HOW MANY RELATIVE PERMEABILITY MEASUREMENTS DO YOU NEED? A Case Study from a North African Reservoir

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ABSTRACT
Whilst there are published methods for estimating the appropriate number of samples for estimating the mean permeability within a workable tolerance, there exists no formal guidelines, to our knowledge, for the selection of relative permeability samples.

In this paper, we examine this issue for a clastic reservoir in North Africa. Rock properties (essentially the porosity and permeability relationships) are adequately characterized by a number of rock types. For this reservoir, seven have been found appropriate, using either Hydraulic Unit or Winland criteria. In a sector simulation model, the impact of the different relative permeability curves is examined. We conclude that a limited number of curves from the more important rock types, defined as those making up the dominant transmissive and storage elements, can be sufficient.

The approach to studying the number of relative permeability curves required, based on geological analysis, rock typing, heterogeneity analysis, and flow simulation is considered to be a framework for the selection of the appropriate material for special core analysis.

INTRODUCTION
Relative permeability characteristics are important in two-phase displacement of oil by water. These displacements occur in the reservoir during the primary and secondary recovery operations. The cost of the relative permeability measurements is quite high, comparing with other core measurements, which guarantees that the number of measurements will be rather limited. Therefore, careful selection for the samples for measurement is always needed. This paper presents a fit-for-purpose relative permeability-sampling scheme.

Previous work (Corbett and Jensen, 1992) identified statistical criteria for determining the number of permeability measurements in order to estimate the mean permeability of a reservoir unit within some tolerance (+/- 20%). The determination of how many relative permeability measurements needed, does not lend itself to a similar statistical treatment. However, in the design of a core analysis programme, the number of samples required for relative permeability measurements is an important consideration. Common strategy seems to pick a number according to a budget – say 10. Measuring too many samples is not cost effective, measuring too few might lead to data gaps at the model-building stage and, ultimately, errors in the simulated field performance predictions.

The fundamental petrophysical units in a reservoir (rock types) can be determined by flow zone indicators (FZI of the Hydraulic Units of Amaefule et al., 1993) or critical entry pressure (Winland plot discussed in Spearing et al., 2001) for routine core plug analysis. The degree of discretisation of the porosity-permeability space will depend on the overall variability of the permeability about the porosity. An understanding of geological control on petrophysical properties can be used with the variability to determine a number of rock types in accordance with the variation in texture (at least for relatively simple – e.g., no dispersed clay – systems). In an North African glacio-marine reservoir sandstone in such a clean sandstone, rock typing using the two above mentioned approaches has been undertaken and the results compared with the primary geological control. For this reservoir, the number of rock types varies in each well – however a field-wide breakdown into 7 hydraulic units seems appropriate. The operator's selection of samples for special core analysis followed determination of FZI but did not take into account the rock type grouping.

A sector model (taken from the full field simulation model) was used to explore the variations in reservoir performance that come from using the various laboratory curves. The laboratory data are not uniformly spread across all rock types. Instead, there is a concentration of measurements in one rock type, with some rock types not represented. The modelling study enabled investigation of the implications of this sampling programme and to develop recommendations for further studies.

PROCEDURES

Rock Typing Background and Approaches

A rock typing approach was suggested for this field because the permeability can vary by several orders of magnitude (e.g., between 10 and 10000mD) for a single porosity value (e.g., 10%). Simple models of a linear relationship between the logarithm of permeability and porosity couldn't be used to distribute permeability in this field.

Hydraulic Unit Approach

A Hydraulic (Flow) Unit (HU) is defined as the representative elementary volume (REV) of the total reservoir rock within which geological and petrophysical properties that affect fluid flow are internally consistent and predictably different from properties of other rock volume (Amaefule et al., 1993). Thus the variation in the petrophysical properties (porosity & permeability) should be small for a given rock type (HU) implying that knowledge of any porosity or permeability will enhance the prediction of the other properties. Moreover the transportation properties (capillary pressure and relative permeability) have to be consistent for a given rock type (HU), therefore the assignation of these properties to the reservoir simulation model should be based on the HU classification.

The HU's for a hydrocarbon reservoir can be determined from core analysis data (k & ϕ). This technique has been introduced by Amaefule et al., 1993 and involved calculating the flow zone indicator (FZI) from the (ϕ_z) and reservoir quality index (RQI) through equation 1. From FZI values, samples can be classified into different HU's (samples with similar FZI value belong to the same HU, see Mohammed, 2002 for details). This reservoir has been classified into seven distinct HU with different hydraulic properties (Fig. 2). Porosity - permeability relationships for each HU break up the poroperm space into relatively homogeneous groupings (i.e. the permeability coefficient of variation within HU is less than 0.5, Corbett and Jensen, 1992).

$$FZI = \frac{RQI}{\Phi_z} = \frac{0.0314\sqrt{\frac{k}{\phi}}}{\left(\frac{\phi}{1-\phi}\right)} \qquad \text{.......(1)}$$

<u>Winland Relationship</u>

Winland of Amoco (Spearing et al., 2001) established an empirical relationship between porosity, permeability, and pore throat radius from mercury injection capillary pressure (MICP) measurements in order to obtain net pay cut-off values in some clastic reservoirs. Winland correlated ϕ and k to pore throat radii corresponding to different mercury saturations and found that the 35th percentile (R_{35}) gave the best correlation. R_{35} was defined empirically by Winland as the pore throat radius where the pore network becomes interconnected, forming a continuous fluid path through the sample. Winland rock typing is based on samples with similar R_{35} belonging to the same rock type. A porosity - permeability relationship can be constructed for the different rock types based on their group R_{35} value. Using the MICP data together with k and ϕ data for 21 samples, a linear regression correlation was performed between measured (MICP R_{35}) and calculated (R_{35}) using least squares. The R_{35} derived in this way was then used to perform the rock typing (Fig. 3), again seven rock types are appropriate.

The definition of Transmissive and Storage Hydraulic Units (THU and SHU)

Transmissive (THU) and storage (SHU) dominated hydraulic units can be defined using the Lorenz plot (Jensen et al., 1997) for the core plug porosity and permeability data. If the data are coded by HU, THU and SHU are defined by the intercept of the tangent with a unit slope to the Lorenz curve. In well A28, the Lorenz plot shows the THU to comprise HU1 and 2 and SHU; units HU3 to HU6. HU7 has a negligible transmissive and storage contribution in this well therefore has not considered further in this study.

Previous Relative Permeability Sampling Scheme in This Field

The previously selected relative permeability samples in this field can be grouped using the same HU approach. As can be seen (Fig. 2 and Table 1) most of the samples were taken from HU4 and 5 with few samples from HU2 and 3. No samples were taken from HU1 and 6. To perform this simulation study, two relative permeability samples (for

HU1 and 6), were used from adjacent fields (Fields B, and H respectively) to fill in the gaps in the data.

Table 1. Laboratory relative permeability curves used in this study

HU	HU1	HU2	HU3	HU4	HU5	HU6
Sample ID	BBA-25(B-31)	BBC-49(A28)	BBE-14(A28)	BBE-10(A28)	BBE-51(A28)	BDI-10(H27)
(Well name)		BBC-6 (A28)		BBC-44(A28)	BBH-53(A28)	
				BBE-54(A28)	BBH-10(A28)	
				BBE-29(A28)	BDL-6 (A17)	
				BBH-44(A28)		

Re-Generation of the Laboratory Relative Permeability Curves Using Corey Technique

Laboratory results can contain artifacts associated with flooding small plugs, even when care is taken, due to the problems associated with capillary end effects and achieving equilibrium. Therefore, laboratory curves have been refined prior to use in a reservoir simulation model. Standard Corey exponential equations were used to analyse and adjust suspect laboratory data. The relative permeability curves used in this study were generated based on the end points (S_{wc}, S_{or} – refer to Table 2 - and k'_{rw}) using the Corey equation. The Corey exponents No and Nw depend on the rock wettability. In order to be consistent, the exponents used in this sector model were taken from a previous study for this field, in which two different cases were considered; intermediate wet and an oil-wet case. The intermediate wet case was considered in this study. The SCAL package was used to generate (using the Cory equation), group and average the relative permeability curves according to their rock type (HU). In terms of the capillary pressure, an equivalent reservoir capillary pressure curve was calculated from the MICP curve for each sample. In the case of a few samples, where there was no MICP data available, an MICP curve from the same HU and with a very similar FZI value was used.

Reservoir Simulation Study

Full field model

The full field model includes the A-Field and adjacent H-Field (Fig. 5). The two fields are in communication and this has been proven via pressure monitoring. The full field model comprises a total of 19 layers; 8 layers represent the Mamuniyat Formation, and the rest represent the Hawaze Formation (this study focuses on the Mamuniyat Formation). The areal size of the grid in this model was 250 m in A-Field and 150m in H Field.

Table 2. End-point saturations for the laboratory relative permeability curves used in this study

Sample ID	Swc	Sor	HU
BBA-25	0.058	0.087	1
BBC-49	0.015	0.223	6
BBC-6	0.02	0.666	2
BBE-14	0.021	0.361	3
BBE-10	0.032	0.074	4
BBC-44	0.009	0.358	4
BBE-54	0.015	0.236	4
BBE-29	0.015	0.197	4
BBH-44	0.033	0.156	4
BBE-51	0.082	0.108	5
BBH-53	0.039	0.37	5
BBH-10	0.023	0.151	5
BDL-6	0.016	0.098	5
BDI-10	0.174	0.074	6

Sector Model

A 3-D sector model (Fig. 6) from the full field model was used to provide a model for investigating the variation in reservoir performance that might occur when various rock types are used and /or various laboratory relative permeability curves are used. The grid dimension of the full field model was preserved in the sector model, in order to use flux boundary control (Mohammed, 2002). The geology of the full field model has also been preserved in the sector model as history matching to the observed field data was achieved using this geology in the full field model. Prior to the extraction of the sector model from the full field model the porosity and permeability for each grid block in the full field model were used to determine the FZI values for each grid block. The FZI value identified the different HU's (HU1-7). The determination and classification of the FZI for each block in the sector model were performed to determine a rock type for each grid block. The different HU's were used to create the saturation data file. In order to include the effect of the full field model in the sector model, the flux boundary condition option was used.

Optimum Number of Relative Permeability Measurements

Relative Permeability Scenarios

In order to examine the effect of using the different laboratory curves in the simulation model (Fig.6), several scenarios were proposed as follows:

- Scenario (A) - six relative permeability curves with one arbitrary curve selected (from Table 1) for each HU.
- Scenario (B) - six average relative permeability curves with the average relative permeability curve for each HU. Table 1 shows those HU's in which there was more than one relative permeability curve available. For these, the HU data were averaged.
- Scenario (C) - one average relative permeability curve using an average relative permeability curve for the entire field.

- Scenario (D) - one relative permeability curve using only one relative permeability from HU1 for the entire field.
- Scenario (E) - two relative permeability curves from HU1 and HU2 (i.e. assigning HU2 curve for HU2-6) .
- Scenario (F) - three relative permeability curves from HU1, HU2, and HU3 (i.e. assigning HU3 curve for HU3-6) .
- Scenario (G) - four relative permeability curves from HU1, HU2, HU3, and HU4 (i.e. assigning HU4 for HU4-6).
- Scenario (H) - five relative permeability curves from HU1, HU2, HU3, HU4, and HU5 (i.e. assigning HU5 curve for HU5 & 6).

These scenarios were tested using the sector model used by this study, the effects of using these different scenarios on field, well, and HU performance are presented below.

Identifying the THU and SHU at Large Scale

Considering the performance and the importance of the different rock types within the reservoir, and consequently, their contribution to the overall reservoir performance is a key issue for understanding the optimum number of the relative permeability curves needed for reservoir characterisation. This study considered carefully the performance of the individual HU by calculating and monitoring total oil and water in place (HUTOIP & HUTWIP respectively), the total oil production (HUOPT), and the HU total water production (HUWPT) for each HU at each timestep in the simulation. The variation of total oil production for the whole field, the well and HU's 1 and 2, versus time is given in Fig. 7. Scenario B is considered to be the base case – using the averages of the data available for each HU. Scenario A shows some variability that might be expected from using a single relative permeability measurement in each HU. Scenarios E and F give overly optimistic production histories. Scenario G seems to be reasonably consistent with scenario A and B. Scenario H has an extra relative permeability curve in a region (HU5) from which no oil is produced (so doesn't alter the model and is therefore superfluous). Scenarios C and D, using only one relative permeability curve, show some significant differences with Scenarios A and B and might therefore have too few relative permeability curves. In all scenarios we saw no production into the well from AHU5 and 6. Note that the suffix "A" is used to denote a HU specific to A-Field.

The total oil production from each HU (Fig. 8) shows that AHU1 has the highest total oil production, despite the fact that this HU has lowest oil in place. There is cross flow within the reservoir recharging this unit as it produces. In contrast, there was no direct production from AHU5 & AHU6, although both HU's showed relatively high oil in place, which decreased with time. Therefore, oil is flowing out of these units to another part of the reservoir. It is clear that the oil flows from AHU5 & 6 to the other HU's (AHU1 & AHU2), through cross flow, in order to get to the well bore. Units AHU3 - 6 could be considered as SHU, as they have the ability to store the fluids more than the ability to flow them to the well bore. Whereas, AHU1 & 2 can be considered as the THU, as they clearly have the ability to pass the fluids through their connected pores to the well bore.

RESULTS AND DISCUSSION

Comparing THU and SHU Results at Large and Small Scale

At core plug scale, the HU-coded Lorenz plot showed that around 80 % of the total flow into the well in our sector model is coming through AHU1 & 2. These HU's are THU, and the remaining 20% of the total flow is coming from the SHU of AHU3, 4, 5, 6 and 7. At the reservoir scale, there are some HU's that are more important than others. For example in this reservoir about 83 % of the total oil production is coming through AHU1 (THU) and about 46% of the oil in place is in AHU3 (SHU). These two HU's are thus very important. In this model 90% of the total oil production coming through THU (AHU1 and AHU2) whereas only 10% of the total oil production coming through SHU (AHU3-6), despite the fact that the latter comprise 75% of the total oil in place in this reservoir. AHU1 & 2 only comprise 25% of the oil in place. That confirms AHU1&2 are THU and AHU3-6 are SHU which validates the interpretation of the core-scale Lorenz plot for this well.

The simulation results suggest that four relative permeability measurements, selected in each of AHU1-4 might be appropriate for this field. One could also consider 8 samples, if the intra-HU variation is also to be further investigated and, similarly, samples in AHU5 and 6 could be taken for completeness. The minimum sampling scheme should be focussed on the most important HU's – namely AHU1-4 in this field. Using simulation to make some assessment of how many relative permeability measurements might be needed is the only practical method – unless long-term production data are available and by then it may be too late to influence the selection. The results from this study may be further analysed to consider how close the simulations 'need' to be to the base case in the same way that the absolute permeability numbers are derived from the consideration of a tolerance (Corbett and Jensen, 1992). The relative variation between each of the scenarios presented here is not large.

CONCLUSIONS

- Two main fundamental types of HU's are present in a reservoir. The first type are the flow- or transmissive-dominated HU's (THU) from which most of the flow (around 90%) in the reservoir is coming through (AHU1 and 2 in this case). The second type is responsible for storing the fluid, storage-dominated HU's (SHU), and these contain most of the oil in place (AHU3, 4, 5 & 6 contain around 75% of the total oil in place in this reservoir). This is consistent with the definition of the THU and SHU using HU-coded Lorenz plot.

- There are some HU's that are more important than the others at the reservoir scale. For example in this reservoir about 83 % of the total oil production is coming through AHU1 which is a THU, and about 46% of the oil in place is in AHU3 which is SHU. This implies that AHU1 and AHU3 are the most important HU's in this reservoir.

- Despite the importance of the AHU1 and AHU3 in this reservoir, there were no relative permeability measurements taken in AHU1. In this study, a sample from B-field (which is also part of Mamuniyat Formation with similar properties) was used. Only one relative permeability measurement was taken in AHU3.

- Most relative permeability measurements in this field were taken in AHU4 and AHU5, with 5 and 4 measurements, respectively. These HU's are considered relatively less important than AHU1 and AHU3. The simulation model results show that the characterisation of AHU5 is less important than AHU4.

- In terms of field and well performance, the optimum field performance (defined as being closest to the simulated base case with the fewest number of curves) was achieved by using four relative permeability curves (i.e curves from AHU1-4) scenarios for the entire model. The locations of these samples are shown on the HU-coded Lorenz plot (Fig. 10).

- This study describes a pragmatic approach to the selection of samples for relative permeability measurement, which has been found to provide focus in this case study. Further production data from the field will allow the study to be further calibrated. Testing this method on other datasets will indicate whether this method can be more generally applied.

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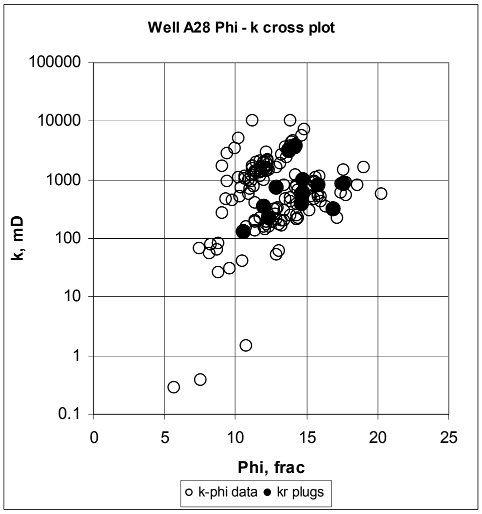


Fig. 1: Well A28 k-phi cross plot showing routine (k, phi), and special (kr) plugs.

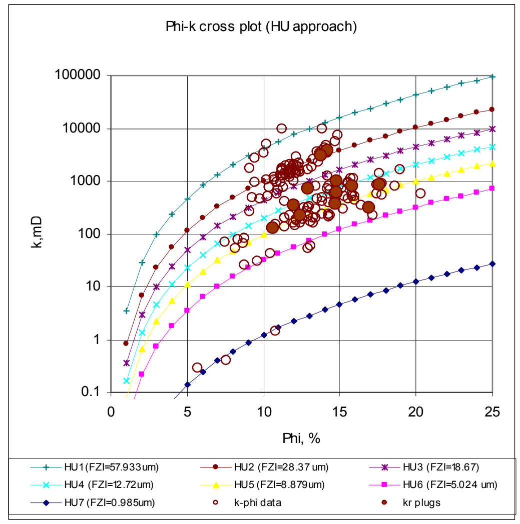


Fig. 2: Well A28 k-phi cross plot using HU showing (k,phi), and special (kr) plugs

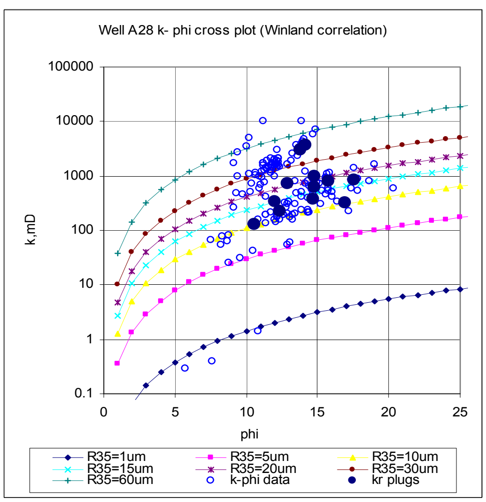


Fig. 3: Well A28 k-phi cross plot using Winland equation

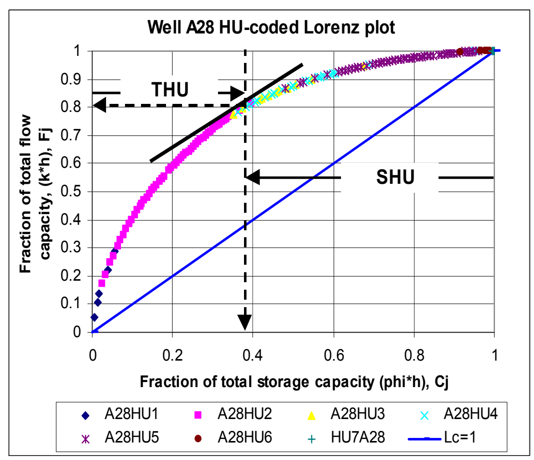


Fig.4 : Well A28 HU coded Lorenz plot shows THU & SHU

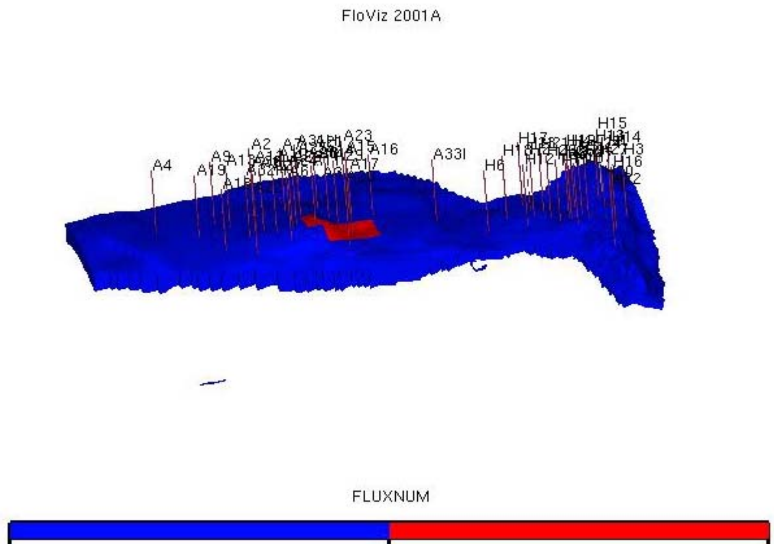


Fig. 5: Full field model shows the different flux regions – identifying the location of sector model in Fig. 6.

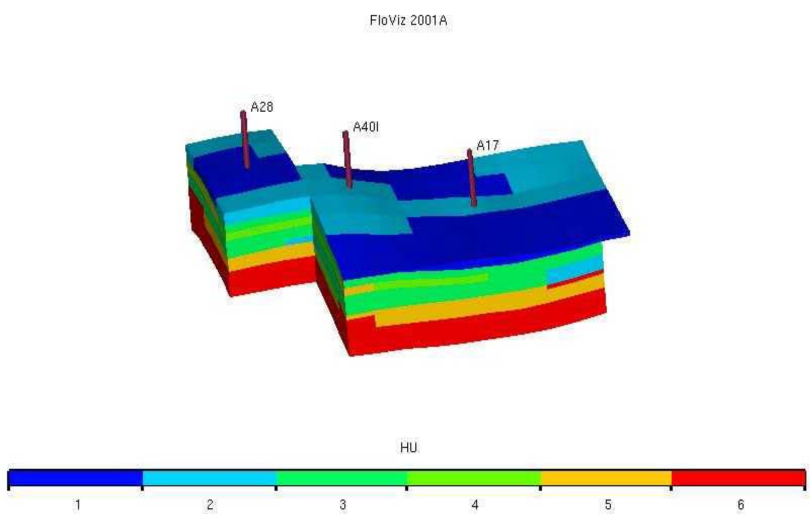
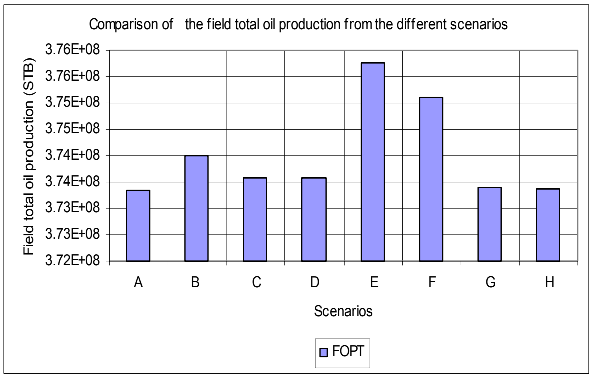
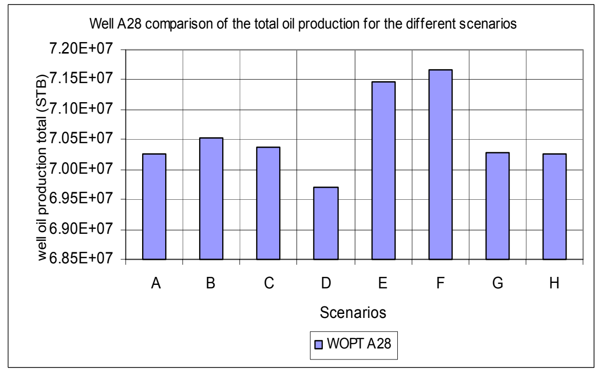


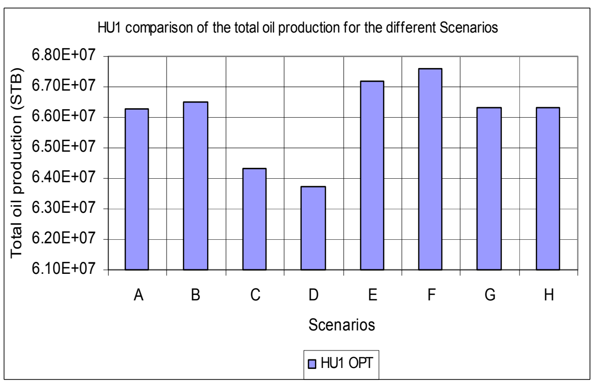
Fig.6: The sector model shows the distribution of different HUs within the area highlighted in Fig.5.



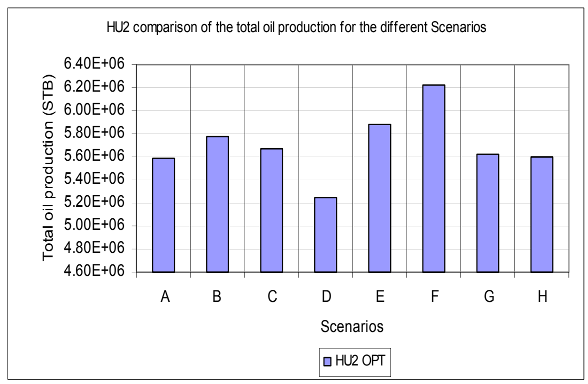
a) Comparison of the field total oil production for the different scenarios (after 33 years production)



b) Comparison of the well A28 total oil production for the different scenarios



c) Comparison of HU1 total oil production for the different scenarios



d) Comparison of HU2 total oil production for the different scenarios

Fig. 7: Comparison of the field, well, and HU's total oil production for the different relative permeability scenarios

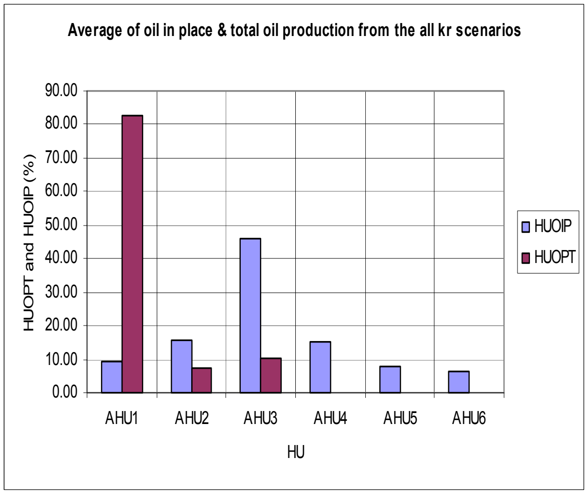


Fig. 8: HU's Performance using the average of the all relative permeability scenario's shwing that most of the production comes into the well trough HU1, draining from HU2 and HU3.

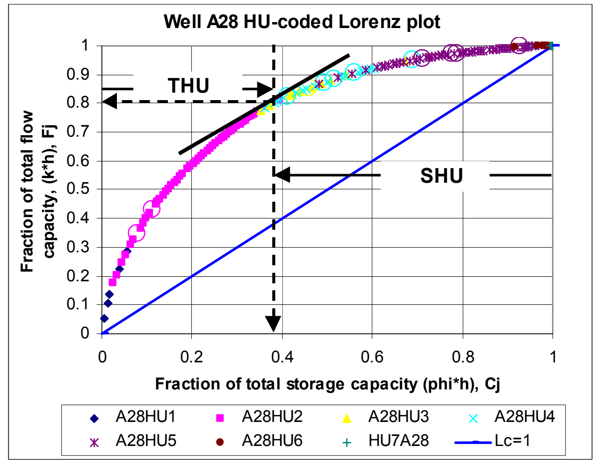


Fig. 9: HU-coded Lorenz plot shows the original kr data points sampled in this field.

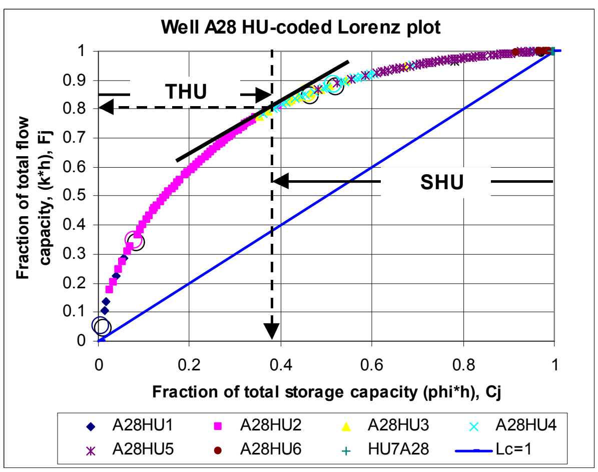


Fig.10: HU-coded Lorenz plot shows the optimum number (4) of kr samples for this model located in the appropriate HU's.