VALIDATION OF FUNDAMENTAL CARBONATE RESERVOIR CORE PROPERTIES USING DIGITAL ROCK PHYSICS

Olivier Lopez[2], Alex Mock[2], Pål Eric Øren[2], Haili Long[2]
Zubair Kalam[1], Volker Vahrenkamp[1], Muhamed Gibrata[1], Samy Seraj[1], Soman Chacko[1], Mohamed Al Hammadi[1], Habeeba Al Hosni[1], Hani Sahn[1] and Antonio Vizamora[1].

[1]Abu Dhabi Company for Onshore Oil Operations and
[2]Numerical Rocks (Norway)

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ABSTRACT
This work presents an integrated multi-scale imaging and modeling method for determining petrophysical and multiphase flow properties of reservoir rocks at the pore, sub-plug, plug and whole core scale. The method is based on the integration of multi-scale X-ray computed micro-tomography (MCT) imaging and numerical 3D rock modeling to characterize heterogeneity, pore classes and porosity types at different scales. Petrophysical and multiphase flow properties are first calculated on the pore-scale and then at larger scales using a multi-stage up-scaling approach. We apply the method to study 100+ reservoir core samples from highly prolific reservoir zones of four different Middle-Eastern giant carbonate fields. The samples are classified into 16 different reservoir rock types (RRT) comprising grainstones, packstones and wackestones with a wide range of porosity and permeability. Porosity, permeability, formation resistivity factor (FRF), cementation exponent (m), saturation exponent (n) and primary drainage capillary pressure (Pc) are calculated and upscaled for all the samples. Nuclear magnetic resonance (NMR) T2 distributions are calculated for selected samples. The results are compared to available measured core analysis data for the same samples.

INTRODUCTION
Digital Rock Physics (DRP) technology enables characterization of detailed pore structures of complex rocks in 3D from nanometer to plug scales and to understand and predict rock properties at the sub-plug scale [1,2,3,4]. Recently, small scale pilot studies have proven that DRP technology offers significant commercial value in its ability to quickly deliver sub-plug scale special core analysis (SCAL) [5,6]. It also provides the opportunity for fast and meaningful sensitivity studies on discrete and homogeneous core material. A limitation of DRP technology has been that small homogeneous samples have been used to predict petrophysical and flow properties at larger scales (core plug or whole core). Multi-scale rock modeling approaches for carbonate rocks have been investigated in different studies, but are limited to mm-scale rock samples [7,8,9]. There is an urgent

need to extend calibrated measurements and predictions made at the pore and sub-plug scale to plug, whole core, log, and ultimately reservoir scales.

This is especially true for carbonate rocks that are multi-scale in nature. Diagenetic overprinting can create a vast variety of rock fabrics and pore structures with pore sizes ranging over more than four orders of magnitude (cm- to nm-scale). As a result, geometrical, petrophysical and multi-phase flow properties depend strongly on the scale of investigation. This makes reservoir rock characterization in carbonate rocks a complex task and severely limits accurate prediction of fluid movements and recovery. To understand and predict petrophysical and multi-phase flow properties at different scales, it is necessary to characterize the different types of heterogeneity (i.e. rock types), to recognize which have important effects on fluid flow, and to capture them and the relevant flow physics at different scales by up-scaling from micro (or Nano) scale to core plug (and whole core, where relevant) scale. When two or more fluids are present, it is important to understand how these heterogeneities interact with fluid forces (capillary, viscous and gravity) acting on different scales. Methods and typical results from multi-phase fluid-flow are discussed for similar samples by Kalam et. al. [11,12] in separate papers in these symposium.

In the present work, a multi-scale imaging and modeling method is applied to characterize heterogeneity and to calculate petrophysical properties at different scales for 100+ core samples from highly prolific reservoir zones of four different Middle-Eastern giant carbonate fields. Using MCT and 3D rock modeling, heterogeneity and dominant pore classes or rock types are characterized at four different scales; from porosity in the "micritic" facies (nm-scale) through intergranular porosity (µm- to mm-scale) and vuggy porosity (mm- to cm-scale) to the whole core scale (dm- to m-scale). Porosity, permeability, FRF, *m*-exponent, n-exponent and primary drainage Pc for the underlying rock types are calculated using DRP technolgy and up-scaled to larger scales using a multi-stage steady-state up-scaling approach. Calculated properties are compared to available special core analysis (SCAL) data for the same core samples.

METHODOLOGY

Imaging

Over 100, 1.5-inch cylindrical reservoir core plug samples are scanned entirely with a Nanotom S nanofocus MCT at a resolution of 12.7µm and 19µm per voxel. The MCT scans of the entire core plug are used to select the location of end-cuts for thin section preparation according to the distribution of heterogeneities. Thin Sections are analyzed with a transmitting light polarizing microscope and a number of rock types are identified based on micro-facies description and classification. Rock types are identified and located in the MCT scans based on the micro-facies description by visual comparison and grey scale variation.

Micro plug sub-samples are drilled at appropriate locations from the end-cuts and scanned with the same scanner or – where appropriate – at the European Synchrotron

Radiation Facility in Grenoble, France. Micro plugs have a diameter from 0.5mm to 10mm and resulting 3D images have resolutions between 0.28µm and 5µm per voxel. For each core plug, 1-3 micro plugs are drilled and imaged corresponding to the number of distinct rock types identified by micro-facies analysis (see Figure 1).

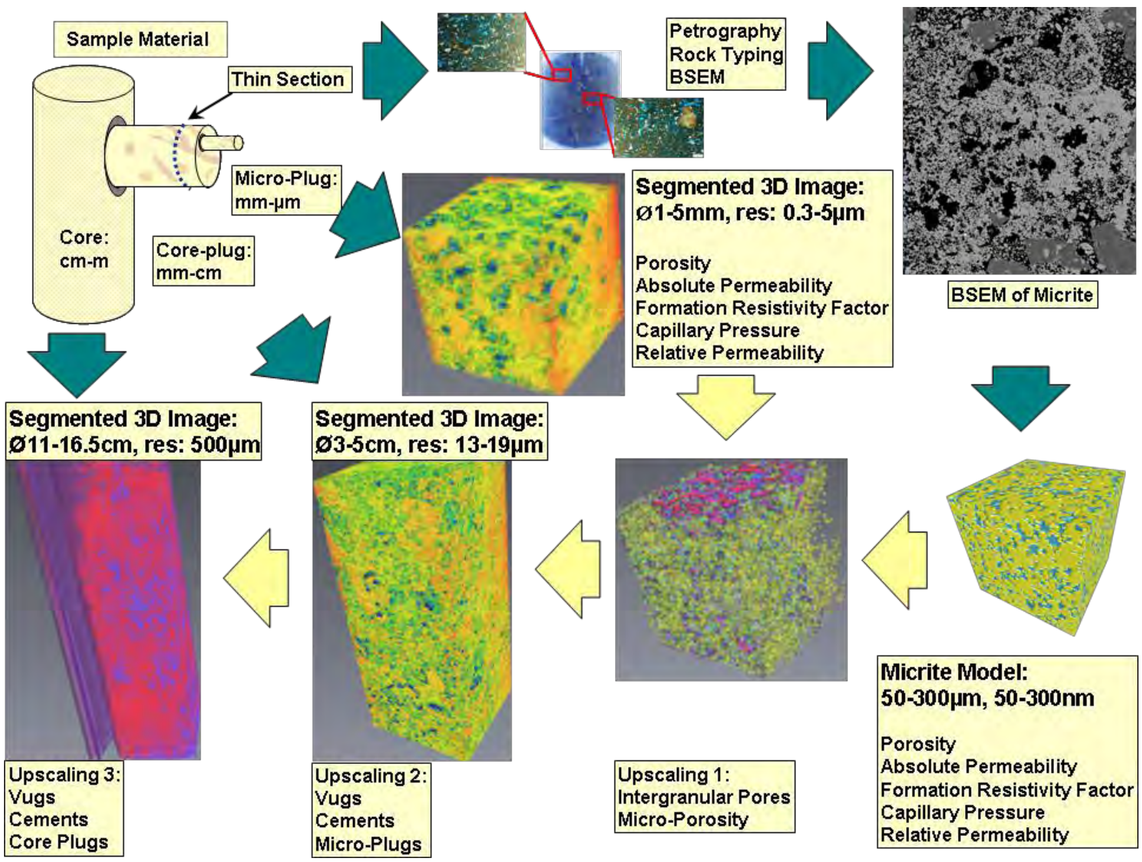


Figure 1. Workflow illustration

In order to obtain properties for micro-porosity below the resolution of these images, 3D models are constructed based on analysis of high resolution backscattered scanning electron microscope (BSEM) images. The basic input for the 3D models are particle/grain size measured on the BSEM images and porosity according to the analysis of grey value histograms of the micro plug image. It is assumed that the grey value is a function of porosity below the resolution of the image in the region of the grey value histogram between pore and solid voxels. Micro-porosity models cover porosities from 0.4 to 0.1 at a resolution of 50nm to 300nm and sizes between 50µm and 300µm (see Figure 1).

Image Analysis and Modeling

In the MCT images, each voxel carries an 8-bit grey scale signal reflecting the amount of X-ray attenuation experienced within the voxel volume. Micro plug images are segmented into three phases according to an analysis of the grey scale histogram. The phases are porosity, matrix/solid and a micro-porous phase. The latter comprises all porosity below the resolution of the image. The grey value within this phase is assumed to reflect the amount of porosity present in the voxel as discussed in the previous paragraph. The image of the core plug is segmented with a similar approach differentiating pores (vugs), solid matrix (cements) and a number of rock types corresponding to the analysis of thin sections and different micro plugs analysed.

Petrophysical properties of 3D images of both the intergranular and the micro-porous pore space are calculated using a Lattice-Boltzmann algorithm to solve the Navier-Stokes equation for absolute permeability [13]. A random walk algorithm is applied to solve the Laplace equation for FRF and to solve a diffusion equation for NMR relaxation [14]. Pc curves are calculated from a simplified network representation of the pore space [15]. Absolute permeability is calculated on 8 non-overlapping sub-samples of the micro plug and micro-porosity model images in order to capture the porosity-permeability correlation at that scale. The correlation (linear or power law) is applied in the up-scaling procedure to populate grid cells of the coarser up-scaling grids.

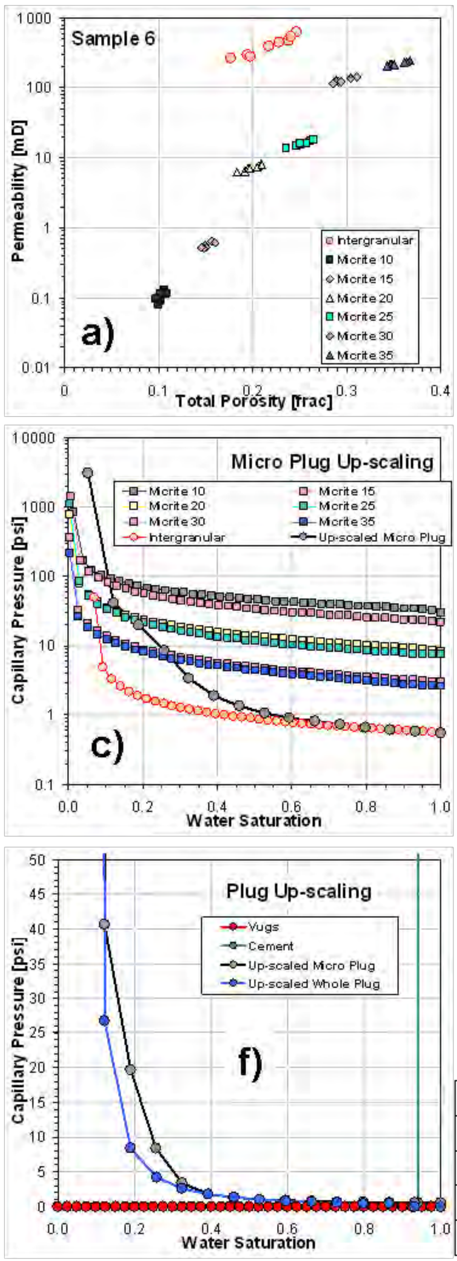
Upscaling Procedure

Effective properties of the micro plug images are determined using steady-state up-scaling methods. Each grid cell represents either intergranular pore/matrix or a micro-porous phase with a distinct porosity. The grid cell size in the up-scaling grid varies from 6µm to 100µm, i.e. the original micro plug image is coarsened by a factor 20. The same procedure is repeated on the segmented and coarsened image of the core plug. The grid cell size there varies between 0.5 and 1mm. Thus, grid cells of the up-scaling grids are approximately the same size as the image sub-samples used to calculate detailed properties.

The following properties are assigned to each grid cell: porosity, absolute permeability tensor (k_{xx}, k_{yy}, k_{zz}) as a function of porosity, directionally dependent *m*-exponents and Pc curve. Single phase up-scaling is done by assuming steady state linear flow across the model. The single phase pressure equations are set up assuming material balance and Darcy's law:

$$\begin{aligned} &\nabla \bullet (k\nabla P) = 0 \text{ with boundary conditions} \\ &p = P_1 \text{ at } x = 0,\, p = P_0 \text{ at } x = L \\ &v \bullet n = 0 \text{ at other faces} \end{aligned} \tag{1}$$

The pressure equation is solved using a finite difference formulation. From the solution one can calculate the average velocity and the effective permeability using Darcy's law. By performing the calculations in the three orthogonal directions, the effective or up-scaled permeability tensor can be computed. The effective FRF is computed in a similar manner by replacing pressure with voltage, flow with current, and permeability with electrical conductivity. The up-scaled *m*-exponent is determined from the effective FRF and the sample porosity. Effective two-phase properties (i.e. Pc) are calculated using two-phase steady state up-scaling methods. We assume that the fluids inside the sample have come to capillary equilibrium. This is a reasonable assumptions for small samples (<30cm) when the flow rate is slow (<1m/day). The entire workflow is illustrated in Figure 1 and exemplified for one sample in Figure 2.



b)

	Cem. Exp. (m) X	Cem. Exp. (m) Y	Cem. Exp. (m) Z	Sat. Exp. (n)
Intergranular	1.90	1.90	1.87	1.95
Micrite 35	1.67	1.66	1.70	1.58
Micrite 30	1.69	1.71	1.73	1.57
Micrite 25	1.69	1.69	1.75	1.56
Micrite 20	1.74	1.78	1.81	1.55
Micrite 15	1.84	1.82	1.84	1.52
Micrite 10	1.99	1.96	2.00	1.61

d) Volume Fractions

Micro Plug		Plug	
Intergranular	0.607	Vugs	0.021
Micrite 35	0.036		
Micrite 30	0.046	Cement	0.003
Micrite 25	0.053		
Micrite 20	0.079	Micro Plug	0.977
Micrite 15	0.080		
Micrite 10	0.098		

e) **Micro Plug Up-scaling: Petrophysical Properties**

Tot. Porosity	0.213			
	X	Y	Z	Avg.
Perm. [mD]	140	141	130	137
Cem. Exp. (m)	1.97	1.97	1.96	1.97
Sat. Exp. (n)	2.05	2.05	2.07	2.06

g) **Plug Up-scaling: Petrophysical Properties**

Tot. Porosity	0.229			
	X	Y	Z	Avg.
Perm. [mD]	145	146	135	142
Cem. Exp. (m)	1.89	1.87	1.90	1.88
Sat. Exp. (n)	1.97	1.97	1.97	1.97

Figure 2. Results for sample 6 (see also Figure 7): a) Porosity-permeability for intergranular porosity and micro-porosity models; b) respective *m* and *n* exponents; c) Pc curves for intergranular and micro-porosity with up-scaled Pc curve for micro plug; d) volume fractions in micro plug and plug; e) resulting

petrophysical properties of micro plug; f) Pc curves for vugs, cement and micro plug in whole plug up-scaling and the up-scaled Pc curves and g) resulting petrophysical properties

Experimental porosity is measured Helium porosity, permeability is Klinkenberg corrected gas permeability and Pc curves are determined by either mercury injection (MICP) or the Porous-Plate method. Other laboratory procedures to acquire the relevant SCAL data have been described earlier [16,17]. Porosity, permeability, NMR and some Pc measurements were conducted on the exact same core plugs used for DRP analysis, but FRF and MICP measurements have been performed on adjacent plugs from the same RRT.

RESULTS AND DISCUSSION

The laboratory results for the studied samples range in porosity from 0.110 to 0.347 and in permeability from 0.63mD to 2983mD. The FRF range from 8.96 to 52.9 with corresponding cementation exponents *m* from 1.83 to 2.59. Porosity and permeability are measured on exactly the same core plugs that have been used for DRP, while FRF and *m* are not available for all samples. Instead, RRT averages and field trends are used for comparison with DRP results.

Figure 3 shows a linear comparison of measured and calculated porosity and permeability. The confidence ranges (± 2 porosity units and factor 2 for permeability) were established prior to the study in order to qualify DRP results. They are not related to experimental uncertainties. In general, DRP results reproduce laboratory measurements very well. In terms of porosity 4 out of 100 core samples (4%) fall slightly outside the confidence range. In terms of permeability 6-8 samples (7%) fall slightly outside the confidence range. The deviations are distributed evenly around the 1:1 correlation line. Moreover, most of the deviations in permeability occur below 10mD.

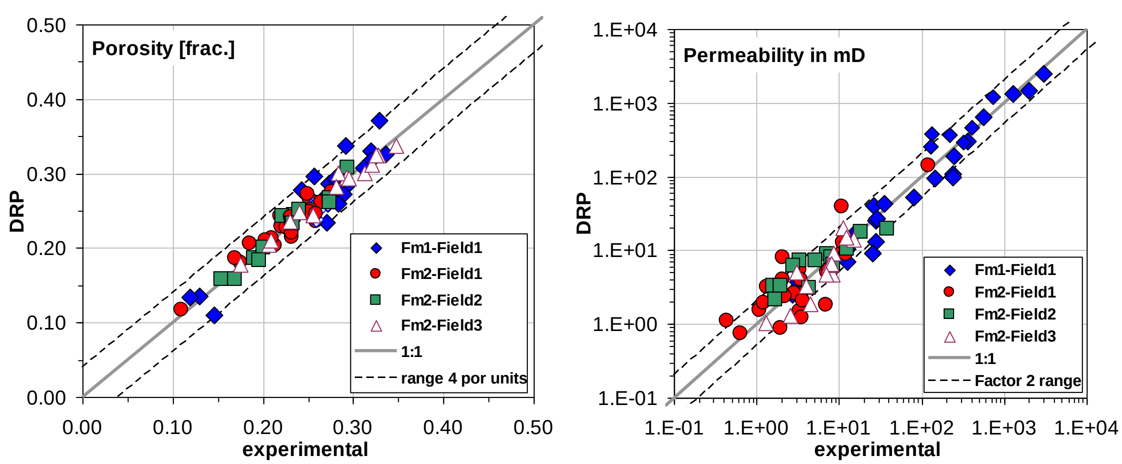


Figure 3: Comparison of DRP and laboratory porosity and permeability

The porosity-permeability cross-correlation (Figure 4) shows that DRP results form exactly the same trend as laboratory data. It should be noted that there are more laboratory results plotted here than in Figure 3 in order to define the field trends more clearly.

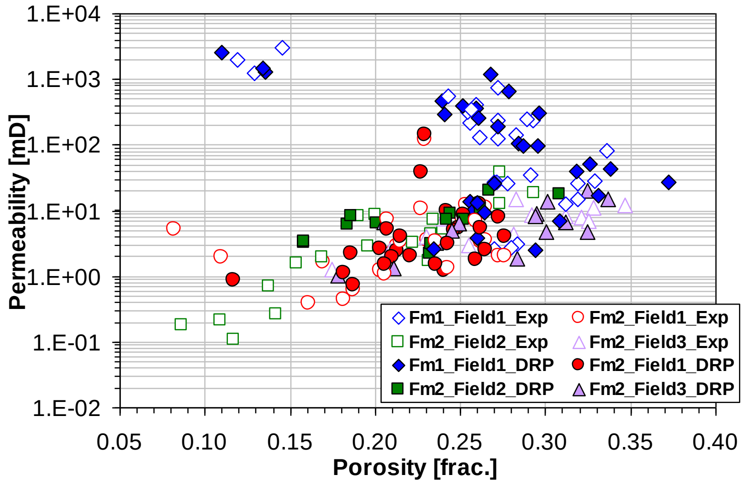


Figure 4: Porosity-Permeability correlation for DRP and laboratory data

The DRP results for FRF and cementation exponent *m* are compared to available laboratory data in Figure 5 as a function of porosity. Laboratory data, comprising minimum of 3 samples/RRT are not always measured on the same samples as DRP results (again, minimum of 3 samples/RRT), but on similar RRT's. DRP results reproduce well the field trends shown within the same range of porosity.

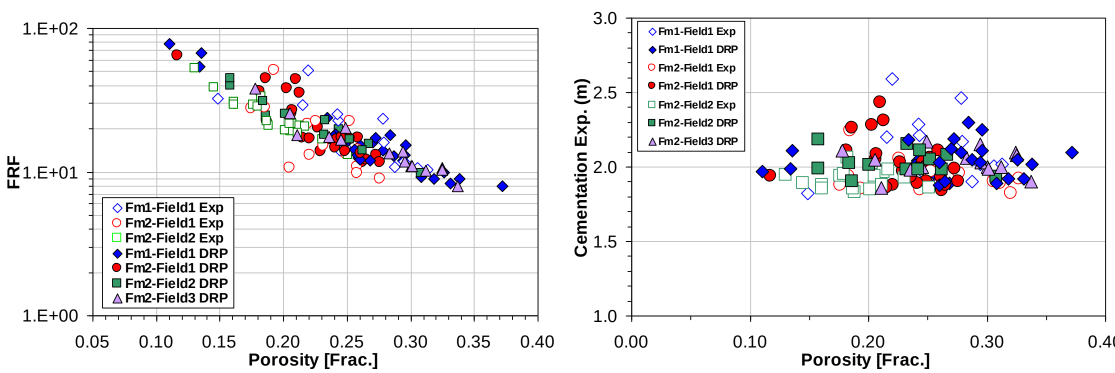


Figure 5: FRF and cementation exponent m as a function of porosity for DRP results compared to available laboratory measurements on samples from the same reservoirs

Oil-water primary drainage Pc curves have been calculated on pore networks derived from the models of the micro-porous phase and the micro plug images. Simulations are conducted under fully water-wet conditions to a maximum Pc of 7 bar (101.5psi). This Pc corresponds to the experimental limits of the SCAL contractor laboratory. The calculated Pc curves are up-scaled to the core plug images. Selected results are presented in Figures 6 to 9.

For Formation 2 in Field 1, results of 4 samples are compared to Pc obtained from Porous-Plate experiments and Pc derived from MICP (Figure 6). The results from DRP are consistent with experimental results. There are slightly larger discrepancies for more heterogeneous samples (25 and 88), consistent with variations between MICP and Porous-Plate results.

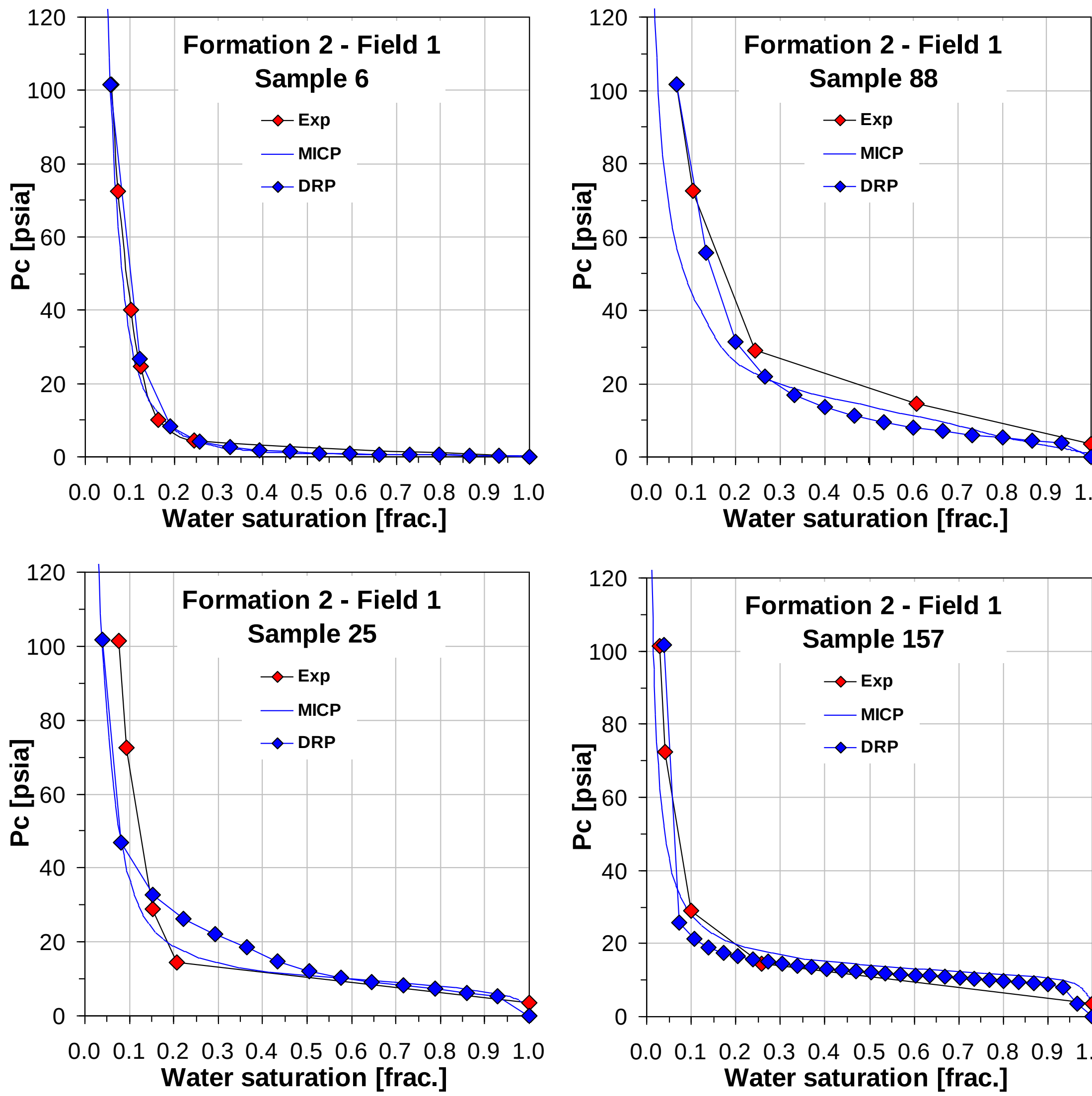


Figure 6: Primary drainage capillary pressure curves from DRP compared to oil-water capillary pressure curves and capillary pressure curves derived from MICP, Field 1 Formation 2

For Formation 1 in Field 1, results of 3 core samples are compared to Pc derived from MICP experiments on samples from the same plugs both in terms of Pc and Leverett-J-function (Figure 7). Sample 9 shows an almost exact fit between the experimental and the DRP Pc curve. Samples 7 and 8 show more difference. MICP samples are smaller than the plug which DRP results are representative for. Thus, measurement differences are expected, especially in heterogeneous samples such as these carbonates. Moreover, permeability calculated from the MICP experiment differs from the measured Klinkenberg corrected gas permeability by a factor 2 or more for samples 7 and 8, whereas the difference for sample 9 is only 25%. Thus, the MICP samples for 7 and 8 are not representative of the core plugs used for DRP evaluations.

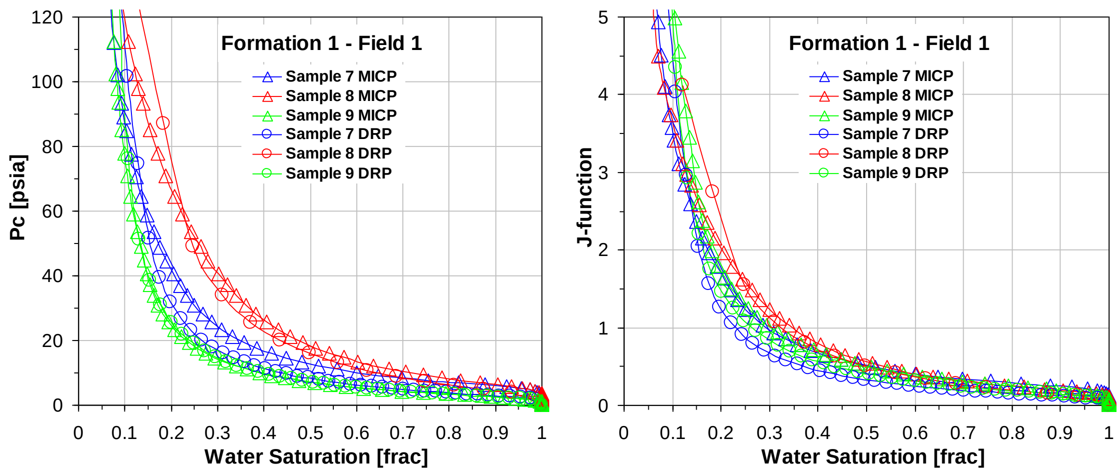


Figure 7: Primary drainage Pc and Leverett-J-function curves from DRP compared to oil-water capillary pressure curves derived from MICP, Field 1 Formation 1

In Figure 8, MICP derived Pc and Leverett-J-function curves are compared to DRP derived results for Formation 2 in Field 3. The results are again consistent with expected behaviour. DRP results calculated for the core plugs show steeper curves suggesting more heterogeneity than the MICP derived curves. This also suggests that the smaller sized MICP samples may not be entirely representative for the core plug in some cases.

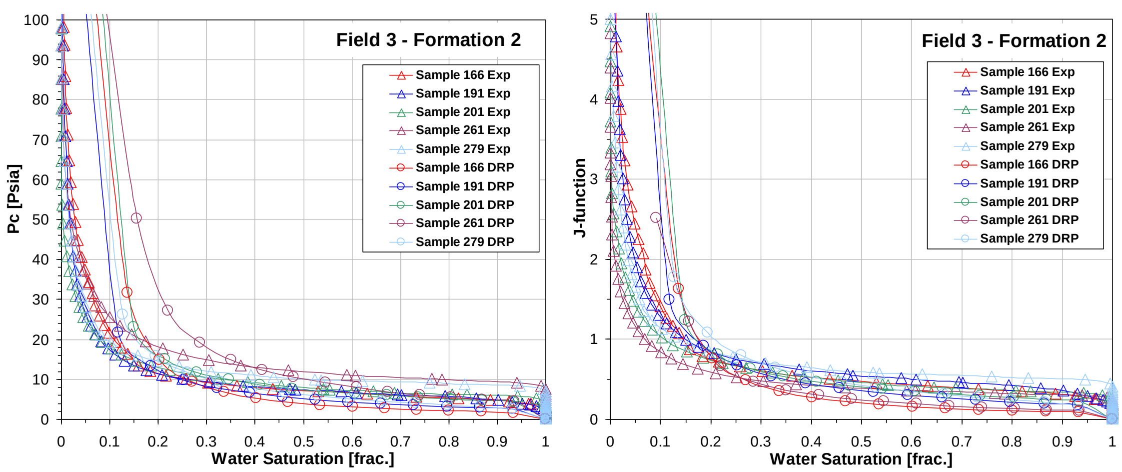


Figure 8: Primary drainage Pc and Leverett-J-function curves from DRP compared to oil-water capillary pressure curves derived from MICP, Field 3 Formation 2

For Formation 2 in Field 2, no laboratory data were available for the studied samples. Therefore, DRP Leverett-J-Function curves are compared to results from the same field (Figure 9). Results are consistent with DRP results with a tendency towards more homogeneous (flatter) curves. However, the same argument applies as put forward for the two samples in Figure 7.

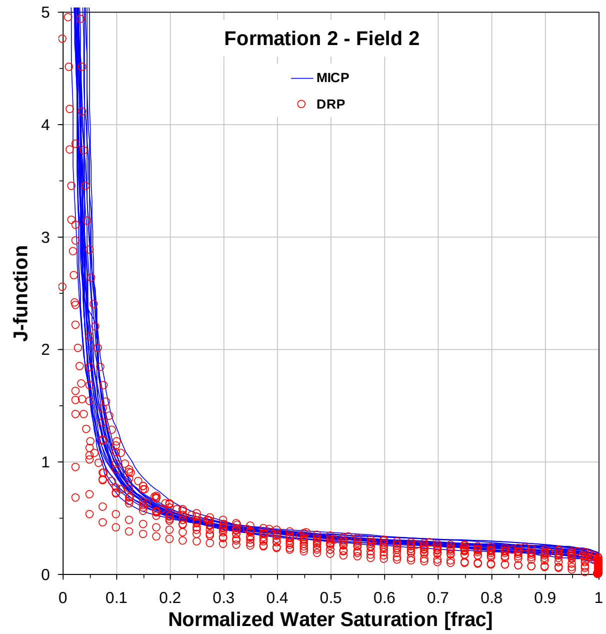


Figure 9: Primary drainage Leverett-J-Function curves from DRP compared to Leverett-J-Function curves derived from MICP, Field 2 Formation 2

Figure 10 shows typical results of NMR T2 relaxation from DRP compared with laboratory experiment (at ambient conditions) on sample 6 from Formation 2 in Field 1. The match is very good. Slight discrepancies can be explained by experimental uncertainties due to noise and different methods to obtain the T2 distribution from the raw data.

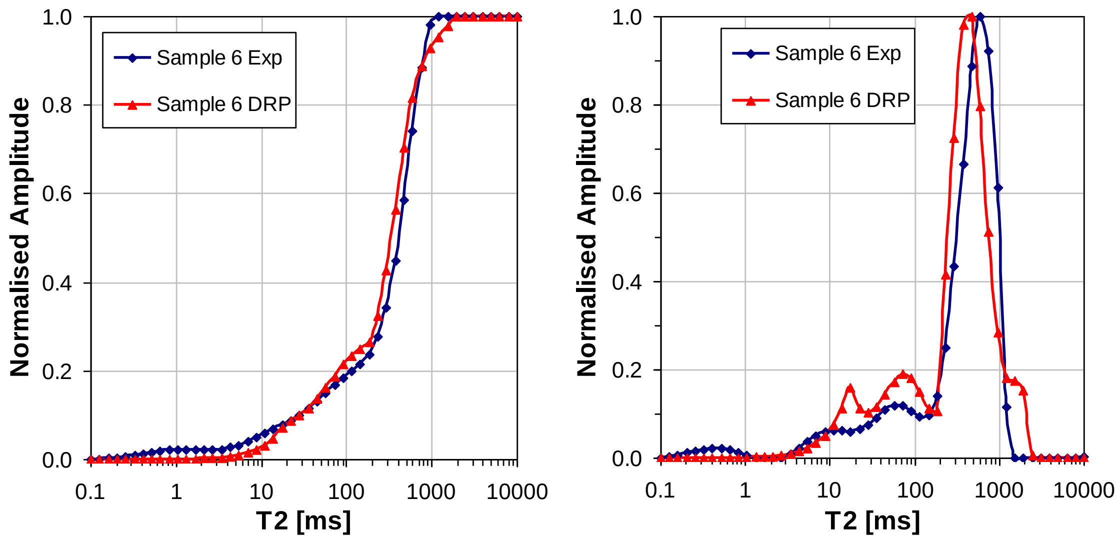


Figure 10: NMR T2 distributions from DRP compared to laboratory measurements, Field 1 Formation 2

CONCLUSIONS

Over 100 carbonate reservoir core samples were digitally characterized in terms of porosity, permeability in three directions (x, y and z), FRF, primary drainage Pc and NMR T2. The predicted core properties are compared and validated with available laboratory measurements on the same core plugs. The results show a consistent match and demonstrate that DRP can be used confidently to identify the fundamental reservoir core characterization features of core plugs and whole cores. Such high quality data is a prerequisite for representative 3D pore network models to be used for 2 or 3 phase flow simulations in accurately predicting relative permeability, Pc and saturation exponent *n* for more complex displacement processes. Results of multiphase flow simulations and experiments, such as two-phase imbibition water-oil relative permeability are presented in a separate paper in these symposium [11].

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