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Prediction of Multiphase Flow Properties from Network Models

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Abstract

The prediction of multiphase transport properties of reservoir rocks has been undertaken. This was done by numerical flow simulation of relative permeability and capillary pressure curves from pore network models extracted from Pore Architecture Models (PAMs). These PAMs are three-dimensional images obtained from 3D image reconstruction of 2D micro-computer tomographic images of the rock structures. Results obtained showed relative permeability depends on pore size distribution; the higher the pore size variability, the higher the wetting characteristics in preference for one of the phases, and the higher is the relative permeability to the non-wetting phase. A uniform pore size structure resulted in more favorable two-phase relative permeability distribution, with the relative permeability depending greatly on the phase saturations. Capillary pressure, on the other hand, was found to increase with image resolution.

Keywords: Network Model, Computer Tomography, Relative Permeability, Capillary Pressure.

1.0 Introduction

Macroscopic transport phenomena and properties observed at the reservoir scale are the result of countless displacements and processes taking place at the microscopic, pore-level scale in reservoir rocks. The architecture and geometry of the pore network and its complementary grain matrix determine several macroscopic properties of the rock, such as absolute and relative permeability, capillary pressure, formation factor, residual oil saturation, and resistivity index [1]. The prediction of macroscopic transport properties of reservoir rocks from the underlying microscopic structure and the pore-scale physics has been the subject of extensive investigation [1]; and the one commonly applied tool in this area of research has been network flow modelling. Network models simulate flow through an idealized representation of the pore space to calculate average properties, such as relative permeability and capillary pressure. A network model is essentially a simplified (lattice) representation of the pore structure, comprising of pore bodies linked by connections usually termed throats [2,3]. The nodes model the volumetric properties of the pore space, whereas the links define the flow properties [4]. Each link connects two nodes, whereas each node can be connected to several neighboring nodes.

Predictive pore-scale network modelling, combined with 2D and 3D imaging techniques, has proven to be a useful tool, complementary to special core analysis, for the determination of single and multiphase flow properties [5] of reservoir rocks. These images are commonly generated using x-ray computed tomography [6,7] stochastic microstructural [8,9], or process-based simulation of rock forming processes [10]. These images are then used to compute flow properties by solving, numerically, the continuum flow equations governing fluid transport. Relative permeability and capillary pressure curves are the most important functions to represent multiphase flow. Relative permeability measurements are expensive and time consuming. These properties are usually obtained from special core analysis (SCAL) procedures, in which experimental measurements are conducted on cores recovered using core barrels during drilling. As a result of high costs and rigours involved in SCAL procedures, researchers have been putting efforts into developing less expensive and less time-consuming alternatives for obtaining petrophysical and transport properties of reservoir rocks. Pore network modelling is one of such alternatives to SCAL procedures.

Fig.1 shows the schematic of the procedures involved in the use of pore network modelling of rock samples to predict multiphase flow properties of reservoir rocks. As can be seen, networks can either be obtained from the thin section and CT-image scanning of the rocks. Figures 2a & b show typical rock samples for determining petrophysical and multiphase flow

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properties of reservoir rocks. Fig. 2b is a core (usually of dimensions: 25mm diameter by 25mm length) for conventional and special core analysis; while Fig. 2a is of smaller dimensions (of the order of 3mm by 3mm) than Fig. 2b, and rock samples of this size can be readily used in pore scale network modelling. Unlike conventional core plugs, where special tools are needed, rock samples such as those in Fig. 2a can easily be obtained from rock fragments obtained during normal well drilling. Conventional core plugs are usually obtained by specially pulling out drilling string and replacing the drill bits with core barrels which are then lowered into the formation for the purpose of recovering cores. This is more expensive and also drilling is stopped, while rig time is still paid for by the company. Sometimes it is difficult to conduct the measurement, either due to unavailability of rock samples or because conventional experimental measurements are difficult, unsuitable, or expensive. Therefore, it is impossible to assign unique relative permeability functions to different rock types in the reservoir, and this limits the accuracy of reservoir simulators in predicting oil recovery. Pore-scale network studies could be used to obtain the most relevant data to model these properties.

The main objective of this work is to predict multiphase flow properties of reservoir rocks from pore-scale network models. Most predictions in the past were based on well-known rocks (model rocks) which are homogenous in nature. Reservoir rocks that are used here-in are not homogenous (heterogeneous) in nature. The samples were obtained from a carbonate and Sandstone reservoirs in the United Kingdom. Pore network Analysis software Tools (PATs) is used to extract realistic networks from Pore Architecture Models (PAMs) generated using the Wu *et al* (2006) PAM software; followed by prediction of multiphase flow properties, in which relative permeability and capillary pressure curves are obtained using a numerical flow simulation. The effect of image magnification on extraction and simulation is also presented.

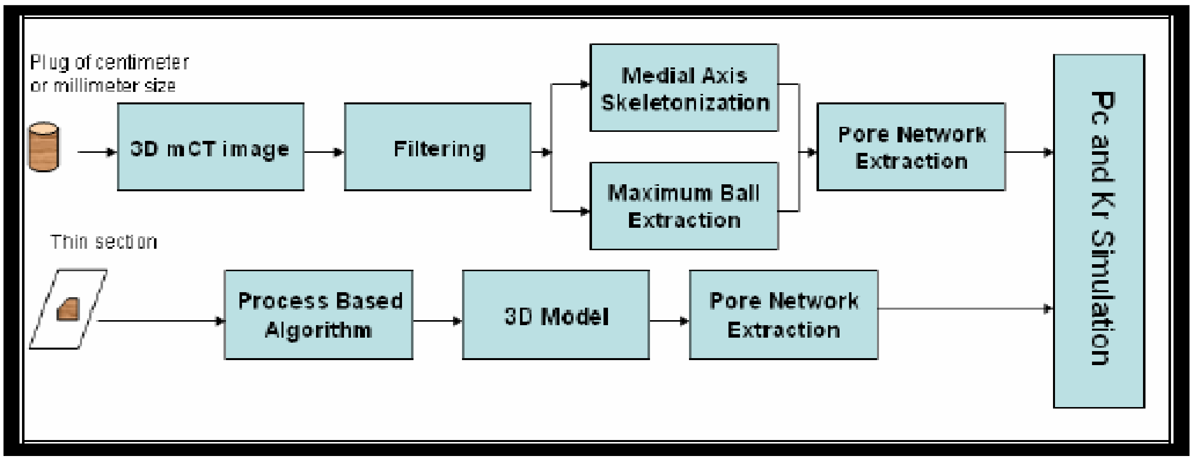


Fig. 1: A Flow Chart of the Application of Network Modelling

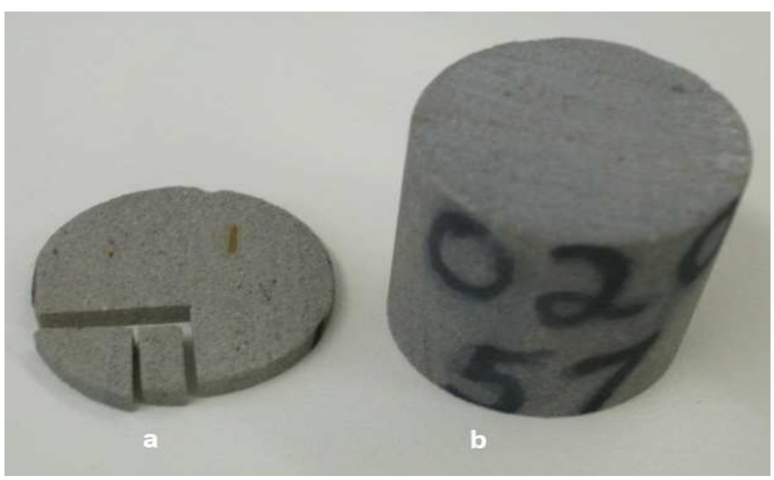


Fig. 2: Typical rock samples for Pore Network Modelling and Core Analysis

Relative Permeability

Immiscible two-phase flow in porous media is commonly described in terms of a generalized Darcy's law using the concept of relative permeability, K_r. This concept is an extension of the popular single phase Darcy's law based on the idea that each fluid flow in separate channels. Relative permeability is described as the amount of impairment to flow of one phase on another. For an oil-water, two-phase, system, it is defined by the expression:

For water,

$$Q_w = \frac{K.K_{rw}.A}{\mu_w}\left(\frac{\Delta P_w}{L}\right) \quad (1)$$

and

For oil flow

$$Q_o = \frac{K.K_{ro}.A}{\mu_o}\left(\frac{\Delta P_o}{L}\right) \quad (2)$$

Q_w and Q_o are the volumetric flow rates of water and oil respectively, *A* is the cross-sectional area, *L* is the length of conduit, *K* is absolute permeability, K_{rw} and K_{ro} are the water and oil relative permeability, μ_w and μ_o are the water and oil viscosities respectively, and ΔP_w and ΔP_o is the pressure drop or difference across the water and oil phases at steady-state conditions.

Capillary Pressure

When the pore space of a rock is shared between two immiscible fluids in equilibrium, the wetting phase occupies the corners of the pores, while the non-wetting phase occupies the central parts of the pores it invaded. The capillary pressure is the pressure difference across the fluid-fluid interface. In more general terms, capillary pressure is the difference in pressure between two (immiscible) phases; defined as the non-wetting phase pressure minus the wetting phase pressure. It depends on the saturation of the phases. For two fluids such as an oil-water system, separated by such an interface, the capillary pressure is given by the Young-Laplace equation, which is:

$$P_c = P_o - P_w = \frac{2\sigma_{ow} Cos\theta}{R} \quad (3)$$

where R is the pore (tube) radius, σ_{ow} is the surface tension, θ is the contact angle, and P_c is the capillary pressure. As can, be observed from the equation, the capillary pressure depends on the pore size distribution (R).

Materials and Methods

The main processes or steps taken in this study include: generation of pore architecture models (PAMs), analysis of pore geometry and topology, and finally measurement of flow properties.

Sample Description

Three sets of two-dimensional images of rock samples were used for the investigation. Image sample A is carbonate-28, at a magnification of x50; sample B is the same carbonate-28, but at a magnification of x200; while sample C is sandstone of magnification x50. The resolution of the carbonate-28x50- sample was 1.33 microns, that of the carbonate-28x200- image was 0.13; while that of the sandstone image was 5.60 microns.

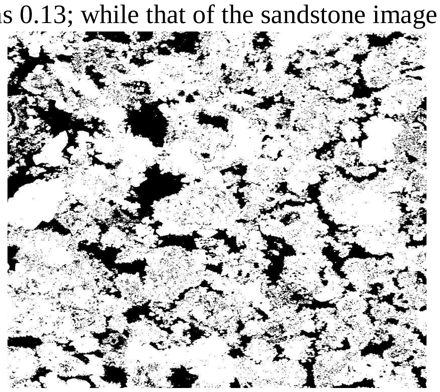


Fig. 3: 2D Image of Carbonate28x50

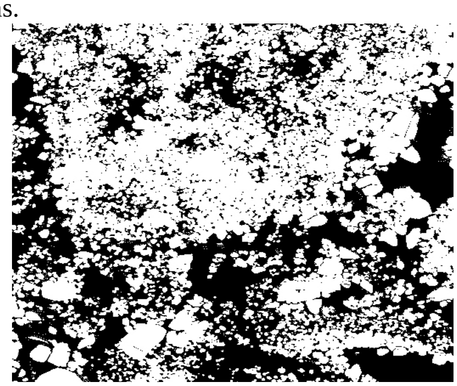
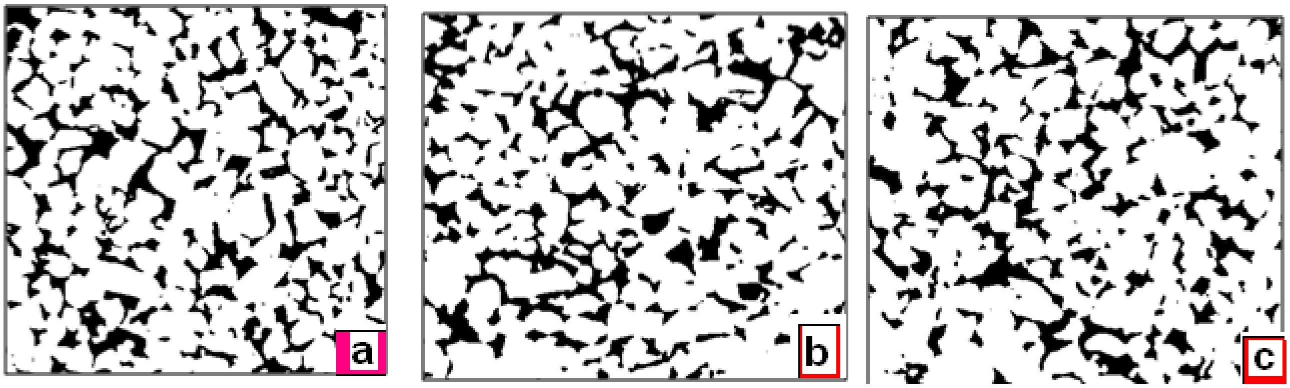


Fig. 4: 2D Image of Carbonate 28x200

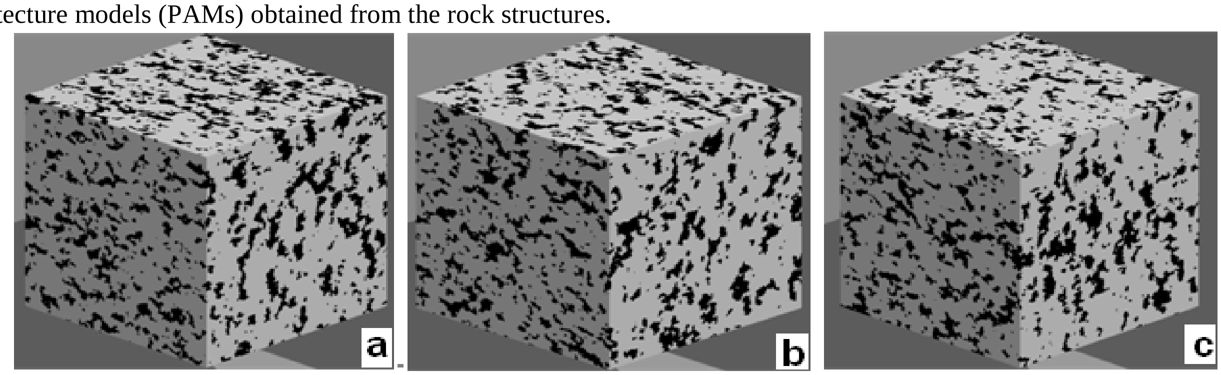


Figs. 5a-c: 2D Images of Castlegate sandstone sample at magnification x50

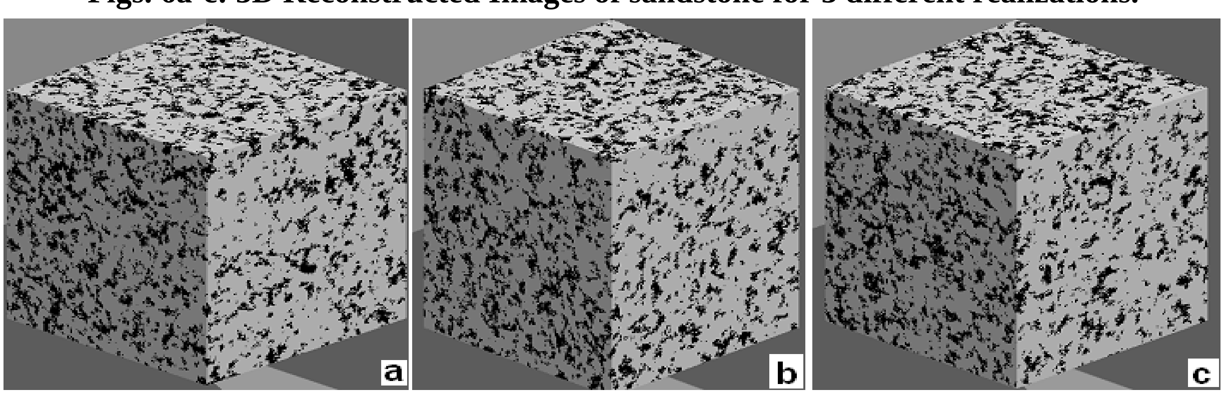
Generation of Pore Architecture Models (PAMs)

Using Wu *et al* [11] PAM software, pore architecture models were generated using the two-dimensional images of the rock samples already obtained. The thin section images of the rock samples obtained where the main input into the program in order to reconstruct 3D images of the rock samples. For the Castlegate sandstone, three 2D images were used for the reconstruction. However, for the carbonates, only one image was available for each, and it was necessary to assume that the image characteristic of this single section applied in all three perpendicular directions.

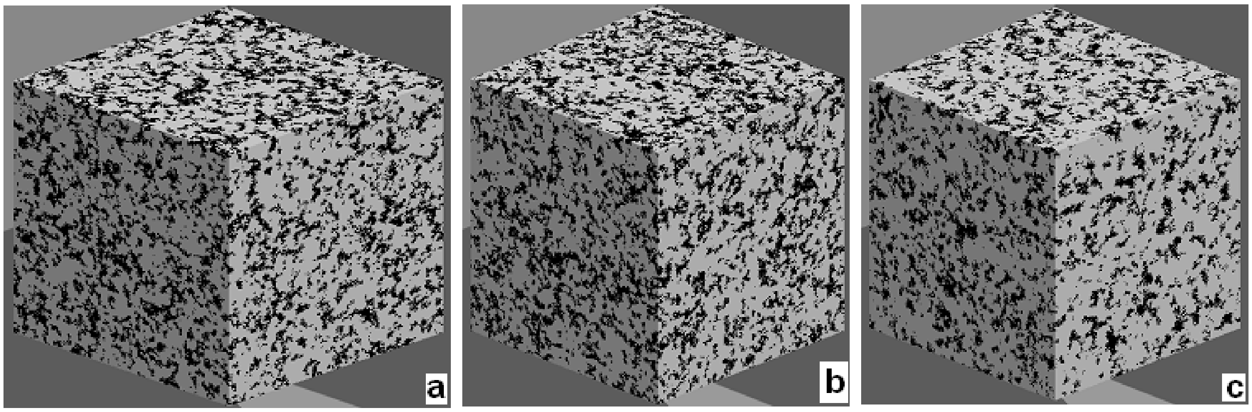
In order to obtain the model parameters, the PAM program digitally images the thin sections and stores the results as binary arrays depicting grain + cements (solids) and pore spaces. For the sandstone, volume dimensions of 300^3 voxels were used; while a 200^3 voxel dimension was applied to the carbonate. The model used in reconstructing the 3D images is a stochastic method; hence 5 different realizations were obtained for the images, giving a total of 15 images for all three samples. Qualitative comparisons of the reconstucted three-dimensional images (Figures 6 to 8) with the two-dimensional images (Figs. 3 to 5) show that there is quite a good agreement between the reconstructed 3D images and the 2D thin section images. The networks extracted from the reconstucted 3D images are shown in figures 9 and 10 for both sandstone and carbonate, respectively. These extracted networks show the pores and throats (pore connectivity and pore size distribution) of the pore architecture models (PAMs) obtained from the rock structures.



Figs. 6a-c: 3D Reconstructed Images of sandstone for 3 different realizations.



Figs. 7a-c: Reconstructed 3D images for the carbonate-28 x50 samples



Figs. 8a-c: Reconstructed 3D Images of the carbonate 28 x200 sample.

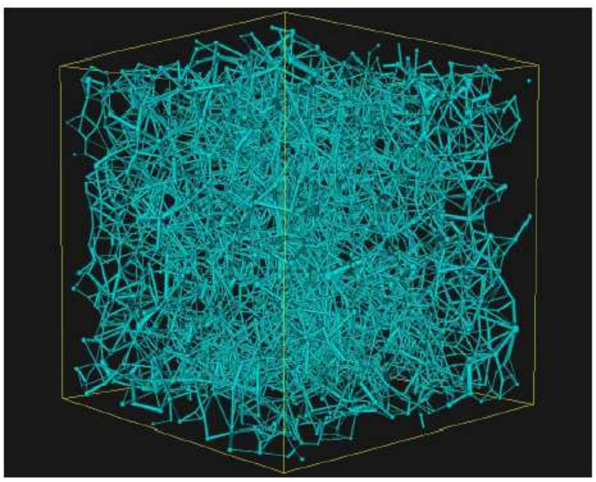


Fig. 9: Extracted Network of Carbonate-28

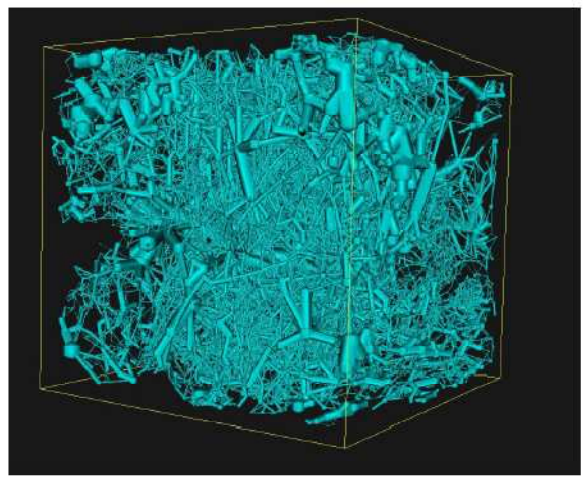


Fig. 10 Extracted Network of Sandstone

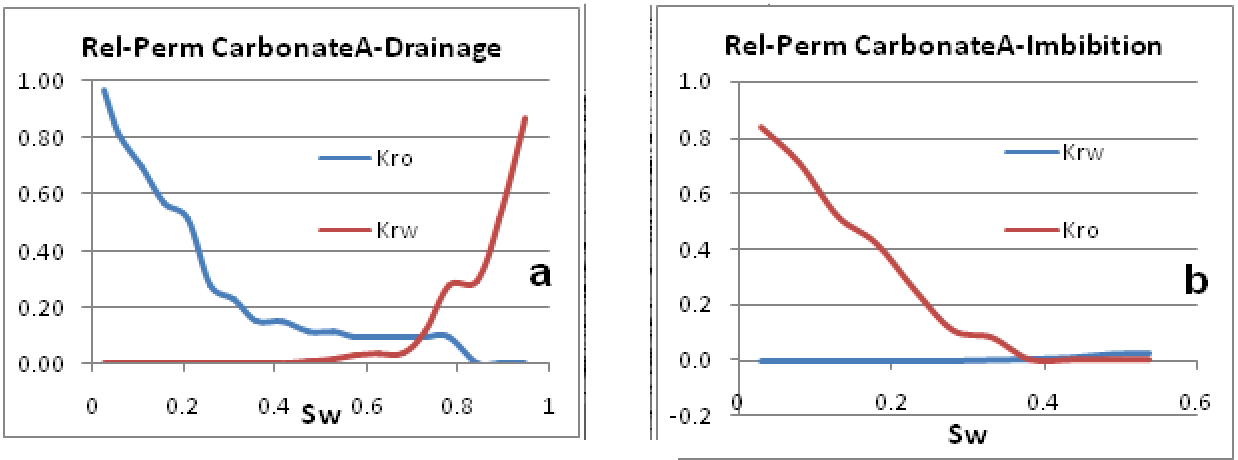
Simulation of Flow Properties

The relative permeability and capillary pressure curves were obtained by numerical simulation from the extracted networks. The simulator used was developed in-house by the Pore Scale Modelling Group at the Institute of Petroleum Engineering, Heriot Watt University, United Kingdom. Its capability has been compared to other simulators as presented by Wu *et al* [11]. In this simulator, the intrinsic permeability for the pore architecture models is calculated using a single-time relaxation scheme, which is an extension of the Lattice-Boltzmann (LB) method. The advantage of the LB method is that non-equilibrium dynamics, especially those involving interfacial dynamics and complex boundaries, can be incorporated relatively easily [2,11]. Details of the computation of the intrinsic permeability can be found in Wu *et al* [11], where the full methodology of the application of the BGK model is presented. Using equations (1) and (2), for water and oil respectively, the simulator generates relative permeabilities from the calculated intrinsic permeabilities. This is done for both drainage and imbibition.

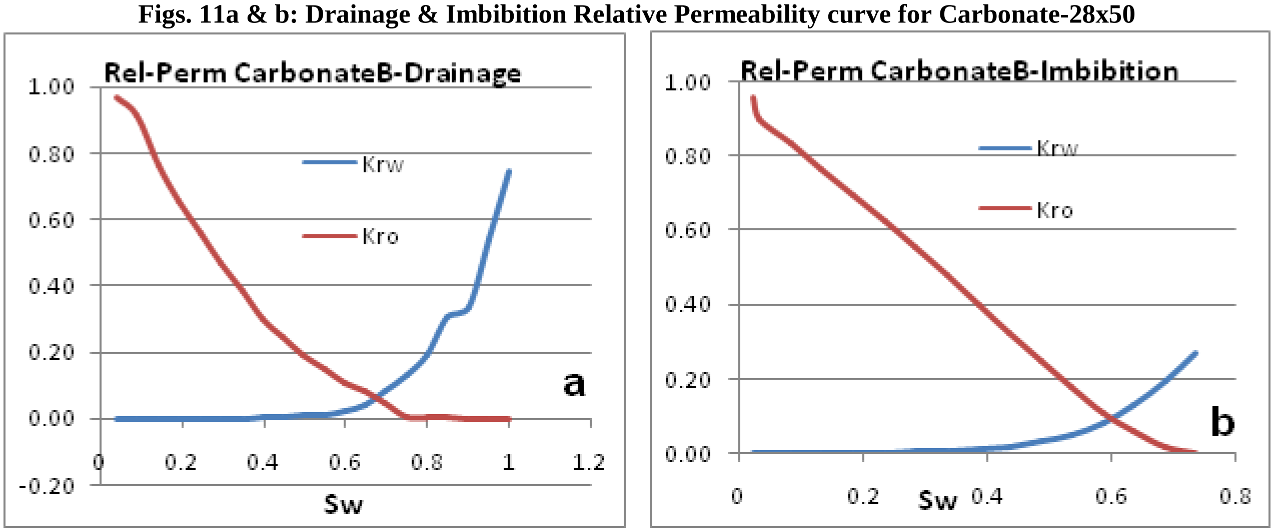
Results and Discussions

Relative permeability curves for both primary drainage and secondary imbibition are shown in Figures 11 to 13 for Carbonate-28x50, Carbonate-28x200 and Sandstone respectively. Similarly, the capillary pressures curves obtained are shown in Figures 14 to 16.

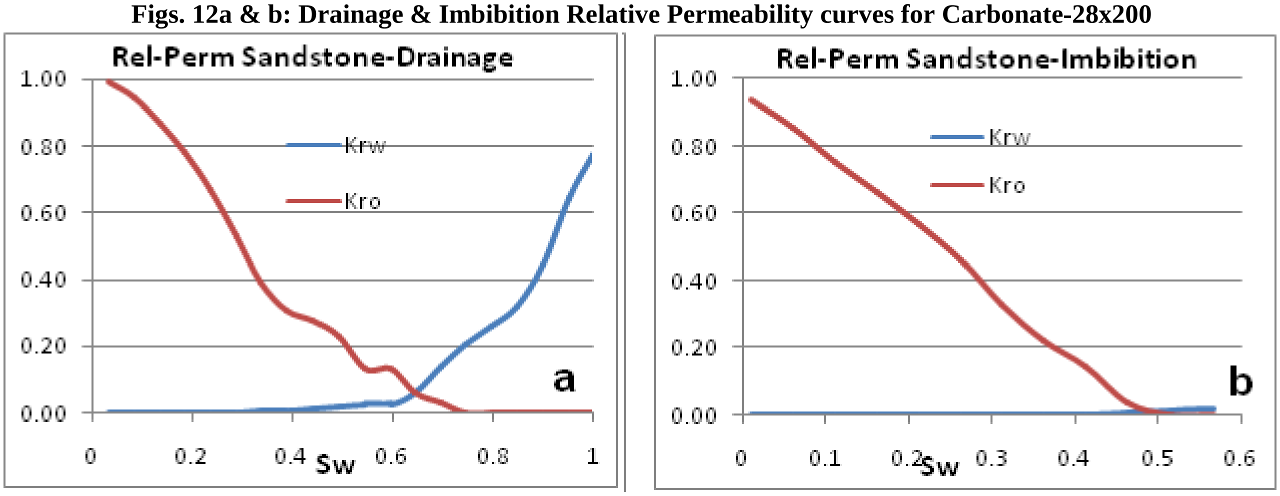
The relative permeability curves for the carbonate sample at image magnification of ×50 and resolution of 1.33microns are shown in Figures 11a & b. These figures show poor two-phase flow characteristics for drainage. The relative permeability for both phases (oil and water is low); permeability to water is only possible at S_w of about 60%. The relative permeability to oil falls to below 20% at a water saturation of about 31.2% (that is, S_o = 69.8%). For imbibition, the there is no apparent water imbibition into the structure even at negligible oil relative permeability. Figures 14a & b represent the capillary pressure curves for this sample, for both drainage and imbibition. These curves indicate intermediate-wet rock. The implication of this is that displacements of one fluid by another within a rock structure having these characteristics will not be favorable.



Figs. 11a & b: Drainage & Imbibition Relative Permeability curve for Carbonate-28x50



Figs. 12a & b: Drainage & Imbibition Relative Permeability curves for Carbonate-28x200



Figs. 13a & b: Drainage & Imbibition Relative Permeability curves for Sandstone

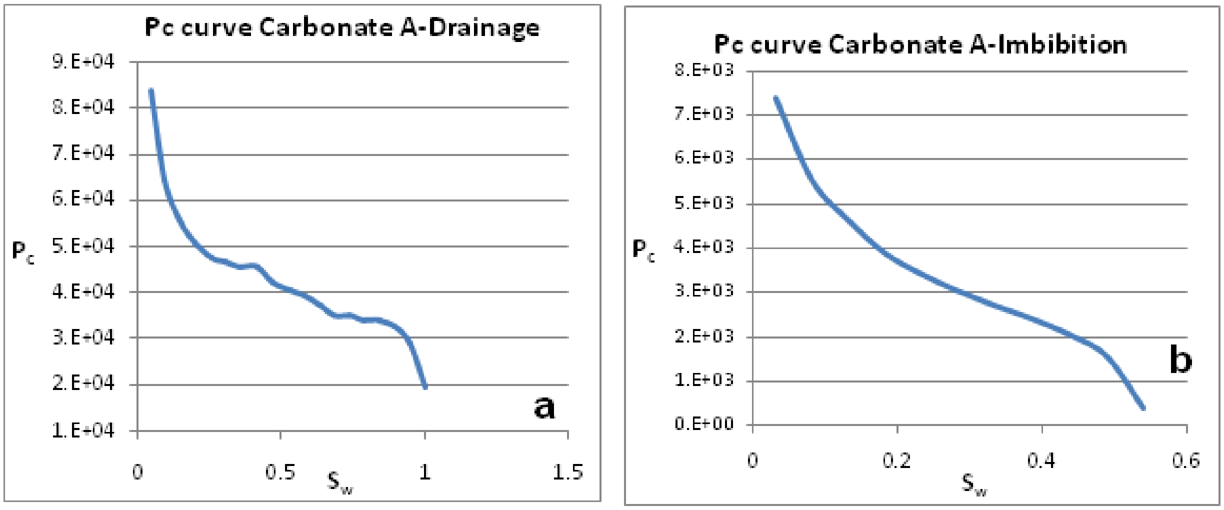


Fig.14a & b: Drainage & Imbibition Capillary curves for Carbonate-28x50

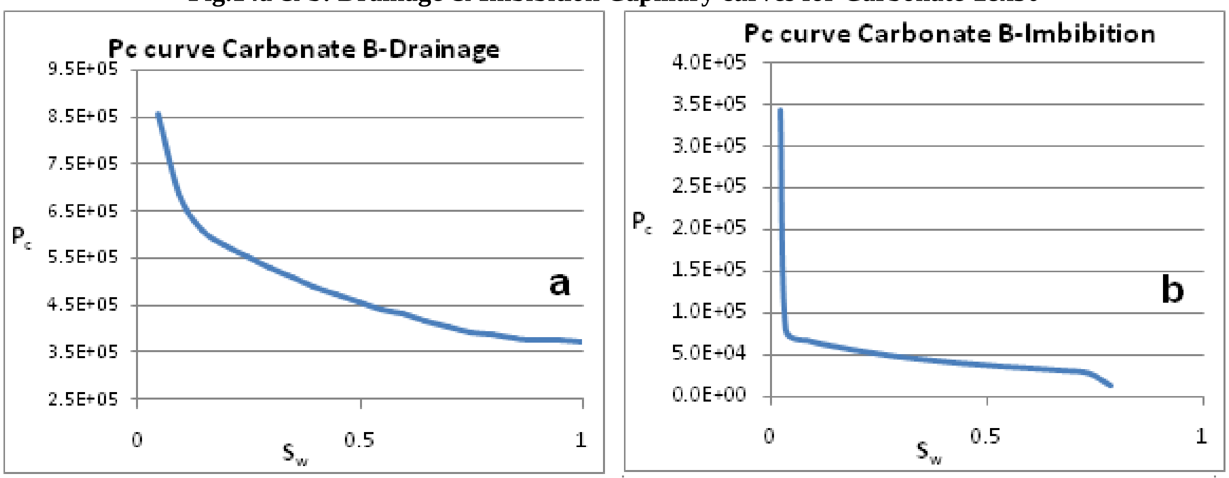


Fig.15a & b Drainage & Imbibition Capillary curves for Carbonate-28x200

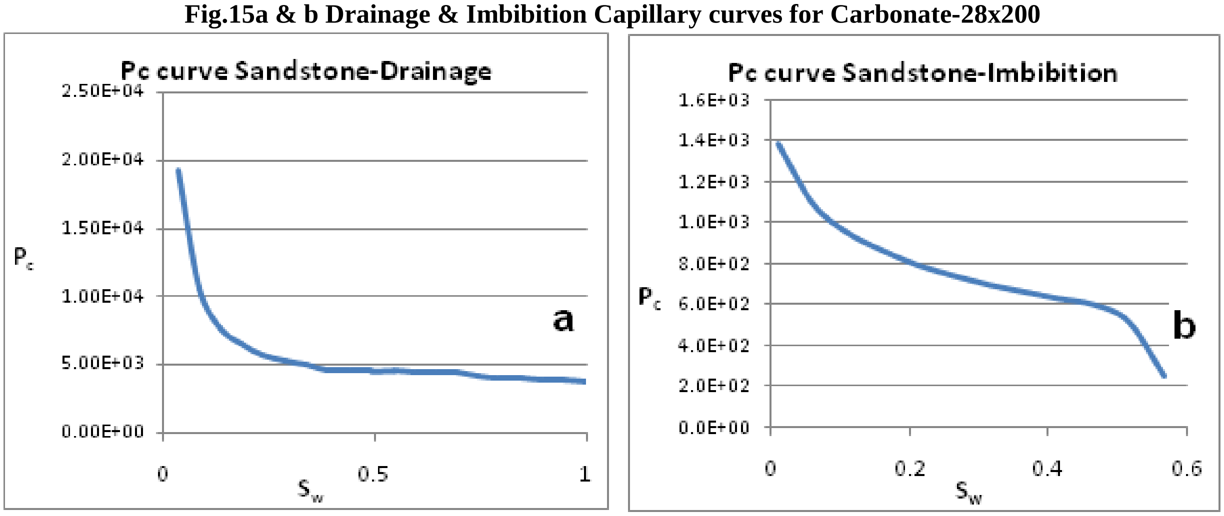


Fig.16a & b: Drainage & Imbibition Capillary curves for Sandstone

Figures 12a & b show the relative permeability curves for the carbonate at magnification of x200 and image resolution of 0.13micron. These figures show a balanced distribution of flow between the two phases, with a critical water saturation of about 50%. Though the carbonate-28x200- reconstructed image has very low absolute permeability the distribution of the permeable pore space between the two phases is more uniform. The relative permeability correlates very well with phase

saturation in this case. In addition, this structure shows greater water imbibition. The capillary pressure curves (Figs.15 & b) for this structure suggest an oil-wet rock. We can therefore infer that the higher image magnification and resolution applied to the carbonate sample have increased its tendency to be strongly oil-wet.
Figures 13a & b show the drainage and imbibition relative permeability curve for the sandstone structure. Water relative permeability is negligible until about 60% water saturation. The imbibition curve shows negligible water imbibition for this sample. The shapes of the capillary pressure curves (Figures 16a & b) are indicative of a strongly water-wet rock structure.

Conclusions

Based on the investigation undertaken and the results obtained in this work, the following conclusions can be made:

- The geometrical-topological characteristics of a reconstructed pore structure are largely affected by the image resolution; the higher the image resolution, the more representative are the values measured;
- The absolute permeability of a pore structure is largely dependent on the pore size connectivity of the pore structure; large interconnected pores resulted in greater effective permeability than smaller interconnected pores, even when the later showed better specific Euler characteristics.
- Relative permeability depends on pore size distribution; the higher the pore size variability, the higher the wetting characteristics in preference for one of the phases, and the higher is the relative permeability to the non-wetting phase. A uniform pore size structure resulted in more favorable two-phase relative permeability distribution, with the relative permeability depending greatly on the phase saturations.

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