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Prediction of Special Core Parameters for Australian Hydrocarbon Basins

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The determination, validation and understanding, and proper use of special core analysis relationships are paramount in the assessment of recovery efficiency of petroleum reservoirs. The most reliable information, resulting in representative relationships, such as for relative permeability and capillary pressure, may be obtained from laboratory experiments. However, being time-consuming and expensive, the number of core samples typically subjected to such investigations tends to be limited, often resulting in data deficiencies and hence improper understanding of the necessary relationships, which are essential for conducting detailed reservoir engineering and simulation studies, with the aim of maximising the extraction of petroleum. For the above reasons, over the past decades, the establishment of mathematical models to predict the required properties has received considerable attention from petroleum engineers, and is one of the active research areas today.

In an attempt to predict valid relationships, difficulties are primarily related to complexity and variability of rocks, in terms of pore structure and mineralogy and associated fundamental properties: porosity, absolute permeability, and fluid saturation. Such variation is a function of the original deposition of grains and

subsequent alteration or diagenesis of a geological formation, most notably rock compaction upon burial, but also other significant alteration, for example the generation of different types of clays, filling part of the pore structure. In addition to pore structure variation, the second complication is associated with the surface chemistry between fluids and the varied rock grains, as well as the interaction between fluids themselves, for example oil and water contained in the pores. Thirdly, in conducting laboratory experiments, the precise experimental conditions may greatly influence results obtained: pressure, temperature and the types of fluids used and their properties, most notably fluid viscosity, flow velocity and interfacial tension.

Investigations by co-researchers and others into single-phase flow and the identification of appropriate geological entities, or facies, representative of (homogeneous) flow behaviour, have led to the conclusion that the Carman-Kozeny model is ideally suited to bridge the gap between the differing views of geologists and engineers. As this model is able to elegantly unify the parameters for single phase flow for the majority of petroleum rocks, the formulation was subsequently extended to two-phase flow situations by the principal supervisor. These concepts were then utilised in this research and further extended, and a number of new relationships were established, which may be used to validate experimental data and relationships or predict such relationships from more fundamental properties.

In deriving the above formulations, an extensive database was utilised, semi-empirically fitting the data for establishing some of the relationships. In other cases the data was used to validate new models, comparing model-generated and experimental results. The database was created by utilising laboratory data generated by commercial laboratories and made available by several petroleum companies, covering onshore and offshore Australian hydrocarbon basins. Both, capillary pressure and relative permeability models were validated using this data, and the new models were demonstrated to have excellent performance in predicting two-phase flow relationships. In a further attempt to validate these models, comparison studies were also conducted with well-known models used by the oil and gas industry. The Brooks and Corey capillary pressure model was used for comparison with the newly established capillary pressure model, and the performance of the new relative permeability model was checked against that of the modified Brook and Corey model, also known as the power law model.

Relative permeability and capillary pressure models depend on the primary parameters mentioned above but are actually formulated in terms of several secondary parameters, functions of primary parameters. As such irreducible water saturation is most significant. If this quantity has not been measured in the laboratory, it may be predicted. New models were established to predict irreducible water saturation, based on an artificial neural network approach. A semi-empirical model, based on trapping parameters, was also investigated, resulting in an alternate formulation for irreducible water saturation, and a universal analytical form that should be applicable to the range of geological formations.

As mentioned above, relative permeability relationships are also controlled by wettability. For the purpose of predicting relative permeability, a new model to link the USBM wettability index to pore structure parameters was also established by this research. As with relative permeability, capillary pressure and irreducible water saturation models, the model was created and validated using the Austalian database. However, the general form of the equation would lend itself for use with any data set.

Finally, the ratio of effective (or relative) permeability endpoints may be taken as an indictor of wettability. Equations to predict effective permeability to oil at irreducible water saturation and effective permeability to water at residual oil saturation have been formulated. Both equations are extensions of the Carman-Kozeny formulation.