Sensitivity of the impact of geological uncertainty on production from faulted and unfaulted shallow-marine oil reservoirs: objectives and methods

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ABSTRACT: Estimates of recovery from oil fields are often found to be significantly in error, and the multidisciplinary SAIGUP modelling project has focused on the problem by assessing the influence of geological factors on production in a large suite of synthetic shallow-marine reservoir models. Over 400 progradational shallow-marine reservoirs, ranging from comparatively simple, parallel, wave-dominated shorelines through to laterally heterogeneous, lobate, river-dominated systems with abundant low-angle clinoforms, were generated as a function of sedimentological input conditioned to natural data. These sedimentological models were combined with structural models sharing a common overall form but consisting of three different fault systems with variable fault density and fault permeability characteristics and a common unfaulted end-member. Different sets of relative permeability functions applied on a facies-by-facies basis were calculated as a function of different lamina-scale properties and upscaling algorithms to establish the uncertainty in production introduced through the upscaling process. Different fault-related upscaling assumptions were also included in some models. A waterflood production mechanism was simulated using up to five different sets of well locations, resulting in simulated production behaviour for over 35 000 full-field reservoir models. The model reservoirs are typical of many North Sea examples, with total production ranging from *c.* 15×10^6 m^3 to 35×10^6 m^3, and recovery factors of between 30% and 55%. A variety of analytical methods were applied. Formal statistical methods quantified the relative influences of individual input parameters and parameter combinations on production measures. Various measures of reservoir heterogeneity were tested for their ability to discriminate reservoir performance. This paper gives a summary of the modelling and analyses described in more detail in the remainder of this thematic set of papers.

KEYWORDS: *oil production, shallow marine, faults, uncertainty, sensitivity*

INTRODUCTION

This thematic set of papers presents the principal results of an intensive modelling programme aimed at advancing our understanding of the influence of geological uncertainties on hydrocarbon recovery factors in progradational shallow-marine reservoirs. The interdisciplinary study (under the project

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acronym 'SAIGUP') was carried out in response to the EU priorities of reducing time to first oil and of improving overall hydrocarbon recovery efficiency. This introductory paper describes the background and objectives of the work and summarizes the approach. Procedural and geological aspects of the modelling, and detailed analyses of the results, are described in the remainder of the thematic set (Carter & Matthews 2008; Howell *et al.* 2008; Manzocchi *et al.* 2008*a, b*; Matthews *et al.* 2008; Skorstad *et al.* 2008; Stephen *et al.* 2008).

The overall objectives of the project have been: (a) to quantify the influences of sedimentology, structure and upscaling on uncertainties in production forecasting from reservoirs with different sedimentological and structural properties; (b) to define geologically relevant dynamic and static heterogeneity measures for improved production forecasting; and (c) to validate conclusions using real-case reservoir and production data. The third objective has been addressed by examining geological and production characteristics of models of reservoirs from the North Sea and the Niger delta. The real cases are not described in the current set of papers, which focuses exclusively on the first two objectives for which models of generic reservoirs have been considered. The approach taken has been to build realistic synthetic full-field reservoir models encompassing quantified variability in small- and large-scale sedimentological characteristics, structural characteristics, upscaling methods and assumptions, and to simulate these for up to 30 years of production history using a variety of field development plans. Geological and methodological characteristics of the models are stored together with well and field production profiles in a database containing results from *c.* 35 000 models. These data have been analysed statistically to identify those variables and variable-combinations imparting the largest sensitivity to field performance indices (e.g. total production, recovery factors and economically motivated factors) and, using more physically or geologically based methods, to identify heterogeneity measures for assessing the likely influences of particular geological factors on production.

BACKGROUND

An accurate early estimate of the reserves of an oil reservoir (defined as the volume of oil that can be produced within economic and operational constraints) has proven elusive globally (e.g. Bentley 2002). An analysis of reserves estimates made annually for UK Continental Shelf oil reservoirs (DTI 1975–2005), for example, shows that changes in estimated reserves over the life of a field either upwards or downwards by a factor of two are not uncommon (Fig. 1a). While in most cases these changes occur in the early stages of the field production, significant – and potentially more costly – reassessment can also occur late in the life of a reservoir (Fig. 1b). That there is no trend, however, between the changes in estimate made early and late in the life of a field (Fig. 1c) suggests that different uncertainties are resolved at different times and, once identified, the change in estimated reserves made to account for the particular uncertainty is generally accurate.

Possible reasons cited for changes in reserves estimation range from corporate culture or policy to economic factors, but there seems little doubt that unforeseen geological, in particular structural, complexity often leads to the most dramatic decreases in reserve estimates (e.g. Corrigan 1993; Dromgoole & Speers 1997). Despite this, Thomas (1998) found that only 30% of companies operating fields in the UK sector of the North Sea regularly used multiple realizations of geological or simulation models to estimate reserves. Since the same survey revealed that 70% of the respondents felt that the

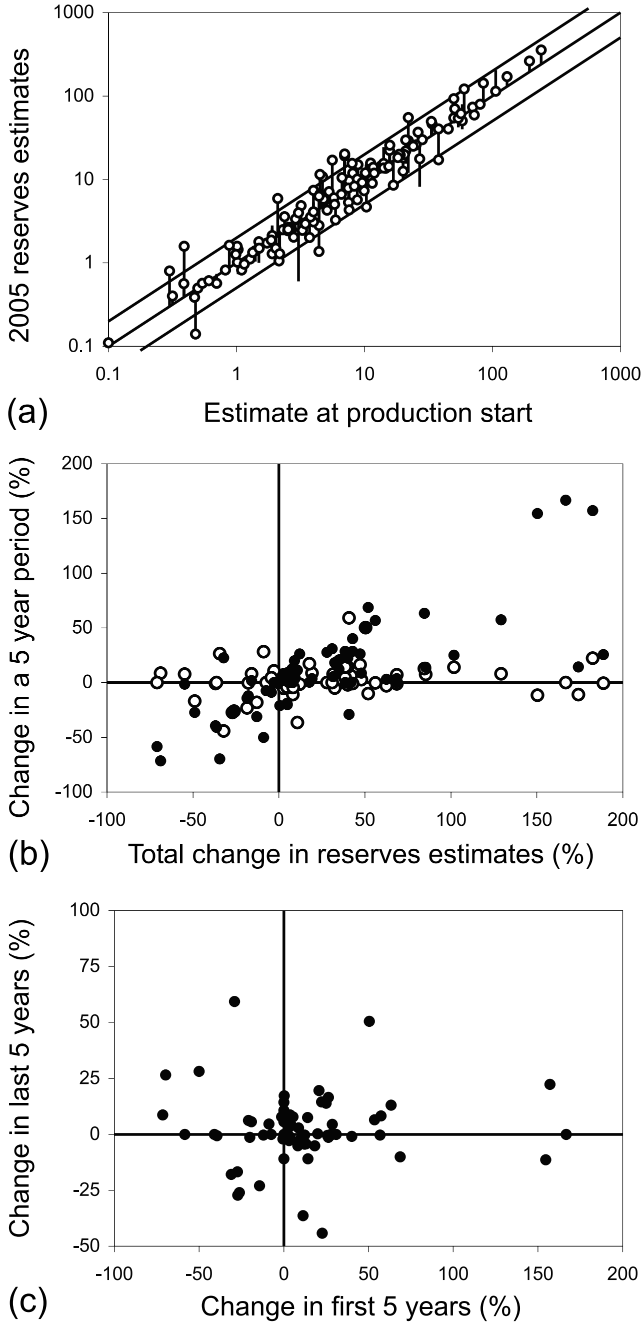

Fig. 1. Changes in estimated reserves for offshore UKCS oil fields (DTI 1975–2005). (**a**) Cross-plot of the estimated reserves (millions of tonnes) made the year production started vs. the most recent estimate (i.e. the 2005 estimate for fields still in production, or the final value for abandoned fields). The error bars represent the total range quoted over all years, and the solid lines show 1: 1, 2: 1 and 1: 2 ratios of the reserve estimates. 138 fields are shown. (**b**) The percentage change in estimated reserves within the first (black circles) and most recent (open circles) five-year periods, cross-plotted against the total range in estimated reserves over the life of a field. (**c**) The percentage change in estimated reserves within the first five years of the field's life against the percentage change over the most recent five-year period. Note that (b) and (c) include only those oil fields for which production started in 1995 or earlier (*n*=68), ensuring that the two five-year periods considered do not overlap.

reservoir description was reasonably accounted for in their reserves estimates, it appears either that little consideration of geological uncertainty is made when estimating reserves, or that this uncertainty is considered to have little influence on the

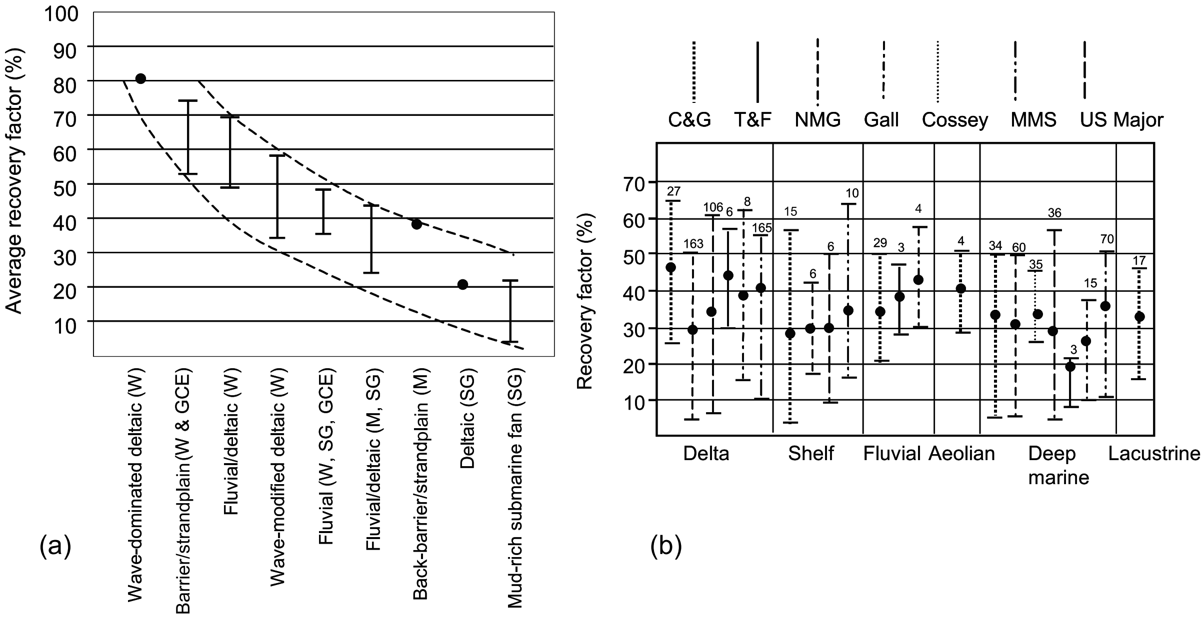

Fig. 2. (**a**) Recovery factor as a function of depositional environment and drive mechanism for major Texas oil fields. W, water drive; GCE, gas cap expansion; SG, solution gas drive; M, mixture of the above. Redrawn from Tyler & Finlay (1991). (**b**) Recovery factor as a function of depositional environment for reservoirs produced by a waterflood or with active water drive, separated by database studied. The circles show the median values, while the lines span the 10–90 percentile range. The number of reservoirs included in each class are indicated. Redrawn from Larue & Yue (2003). T&F shows the data examined by Tyler & Finlay; for an explanation of the other datasets see original source.

recovery factor of the reservoir and controls primarily only the estimate of oil in place, allowing reserves to be estimated using Monte Carlo methods.

The present study does not address the full range of contributors to reserves uncertainty as all the reservoir models share a common gross-rock volume and production mechanism. Instead, the study focuses principally on links between geological characteristics and recovery factor. Recovery factor (also widely called recovery efficiency) is the ratio between produced (or producible) oil and oil in place, and is universally acknowledged to be dependent on the drive mechanism of the reservoir. What is more controversial is the role of geological reservoir characteristics. Tyler & Finlay (1991) concluded from a study of Texan oil fields that recovery factor is related to geological depositional environment and drive mechanism (Fig. 2a). More recently, however, Larue & Yue (2003) analysed the dataset used by Tyler & Finlay, as well as five other compilations. They argued that the depositional environment appears to be only a weak determinant on recovery factor at best (Fig. 2b), and its apparent significance in the work of Tyler & Finlay is a function of combining drive mechanism and depositional environment in the same plots. The principal correlation Larue & Yue (2003) were able to identify from the combined datasets was a general increase in recovery factor with increasing average reservoir permeability, a trend they ascribe to economic factors. Structural aspects were not considered in either study.

These workers were concerned with identifying average trends as a function of depositional environment, rather than with estimating the uncertainty on the recovery factors of individual reservoirs as a function of their known and unknown geological characteristics. The compilation of Larue & Yue appears to show less variability in recovery factor in fluvial and aeolian reservoirs than others (Fig. 2b), but is the range observed for these reservoirs (*c.* ± 10%) appropriate for an individual reservoir, or should significantly lower uncertainty than this be expected? Reservoir-specific estimates of uncertainty exist (e.g. Lia *et al.* 1997), but there are not enough such studies (in the public domain at least) to draw quantitative links between geological complexity and production uncertainty as a function of generic aspects of the reservoir geology. Larue & Yue (2003) reported considerable frustration in their efforts to make such links from public domain data from real reservoirs, due to the quality and type of data contained in the individual databases, and the different definitions and data types used in different databases. These difficulties obviously can be avoided in a study such as the one presented here, as the details of every model and all the geological assumptions used to generate it are known, and a consistent set of reservoir production profiles are generated for each simulation model using well-defined controls.

In summary, existing studies have either addressed differences in recovery as a function of broad geological characteristics of reservoirs, or have addressed uncertainty in the production forecasts of specific reservoirs. This study aims to use a broad range of synthetic reservoir models of one major depositional class to assess the levels of uncertainty on production estimates as a function of the variability in model properties. The models all have the same gross-rock volume, which is therefore not a contributor to the production uncertainty.

MODELLING CONSIDERATIONS AND APPROACH

A wide scale-range of geological heterogeneities influence oil recovery, and the literature on the subject is vast (e.g. Weber & van Geuns 1990; Kjønsvik *et al.* 1994). It is futile to attempt to include combinations of all heterogeneity types in a manageable study, and the starting point of our considerations was the pair of heterogeneity matrices shown in Figure 3, and the decision to focus on shallow-marine depositional environments. Further decisions on which factors should be kept constant and which varied and in what combinations focused around four principal considerations:

- that there must be sufficient overlap between models to allow quantitative assessment of the contributions, and

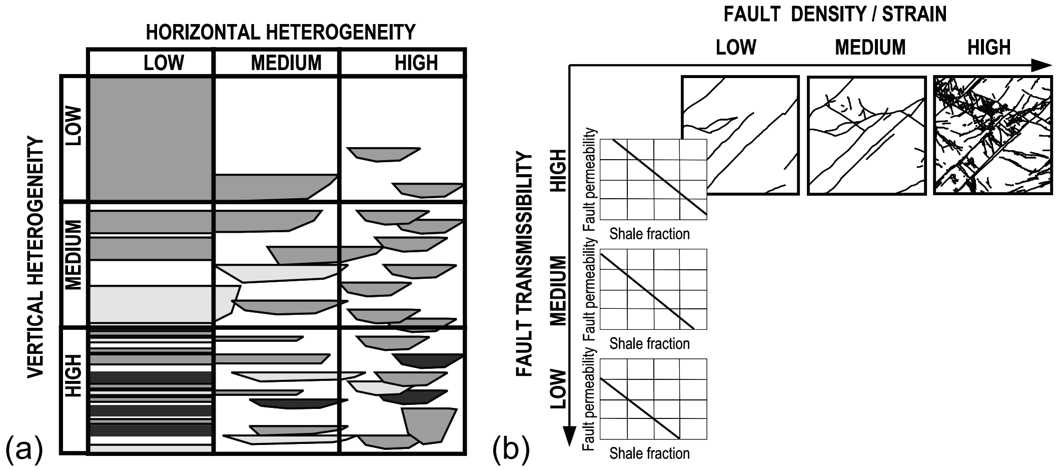

Fig. 3. Conceptual (**a**) sedimentological and (**b**) structural heterogeneity matrices. (Source: (a) from P. W. M. Corbett (pers. comm.), after Tyler & Finlay 1991.)

Table 1. *The six facies, from distal to proximal, with the expectations of vertical and horizontal permeability, porosity and* V_{shale}

Facies	Facies models	K_v (mD)	K_h (mD)	Porosity	V_{shale}	S_{wi}
Offshore	Interbedded mudstones and sandstones	0.0	0.06	0.02	0.6	0.3817
Offshore transition zone	Hummocky cross-stratification in sheets interbedded with shales	0.0	20.09	0.12	0.4	0.3817
Lower shoreface	Amalgamated hummocky cross-stratified beds	1.65	90.02	0.15	0.25	0.284
Upper shoreface	Medium-grained trough cross-beds and planar-laminated clean sandstone	164	854.1	0.2	0.15	0.1458
Coastal plain	Interbedded mudstones and sandstones	0.0	2.72	0.05	0.5	0.3817
Channels	Fining-upwards trough cross-beds	90.02	445.9	0.2	0.2	0.1458

Except for the zero vertical permeability facies, permeabilities are drawn from log-normal distribution, while porosity and V_{shale} are normally distributed. Irreducible water saturation (S_{wi}) is constant per facies and the water saturation at irreducible oil is 0.7 for all facies. Net:gross ratio is taken as $(1 - V_{shale})$.

variability in contributions, of parameters and parameter combinations towards variability in reservoir performance;
- that in addition to geological parameters, commonly made assumptions in how these are modelled should also be addressed;
- that although synthetic, each model would be sufficiently complex to represent a plausible reservoir, would be developed by a plausible production plan and that production from most reservoir models would be viable economically;
- that something of the order of 20 000 such models could be run over the course of the project.

The study focuses on reservoir-scale flow using mainly commercial modelling packages, and the work flow is roughly analogous to that used in any comprehensive reservoir evaluation study. All models are of progradational shallow-marine sedimentary environments built within a sequence stratigraphic framework. Using different grids for each sedimentological model is impractical, given the numbers of models generated, and a regular grid has been used for all. Each geological model contains *c.* 1.5 million cells at a resolution of $37.5 \times 37.5 \times 1$ m within the overall modelling volume of 3 km × 9 km × 80 m. All models are built with six facies associations, each with the same grid-block-scale property expectations (Table 1). The facies model is populated with petrophysical properties and upscaled to the resolution of the simulation model ($75 \times 75 \times 4$ m), which contains *c.* 79 000 active cells. The overall reservoir structure considered is a typical tilted fault block with three-way dip closure and a constant gross-rock volume above a constant oil–water contact. The recovery mechanism used throughout was a voidage replacement water-injection scheme, and most models were simulated with one of four sets of well locations. The oil and water properties were

Table 2. *The model fluid and rock properties*

	Formation volume factor (vol/vol)	Viscosity (cP)	Density (in reservoir) (kg m^{-3})	Compressibility (bar^{-1})
Oil	1.5	1.0	721	10^{-4}
Water	1.0	0.4	1000	10^{-5}
Rock	1.0			10^{-5}

not varied and are based on typical values for Brent-province reservoirs (Table 2).

Smaller-scale sedimentological aspects and upscaling

One of the most significant problems in building an accurate simulation model of a reservoir is ensuring an adequate representation of geological heterogeneity from scales a few times smaller than the grid-block to a few times larger than it. Heterogeneities smaller than this can be averaged out within the grid-block volume. Larger heterogeneities can be modelled explicitly. There are no straightforward solutions to modelling heterogeneities at intermediate scales, since representivity cannot be assumed. It is fortunate that the study is considering shallow-marine reservoirs, since the most important reservoir facies (upper and lower shoreface) are structured at scales representative within the grid-block volume. Following Daws & Prosser (1992) and Corbett (1993), it was assumed that the lower shoreface comprises hummocky cross-stratified laminae and the upper shoreface comprises trough cross-stratified laminae overlain by planar-bedded facies, each representative at scales of a few metres or less. This assumption of representivity at a small scale justifies the use of a single method for upscaling the absolute properties of the geological model to the grid-block model, but it is recognized that representivity is an issue for two of the less significant facies modelled (the offshore and the coastal plain), since individual sandstones may be connected over a few grid-blocks, but disconnected at larger scales (e.g. King *et al.* 1998).

The effects of the lamina-scale heterogeneity in the different facies are therefore averaged within the grid-block properties, and larger-scale sedimentological trends are modelled as correlated Gaussian fields on a facies-by-facies basis in the sedimentological model. Each grid-block in the simulation model is represented by values of porosity, net:gross ratio, directional permeabilities and an index to the facies contained in the grid-block. This index assigns, on a facies-by-facies basis, the relative permeability curves applied to the grid-blocks. Absolute directional permeabilities are upscaled from the geological model using a modification to the method of Warren & Price (1961), and other parameters are simple averages. Further details of the construction of the sedimentological models are given in Howell *et al.* (2008).

Most of the models use the same set of facies-specific pseudorelative permeability curves. These were generated using the Geopseudo method, in which upscaling is performed in stages and at scales representative of the facies considered (e.g. Corbett *et al.* 1992). A smoothing of these curves, and the omission of capillary pressure, results in an average saving in CPU time of 40%. Full details of the original derivation and subsequent modification of these functions are given in Stephen *et al.* (2008) and Matthews *et al.* (2008), respectively. Sensitivity to assumptions made during the derivation of these default pseudorelative permeability functions is addressed by Stephen *et al.* (2008).

Larger-scale sedimentological aspects

The large-scale sedimentological parameterization was varied on the basis of a conceptual heterogeneity matrix (Fig. 3a). On this matrix, scales of horizontal and vertical heterogeneity are expected to have different effects on recovery factors, with low heterogeneity reservoirs (e.g. wave-dominated deltas) expected to produce better than reservoirs with low horizontal but high vertical heterogeneity (e.g. deep-marine reservoirs) or low vertical but high horizontal heterogeneity (e.g. single-unit fluvially dominated deltas). The worst performing reservoirs expected are highly heterogeneous in 3D (e.g. stacked fluvially dominated deltas). Howell *et al.* (2008) give a comprehensive review of the types of heterogeneity in shallow-marine reservoirs and discuss how the conceptual framework was translated into plausible sedimentological reservoir models. For vertical heterogeneity these include vertical facies trends and the occurrence of cemented layers within parasequences, and facies transitions across parasequence boundaries as well as the sealing potential of the boundary itself. Horizontal heterogeneity is a product of shale drapes and cemented clinoform surfaces within the marine facies, lateral facies changes and the presence of channels in the coastal plain. At a smaller scale, the lamina-scale permeability structure of the facies can change the levels of both heterogeneity types.

A sequence stratigraphic framework was used to model systems with different levels of horizontal and vertical heterogeneity within a progradational shallow-marine setting as a function of combinations of five basic sedimentological variables (Fig. 4). The 80 m thick models contain two, four or six parasequences with parallel boundaries (Fig. 4a–c). Within each parasequence the aggradation angle (Fig. 4d–e) and shoreline lobosity (Fig. 4f–h) control the gross stratigraphic geometry. Aggradation angle is a function of the balance between sediment supply and the rate of subsidence. When the rate of sediment supply is high compared to the rate of subsidence, the aggradation angle is low and the vertical heterogeneity of the reservoir is greater (Fig. 4d). The lobosity level controls the shape of the shoreline, which ranges from relatively straight in foreshore systems (Fig. 4f) to elongate in wave fluvially dominated deltas (Fig. 4h). Characteristic densities of channels in the coastal plain and clinoforms in the marine facies are modelled, and these both increase with increasing shoreline curvature (i.e. with increasing fluvial influence).

The fourth basic sedimentological variable considered is the level of the continuity of the parasequence-bounding and clinoform surface cements. If the clinoforms are highly cemented (Fig. 4j), horizontal flow between clinoform-bounded upper shoreface compartments is inhibited. If the parasequence boundaries (Fig. 4k) are highly cemented, vertical flow across parasequence boundaries is inhibited. The continuity of these cements is therefore an important source of both heterogeneity types. The final sedimentological variable altered systematically is the relationship between the sedimentological progradation direction and the waterflood direction. Versions of parametrically identical models were compared in which the progradation direction is perpendicular to the waterflood direction (Fig. 4l) or parallel to it, with the waterflood either up depositional dip (Fig. 4m) or down depositional dip (Fig. 4n). These three progradation directions are referred to throughout the study as directions 0, 1 and 2.

Many aspects of the models are constant, for example the thicknesses of each facies tract. Values used for both variable and constant parameters derive from a review of ancient and modern shallow-marine systems (Howell *et al.* 2008). Combinations of values chosen for three levels each of aggradation angle, shoreline shape, barrier continuity and progradation direction were considered in the initial modelling, using four parasequences. Later models investigated the variability introduced by modelling different realizations of parametrically identical models, models containing two or six parasequences, models with 100% cement coverage, and models in which the variograms used to populate the petrophysical properties were rotated by 90°. Further details are given in Howell *et al.* (2008) and Skorstad *et al.* (2005, 2008).

Structural aspects

Structural variability, conceptualized on the matrix shown in Figure 3b, comprises different fault transmissibility levels combined with different fault densities to give a suite of structural models ranging from strongly compartmentalized systems of low permeability faults, to low fault density systems in which fault properties are of negligible effect. Three basic fault systems have been used. In structure A (models A1, A2, A3) the faults predominantly strike perpendicular to the waterflood direction and, in structure C (models C1, C2, C3), predominantly parallel to it (Fig. 5a). Structure B (models B1, B2, B3) is compartmentalized, with faults striking in both directions. The fault systems are based on natural examples (Manzocchi *et al.* 2008a) and were sampled at three strain levels (Fig. 5b), with the faults in the highest density models (models A1, B1, C1) being smaller in or absent from the lowest density ones (models A3, B3, C3). The largest faults in the highest strain versions have maximum throws slightly less than the total model thickness (80 m). All models share a common gross-rock volume, and each system merges into a common unfaulted

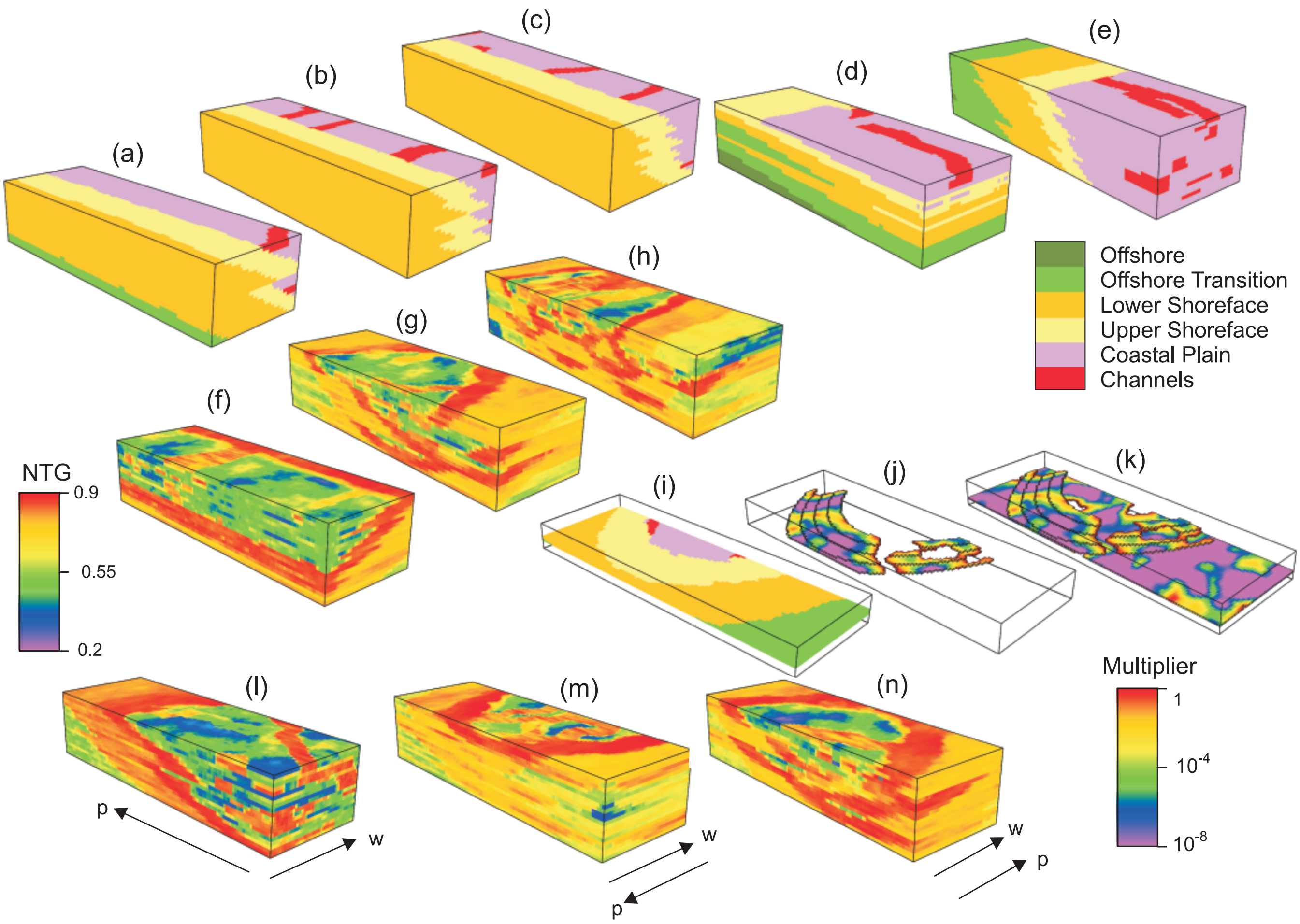

Fig. 4. Upscaled sedimentological models showing the five basic sedimentological variables considered. (**a**) Two parasequence, (**b**) four parasequence and (**c**) six parasequence models with high aggradation angle. (**d**) Low and (**e**) high aggradation angle models. (**f**) Low, (**g**) moderate and (**h**) high shoreline lobosity (curvature) models with medium aggradation angle. (**i**) Single parasequence in a model with moderate shoreline lobosity. (**j**) The dipping clinoforms contained in the marine facies of this parasequence are represented as vertical and horizontal transmissibility multipliers. (**k**) As (j), but showing also the cemented boundary at the base of the parasequence. This model has 90% cement coverage. (**l**) Waterflood direction (arrow labelled 'w') is perpendicular to progradation direction (arrow labelled 'p'). (**m**) Waterflood is down depositional dip and (**n**) waterflood is up depositional dip. (l)–(n) Medium lobosity, medium aggradation angle models. (d)–(n) Models with four parasequences, the number most frequently used. Cells in (a)–(e) and (i) are coloured by facies, and in (f)–(h) and (l)–(n) by net: gross ratio. (i)–(k) Vertical exaggeration of $\times 3$; remainder are all $\times 10$. Note that (g) and (n) are different realizations of parametrically identical models.

end-member reservoir (model U) at zero strain (Fig. 5a). These ten structural models were used throughout.

Fault properties were estimated using shale gouge ratio (SGR) as a proxy for fault-rock permeability, and fault throw as a proxy for fault-rock thickness, and included in the simulation models as single-phase transmissibility multipliers using the method described by Manzocchi *et al.* (1999). Up to nine fault-rock cases were considered, ranging from a pure juxtaposition case (i.e. no fault rock included) to extremely low permeability relationships. These are discussed in more detail in Manzocchi *et al.* (2008*a*). The initial modelling suite used only three relatively permeable relationships. More (and less) sealing faults were addressed in a later modelling phase. Numerical and geological assumptions made during the representation of faults as transmissibility multipliers on continuous faults were also addressed, and are discussed by Manzocchi *et al.* (2008*b*).

Reservoir development plans

Four development plans were prepared, each tailored around the unfaulted and three faulted end-member reservoirs (Fig. 5a). With the exception of the plan designed around structure C, all have four crestal and four mid-row producer wells, with the positions of the wells guided by the larger (i.e. seismically resolvable) faults. Structure C contains faults perpendicular to the strike of the tilted fault block and, in this case, eight crestal producers are placed in the largest compartments. All development plans have three injectors close to the oil–water contact. All wells are active from the start of production and simple well controls are used in all cases. These are:

- production wells were controlled on a fixed BHP 50 bars below the initial reservoir pressure at the OWC depth;
- wells were considered uneconomic and shut in if production rate fell below 50–100 m^3 per day (the threshold for each well depends on its location);
- production wells were worked over whenever the water cut reached 30%;
- injection wells operate on voidage replacement, subject to a maximum pressure of 50 bars above the initial reservoir pressure.

The models were run for a total of thirty years if they were not stopped beforehand due to well controls. Further details of the development plans are given in Matthews *et al.* (2008).

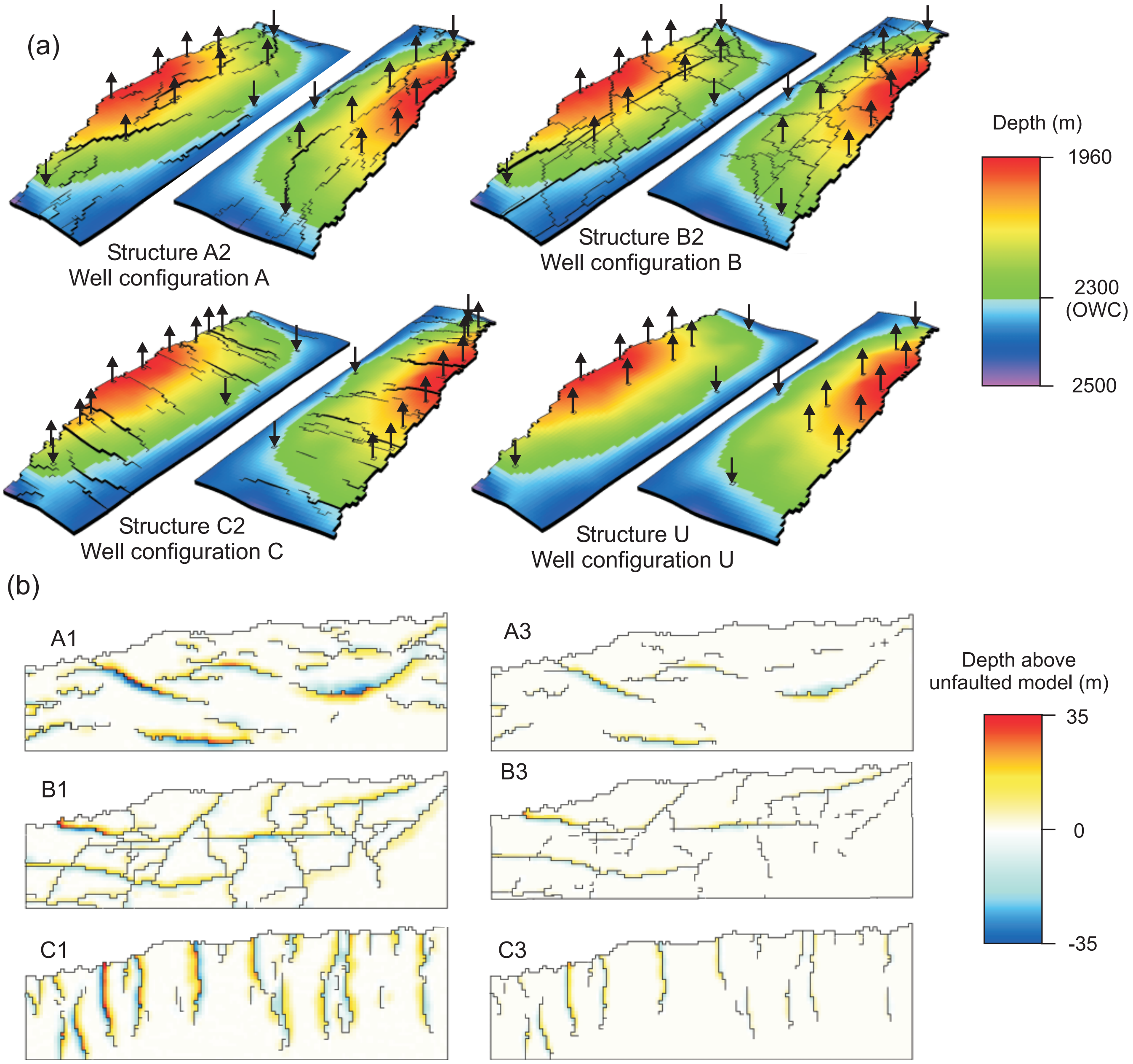

Fig. 5. (**a**) The intermediate fault density versions of the three basic fault structures and the common unfaulted end-member model. Each structure shows the well locations of the development plan designed around the structure. (**b**) The difference in depth between the top surface of the high (A1, B1, C1) and low (A3, B3, C3) fault density versions of each model and the unfaulted end-member.

Modelling tools

The modelling was performed on an almost completely automated assembly line involving four sites. The geological models were built and upscaled in Roxar's RMS software, making extensive use of the work-flow manager and internal scripting languages to ensure automation. Stand-alone software was written to model the clinoform surfaces, which could not be modelled in RMS. Fault transmissibility multipliers were calculated in the joint Badleys/Fault Analysis Group TransGen software for each faulted version of each upscaled sedimentological model. Modifications to the code were required for combining overlapping vertical transmissibility multipliers associated with faults and clinoforms, and for including more innovative factors, such as two-phase fault-rock properties and the effects of fault relay zones (Manzocchi *et al.* 2008*b*). In the upscaling satellite study (Stephen *et al.* 2008), the facies-scale models were prepared using Heriot-Watt's Geopseudo Toolkit and Schlumberger's Eclipse simulator. The full-field simulations were the rate-limiting part of the work flow and, following some tests of comparative run times, were performed using Roxar's More simulator on a 24-node cluster of Sun Ultra 5 workstations. The median run time was 5.5 hours and the simulation modelling took a total of 23.3 CPU years.

MODEL RUNS

The modelling was performed in three major phases (Table 3). In Phase 1, 81 sedimentological models, comprising combinations of three levels each of aggradation angle, shoreline curvature, barrier continuity and progradation direction, were combined with the unfaulted structure and each of the three faulted models sampled at three strain levels using three fault

Table 3. *Summary of the 35 241 models*

Model suite	Sedimentological models applied	Unfaulted models		Faulted models			
		Development plans used	Unfaulted simulations	Fault structure cases	Fault property cases[a]	Development plans used[b]	Faulted simulations
Phase 1							
Basic suite	81 (028–108)	4 (A,B,C,U)	324	9	3 (1,2,3)	4 (A,B,C,U)	8748
Alternative sedimentologies	27 (001–027)	4 (A,B,C,U)	108	9	3 (1,2,3)	4 (A,B,C,U)	2916
Alternative wells	81[c]	1(D)	81	9	3 (1,2,3)	1(D)	2187
Engineering pseudos[d]	18[c] (× 5)[e]	5 (A,B,C,D,U)	216	9	3 (1,2,3)	5 (A,B,C,D,U)	5832
Phase 2							
Barrier models	12 (109–120)	4 (A,B,C,U)	48	9	3 (2,4,5)	4 (A,B,C,U)	1296
Realizations	240 (121–360)	4 (A,B,C,U)	960	3[f]	1[f]	2 (U, ss)	1440
Zone thickness models	48 (361–408)	4 (A,B,C,U)	192	6[g]	3 (2,4,5)	1 (ss)	864
Fault property cases	9[h]	—	0	9	6 (0,4,5,6,7,8)	4 (A,B,C,U)	1944
Optimized plan	9[h]	1 (E)[i]	9	9	9 (0 to 8)	1 (E)[i]	729
Upscaling satellite							
Upscaling pseudos[d]	9[h] (× 54)[e]	1 (U)	297	9	5 (1,2,3,4,5)	1 (U)	5454
Fault upscaling[d,j]	9[h]	—	0	6[g]	3(0,2,5) (× 15)[e]	2 (U, ss)	1596

[a]The numbers in parentheses refer to codes of the SGR to permeability cases defined by Manzocchi *et al.* (2008*a*).
[b]'ss' in the development plan column means that the structure specific development plan is used.
[c]The sedimentological models used in these suites are selected from models 001 to 108.
[d]Only a selection of variable combinations have been run in the engineering pseudos, upscaling pseudos and fault upscaling suites. See Matthews *et al.* (2008) and Stephen *et al.* (2008) for details of the first two of these.
[e]The numbers in parentheses indicate the number of different upscaling cases considered.
[f]In the 'realizations' suite, a fault density and fault property level is chosen at random and applied to all ten realizations with the same basic sedimentological characteristics.
[g]The six fault models used exclude the intermediate fault density level of the three basic structures.
[h]These nine sedimentological models are the sub-set of the basic suite shown in Figure 6.
[i]The well locations for development plan E were optimized for sedimentological model 044 combined with structural model B2 and fault property case 5 (defined by Manzocchi *et al.* 2008*a*). Details are given by Carter & Matthews (2008).
[j]The fault upscaling suite involved prototyping several modelling innovations described with reference to a more focused set of models by Manzocchi *et al.* (2008*b*).

permeability predictors to give 3^4 unfaulted and 3^7 faulted reservoir models. Each of these 2268 geological models was flow simulated using the four development plans, to give a set of 9072 field production results. A further 11 340 sets of production results were also generated in Phase 1. These were either concerned with assessing the validity of assumptions made in selection of the grid-block pseudos (the 'engineering pseudos' suite, described by Matthews *et al.* 2008), or were run using sedimentological models or development plans that were subsequently replaced in the basic Phase 1 suite. Results from Phase 1 models are discussed by Manzocchi *et al.* (2008*a*), Matthews *et al.* (2008) and Skorstad *et al.* (2008).

Phase 2 focused on geological aspects not covered in Phase 1 or on unexpected aspects of the model responses from Phase 1, and many of the models use a limited suite of nine sedimentological models including only three of the variables addressed in Phase 1 (Fig. 6). Sets of models run in Phase 2 for which new sedimentological models were prepared included a suite with stronger sedimentological barriers, a suite based on sedimentological models with thicker and thinner parasequences and a suite containing up to ten different stochastic realizations of existing models. Additionally, a suite was run with a wider range of fault-rock permeability predictors applied to existing sedimentological models. Many of these results are discussed in conjunction with the Phase 1 results (see references above), and the specific topic of the different sedimentological realizations by Skorstad *et al.* (2005). A fifth Phase 2 suite addressed the performance of a development plan optimized to a specific geological model in producing from reservoirs with geological characteristics of varying similarity to the model for which it was optimized (Carter & Matthews 2008).

Sensitivity to upscaling issues was assessed in parallel to these two modelling phases. The reason for a parallel investigation of upscaling effects rather than fully integrating this topic into the main modelling programme was the requirement for an initial, fairly time-consuming, analysis to find the most significant small-scale upscaling variables to include with the larger-scale upscaling variables in the full-field simulation modelling. The final grid-block upscaling study (Stephen *et al.* 2008) included as variables the assumed lamina-scale single- and two-phase petrophysical properties, the algorithm used for the upscaling (e.g. Barker & Dupouy 1999), the inclusion or omission of anisotropic relative permeability curves and the accuracy with which the flow rate present in different model cells is included in the pseudoization. Fault upscaling assumptions considered the accuracy of the transmissibility calculation between partially juxtaposed grid-blocks, the inclusion of spatial variability in the fault zone property calculations, inclusion of two-phase fault-rock properties (e.g. Manzocchi *et al.* 2002) and inclusion of stochastic fault relay zones. Details of the kinds of factors considered are given in Manzocchi *et al.* (2008*b*).

The modelling followed a full factorial experimental design approach (complicated slightly by the existence of the unfaulted models), using three levels for the geological factors and four different development plans. A fractional factorial design would, in principle, have allowed identification of the relative importance of each factor with many fewer simulation runs (Box *et al.* 1978); however, a full factorial design was selected in preference for two main reasons. First, effects of interactions between factors were expected to be significant (e.g. Skorstad *et al.* 2008; Stephen *et al.* 2008) and this design allows assessment of all possible interactions. Secondly, formal statistical

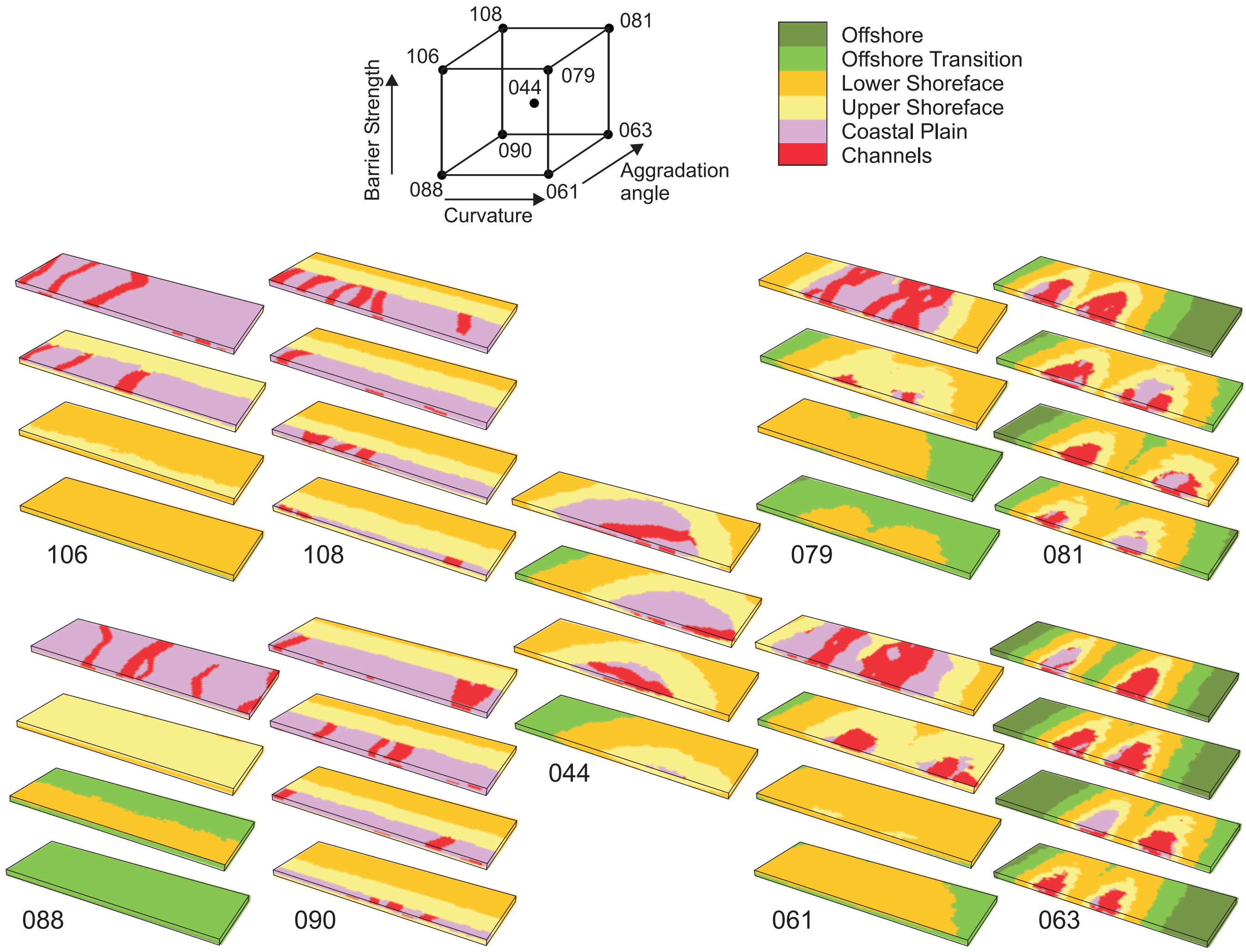

Fig. 6. The subset of nine sedimentological models used in many of the detailed Phase 2 or satellite studies (Table 3). All models contain four 20 m thick parasequences and have the same progradation direction (waterflood parallel to progradation direction and up sedimentological dip; i.e. direction 2). The facies in each parasequence are shown. Eight of the models have combinations of high and low levels of curvature, barrier strength and aggradation angle. The ninth model has intermediate levels of these (see the cubic matrix). The three-digit numbers are the model names.

factor analysis was not the only objective of the modelling and, for the less statistical and more physically based analyses (applied, for example, by Manzocchi *et al.* (2008*a*)), many model responses are required.

ANALYSIS

A consistent set of static and dynamic data from all models are retained for analysis. Grid-block properties of the static models (at both the geological model and simulation model scale) are retained in their entirety. The basic geological settings used to generate each model (e.g. the deterministic fault permeability predictor or the level of a sedimentological parameter) are retained, as well as any model or parasequence-specific parameters generated stochastically based on the probability density function (pdf) for the deterministic sedimentological level. Given the volume of data, it is impossible to store saturation and pressure in each grid-block at each time for each model, but since each model takes on average a few hours to run, single models were re-simulated and these data acquired where needed. Instead, field and well oil and water injection and production rates and pressures were output and stored at three-monthly intervals.

A summary of the production characteristics of the model reservoirs is given in Figure 7. Total recovery (Fig. 7a) ranges from *c.* 15–35 $\times 10^6$ m^3 (90–220 $\times 10^6$ stock tank barrels). Recovery factors (Fig. 7b) range from about 30% to 55%, with a modal value of 45%, typical of waterfloods in a shallow-marine environment (e.g. Fig. 2b). The modal field life is *c.* 20 years (Fig. 7c) and the production rates are comparable to similar-sized North Sea reservoirs (Fig. 7d). Total production was achieved with between 9×10^6 and 20×10^6 barrels produced per well, comparable with ranges for North Sea reservoirs (Thomas 1998).

Most of the analytical work focused on evaluating three field-wide, rather than well-specific, production indices. These are the total oil production of the reservoirs over their active life, the dimensionless recovery factor and a measure of the discounted value of the reservoir. The latter is a particularly useful measure of the performance of a reservoir, since it crudely includes economic factors by assigning a greater weighting to earlier production. The discounted value (in m^3) is defined by

$$V = \int_0^{30} (1 + a)^{-m} R_m dm,$$

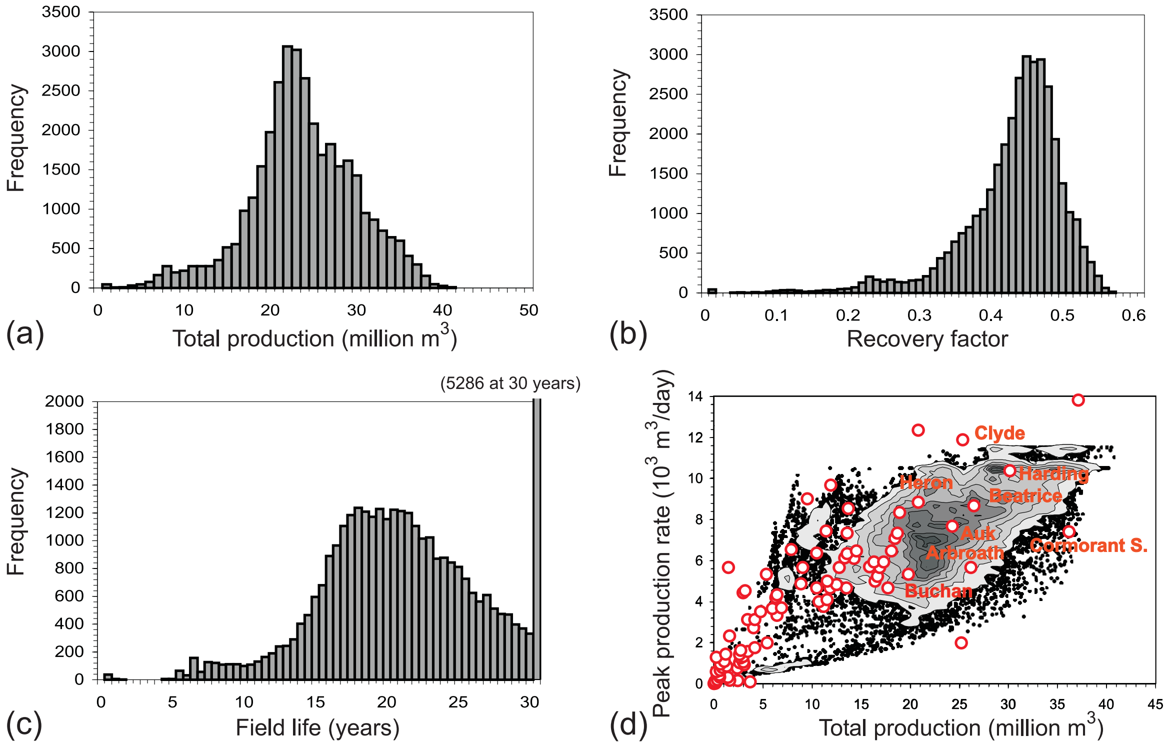

Fig. 7. Histograms of (**a**) total production, (**b**) recovery factor and (**c**) field life of all models. (**d**) A contoured joint pdf of peak production rate vs. total production for the models, with outliers indicated by small crosses. The large open circles show UKCS offshore oil fields (DTI 2001); those with comparable reserves to the SAIGUP models are indicated by name.

where R_m is the production rate at time m, and α is the discount factor. If a discount factor of 0.0 is used, then V is simply the total production of the reservoir. Most analyses have used a discount factor of 0.1, implying that oil produced in year m is 10% more valuable than oil produced in year $m+1$.

A variety of methods was used for analysis. The simplest is a visual inspection on a cross-plot. Figure 8 gives an example, showing recovery factor against stock tank oil initially in place (STOIIP) for the unfaulted, four parasequence models separated out by the three levels of each of the four basic sedimentological variables. This set of plots reveals several things, for example that the reservoirs with waterflood perpendicular to progradation (i.e. direction 0) or with low aggradation angles have lower than average STOIIP, that recovery factor is correlated with STOIIP, and that the strongest correlation is for the subset of models with parallel shorefaces. Visual inspection is a time-consuming approach to the data analysis and, although it can result in a good qualitative understanding of trends linking geological to production behaviour within the data, it is a fairly hit-and-miss process.

Quantitative measures of the relative importance of underlying parameters in a response can be obtained through factor analysis (e.g. Box *et al.* 1978). In this method the relative contributions of each underlying input parameter and each combination of parameters to the total variability in the production index is determined. The method has the advantage over the commonly used tornado plot deriving from one-factor-at-a-time experimental designs in that contributions of parameter combinations are also assessed. For example, Figure 9, which compares the sensitivity rankings of Skorstad *et al.* (2008) and Stephen *et al.* (2008) from analyses of models built using different but overlapping subsets of the total input variables considered, indicates that the curvature of the shoreface (e.g. Fig. 4f–h) has a more important control on the total oil production from the model reservoirs through its interactions with the aggradation angle than it has as an independent factor.

These analyses are entirely statistical in nature and aim to assess the sensitivity of reservoir responses to geological and engineering input variables. Results are specific only to the levels of variability in input parameters used, and cannot be extrapolated beyond. For example, Skorstad *et al.* (2008) show that for the Phase 1 suite of models the choice of fault permeability predictor is not a significant control on the total recovery from the models. However, Manzocchi *et al.* (2008*a*) show that the fault-rock properties significantly influence uncertainty in reservoir performance over a range of permeability not captured by the Phase 1 models. If the uncertainty in fault properties in a particular reservoir covers this relatively narrow (2 orders of magnitude) range, then it will be a much more significant variable than these results (Skorstad *et al.* 2008) indicate.

A further set of analyses aim to test the predictive capabilities of heterogeneity measures derived from the static models. The objective of such measures is that it should be possible to estimate them from known properties of a reservoir and that they should provide an index to likely reservoir behaviour in a general and transportable fashion. For example, Figure 10 assesses the correlation of two commonly used heterogeneity measures (the Lorenz and Dykstra–Parsons coefficients; see Lake & Jensen (1991) for details) with recovery factor for the 1392 unfaulted models. Both these parameters are derived as a function of properties measured in wells, and the coefficients measured at individual wells were averaged to define a single value per reservoir/development plan combination. It appears that the coefficients are discriminatory only in the sedimentologically more simple reservoirs (parallel shorelines, waterflood parallel to progradation direction) and the Lorenz coefficient performs better than the Dykstra–Parsons coefficient.

Two structural heterogeneity measures were found which parameterize effects of fault juxtaposition and fault-rock

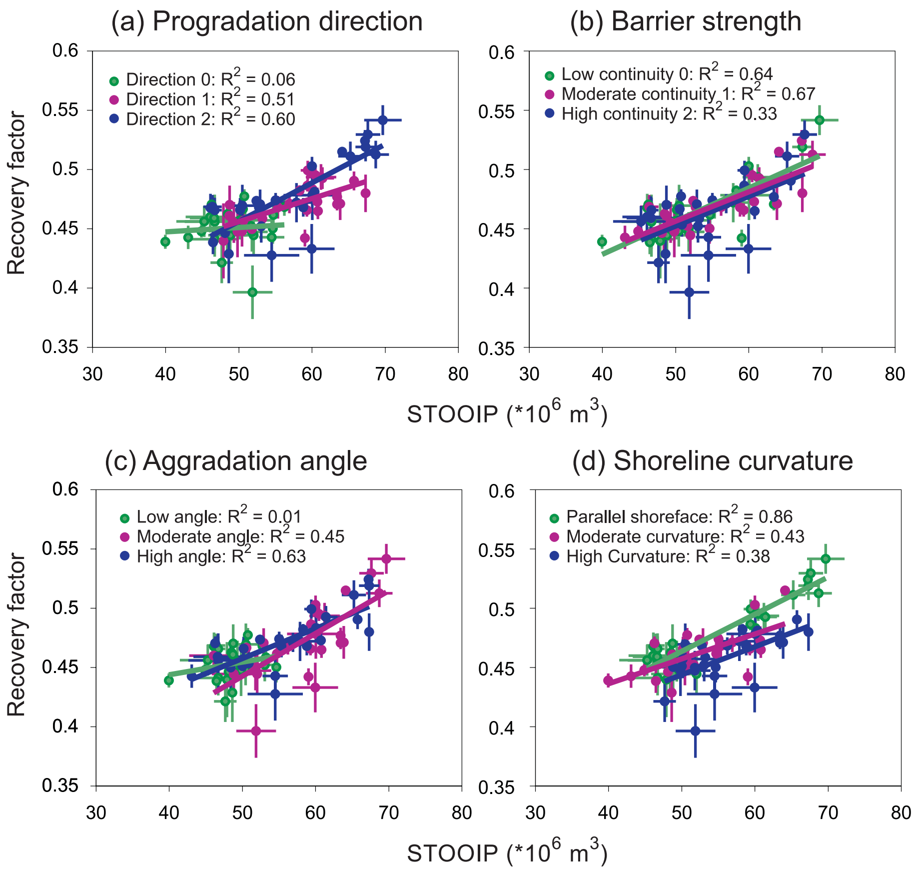

Fig. 8. Recovery factor vs. oil in place for unfaulted models. The circles indicate the average behaviour of between 4 and 48 realizations of each of the 81 sedimentological parameterizations considered in the Phase 1 modelling. These are subdivided by colour as a function of the three levels used for (**a**) progradation direction, (**b**) barrier strength, (**c**) aggradation angle and (**d**) shoreline shape. A best-fit linear correlation and Pearson's correlation coefficient (R^2) are reported for each series (this is for convenience only: a linear correlation is not necessarily expected or implied).

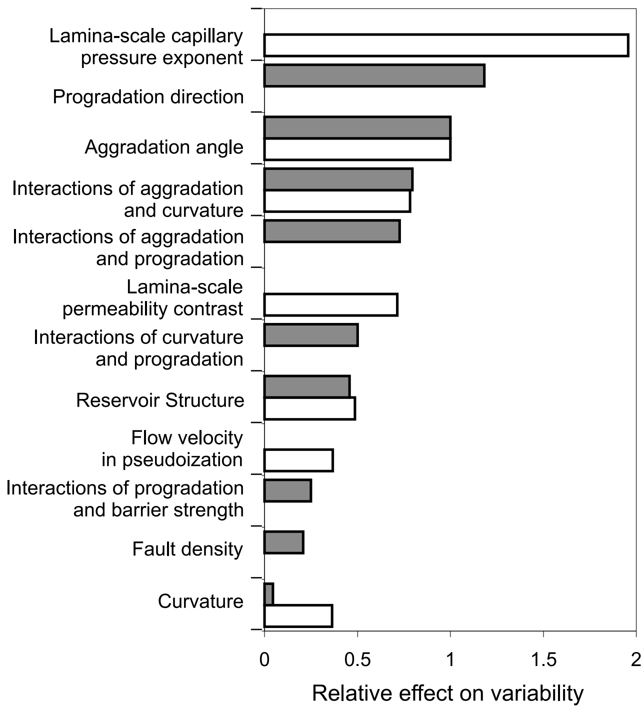

Fig. 9. Comparison between the most influential geological parameters or combinations of two parameters on the total oil production in the basic Phase 1 model suite (grey bars; Skorstad *et al.* 2008) and the upscaling model suite (white bars; Stephen *et al.* 2008). The relative effects in each analysis were normalized to the effect of aggradation angle (the highest-ranking parameter common to both analyses).

permeability within different sedimentological models, allowing rapid estimation of when faults are likely to be significant controls on field behaviour. These measures are described by Manzocchi *et al.* (2008*a*) and the discriminatory ability of one of them (called H_F) is shown in Figure 11. This figure compares the recovery factors obtained for 729 models (derived from faulted versions of nine basic sedimentological models) when using a development plan optimized for one single model, with those obtained when using the original development plan designed around the actual faulted structure present in each model (Carter & Matthews 2008). The development plan was optimized to a reservoir containing a particular sedimentological model, structure B faults and low fault permeabilities. Figure 11 shows that other structure B reservoirs perform well using this development plan across all sedimentological models for all three fault density levels provided they have similar heterogeneity factors ($1-H_F$ in the range 0.02 to 0.1). Most structure B reservoirs with more or less sealing faults, as well as structure A and C reservoirs, give better recovery when produced using the development plan originally designed around the faults. These results could be used to guide a hypothetical reservoir management decision. The improvement in recovery factor (for $1-H_F$ in the range 0.02 to 0.1) is not specific to either the sedimentological model or the strain level, but only to fault geometry. Therefore the optimized plan might be chosen if there is low uncertainty in fault-rock properties (and hence in H_F) since this plan is likely to provide superior recovery factors despite uncertainty in fault displacements or sedimentological architectures. However, if there is considerable uncertainty concerning fault-rock properties, then the original development plan would provide a lower risk option across the full uncertainty range.

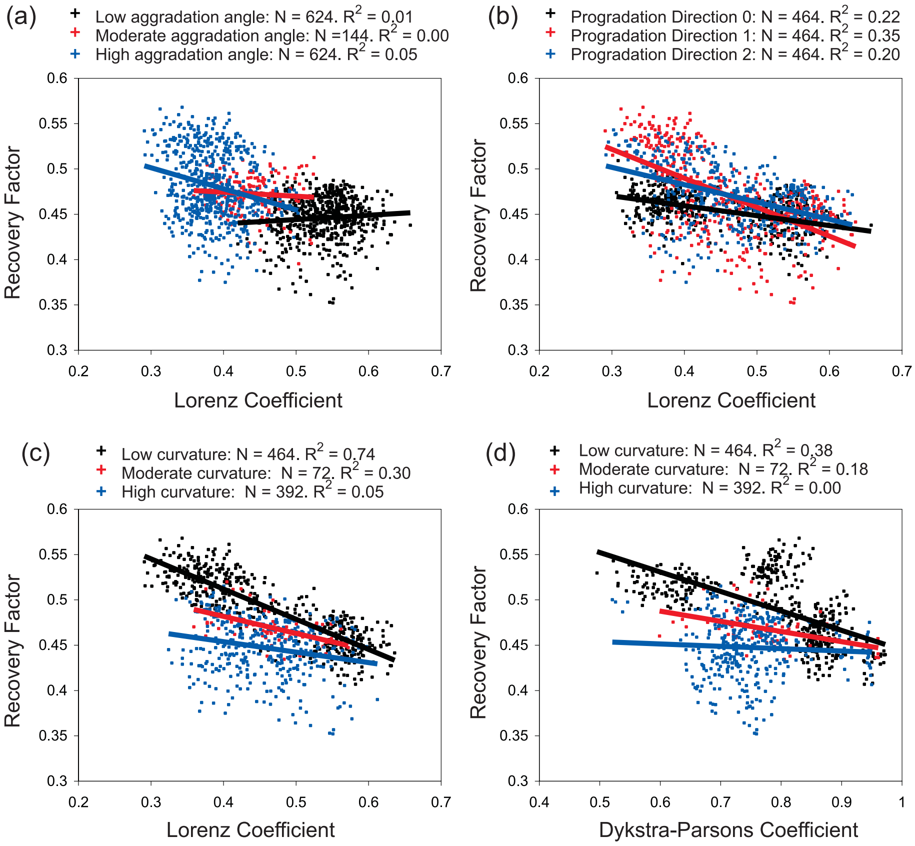

Fig. 10. Recovery factor for the 1362 unfaulted Phase 1 and 2 models shown in Figure 8, as a function of average Lorenz coefficient, separated by (**a**) aggradation angle and (**b**) progradation direction. (**c**) The results for progradation directions 1 and 2 (i.e. waterflood parallel to depositional dip) as a function of shoreline curvature. (**d**) As (c), but for the Dykstra–Parson's coefficient. Pearson's linear correlation coefficient (R^2) is reported for each series.

DISCUSSION AND CONCLUSIONS

The SAIGUP study generated field production profiles for over 35 000 distinct shallow-marine reservoir models as a function of differences in sedimentology, structure, upscaling and well configurations. The focus throughout was on modelling realistic reservoirs and all the models could be accurate representations of possible geological systems. This was an original objective of the study and, in the view of the majority of the authors, increases the relevance of the results and of existing and subsequent analyses based upon them. The minority view is that the systems generated are simply too complex for formal analysis, and the project should therefore have concentrated on parametrically more simple models.

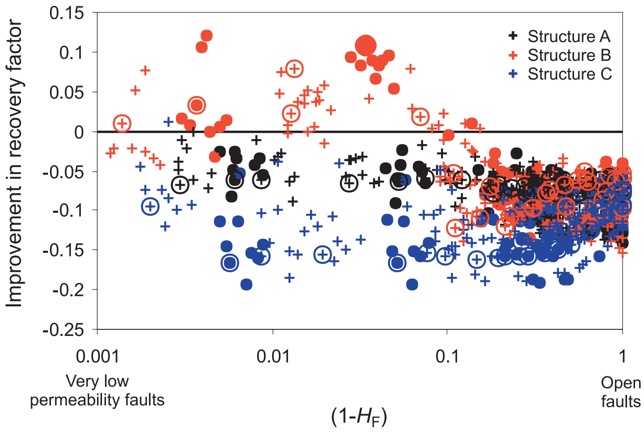

Fig. 11. Improvement in recovery factor obtained when using a development plan optimized for a single model as opposed to the plan designed around the particular structure present (i.e. A, B or C), for 243 reservoirs with each structure, as a function of a fault heterogeneity factor (H_F). The development plan was optimized on the basis of maximizing the recovery factor of the single, relatively low fault permeability structure B reservoir indicated by the larger filled circle (Carter & Matthews 2008). Reservoir models sharing the same sedimentological models are indicated by large circles filled by crosses, while reservoirs sharing the same fault density level are indicated by smaller filled circles. Reservoirs with neither parameter in common are shown as crosses. See text for discussion.

This paper serves as an introduction to the modelling described in more detail in the other papers in this thematic set. It has described the rationale and overall objectives of the modelling and provided summaries of both the geological and engineering input used in the modelling and of the analytical methods applied. Table 3 summarizes the scope of the synthetic modelling. Many possible unknowns or variables were not included in the modelling.

- Petrophysical properties. The same, facies-dependent, petrophysical properties (Table 1) were used in all models. The sensitivity to uncertainty in these properties (including intra-facies K_v: K_h ratios) is therefore unknown.
- Single-phase grid-block upscaling. Whilst variable methods for two-phase upscaling were applied, a single method was used to determine the directional absolute grid-block permeabilities.
- Fluid properties. These are constant throughout, as is the general recovery mechanism.
- Gross reservoir structure. Although different fault systems were modelled, they are all contained in the same basic tilted fault-block with the same overall reservoir dip and gross rock volume.
- The development plans include only vertical wells and, with the exception of the optimized one, are not guided by specific reservoir sedimentological characteristics.
- The basic parasequence architecture. The largest sedimentological compromise made is modelling all sequences as constant thickness, parallel-bounded zones.

Further modelling studies tied into this existing parameter space, investigating the influence of some or all of the above factors, would certainly be of value. By necessity many compromises were required from all disciplines in this study which has concentrated principally on geological rather than engineering aspects of reservoir production. An issue associated particularly with the upscaling work is the absence of truth-cases. Whereas the differences in production forecast obtained from running the same model with a variety of upscaling methods meets our objectives by providing an uncertainty on the forecast as a function of the methods, the relative accuracy of the methods cannot be established without high resolution flow modelling.

The few examples of analyses presented in this introductory paper (Figs 8–11) have combined results presented individually in the other papers. The suite of analyses (Carter & Matthews 2008; Manzocchi 2008*a*, *b*; Matthews *et al.* 2008; Skorstad *et al.* 2008; Stephen *et al.* 2008) assessed the sensitivity of reservoir performance to five large-scale and two small-scale sedimentological variables, three fault-related variables, three assumptions made in the sedimentological upscaling process, three classes of assumptions made in the representation of the faults, and to the locations of the wells in the development plans. Except in fault-compartmentalized reservoirs, variability in sedimentary variables at both the small and large scale dominates uncertainty in total oil production, but structural aspects of the reservoirs are as important as sedimentological ones in terms of recovery factors. The most important large-scale sedimentary variables are the aggradation angle and (at higher aggradation angles) the progradation direction, while the shape of the capillary pressure is the most important small-scale factor examined. Fault permeability is a significant variable only over a two-order of magnitude range. In fault-compartmentalized reservoirs, fault permeabilities and the presence of potentially unbreached relay zones are critical.

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