

## Coal Bed-Methane Reservoir Simulation Study

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### Abstract

Coal-bed methane (CBM) production behaviour is difficult to predict or analyse due to its highly intricate reservoir characteristics. Gas production from (CBM) reservoirs is governed by complex interaction of diffusion from the matrix to fractures and two phase gas and water flows through the fracture system to the production wells. The parameters that control the flow physics of these two systems are highly variable during the fluid production process. Generally CBM reservoir performance is evaluated using simulation software which requires experimental or/and field data to parametrize the various governing equations that determine performance. Amongst the parameters that affect simulation outcomes, coal absolute permeability and relative permeability are key factors controlling CBM productivity.

The absolute permeability of coal varies during production due to matrix shrinkage and geo-mechanical stress-strain effects, and may be highly anisotropic. Relative permeability controls water production during the dewatering stage and the shape of gas production curve. Very little is actually known about relative permeability in coal and although it may be interpreted as a physical phenomenon, the factors controlling it in coal remain largely unexplored. It is often the case that relative permeability is used as a fitting parameter in history matching studies.

History-matched relative permeability curves ( $K_r$ ) for a coal often exhibit very different behaviour from laboratory-based curves (Figures 1 and 2), for reasons which remain largely unexplained. For practical predictive purposes, it is necessary to find methods to adjust or scale values of  $K_r$  from laboratory tests so that they are relevant to field applications.

A simplified coal seam gas reservoir simulation was carried out to examine the relative significance of transport parameters on fluid production. The simulation is carried out using GEM from the CMG suite. This software has distinct functions permitting dual porosity and permeability for modelling fractured reservoirs, and simulates primary CBM production through models for gas sorption in the matrix system, gas diffusion through the matrix and two phase (gas and water) flow through the fracture systems.

The purpose of the study is not to replicate a realistic reservoir, rather to illustrate the sensitivity of production rate under different conditions. Most of the required data used in this study comes from the German Creek coal seam, Well-DR4, Bowen basin of Australia (Meaney and Paterson 1996). Additional data elements of not available from this primary study are average values extracted from different literature studies or/and experimentally measured.

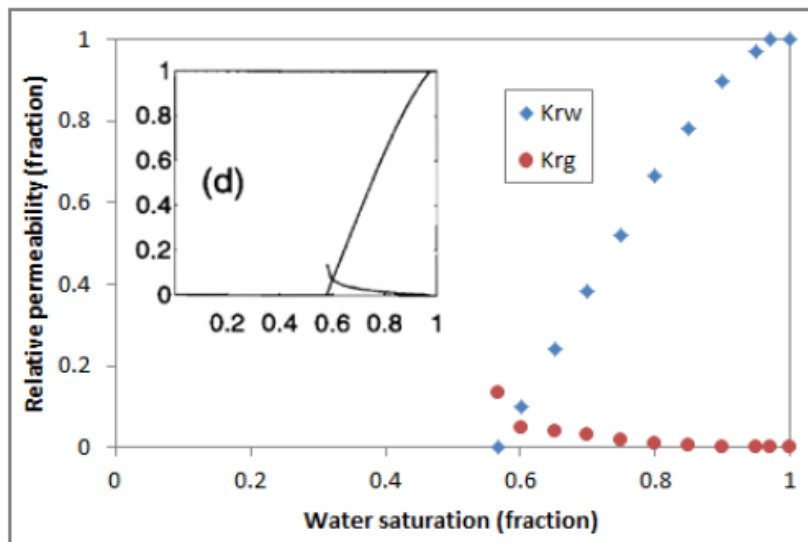


Figure 1. Coal Relative Perm from laboratory; Well DR4, GC coal seam, Bowen basin (Meaney and Paterson 1996).

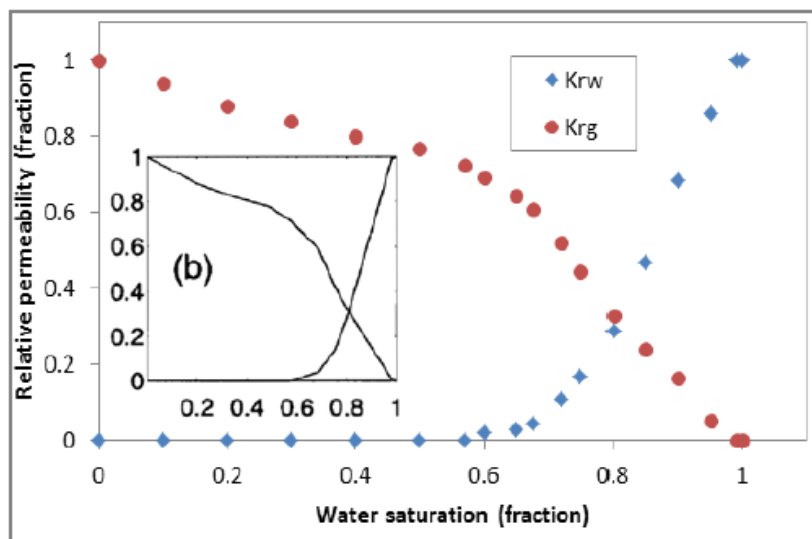


Figure 2. Coal Relative Perm from HM of field production; Well DR4, GC coal seam, Bowen basin (Meaney and Paterson 1996).

The reference provides production profiles for water and gas, based on history matched simulations, using relative permeability as a variable to obtain the match. The production history profiles are derived and replicated, and this result is taken to represent the base or ‘true’ production case.

Then, using the laboratory relative permeability measurements as a base, we systematically alter this to provide a suite curves for testing (Figure 3). The true production profile is then fitted using each relative permeability curve, but allowing other uncertain reservoir characteristics, which affect production (absolute permeability, cleat spacing, porosity, and geo-mechanical effects) to vary within plausible boundaries (Figure 4). The CMOST from CMG suite is well suited to this exploration.

Such studies provide insights into the effects of shape and magnitude of Kr on the production profile. They also reveal which parameters have the most significant effects on production behaviour and more importantly, the approximate ranges they need to provide reasonable history matching assuming that laboratory relative permeability curves are reliable.

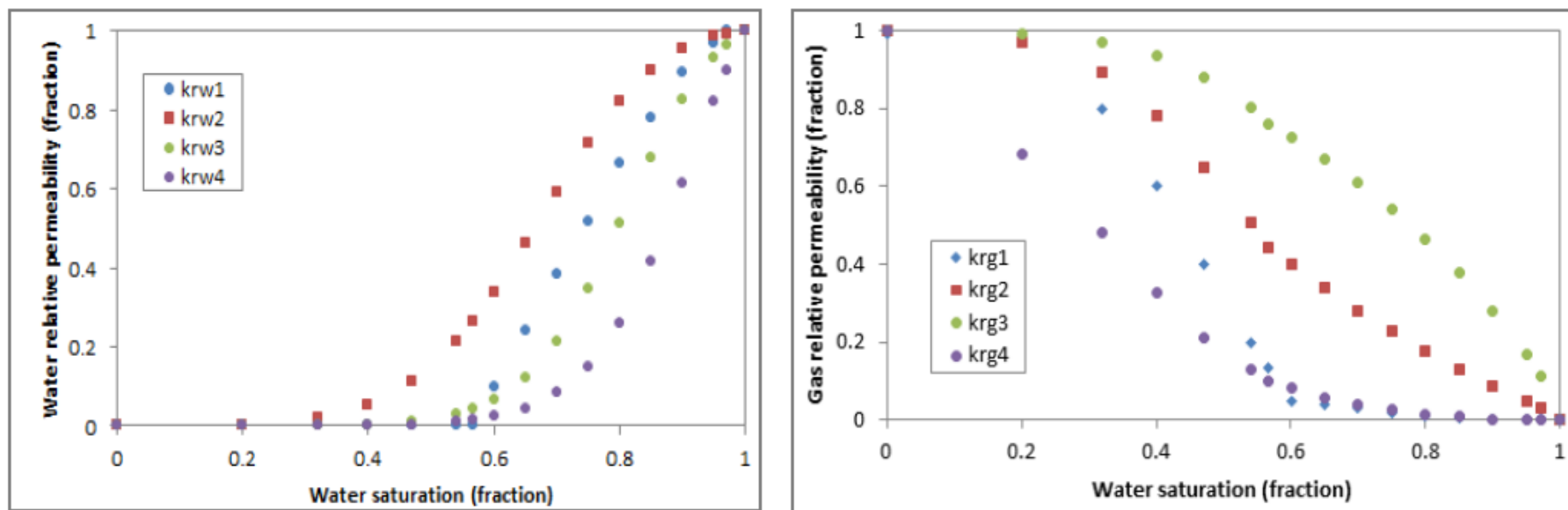
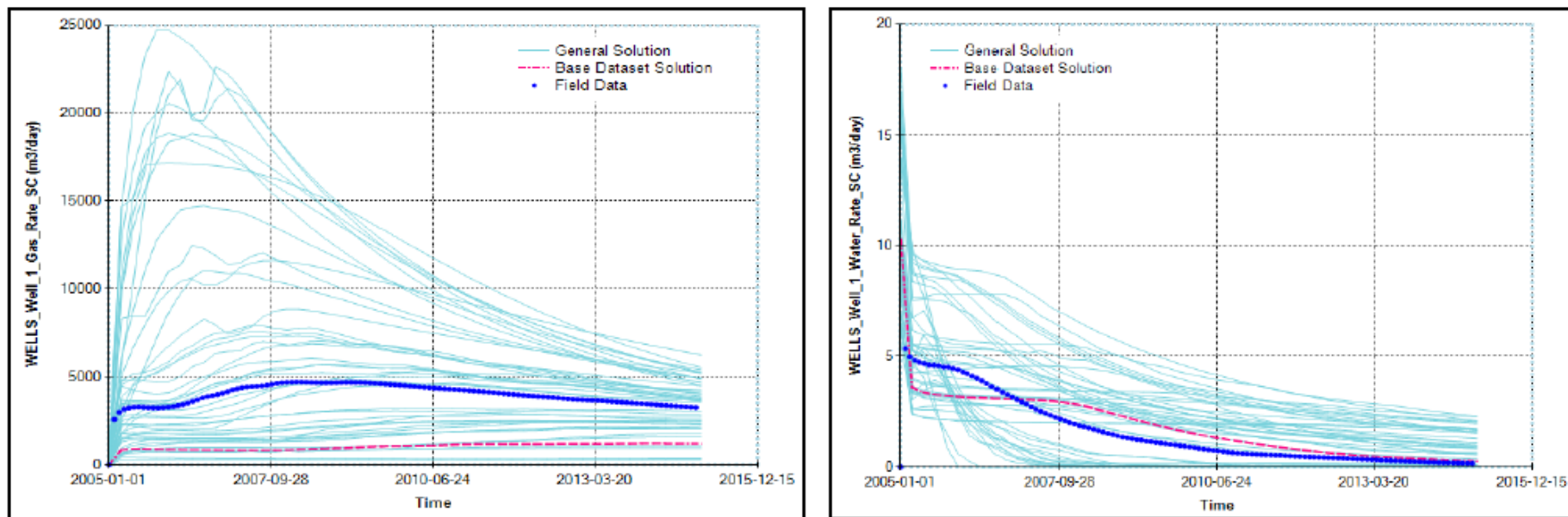


Figure 3. Various gas and water relative permeability curves.



**Figure 4. Simulation of the case scenarios.**

Relative permeability,  $K_r$ , is a dominating parameter in CBM production simulation. It determines not only when commercial gas production is achieved, but also predicts the amount of water production that needs to be managed with during CBM production stage. The fact that laboratory relative permeability measurements for CBM need substantial adjustment to fit field production data suggests a serious gap in knowledge or technique in this area.

Computer Modelling Group is acknowledged for provision of software used in reservoir simulation.