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# Gas-Liquid Relative Permeability Measurements in nano-Darcy Porous Media: Primary Depletion and High-Pressure Gas Cycling Enhanced Oil Recovery (GCEOR)

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## ABSTRACT

Gas and oil production from unconventional assets has contributed significantly to North American energy self-sufficiency. Unconventional production suffers from three specific weaknesses: rapid primary production decline, poor recovery factor and fracture-driven interference with infill wells. Many authors use reservoir simulation to predict unconventional production but these forecasts are often uncalibrated and suffer from a paucity of fundamental experimental data, particularly flow data that combines phase behavior with representative porous media at reservoir conditions.

Fluid phase behavior is easily measured, modelled and included into black oil and compositional reservoir simulation models. Reservoir models and hydraulic fracture models also provide the static features of the geological structure. The transfer function (relative permeability) that combines fluid phase behavior, pressure gradients and geology has not been reported in nano-Darcy rock.

Relative permeability measurements can be viewed as a function of six or more parameters:

1) Phase Behavior; 2) Interfacial Tension (IFT); 3) Viscosity Ratios; 4) Wettability; 5) Rock Properties; 6) Gravity

The challenge of nano-Darcy rock is that in order to induce flow, traditional axial-flow testing requires higher differential pressure which then creates the potential for flow measurements to involve different phase behavior, IFT and viscosities – that is, different phase behavior, IFT and viscosity from one end of the porous media to the other. Since these parameters are treated explicitly in the numerical simulators, relative permeability measurements should be made with constant phase behavior, IFT and viscosity conditions. In order to mitigate the effects of changing fluid properties during flow, radial flow experiments were conducted. A form of the Darcy equation ($Q = k A \Delta P / \mu L$) describes why radial flow is superior to traditional axial core testing. For a permeability of 100 nD and a viscosity of 0.5 mPa-s, with typical differential pressure gradients observed in axial conventional core flows, the laboratory time required to inject one hydrocarbon pore volume (HCPV) of fluid would be approximately 22 weeks. Using radial flow in the same porous media with the same differential pressure gradient observed in unconventional porous media, approximately three hours would be required to inject one HCPV.

Radial-flow, constant IFT, constant differential pressure flow experiments were conducted in 537 nD full-diameter rock and the gas and oil production histories were regressed using a compressible, radial flow, two-phase simulator. Gas-Oil relative permeability curves were regressed at low pressure, corresponding to lowest primary depletion pressure (Highest IFT 6.7 d/cm) and the highest pressure corresponding to the lowest IFT GCEOR scenario (0.002 d/cm). Radial-flow allows for larger hydrocarbon pore volume, which provides improved saturation resolution without increasing the required differential pressure to induce flow. The resulting relative

permeability data may provide a reference for those simulating primary depletion and GCEOR in low permeability porous media in the absence of any specific relative permeability on their own relevant rock.