EVALUATION OF THE RELIABILITY OF PREDICTION OF PETROPHYSICAL DATA THROUGH IMAGERY AND PORE NETWORK MODELLING

Caubit, C. (1), Hamon, G. (1), Sheppard, A.P. (2), Øren, P. E. (3)
(1) TOTAL (2) Australian National University (3) Numerical Rocks

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ABSTRACT

Prediction of petrophysical data by pore network imaging and modelling has recently received a lot of attention. This technique was pioneered by P.E. Øren but several other solutions have now been proposed that incorporate different imaging technologies, different methods for obtaining detailed pore space models, and/or different algorithms for extracting simplified networks for multi-phase flow simulations. However, very few comparisons between these techniques have been made to date. This paper compares the approaches proposed by two research teams: The Australian National University (X-ray imagery reconstruction) and Numerical Rocks (Digitized thin section and geologically based reconstruction) through a blind test.

For this blind test, very different samples with a large range of petrophysical properties were shipped to the collaborating teams. Then they constructed a 3D digital model of the rocks, as well as simplified pore networks, with their own techniques. All the multiphase flow simulations were performed on the simplified networks with the flow simulators from P. Valvatne, M. Piri and Numerical Rocks (eCore). Finally all the simulated results were compared to experimental in-house data measured in the Total laboratory.

According to this comparison, we conclude that the porosity and classical capillary pressure (*i.e.* not L-shaped) are correctly predicted when the clay content and/or the micro-porosity are well captured. In addition, uncertainty in absolute permeability can be attributed to voxel precision for ANU and the capability to capture heterogeneities for both approaches. Regarding flow simulations, the gas/oil Krs are reliable when all the previous parameters are well reproduced, however it is impossible to predict residual gas saturation to water. In summary, the ability to capture micro-porosity and heterogeneities seems to limit the capacity of prediction. Consequently the combined techniques of imagery and PNM cannot currently be considered as an industrial tool on the whole range of rock investigated in petroleum engineering.

INTRODUCTION

The microstructure of a porous medium, the physical characteristics of the solids and the fluids that occupy the pore space determine several macroscopic transport properties of the medium. One way to study this microstructure is through pore network models, in which the pore space is represented by a 3D network of interconnected pore bodies and pore throats. Currently these networks are extensively used to determine macroscopic properties including capillary pressure, relative permeabilities and residual saturation for two- [1] or three-phase flow [2]. This technique is very valuable to the core analyst for many reasons: 1) the pore throat network provides important geometrical and topological information to characterise the morphological structure of the pore space; 2) It allows the reconciliation between the sedimentological descriptions and the petrophysical characteristics; 3) PNM remains one of the most promising methods for modelling multiphase flow in porous media [1,2].

In the literature, pore networks are often used to match relative permeabilities; however the capacity of prediction is rarely evaluated by a complete blind test (*i.e.* without any information on the sample provided). In this paper we describe the exercise with two teams: Numerical Rocks (NR) and the Australian National University (ANU). These teams use different techniques to extract pore networks from real samples. NR reconstructs 3D digital models from digitized thin section (SEM images) by a geologically based model from which the simplified pore network is extracted [3,4,5,6,7]. ANU instead generates 3D digital models from microtomographic images, then extracts the pore network using specific algorithms [8,9,10,11]. The algorithms for 3D reconstruction and pore network extraction are different for the two teams but the objective, remains the same: to predict petrophysical data through imagery and pore network modelling.

The blind test consists of:

1) Very different samples (six artificial and outcrop, and six unconsolidated and consolidated reservoir rocks) with a large range of petrophysical properties were selected and shipped to the collaborating teams. Porosity, permeability, drainage capillary pressure, clay content, and relative permeability were measured but not made available to the collaborating teams.

2) Collaborating teams reverted their estimates of porosity, permeability and capillary pressure extracted from 3D digital models of rocks, as well as simplified pore networks.

3) Multiphase flow simulations were performed using the simplified pore networks as input for the two-phase and three-phase pore network flow simulators from P. Valvatne[1], M. Piri [2] and Numerical Rocks (eCore[12,13]).

4) The following predicted and in-house experimental data were compared: porosity, permeability, drainage capillary pressure, gas/oil relative permeabilities and residual gas saturation to water.

OUTCROP AND ARTIFICIAL SAMPLES

In this section the results related to the outcrop and artificial samples shipped to the Australian National University are presented. It was decided not to send these samples to Numerical Rocks because P. E. Oren and his co-workers have already published several papers on geologically based reconstruction of outcrop sandstones like Fontainebleau [4] and Berea [5]. These papers presented encouraging results in terms of prediction of petrophysical data. For our study we have chosen five sandstones including one Berea, one Clashach and three Fontainebleau (FTB), as well as one artificial sample the Aerolith 10 (A10) which is made up of packed grains of silica. These samples exhibit a large range of porosity and permeability, and varying amounts of clay content in order to assess the capacity of ANU to image porous media microstructure with X-ray micro-tomograph.

Porosity and Permeability Results

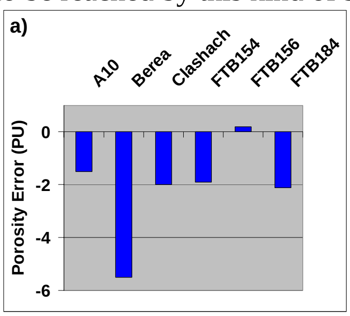
Table 1 displays our in-house data related to the six artificial and outcrop samples in terms of porosity and permeability range: 7.8 to 40.3% for the porosity; 31 to 4750 mD for the permeability.

Figure 1a compares the experimental and predicted porosity extracted from the simplified pore networks (these values are very close to those deduced from 3D images). Globally the porosity is underestimated by -1.5 PU for the clean rocks. For the Berea, the error is larger and equal to 5.7 PU. The difference can be attributed to the significant clay content of this sample. However, during the reconstruction of the 3D digital model, and particularly during the three phase segmentation, ANU is also able to estimate a volume of clay. This volume of clay incorporates the microporosity, which is not resolved by the X-ray micro tomography. This volume of microporosity is deduced from the estimated clay volume, using an empirical relationship [12] and can be used as an input parameter in the PNM simulator. Consequently, if the calculated micro-porosity (PN flow simulator) is added to the macro-porosity derived from the void space (3 phase segmentation) the error on the total porosity is reduced to 0.5 PU.

For all these samples, the absolute permeability was derived from simplified pore networks (PNM simulation) or directly from 3D images (lattice Boltzmann simulation [14,15]). All the permeability results are presented in Figure 1b with an average relative error of ±40%. Moreover, significant differences are observed between the two methods of calculation which can be explained by the simplification of the geometry when the pore network is extracted from 3D the digital model. The discrepancy between experiment and simulation is much more striking for the FTB 154 due to its low porosity and permeability. The limits of X-ray micro-tomograph seem to be reached by this kind of sample.

	ϕ (%) In-house	k (mD) In-house
A10	40.3	4750
Berea	23.9	747
Clashach	17	1000
FTB154/54	7.8/8.2	69/31
FTB156/56	13.2/13.4	880/487
FTB184	19.7	2880

Table 1: Permeability and porosity from laboratory measurement



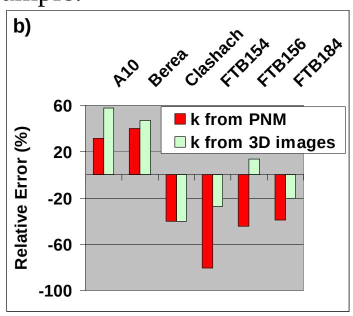


Figure 1: Prediction accuracy a) ϕ extracted from pore network b) k extracted from pore network & 3D images

Globally, porosity and permeability predictions reverted by ANU are reliable. The uncertainty on porosity is mainly due to the difficulties in imaging the micro-porosity with the X-Ray micro-tomograph. As far as the permeability is concerned, the CT images can identify the pore space with one voxel precision. This means that the estimated throat radius has an uncertainty of ±3 microns. If the throat radius is around 15-20 microns, this 15-20% uncertainty in throat size changes the permeability by a factor 1.5 or 2, since permeability is proportional to the throat radius squared.

Drainage Capillary Pressure Results

In this section our in-house and simulated data are compared in terms of drainage capillary pressure for each sample except for FTB 184 (the experimental data were not available). All the experimental capillary pressure data gathered in Figure 2 were obtained by mercury injection. The simulations of capillary pressure were carried out with Valvatne's two-phase code with appropriate scaling of interfacial tensions. As shown in Figure 2, the results obtained through PNM simulation are very satisfactory except for FTB 154. Again, for FTB 154 the difference can be explained by the low porosity and permeability and a throat size beyond the imaging capability of the X-Ray micro-tomograph. For Clashach the discrepancy can be attributed to the possible existence of micro-porosity down to one micron which is impossible to observe by X-Ray imagery; this explanation is consistent with the underestimation of porosity.

For all the other samples, the quality of the simulations is very encouraging. Therefore, for these samples the combined techniques of X-Ray imagery and pore network modelling provide very reliable results in terms of pore throat distribution, which is the main parameter impacting the capillary pressure.

In summary, the capillary pressures predicted using imagery and pore networks are reliable except for samples with low permeability (i.e. k<50md) and/or with a significant amount of micro-porosity.

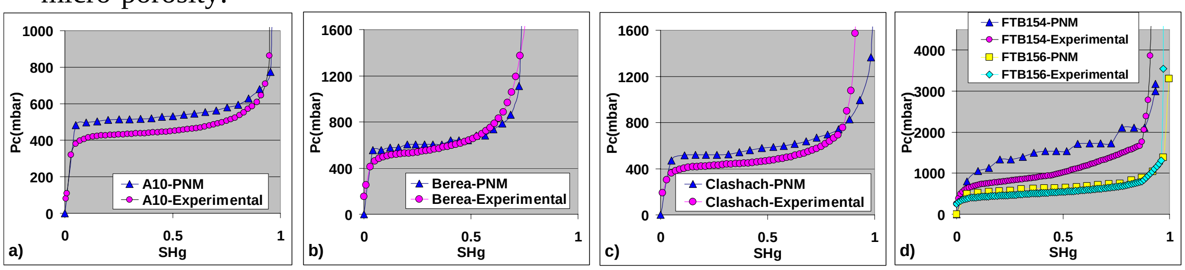


Figure 2: Drainage capillary pressure results, Comparison between experimental data & PNM simulations a) A10, b) Berea c) Clashach & d) FTB.

Gas/Oil Relative Permeability Results

Figure 3 shows the simulated and experimental results related to the gas/oil relative permeabilities for A10, Berea & Clashach. It is worth noting that we have chosen gasflooding rather than waterflooding in order to avoid most of the issues linked to wettability which could strongly impact the reliability of PNM prediction.

We assumed a strong wetting to liquid and all the preliminary simulations were performed with a gas/oil contact angle equal to zero. Without tuning, none of the first attempts of these simulations was satisfactory because the irreducible water was not reproduced. To improve the quality of the result in terms of gas/oil relative permeability, we have modified the clay content in order to match the irreducible water. All the data derived from these simulations are gathered on Figure 3. There is a very good agreement for the oil relative permeability except for low oil saturation, but the gas relative permeability is very poorly reproduced except for the Clashach. The krg discrepancy might be attributed to the impact of the Swi. Its influence on relative permeability was evaluated on the reservoir samples (next section) with a three-phase PNM simulator [2].

To conclude, the clay content appears to have a major impact on the irreducible water and the gas/oil relative permeability, which limits the predictive capacity. However, it seems that when the porosity, the clay content and the capillary pressure are all well captured, the kro is very well reproduced for high oil saturation as shown for the Berea.

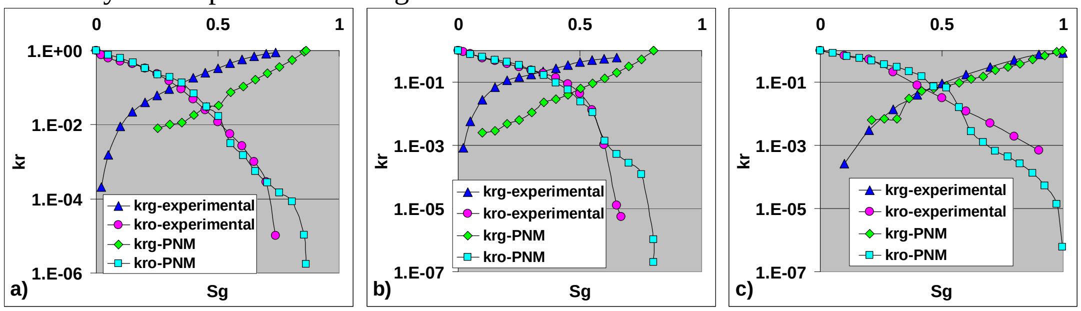


Figure 3: Gas/Oil Rel. Perm. results, Comparison between experimental data & PNM simulations a) Berea b) A10 & c) Calshach

Residual Gas Saturation to Water Results (Sgrw)

We chose to predict the residual gas saturation to liquid because a strong wetting to liquid prevails during the capillary rise experiments. Assuming that the gas/water contact angle is equal to zero, none of the simulations provided reliable results for any samples. In order to improve the quality of the simulated Sgrw, we decided to modify the contact angle. We succeeded in reproducing a specific trend related to the three FTB samples [16] with a distributed contact angle ranging between 52° and 90° as illustrated by Figure 4. However, the range of distributed contact angle determined for the FTB is questionable because it is representative of intermediate wetting rather than a strong wetting to liquid.

This kind of result is often observed in the literature, for instance Valvatne provided two-phase water/oil relative permeability in very good agreement with Oak's experimental data [17] with a contact angle in excess of 60° whereas the experiments were performed on water-wet Berea [17]. Several hypotheses are proposed to explain this kind of distributed contact angles:

- The influence of the pore space roughness which can increase the value of the contact angle compared to the expected value.
- The impact of the pore body filling algorithms. Several algorithms are available providing very different results in terms of contact angle.
- The effect of dynamic PNM (compared to quasi static) and pore shape. Nguyen *et al.* [18] provide an approximate match of the Oak's data set with a contact angle of zero if the viscous forces and the experimental flow rate are accounted for. In this case it is necessary to use hexagonal pore shape.

In order to determine if the contact angle derived from the simulations with the FTB samples can be considered as a sound recipe to predict Sgrw, we have performed exactly the same simulations with the A10, Clashach and Berea. As shown in the Table 2 the results are very disappointing, highlighting the large difficulties in correctly reproducing the Sgrw.

To conclude, it appears that the prediction of the residual gas saturation at strongly liquid wet conditions was not successful.

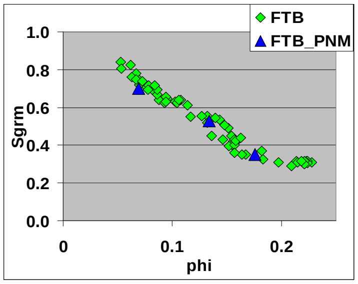


Figure 4: FTB, Sgrw experimental trend reproduced with PNM simulations.

	Sgr_{max} (S_{wi}=0)		Sgr (S_{wi}=0.25)
Porous media	A10	Clashach	Berea
PNM Sim.	0.3	0.67	0.47
In-house data	0.18	0.37	0.3

Table 2: Experimental Vs Simulated residual gas saturation to water with exactly the same gas/water contact angle distribution used for the FTB simulations.

RESERVOIR SAMPLES

This section gathers all the results related to the reservoir samples. Exactly the same strategy described previously was applied to assess the performance of the prediction of the petrophysical data. In this case, the same samples were shipped to ANU and NR for the blind test. The main aim was to put in evidence and explain the discrepancy observed between the prediction and the experimental data. As previously, the samples were selected with a wide range of properties in order to have a reliable blind test.

Porosity and Permeability Results

Figure 5 shows the porosity and the permeability derived from monophasic PN flow simulation. Initially, NR provided 3 or 4 realizations for each sample. Each realization corresponds to a different hypotheses made by NR in terms of intergranular porosity and clay distribution to reproduce the observations made on the thin sections. As shown on Figure 5a and 5c, these realizations lead to a significant scatter: 5PU for the porosity and up to a factor of 5 for the permeability. The results in terms of porosity remain acceptable whereas the permeability is not well reproduced. This especially true for the samples 1806 and 2313 where the porosity and the permeability are systematically overestimated. This is also true for the single realisation provided by ANU for each sample.

The predicted porosity and permeability of samples 1806 and 2313 are greatly overestimated. In fact these two samples are unconsolidated sands. Resin was injected in the rock samples while still mounted in the core holders at reservoir effective stress, to be able to cut later a thin section (NR) or a thin cylindrical piece of material (ANU). During the impregnation process, it is suspected that the resin underwent an expansion which modified the initial pore space. This result is confirmed by the thin section (NR) and the grain partitioning (ANU) which put in evidence the absence of contact between the grains at several locations. Consequently these networks were discarded and no flow simulations were performed.

All the comments related to porosity and permeability made on the pore network extracted by ANU from the outcrop samples remain relevant for the samples 122, 153, 5589 and 1293. The results for sample 153 illustrate very well the scatter of realizations provided by

NR, based on observations of the thin section which pointed out, at the very small scale, three different zones in terms of cementation, clay distribution and intergranular porosity. These three zones lead to three digital models with very scattered permeability as shown in Figure 5c. This example highlights the difficulties of the comparison between pore networks and core results, even when CT scan images of the core sample do put in evidence acceptable rock homogeneity. Finally, the porosity prediction remains acceptable for the reservoir samples whereas the permeability prediction is clearly more scattered.

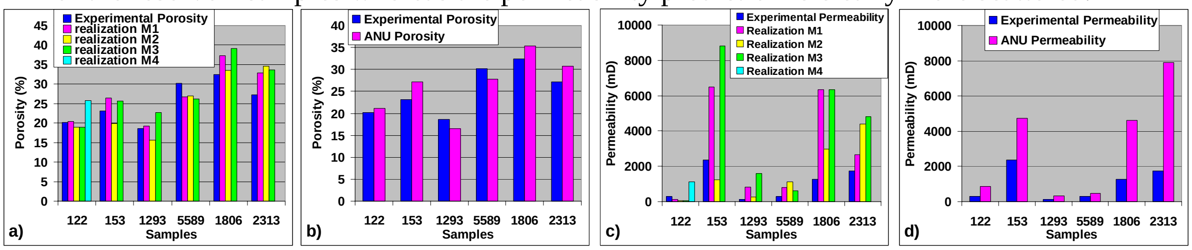


Figure 5: Extracted k & ϕ from pore network Vs Experimental data, a) ϕ from NR, b) ϕ from ANU, c) k from NR & d) k from ANU.

Drainage Capillary Pressure Results

Figure 6 gathers the experimental and simulated capillary pressure. The PN simulations were performed without any tuning procedure. Valvatne's two-phase code was used. The following results concern only the samples 122, 153, 5589 and 1293. In order to assess the performance of prediction, the drainage capillary pressure was characterised by three criteria: the displacement pressure, the shape of the curve and the range of very low non-wetting phase saturation.

The main results in terms of displacement pressure are the following:

- For ANU, the displacement pressure is systematically very well reproduced for all samples indicating that the pore throat distribution is very well captured by the combined techniques of X-ray imagery and pore network extraction. Therefore, we can be confident on the capacity of prediction of this parameter, which is very important to characterise drainage capillary pressure.
- For NR, the displacement pressure is slightly scattered according to the different realisation derived from the analysis of the thin section. However, the prediction remains largely acceptable except for the sample 122 due to heterogeneity issue.

The main results in term of shape and the very low saturation range are the following:

- For ANU, very different results are observed depending on the sample. On the one hand, for the 5589 the low saturation range is quite well reproduced highlighting that the clay content and the associated micro-porosity are very well captured. However the shape is poorly reproduced. It seems difficult to generate a capillary pressure curve unless it is L-shaped. On the other hand, for all the other samples the shape is correct whereas the Pc curve is not well captured in the very low saturation range. Again, local heterogeneities and scale issues might explain some discrepancies. For instance, for the sample 122 the picture on the right shows the companion 25

mm diameter plug shipped to ANU with a “X” locating roughly where the 5mm plug was cored. The presence of darker zones suggests the presence of very small (millimetre) scale heterogeneities in these reservoir samples and highlights that the predictions might be very sensitive to the volume and location of samples observed for pore network modelling.

- For NR, it is always possible to find at least one realisation which is in very good agreement with the experimental data except for the sample 1293. For the sample 1293, neither NR nor ANU succeeds in reproducing the capillary pressure in the very low saturation range. No clear explanation was found and we decided to discard this sample from the next part of the blind test (*i.e.* multiphase flow simulation).

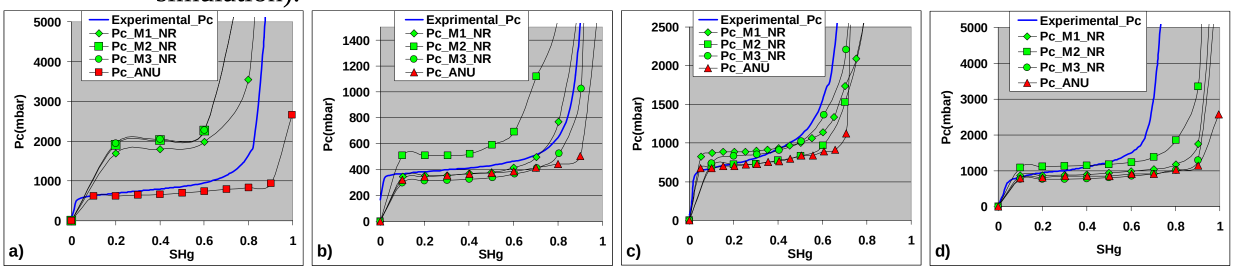


Figure 6: Simulated Vs Experimental drainage capillary pressure for each samples, a) Samples 122, b) samples 153, c) Samples 5589 d) Samples 1293.

Gas/Oil Relative Permeability Results

In order to assess the impact of the Swi on the gas/oil relative permeability, we compared the results from two-phase (Valvatne) and three-phase (Piri) PN flow simulations for the sample 153 on Figure 7. Figure 7a shows the comparison of oil relative permeability curves. No significant differences were observed; only slight discrepancies are noted which can be attributed to the different conductivity model for layers that is implemented in each code. The same exercise was carried out for the three-phase simulators (eCore and Piri’s code); in this case the kro were very similar for high oil saturation whereas the Sorg was significantly different. This discrepancy might be explained by the capillary model implemented in eCore, which is not only based on geometric criteria but is also thermodynamically consistent [19]. It might lead to less stability for oil layers, and thus explains the larger Sorg shown Figure 7b. In the following, we carried out all the simulations with Valvatne’s code.

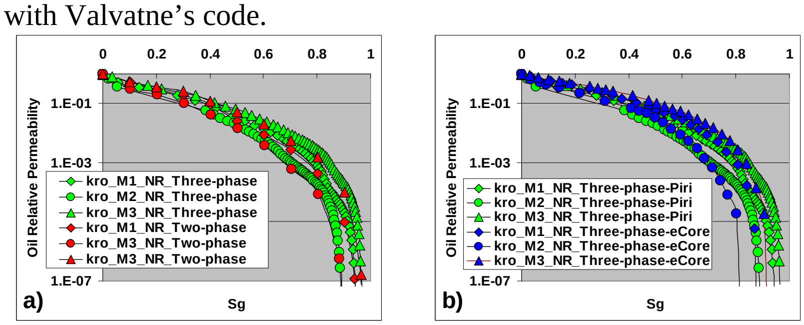


Figure 7: Simulated kro with two- & three-phase simulators for the sample 153 (Network from NR), a) Two- & three-phase comparison: Valvatne’s code Vs Piri’s code, b) Three-phase comparison: Piri’s code Vs eCore

The simulated gas/oil relative permeability for the samples 122, 153 and 5589 are presented in Figure 8. The same procedure as for the outcrop samples was applied. For ANU, we were obliged to estimate a clay content for the samples 122 and 153, to improve the results. By including the appropriate clay content in the two phase code, the relative permeabilities were largely improved, except for the krg of the sample 153. At the same time the capillary pressure curve is now much better captured in the low saturation range. On the other hand, for the sample 5589 (which underwent, like the Berea, a three-phase segmentation including clay), the kro is directly well reproduced except for low oil saturation whereas the simulated krg remains unsatisfactory. These results confirmed that when the porosity and the capillary pressure are well predicted, the simulated oil relative permeabilities are in good agreement with the experimental data but the capacity of gas relative permeabilities prediction seem to be much more limited.

For NR, it is always possible to find a realization which reproduces quite well the gas/oil relative permeabilities. The agreement with experimental data is poorer for samples with high clay content as shown Figure 8c.

It should be noted that the same realization provides the best results for porosity, permeability, capillary pressure and oil relative permeability.

To conclude, the current prediction capabilities seem to be limited by the ability to capture the amount of microporosity by the micro tomography for ANU's approach and the ability to select a representative realisation among the different reconstructions for NR. When these conditions are satisfied, for both approaches, there is a consistent set of descriptors of the pore network which honours the experimental data: porosity, permeability, drainage capillary pressure, and gas/oil relative permeability curves.

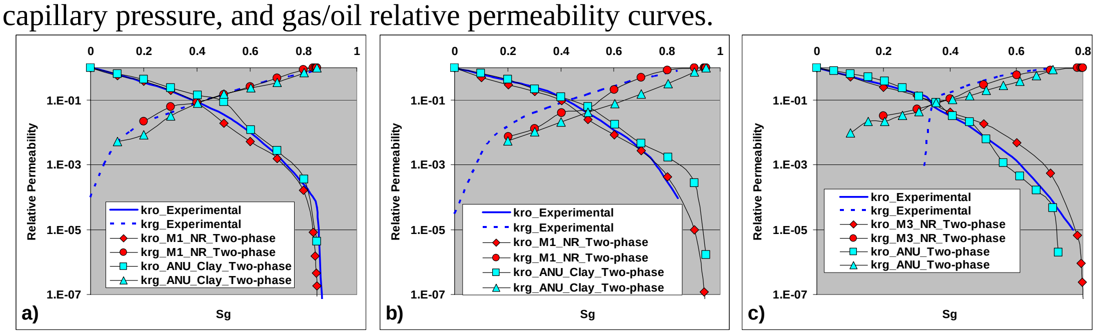


Figure 8: Two-phase simulations, Experimental Vs simulated gas/oil relative permeability, a) Samples 122, b) Samples 153 & d) Samples 5589.

Comparison of Prediction Performance Between PNM & Petrophysical Database

To assess the reliability of relative permeability prediction through imagery and pore network modelling, we compared these new techniques with a more conventional engineering approach. Firstly, we extracted from our database the gas/oil relative permeability curves with the same characteristics as sample 153 and then compared them with the experimental data of sample 153. The comparison (Figure 9a) of the oil relative permeability curves as a function of normalized gas saturation indicates that the Krog curve can be easily and correctly estimated by the conventional engineering approach. Secondly we compared the experimental data of sample 153 against the predictions by pore network modelling: we took into account all the realisations provided by NR and the ANU (with the appropriate estimate of clay content). The Figure 9b shows that the experimental data are within the scatter of all predictions for this sample.

This result is very encouraging, as it shows that, if not yet perfect, the pore network modelling approach compares very well with more conventional methods.

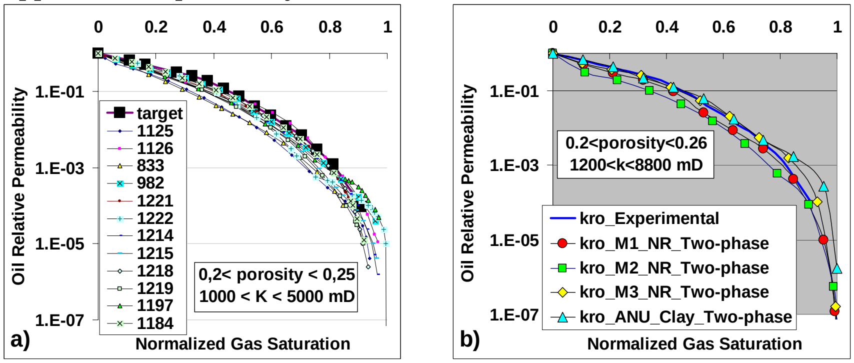


Figure 9: Relative oil permeability prediction performance, Petrophysical data base Vs PNM simulation for the sample 153.

Residual Gas Saturation to Water Results (Sgrw)

Only the samples providing the best results in term of gas/oil relative permeability were used (i.e. 122 and 153). As for the outcrop, a reliable, direct prediction of Sgrw is not possible. If the gas/water contact angle is tuned towards large values in the two-phase code, the experimental Sgrw can be reproduced. However, these contact angles are not deemed representative of the strongly liquid wet conditions prevailing during capillary rise tests.

Team	ANU		Numerical Rocks	
Sample	122	153	122	153
Initial Sg	1	1	1	1
Simulated Sgr	0.352	0.339	0.378	0.345
Experimental Sgr	0.35	0.34	0.35	0.34
Contact angle used	0-70°	0-63°	67-90°	67-90°

Table 3: Experimental Vs simulated residual gas saturation for the samples 122 &153

CONCLUSIONS

The main conclusions of this paper are the following:

- The porosity predictions are reliable as long as they are not strongly influenced by the micro-porosity or/and the clay content which are difficult to image by X-ray or SEM.
- Uncertainty in absolute permeability is due to voxel precision for ANU and the ability to capture very small scale heterogeneity within the volume of the piece of rock used for the construction of the pore networks for both approaches.
- The capillary pressure is well reproduced when the micro-porosity and/or clay content is correctly captured. However some difficulties appear when the capillary pressure curves are not “flat” (*i.e.* not L-shaped). The reasons for this are unknown.

- When the porosity, absolute permeability and the capillary pressure are well predicted, the prediction of the oil relative permeability to gas can be considered as reliable.
- The prediction capabilities of the pore network modelling approach for oil relative permeabilitiy compares very well with more conventional engineering methods, such as petrophysical database.
- No direct reliable prediction of the residual gas saturation to liquid was achieved with a relevant contact angle. This result can be explained by a lack of physics in the PNM simulator.
- The current prediction capabilities seem to be limited by the ability to capture the amount of microporosity by the micro tomography for ANU's approach and the ability to select a representative realisation among the different reconstructions for NR.
- For both approaches, when these conditions are satisfied, there is a consistent set of descriptors of the pore network which honours the experimental data: porosity, permeability, drainage capillary pressure, and gas/oil relative permeability curves, allowing that for ANU, the krg capacity of prediction seems more limited.
- Assuming the previous conclusions, the combined techniques of imagery and PNM cannot currently be considered as an industrial tool on the whole range of rock investigated in petroleum engineering.

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