Full Pore System Petrophysical Characterization Technology for Complex Carbonate Reservoirs – Results from Saudi Arabia

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Extended Abstract

We have developed new, petrophysical characterization technology for complex carbonate reservoirs using Petrophysical Rock Types (PRT). This technology has been proven in the largest carbonate reservoirs in the world in Saudi Arabia. PRTs are derived from the Thomeer analyses of nearly 2,000 high pressure mercury injection capillary pressure (MICP) curves that are used as calibration data. The Thomeer parameters for each core plug sample are determined by applying a closure correction and fitting the Thomeer hyperbola to the capillary pressure data obtaining a near exact fit (Figures 1 and 2).

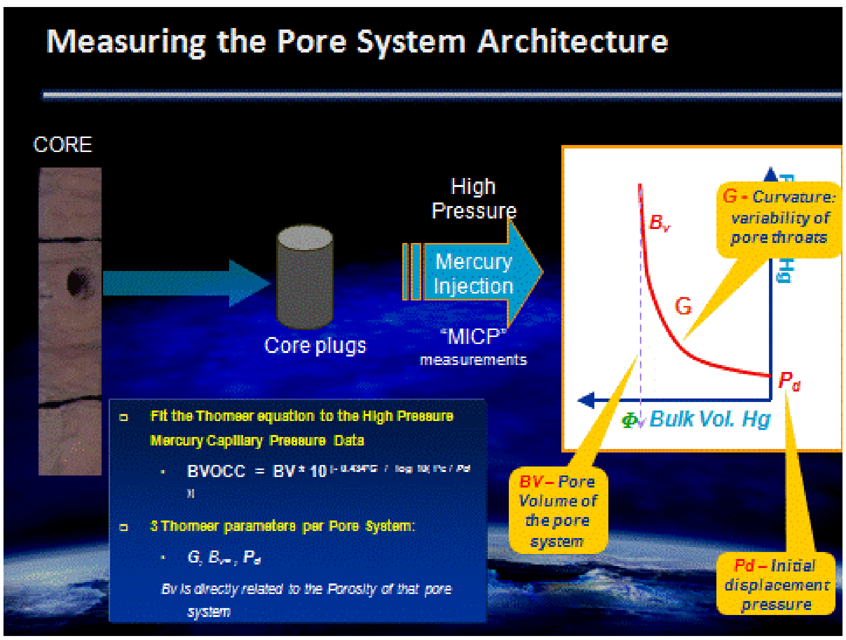


Figure 1) Three Thomeer parameters per pore system (G, Pd and BV) can be used to replicate a capillary pressure curve

Thomeer parameters (initial displacement pressure – Pd, geometric factor – G, and fractional bulk volume mercury injected - BV) are determined for each sample resulting in a characterization of the pore space architecture. This is particularly important in our complex, multimodal carbonates where the best reservoir rocks consist of both intergranular macroporosity and intraparticle microporosity.

With our large hydrocarbon columns, oil easily enters the common second pore system's intraparticle Type 1 microporosity once hydrocarbon column heights exceed 200 feet. The bulk of the Arab D oil is stored in bimodal limestone with a PRT classification of M_1, i.e. a macroporous rock with Type 1 micro porosity (Figure 3).

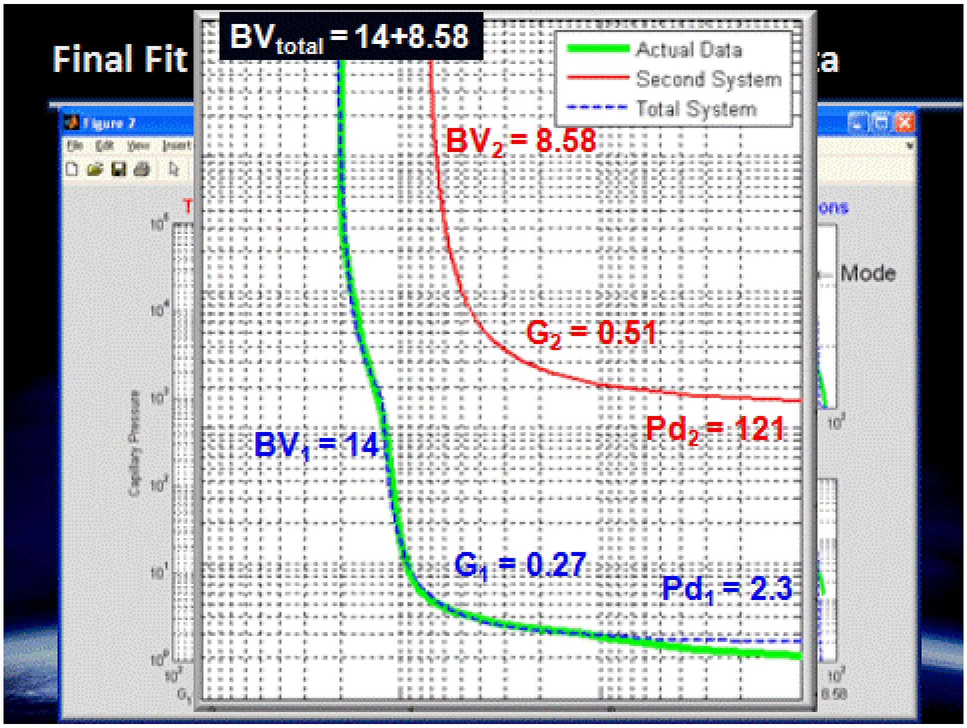
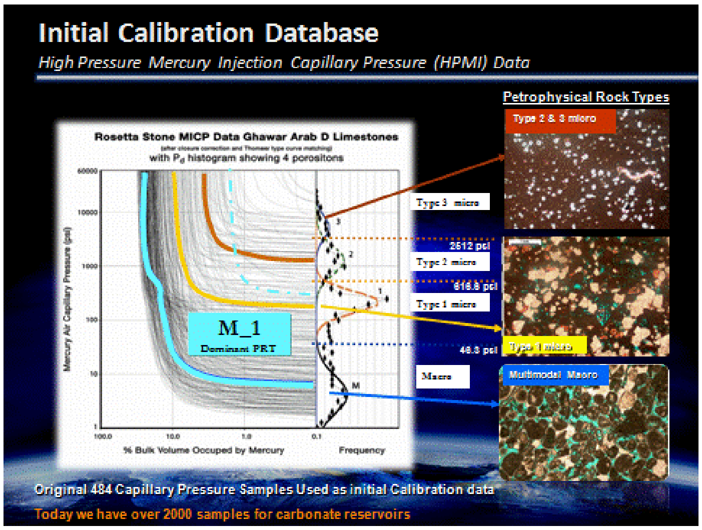


Figure 2) Assuming a dual porosity system in this case, the Matlab optimization results in a near exact fit of the fitted data (blue dashed line) to the actual capillary pressure curve (green curve). The Thomeer parameters used to match the capillary pressure data are shown on the figure for both pore systems.



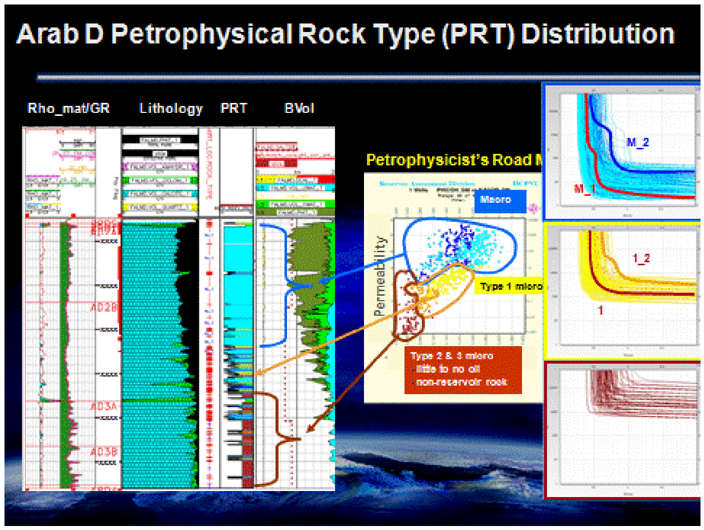


Figure 3a **Figure 3b**

Figure 3) Rosetta Stone calibration data set with 484 HPMI capillary pressure samples classified by four porositons on the left (3a). Three common PRTs from four porositons are shown in the photomicrographs; a bimodal M_1, a monomodal Type 1 and a micritic Type 2-3 micro porosity sample. The bimodal M_1 PRT, a Macro with a Type 1 micro component, is the most dominant PRT in the Arab D of Saudi Arabia. The figure on the right shows the vertical distribution of the PRTs on a type well.

The PRT classification is obtained by querying our Thomeer parameter databases (Figure 3). Moreover, the databases provide rock properties, correlations and statistics for each reservoir. Clerke[1] has defined PRTs as clusters in the three dimensional space of Thomeer parameters (Figure 4).

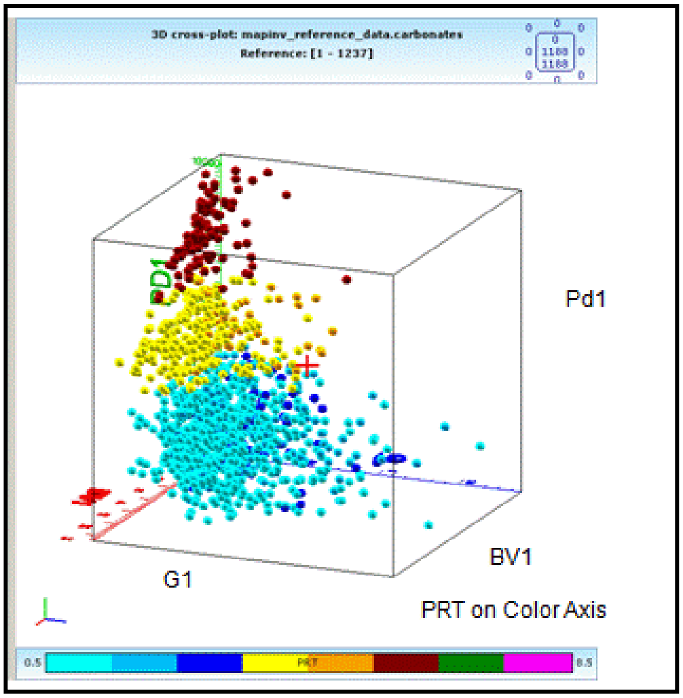


Figure 4) 3D cross plot of the Thomeer parameters, Pd1, G1 and BV1 for the 484 sample database

Using "Map Inversion Rock Typing" (MIRT), we exploit the ordered distribution of Thomeer parameters and PRTs on a two dimensional (porosity-permeability) petrophysical map (Figure 5). Thomeer parameter information is obtained by querying this petrophysical map using core-calibrated well-log predictions of porosity and permeability.

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1 **Clerke, E. A., Mueller III, H. W., Phillips, E. C., Eyvazzadeh, R. Y., Jones, D. H., Ramamoorthy, R., Srivastava, A., (2008)** "Application of Thomeer Hyperbolas to decode the pore systems, facies and reservoir properties of the the Upper Jurassic Arab D Limestone, Ghawar field, Saudi Arabia: A Rosetta Stone approach", GeoArabia, Vol. 13, No. 4, p. 113-160, October.

2 **Buiting, J.J.M, (2007),** *'Fully Upscaled Saturation Height Functions for Reservoir Modeling based on Thomeer's Method for Analyzing Capillary Pressure Measurements'*, SPE 105139.

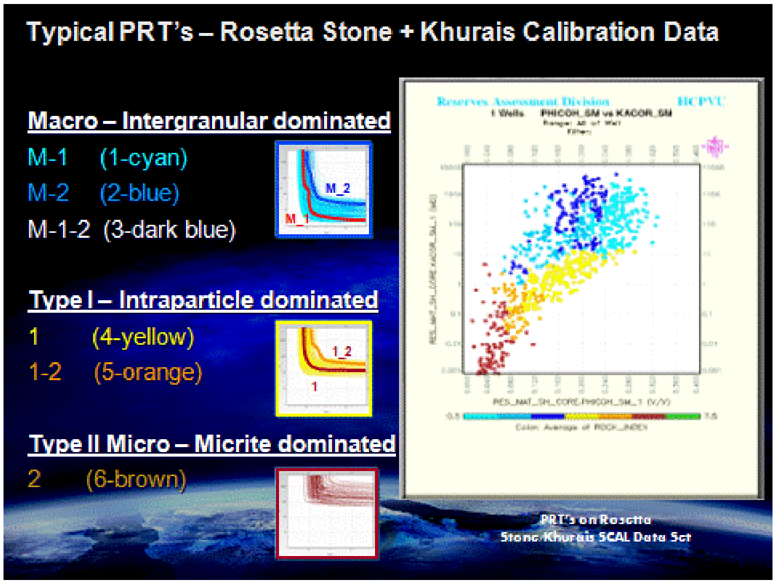

Figure 5) Cross plot of Porosity vs. Permeability with PRT's on Z axis for calibration data

The query returns PRT classifications (and their probabilities) with associated Thomeer parameters for each well level. These organized realizations of pore system data are used within a stratigraphic framework to distribute throughout the 3D reservoir model. The realizations are readily used as input to calculate saturation-height behavior.

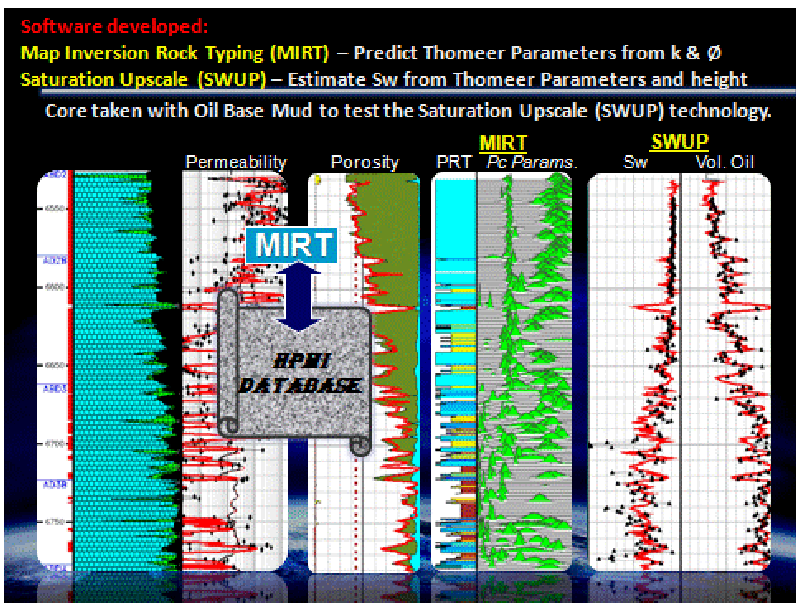

Figure 6) Comparison of oil base mud core saturations (black asterisks) with. the Buiting-Thomeer Upscaled Water Saturations (SWUP) (red lines in the far right track) based on the Thomeer capillary pressure parameters. In this example, the water saturation in the core represents in situ water saturations. MIRT is initially run using an appropriate formation calibration data set to obtain the appropriate Thomeer parameters from porosity and permeability. Then SWUP is run to determine water saturations based on the Thomeer capillary pressure parameters, fluid densities and height above Free Water Level (FWL).

Saturation-height results are compared to validation data: oil-based mud core saturations and/or well log saturations (Figure 6). The oil-based mud core saturations confirm the validity of the fully upscaled Buiting-Thomeer (SWUP) saturation model[2]. Moreover, it confirms the necessity for the inclusion of multiple pore systems. Our result comparisons are shown at two levels: the saturation-height model at the well level and what is deployed at the 3D model level (Figure 7). Upscaling from core plug to reservoir scale is an essential step in saturation-height and permeability modelling.

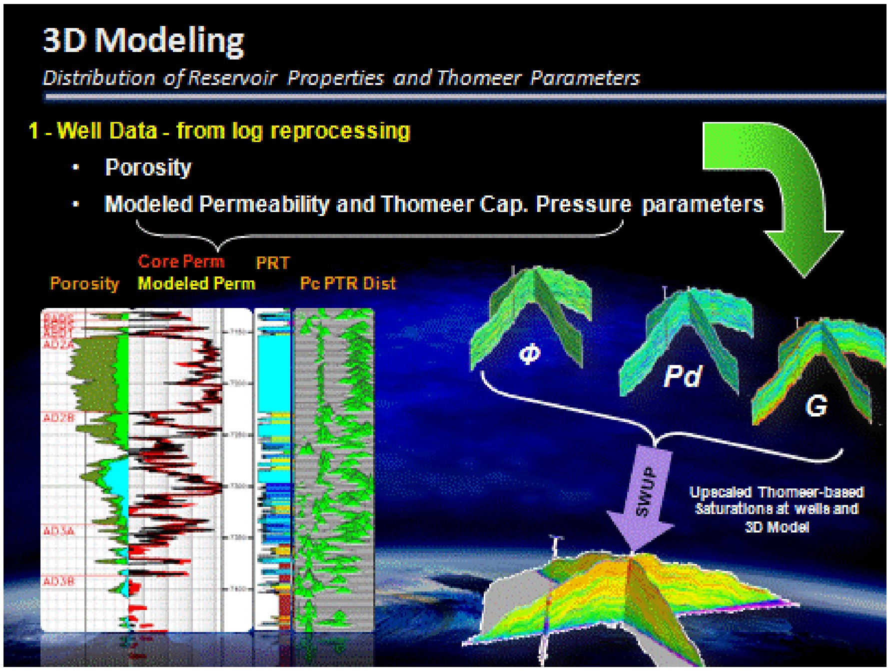

Figure 7) Porosity, Permeability and Thomeer capillary pressure parameters are distributed throughout the 3D model and then saturations are calculated in the model using SWUP.

The basic equations used in the applications are shown below:

$$P_{c,res} = 0.433\,h\,(\rho_W - \rho_o) \quad \text{..........} 1$$

where h is height above the FWL. The conversion to equivalent mercury pressure is:

$$P_{c,Hg} \approx \frac{367}{\sigma \cos(\theta)} P_{c,res} \quad \text{..........} 2$$

resulting in the bulk volume oil occupied, which can be expressd in terms of Thomeer functions:

$$B_{v,occ} = \sum_{i=1}^{3} B_{v\infty,i}\, e^{\frac{-G_i}{\log(P_{c,Hg}) - \log(P_{d,i})}} \quad \text{..........} 3$$

assuming up to three pore systems. However, without plug-to-reservoir upscaling, the artefacts of using just plug data are exposed. At a minimum for any upscaling at the log level, we would suggest bulk volume averaging to the same resolution of the log measurements or cell size to be used in the model:

$$B_{v,occ}^{Up}(P_c) = \frac{1}{N}\sum_{j=1}^{N} B_{v,occ,j}(P_c) \qquad \text{.......................................4}$$

Here N is in the number of levels, but for a full upscaling this has to be increased to numbers equivalent to large rock volumes, such as geo-cells.

The same SWUP code that is used at the well level is also used in 3D modelling and reservoir simulation software for quality and consistency purposes. Experience has shown that SWUP saturations are nearly identical in the 3D model (Figure 8) to log analysis saturations if proper saturation parameters are employed in the log analysis. Our technology results are a vast improvement to previous J function field models employed in complex carbonate reservoirs. Results from this saturation-height method have been compared to validation data and exceed previous industry results.

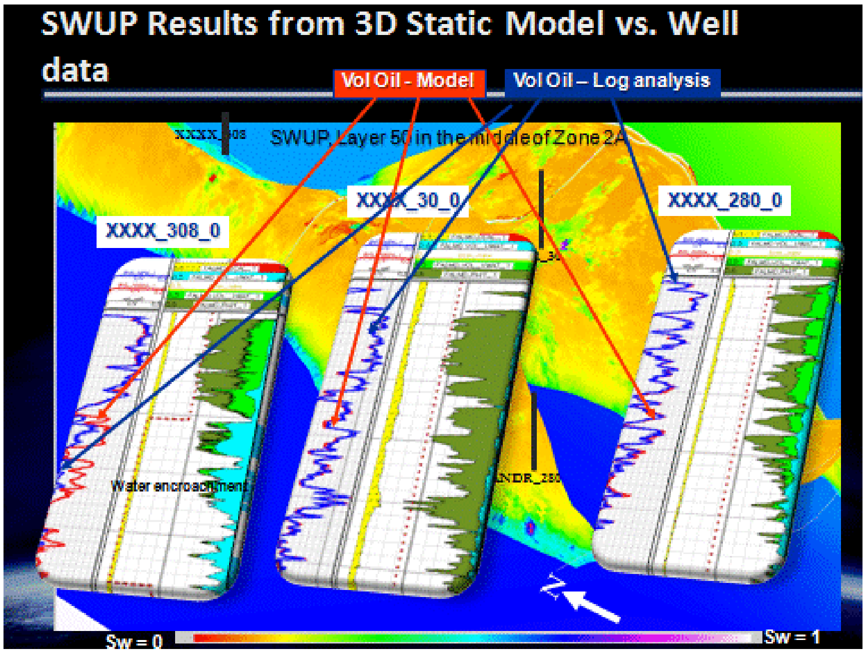

Figure 8) Saturations from 3D static model "painted" at the wells, exported to log analysis software and compared to properly calibrated resistivity based saturations at the well level.