

3D imaging and characterization of the pore space of carbonate core; implications to single and two phase flow properties

M.A. Knackstedt^{1,2}, C. H. Arns¹, A. Ghous^{1,2}, A. Sakellariou¹, T. J. Senden¹, A.P. Sheppard¹, R. M. Sok¹, V. Nguyen², W. V. Pinczewski²

¹Department of Applied Mathematics, Research School of Physical Sciences and Engineering, Australian National University, Canberra, Australia

²School of Petroleum Engineering, University of New South Wales, Sydney, Australia

Copyright 2006, held jointly by the Society of Petrophysicists and Well Log Analysts (SPWLA) and the submitting authors.

This paper was prepared for presentation at the SPWLA 47th Annual Logging Symposium held in Veracruz, Mexico, June 4-7, 2006.

ABSTRACT

The ability of a rock to store and flow fluids is dependent upon the pore volume, pore geometry and its connectivity. Carbonate rocks are inherently heterogeneous having been laid down in a range of depositional environments and having undergone significant diagenesis. They are particularly difficult to characterise as the pore sizes can vary over orders of magnitudes and connectivity of pores of different scales can impact greatly on flow properties. For example, separate vuggy porosity in a underlying matrix pore system can increase the porosity, but not the permeability and lead to large residual oil saturations due to trapping in vugs. A touching vug network can have a dramatic effect on permeability and lead to higher recoveries.

In this paper we image a set of carbonate core material from outcrops and reservoirs in 3D via micro Computed Tomography (μ CT). The morphology of the pore space from different core material exhibits a broad range of topology and connectivity. Images at lower resolution (larger sample size) allow one to deduce the size, shape and spatial distribution of the (disconnected) vuggy porosity. Higher resolution images (down to 2 micron resolution) on subsets of the core allow one to probe the 3D intergranular porosity. The delineation of regions with submicron porosity is achieved via a differential contrast technique in the μ CT. Experimental MICP measurements performed on the imaged core material are in good agreement with image-based MICP simulations. These results indicate the quality of the imaging method allowing one to probe the spatial distribution of the vuggy / macro / micro porosity contributions across several orders of magnitude in scale.

High resolution numerical simulations of single phase flow and solute transport are undertaken on the resolved digital image data. A hybrid numerical scheme is developed to include the contribution of microporosity to the

overall core permeability. These results show in many cases, the dominance of a few flow paths in dictating the permeability of the core material. The role of microporosity in the flow fields is illustrated via 3D visualisation, measurement of local flow velocities and solute transport results.

Pore network models generated from the images illustrate the large variations in topology and geometry observed in carbonate samples. Both the visual appearance and quantitative details of the pore network show dramatic differences. Resultant two phase imbibition residual saturations are shown to be strongly dependent on the different topological and structural properties of the pore network. Laboratory measured rate dependent residual saturations for clastic and carbonate cores are compared with numerical simulations with encouraging results.

These results illustrate differences in the petrophysical characteristics of the different cores when classified by core descriptive parameters (Lucia, 1999), porosity - permeability, MICP (Skalinski et al., 2005) and relative permeability (Hamon, 2003). 3D imaging and analysis may assist in the integration of different rock-typing methods.

INTRODUCTION

Carbonate reservoirs contain more than 50% of the world's hydrocarbon reserves. In carbonate rocks, the processes of sedimentation and diagenesis produce microporous grains and a wide range of pore sizes, resulting in a complex spatial distribution of pores and pore connectivity. A reliable petrophysical interpretation for predicting the transport properties and producibility of carbonates is lacking. Much of the poor reliability in estimating carbonate properties is due to the diverse variety of pore types observed in carbonates. Unlike sandstones, many carbonate sediments have a bi- or tri-modal pore size distribution with organisms playing an important role in forming the reservoirs. Carbonate rocks are further complicated by the significant diagenesis occurring through chemical dissolution, reprecipitation, dolomitization, fracturing, etc. For these reasons the size and shape of any porous network is expected to be very heterogeneous and exhibit pore sizes

ranging from sub-micron to meters. Excluding fractures, three qualitatively different contributors to porosity can be identified: Vuggy porosity ($r \geq 100 \mu\text{m}$), intergranular ($r \geq 5 \mu\text{m}$) and intragranular ($r < 5 \mu\text{m}$) (Ramakrishnan et al., 2001). The sizes associated with the three types of porosity may vary across studies and are given as indicative values only. These features distinguish the petrophysical properties and productivity of carbonate fields from other sedimentary rocks including sandstones and shales.

In previous work we have described the development of a capacity to characterize and predict petrophysical properties from experimental 3D images of clastic rock microstructures from microtomographic images (Arns et al., 2004; Knackstedt et al., 2004). Data derived from fragments of a range of cores including homogeneous and reservoir sands have been compared with conventional laboratory measurements and shown to be in good agreement (Arns et al., 2004; Knackstedt et al., 2004; Arns et al., 2003; Knackstedt et al., 2003).

In this paper several reservoir and outcrop carbonate core plugs are imaged in 3D over a range of length scales using high resolution X-ray microtomography (μ -CT). Images at lower resolution (larger sample size) do not exhibit connected porosity but do allow one to deduce the size, shape and spatial distribution of the vuggy porosity. Higher resolution images on subsets of the plug do exhibit interconnected porosity and allow one to measure the characteristic intergranular pore size.

At the highest resolution the resolved porosity is less than the value measured in the laboratory indicating a substantial presence of sub-micron porosity. Although pores at the submicron scale are not directly accessible via our current micro-CT capabilities one can investigate the regional distribution of microporosity via a chemical contrasting technique on the micro-CT facility. From the microporous mapping one can visualise the spatial distribution of the vuggy/macro/micro porosity contributions. The submicron pore structure can then potentially be resolved via Focused Ion Beam technology (Tomutsa and Silin, 2004). Experimental mercury injection capillary pressure (MICP) measurements performed on the imaged core material are in good agreement with image based numerical simulations indicating the quality of the imaging method.

High resolution numerical simulations of single phase flow and solute transport are undertaken on the resolved digital image data. The role of microporosity in the flow fields is illustrated via 3D visualisation, measurement of local flow velocities and solute transport results. Pore network models generated from the images illustrate the varied topology and geometry observed in carbonate samples. Resultant two phase imbibition residual saturations and relative permeabilities are shown to be strongly dependent on the different topological and structural prop-

erties of the pore network.

The success of the approach demonstrates the feasibility of combining digitized images with numerical calculations to predict properties and derive correlations for carbonate lithologies.

METHODS

This section describes the methodology of image acquisition and phase identification methods for the carbonate sample studied.

Tomographic Imaging

A high-resolution and large-field X-ray μ CT facility has been used (Sakellariou et al., 2003; Sakellariou et al., 2004a; Sakellariou et al., 2004b) to analyse the 3D structure in carbonate core plugs across a range of scales down to a micron. The CT has a cone beam geometry. Details of the equipment and experimental methodology used to image the microstructure of sedimentary rock have been given previously (Sakellariou et al., 2004a; Knackstedt et al., 2004; Arns et al., 2005b). Here we briefly describe the experimental work undertaken and present the primary results of the imaging, visualization, permeability, drainage displacement and pore network modeling studies. Examples of slices through some of the carbonate image data is given in Fig. 1.

Samples imaged

The three samples primarily considered in this paper include:

1. Gambier limestone, a Oligocene-age outcrop quarried limestone from Mt. Gambier, Australia. Air permeabilities and porosities measured on this sample respectively fall in the range of 4-10 Darcies and 50–55%. The limestone is composed of readily identifiable coral fossil fragments with a minor amount of coarse sparry calcite. A optical microscope view of the sample is shown in Fig. 2(a) and a slice from the tomographic image of the core is shown in Fig. 2(b). The tomographic image is captured on a 5.5 mm diameter piece at 3.02 micron resolution. The image volume considered is 1200x1200x1800. The resultant 3D pore structure is very complex exhibiting a broad range of pore and throat sizes. A small 3D image of a subset of the sample is shown in Fig. 2(c)– the full image volume is over 2000 times this image size. Water-flood recovery data under varying wettability conditions and flooding rates (Tie and Morrow, 2005) have been measured on core material from this formation.

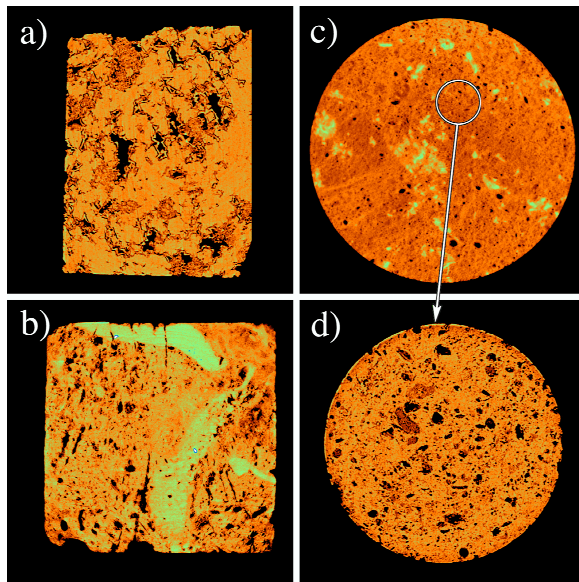


Figure 1: Slices from carbonate tomograms obtained via micro-CT imaging. Material density increases from black (pore space) through red, orange, yellow and to blue being the most dense. a) is a 4 x 5 mm section through the West Texan carbonate from this study, b) is a 4 x 4 mm section through an Asian carbonate, c) is a section through a 40 mm diameter vuggy Middle Eastern carbonate at 21 micron resolution. d) shows a 4 mm subsample of c) at 2.2 micron resolution.

2. A sample from a West Texas field was considered (Hidajat et al., 2004). This sample is clumpy in appearance with no clear depositional texture evident. A large amount of intergranular porosity is evident leading to higher permeabilities in regions. This sample is imaged at 3 different resolutions. First a 2 cm sample was imaged at 11.2 micron resolution, where some pores are evident (Fig. 3(a)). A second image at 6.04 micron resolution (1.1 cm sample) allows one to discern macroscopic interconnected porosity, but smaller details are still washed out of the image (Fig. 3(b)). A 5 mm subset was then imaged at 2.6 micron resolution where the connected porosity is strongly evident and local pore features are more clearly observed (Fig. 3(c)).
3. A Middle Eastern reservoir carbonate core plug was imaged in 3D over a range of length scales (Arns et al., 2005a). An image of the full 40 mm diameter plug was scanned at 21 μm resolution (Fig. 1(c)) allowing one to deduce the size, shape and spatial distribution of the disconnected vuggy porosity. A higher resolution images (down to 1.1 μm voxel size) on subsets of the plug (Fig. 1(d)) do exhibit interconnected porosity and allow one to

measure the characteristic intergranular pore size. Some microporosity remains evident in the image. Conventional experimental data made on the large sample gave porosity of 21.7% and permeability of 4.6 mD.

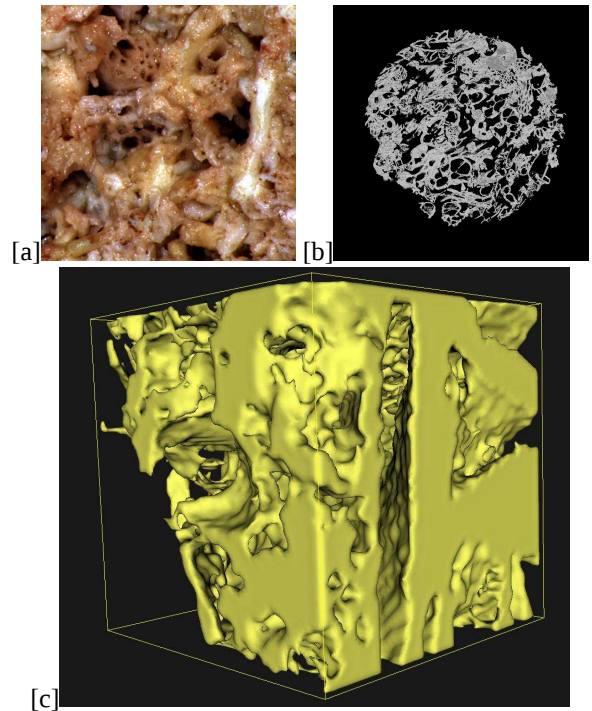


Figure 2: Images of the Mt. Gambier limestone (a) Optical microscope, (b) slice from a tomogram (5mm diameter core) and (c) a small subset of the full image in 3D.

Phase Identification

The tomographic image consists of a cubic array of reconstructed linear x-ray attenuation coefficient values, each corresponding to a finite volume cube (voxel) of the sample. An immediate goal is to differentiate the attenuation map into distinct pore and grain phases for each of the samples imaged. Ideally one would wish to have a multi-modal distribution giving unambiguous phase separation of the pore and various mineral phase peaks. In particular one would like to obtain a clear bimodal distribution separating the pore phase from mineral phase peaks. This idealised phase extraction is possible on a clean clastic sample, where the mineralogy is simple. An example of the attenuation histogram and resultant phase identification of a clean sand is given in Fig. 4(a-c). Unfortunately in more complex core samples, and particularly in carbonates, the presence of pores at scales below the image resolution leads to a spread in the low

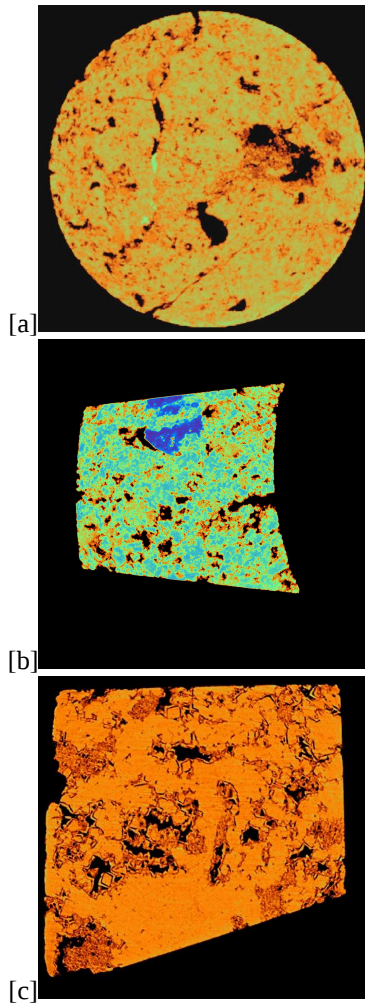


Figure 3: Slices through the tomogram of the West Texas carbonate sample imaged at three different resolutions; (a) 11.2 microns, (b) 6.04 microns and (c) 2.6 microns. An orthogonal slice of the image at the highest resolution is shown in Fig. 1(a).

density signal making it difficult to *unambiguously* differentiate the pore from the microporous and solid mineral phases. One also may wish to undertake three-phase identification— phase separation of the resolvable pore phase, intermediate microporous phase and the matrix phase. To quantitatively analyse tomograms we have developed a well-defined and consistent method to label each voxel (Sheppard et al., 2004). The first stage comprises a nonlinear anisotropic diffusion (AD) filter (Perona and Malik, 1990) which removes noise while preserving significant features, i.e. the boundary regions between the phases. The second stage applies an unsharp mask (UM) sharpening filter (Pratt, 2nd Ed 1991) which has proven itself in practice to be highly effective at sharpening edges without overly exaggerating the noise. Finally, the phase separation is performed using a

combination of watershed (Vincent and Soille, 1991) and active contour methods (Caselles et al., 1997).

We describe the phase identification process for the high resolution image of the West Texas carbonate. The intensity histogram for the sample is given in Fig. 4(d) before and after filtering. Segmentation was performed on the sample assuming absolute thresholds of ≤ 18000 for the pore phase and ≥ 22000 for the "solid" phase. Phase separation in the ambiguous intensity regions between these phases was then made using the active contours and watershed methods. A subset of a tomographic slice along with the resultant pore phases after phase separation are shown in Fig. 4(e). The resultant phase fraction obtained for this image was $\phi_{pore} = 18.7\%$.

Data on the resolved porosities from all images of the West Texas (WT) and Middle Eastern (ME) carbonates at varying resolution is summarised in Table 1. The data shows that we are able to resolve significantly more of the pore space at higher resolutions. At the lowest resolution ($11\mu m$ for the West Texas and $21\mu m$ for the Middle Eastern carbonate), the visualised porosity is not connected; the image is instead made up of disconnected porous components. This indicates the need to resolve smaller pores to identify the important fluid transport pathways. The contribution to the porosity of pores at different length scales can be examined in the same core at successively lower resolutions. Analysis of the pore shapes at lower resolutions can be undertaken; details of this for the ME sample are given in (Arns et al., 2005a).

Table 1: Details of the sample type, tomogram resolution (μm), image size (voxels), image porosity (ϕ_{image}) and experiment porosity (ϕ_{exp}) for the samples considered in this study. The large jump in ϕ_{image} observed for the WT sample at highest resolution is partly due to the intentional choice of a more fractured (higher permeability) subset for imaging.

Sample	Res.(Microns)	Size	ϕ_{image}	ϕ_{exp}
MG	3.06	2000 ³	51.3%	54%
WT	11.0	2000 ³	3.5%	23.4%
	6.1	2000 ³	5.5%	23.4%
	2.6	2000 ³	18.5%	23.4%
ME	21.1	2000 ³	3.2%	21.3%
	1.1	2000 ³	15.6%	21.3%

Image quality: Match to MICP data

A quality control step on the image data can be undertaken by comparing MICP measurement on the imaged core material to simulations of MICP undertaken directly on the images. Drainage simulations can be performed

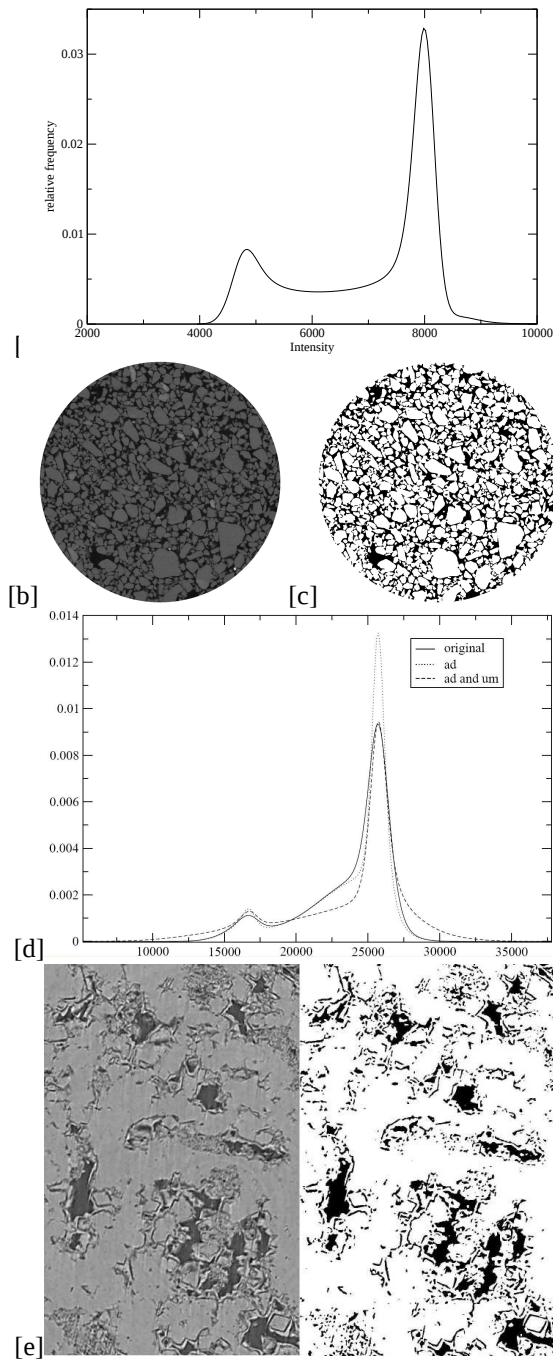


Figure 4: (a) The attenuation distribution obtained from a clean reservoir sand showing a clear distinction between pore and mineral phases. (b) shows a slice from the tomogram and (c) the resultant binarized image. (d) shows the histogram for the West Texas carbonate sample at 2.6 micron resolution; (e) shows a comparison of the attenuation map and the resultant binarized image volume.

directly on voxelated images by defining locally for every voxel within the structure, the diameter of the largest sphere which fully lies within the pore phase and covers that voxel (Coles et al., 1998; Hilpert and Miller, 2001). At a fixed capillary pressure (pore entry radius) we consider all the spheres which have radius greater than or equal to the equivalent pore entry radius. Starting with the largest sphere and incrementing the sphere radius downwards (equivalent to incrementing capillary pressure upwards), the non-wetting phase saturation is measured as the subset of all spheres that have invaded the pore space. This results in a capillary pressure/equivalent pore radius vs. saturation ($P_c/r : S$) curve for the imaged core. This can be directly compared to experimental MICP data on the same core material. We find in all cases good agreement between the experimental and image-based results. In Fig. 5 we show the comparison between the image based and experimental data for a Mt. Gambier sample and the intermediate resolution West Texas sample. In both cases the numerical fit to the experimental curve is good. The image has a necessary cut-off at porosities below the experimental curve due to an inability to image pore sizes below image resolution (≈ 3 microns and ≈ 6 microns in the two cases shown). The Mt. Gambier image captures most of the porosity within the sample. In contrast, the intermediate West Texas sample exhibits most porosity in the $0.5 - 3 \mu\text{m}$ pore size range (below image resolution). Imaging of this core at $2.6 \mu\text{m}$ resolution enables one to capture significantly more of the pore space as “resolvable” porosity.

Microporous Imaging

As seen in Fig. 5(b), microporosity, pores at the sub-micron scale are not directly accessible via our current micro-CT capabilities. The presence of microporosity in carbonates is well documented. Visual representation of the micropore structure in carbonates is given in e.g. (Cantrell and Hagerty, 1999). This microporosity plays a key role in understanding rock properties. In this subsection we discuss imaging methods for considering microporosity in carbonates including methods to potentially map the structure and the topology of microporous regions to better understand flow, production and recovery data. We also describe preliminary results of a method to visualise the topology of microporous regions.

To observe the partitioning of microporous regions within a sample we undertake two experiments on a small subset (6mm diameter) of the West Texas carbonate at lower resolution (in this case 8 microns). In the first experiment one obtains a dry image. We then undertake drainage experiments within the micro-CT with X-ray opaque fluids. Drainage to pore sizes in the submicron range will allow discrimination of pathways which connect the larger (resolved) porosity at different scales. To date we have not undertaken a full drainage experiment, but have un-

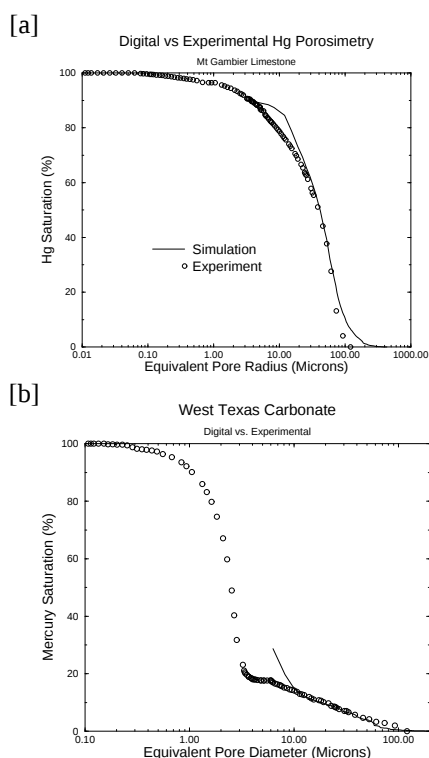


Figure 5: Comparison of image based MICP calculations to direct MICP measurement on the same core samples for (a) Mt. Gambier limestone and (b) the intermediate resolution West Texas sample.

dertaken a study on a dry and then completely saturated sample. In Fig. 6(a) we show a slice of the system under wet conditions and the predicted regions of microporous rich material after phase separation. In this sample we measure $\approx 3\%$ resolved porosity, and $\approx 20\%$ total porosity where we use the CT density of the wet-dry image to estimate local porosity contributions. The measured porosity of the sample from He and Hg porosimetry is 23%. A 3D visualisation of the macroporous, microporous rich and matrix phase from a small subset of the image ($128 \times 256 \times 395$) is shown in Fig. 6(b).

Ongoing work includes the tomographic imaging of these "nested" microporous regions via higher resolution tomographic imaging methods (e.g. Focused Ion Beam (FIB) tomography and laser confocal imaging). To date we have used FIB technology; FIB allows for the milling of layers as thin as 10 nanometres. After each milling step a new surface is exposed and a 2D image of the surface can be generated. By serial stacking of the 2D images a 3D reconstruction can be generated. 2D images of the West Texas carbonate sample at submicron resolution are given in Fig. 7. The detailed information from higher resolution methods should allow one to populate the topology of the microporous regions with realistic and detailed pore geometry information.

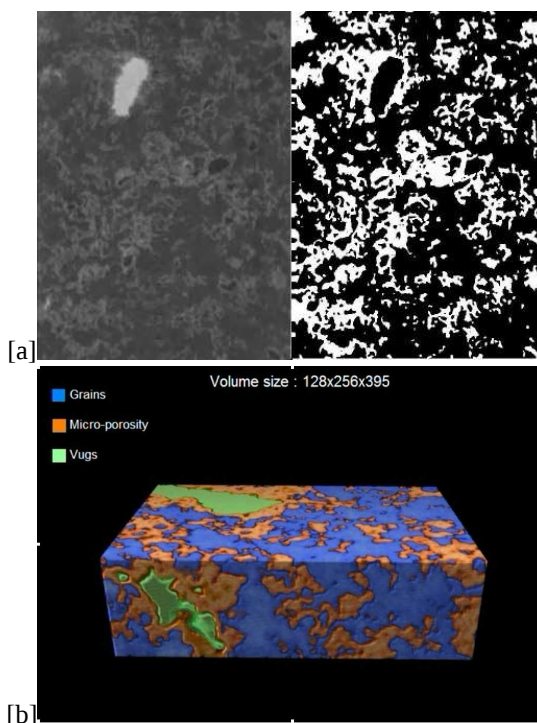


Figure 6: (a) Snapshot of the microporosity rich regions from one slice of the tomogram. (Left) shows the attenuation map with the bright spot in upper left a large (resolvable) pore; Right shows the image after phase separation where the perceived microporous rich region is shown in white; matrix and resolved macropores are given in black. (b) Snapshot from a 3D visualization of a large pores (green) and the connectivity via microporosity

SINGLE PHASE FLOW RESULTS

A microstructure defined by a digital image is already discretized and lends itself immediately to numerical computation of many properties. In this subsection we describe the numerical methods used to calculate petrophysical parameters on 3D digital images. In this paper we focus on the single phase permeability of the rock. The permeability calculation is based on the Lattice Boltzmann method (LB) (Martys and Chen, 1996; Qian et al., 1986). Details of the method have been previously described (Arns, 2004).

Estimation of the permeability on the resolvable porosity should give good results for the Mt. Gambier and the Middle Eastern sample as the resolved porosity is well connected and one would not expect the unresolved porosity to contribute significantly to the overall permeability. Permeabilities calculated on subsets of the full Mt. Gambier image are given in Fig. 8. The values observed agree well with experimental data showing 2-10 Darcy permeability. The permeability of the Middle East-

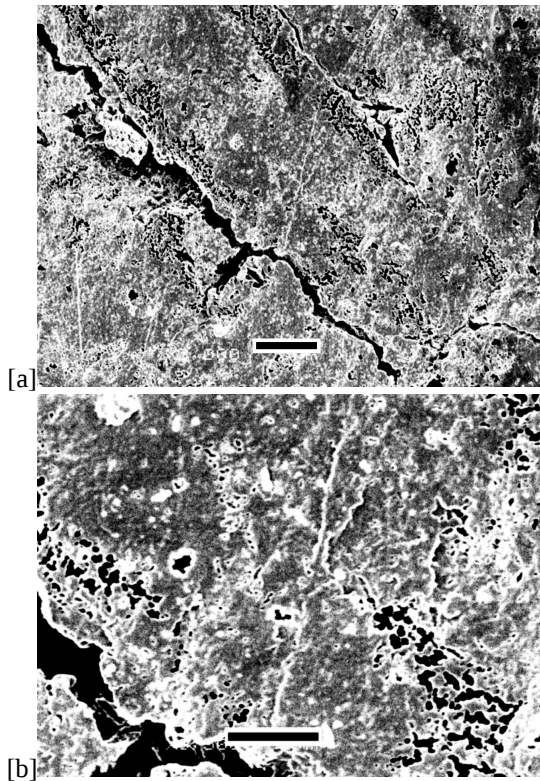


Figure 7: SEM images of FIB prepared surfaces of the West Texas carbonate (a) Scale bar is 5 microns and (b) scale bar is 2 microns. Note the presence of significant porosity in the range 0.5 – 3 microns as observed in the MICP data for this sample (recall Fig. 5(b)).

ern carbonate was calculated for the full image volume at the highest resolution in three orthogonal directions and gave $k_x = 5.84$, $k_y = 2.18$, $k_z = 4.19$ mD in good agreement with experimental data of 4.6 mD.

Methods for calculation at two length scales

Given the importance of microporosity to the overall properties of many of the carbonates and particularly the West Texas carbonate sample (recall Fig. 5(b)), there is a need to undertake a study of the transport properties of the core material incorporating both the resolvable porosity and the microporosity. It is impossible to simultaneously solve for properties of microporous carbonate systems incorporating all the microstructural features of the carbonate due to the varying (hierarchical) length scales which collectively contribute to transport. However, one can use the division of the carbonate into two regions as described experimentally; (1) the larger resolved pores and (2) the regions of microporosity. The approach we use is to divide the porous material into two regions; the first made up of resolvable porosity and the second made up of microporous rich regions. In the larger pores

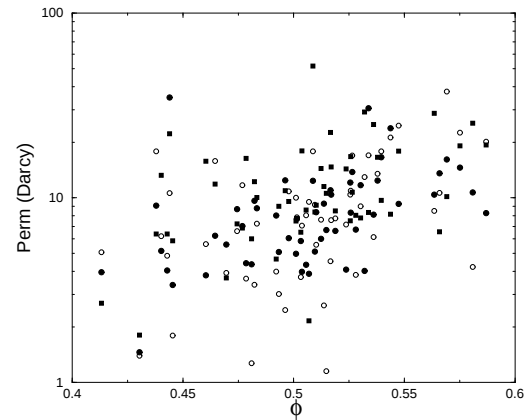


Figure 8: Permeability derived from subsets of the Mt. Gambier image. The results are in good agreement with laboratory data on the same rock; 2-10 Darcy.

the Stokes' equations for incompressible flow are solved. Regions with the smaller unresolved pores are described by Darcy's law where one must input the effective permeability of the microporous regions. The two boundary conditions to be satisfied at the macropore/micropore interface are continuity of the fluid velocity and shear stress. The Brinkman equation (Brinkman, 1947), a generalization of Darcy's law facilitates the matching of boundary conditions between the larger pores and the permeable medium. Although the Brinkman equation is semiempirical, it has been validated by a detailed numerical solution of the Stokes' equations in regions near the interface between regions of dissimilar permeability (Martys et al., 1994).

It is relatively straight forward to integrate this approach into a standard lattice-Boltzmann solver (Spaid and Phelan, Jr., 1997; Martys, 2001). We label each of the lattice sites as either Navier-Stokes or Brinkman site, and for Brinkman sites rescale the velocity at Brinkman sites according to $v(\bar{x}, t) \rightarrow v(\bar{x}, t)(1 - \beta\tau)$, where τ is the relaxation parameter (we used $\tau = 1$), and β the strength of the momentum sink (Spaid and Phelan, Jr., 1997). As we have only experimentally located the microporosity, but have yet to generate information about the local contribution to permeability, we use a set of varying β from $\beta = 0.1$ to $\beta = 0.001$.

We study both the flow fields and the dispersion of a neutral tracer through the system. The movement of a tracer in a fluid flow field is, at the pore scale, defined by a balance between diffusion and convection in the asymptotic dispersion regime (both diffusion and convection matter). Given the solution of the Stokes or Brinkman equation, we consider a stochastic process on this velocity field to solve the diffusion-advection equation using a random walk technique (Makse et al., 2000) in 3D. We introduce a large number of walkers at the inlet, and then

simulate each trajectory until the walkers reach the outlet, resulting in 100% recovery of the tracer. In Fig. 9 we show the neutral tracer residence time distributions for the *resolvable* porosities of the 3 highest resolution carbonate images at varying flow rates. All exhibit a significant broadening of the distribution with decreasing flow velocity.

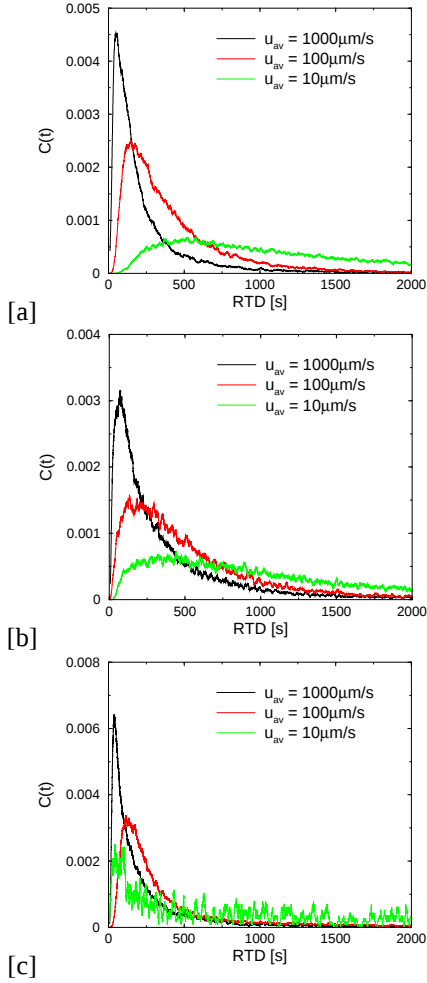


Figure 9: Neutral tracer residual time distributions for delta pulses and different flow fields, in the resolved pore space, for three subsections of carbonate rock, calculated by solving the diffusion-advection equation. [a] Gambier limestone (300^3 , voxel size $3.0 \mu\text{m}$), [b] WT carbonate (300^3 , voxel size $2.6 \mu\text{m}$), [c] ME carbonate (400^3 , voxel size $1.1 \mu\text{m}$).

The role of microporosity is illustrated in Fig. 10. The microporosity can lead to a more disperse flow field (when macropores are poorly connected).

Pore scale flux analysis - Given the velocity field for the flow of an incompressible fluid through the structure de-

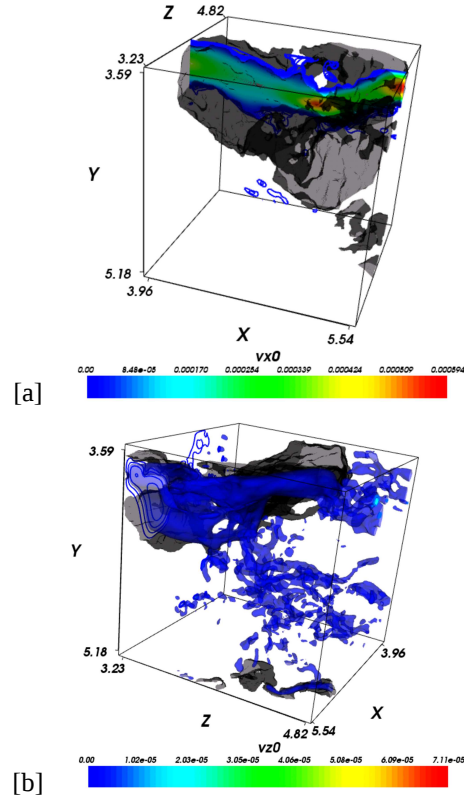


Figure 10: Calculation of flow fields for a subsection of a carbonate (200^3 , voxel size $8.4 \mu\text{m}$) using the Brinkman equation, illustrating the effect of microporosity. The grey surfaces indicate resolved porosity. [a] flow in x-direction; a large pore cluster connects and therefore the velocity field is dominated by the macroporosity; indicated by a contour plane. [b] flow in z-direction; the only conductive pathway is through the microporous region, the velocity field is now slower and more dispersed; indicated by a connecting velocity iso-surface.

finied by a tomogram, e.g. by using a lattice-Boltzmann simulation as detailed above, one can directly calculate the flux between two neighbouring voxels i and j as the projection of the velocity between those points $\bar{v}_{ij} = \frac{1}{2}(\bar{v}_i + \bar{v}_j)$ onto the connection vector between these points $\bar{r}_{ij} = \bar{r}_j - \bar{r}_i$ times the density, or

$$\bar{q}_{ij} = \rho \frac{\bar{v}_{ij} \bar{r}_{ij}}{|\bar{r}_{ij}|} \frac{\bar{r}_{ij}}{|\bar{r}_{ij}|}. \quad (1)$$

Given further a partitioning of the pore space into n_p labelled pore bodies, we can derive an $n_p \times n_p$ matrix $\bar{q}$ of pore-pore fluxes, where a single entry counts the flux across an interface between pore p_i and pore p_j , given by the sum over all voxel-voxel fluxes across this interface

$$q_{p_i p_j} = \sum_v \bar{q}_{ij}^{(v)}. \quad (2)$$

Here (v) denotes the index over all voxel-voxel connections. Then the total flux across a pore p_i is the sum over the absolute values of the i - th column or row of the flux matrix $\bar{q}$, divided by two

$$q_{p_i} = \frac{1}{2} \sum_{p_j} |q_{p_i p_j}|. \quad (3)$$

We normalise this flux by the total flux q_t across the inlet or any other complete plane perpendicular to the macroscopic flow direction (using the same symmetry, e.g. neighbourhood rules).

In Fig. 11 we show the local flux per pore versus pore size based on pore partitioning of two Castlegate sandstone samples (a-b) compared to the West Texas sample (c) and Middle Eastern sample (d). In this plot no microporosity contribution is considered. The carbonates exhibit a much broader distribution of local flux with pore size; the WT sample exhibits a variation of over 5 orders of magnitude in relative flux for pores of the same size; the Castlegate data shows a variation of at most 2 orders of magnitude. This high variability illustrates the effect of the poor connectivity of larger pores on flow properties in carbonates.

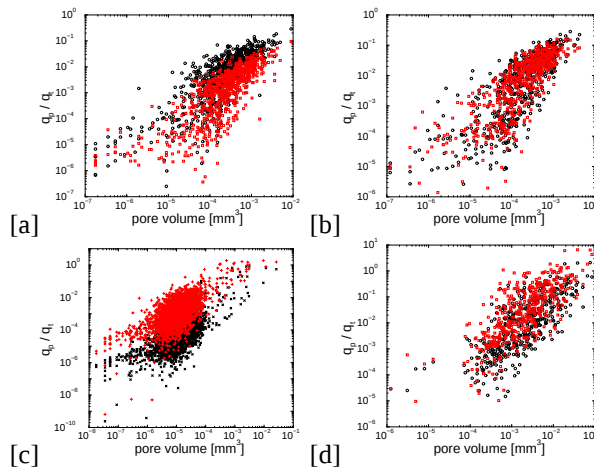


Figure 11: Local flux per pore as a function of pore size for two subsections of Castlegate sandstone [a-b] and the (c) West Texas and (d) Middle Eastern Carbonate.

Multiphase Flow

In this section we describe the potential for 3D imaging and analysis of carbonate cores to give reliable predictions of relative permeability and residual saturation of core materials. There are two main sections. The first describes the development of realistic network descriptions of the pore space of carbonate core material generated from tomographic images. Secondly, a dynamic network model which accurately accounts for the displacement

mechanisms in multiphase flow will be reviewed and results on carbonate and clastic images compared to experimental data obtained on the same core material.

Network Generation from tomographic images

Network models are considered as practical reservoir description and simulation tools to study a variety of two- and three-phase displacement processes. The guiding idea is that, in the context of capillary dominated flow, the pore space can be naturally discretised into subvolumes separated at the locally narrowest constrictions. The subvolumes and the constrictions can then be identified with the nodes (pore bodies) and links (pore throats) of a network. The advancement of the fluid-fluid interface through a link or node in the network is governed by the relationship between the capillary pressure, the material wettability and the local channel cross-section geometry. To date network models used for the study of multiphase flow have been based on idealized networks (Kamath et al., 2001; McDougall et al., 2001) or are generated by stochastic realizations based on thin section data or MICP data (Øren et al., 1998). This work has been primarily limited to clastic samples. We have previously described and validated robust techniques for partitioning the pore space of a porous material into simple regions, thereby allowing it to be represented by a network of simple building blocks. A simple illustration of the network generation for the small subset of Mt. Gambier shown in Fig. 2(c) is shown in Fig. 12. Detailed descriptions of the methods used to generate the network are beyond the scope of the paper and are given elsewhere (Sheppard et al., 2005). Here we show that the generation of networks directly from a range of microtomographic images leads to a strongly varying topology and pore geometry exhibited by different rock types. We then investigate the implications to multiphase flow properties.

In Fig. 13 we show 3 images of network subsets; one derived directly from a 3D image of a simple sandstone (Castlegate), one derived from the 3D image of Mt. Gambier limestone and the third derived from the 3D image of the West Texas carbonate obtained at 2.6 micron resolution. The networks in Fig. 13 contain less than 4% of the full image volume obtained from the full tomogram. The difference in the network structure for these three samples is visually dramatic.

From the images a number of important network parameters can be ascertained; two of the more important parameters is the coordination number of the pores in the network Z and the aspect ratio of the pore radii (R_p) to the throat radii (R_t). Mean data and data weighted by pore volumes are given in Table 2. We observe that despite the varying topology, the mean Z of the sandstone and Mt. Gambier are similar, while the West Texas carbonate is on average lower. The weighted coordination number is however much larger for both carbon-

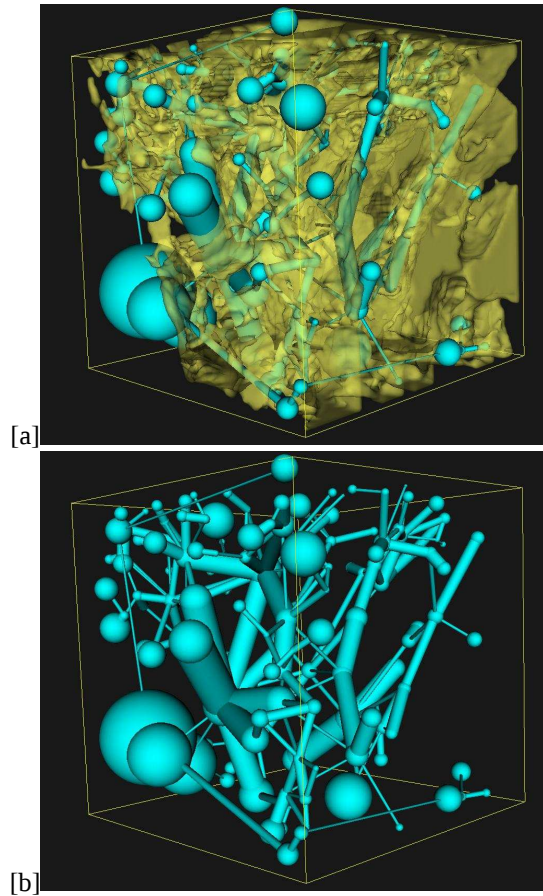


Figure 12: Network generated for the small image shown in Fig. 2(c). (a) shows the network embedded in the image and (b) the network after removing the solid phase structure.

ates reflecting the strong interconnectivity of the larger pores. The aspect ratio of the Mt. Gambier system is significantly larger than the sandstone on both a mean and weighted scale. The volume weighted average again highlights the large aspect ratio exhibited by the larger pores, which can in turn dominate the multiphase flow properties.

Table 2: Details of the network structure for the three samples shown in Fig. 13. Z_m gives the mean coordination number, Z_w the volume weighted mean and Z_{max} the maximal pore coordination number. The mean $(\frac{R_p}{R_t})_m$ and volume weighted $(\frac{R_p}{R_t})_w$ pore to throat aspect ratios are also given.

Sample	Z_m	Z_w	Z_{max}	$(\frac{R_p}{R_t})_m$	$(\frac{R_p}{R_t})_w$
CS	5.4	9.0	49	2.9	4.0
MG	5.6	30.4	372	6.5	20.3
WT	3.8	35.0	276	3.4	28.0

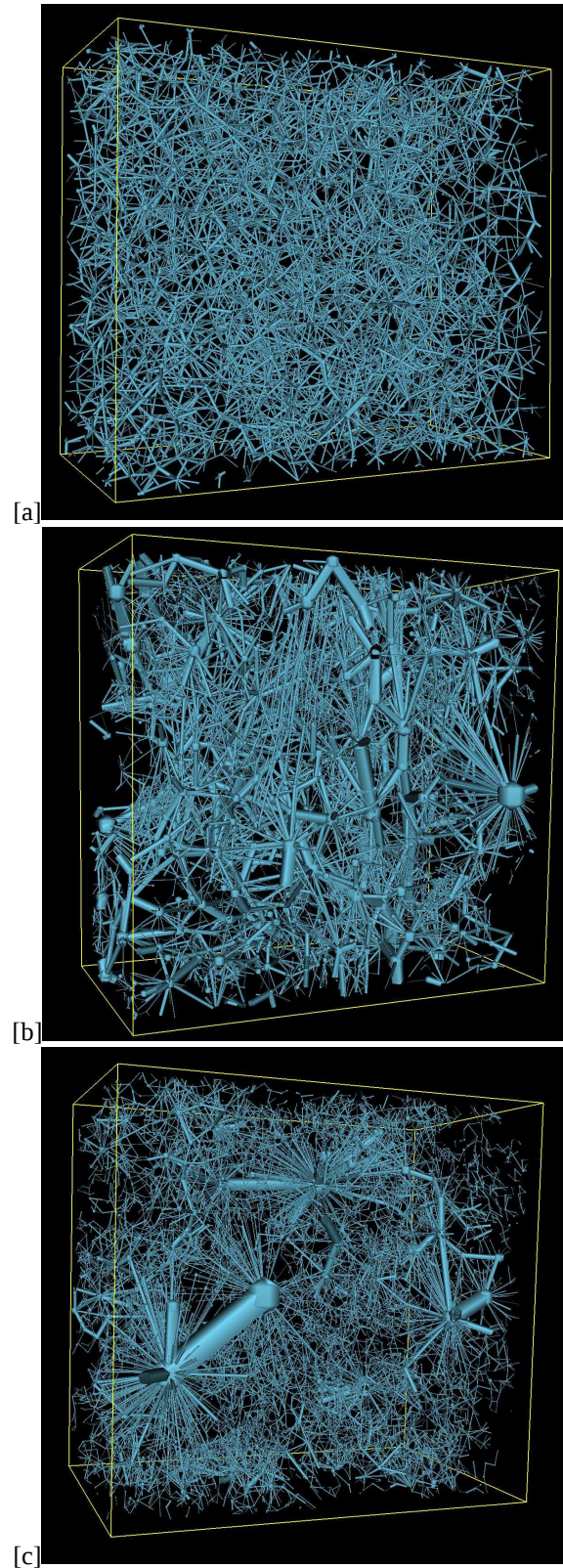


Figure 13: Networks of (a) Castlegate sandstone ($520^2 \times 230$ subset), (b) Mt. Gambier limestone and (c) West Texas carbonate (both $660^2 \times 320$ subsets). The size of the pores and throats reflects their actual size in the partitioning of the 3D image. The variation in structure across the 3 samples is dramatic.

Multiphase Flow Properties on Network Images: Prediction of Residual Saturation

A dynamic network model for imbibition based on a physically realistic description of the complex dynamics of film flow, film swelling and snap-off has been developed by our group (Nguyen et al., 2004; Nguyen et al., 2006). The model shows that the competition between snap-off and frontal displacements is rate dependent resulting in rate dependent relative permeability curves and residual saturations. The dynamic model illustrates the complex interaction between displacement rate, contact angle, connectivity, pore/throat aspect ratio and pore and throat shapes on residual saturation. Here we compute residual saturations on a clastic (strongly water wet Berea sandstone) and a model carbonate (Mt. Gambier) sample. The results illustrate the magnitude of the rate effect on relative permeability for different rock types and how multiphase flow properties depend largely on the pore structure.

Chatzis and Morrow (Chatzis and Morrow, 1984) report measurements of residual saturations for the displacement of initially continuous oil from water-wet sandstone cores as a function of capillary number. Their data for three of their higher permeability Berea cores (CQ-5 - $\phi = 0.20$, $k = 772 \text{ md}$; CQ-11 - $\phi = 0.21$, $k = 859 \text{ md}$ and CQ-A7 - $\phi = 0.21$, $k = 852 \text{ md}$) are plotted in Fig. 14(a). The data shows that the normalised residual oil saturation, S_{or}/S_{or}^* , (ratio of residual oil saturation, S_{or} , divided by the waterflood residual oil saturation at low capillary number, S_{or}^*) reduces with increasing displacement rate. The reduction in residual oil saturation occurs at capillary numbers which are several orders of magnitude lower than capillary numbers for the onset of mobilisation. Chatzis and Morrow suggest that the reduction of residual oil saturation with displacement rate is due to a reduction in trapping with increasing rate. Fig. 14(a) also shows a plot of computed residual oil saturations using a Berea network model generated from a process based reconstruction of Berea sandstone (Lerdahl et al., 2000). The network has very similar structure to that shown in Fig. 13(a) for Castlegate sandstone. The predicted variation in residuals displayed by the experimental data for different cores with similar porosities and permeabilities agrees well with the computed data on the Berea network.

Tie and Morrow (Tie and Morrow, 2005) have recently reported the results of a rate sensitivity study for three outcrop limestones including Gambier. They show that residual oil saturations for limestones display sensitivity to rate at capillary numbers much lower than that observed for consolidated sandstones. Their findings are consistent with the earlier studies of (Kamath et al., 1995; Kamath et al., 2001) for carbonate reservoir cores. At the time of submission the calculation of the residual saturation had not yet been directly undertaken on the

Mt. Gambier network image (Fig. 13(b)). However we performed an initial study of the effect of carbonate network structure by incorporating the important geometrical difference of pore-throat aspect ratio observed when comparing the sandstone structure to the Mt. Gambier limestone. Fig. 14(b) shows the effect on residual oil saturation of increasing the aspect ratio from 1.7 to 6.8 for the Berea network. The higher aspect ratio case displays a rate sensitivity at capillary numbers several orders of magnitude lower than for Berea sandstone where the aspect ratio is smaller. This is qualitatively similar to the differences between sandstones and carbonates measured by (Chatzis and Morrow, 1984; Kamath et al., 1995; Tie and Morrow, 2005; Kamath et al., 2001). This result illustrates the importance of capturing the true network topology and geometry when calculating multiphase flow properties via network models. The complex interactions between displacement rate, contact angle, aspect ratio and pore shape make it difficult to correctly interpret measured imbibition residual saturation data without the aid of realistic image structure and the aid of a dynamic model based on a realistic description of film flow.

CONCLUSIONS

- A set of carbonate core samples has been imaged in 3D across a range of resolutions. The resultant 3D pore structure exhibits extremely strong variations across samples. The contribution to porosity and 3D connectivity of pores at different length scales is examined.
- MICP measurements performed on the imaged core material are in good agreement with image-based MICP simulations.
- The topology of the microporous phase (pores below image resolution) is probed via a chemically-based X-ray contrasting technique. Focussed Ion Beam SEM may allow the 3D resolution of cores at submicron scales.
- High resolution numerical simulations of single phase flow and solute transport are undertaken on the resolved digital image data. A hybrid numerical scheme is developed to include the contribution of microporosity to the overall core permeability.
- Pore network models generated from the images illustrate the large variations in topology and geometry observed in carbonate samples. Both the visual appearance and quantitative details of the pore network show dramatic differences. Resultant two phase imbibition residual saturations are shown to be strongly dependent on the different

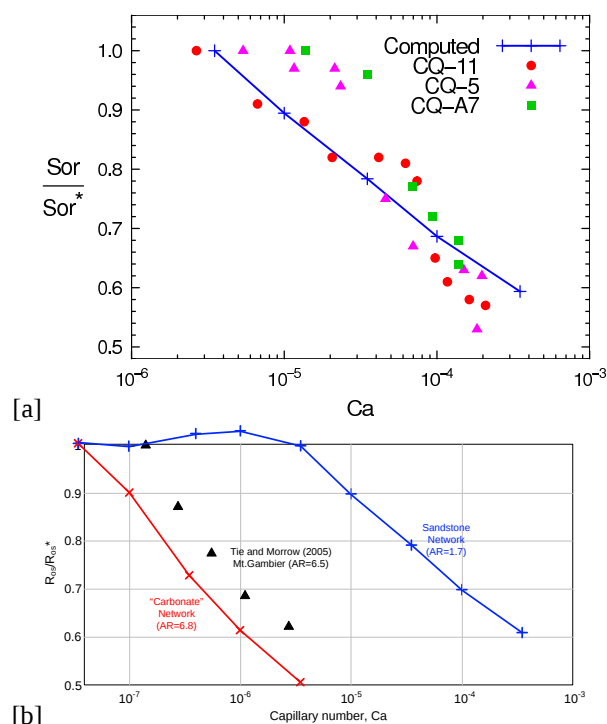


Figure 14: (a) Comparison between residual oil saturations for water-wet Berea cores reported by Chatzis and Morrow (1984) and the dynamic network prediction based on a realistic 3D image. (b) Effect of increased aspect ratio on computed residual saturation for the dynamic network of Berea sandstone (blue curve) and Mt. Gambier limestone (red curve). The experimental data of Tie and Morrow, 2005 (triangles) for Mt. Gambier limestone shows a reasonable match to the Mt. Gambier dynamic network model.

topological and structural properties of the pore network.

Petrophysical units, or rock types, are defined to help petrophysicists and reservoir engineers assign petrophysical characteristics to different zones of a reservoir. Porosity, permeability, grain density, mercury injection capillary pressure curves are often used as markers of the type of porous rocks. Rocks are clustered into groups based on these measures; these groups are assumed to have similar flow and storage capacity. Facies are identified using depositional and diagenetic criteria which are tied to poro-perm data. Relationships are used to tie the petrophysical to the geological models along with log typing to estimate initial hydrocarbons in place. It is also frequently assumed that the rock types defined by this process are valid to assign two-phase flow characteristics (e.g. relative permeability) independent of the recovery process. Recently (Hamon, 2003) showed that conventional rock typing methods may not capture the actual

variability of relative permeability curves and that there is no systematic correspondence between rock types used to estimate hydrocarbons in place and those required to describe production behaviour. The application of 3D imaging and analysis technology to rock cores will certainly aid the development of improved cross-property correlations. Excitingly, the development of libraries of 3D images which will allow a more rigorous and quantitative description of rock type and texture of carbonates and clastics. This should, in turn, give one the potential to more fully integrating classical rock typing methods; sedimentological descriptions, elastic behaviour, poro-perm trends and MICP data to multiphase flow properties like relative permeability and residual saturations.

ACKNOWLEDGEMENTS

The authors acknowledge the Australian Government for their support through the ARC grant scheme. We further thank Lincoln Paterson for provision of the Mt. Gambier Limestone and George Hirasaki and Mark Flaum for provision of the West Texas core material. We thank the A.N.U. Supercomputing Facility and the Australian Partnership for Advanced Computing for very generous allocations of computer time.

REFERENCES CITED

- Arns, C. H., Sakellariou, A., Senden, T. J., Sheppard, A. P., Sok, R. M., Pinczewski, W. V., and Knackstedt, M. A., 2003, Petrophysical properties derived from x-ray ct images: APPEA Journal, pages 557–562.
- Arns, C. H., Knackstedt, M. A., Pinczewski, W. V., and Martys, N., 2004, Virtual permeametry on microtomographic images: J. Petroleum Sci. and Eng., **45**, 41–46.
- Arns, C. H., Bauget, F., Limaye, A., Sakellariou, A., Senden, T. J., Sheppard, A. P., Sok, R. M., Pinczewski, W. V., Bakke, S., Berge, L. I., Oren, P. E., and Knackstedt, M. A., December 2005, Pore scale characterization of carbonates using micro x-ray ct: SPE Journal, pages 475–484.
- 2005b, Digital core laboratory: Petrophysical analysis from 3d images: Petrophysics, **46** (4), 260–277.
- Arns, C. H., 2004, A comparison of pore size distributions derived by nmr and x-ray ct techniques: Physica A, **339**, 159–165.
- Brinkman, H. C., 1947, A calculation of the viscous force exerted by a flowing fluid on a dense swarm of particles: Appl Sci. Res. Section A, **1**, 27.

- Cantrell, D. L., and Hagerty, R. M., 1999, Micro-porosity in arab formation carbonates, saudi arabia: *GeoArabia*, **4**.
- Caselles, V., Kimmel, R., and Shapiro, G., 1997, Geodesic active contours: *Int. J. Comput. Vis.*, **22**, 61–79.
- Chatzis, I., and Morrow, N., 1984, Correlation of capillary number relationships for sandstone: *SPE Journal*, pages 555–562.
- Coles, M. E., Hazlett, R. D., Muegge, E. L., Jones, K. W., Andrews, B., Dowd, B., Siddons, P., Peskin, A., Spanne, P., and Soll, W. E., 1998, Developments in synchrotron x-ray microtomography with applications to flow in porous media: *SPE Reservoir Evaluation and Engineering*, **36531**, 288–296.
- Hamon, G., October (SPE 84035) 2003, Two-phase flow rock typing: Another perspective: Two-phase flow rock typing: Another perspective:, Society of Petroleum Engineers, SPE Annual Technical Conference held in Denver, Colorado.
- Hidajat, I., Mohanty, K. K., Flaum, M., and Hirasaki, G., 2004, Study of vuggy carbonates using nmr and x-ray ct scanning: *SPE Reservoir Evaluation and Engineering*, pages 365–377.
- Hilpert, M., and Miller, C. T., 2001, Pore-morphology based simulation of drainage in totally wetting porous media: *Advances in Water Resources*, **24**, 243–255.
- Kamath, J., Meyer, R. F., and Nakagawa, F., 1995, Water/oil relative permeability endpoints of intermediate-wet low permeability rocks: *SPE Formation Evaluation*.
- Kamath, J., deZabala, E. F., and Nakagawa, F., 2001, Understanding waterflood residual oil saturation of four carbonate rocks: Understanding waterflood residual oil saturation of four carbonate rocks:, Presented at the 76th SPE Annual Technical Conference and Exhibition.
- Knackstedt, M. A., Arns, C. H., Sakellariou, A., Senden, T. J., Sheppard, A. P., Sok, R. M., Pinczewski, W. V., and Bunn, G., October 2003, Virtual core lab: Properties of reservoir rock derived from x-ray ct images: Virtual core lab: Properties of reservoir rock derived from x-ray ct images:, SEG Technical Program.
- Knackstedt, M. A., Arns, C. H., Sakellariou, A., Senden, T. J., Sheppard, A. P., Sok, R. M., Pinczewski, W. V., and Bunn, G. F., 2004, Digital core laboratory: Properties of reservoir core derived from 3d images: Digital core laboratory: Properties of reservoir core derived from 3d images:, Presented at the Asia-Pacific Conference on Integrated Modelling for Asset Management.
- Lerdahl, T. R., Oren, P. E., and Bakke, S., April 2000, A predictive network model for three phase flow: A predictive network model for three phase flow:, *Soc. Petr. Eng.*, 2000 SPE/DOE Improved Oil Recovery Symposium, 59311.
- Lucia, F. J., 1999, Carbonate reservoir characterisation: Springer-Verlag.
- Makse, H. A., Johnson, D. L., and Schwartz, L. M., 2000, Packing of compressible granular materials: *Phys. Rev. Lett.*, **84**, no. 18, 4160–4163.
- Martys, N. S., and Chen, H., 1996, Simulation of multicomponent fluids in complex three-dimensional geometries by the lattice boltzmann method: *Phys. Rev. E*, **53**, 743–750.
- Martys, N. S., Torquato, S., and Bentz, D. P., 1994, Universal scaling of fluid permeability for sphere packings: *Phys. Rev. E*, **50**, 403.
- Martys, N. S., 2001, Improved approximation of the Brinkman equation using a lattice Boltzmann method:, **13**, no. 6, 1807–1810.
- McDougall, S. R., Criuckshank, L., and Sorbie, K. S., September 2001, Anchoring methodologies for pore scale network models: Application to relative permeability, International Symposium of the Society of Core Analysts, SCA2001–11.
- Nguyen, V. H., Sheppard, A. P., Knackstedt, M. A., and Pinczewski, W. V., November 2004, A dynamic network model for imbibition: A dynamic network model for imbibition:, *Soc. Petr. Eng.*, 2004 SPE International Petroleum Conference, 90365:1–21.
- Nguyen, V. H., Sheppard, A. P., Knackstedt, M. A., and Pinczewski, W. V., 2006, The effects of displacement rate and wettability on imbibition relative permeabilities: *J. Petroleum Sci and Tech.*, page accepted.
- Øren, P., Bakke, S., and Arntzen, O. J., 1998, Extending predictive capabilities to network models: *SPE Journal*, **3**, 324–336.
- Perona, P., and Malik, J., 1990, Scale-space and edge-detection using anisotropic diffusion: *IEEE Trans. Pattern Anal. Mach. Intell.*, **12**, 629–639.
- Pratt, W. K., 2nd Ed, 1991, Digital image processing: John Wiley and Sons, New York.

Qian, Y. H., d'Humieres, D., and Lamelland, P., 1986, Lattice bkg models for navier-stokes equation: Europhys.Lett., **2**, 291.

Ramakrishnan, T. S., Ramamoorthy, R., Fordham, E., Schwartz, L., Herron, M., Saito, N., and Rabaute, A., 2001, A model based interpretation methodology for evaluating carbonate reservoirs: A model based interpretation methodology for evaluating carbonate reservoirs: Proceedings of the 2001 SPE Annual Technical and Exhibition, New Orleans, October, 2001.

Sakellariou, A., Arns, C. H., Limaye, A., Senden, T. J., Sheppard, A. P., Sok, R. M., Pinczewski, W. V., Knackstedt, M. A., Berge, L., and Øren, P., October 2003, μ -ct facility for imaging reservoir rocks at pore scales: μ -ct facility for imaging reservoir rocks at pore scales: SEG Technical Program.

Sakellariou, A., Sawkins, T. J., Senden, T. J., and Limaye, A., 2004a, X-ray tomography for mesoscale physics applications: Physica A, **339**, 152–158.

——— 2004b, An x-ray tomography facility for a wide range of mesoscale physics applications An x-ray tomography facility for a wide range of mesoscale physics applications, SPIE, Proceedings of SPIE, 166–171.

Sheppard, A. P., Sok, R. M., and Averdunk, H., 2004, Techniques for image enhancement and segmentation of tomographic images of porous materials: Physica A, **339**, 145–151.

Sheppard, A. P., Sok, R. M., and Averdunk, H., 2005, Improved pore network extraction methods: Improved pore network extraction methods: Presented at the 19th International Symposium of the SCA.

Skalinski, M., Gottlib-Zeh, S., and Moss, B., 2005, Defining and predicting rock types in carbonates: Preliminary results from an integrated approach using core and log data in tengiz field: Defining and predicting rock types in carbonates: Preliminary results from an integrated approach using core and log data in tengiz field: Presented at the SPWLA Annual Logging Symposium.

Spaid, M. A. A., and Phelan, Jr., F. R., 1997, Lattice Boltzmann methods for modeling microscale flow in fibrous porous media: **9**, no. 9, 2468–2474.

Tie, H., and Morrow, N., November 2005, Low flood rate residual saturations in carbonates: Low flood rate residual saturations in carbonates: Soc. Petr. Eng., Proceedings of the International Petroleum Conference, IPTC 10470.

Tomutsa, L., and Silin, D., Nanoscale pore imaging and pore scale fluid flow modeling in chalk: Technical report, LBNL Internal report-56266, 2004.

Vincent, L., and Soille, P., 1991, Watersheds in digital spaces— an efficient algorithm based on immersion: IEEE Trans. Pattern Anal. Machine Intell., **13**, 583–598.

ABOUT THE AUTHORS

M.A. Knackstedt: Mark Knackstedt was awarded a BSc in 1985 from Columbia University and a PhD in Chemical Engineering from Rice University in 1990. He is Professor and Head of the Department of Applied Mathematics at the Australian National University and a Visiting Professor at the School of Petroleum Engineering at the University of NSW. His primary interests lie in modelling transport, elastic and multi-phase flow properties of geological materials and development of 3D tomographic image analysis for complex materials.

C. H. Arns: Christoph Arns was awarded a Diploma in Physics (1996) from the University of Technology Aachen and a PhD in Petroleum Engineering from the University of New South Wales in 2002. He is a Research Fellow at the Department of Applied Mathematics at the Australian National University. His research interests include the morphological analysis of porous complex media from 3D images and numerical calculation of transport and linear elastic properties with a current focus on NMR responses and dispersive flow.

A. Ghous: Abid Ghous is a doctoral candidate in Petroleum Engineering at UNSW. He has an MSc degree from UNSW and a BSc in Petroleum Engineering from University of Engineering and Technology, Lahore (2002).

A. Sakellariou: Arthur Sakellariou was awarded a B.Sc (Hons) in 1994 and a Ph.D. in Experimental Physics in 2002 from The University of Melbourne. His work at ANU includes the continual development of an advanced X-ray tomography facility. His thesis work concentrated on developing a technique to measure the three dimensional distribution of mass density and elemental composition in micro-samples with a nuclear microprobe. His primary interest remains in tomography and its associated software and hardware technology.

T.J. Senden: Timothy John Senden received his training and PhD in physical chemistry at the Australian National University in 1994. His principal techniques are atomic force microscopy and surface force measurement, but more recently micro-X-ray tomography. His research centres around the application of interfacial science to problems in porous media, granular materials, polymer

adsorption and single molecule interactions.

A.P. Sheppard: Adrian Sheppard received his B.Sc. from the University of Adelaide in 1992 and his PhD in 1996 from the Australian National University and is currently a Research Fellow in the Department of Applied Mathematics at the Australian National University. His research interests are network modelling of multiphase fluid flow in porous material, topological analysis of complex structures, and tomographic image processing.

R. M. Sok: Rob Sok studied chemistry and received his PhD (1994) at the University of Groningen in the Netherlands and is currently a Research Fellow in the Department of Applied Mathematics at the Australian National University. His main areas of interest are computational chemistry and structural analysis of porous materials.

V. Nguyen: Viet Nguyen holds a BSc (Petrol. Eng, UNSW, 2002) and recently completed his PhD requirements at UNSW. His main research interests lie in the development of multiphase flow modelling on networks.

W. V. Pinczewski: W.V Pinczewski holds BE (Chem.Eng) and PhD degrees from the University of New South Wales (UNSW). He is Professor and Head of the School of Petroleum Engineering at UNSW. His research interests include improved oil recovery, multi-phase flow and transport properties in porous media and network modelling.