USING DIGITAL ROCK TECHNOLOGY TO QUALITY CONTROL AND REDUCE UNCERTAINTY IN RELATIVE PERMEABILITY MEASUREMENTS

Josephina Schembre-McCabe and Jairam Kamath
Chevron Energy Technology Company

This paper was prepared for presentation at the International Symposium of the Society of Core Analysts held in Vienna, Austria, 27 August – 1 September 2017

ABSTRACT
Digital Rock Technology (DRT) has experienced tremendous progress in the last decade, with an increasing number of companies providing imaging hardware, modeling software and digital core analysis services. While prediction remains the most discussed application of DRT, this paper discusses its use to quality control water displacing oil relative permeability (k_r) experimental measurements. The k_r data was collected from three wells over a span of seven years, and it showed a very large spread. To identify potential outliers, we performed micro-CT imaging on six samples that were selected based on similarity in rock properties but differences in measured relative permeability behavior. The three-phase segmentation process was guided by measured values of porosity and clay. Consistency checks verified that we could reproduce permeability, drainage capillary pressure, and gas oil relative permeability. Water displacing oil relative permeability was then calculated using pore network models for water-wet and oil-wet conditions, and used to establish a maximum range for each sample. This range was instrumental in identifying suspicious behavior, and reducing uncertainty in recovery predictions.

INTRODUCTION
DRT based prediction of primary drainage and imbibition water-oil relative permeability can be in good agreement with experimental data if the pore structure, connectivity, and wettability of the porous media is captured accurately [1,2,3,1,2,3,4]. However, accurate characterization of wettability inputs such as contact angles and distribution of oil-wet surfaces is a challenge [8,9]. In this work, we use wettability measurements only as a guide, and focus on comparing experimental results with pore network simulations of strongly water-wet and oil-wet relative permeability behavior. We expect these simulations to be reasonably accurate [10,11].

RELATIVE PERMEABILITY AND WETTABILITY DATA
Water displacing oil Unsteady State (USS) relative permeability data was collected on three wells over a seven-year period. The data was fitted using a power law model, and Figure 1 displays the normalized relative permeability curves. The same testing protocols (reservoir temperature, preserved, unsteady state) were used over the years, but the data showed a very large variation with remaining oil saturation (SO) from fractional flow

calculation ranging from 30 to 65% OIP after 1 pore volume injected (PVI). Fractional flow is calculated assuming water-oil viscosity ratio of 0.13. The objective of this work was to understand the reasons for this large variability and to identify potential outliers.

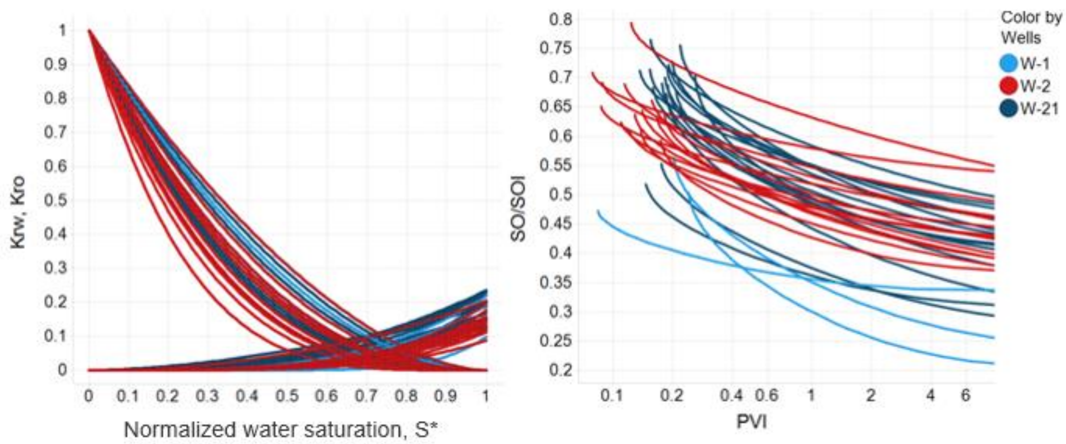


Figure 1: Imbibition Water-Oil Relative Permeability (Left) and So / Soi from fractional flow calculations (Right).

Figure 2 displays Amott and USBM index for samples in wells W-1 and W-2, in which measurements (reservoir temperature, preserved) were performed in a combined sequence on the neighboring plugs. Marked symbols indicates samples that are close to those we analyzed in this study. This plot is also useful to understand the distribution of oil-wet surfaces – the line [12] for Fractional Wet (randomly distributed water-wet and oil-wet) is shown for reference.

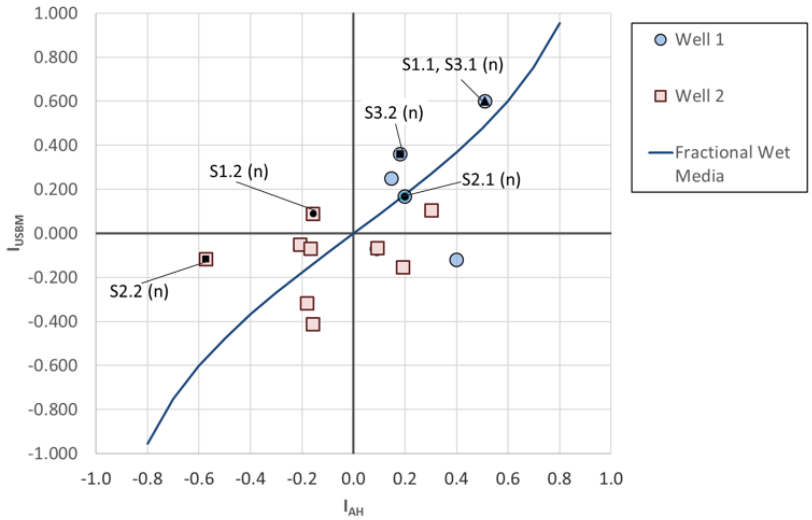


Figure 2: Amott and USBM indices for samples from well 1 and 2. Marked symbols indicate samples that were close to those analyzed in this study – well 1 (samples 1.1,2.1,3.1and 3.2); well 2 (samples 1.2 and 2.2).

WORKFLOW

The workflow consists of five stages:

- Selection of Samples
- Micro-CT and Segmentation
- Pore Network Simulation - Consistency Checks
- Comparison of Calculations for Water Wet and Oil Wet Scenarios with Measured Data
- Uncertainty Reduction

Selection of Samples

Table 1 shows the 3 sample groups used in this study. Each group contains two samples that have similar porosity and permeability (**Figure 3**) and pore throat size distributions (**Figure 4**).

Table 1: Properties of samples used in the analysis

Group	Sample	Well	Formation	Porosity	Permeability	Clay Cont (total)
1	1-1	W-1	F2	20	19	16
	1-2	W-2	F2	20	25	14
2	2-1	W-1	F1	21	18	17
	2-2	W-2	F1	22	16	22
3	3-1	W-1	F1	20	6	23
	3-2	W-1	F1	20	10	23

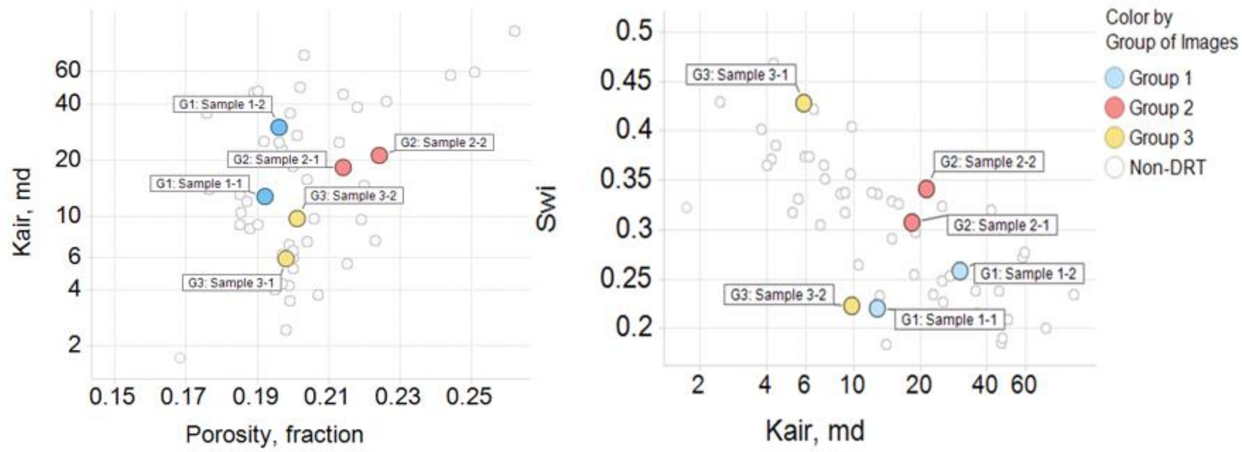


Figure 3: Groups of Samples selected for the study

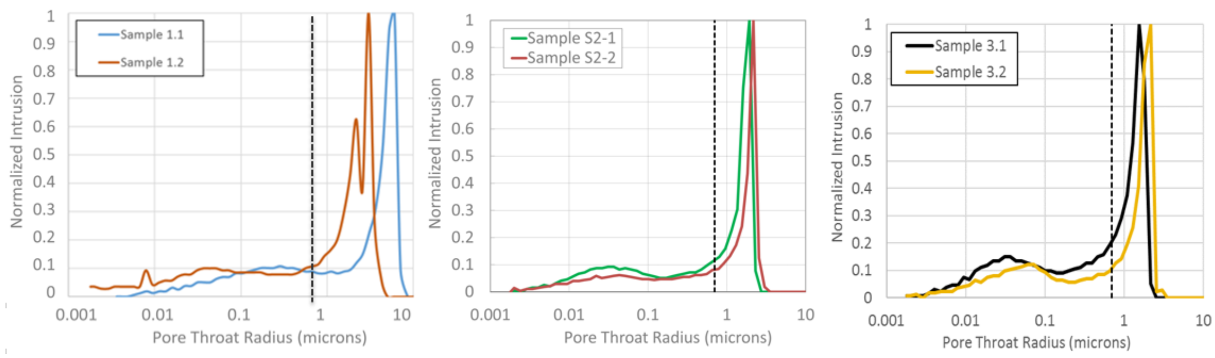


Figure 4: Pore Throat Size Distribution for selected samples, dashed lines indicate voxel size for reference

The relative permeability data and corresponding remaining oil saturation, ROS are in figures 5-7. Similar samples can exhibit significantly differing behavior.

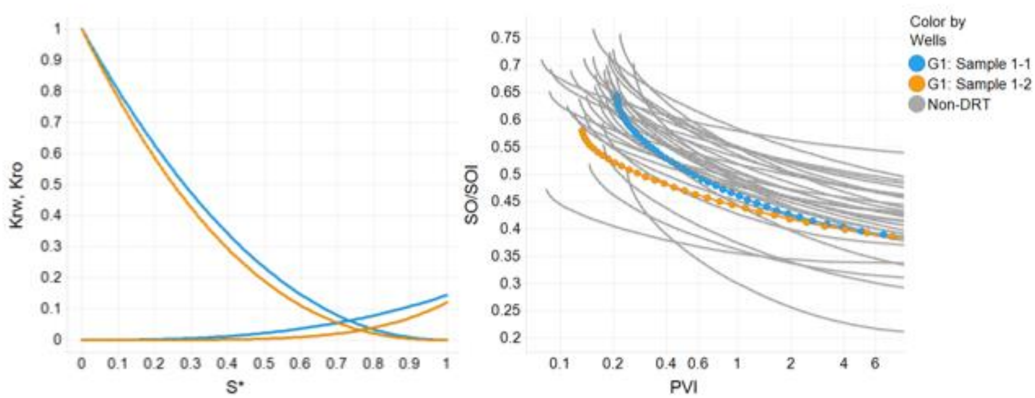


Figure 5: Group 1 - Relative Permeability (Left) and ROS from fractional flow calculations (Right)

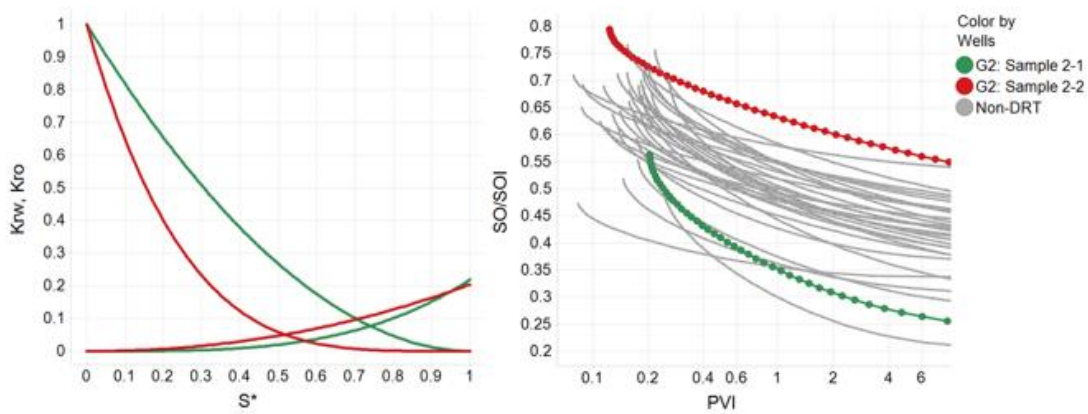


Figure 6: Group 2 - Relative Permeability (Left) and ROS from fractional flow calculations (Right)

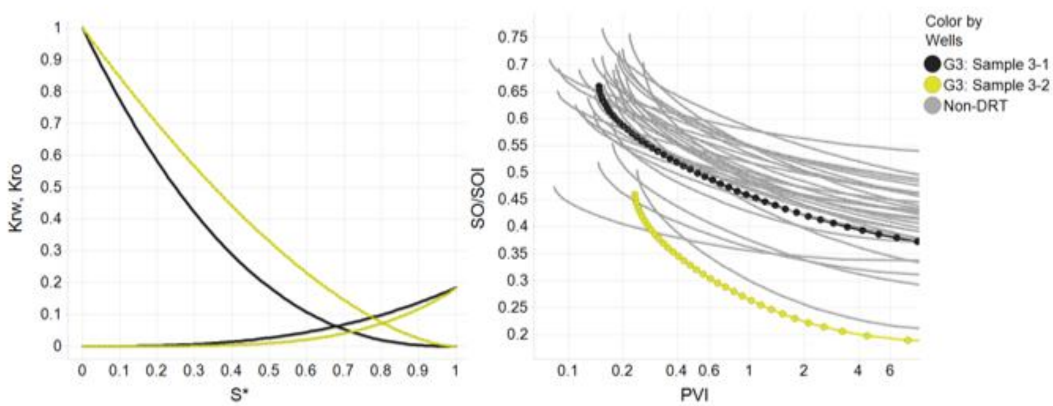


Figure 7: Group 3 - Relative Permeability (Left) and ROS from fractional flow calculations (Right)

Micro-CT and Segmentation

Micro-CT 3D images at 0.7 μm voxel size were obtained on samples of 3mm diameter using X-Radia VersaXRM-500, Figure 8 shows a slide of 3D Micro-CT before segmentation. Due to the amount of clay and their distribution, the segmentation process was guided by values of porosity (resolvable and total) and clay estimated from other laboratory measurements (PKS, MICP, QXRD, 2D QEMSCAN® (2μm/pixel) to narrow the uncertainty in the segmentation process [13, 14]. We used an in-house enhanced histogram thresholding method to perform segmentation. This partitioning yields at least 3 regions -- pore phase, a sub-resolution-porosity, and a solid phase.

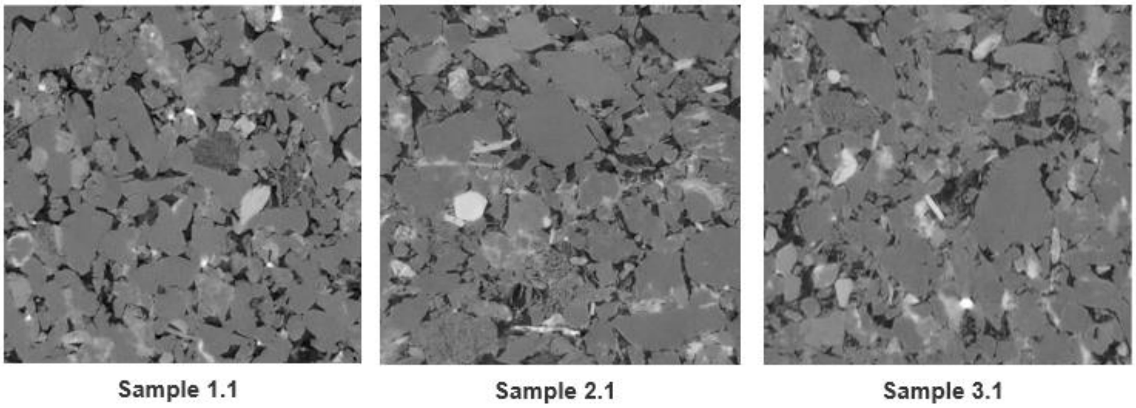
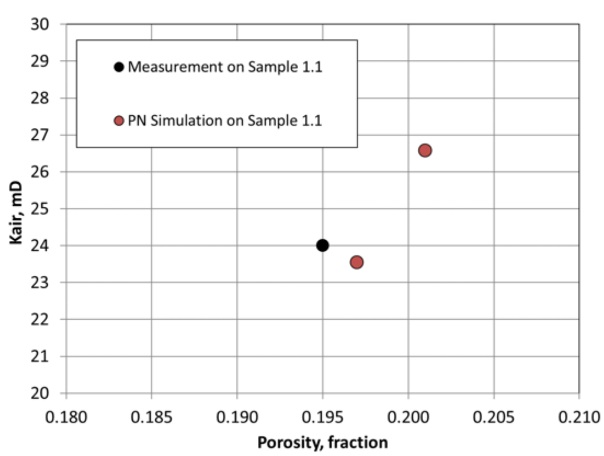


Figure 8: Two-dimensional section of Micro-CT (μm voxel size) scans for sample 1.1, 2.1 and 3.1. Voxel resolution is 0.7 μm.

Pore Network Simulation - Consistency Checks

Once the segmentation was completed, we performed consistency checks for absolute permeability, drainage capillary pressure, and gas-oil relative permeability using REV sub-volumes (800^3 pixels) to test the pore network representativeness of the samples. We used commercial software (e-core) [10] to extract the pore network and perform numerical simulations.

We show one example of the consistency checks performed in each of these samples using results from sample 1.1. **Figure 9 -left** reveals that computed permeability agrees well with measurements on sample 1.1. **Figure 9-right** compares the drainage capillary pressure (MICP) of sample 1.1 and pore network simulation.



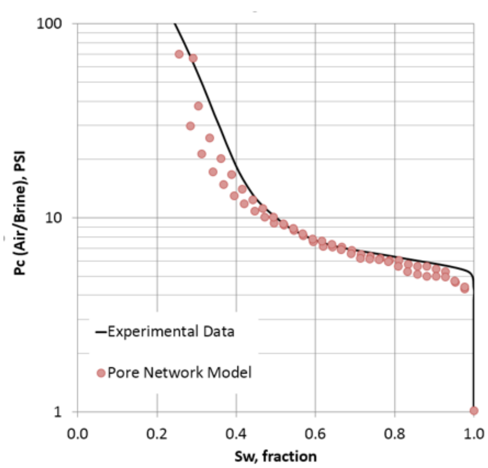


Figure 9: Consistency check for sample 1.1: Permeability vs porosity (left); primary drainage capillary pressure (right)

Figure 10 demonstrates the good agreement between calculated and measured gas-oil centrifuge relative permeability and pore network model.

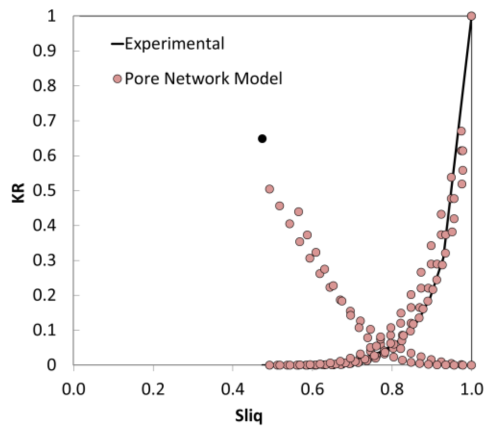


Figure 10: Consistency check for sample 1.1. Comparison of Experimental and Simulated Gas-Oil Kr

COMPARISON OF CALCULATIONS FOR WATER WET AND OIL WET SCENARIOS WITH MEASURED DATA

The sensitivity studies on imbibition were performed for scenarios representing water-wet (contact angle 30-70^0) and oil-wet (contact angle 120-150^0) conditions [10]. The comparisons of experimental and results from the pore network simulation consisted of relative permeability and fractional flow plots. Information from wettability tests (**Figure 2**) on neighboring samples in wells 1 and 2 was used to check for consistent behavior.

<u>Group 1:</u> Relative permeability for the two samples in this group are shown in **Figure 11** Displacement efficiency plots calculated with each relative permeability set are shown in in **Figure 12**. A comparison of experimental results with the pore network model simulations suggests that sample S1.1 is in the water-wet to mixed-wettability range, and this is consistent with the wettability tests. However, sample S1.2 is outside even the water-wet range, and this is contrary to the wettability data. Samples belonging to well 2 with the same behavior were removed from the sample pool.

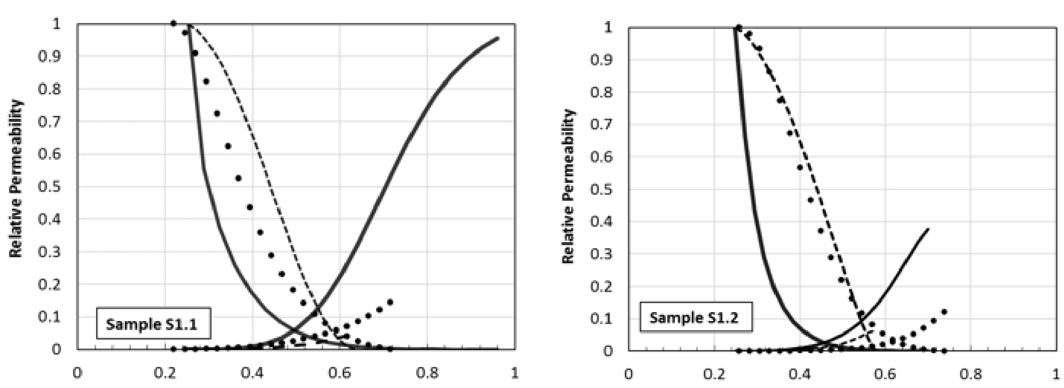


Figure 11: Group 1 - Comparison of experimental (solid circles) and calculated imbibition water/oil kr for water-wet (dashed line) and oil-wet (solid lines) scenarios for S1.1 and S1.2

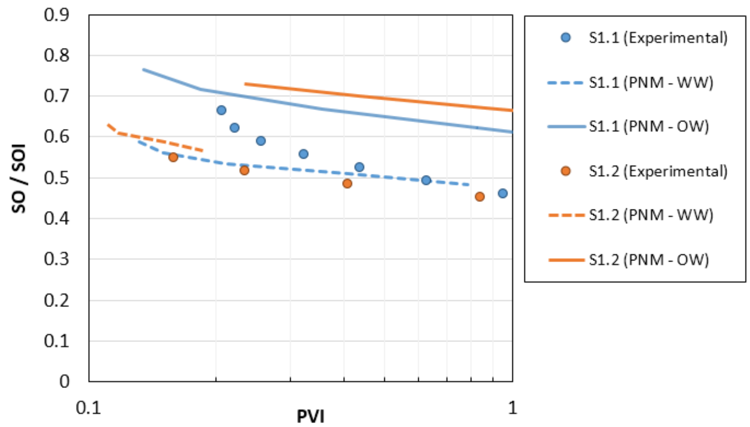


Figure 12: Group 1 - Comparison of So /Soi vs PVI using k_r from Figure 10

Group 2: Relative permeability for the two samples in this group are in **Figure 13**; displacement efficiency plots calculated with each relative permeability set are in in **Figure 14.** The comparison of experimental results with the pore network model simulations are consistent with the wettability data in that sample S2.1 is more water wetting than sample S2.2. However, it is worth noting that sample S2.1 is in extreme water wetting range and sample S2.2 in the highly oil wet range. Samples with similar pore structure exceeding the oil-wet and water-wet thresholds in **Figure 14** were flagged for further analysis.

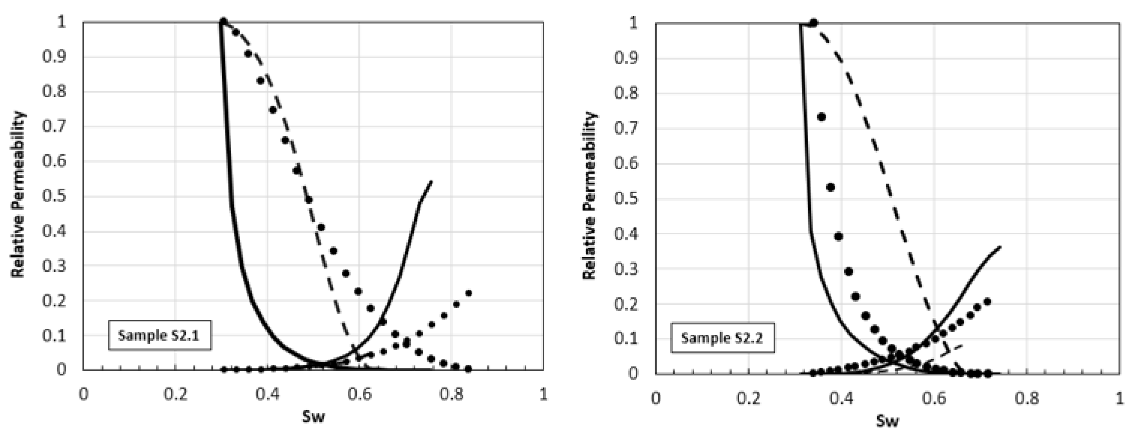


Figure 13: Group 2: Comparison of experimental (solid circles) and calculated kr for water-wet (dashed line) and oil-wet (solid lines) for S2.1 and S2.2

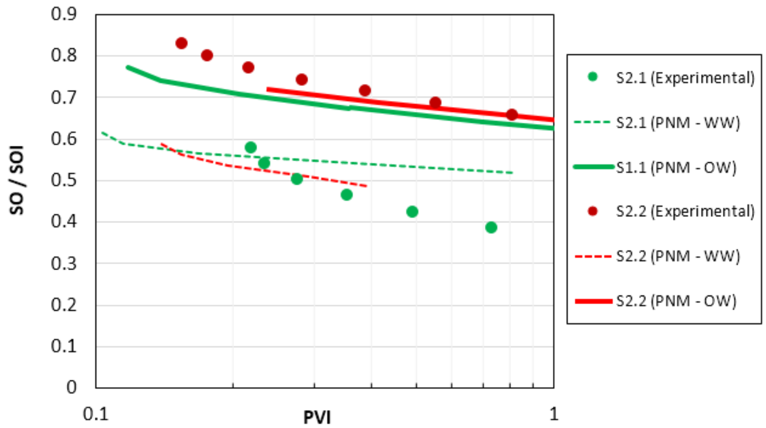


Figure 14: Group 2 - Comparison of So/Soi vs PVI using k_r from figure 12

<u>Group 3:</u> The samples in this group are the most challenging due to the low permeability and comparatively large amount of clay. This causes more uncertainty in the segmentation. Relative permeability for the two samples in this group are shown in **Figure 15;** displacement efficiency plots calculated with each relative permeability set are shown in in **Figure 16.** Comparison of experimental results with the pore network model simulations suggests that results of sample S3.1 are consistent with the wettability data. However, sample S3.2 appears very water-wet and this this sample was flagged for further analysis as it is inconsistent with the wettability data.

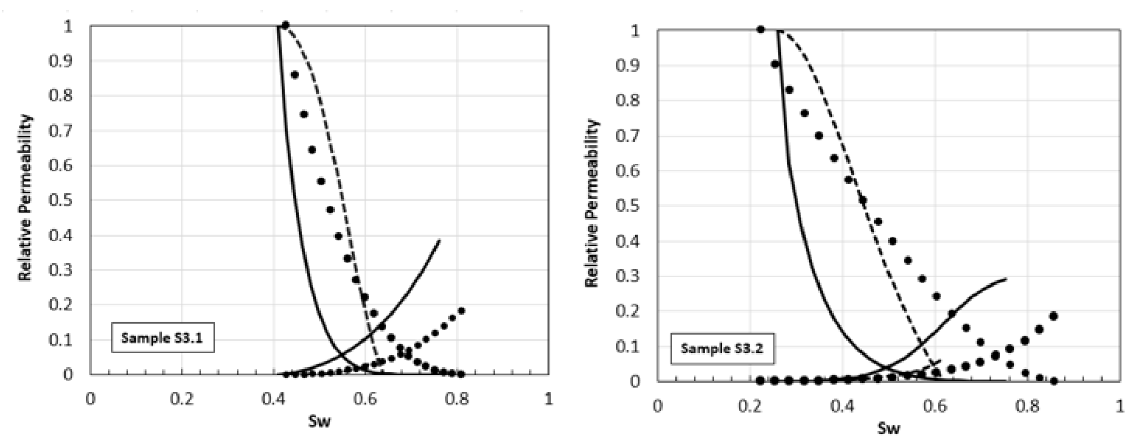


Figure 15: Group 3: Comparison of experimental (solid circles) and calculated kr for water-wet (dashed line) and oil-wet (solid lines) for S3.1 and S3.2

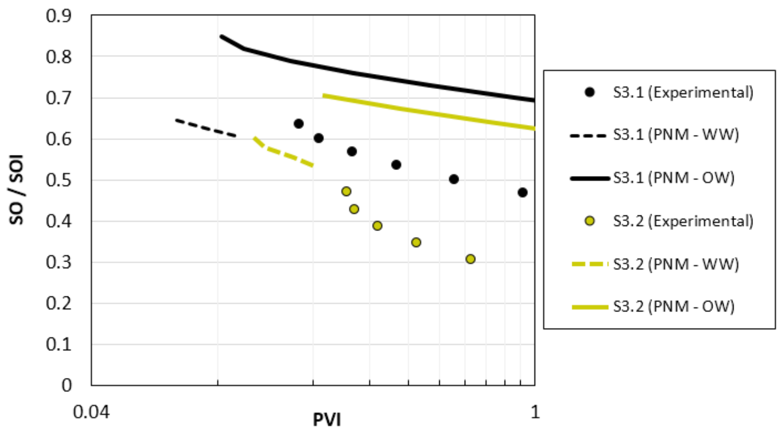


Figure 16: Group 3 - Comparison of ROS vs PVI using k_r from figure 14

UNCERTAINTY REDUCTION

Results from this analysis provided a guideline to confirm suspicious behavior, especially in well 1. **Figure 17 - left** shows water displacing oil relative permeability data after removal of samples. The effect of removal of samples in the reduction of the uncertainty in waterflood uncertainty is highlighted in **Figure 17-right,** where the range of oil saturation after 1 PVI decreases from 30% - 60% OIP (**Figure 1-right**) to 42% – 58% OIP.

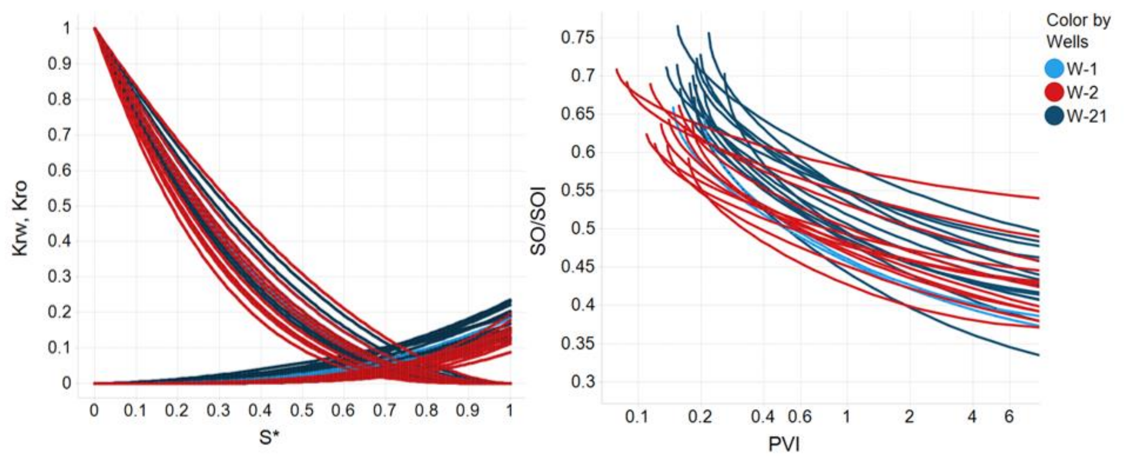


Figure 17: Relative Permeability (Left) and So / Soi from fractional flow calculations (Right) after identification of outliers and removal of samples

CONCLUSIONS

- Digital rock technology was used to reduce the uncertainty in waterflood ROS after 1 PVI from the prior range of 30% - 60% OIP to 42% – 58% OIP. The extreme wetting scenarios used in pore network calculations, along with guidance from wettability data, was instrumental in identifying outliers.

- Pore network models successfully reproduced permeability, drainage capillary pressure, and gas oil relative permeability measurements; and these were important in gaining confidence in water oil relative permeability calculations.

ACKNOWLEDGEMENTS

Authors acknowledge Chevron management and Chevron Energy Technology Company for their support and permission to publish these results. We thank Will Richardson for his contribution in the discussion of experimental data.

REFERENCES

1. Bakke, S. and P.E. Øren, "3D Pore-Scale Modeling of Sandstone and Flow Simulations in the pore Networks, SPE Journal (1997), **2**, 136-149
2. Blunt, M. J., M. D. Jackson, M. Piri, and P. H. Valvatne, "Detailed physics, predictive capabilities and macroscopic consequences for pore-network models of multiphase flow, Adv. Water Resour (2002), **25**, 1069-89.
3. Øren, P. E., S. Bakke, and O. J. Arntzen, "Extending Predictive Capabilities to Network Models," *SPE Journal*, (1998), **3**, 324-336.
4. Golab A, A. Arena, I. Barranco, R. Salazar-Tio, J. Hamilton, N Idowu, P. Rajan, S. Sommacal, B. Young, A. Carnerup, and J. M. Schembre-McCabe, "Mineralogical and Petrophysical Characterization of a Fine-Grained Sandstone With Significant Clay Coating Using 3-D Micro-CT and SEM Imaging From a 5mm Plug,". International Conference & Exhibition 2015 Sep 16.
5. Masalmeh, S. K., Jing, X., Roth, S., Wang, C., Dong, H., and Blunt, M. "Towards Predicting Multi-Phase Flow in Porous Media Using Digital Rock Physics: Workflow to Test the Predictive Capability of Pore-Scale Modeling", SPE 177572 presented at the International Petroleum Exhibition and Conference, Abu Dhabi (2015).
6. Al-Kharusi AS and M. J. Blunt, "Multiphase flow predictions from carbonate pore space images using extracted network models," Water Resources Res (2008), 44, W06S01.
7. Idowu, N. A., C. Nardi, H. Long, T. Varslot, and P.E. Øren, "Effects of segmentation and skeletonization algorithms on pore networks and predicted multiphase-transport properties of reservoir-rock samples,". SPE Reservoir Evaluation & Engineering (2014) Nov 1;17(04):473-83.
8. Idowu, N.A., H. Long, P. E. Øren, A. M. Carnerup, A. Fogden, I. Bondino, and L. Sundal, "Wettability analysis using micro-CT, FESEM and QEMSCAN, and its applications to digital rock physics," Proceeding of the International Symposium of the Society of Core Analysts, St. John's Newfoundland and Labrador, Canada (2015) SCA2015-010.
9. Bondino, I, G. Hamon, W. Kallel, and D. Kachuma,"Relative Permeabilities from Simulation in 3D Rock Models and Equivalent Pore Networks: Critical Review and Way Forward," Petrophysics, Vol. 54, No. 6 (2013), 538-546
10. Øren, P. E. and S. Bakke, "Reconstruction of Berea sandstone and pore-scale modeling of wettability effects," *J. Petroleum Science and Engineering* (2003), **39**, 177-199.

11. Valvatne, P.H. and M. J. Blunt, "Predictive pore scale modeling of two-phase flow in mixed water wet media," Water Resource Research, (2004) 40(7), W07406.
12. Dixit, A.B., Buckley, J.S., McDougall, and S.R., Sorbie, K.S., "Core Wettability: Should I_{AH} equal I_{USBM}?, *Proceeding of the International Symposium of Core Analysts* (1998), SCA1998-09.
13. Schembre-McCabe, J., Salazar-Tio, R., Ball, G., and J. Kamath, "A framework to validate Digital Rock Technology," *Proceedings of the 2011 International Symposium of the Society of Core Analysts*, Austin (2011), SCA 2011-028.
14. Schembre-McCabe, J., R. Salazar-Tio and J. Kamath, "Two examples of adding value through Digital Rock Technology," Proceedings of the 2012 Annual Symposium of the Society of Core Analysts, Aberdeen, Scotland, UK (2012), SCA 2012-081.