The Effect of Microporosity on the Fluid Properties in Heterogeneous Formations*

Ayaz Mehmani[1], Masa Prodanovic[1], and Adrian P. Sheppard[2]

Search and Discovery Article #120085 (2012)*
Posted December 31, 2012

*Adapted from extended abstract prepared in conjunction with poster presentation at AAPG Hedberg Conference, Fundamental Controls on Flow in Carbonates, July 8-13, 2012, Saint-Cyr Sur Mer, Provence, France, AAPG©2012

[1]The University of Texas at Austin, PGE Dept., Austin, TX (masha@ices.utexas.edu)
[2]Australian National University, Canberra, Australia

Abstract

Carbonate rocks are ubiquitous oil and gas reservoirs that have important pore scale features on millimeter scale (vugs, fractures), micron and submicron scale. Furthermore, submicron porosity has a dominant effect on petrophysical properties. A robust method for modeling multiphase flow in rocks dominated by microporosity would thus greatly improve predictions and producibility in carbonate reservoirs.

Pore space characterization on various scales is available, albeit from disparate sources. Computed tomography is widely used for imaging rock cores and sediments with voxel length from a few microns to a few millimeters. Recently, focused ion beam microscopy has been employed to give insight into submicron porosity of carbonate rocks. It would thus be of great interest to utilize the available experimental information from two (and possibly more) length scales in flow modeling.

In order to reduce computational cost, yet capture relevant physics, porous media are modeled as networks of pores and throats (constrictions). We present an algorithm to geometrically match pore throat networks from two separate length scales (see Figure 1), that can be extracted directly from 3D images, or be constructed to match the relevant small-scale properties of the pore space. While many multiscale approaches exist, to our knowledge this is the first time network modeling is used on both scales.

Discussion

We present two different implementations of the proposed algorithm: for model networks in sphere packings as well as image based networks of carbonates. Drainage capillary-pressure relationships and relative permeability results obtained for two scale networks where microporosity is added in parallel (i.e. partially dissolved grains) to the intergranular porosity are shown in Figure 2. Similar relationships for the case where microporosity is added in parallel (i.e. pore filling microporosity) is shown in Figure 3. The addition of a microporous reservoir, and specifically its connectivity and spatial distribution considerably, shifts the relative permeability curve. As can be seen from Figure 2, relative permeability shows a specific trend with addition of microporosity when it is acting in parallel, but no such trend can be identified when microporosity starts dominating the main fluid pathways (Figure 3).

Conclusion

Therefore, the spatial arrangement as well as the connectivity of the micropore and macropore networks has a strong influence on the trapped phase. There is no algorithm limitation on the number of different scales accommodated, but one is bounded by computational resources.

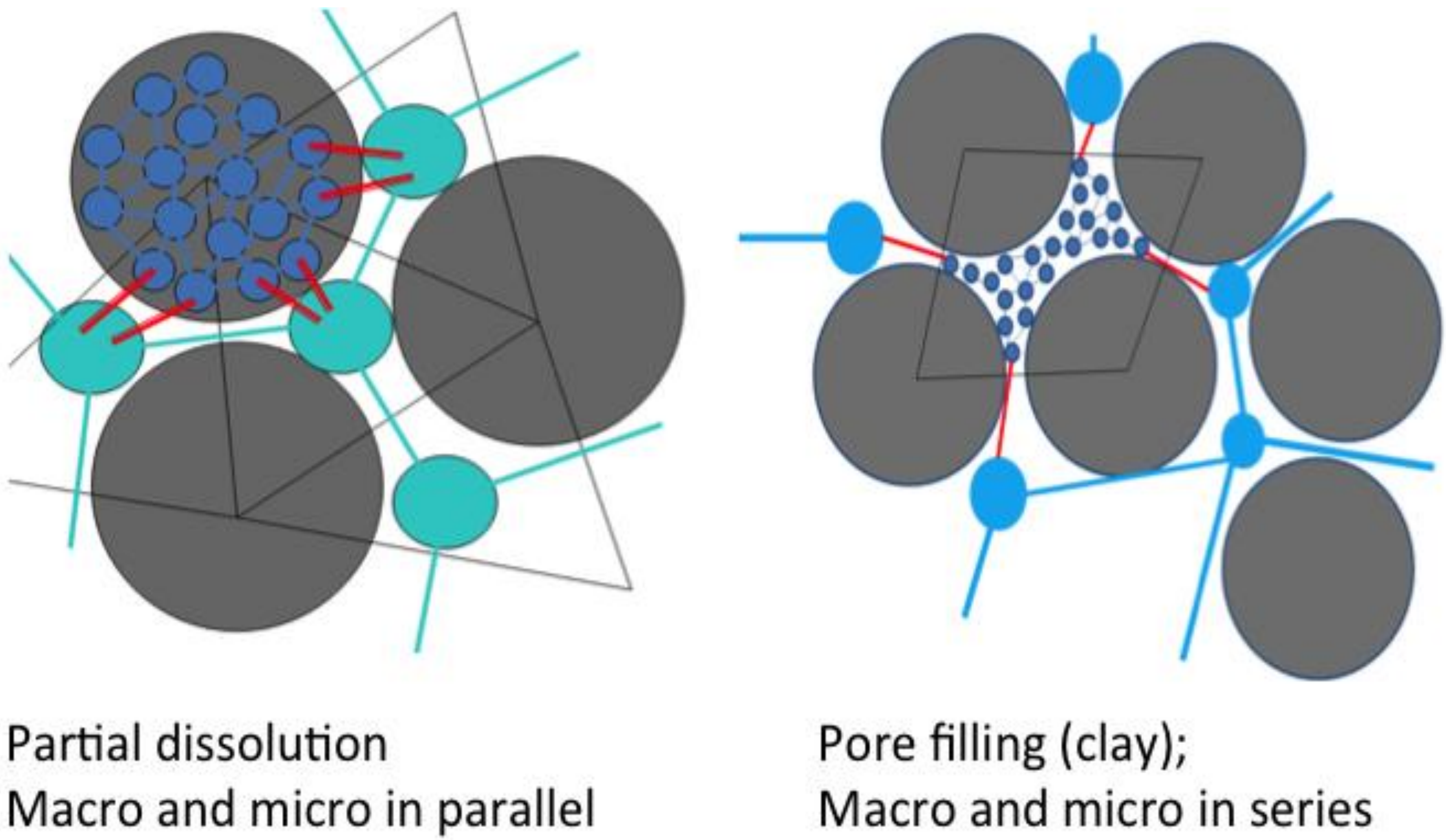

Figure 1. Proposed construction of two scale pore networks for model media. An intergranular network pores are shown in large circles. For microporous regions, we will take a network of shape similar to what is observed in an SEM image, and rescale it with appropriate length ratio and map it into the microporous region. Throats connecting the two networks across the known boundary of the two regions (shown in red) are subsequently be identified in order to get a single network that contains both length scales. The connections between two lengths scales can be non-planar (arbitrarily complex).

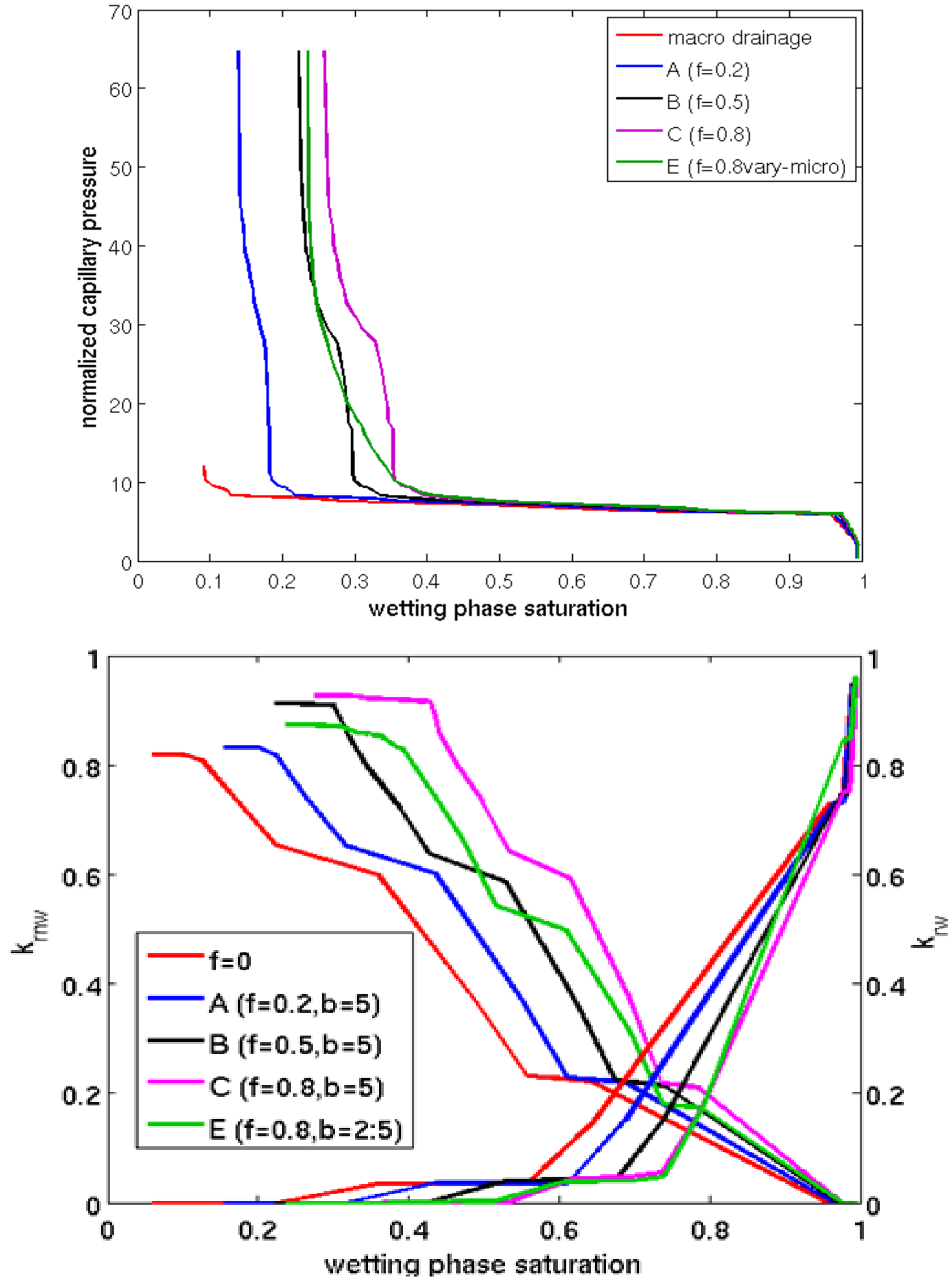

Figure 2. Drainage capillary pressure and relative permeability relationships for a model two-scale porous media with different total fractions of partially dissolved grains (see Figure 1). The length scale ratio of intergranular to microporosity was 5:1.

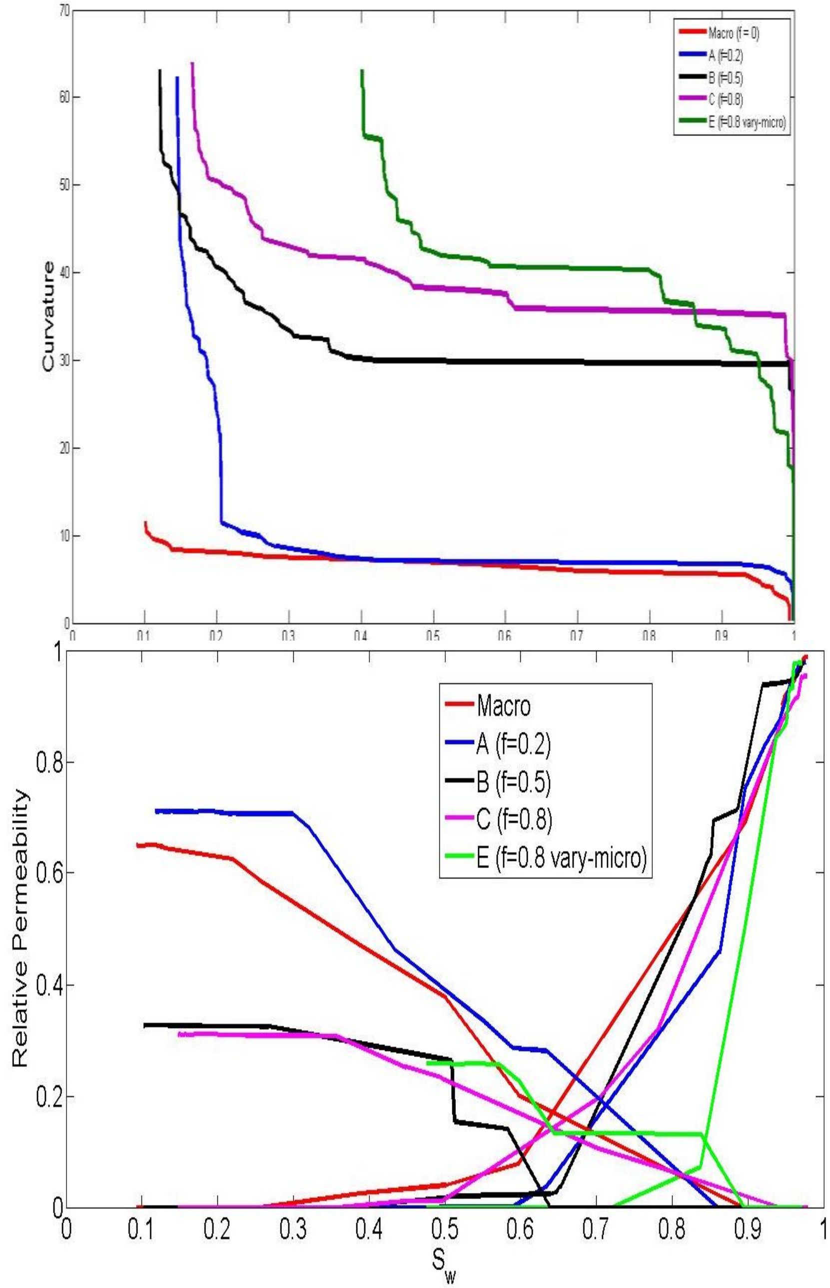

Figure 3. Drainage capillary pressure and relative permeability relationships for a model two-scale porous media with different total fractions of microporosity (clay) filled macropores (see Figure 1). The length scale ratio of intergranular to microporosity was 5:1.