9th Biennial International Conference
& Exposition on Petroleum Geophysics

"HYDERABAD 2012"

P-523

Pore-level Reservoir Characterisation and Modelling: It's the Little Things That Count

Professor John G. Kaldi, *CO2CRC*

Introduction

One of the key components of reservoir characterisation is the integration of different data sources at various scales to build a viable geological (static) model. The data sources utilised for the static model building process can include core and wireline well log data to help determine depositional environments, rock and fluid properties, porosity/permeability relationships and detailed stratigraphic setting of the reservoir. Multiple wells are useful for correlation and to guide seismic interpretations. Modern and ancient analogues are also vital to the accurate upscaling of micro and meso scale features that can be used to drive the construction of dynamic (reservoir simulation) models. In addition, understanding pore level reservoir properties commonly helps determine the amounts, types and rates of fluids that can be produced or injected into a reservoir. Characterising and modelling reservoir heterogeneities at this fine scale can be done by evaluating the architecture of the pore system of the reservoir. Pore geometry refers to the size, shape, and distribution of pores and pore throats in a reservoir rock. It can be compared to the architecture of a building - i.e. the configuration of rooms (pores) and doors (pore throats) of various shapes and sizes. The main pore geometries commonly encountered in reservoir rocks include interparticle pores, intraparticle pores, micropores and moldic pores. The relative amounts of these pore types within a reservoir can be an indication of expected reservoir properties and production behaviour of these types of reservoirs. . Pore geometry has significant on both drainage and imbibition cycle capillarity and relative permeability properties. These in turn control saturation vs. height functions and recovery efficiencies (the relative quantities of fluids produced on primary depletion as well as the distribution of remaining fluids for secondary production). In addition, potential formation damage prone intervals can be identified from the understanding of pore geometry in conjunction with detailed rock properties such as mineralogy and clay morphology. Pore geometry is evaluated using fairly routine analytical techniques such as thin-section petrography, Scanning Electron Microscopy (SEM), pore casts, mercury injection capillary pressure (MICP), CT scans and relative permeability curves. An understanding of the pore geometry of reservoir rocks early in production is desirable in order to predict reservoir behaviour during field life (figure 1).

An understanding of the movement of hydrocarbon through the pore system of the rock is critical to understanding both primary saturation as well as the residual saturations in the reservoir during production. Simply put, in order to migrate through the pore system, generated hydrocarbons need sufficient buoyancy pressure to exceed capillary forces at each and every pore throat. Buoyancy can be expressed as the density difference (in g/cc) between the generated hydrocarbon and the formation brine times the effects of gravity and column height. The greater the column height the greater the buoyancy effect and hydrocarbon can exceed greater and greater capillary forces and enter smaller and smaller pore throats. In a water wet reservoir, there will always be a certain amount of bound (or irreducible) formation water (see fig 2).

Australian School of Petroleum University of Adelaide, Australia
jkaldi@asp.adelaide.edu.au

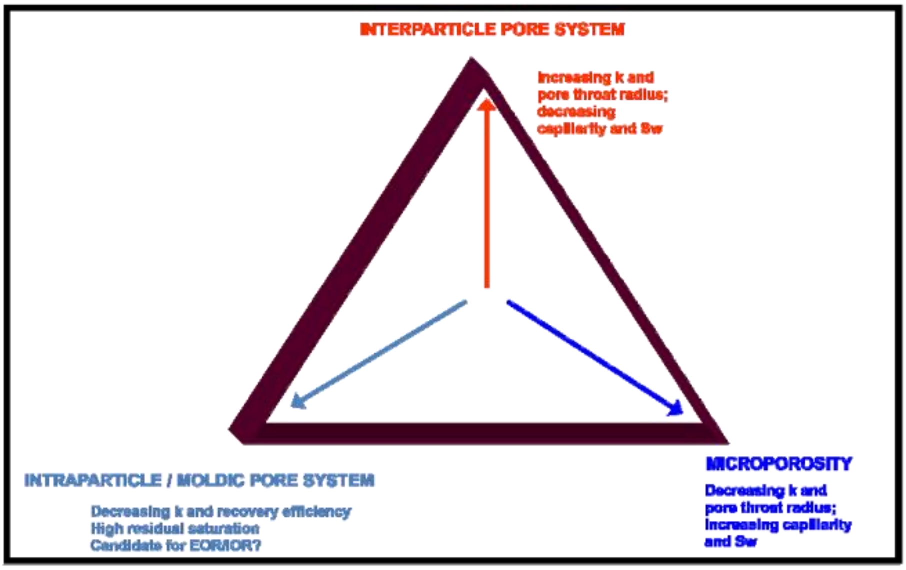

Figure 1: Ternary diagram indicating various reservoir properties typical of main pore geometries. Reservoirs with predominantly interparticle pore systems will generally have better reservoir quality, with larger pore throat radii, higher permeabilities, lower capillary pressures and lower water saturations. Reservoirs made up mainly of microporosity will generally be charaterised by smaller pore throat sizes, lower permeabilities and higher capillary pressures and water saturations. Reservoirs made up of intraparticle or moldic pore systems will tend to have low permeabilities and recovery efficiencies and high residual hydrocarbon saturations, thus being potential candidates for EOR/IOR.

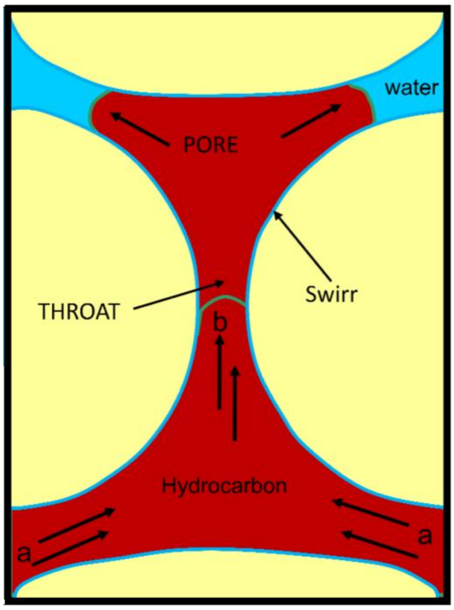

Figure 2 a) Generated hydrocarbon enters reservoir pore system; b) In order to migrate, hydrocarbon needs sufficient buoyancy pressure to exceed capillary forces at each pore throat c) A thin film of water remains around each grain: "Irreducible water saturation" (Swirr)

As hydrocarbon is produced at the wellbore, water is imbibed to replace produced oil or gas in the reservoir pore system. With increased production, the water surrounding each grain joins up causing "snap off" of hydrocarbon and creation of residual (non- moveable) hydrocarbon (figure 3).

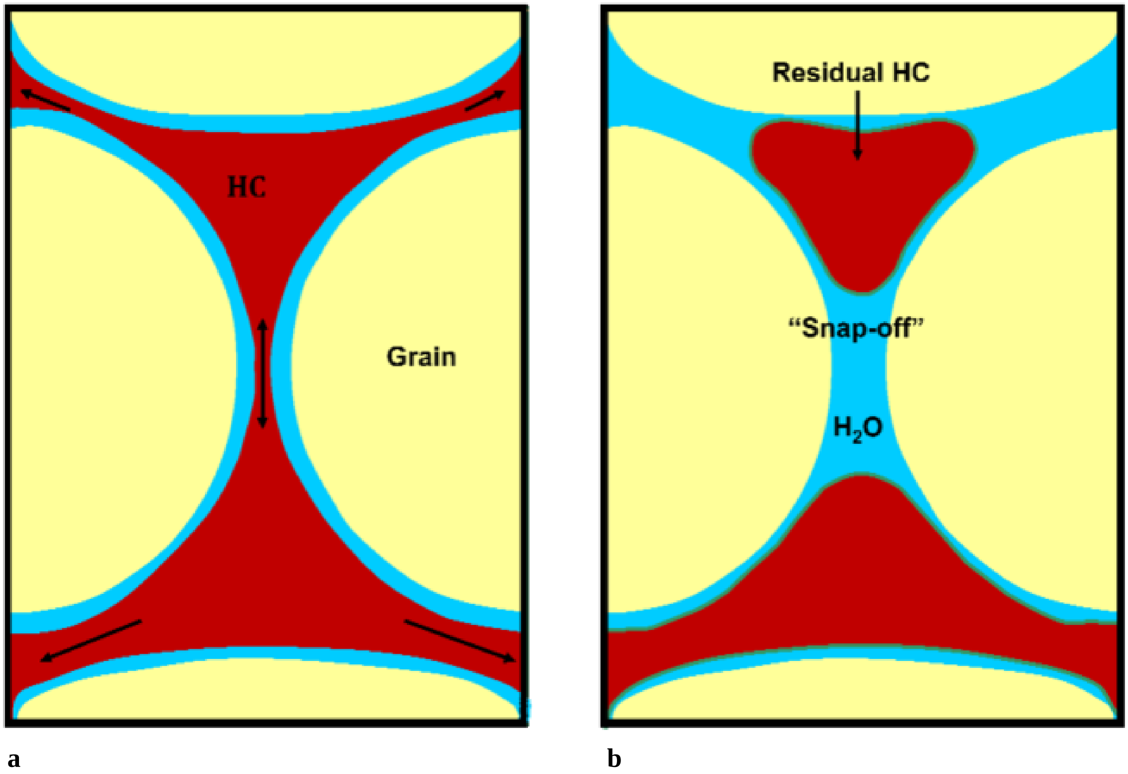

Figure 3 a) As hydrocarbon is produced at the wellbore, water is imbibed to replace produced oil or gas in the reservoir pore system; b) With increased production, the water surrounding each grain joins up causing "snap off" of hydrocarbon and creation of residual (non-moveable) hydrocarbon.

Hydrocarbon entering the pore system over geological time can be modelled in the laboratory using capillary pressure techniques. The hydrocarbon charging of a reservoir is commonly referred to as the "drainage" phase and is plotted as capillary pressure vs wetting phase (water) saturation (figure 4). By converting pressure to height, these plots provide crucial information on the saturation vs depth relationships of various rock types.

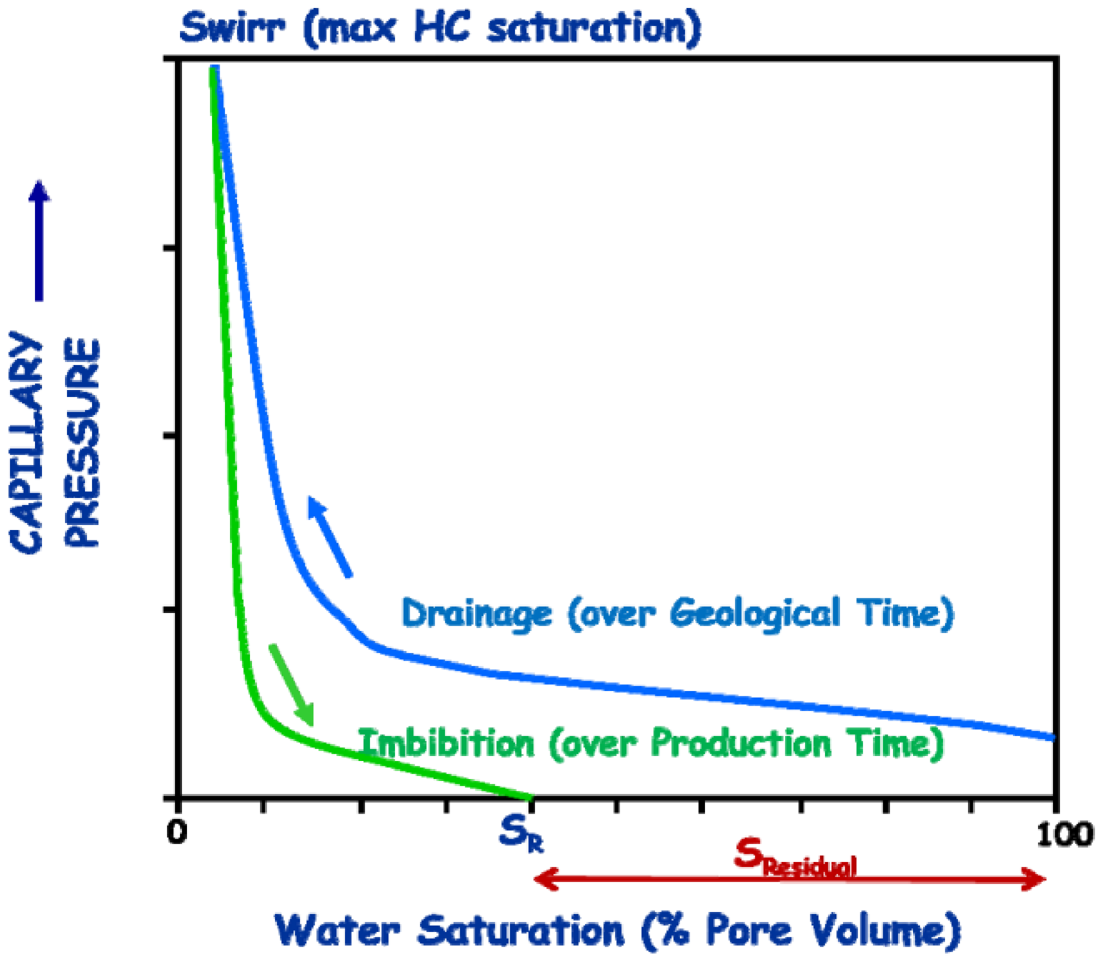

Figure 4: Capillary pressure plots showing various components of hydrocarbon charging of the reservoir (drainage curve) and hydrocarbon production (imbibition curve). Maximum hydrocarbon saturation after charge is the irreducible water saturation point (Swirr) and the residual hydrocarbon saturation is the difference between entry pressure of drainage curve and endpoint of imbibitions curve.

In conclusion, the types of data discussed in this paper clearly demonstrate that reservoir quality and the calculations of volumetrics are not simply controlled by porosity, but by factors such as pore geometry, permeability, relative permeability and the relationships between moveable oil and water and irreducible water and residual hydrocarbon saturations. It is also pore geometry that exerts a significant control on the volumes, rates and even types of reservoir fluids that can be produced from or injected into a reservoir.