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Impact of Stratigraphic and Sedimentological Heterogeneity on Hydrocarbon Recovery in Carbonate Reservoirs

By

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A report submitted in partial fulfillment of the requirements for the MSc and/or the DIC

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Declaration of own work

I declare that this thesis:

Impact of Stratigraphic and Sedimentological Heterogeneity on Hydrocarbon Recovery in Carbonate Reservoirs

is entirely my own work and that where any material could be construed as the work of others, it is fully cited and referenced, and/or with appropriate acknowledgement given.

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1 Abstract

High resolution models were constructed to represent a range of different types of heterogeneities, identified from published examples and constrained to Jurassic carbonate outcrops near the village of Amellago in the High Atlas Mountains of Morocco. These models were used in conjunction with experimental design techniques to rank the impact of a series of stratigraphic heterogeneities on flow in carbonate reservoirs. We have developed a series of flow simulations under pattern drive water flooding, to assess two different approaches to modelling imbibition relative permeability and capillary pressure, where the first approach uses only one set of curves for the whole reservoir, and the second uses three curves, assigned to different parts of the reservoir, on the basis of vertical permeability. Additionally we evaluated how using mobility ratios (for example contrasting oil viscosities) impact the results. A key finding is that variation in porosity and permeability values predominantly control the oil recovery and time to break through. In most cases, the same significant heterogeneity impact flow, regardless of the imbibitions modelling approach and mobility ratio used. The results are applicable to other similar carbonate reservoirs.

2 Introduction

Carbonate reservoirs host a significant amount of world's hydrocarbon reserves. In the Middle East region alone, carbonate reservoirs hold approximately 60% of the petroleum reserves. Carbonate reservoirs contain numerous stratigraphic, sedimentological and diagenetic heterogeneities. Although these complexities might be below the resolution of seismic images, they may still result in a non-uniform fluid flow in the reservoir, and subsequently have a significant impact on the recovery of hydrocarbons (Ghedan *et al.* 2010).

Published work on geostatistical analysis of permeability data in carbonate outcrops by Jennings *et al.* (2000) largely investigated pore-scale heterogeneities in carbonate reservoirs. It reports that, permeability data from Permian dolomitized shallow-water platform carbonate outcrops, situated in west Texas and New Mexico, show two to five orders of magnitude variability, most of which occurs within distances of 1 to 2 m , also a variety of longer-range features are observed, including vertical inter-bed average-permeability contrasts, lateral periodicities and trends. Stochastic two-dimensional areal and vertical cross-section models were used to investigate these heterogeneities. Simulation results from this study demonstrates that some long-range characters control overall flow behaviour even though when short-range variability composes most of the variance. The short-range heterogeneities however produce local smearing of displacement fronts.

In contrast Bourne *et al.* (2000) focused on field-scale heterogeneities in carbonate reservoir, where a semi-deterministic method is presented to systematically predict the spatial distribution of natural fractures and their effect on flow simulations. These predictions are associated with noticeably reduced uncertainty since the models are constrained and validated with seismic, borehole, well test and production data. Several examples show the success of this method, thus there is a high degree of predictability in the properties of natural fracture networks.

Work by Borgomano *et al.* (2008) points out, that the process of stratigraphic well correlations is vital for carbonate reservoir modelling and must be adapted to geological factors that control the distribution of rock properties, the spatial heterogeneity of the reservoir, the well spacing, and the objectives of the reservoir model. The most significant error is created when the stratigraphic rules force unrealistic spatial correlations of random noise sampled in the wells. Lithostratigraphic rules may be applied in a situation where the average well spacing is less than the lateral dimensions of critical sedimentary objects, if the average well spacing exceeds these object dimensions ,in that case, sequence-stratigraphic rules are more valid.

Simple modeling techniques were used by Labourdette *et al.* (2008) to present a workflow which enables sedimentologists to deterministically integrate their interpretations and concepts into the reservoir characterization workflow. This workflow incorporates sedimentological uncertainty on heterogeneity distribution, leading to generation of a 3D proportion cube, which is a unique output and may act as an input for various facies distribution methods (e.g. TGS, SIS or Object-based) without any corruption of initial inputs. Then geostatistical methods maybe used to populate these results with petrophysical properties. Integration of deterministic modeling with stochastic or geostatistic models provides useful solutions to the main challenges of reservoir modeling, the construction of 3D geologically realistic representation of heterogeneity and the quantification of uncertainty through the generation of, not one, but a variety of possible models or ‘realizations’.

Ghedan *et al*. (2010) studied thief zones under variable levels of reservoir heterogeneity in carbonate reservoirs, aiming to aid reducing water-cut, increasing well productivity and oil recovery. It was learnt that thief zones will perform similarly regardless of their location in the reservoir stack of layers, and layers with high permeabilities will not act as thief zones if the ratio of their permeability to the average reservoir permeability is approximately 1.5 or less. Moreover it was found that variation in API gravity of oil does not considerably affect the performance of thief zone and for any thief zone’s horizontal permeability, water-shut-off (WSO) treatment would be more effective with lower k_v:k_h values.

Carbonate reservoirs have been extensively discussed in the literature within the context of reservoir modeling, however due to their numerous intrinsic complex heterogeneities, carbonate reservoir characterization and modeling remains an important challenge for the petroleum industry. Therefore it is vital to identify which heterogeneities have an impact on production.

The overarching aim of this project is to investigate the impact of a series of stratigraphic and sedimentological heterogeneities on flow in carbonate reservoirs. The results will aid reservoir engineers to have a better prediction of production behavior (in similar reservoirs) and therefore optimize the reservoir operating conditions to achieve the maximum oil recovery. The specific objectives are:

1. To identify the key geologic heterogeneities that impact on flow, and to understand why these heterogeneities are important.
2. To investigate whether the same key heterogeneities are identified in different production scenarios.

The outcrop analog chosen to constrain the models used in this project is situated in the eastern High Atlas Mountains of Morocco, 5 km to the NW of the village Amellago that is located approximately 30 km north of Goulmina. (Figure 1)

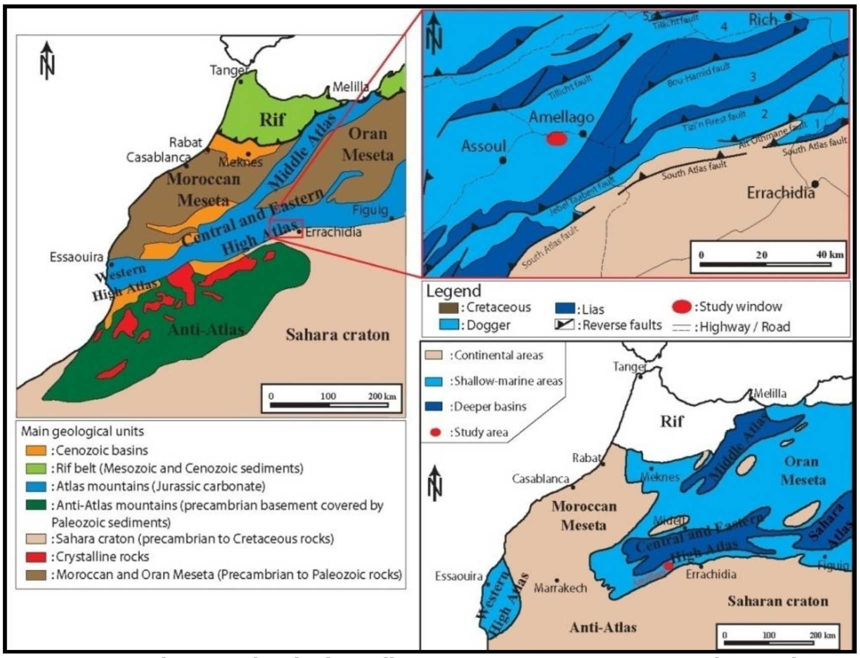

Figure.1. Outcrop location, The Island; Amellago, Morocco; Jurassic succession, Christ *et al.* 2011

Published work on the Assoul Formation of the Amellago outcrop has focused on detailing the sedimentological architecture of the succession (for example Christ *et al.* 2011). To gain an understanding of larger-scale geometries, associated with the outcrop, published result from the underlying Amellago Formation (Pierre *et al.* 2010) have been used in conjunction with a forward stratigraphic model (CARB3D$^+$). CARB3D$^+$ is a process-based 3D forward model which simulates sedimentary facies, geometries, and early diagenesis of isolated carbonate platforms in a sequence stratigraphic context. Paterson *et al.* 2008 used CARB3D$^+$ to investigate the sensitivity of platform architecture to various fundamental controls.

3 Methodology

3.1 Reservoir Modelling

3.1.1 Geologic heterogeneity in the reservoir and hierarchical approach

A variety of stratigraphic, sedimentological and diagenetic heterogeneities occur across the Jurassic carbonate ramp analog of the Amellago outcrop. These heterogeneities occur across a wide range of length scale, from field to pore scales, and their architecture and distribution depends upon the depositional environment. Using a hierarchy of heterogeneities, based on the length scale of the features within the system, enables us to conduct a top down reservoir modeling approach, where we start with a simplest model and then gradually add increasing levels of heterogeneity. Such a hierarchy is shown in figure 2, each of these levels are constituted of different heterogeneities as tabulated in appendix B1.

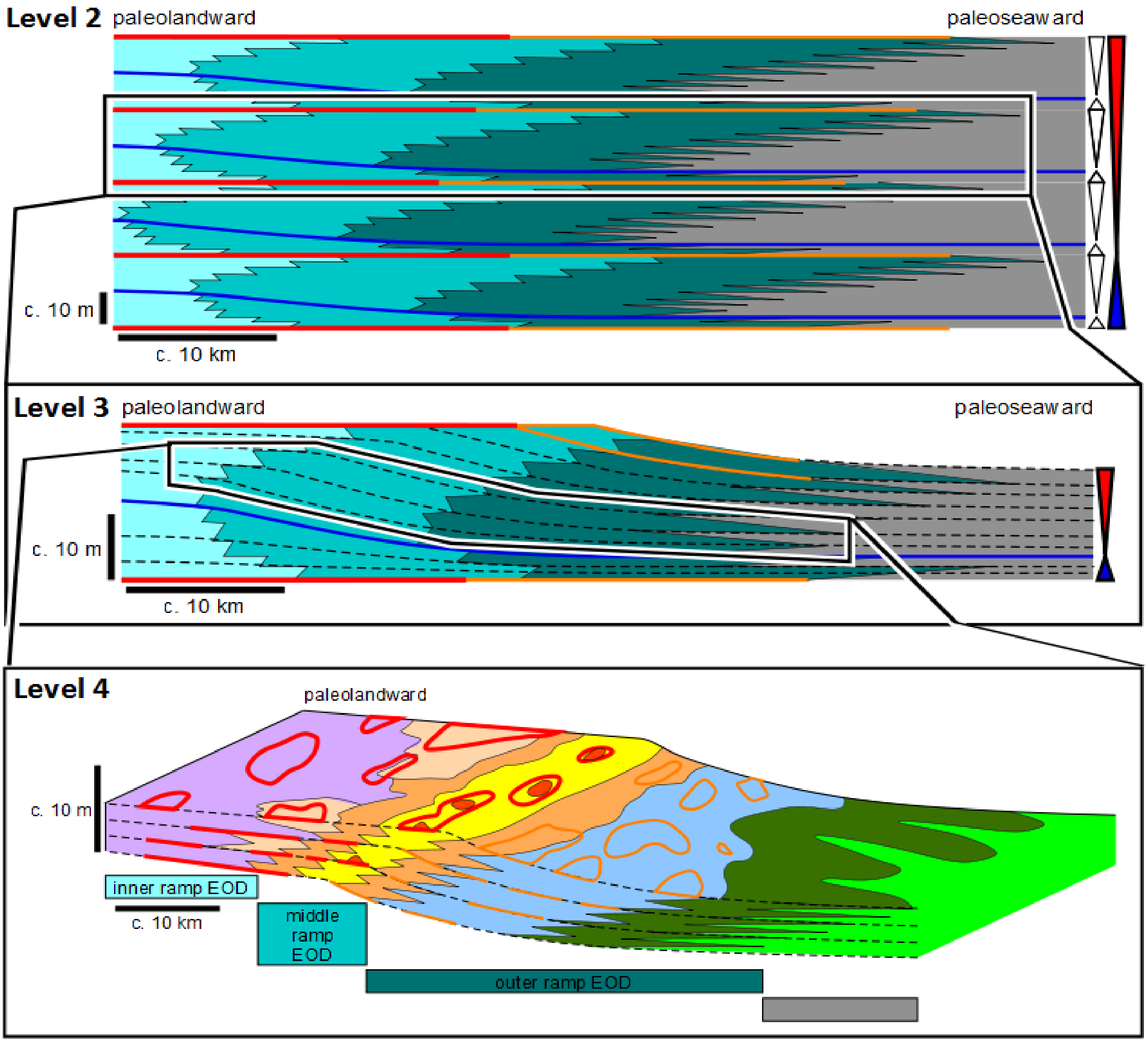

Figure.2.Hetrogeneity hierarchy in carbonate reservoir (modified from Fitch *et al*. 2011a).

3.1.2 Data base

Models are not merely based on a dataset from part of the reservoir; rather they are designed to be generic. They are constructed based on a conventional modeling in conjunction with surface-based modeling techniques; this allows an accurate and efficient representation of heterogeneities. Flow simulation of a series of "nested" models at different length scales will enable us, to identify heterogeneities, which lie below seismic resolution and within inter-well volumes, and investigate their impact on oil recovery.

3.1.3 Model description

This project was conducted on high resolution models that have been built as part of a large research framework, four EOD's are documented in the model; lagoon, mid ramp, outer ramp and pelagic (indicated in figure 3). These models are constructed to represent a range of specified heterogeneities, identified from published examples and constrained to an outcrop analog and associated forward modelled stratigraphic framework.

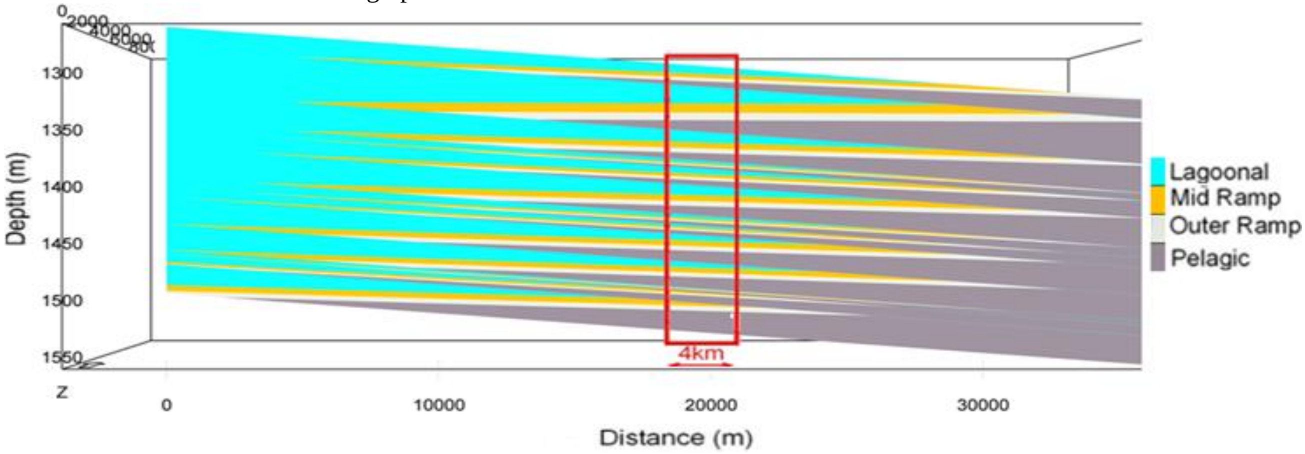

Figure.3. Reservoir cross section, showing four EOD types, across the reservoir. Red box indicates the section that was extracted from a larger model, to constrain the models used in this project (modified from Fitch *et al*. 2011b).

This project focuses predominantly on stratigraphic heterogeneities, we analyse the impact of selected heterogeneity on water displacement, using a simulation based sensitivity analysis. Six key heterogeneities, in different levels, were chosen for examination (Figure 4).

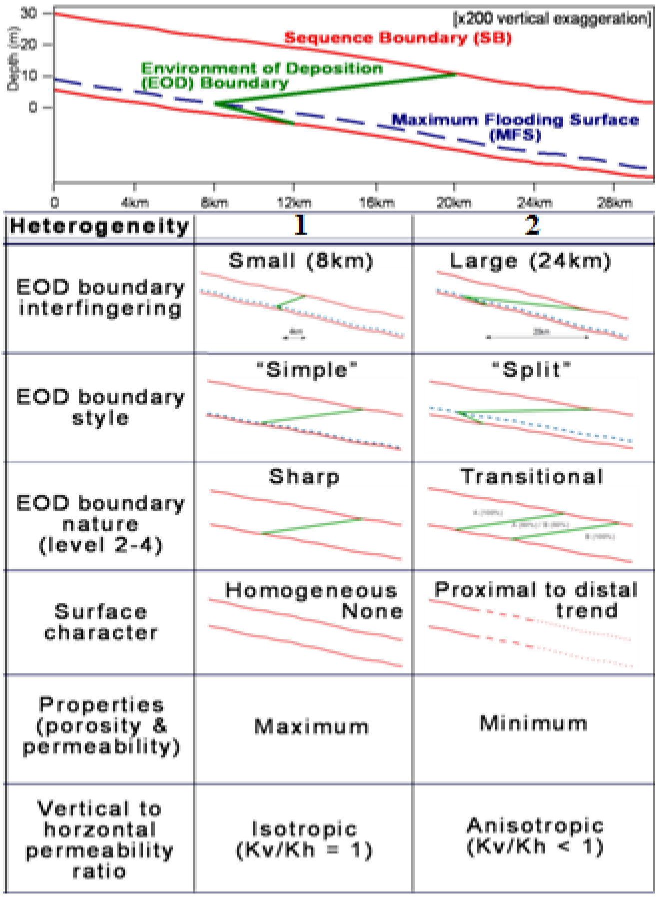

Figure.4.Conceptual models of the modeled heterogeneities. The first column from left shows factors (heterogeneities) analysed in this study. The impact of each heterogeneity on the response was investigated when each factor is varied from setting 1 to setting 2. EOD – environment of deposition, SB – sequence boundary, MFS – maximum flooding surface (modified from Fitch *et al*. 2011b).

3.1.4 Key heterogeneities and settings

Carbonate ramp systems are commonly presented throughout the geological record, however there are very few areas which have seismic-scale, continuous and structurally unreformed outcrops, allowing reliable interpretation of facies distributions and stacking patterns (Pierre *et al.* 2010).Therefore in terms of carbonate reservoir modelling, the challenge is to link the heterogeneities measured at well and core scales to the spatial heterogeneities at flow unit and reservoir scales. Seismic data and well correlations are the only possible connections between these two scales. The inherent complexity of the carbonate reservoir at all scales (from pore network to stratigraphic architectures) makes it essential to concentrate stratigraphic well correlation efforts on the level of reservoir heterogeneity, which matters in terms of reservoir and flow units (Borgomano *et al.* 2008). The selected stratigraphic heterogeneities and their origins are described below.

3.1.4.1 Environment of deposition (EOD) boundary interfingering length

The length of the EOD boundary interfingering ranges from hundreds of meters to tens of kilometres, we have decided to focus on two end-member types; (setting 1) 8km long and (setting 2) 24km long. (Borgomano *et al.* 2002; Pierre *et al.* 2010; Vennin *et al.* 2003). Mid ramp and lagoon have a much higher porosity and permeability values than the other EODs (as stated in table 1) and therefore are considered to have a higher reservoir quality. The 8km EOD boundary interfingering contains more of the lagoon and mid ramp section compare to the 24km EOD boundary interfingering and hence has a higher quality of reservoir.

3.1.4.2 Environment of deposition (EOD) boundary style

Two settings are defined for the style of boundaries introduced between environments of deposition. Setting 1 has a simple linear boundary prograding between two sequence boundaries (Asprion *et al*. 2009; Handford & Baria 2007; Kenter *et al.* 2009; Purkis *et al.* 2005; Verwer *et al.* 2009; Williams *et al.* 2011), and in setting 2 the boundary is split in two by a maximum flooding surface (MFS) so that retrogradation occurs below the MFS and progradation above it (Asprion *et al.* 2009; Pierre *et al*. 2010; Williams *et al.* 2011).

3.1.4.3 Surface character

In terms of surface character a sequence boundary (SB), can either take setting 1, having no properties different to the under- or overlying sediments, or setting 2 where low porosity and permeability values are assigned so that the surface acts as a barrier to flow. This heterogeneity is modelled to account for the presence of hard ground surfaces and can be considered to be thin well cemented layers (Christ *et al.* 2011; Pomar *et al.* 2001). Surface properties in setting 2 may act as a barrier to vertical flow in the reservoir.

3.1.4.4 Environment of deposition (EOD) boundary nature

The EOD properties may change sharply at an EOD boundary (setting 1), or this change can be gradational / transitional (setting 2). This transitional boundary is modelled across a length of 300m, which is representative of small scale inter-fingering documented in published examples which is not explicitly included in these stratigraphic-scale models (Asprion *et al.* 2009; Pierre *et al.* 2010; Williams *et al*. 2011). Moving from one side of boundary to the other, in setting 1, the quality of the reservoir abruptly changes from low (e.g. outer ramp) to higher (mid ramp) whilst in case 2 we have an extra “medium” reservoir quality, in the transitional region, meaning that setting 2 has a marginally higher reservoir quality than setting 1.

3.1.4.5 Porosity and Permeability

Setting 1 is grain-dominated (more than 50% grain) and has a high porosity and permeability, whereas setting 2 is mud-dominated (less than 20% grain) and possess low porosity and low permeability values (indicated in table 1, denoted by High and Low).

3.1.4.6 Permeability anisotropy

Sedimentary structures such as lamination and cross-beddings may introduce anisotropy in permeability (Choi *et al.* 2011). We have setting 1 which is isotropic (k_v:k_h =1), while setting 2 is anisotropic where k_v:k_h ratio is less than one (table 1). Procedure of computation of the high and low, porosity and permeability values and also permeability anisotropy outlined in appendix B2.

Environment of Deposition (EOD)				**Properties**							
				High[2]				Low[3]			
					$K_h = K_v$ (mD)	K_h (mD)	K_v (mD)		$K_h = K_v$ (mD)	K_h (mD)	K_v (mD)
No	Name		Lithology and sedimentary structure[1]	Porosity	Permeability	Perm X & Y	Perm Z	Porosity	Perm	Perm X & Y	Perm Z
1	Lagoon	Semi-restricted ramp	Bioclastic wackestone, packstone and framestones; Low to medium bioturbation; presence of micritization and microencrustation.	0.21	122	318	47	0.02	64	166	24
2	Mid Ramp	High energy ramp	Packstone, grainstone and floatstone-rudstone; Ooids, peloids and bioclastic components; Cross-bedding, encrustation and spary cements dominate.	0.38	2900	4240	1970	0.18	574	841	392
3	Outer Ramp	Marly open ramp	Marl, carbonate mudstone and wackestone; localised bounstone; bioclastic and peloidal grain components; low to medium bioturbation; rhythmic terrigenous sediment input.	0.17	0.70	3.0	0.21	0.001	0.17	0.58	0.05
4	Pelagics	Pelagics	Marl and shale dominated	0.11	0.06	0.15	0.02	0.0001	0.003	0.01	0.001

Table.1.Porosity and permeability values assigned to EODs, [1]Summary from Amour et al. (2011), [2]High properties may be considered to be grain-dominated, [3]Low properties may be considered to be mud- dominated.

3.1.5 Experimental Design

We applied experimental design (Box *et al.* 1987; Christopher *et al.* 2003) to analyse the simulation results of a number of different scenarios, looking to identify the key heterogeneities and quantify their impact on flow. A two-level fractional factorial design was conducted, where each factor (heterogeneity) can take one of two settings, denoted 1 and 2 in figure 4. The experimental design enables us to efficiently quantify the impact of changing each factor from setting 1 to setting 2. As mentioned in section 3.1.3 six heterogeneities were selected to be investigated in the screening studies (figure 4); this gives us 2^6=64 scenarios to investigate. A 2^{6-3} resolution IV experimental design is used to quantify the impact of each heterogeneity on production. This experimental design requires 8 simulation experiments. Table 2 summaries 8 models that are chosen to be investigated based on the experimental design.

	Models							
Factor (heterogeneity)	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**
1.EOD Boundary interfingering length	Large (24km)	Large (24km)	Large (24km)	Small (8km)	Small (8km)	Large (24km)	Small (8km)	Small (8km)
2.EOD Boundary Style	Split Linear (SB-MFS-SB)	Split Linear (SB-MFS-SB)	Simple Linear (SB-SB)	Simple Linear (SB-SB)	Simple Linear (SB-SB)	Simple Linear (SB-SB)	Split Linear (SB-MFS-SB)	Split Linear (SB-MFS-SB)
3. Surface Character	Barrier (proximal to distal trend)	None	None	None	Barrier (proximal to distal trend)	Barrier (proximal to distal trend)	None	Barrier (proximal to distal trend)
4.EOD Boundary nature	Transitional	Transitional	Sharp	Transitional	Transitional	Sharp	Sharp	Sharp
5.Porosity & Permeability values	Low	High	High	Low	High	Low	Low	High
6.Permeability anisotropy	K_v:K_h<1 (anisotropic)	K_v:K_h=1 (isotropic)	K_v:K_h<1 (anisotropic)	K_v:K_h<1 (anisotropic)	K_v:K_h=1 (isotropic)	K_v:K_h=1 (isotropic)	K_v:K_h=1 (isotropic)	K_v:K_h<1 (anisotropic)

Table.2. Six stratigraphic heterogeneities investigated. The columns, numbered 1 to 8 show different models that will be analysed. EOD – environment of deposition, SB – sequence boundary, MFS – maximum flooding surface.

The number of grid blocks, size and STOIIP of each model is presented in table 3.

Model	STOIIP (billions bbl)	Number of grid blocks(i,j,k)	Reservoir length, laterally (m)	Reservoir top datum depth(m)	Reservoir bottom datum depth(m)	Reservoir thickness(m)
1	0.5	60×60×321	4km×4km	1284	1515	231
2	3.3	60×60×305		1284	1515	231
3	4.2	60×60×76		1290	1516	226
4	1.6	60×60×170		1284	1514	230
5	5.1	60×60×176		1284	1514	230
6	0.9	60 ×60 ×92		1285	1516	231
7	0.8	60×60×144		1306	1528	222
8	3.7	60×60×156		1304	1528	224

Table.3. Models and their characteristics.

Based on the average value of STOIIP, obtained from each of the 8 models, it was decided to place 20 producers and 16 injectors using a pattern drive mechanism, as indicted in figure 5. The well spacing between the producers is set to be at 800 m whereas the spacing between the producer and injector is set at 400 m. Water injection rate for each well was specified to be constant and at approximately 12,600 bbl/day, whereas liquid production rate (per well) was set to be around 10,000 bbl/day. The oil water contact was set to be at the bottom most part of model and under the reservoir (at a depth of 1800 m).

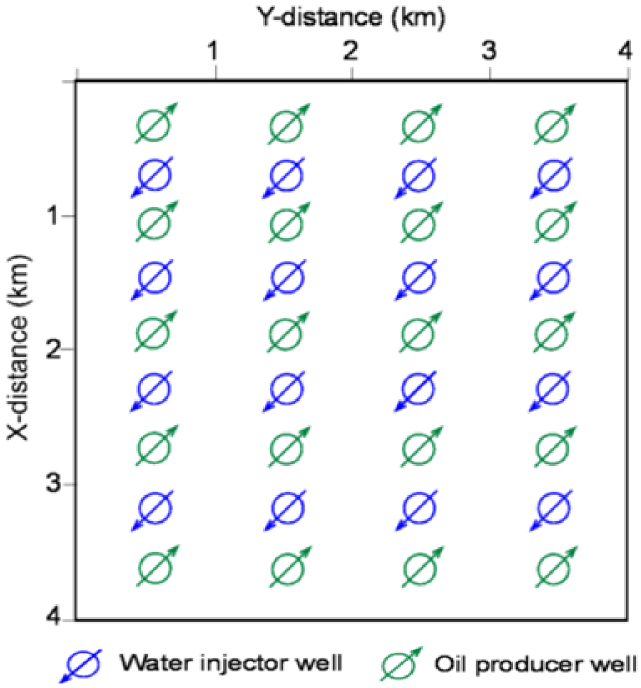

Figure.5.Well placement on the models (top view)

In order to prevent fracturing the reservoir by water flooding, a pressure boundary condition was used to define flow such that the pressure drop between the producer and a injector lies within 0.03 -0.14 bar/ft (0.5-2 psi/ft). Therefore to comply with this pressure drop range, the minimum bottom hole pressure of the producers were set to be 155 bar (2250psi) which is 3 bar (50 psi) above the oil bubble point pressure (ensuring that no gas is evolved from solution). Bottom hole pressure, upper limit, of the injectors was set to be 245 bar (3562psi).

3.2 Reservoir simulation strategy

3.2.1 Development strategy and Assumption

It was decided to include hysteresis in simulations; it enables us to specify different saturation functions for drainage (decreasing wetting phase saturation) and imbibition (increasing wetting phase saturation) processes. The primary drainage curve is for a process which starts at the maximum possible wetting phase saturation, Sw_{max}. If the wetting phase saturation decreases to Sw_{min}, this primary drainage curve is used. In a similar way, if the initial saturation is Sw_{min}, and the wetting phase saturation increases to Sw_{max}, the imbibition data will be used. The drainage capillary pressure curves are used for

equilibration but the simulation advances using the imbibition relative permeability and capillary pressure curves. For water flooding, two different approaches were used to model imbibition relative permeability and capillary pressure. The first approach uses only one set of curves for the whole reservoir, and the second uses three curves, assigned to different parts of reservoir, on the basis of permeability (outlined in sections 3.2.3 and 3.2.4 respectively). The same drainage capillary pressure and relative permeability was used to initialize the model (outlined in section 3.2.2). Production was simulated assuming incompressible flow and no dissolved gas in the oil, using the fluid and reservoir properties summarised in tables 4 and 5 respectively. (The equations and parameters used to obtain all the plots shown in sections 3.2 are presented in appendix B3).
Moreover, to evaluate how using contrasting mobility ratios (for example different oil viscosities) impact flow, two different oil viscosities, namely 0.52 centipoise and 4 centipoise were used in our simulations.

Fluid properties		
	Oil	Water
Density (kg/m3)	850	950
Viscosity (centipoise)	0.52 or 4[1]	0.36
Bubble point pressure (bar)	152	
Formation volume factor (rm^3/sm^3)	1	1
Compressibility (1/bar)	1×10^{-4}	3×10^{-5}

Table.4. Fluid properties. [1] Oil viscosity can either be 0.52 cp or 4.0 cp depending upon the mobility ratio used in the simulation.

Reservoir properties	
Pressure (bar)	206
Temperature (Fahrenheit)	250
Rock compressibility (1/bar)	5×10^{-6}
Wettability	Intermediate oil-wet

Table.5. Reservoir properties

3.2.2 Water-oil primary drainage

Sw_i were assigned, based on gravity equilibrium, using oil-water drainage capillary pressure (figure 6A). Corey equations were used to define oil-water drainage relative permeability (figure 6B).

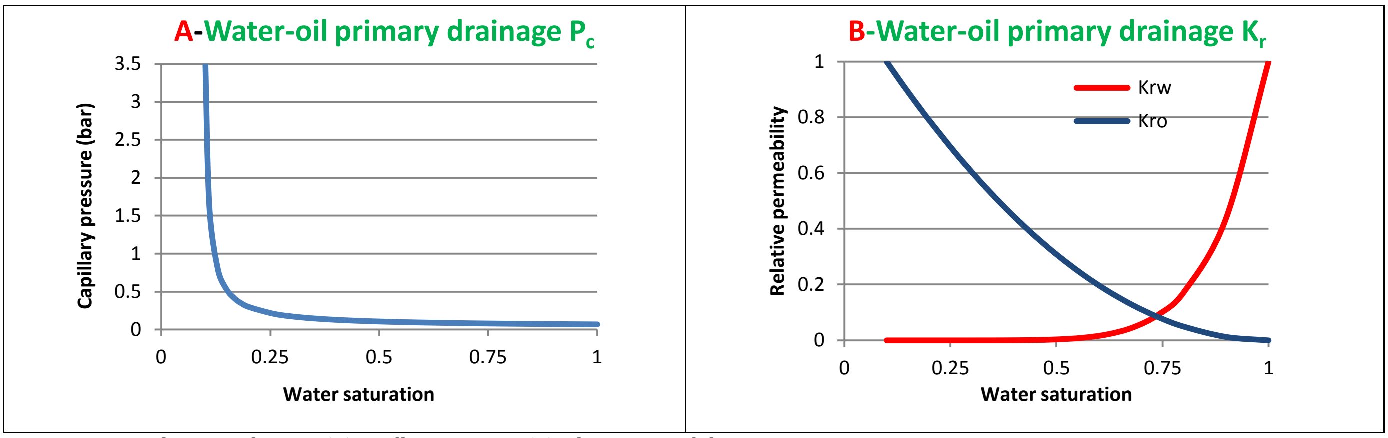

Figure.6. Water-oil primary drainage (A) capillary pressure , (B) relative permeability

3.2.3 Single set of curves imbibition modelling approach

In this approach, one set of curve for capillary pressure (figure 7A) and relative permeability (figure 7B), water-oil imbibition were assigned for the whole reservoir.

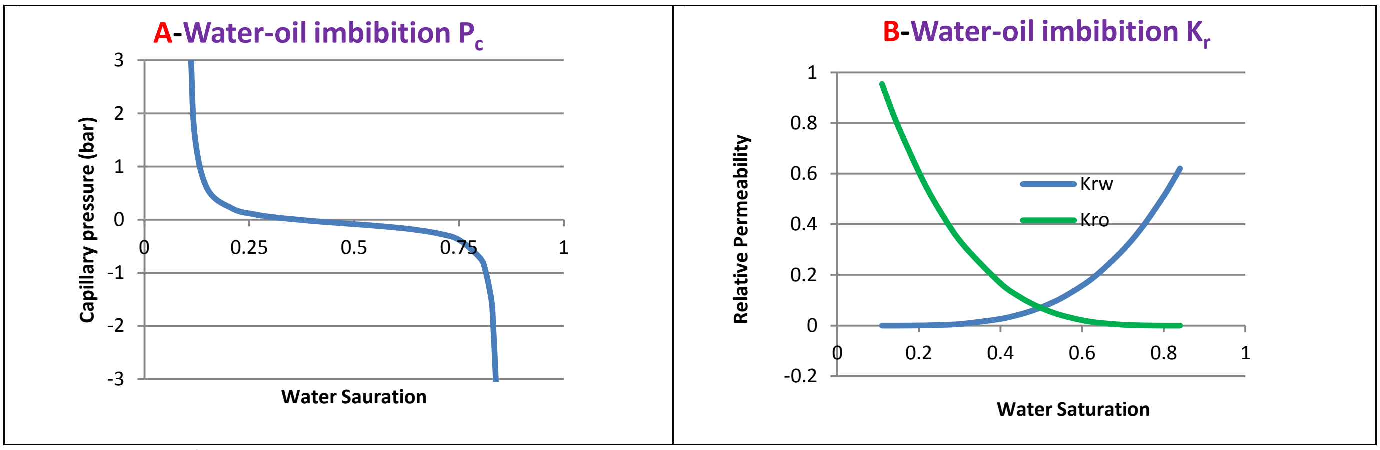

Figure.7. Single set of imbibition curves (A) capillary pressure , (B) relative permeability

3.2.4 Three sets of curves imbibition modelling approach

In this approach, the reservoir was divided into 3 main groups, based on permeability, (1.low group: permeability<10mD; 2.moderate group: permeability 10-100 mD and 3. high group: permeability >100 mD). Capillary pressure (figure 8A) and relative permeability (figure 8B) water-oil imbibitions were assigned based on grouping.

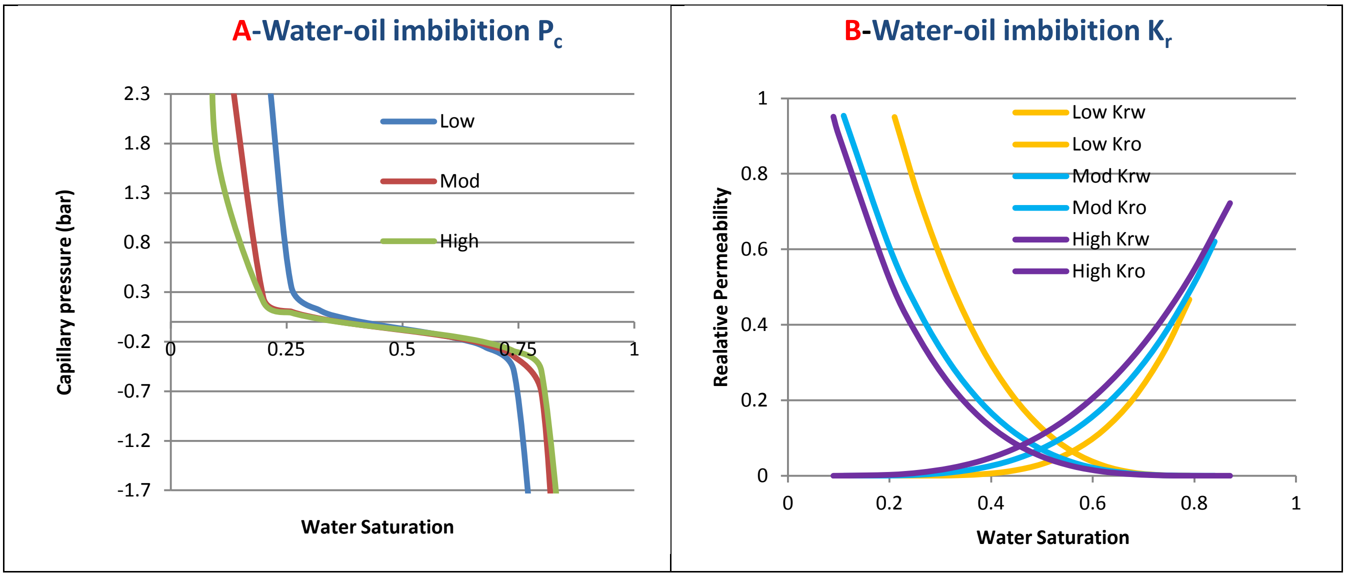

Figure.8. Multiple imbibition curves modelling approach (A) capillary pressure , (B) relative permeability

4 Results

We have found that model 5 shows the highest oil recovery, approximately 1.5 billion barrels (after 30 years) and the longest time to break-through, nearly 7 years (reaching a filed water-cut of 1%). Recovery factor ranges from 26 to 58%. The total oil recovery and water-cut as a function of time for each of the 8 simulation experiments can be observed in figure 9.

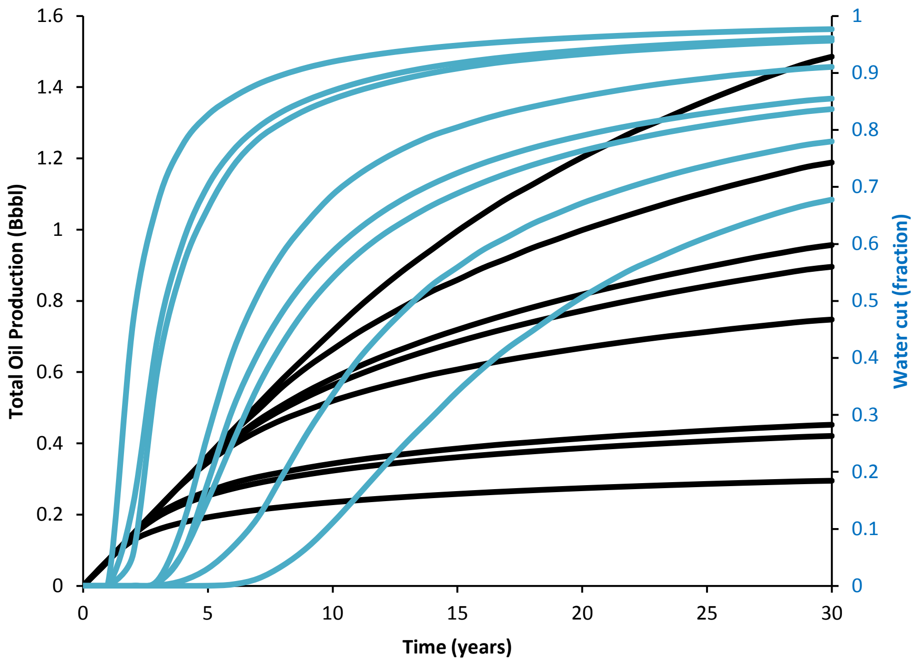

Figure.9. Oil recovery (black curves) and water-cut (blue curves) as a function of time for each of the 8 simulation experiments, using a single set of imbibition curves for the whole reservoir and oil viscosity of 0.52 cp.

The production results (oil recovery, oil recovery factor, field total water produced, time to breakthrough) for different simulation scenarios have been presented below.

Models	Water produced after 30 years (billions of barrels)	Oil recovery after 30 years (millions of barrels)	Time to break-through (1% water-cut) years	Oil recovery factor (%)
Model 1	1.9	295.1	1	58
Model 2	1.3	895.6	3.2	27
Model 3	1.0	1188.3	4	29
Model 4	1.4	747.6	3	47
Model 5	0.7	1485.9	6.8	29
Model 6	1.7	452.3	1.8	53
Model 7	1.7	420.7	1.4	54
Model 8	1.2	957.0	3.2	26

Table.6 Production results from single imbibition curves modelling approach and oil viscosity of 0.52 cp

Models	Water produced after 30 years (billions of barrels)	Oil recovery after 30 years (millions of barrels)	Time to break-through (1% water-cut) years	Oil recovery factor (%)
Model 1	1.9	312.1	1.2	61
Model 2	1.2	1008.9	4.0	30
Model 3	1.2	1327.7	5.3	32
Model 4	1.4	802.1	3.6	50
Model 5	0.5	1623.5	8.8	32
Model 6	1.7	479.6	2.1	56
Model 7	1.7	446.3	1.6	57
Model 8	1.1	1073.7	4.0	29

Table.7. Production results from multiple imbibition curves modelling approach and oil viscosity of 0.52 cp

Models	Water produced after 30 years (billions of barrels)	Oil recovery after 30 years (millions of barrels)	Time to break-through (1% water-cut) years	Oil recovery factor (%)
Model 1	1.9	219.8	0.6	43
Model 2	1.6	613.9	1.6	18
Model 3	1.3	831.6	2.6	20
Model 4	1.6	541.6	2.2	34
Model 5	1.1	1054.3	3.9	21
Model 6	1.8	331.8	1.0	39
Model 7	1.9	310.4	0.8	40
Model 8	1.5	660.4	1.7	18

Table.8. Production results from single imbibition curves modelling approach and oil viscosity of 4 cp

Models	Water produced after 30 years (billions of barrels)	Oil recovery after 30 years (millions of barrels)	Time to break-through (1% water-cut) years	Oil recovery factor (%)
Model 1	1.9	240.4	0.7	47
Model 2	1.5	712.7	2.2	21
Model 3	1.2	971.7	3.7	23
Model 4	1.6	603.8	2.1	38
Model 5	1.0	1211.5	5.4	24
Model 6	1.8	365.2	1.3	43
Model 7	1.8	341.3	1.1	44
Model 8	1.4	771.7	2.3	21

Table.9. Production results from multiple imbibition curves modelling approach and oil viscosity of 4 cp

In order to investigate, how different approaches of modeling imbibitions relative permeability and capillary pressure, impact our results, we compared the production results from a scenario where one set of capillary pressure and relative permeability curves is used for the whole reservoir with a situation where three set of curves, assigned to different parts of reservoir, on the basis of permeability.

Water produced after 30 years	Time to breakthrough (1% field water-cut)

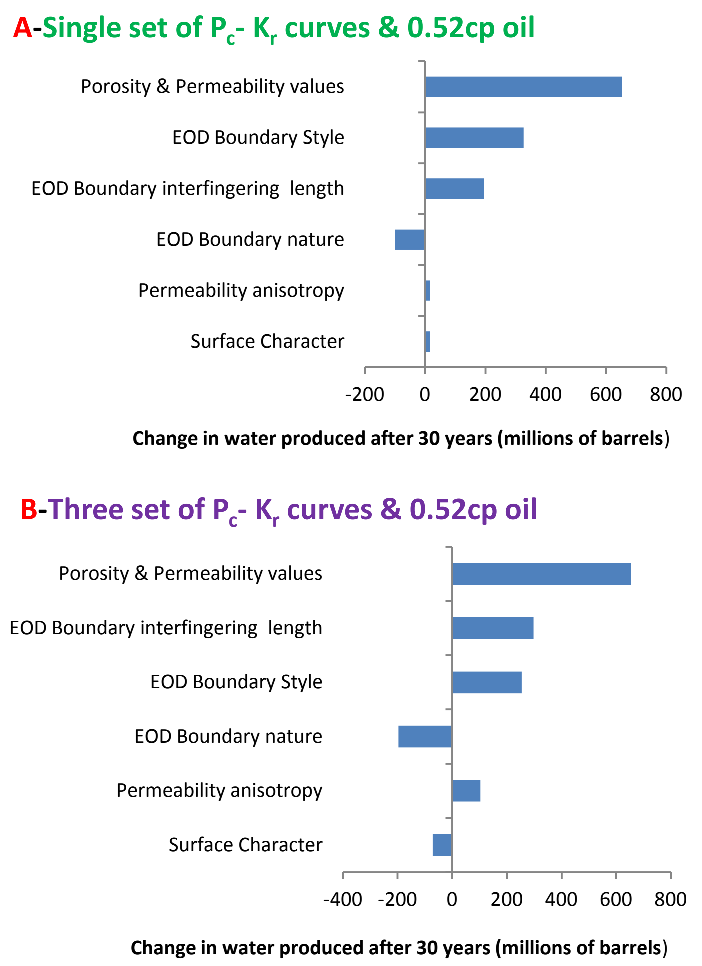

Figure.10. Change in water produced after 30 years for (A) imbibition modeled using one set of p_c and k_r curves for the whole reservoir and (B) imbibition modeled using three sets of p_c and k_r curves ,observed when each factor in the sensitivity analysis is varied from setting 1 to setting 2 (figure 4). If the bar lies to the right then the change is positive.

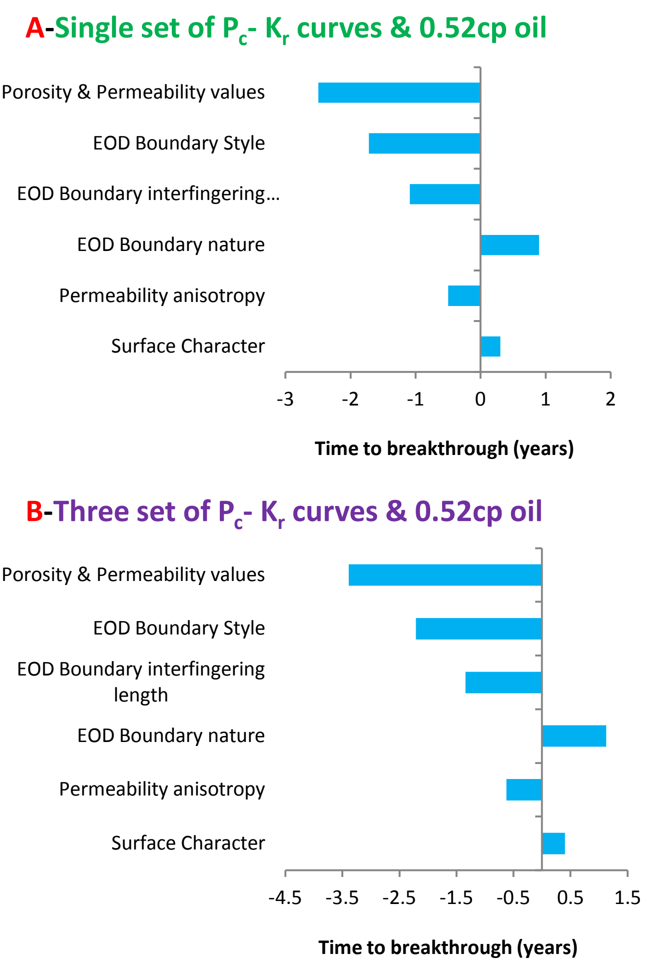

Figure.11. Change in time to breakthrough (time to reach a field water-cut of 1%) for (A) imbibition modelled using one set of p_c and k_r curves for the whole reservoir and (B) imbibition modelled using three sets of p_c and k_r curves.

Variation in porosity-permeability values has the largest impact on field water produced for both imbibition modeling approaches (figure 10A and 10B). Using three set of curves, varying the EOD boundary nature decreases the field total water produced by approximately 200 million barrels (figure 10B) while this variation, in one set of curves, decreases water production by only around 100 million barrels (figure10A).Varying permeability anisotropy from setting 1 to setting 2 increases water production by around 20 million barrels when using a single set of curves (figure 10A) but by100 million barrels when using multiple curves (figure 10B).

A sequence boundary (in terms of surface character) may vary from setting 1 , having the same properties as the under- or overlying sediments, or setting 2 where zero porosity and permeability values are specified so that the surface acts as a barrier to flow. Therefore one might expect that variation of surface character from setting 1 to setting 2 reduces the water production. Nevertheless we found that this variation increases the water production when using single set of curves modeling approach (figure 10A) though causes a decrease in water production in three set of curves modeling approach (figure 10B). We observe that the same heterogeneity that lies to the left of the graph in figure 11B, lie to the right of the graph in figure 10B, and vice versa.

This is due to the fact that heterogeneities that increase the production of water decrease the time to breakthrough, and heterogeneity that decrease the production of water, result a longer breakthrough time. Variation in porosity-permeability values, EOD boundary style and interfingering length, respectively, have the most significant impact on the time to breakthrough, for both imbibitions modeling approaches (figures 11A and 11B). Other heterogeneities have less impact on time to breakthrough.

Oil recovery factor after 30 years

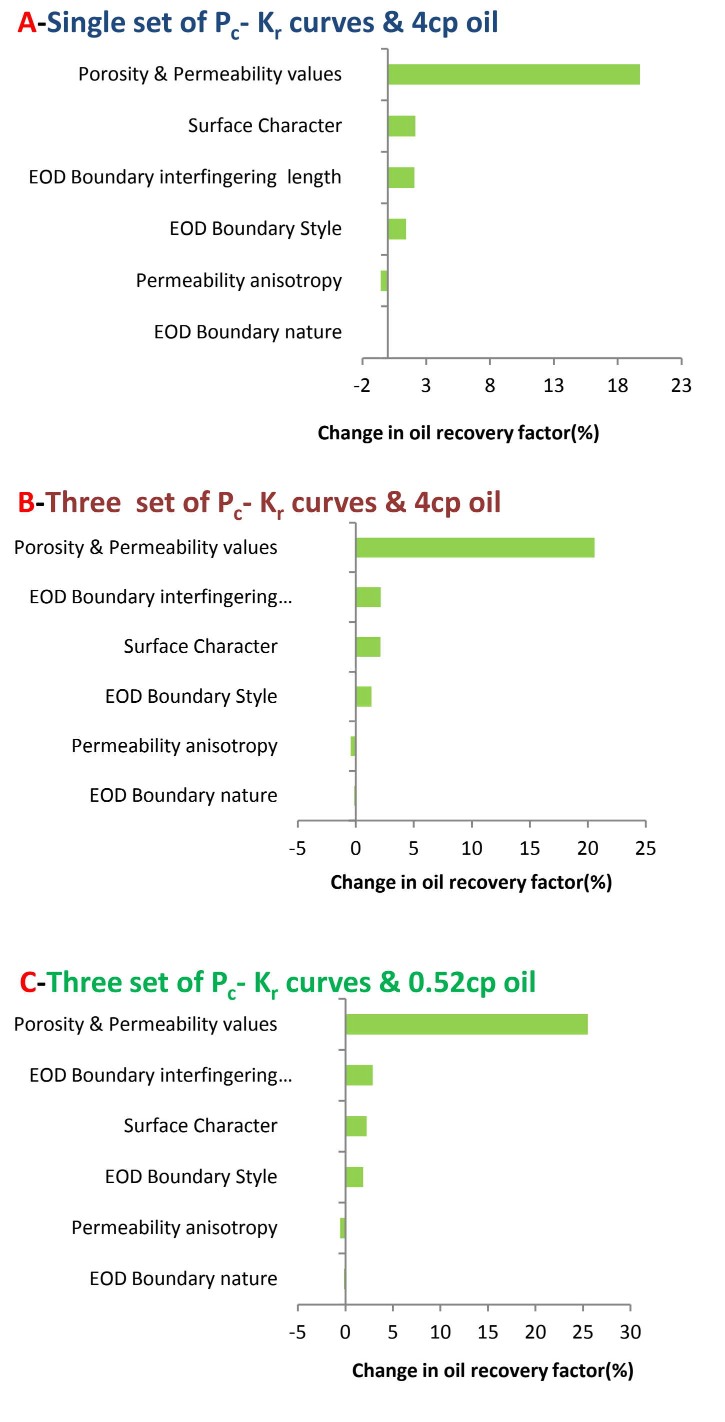

Figure.12. Change in oil recovery factor after 30 years for (A) imbibition modelled using one set of p_c and k_r curves for the whole reservoir and oil viscosity of 4cp, (B) imbibition modelled using three sets of p_c and k_r curves and oil viscosity of 4cp and (C) imbibition modelled using three sets of pc and k_r curves and oil viscosity of 0.52cp.

Oil recovered after 30 years

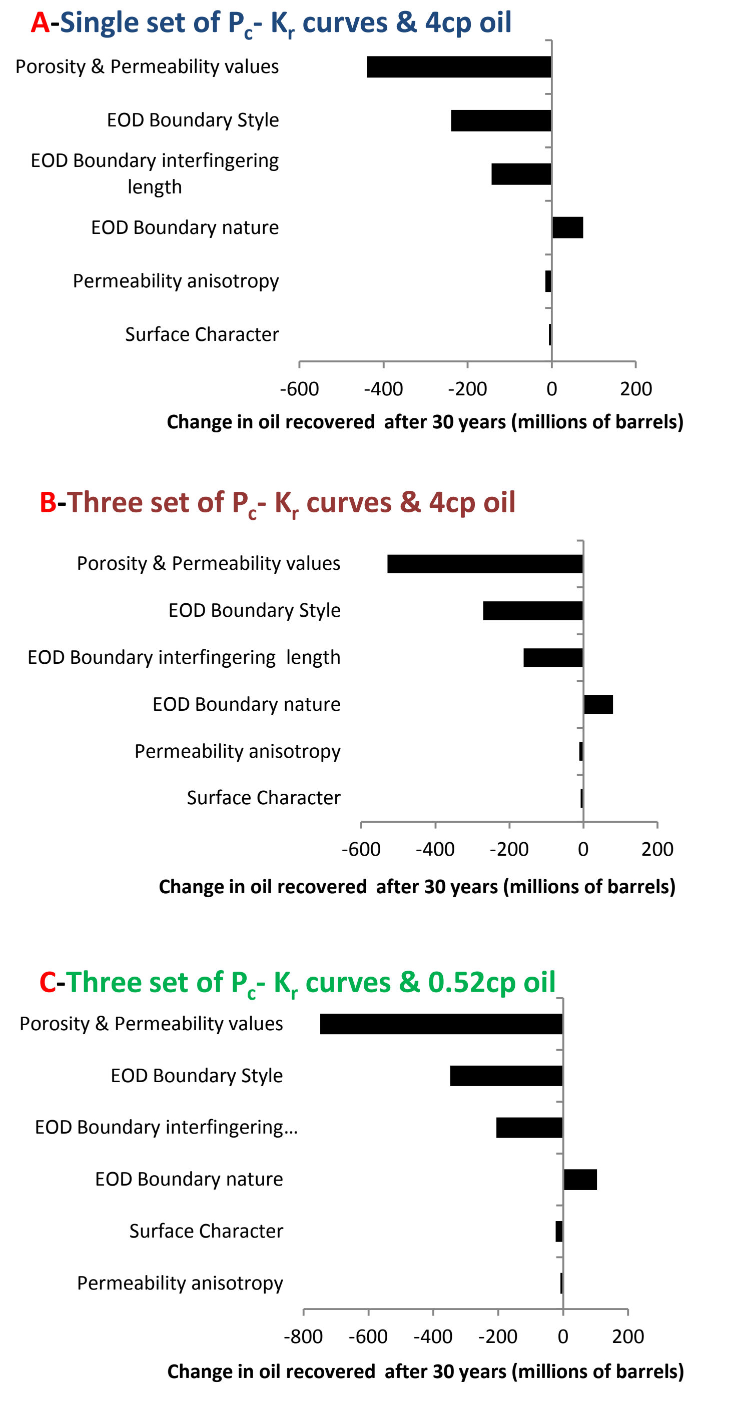

Figure.13. Change in oil produced after 30 years for (A) imbibition modelled using one set of p_c and k_r curves for the whole reservoir and oil viscosity of 4cp, (B) imbibition modelled using three sets of p_c and k_r curves and oil viscosity of 4cp and (C) imbibition modelled using three sets of pc and k_r curves and oil viscosity of 0.52cp.

Varying the porosity and permeability value from setting 1, grain dominated and having high property values to setting 2, mud-dominated and comprising low property values, oil recovery is decreased, due to lower oil volume in place. This is observed for both imbibitions modelling approaches (figure 13A and 13B). However when using one set of curves, variation of the porosity and permeability values decreases the oil recovery by approximately 400 million barrels(figure 13A), whereas this variation decreases the oil recovery by around 500 million barrels when using three sets of curves (figure 13B).

In terms of EOD boundary nature, in setting 1, when moving from one side of boundary to the other, the quality of the reservoir sharply changes from low (e.g. outer ramp) to high (mid ramp) whilst in setting 2 we have an extra “medium” reservoir quality, in the transitional region, meaning that setting 2 model has a marginally higher reservoir quality than setting 1.Therefore varying EOD boundary nature from setting 1 to setting 2, increase the oil recovery regardless of imbibitions modelling approach (figure 13A and 13B). All other heterogeneities have similar impact on oil recovery in both cases.

Variation of porosity and permeability values, EOD boundary style and EOD boundary interfingering length from setting 1 to setting 2 decreases the oil recovery (figure 13B), thus one might expect to observe a decrease in recovery factor due to these variations in figure 12 B, however we have to bear in mind that these variation also have an impact on the value of STOIIP. Therefore although for example variation in porosity and permeability value decreases the oil recovery, this variation increases the recovery factor because STOIIP is decreased.

The variation in oil recovery factor for both imbibition modeling approaches is again principally controlled by the variation of porosity-permeability values from setting 1 to setting 2 (figure 12A and figure 12B). EOD boundary interfingering length is the second most significant heterogeneity in figure 12B and the third in figure 12A. Variation in permeability anisotropy (from isotropic to anisotropic) decreases the oil recovery factor, in both imbibition modeling approaches. Generally it appears that regardless of the imbibition modeling approach, heterogeneities have a very similar impact on oil recovery and oil recovery factor.

Furthermore, to evaluate the impact of using contrasting mobility ratios (for example different oil viscosities) on oil production and oil recovery factor, two different oil viscosities, namely 0.52 centipoise and 4 centipoise were used in our simulations.

In spite of using different mobility ratios, in both cases oil recovery factor is predominantly controlled by variation in porosity-permeability values (figures 12B and 12C). When the porosity and permeability values were varied from setting 1 to setting 2, using oil viscosity of 4cp , the oil recovery was decreased by around 550 million barrels (figure 13B) while this variation caused a much higher decrease in oil recovery, 750 million barrels, when using 0.52cp oil, (figure 13C). The second most significant impact on oil recovery is EOD boundary style in both cases followed by EOD boundary interfingering length.

As outlined previously, four environments of deposition (EODs) are assigned in the model, each having different properties occurring across the reservoir, mid ramp and lagoon dominantly have much higher values of porosity and permeability than the other EODs and therefore are expected to have a higher reservoir quality. EOD boundary interfingering length setting 1 (8km long) posses more of the lagoon and mid ramp section compare to the 24km EOD boundary interfingering, therefore varying EOD boundary interfingering length from setting 1 to setting 2, less oil is recovered, due to poorer quality of the reservoir, regardless of the mobility ratio (figures 13B and 13C).

Varying permeability anisotropy from setting 1 to setting 2, using oil viscosity of 4cp, oil recovery reduces by approximately 11 million barrels, whilst this variation causes only around 8 million barrels decrease in oil recovery when using oil viscosity of 0.52 cp (figures 13B and 13C).

5 Discussion

Which stratigraphic heterogeneities control flow?

In our study production results revealed that variation of porosity and permeability, predominantly has the greatest impact on responses (oil recovery, oil recovery factor, water produced and time to breakthrough) compared to all other heterogeneities. Varying the porosity and permeability values from high to low, decreases the oil recovery (due to lower oil volume in place and poorer connectivity), increases the recovery factor (because STOIIP is decreased), produces more water and reduces the time to breakthrough.

Permeability anisotropy controls the effective vertical permeability and its presence may decrease the oil recovery. However this heterogeneity seems to have a very insignificant impact on flow. This might be due to the fact that our model has a flat structure where the flow path is mainly horizontal, if we had a thicker reservoir with more layers and/or horizontal wells, one might expect the permeability anisotropy to have a more significant impact on flow.

Variation of EOD boundary interfingering length from small (8km) to large (24 km), decreases the oil recovery, increases the water production and reduces the time to breakthrough, due to reduction in quality of the reservoir. Varying EOD boundary style from setting 1 to setting 2, again, results a lower quality reservoir, reducing the total amount of oil recovered and increases field water production.

Do the same heterogeneities control flow, regardless of the relative permeability/capillary pressure imbibition model used?

To explore how different approaches of modeling imbibition relative permeability and capillary pressure, influence our results (oil recovered, oil recovery factor, water produced and time to breakthrough); we have compared two imbibitions modeling approaches. The first one uses one set of capillary pressure and relative permeability curves for the whole reservoir and the second one uses three set of curves, assigned to different parts of reservoir, on the basis of permeability. In most cases, we have found that the same heterogeneities have a significant impact on both imbibitions modelling approaches. However there were few cases where different modelling approaches gave different production results:

In one set of curve imbibitions modeling approach, variation of the porosity and permeability values from setting 1 to setting 2, decreases the oil recovery by 400 million barrels and time to breakthrough by 2.5 years whereas using three set of curves imibibition modeling approach this variation decreases the oil recovery by 500 million barrels and time to breakthrough by approximately 3.5 years.

Variation of surface character increases the field total water produced for, one set of curve imbibitions modeling approach, whilst this variation decreases water produced when using three set of curves imbibition modeling approach.

Do the same heterogeneities control flow, regardless of the mobility ratio?

In order to assess the impact of using mobility ratios (for example different oil viscosities) on our responses (oil recovered, oil recovery factor, water produced and time to breakthrough), two different oil viscosities, namely 0.52 centipoise and 4 centipoise were used in our simulations. Generally same heterogeneities, impacted on flow regardless of mobility ratio, however some differences were observed:

When the porosity and permeability values vary from setting 1 to setting 2, the oil recovery decreases by around 550 million barrels, using oil viscosity of 4cp, while this variation causes a much higher reduction on oil recovery, 750 million barrels, when using 0.52cp oil.

Variation of permeability anisotropy from isotropic to anisotropic, reduces the amount of oil recovered by approximately 11 million barrel when using oil with a viscosity of 4cp, however this variation in permeability anisotropy causes only around 8 million barrels decrease in oil recovery when using oil viscosity of 0.52 cp.

Shortcoming of the study and future work

For the 8 models, we have a range of STOIIP values, from 0.5 billion barrels (model 1) to 5.1 billion barrels (model 5). In order to conduct a fair experiment, the same number of wells, injection and production rate were assigned for all the models, based on the average value of STOIIP (from all 8 models). In simulations, a pressure boundary condition was specified to define flow such that the pressure drop between the producer and injector lies within the range of 0.5-2 psi/ft.

Although model 5 results a high oil recovery of 1.5 billion barrels, its recovery factor is only 30%, because of its huge STOIIP (5 billion barrels). Therefore in practice the production ability from model 5 is underestimated, but it is producing at this rate in order to comply with the pressure boundary condition set.

On the other hand, the oil recovery from model 1 is only 295 million barrels but its recovery factor is nearly 60% because its STOIIP is very small (only 0.5 billion barrels). In contrast to model 5, whose ability is underestimated, model 1 is "over-producing" in order to reach the rate of production specified, nevertheless have violated the specified pressure drop constraints. Therefore in the future one should aim to reach a compromise between the rate of production and pressure drop.

The models that were used for our simulations have a flat structure where the flow path is predominantly horizontal, that is why permeability anisotropy seems to have a very insignificant impact on flow. Therefore in this study we have not truly captured the effect of this heterogeneity. Using a model containing more layers, in the future, may better exhibit how permeability anisotropy control the vertical permeability and flow in the reservoir

In this project we have mainly focused on quantifying the impact of EODs (which are large-scale heterogeneities) on flow, however there are smaller scale heterogeneities within these EODs that we have neglected, one can explore the impact of these smaller scale heterogeneities on production results, in the future.

6 Conclusions

In this project we investigated the impact of a series of stratigraphic heterogeneities on flow in carbonate reservoirs, using high resolution models that have been built as part of a large research framework. Experiential design was employed to quantify the impact of these heterogeneities efficiently. For water flooding, two different approaches were used to model imbibition relative permeability and capillary pressure. The first approach uses only one set of curves for the whole reservoir, and the second uses three curves, assigned to different parts of reservoir, on the basis of permeability. The same drainage capillary pressure and relative permeability was used to initialize the model. Moreover, to evaluate how using contrasting mobility ratios (for example different oil viscosities) impact flow, two different oil viscosities, namely 0.52 centipoise and 4 centipoise were used in our simulations. We have found that, in most cases, the same heterogeneities have a significant impact on flow, regardless of the imbibitions modelling approach and mobility ratio.

7 Nomenclature

SB	Sequence boundary
Bbbl	Billion of barrels
bbl	Barrel
Cp	Centipoise
EOD	Environment of deposition
ft	Foot
m	Meter
max	Maximum (high)
mD	Millidarcy
MFS	Maximum flooding surface
min	Minimum (low)
OWC	Oil water contact
RF	Recovery factor
STOIIP	Stock tank oil initially in Place
WSO	Water-shut-off
3D	Three dimensional

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9 Appendix A (Critical literature review)

Paper n°	Year	Title	Authors	Contribution
SPE Reservoir Evaluation & Engineering, 3 (4), pp 292-303	2000	Geostatistical analysis of permeability data and modelling of fluid flow effects in carbonate outcrops	Jennings, J.W., Ruppel, S.C., and Ward, W.B	Geo-statistical analysis focused on two outcrops namely San Andres and Victorio Peak
SPE 87253	2000	Predictive modelling of naturally fractured reservoirs using geomechanics and flow simulation	Stephen J. Bourne, Franz Brauckmann, Lex Rijkels, Ben J. Stephenson, Alex Weber and Emanuel J.M. Willemse; Shell International, The Hague, BEB, Hannover	Presents a semi-deterministic method to systematically predict the spatial distribution of natural fractures and their effect on flow simulations
AAPG Bulletin, 92 (6), pp 789-824.	2008	Stratigraphic well correlations for 3-D static modelling of carbonate reservoirs	Borgomano, J.R.E., Fournier, F., Viseur, S. and Rijkels, L	Discusses the principles of stratigraphic well correlations that form the foundation of most carbonate reservoir models used in hydrocarbon flow simulations.
Geological Society, London, Special Publications, 309, 75–85.	2008	Reservoir-scale 3D sedimentary modelling: approached to integrate sedimentology into a reservoir characterization workflow	Labourdette, R., Herge, J., Imbert, P., and Insalaco, E	Uses a 3D model to incorporate sedimentology into a reservoir characterization work flow
SPE Reservoir Evaluation & Engineering, Dec 2009, SPE 131004	2009	Integrated modelling of the fractured carbonate Midale Field and sensitivity analysis through experimental design	Bogatkov, D., and Babadagli, T.	Uses an integrated solution by combining direct and inverse approaches to fracture networks characterization in a stochastic numerical model.

Table.A-1.Critical Literature review

Paper number:
SPE Reservoir Evaluation & Engineering, 3 (4), pp 292-303

Paper title:
Geostatistical analysis of permeability data and modeling of fluid flow effects in carbonate outcrops

Authors:
Jennings, J.W., Ruppel, S.C., and Ward, W.B

Objective of the paper:
The aim of the papers is the modelling of fluid flow effects, focused on two outcrops: a San Andres outcrop at Lawyer Canyon, Algerita Escarpment, Guadalupe Mountains, New Mexico, and a Victorio Peak outcrop, Apache Canyon, Sierra Diablo Mountains, Texas.

Methodology used
Short-range heterogeneities modeled with *K*-Bessel semivariograms having asymptotic power-law behavior at the origin. The periodicities modeled with ‘‘holeeffect’’ *J*-Bessel semivariograms.

Conclusion reached
Having measured permeability at outcrops of the San Andres and Victorio Peak formations reveals two major types of heterogeneity: short-range variability within single rock-fabric units and various other longer-range features. The short-range heterogeneities are weakly correlated, exhibiting power-law semivariogram behavior having small exponents while the long-range heterogeneities include vertical, average-permeability contrasts between beds. The long-range features can control overall large-scale displacement, even when they compose much less than half of the overall variance, whereas the short-range heterogeneities compose most of the overall variance.

Paper number:
SPE 87253
Paper title:
Predictive modeling of naturally fractured reservoirs using geomechanics and flow simulation.

Authors:
Stephen J. Bourne, Franz Brauckmann, Lex Rijkels, Ben J. Stephenson, Alex Weber and Emanuel J.M. Willemse; Shell International, The Hague, BEB, Hannover.

Objective of the paper:
The aim of this paper is to present a semi-deterministic method to systematically predict the spatial distribution of natural fractures and their effect on flow simulations, which enables the calculation of field-scale fracture models.

Methodology used
A semi-deterministic method is used to systematically predict the spatial distribution of natural fractures and their effect on flow simulations. Firstly, present-day structural reservoir geometry (based on geomechanical models of rock deformation such as elastic faulting) is used to calculate the stress distribution at the time of fracturing. Secondly, the calculated stress field, investigated earlier, is used to govern the simulated growth of fracture networks. Finally, the fractures are upscaled dynamically by simulating flow through the discrete fracture network per grid block, enabling field-scale multi-phase reservoir simulation.

Conclusion reached
Physics can be used to predict fractures that affect flow across entire naturally fractured reservoirs. Traditional methods of fracture modeling rely on stochastic realisations of the large numbers of fracture networks consistent with borehole fracture data to explain inflow data while the fracture model presented here uses geomechanical methods to predict the field-scale distribution of fractures that affect flow with reservoir simulations. Permeability of fracture clusters is sensitive to uncertainties though these uncertainties can be significantly reduced using well test data and production history. Furthermore, uncertainty can be minimised by integrating all the available static and dynamic data. As the model parameters are field-scale (i.e. mean rock strength, remote stress, etc.), information from each well constrains the whole fracture model and not just the areas close to wells. This makes the model suitable for fracture prediction and flow forecasting in all parts of the reservoir and not just those parts around existing wells.

Paper number:
AAPG Bulletin, 92 (6), pp 789-824.

Paper title:
Stratigraphic well correlations for 3-D static modelling of carbonate reservoirs

Authors:
Borgomano, J.R.E., Fournier, F., Viseur, S. and Rijkels, L

Objective of the paper:
(1) Review the processes of stratigraphic well correlation in carbonate reservoirs
(2) Discuss its impact on reservoir and flow unit modeling
(3) Present some recommendations adapted to specific stratigraphic systems and reservoirs.

Conclusion reached
The process of stratigraphic well correlations is very significant for carbonate reservoir modeling and the stratigraphic method must be adapted to the goal of the reservoir model. The ultimate objective of the correlation is to capture in the model the correlatable petrophysical heterogeneities that matter for the definition of reservoir and flow units. The largest error is introduced when the stratigraphic rules force unrealistic spatial correlations of random noise sampled in the wells.

Paper number:
Geological Society, London, Special Publications, 309, 75–85.

Paper title:
Reservoir-scale 3D sedimentary modelling: approached to integrate sedimentology into a reservoir characterization workflow

Authors:
Labourdette, R., Herge, J., Imbert, P., and Insalaco, E

Objective of the paper:
The objective of this paper is to demonstrate the quantitative influence of introducing sedimentological information into the reservoir characterization workflow using a simple deterministic workflow.

Conclusion reached
Based on a simple modeling technique, a workflow is generated which enables sedimentologists to integrate their interpretations and concepts into the reservoir characterization workflow. This workflow also integrates sedimentological uncertainty on heterogeneity distribution which results the construction of a 3D proportion cube used in uncertainty studies.
Deterministic modeling can be combined with stochastic or geostatistic models. To present remarkable solutions to the main challenges of reservoir modeling, the generation of 3D geologically realistic representation of heterogeneity and the quantification of uncertainty.

Paper number:
SPE Reservoir Evaluation & Engineering, Dec 2009, SPE 131004

Paper title:
Integrated modeling of the fractured carbonate Midale Field and sensitivity analysis through experimental design

Authors:
Bogatkov, D and Babadagli, T.

Objective of the paper:
The objective of this paper is to apply a widely accepted integrated procedure to characterize the matrix/fracture system of the Midale field in southern Saskatchewan, Canada.

Conclusion reached

- An integrated method is presented for characterization, modeling, simulation and analysis of NFRs.
- Using improved reservoir model and scientific approach in sensitivity analysis, enables us to achieve a good representation of reservoir heterogeneity, reduction of fracture spacing uncertainty and quantitative assessment of sensitivities.
- Experimental design and statistical analysis were used to quantify, the relative influence of matrix and fracture properties on the quality of the pressure profile.

10 Appendix B (methodology)

10.1 B1 (Stratigraphic hierarchy levels and heterogeneities)

Scale		"Heterogeneity"	End Member 1	End Member 2	End Member 3
LEVEL 1 *(Large Stratigraphic)*	100's m	Ramp Style	Homoclinal	Distally Steepened (1)	Distally Steepened (2)
		& slope angle	0.1deg.	0.1 - 10 - 0.1 deg. (C3D+)	0.1 - 20 - 0.1 deg (MAX)
		Mud- vs Oo-dominated Ramp	Grain-dominated Facies (>50% Grains)	Mud-dominated Facies (<20% Grains)	No Grains
LEVEL 2 *(Medium stratigraphic)*	10's m	**D''** - Major Discontinuity Surfaces (basin wide) *Hardgrounds (hDS'')*	Continuous surfaces, transitions occur at FWWB and SWB	Discontinuous surfaces, over 1-10km, transitions occur at FWWB and SWB	Tendency for associated lag-zones (SWB)
		EOD Belts	Linear (Lower C3D/Bahamas)	Irregular (Abu Dhabi)	Orientation to coastline (eg LSD)
			Linear x-section (simple)	Curvilinear x-section	
			Sharp Change in Properties at boundary	Trend / Gradational properties across boundary	
		Surfaces and EOD belts – Interfingering	Long (10's Km)	Short (km - 100m)	None / Long-Short Combination

Table. B-1. Heterogeneities present in level 1 and level 2. (These levels are shown in the heterogeneity hierarchy presented figure 2)

Scale	"Heterogeneity"	End Member 1	End Member 2	End Member 3	
LEVEL 3 ***(Small Stratigraphic)***	1-10s m	DS'' Slope Angles	Flat surfaces	Undulating surfaces (C3D 0-2deg.)	0.1 - 20 - 0.1 deg (MAX)
		DS''' -Minor Discontinuity Surfaces *Hardgrounds (hDS''')*	Continuous surfaces, transitions at FWWB and SWB	10'sm - km discontinuous surfaces	
		EOD Belts	Linear (Lower C3D/Bahamas)	Irregular (Abu Dhabi)	
			Sharp EoD boundaries	Gradational EoD boundaries	
			Narrow range of physical properties	Wide range of properties (isotropic)	Wide range of properties (anisotropic)
		Surfaces and EOD belts - Interfingering	Long (10's Km)	Short (km - 100m)	Long-Short Combination
		Prograding clinoform wedges within Oo-dominated EODs...			

Table. B-2. Heterogeneities present in level 3. (This level is shown in the heterogeneity hierarchy presented figure 2)

Scale		"Heterogeneity"	End Member 1	End Member 2	End Member 3
LEVEL 4 ***(Depofacies)***	metres	Lateral distribution of Depofacies within EOD Belts	Isotropic mix of depofacies	Linear facies belts, within linear EOD (Preferred Orientation?)	Anisotropic facies belts
		Vertical distribution of Depofacies between DS"	Homogeneous vertically [e.g. PKST]	Coarse Upwards [e.g. MD-PK-GRST upward (margin)]	Fine Upwards [e.g. MD-PKST capped Mud-rich PKST]
		% Grain within Depofacies type (SPC props)	>50% Grains	<20% Grains	None
		Ooid-shoals	None	“Linear" sand belts	Barrier bars
				Continuous vs. pinch & swell	Lenses - pinchouts
		Patch Reefs (bioconstructions)	None	Abundant	Sparse
				Small	Large
		Mud Mounds	None	Abundant	Sparse
				Small	Large

Table. B-3. Heterogeneities present in level 4. (This level is shown in the heterogeneity hierarchy presented figure 2)

10.2 B2 (porosity & permeability computation)

We obtained the properties (porosity and permeability values) for each of the EODs from the outcrop (indicated in table B-4, second and third column from left), then the standard deviation values of these properties were calculated.

FA Island Props;	Porosity	Permeability	Porosity STD	Permeability STD
Lagoon	0.08	81.07	0.05	0.10
Mid Ramp	0.28	1233.10	0.02	2.91
Outer Ramp	0.05	0.14	0.05	0.08
Pelagics	0.01	0.00	0.07	0.19

Table. B-4. properties from the outcrop and their standard deviation values. STD: standard deviation

We then computed the maximum and minimum geometric average values for permeability and porosity (indicated in Table B-5)

	Porosity (maximum)	Permeability (maximum)	Porosity (minimum)	Permeability (minimum)
Lagoon	0.21	122.12	0.02	63.67
Mid Ramp	0.38	2891.16	0.18	574.08
Outer Ramp	0.17	0.73	0.00	0.17
Pelagics	0.11	0.06	0.00	0.00

Table.B-5. Geometric average values of porosity and permeability.

Afterwards, the geometric average permeability values were converted to arithmetic and harmonic average permeabilities.

	Permeability (Maximum)		
	permeability (geometric)	permeability (arithmetic)	permeability (harmonic)
Lagoon	122.12	318.20	46.87
Mid Ramp	2891.16	4235.77	1973.39
Outer Ramp	0.73	2.47	0.21
Pelagics	0.06	0.15	0.02

Table.B-6. Arithmetic and harmonic permeability values of high permeability

	Permeability (minimum)		
	permeability (Geometric)	permeability (Arithmetic)	permeability (Harmonic)
Lagoon	63.67	165.89	24.43
Mid Ramp	574.08	841.06	391.84
Outer Ramp	0.17	0.58	0.05
Pelagics	0.00	0.01	0.00

Table. B-7. arithmetic and harmonic permeability values of low permeability

High porosity and Permeability anisotropy	Permeability (maximum)		
	K_h	K_v	K_v:K_h
Lagoon	318.20	46.87	0.15
Mid Ramp	4235.77	1973.39	0.47
Outer Ramp	2.47	0.21	0.09
Pelagics	0.15	0.02	0.13

Table.B-8. Permeability anisotropy for high permeability. K_v –vertical permeability=the harmonic average permeability. K_h – horizontal permeability = the arithmetic average permeability

Low porosity and permeability anisotropy	Permeability (minimum)		
	K_h	K_v	K_v:K_h
Lagoon	165.89	24.43	0.15
Mid Ramp	841.06	391.84	0.47
Outer Ramp	0.58	0.05	0.09
Pelagics	0.01	0.00	0.13

Table. B-9. permeability anisotropy for low permeability. Permeability anisotropy for high permeability. K_v –vertical permeability=the harmonic average permeability. K_h – horizontal permeability = the arithmetic average permeability

10.3 B3 (drainage and imbibition curves computation)

10.3.1 Water-oil primary drainage

Equation used to compute water-oil primary drainage P_c:

$$Pc = Pc_{th} + \left(\frac{1 - S_{wn}}{1 + aS_{wn}}\right)(P_{max} - P_{cth})$$

Where:

Parameter	Value/definition
Swn: n malized water saturatio	(Sw-Swir)/(1-Swir)
Pc_{th}: Threshold cap entry pressure	1(psia)
a: shape fa tor	120
P_{max}	55 (psia)
Sw_r	0.1

Table. B-10. Parameters and values used in the equation, to calculate water oil primary drainage Pc

Equations (Corey equations) used to compute water-oil primary drainage K_r

$$K_{rw} = K_{rwro}\left(\frac{(S_w - S_{wi})}{1 - S_{wi} - S_{orw}}\right)^m$$

$$K_{ro} = \left(\frac{(1 - S_w - S_{orw})}{1 - S_{wi} - S_{orw}}\right)^n$$

Treat as intermediate oil-wet for all permeability ranges

Parameter	value
Oil corey (m)	7
Water corey (n)	2
Krwro	1
Swi	0.1
Sorw	0

Table. B-11. parameters and values used in corey equations, to calculate water-oil primary drainage Kr

10.3.2 Single set of curves imbibition modelling

Equation used to compute water-oil imbibitions Pc:

$$P_c = Pc_{cross} + \frac{a}{\tan(S_{wn} * \pi)}$$

Parameter	Value/definition
Sw	(Sw-Swir)/(1-Swir-Sorw)
Pc(cross)	-1(Psi)
a	2
Sw	0.1
Sorw	0.15

Table.B-12.Parameters and values used in the equation, to calculate water oil imbibitions P_c- single set of curve imbibitions modelling approach

Computing water-oil imbibitions k_r

Corey equations presented in section 10.4.1 and the following values were used to compute water-oil imbibitions k_r

Parameter	value
Oil Corey (m)	3.5
Water Corey (n)	3.5
Krwro	0.65
Swi	0.1
Sorw	0.15

Table.B-13.Parameters and values used in corey equations, to calculate water-oil imbibition K_r- single set of curve imbibitions modelling approach

10.3.3 Three sets of curves imbibition modelling

The same equations as section 3.2.2 and the following parameters

Computing water-oil imbibitions P_c:

Equations presented in section 10.4.2 and the following values were used to compute water-oil imbibitions P_c

	Permeability		
Parameter	Low : <10 mD	Moderate : 10-100 mD	High: >100mD
Pc(cross)	-1	-1	-1
a	2	2	2
Swi	0.2	0.1	0.08
Sorw	0.2	0.15	0.12

Table.B-14. Parameters and values used in the equation, to calculate water oil imbibitions P_c - three sets of curves imbibitions modelling approach

Computing water-oil imbibitions k_r

Corey equations presented in section 10.4.1 and the following values were used to compute water-oil imbibitions k_r

	Permeability		
Parameter	Low: <10 mD	Moderate: 10-100 mD	High: >100mD
m	4	3.5	3
n	3	3.5	4
Krwro	0.5	0.65	0.75
Swi	0.2	0.1	0.08
Sorw	0.2	0.15	0.12

Table.B-15 .parameters and values used in corey equations, to calculate water-oil imbibition K_r- three sets of curve imbibitions modelling approach