed for that particular fault pattern shows a higher recovery than the other well patterns. For the other structural patterns, the table indicates that the different well designs are equally good. All well designs do, however, consider the shape of the anticline as seen in Figure 3 in addition to the fault patterns, so a random well pattern will not produce as well as the ones used here (see Carter & Matthews (2008) for examples). This also means that the combined effect between fault parameters and well pattern shown in Figure 11 is primarily due to the importance of designing an optimal well pattern for the reservoirs with a strike-perpendicular fault pattern.

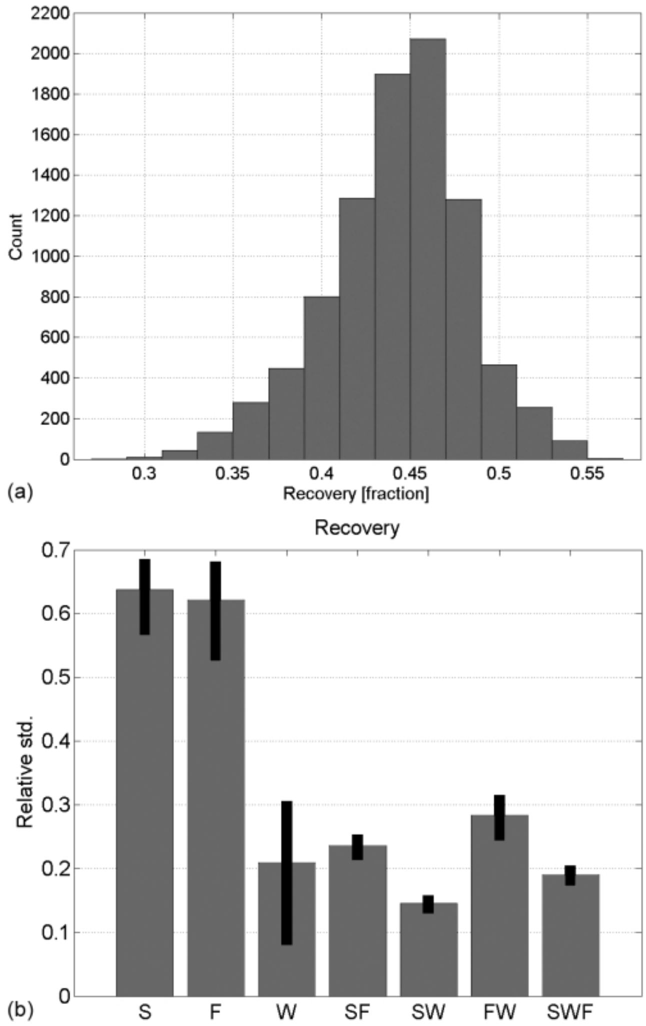

Fig. 11. (**a**) Variability in recovery factor; (**b**) decomposed into explanatory disciplinary variables. Disciplinary effects are sedimentology (S), faults (F), well locations (W) and their interaction effects.

Table 1. *Mean recovery factors for different sets of fault structural patterns and well sets*

Fault\Well pattern	A	B	C	U
Strike-parallel (A)	0.46	0.44	0.45	0.45
Compartmentalized (B)	0.46	0.46	0.46	0.46
Strike-perpendicular (C)	0.40	0.39	0.44	0.41
Unfaulted (U)	0.47	0.46	0.47	0.47

Standard deviations are approximately 0.03 for all estimates. Consequently, the choice of well set is, on average, not critical for the unfaulted (U), the strike-parallel (A) or the compartmentalized (B) fault structural pattern. The only significant difference is found for the strike-perpendicular case (C), where the well set designed for this pattern produces 1–1.5 standard deviations better than the other well sets.

A detailed analysis within the different parameter groups confirms that the relative importance within each group is almost equal to the situation seen for the total production variable, seen in Figures 6 and 7. Aggradation angle and progradation direction are the two sedimentological parameters most influenced by fault parameter settings. Figure 12 shows the sensitivity of aggradation (Fig. 12a) and progradation (Fig. 12b) towards fault parameter settings. The main effects of aggradation and progradation on recovery are computed for the 112 different subsets of the data corresponding to the fault

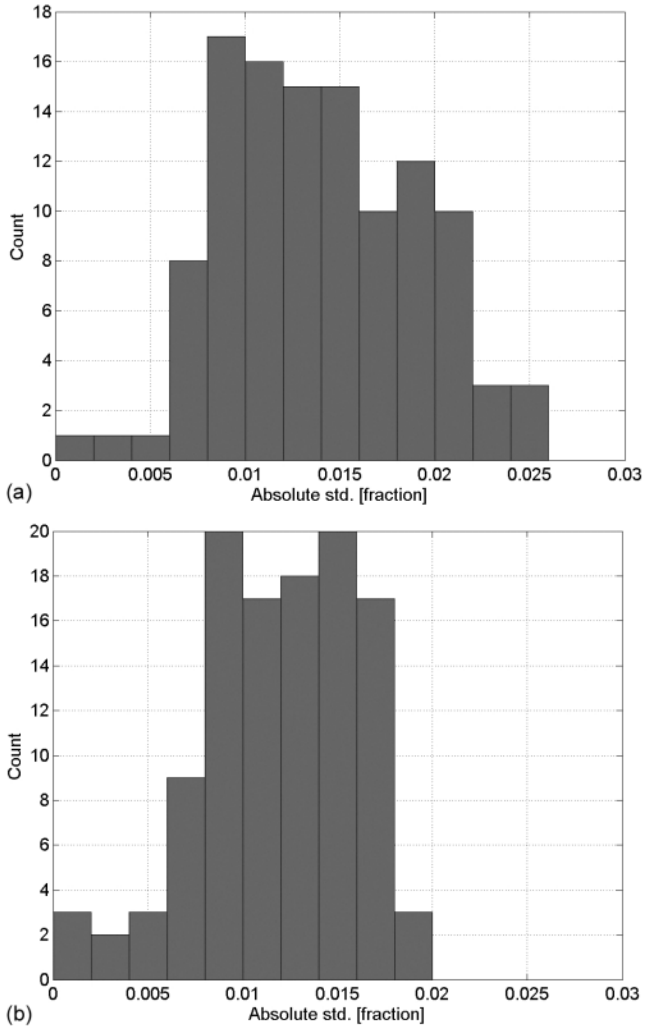

Fig. 12. The sensitivity of aggradation and progradation to fault parameters: the contribution of (**a**) aggradation and (**b**) progradation to the variability of recovery factor for each of the 28 fault parameter settings on all four well sets.

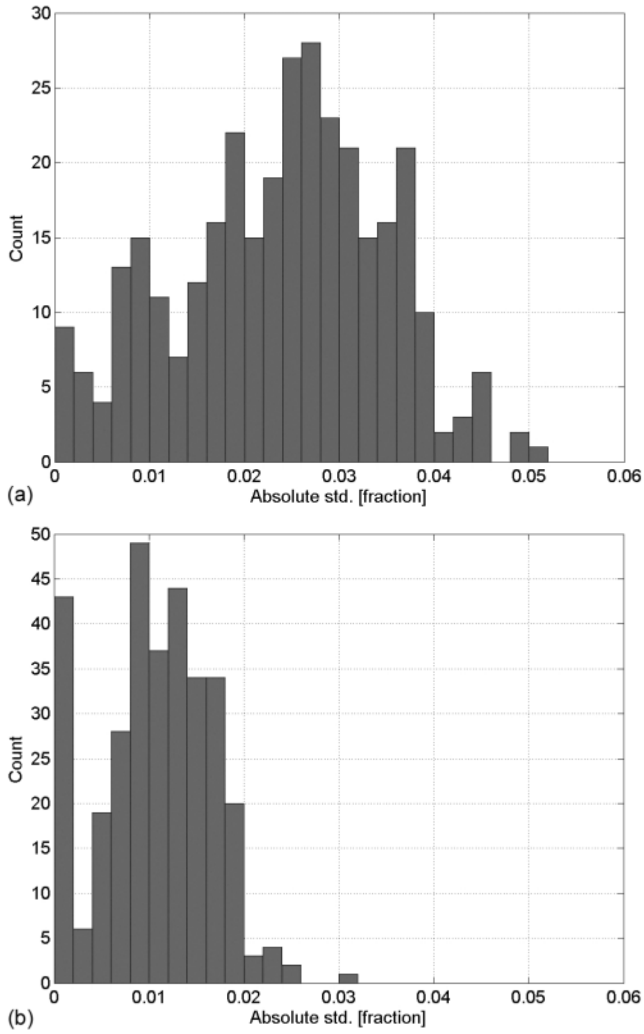

Fig. 13. The sensitivity of fault structure and fault density/throw to geological parameters: the contribution of (**a**) fault structure pattern and (**b**) fault density/throw to the variability of recovery factor for each of the 81 sedimentological models.

parameter settings. The effects are reported in terms of absolute standard deviations. The figure shows the histogram of these 112 standard deviations for aggradation and progradation. Averaging the data for the four well sets yields more stable estimates and is used in the analysis below. The lowest effect of aggradation is observed in the compartmentalized fault pattern with high cases of fault density/throw and low fault permeability; in this case the main effect of aggradation yields a variance component with a standard deviation of 0.007. The highest effect of aggradation is observed in the strike-perpendicular fault case with the high cases of fault density/throw and fault permeability. In this case the standard deviation is 0.021, three times larger than the low case and representing 25% of the variance of the recovery factor. The lowest effect of progradation is observed in the strike-parallel fault case with low values for fault density/throw and fault permeability; this contribution has a standard deviation of 0.007. The largest contributions are for the compartmentalized fault pattern in general.

Fault structure and fault density/throw are the two fault parameters most influenced by the sedimentological model. Figure 13 shows the sensitivity of these two parameters to the sedimentological model. The main effects of fault structure (Fig. 13a) and fault density/throw (Fig. 13b) on recovery are computed for the 324 subsets of data that correspond to each sedimentological model. The effects are reported in terms of absolute standard deviations. The figure shows the histogram of these 324 standard deviations for fault structure and fault density/throw. Generally, low aggradation angles and medium shoreline curvature tend to give larger fault structure effects. The fault density level is seen to have an increasing effect as the barrier level decreases. This means that for a high barrier level, the span of fault density used here is not an important contributor to the variability.

The maximum variability for the well-set averaged fault structure, with a standard deviation of 0.037, is obtained for the sedimentological model with low aggradation angle, and waterflood direction towards the progradation direction, 50% barrier coverage and medium shoreline curvature. For fault density/throw, the maximum standard deviation of 0.025 is also obtained with low aggradation angle, and waterflood direction towards the progradation direction, but with high barrier coverage (90%) and low shoreline curvature.

Sealing barriers

One of the most surprising results was the low importance of the sedimentological surface barrier continuity to all production

Table 2. *Group averages of oil production, discounted production and recovery factor for the four levels of barrier coverage*

Production response\Barrier coverage	10%	50%	90%	100%
Oil production (10^6 Sm^3)	24.9	25.2	23.7	23.0
Discounted production (10^6 Sm^3)	14.9	15.0	13.9	13.4
Recovery factor	0.455	0.451	0.433	0.416

These mean data do not show more than a slight tendency towards less production for the highest barrier levels. The data do indicate that for the barriers to be important they need to be almost or fully sealing.

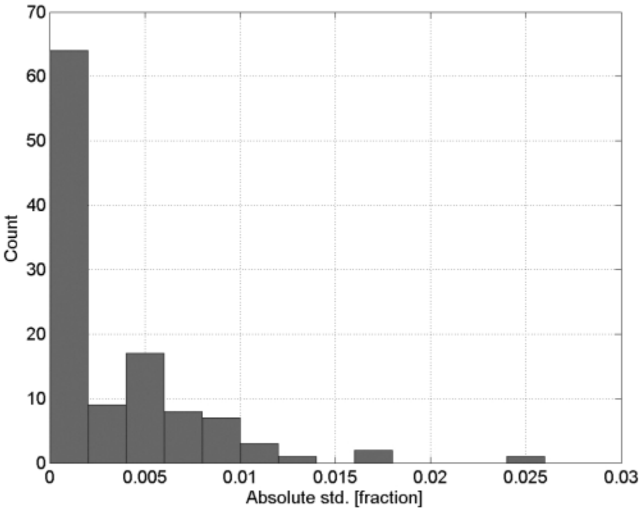

Fig. 14. The sensitivity of barriers to fault parameters: the contribution of barriers to the variability of recovery factor for each of the 28 fault parameter settings on all four well sets.

responses. As it was suspected that the three different levels used in the main analysis were not discriminating enough, a separate investigation was made where an even higher sealing level was introduced. These barriers were 100% sealing unless they were within or on the edge of channel facies (since clinoforms would not be preserved in this environment). For both the wave-dominated and fluvially dominated end-member curvature cases, new realizations were run with the three different progradational directions using high and low aggradation angles. Flow simulations on these realizations from all well sets gave 48 new production data for this dense barrier level. The results shown in Table 2 indicate that the main effect of the barriers as modelled here is low, but that an effect is seen only for very high barrier levels. For comparison, the standard deviations for all barrier levels are about 5×10^6 Sm^3, 3×10^6 Sm^3 and 0.04 in oil production, discounted production and recovery factor, respectively, for the 10%, 50% and 90% levels. For the 100% case it was higher: 6.3×10^6 Sm^3, 3.5×10^6 Sm^3 and 0.06, respectively, again confirming that barriers have the largest effect when their coverage is complete.

Figure 14 shows the sensitivity of the barrier level towards the fault-related parameters found within the original 9072 production models. It is seen that the absolute standard deviations are small. But a detailed look at these data shows that all three of the tail data in the figure originate from the compartmentalized fault structure, simulated using a well set not designed for this structure. Moreover, they also have in common that the fault density is high and the fault permeability is low. Consequently, it is possible to conclude that the barriers do have an effect if the faults are also relatively sealing, and that this effect decreases if the wells are located with reference to the faults. One of the reasons for the barriers not being more important is that the wells in these models are vertical, so vertical communication is less critical as long as there is a horizontal passage to the wells. Since the barriers were not 100% sealing as long as channels are found on the edge of the coastal plain lobe – and the channel facies are among the most permeable facies in the reservoirs – the flow will find those holes in the barriers. When the production is continued long enough, the oil will finally reach a producer, although the production will be reduced compared to a situation with less sealing barriers. A higher number of clinoforms within the zones than used in this project will also imply a higher variability effect than seen here. Faults, however, will break up the sedimentological barriers and, unless the faults are at least as sealing as the barriers, they will tend to negate their effects.

When looking at water production, it was seen that the barrier level did play a more important role. The water production relative to the 10% barrier level increased by approximately 11%, 15% and 26% for the 50%, 90% and 100% barrier levels, respectively, and again with a higher standard deviation for the dense case. Consequently, the barrier level affects the cost of producing the oil, although in this synthetic setting it did not have a significant effect on the oil production.

Principal component analysis

The first few principal components of the production summarize the primary behaviour of the production (see, for example, Johnson & Wichern (1988, pp. 340–371) for reference). The principal components are just orthogonal, linear combinations of the eigenvectors of the production covariance. An approximation of the production variability can then be described by a sum of the first few principal components multiplied by their scalar factors. Note that the transformation using principal component analysis often is referred to as the Karhunen-Loeve transform. Figure 15 shows the production variability due to the first three principal components, which represent 50%, 31% and 8% of the variance, respectively. It is seen that the first component is zero after approximately 14 years and that including the three first components provides a good estimate of the total variability, although, of course, too smooth compared to the full variability.

The principal components can be analysed in the same manner as the production responses above. The sedimentological factors dominate the first three principal components. The variance split of the first principal component is very similar to the split for discounted production (see Figs. 8–10). For the second principal component, the aggradation angle is the single most important sedimentological factor, and fault structure dominates the fault effects. As the order of the principal component increases, higher-order interactions explain a larger part of the variability. The SAIGUP data provide a large database of input variables with production responses. It is possible to use those data to predict both the production profile and its uncertainty for other new reservoirs that fit into the SAIGUP parameter span.

DISCUSSION

Several key parameters that describe a prograding shallow-marine reservoir were investigated for their relative importance on the production variability. This article, initially considering 9072 production responses, but adding 48 additional responses for evaluating the dense barrier effect, assumed that the uncertainties in the parameters chosen in this study are generally larger than other sedimentological and fault-related

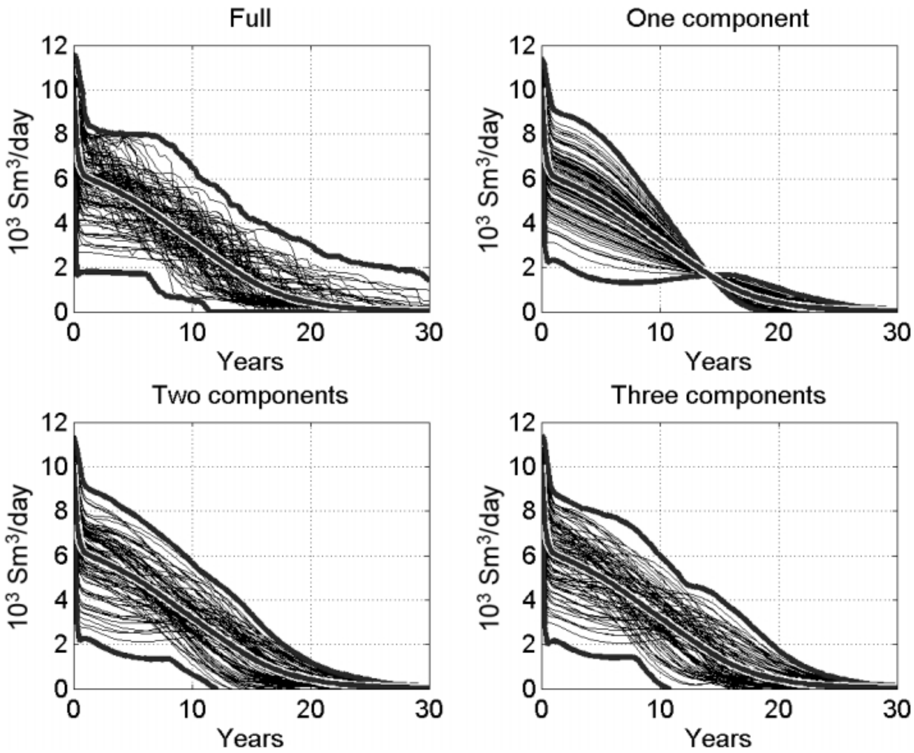

Fig. 15. Principal components of 50 production rates and pointwise mean, maximum and minimum rates. The full profiles are shown together with responses obtained from adding the first, the first two and the first three principal components.

parameters that control production from a reservoir. Several factors were kept constant for all production responses analysed:

- the gridding and choice of flow simulation scheme;
- the upscaling of absolute permeability;
- the choice of relative permeability functions.

The last of these is a significant uncertainty and forms the focus of the study of Stephen *et al.* (2008). The others are outside the scope of the project, as is the contribution on production uncertainty arising from volumetric uncertainty. This was identified as an important parameter for production uncertainty in a specific reservoir by Lia *et al.* (1997), but its level cannot be generalized since it will depend on the number of well data and on the quality of the seismic data. A real case production uncertainty analysis, however, should certainly include these aspects.

Lia *et al.* (1997) quantified the production uncertainty from the Veslefrikk Field, a Middle Jurassic Brent Group reservoir. The study concluded that the coverage of the shale barriers, the sealing effect of the faults, the seismic velocity and the porosity model contributed most to the production uncertainty. Two of these parameters (seismic velocity and porosity) have not been included in the present study, and the other two (the level of barrier coverage and the fault permeability) have not proven to be particularly significant. There are several reasons for this. First, the level at which a parameter is modelled clearly controls its significance. Lia *et al.* (1997) examined the largest possible range of fault properties, varying from completely sealing to completely open, and concluded that this is the most significant uncertainty on production from the natural reservoir. The present study, however, considered a more modest range in fault-rock permeability uncertainty (spanning a *c.* 1.5 orders of magnitude range) and found fault-rock permeability to be of only minor influence on total production or recovery factor. Manzocchi *et al.* (2008*c*) show that a 1.5 orders of magnitude fault permeability range is not necessarily too small to be of potential significance to production uncertainty in the reservoirs examined; however, the fault-rock permeabilities would need to be approximately two orders of magnitude lower overall for a 1.5 orders of magnitude range to be a significant uncertainty. Both the range considered here and a range two orders of magnitude less permeable are realistic in Brent Group reservoirs, and represent faults forms at burial depths of *c.* 2.5 km and 4 km, respectively (Jolley *et al.* 2007).

A second reason for the discrepancy between the results of this study and of the study of Lia *et al.* (1997) is illustrated by the strong effects of the interactions between parameters. Sedimentological barriers have not been influential in this study; however, their influence has been shown to increase as the fault properties become less permissive. Therefore, had the modelling included less permissive faults overall, not only would the precise level of fault permeability be a more significant variable (as discussed above), but so too would the level of barrier coverage. A conclusion from the Veslefrikk study is that the model parameters and the heterogeneity contributed approximately 75% and 25%, respectively. This is quite close to what was found in the present study for the recovery factor. For the total and discounted production, the model parameters contributed almost 90% of the variability.

This study shows the relative effect of changing parameters within typical uncertainty ranges. Other reservoirs may have other ranges of uncertain parameters. The methodology used here illustrates how to treat the uncertainty for a particular study. Both the cost of providing better estimates and the expected effect for the different parameters, as suggested here, can be a guide where to focus the effort of reducing the uncertainty in production responses. Note that since these SAIGUP reservoirs consist of four stacked zones, parameters that vary in all layers, such as the petrophysical parameters, will have less effect since random effects are reduced compared to, for example, a single zone reservoir. The well controls are naïve in the sense that only vertical wells were used. Also, new wells replacing low production wells were not an option in this study.

CONCLUSIONS

This study of 9120 production responses for this class of siliciclastic shallow-marine reservoir supports a number of conclusions.

1. Variance decomposition is a useful tool for understanding the production uncertainty. Higher-order effects can be a significant explanation for the variability and should not be omitted in production uncertainty studies.
2. Aggradation angle and progradation direction relative to the waterflood dominate the total production, while the structural pattern dominates the fault effects.
3. The discounted production variability is explained primarily by the sedimentological parameters of aggradation and progradation, but has large higher-order effects. The fault effects are explained almost equally by the fault structure, the fault density and the fault permeability.
4. Fault-related and sedimentological parameters are equally important for describing the uncertainty in the recovery factor, with fault structure, aggradation angle and progradation direction being the dominant parameters.
5. The barriers showed significant effects only when they were highly continuous. This supports a practice of allowing production uncertainty analysis including barriers to be simplified by including barriers as an indicator variable only.
6. The non-superiority of the well locations designed for the different structural patterns, except for the strike-perpendicular system, confirms that defining optimal well locations is a complex task, related not only to the fault pattern.

The authors would like to thank Alan Irving (Total) and Jan C. Rivenæs (StatoilHydro) for their constructive and invaluable review of the paper. We are very grateful to Badley Geoscience, BG International, Roxar and Shell for their support of the SAIGUP project and for their sponsorship of the production of this thematic set.

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Received 29 January 2007; revised typescript accepted 5 October 2007.