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Carbonate Reservoir Rock Typing – The Link between Geology and SCAL

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Abstract

Reservoir rock typing is a process by which geological facies are characterized by their dynamic behavior. The dynamic behavior of the facies is assessed by studying the rock texture, the diagenetic processes which overprinted the initial fabric, and the interaction between the rock itself and the fluids. Porosity, permeability and pore size distributions characterize the rock texture while capillary pressure, relative permeability and wettability describe the rock-fluid interaction.

Reservoir rock typing is a synergetic process between geology and petrophysics/SCAL. It is therefore a process by which various petrophysical parameters and dynamic measurements obtained from SCAL are integrated in a consistent manner with geological facies (lithofacies) to estimate their flow (dynamic) behavior.

The relationships between lithofacies and reservoir rock types (RRTs) is complex because of the inter-play between facies, diagenetic processes and the rock-fluid interaction (wettability changes) in the reservoir. Similar lithofacies, deposited under the same depositional environments, may exhibit different petrophysical properties due to diagenesis. Therefore, lithofacies deposited under similar geological conditions may experience different diagenetic processes resulting in different petrophysical groups with distinct porosity-permeability relationship, capillary pressure profile and water saturation (Sw) for a given height above the Free Water Level (FWL). On the contrary, lithofacies deposited in different depositional environments, might exhibit similar petrophysical properties and dynamic behavior.

The authors emphasize on the need to have a good understanding of the original facies, depositional environments, subsequent diagenetic processes and rock-fluid interaction (via SCAL) to be able to unravel the relationships between lithofacies, petrophysical groups and rock types.

A workflow for carbonate rock typing addressing some of the industry pitfalls and the differences between lithofacies, petrophysical groups and rock types are presented in this paper.

Introduction - Nomenclature

Before proceeding into the rock type description and its link with geology and SCAL, it is important to provide a few basic definitions of the common technical terminologies found in the literature such as *lithofacies*, *facies associations*, *petrophysical groups*, *rock types* and *flow units*. In this paper we define ***lithofacies*** or lithofacies types as a depositional facies, or lithotype, based on sedimentary texture (Dunham 1962; Embry and Klovan 1971), grain types (skeletal grains, peloids, ooids, etc.), and, optionally, sedimentary structures (cross-bedding, bioturbation, lamination, etc.). Typical lithofacies types are skeletal wackestone, skeletal-peloid packstone or cross-bedded ooid grainstone. ***Facies associations*** are groups or bins of lithofacies from the same depositional environment/facies tracks with common ϕ-k relationships/trends. ***Petrophysical groups*** are units of rocks (can consist of multiple lithofacies) with similar petrophysical correlations and common porosity and permeability bins in the ϕ, k domain. Petrophysical groups can be characterized by conventional core analysis and Mercury Injection Capillar Pressure (MICP) data. ***Flow units*** are petrophysical groups with spatial continuity at the Field scale. They define the hydraulic units or flow zones (layering) of the reservoir, which should be preserved during upscaling. So, flow units, hydraulic units and speed zones are all expressions with similar meaning. ***Rock types*** are units of rock deposited under similar geological conditions (not a must), which experienced similar diagenetic processes resulting in a unique pore network and wettability, which is translated into a unique ϕ-k relationship, capillary pressure profile and relative permeability dataset for a given height above the FWL. Rock types are therefore characterized using SCAL data. MICP and conventional core analysis are not enough to characterize rock types.

Basically, reservoir rock typing is a process by which geological facies or lithofacies are characterized by their dynamic behaviour. The dynamic behaviour of the facies is established by studying the rock fabric, the diagenetic processes which overprinted the initial fabric, and the interaction between the rock itself and the fluids. Porosity, permeability and PSD characterize the rock fabric while Pc, Kr, wettability describe the rock-fluid interaction. In other words, rock typing is a synergetic process between geology and SCAL.

Facies and the Role of Sedimentology

Lithofacies types (LF) are described from, preferrably, slabbed cores using a hand lens and with the help of petrographic thin section analysis. Lithofacies types are defined by the sedimentary texture (Dunham, 1962; Embry and Klovan, 1971), the grain types, and, optionally, by the sedimentary structures. Lithofacies types are the basic building blocks for all subsequent analyses. Conventional porosity and permeability data derived from core plugs should be tied to the lithofacies types. Core description (lithofacies description) should be done in a great detail, because it is always easy to lump lithofacies types together at a later stage, but impossible to split lithofacies after core description is finished. It is understood that the level of detail contained in the number of lithofacies types might not be needed to accurately describe the reservoir, or might not be able to be handled by the geological model. Therefore, it is recommended to lump or bin lithofacies types into facies association (FA, facies bins). The lumping should be done using common lithofacies tracts (facies of similar depositional environment) and one should be very careful of grouping them based on porosity versus permeability cross-plots without prior knowledge of the diagenetic overprint. Binned lithofacies types with similar diagenetic overprint should follow the same porosity-permeability trends. In addition, the lithofacies types binned in the facies associations should have approximately the same range of porosity-permeability. The facies associations which might contain between 1 to five individiual lithofacies types, represent depositional environments or sub-environments and, therefore, very often correspond to groups of distinct common texture: e.g. wackestone, packstone, grainstone, floatstone, rudstone, or boundstone facies associations.

Lithofacies types should be described within a sequence stratigraphic framework, because the vertical stacking of lithofacies (shallowing-upward, deepening-upward, thinning-upward, or thickening-upward) depends on the system tracts (TST: retrograding system, HST: prograding system). Time-lines (chronostratigraphic boundaries: sequence boundaries, maximum flooding surfaces, and flooding surfaces) identified on core (e.g. erosive surfaces, burrowed surfaces, bored surfaces, etc.) and subsequently tied to well-logs (distinctive well-log character) should be used to subdivide the reservoir at a third- (depositional sequences) fourth- (high-frequency sequences or parasequence sets, and, if needed, fith-order (parasequences) scale. Lithofacies or facies association maps (GDE: gross depositional environment or EOD: environment of depostion maps) should be built at fourth- or fifth-order scale. These GDE/EOD maps also serve as a quality check for the correct lithofacies interpretation (are the facies association/lithofacies tracts following Walther's law?), Walther 1893).

The Role of Diagenesis

Carbonates, unlike sandstones are very succeptable to diagenesis. Leaching and/or cementation and dolomitization often occurs already at a very early stage, shortly after deposition (synsedimentary and eodiagenetic). During burial (mesodiagenetic), carbonates are continously exposed to diagenetic processes such as pressure dissolution (compaction/stylolitization), deep burial cementation, dolomitization, or leaching. Analyzing the amount of diagenesis and the diagenetic environment therefore is crucial for the correct reservoir quality prediction. The diagenetic overprint (cementation) might transform a primarily excellent reservoir rock (lithofacies type) like a high-energy, shallow water ooid grainstone into a poor to non-reservoir rock; petrophysically indistinguishable from a primary poor reservoir rock like a low energy, deeper marine mudstone or skeletal wackestone. Figure 1 exhibits an example of the effect of diagenesis on a skeletal peloidal grainstone facies with ϕ=20% and k=25mD. After cementation this facies could exhibit reduced petrophysical properties (ϕ=14% and k=2mD), while after dissolution (the other extreme of diagenesis) the same facies could exhibit an enhancement of properties (ϕ=23% and k=305mD). So, rocks (facies) deposited under the same geological environment could exhibit a wide spectrum of petrophysical properties as a result of diagenesis.

Linking Diagenesis, Rock Fabric and Capillary Pressure

The diagram shown in Figure 2a ilustrates the facies progression of depositional environments for a ramp profile, whereby the facies are systematically arranged based on topography and current energy (Lucia 1999). Using the Lucia diagram as a model, we try to establish the link between facies, depositional environment and diagenesis. The inter-play of all these factors affect the rock fabric of a particular facies and, therefore, their capillary pressure behaviour.

Figure 2a exhibits six different lithofacies, each one with its own rock fabric and capillary pressure behaviour. The ramp crest sediments exhibit better petrophysical properties with a capillary pressure exhibiting very low irreducible water saturation (Swi). On the contrary, the tidal flat sediments exhibit very high Swi, typical of low porosity and permeability fabric.

If diagenesis takes place in this type of environment (see Figure 2b), the rock fabric and capillary pressure of the different facies changes according to the type of diagenesis (cementation, leaching, dolomitization etc) and different petrophysical groups will be established. From the six initial facies three petrophysical groups will be created as a result of diagenesis (see

Figure 2b). If, for instance, cementation takes place in the ramp crest facies, the porosity and permeability will be impaired with a right shift in the capillary pressure curve. If dolomitization occurs in the middle ramp facies, the properties would improve with an increase in the porosity and permeability and, as a consequence, a reduction in the Swi (see left shift in the capillary pressure curve).

Petrophysical Grouping

In order to establish the petrophysical groups within a facies association, the use of MICP data is critical namely the pore throat radius and their distribution and capillary pressure data as the same facies may include different PGs (Fig 3.a) because of the reasons described above.

In the same way and due to the diagenetic overprint on the initial rock fabric, different facies can appear to belong to a same petrophysical group (Fig 3.b), however it is not recommended to lump multiple facies into one petrophysical group, even when they show the same porosity and permeability and comparable capillary pressure data. Lumping the two lithofacies types would eliminate the predictability of the lithofacies tracts within the geological model. As an alternative to populating the geological model with only petrophysical groups, it is suggested to build the petrophysical groups model conditioned to a facies associations model within a sequence stratigraphic framework (Fig 4.a) and to incorporate additional trend grids like early and late diagenetic events (diagenetic model – Fig 4.b) and grids exhibiting fracture networks. Thus, the geological model will show areas with similar facies associations corresponding to different petrophysical groups or, alternatively, areas with distinct facies but with similar petrophysical groups (Fig 4.c).

It is important to note that although multiple facies can follow the same ϕ, k relationship (Fig 4.d) it does not necessarily mean they all belong to the same petrophysical group. The petrophysical group changes along the best-fit line of the ϕ-k plot, based on the porosity-permeability bins as exibited in Fig 4.e. For instance, Fig 4.d exhibits three groups for the oolitic grainstones (yellow dots) with the same ϕ-k relationship. However, they belong to three distinct petrophysical groups (Fig 4.e) as follows:

On the contrary, different lithofacies, skeletal and oolitic grainstones for instance, (orange and yellow dots of Fig 4.d) plotted in the same ϕ-k domain, exhibiting similar ϕ-k bins, belong to the same petrophysical group. The same phenomena occurs to skeletal packstone and grainstone samples within 10-15 porosity range and with permeabilities above 10 mD (Fig 4.d). When properly sorted, according to their ϕ, k domain (Fig 4.e), these different lithofacies fall within the same petrophysical group.

The relationship between porosity and permeability for a defined PG is commonly established by the Pittman plot (Fig 4f). This plot is a semi-log crossplot of permeability versus porosity that includes isopore throat lines called R35 ports corresponding to the calculated pore throat radius at 35% mercury saturation from MICP data. From this plot it is clear that the same relation can be applied for different petrophysical groups leading to the conclusion that ϕ-k plots are not *per se* enough to discriminate the petrophysical groups in a reservoir.

In summary, petrophysical groups in a 3D model define the rock volume in which the distributed petrophysical properties (porosity, permeability and water saturation) are characterized by similar functions and similar bins.

The recommended workflow to capture the petrophysical groups in a 3D geological model honouring the geological and diagenetic processes is as follows:

1. Model the depositional facies within a sequence stratigraphic framework (Fig 4.a)
2. Study the diagenetic overprint and overlay the diagenetic maps onto the facies model (Fig 4.b)
3. The end product is a 3D representation of a model with petrophysical groups with distinct petrophysical properties (Fig 4.c). The ϕ–k cross-plots (Figs 4.d – 4.f) illustrate this process.

The petrophysical groups when spatially propagated in the 3D model define the main flow units of the reservoir. What is then the minimum number of flow units to be captured in a reservoir ? How do we define them ?

Flow Units

The best way to assess the minimum number of flow units in a reservoir is to make use of the Stratigraphic Modified Lorenz Plot (SMLP) technique (Gunter et al., 1997). To compute the SMLP, continuous (foot-by-foot) core porosity and permeability and the respective k/phi ratio are arranged in a stratigraphic order. Subsequently, the products of k*h and ϕ*h were calculated, the partial sums were computed and, subsequently, a normalization to 100% was carried out. Table 2 is self explanatory for a thin reservoir zone. As mentioned above, the products of ϕ*h and k*h are referred as *storage capacity* and *flow capacity* respectively.

The next step was then to plot both values ϕ*h and k*h) on a single well with enough petrophysical information. The advantage of a SMLP, when applied to a single well (Fig 5.a), is that it resembles the gradients of a PLT profile versus depth, whereby the shape of the SMLP curves is indicative of the flow performance of the reservoir. The main flow units are therefore captured in their correct stratigraphic order. Segments with steep slopes have a greater percentage of reservoir flow capacity relative to storage capacity, and by definition, have a high reservoir process speed. They are referred in the literature as “speed zones” (Chopra et al., 1998), and sometimes mentioned as hydraulic units. In this paper, flow units, speed zones and hydraulic units are synonymous. Segments with flat behaviour (samples from Ao) have storage capacity but little flow capacity and are typically tight or dense stylolitic zones within the carbonate reservoirs. Segments with neither flow nor storage capacity are seals, if laterally extensive. Preliminary flow units (speed zones, tight zones and seals) are interpreted by selecting changes in slope or inflection points.

In the example of Figure 5, there are basically three main flow units, as depicted from the three line gradients of Fig 5.b. The Upper part of the reservoir Ao (represented by samples X10-X7), consists of a unit with very low flow capacity (only 5%). The middle part of the reservoir (Zones A1-A3), provide 50% of the flow capacity. The Lower part of the reservoir, the thinner A4 interval, provides 45% of the total flow capacity and this, in comparison, the best flow unit (steeper gradient). This plot is very useful for the optimization of the number of petrophysical groups and to assess their distinct dynamic behaviour.

Reservoir Rock Typing

Rock types can be characterized by integrating SCAL data and fluid model with the petrophysical grouping.
Although a 3D representation of the petrophysical groups can be built using the above mentioned process, the full dynamic representation of the fluid flow in these rocks need to be established. This has to be assessed during SCAL analysis, because rocks with similar fabric (similar pore size distribution and similar capillary pressure) might exhibit different dynamic behaviours depending upon their location in the fluid column. For instances, skeletal packstones (PG-5 in Fig 4.c) might have different dynamic properties if they are located above or below the FWL. Their different wettabilities will translate into different relative permeability curves.

In summary, the main difference between petrophysical groups and rock types is the study of the rock-fluid interaction within each petrophysical group. The rock-fluid interaction assesses the relative permeability of each sample and dictates how fast both fluids (oil, water, gas) move within each rock fabric.

The sequence of images on Figure 6 (Figs 6.a – 6.e) illustrate conceptually the link bewteen petrophysical groups, fluid model and the distribution of rock types.

From the example of Figure 6, one can see that the number of rock types in a reservoir is greater than the number of petrophysical groups. Exceptions might occur if the reservoir does not exhibit wettability variations. If we consider the data from Table-1 representing the petrophysical groups and take into consideration the effect of fluid distribution and wettability variations, the following rock types would occur (see Table-3):

In retrospect, and taken into consideration all the dataset presented in Figures 4 (c-e) & 6 (d-e), one can see that from the initial four facies associations, six petrophysical groups have been determined. This was achieved by integrating the diagenetic model. If the fluid model is considered in the process and wettability variations are taken into consideration, nine (9) rock types are established.

Table-4 summarizes the key data used for the characterization of facies, petrophysical groups and rock types with their respective applications. While facies and petrophysical groups are based on the characteristics of the rock fabric, rock types are based on the interaction between the rock and the fluid. The former describe the static parameters of the reservoir while the latter describe the dynamic component. Facies and petrophysical groups are used by the geoscientists to build the fine scale geological models and for the determination of the oil-in-place while rock types are used by the reservoir engineers for the assessment of the recovery factors using fluid flow simulation. Although the upscaling of properties from static to dynamic model is an essential and important part of the process, aiming at preserving the dynamic characteristics of the averaged grid blocks, the discussion of this topic is outside the scope of this paper.

The plot of Figure 7 exhibits the amount of information available during a rock type study.

Basically, a 3D geological model based on rock types should exbibit less heterogeneity than a model based on lithofacies alone. This is because there is no need to model each individual lithofacies. As mentioned before, lithofacies should be combined using a sequence stratigraphic framework to produce meaningful facies associations. The facies association model when properly integrated with the diagenetic maps and conventional core analysis data should produce a reliable petrophysical group model. The petrophysical model should have higher heterogeneity than the facies association model and when integrated with SCAL and fluid model, a rock type model is generated. This rock type model should have higher heterogeneity, as the same petrophysical group could be defined by multiple rock types as explained before.

Figure 8 is the representation of different rock types in the simulation model. Each region has a unique set of petrophysical properties, capillary pressure and relative permeability data.

When the rock types are defined in the dynamic model, the initialization can take place by assigning the respective capillary pressures and relative permeabilities.

Common Pitfalls in Rock Typing Studies

1. Sedimentological maps are produced but are not integrated in the modelling process.
2. Sedimentological lithofacies and diagenetic descriptions are not completed in a consistent approach, preferably by the same interpreter for all wells.
3. Facies are described without considering diagenetic overprints as a discriminant factor.
4. Diagenetic studies are done but are not incorporated in the workflow, either because the information is descriptive (not captured numerically) or lack of spatial data.
5. Sampling for SCAL is done before taking into account the distribution of the petrophysical groups within the fluid model (above or below the FWL).
6. Porosity-permeability cross-plots are done without sorting the data by facies and diagenetic overprints.
7. Poro-perm transforms are applied without linking to geological facies and stratigraphic position.
8. Arbitrary use of MICP poro-perm data in conjunction with conventional core poro-perm data without proper consideration for the scaling effects.

Predicting Permeability - The Scale Issue

Carbonates are very heterogeneous and the permeability varies by several orders of magnitude within 1 foot interval. This high level of heterogeneity is confirmed by probe-permeametry conducted on carbonate rocks (Fig 9). Although there are several prediction techniques, the prediction of permeability from open-hole logs is a great challenge.

Sampling for SCAL

The sampling for SCAL should take into consideration the distribution of the petrophysical groups within the fluid model, i.e., rocks from the same petrophysical group should be sampled in the oil leg as well as in the water leg to assess wettability variations and, therefore, account for variations in the relative permeabilities. If this is not done a proper rock type characterization can not be established.

The Role of SCAL in Rock Typing

To test the above developed distinctions between, petrophysical groups, facies associations and reservoir rock types, SCAL measurements were performed from well selected reservoir cores from a Middle East carbonate reservoir. The study was part of an objective to obtain representative petrophysical and reservoir characterization data for modelling the performance of a specific reservoir zone, and assessing options for future reservoir management. This comprised a comprehensive program in establishing representative reservoir condition protocols for measuring water-oil capillary pressure, saturation exponents ‘n’, water-oil and gas-oil relative permeabilities and comparison of gas process displacement options such as secondary gas injection, tertiary gas injection and WAG/SWAG. In this paper we only report measurements related to the water-oil capillary pressure and relative permeability at full reservoir conditions.

Reservoir fluids were synthesized from PVT measurements carried out as part of the project brief. Tests were performed on freshly preserved reservoir cores after very careful screening using X-ray CT scanning, NMR analysis, MICP and Thin Section Analysis on relevant trims and standard poroperm measurements. Based on preliminary studies, the reservoir cores were classified to six reservoir rock types (RRT 1 to RRT 6), varying in permeability from oolitic grainstones of several hundred mD level (RRT 1 & RRT 2) to skeletal packstones of micro Darcy level (RRT 6). The porosities similarly varied from maximum of 35% for RRT 1 to less than 15% for RRT 6.

Capillary pressure (Pc) data were acquired using the semi-dynamic method or SDM, and detailed analysis including impact of heterogeneity and its assessments are reported elsewhere (Lenormand et al 1993, 1995, Lombard et al 2002 and Lombard and Kalam 2004). The principle is based on the balance between the capillary pressure and the viscous pressure drop. The sample is set in a core holder, without any semi-permeable membrane. During an experiment, one fluid is injected through the sample while the second one washes the outlet face of the core. A separator is used to measure fluid production. Local saturation profiles can be measured with different techniques (ultrasonic method, X-ray or Gamma ray). A steady state equilibrium is reached if inlet and outlet pressures and saturation profiles are both constant. Table 5 shows the basic parameters for each of the six samples tested successfully. The target Swi values were achieved using Porous Plate with in situ saturation monitoring.

Figure 10 shows the imbibition capillary pressure SDM results for the six RRT tested; RRT 6 core (lowest permeability) was difficult to test with the present set up and hence gave anomalous data, and should be ignored. The samples showed negligible spontaneous imbibition (after aging in live crude at Swi) of brine after 5-7 days, indicating that they are in general oil wet to intermediate wettability. Although RRT 1 to RRT 5 show the trend of increasing entry pressures (as expected) with lower permeability, almost all the data gave residual oil saturations of 10 to 15%. The J-function plot shows the impact of the individual RRT better compared with the Pc curves. It is clear that the RRT 1 and RRT 2 samples having oolitic grainstones and consisting of comparatively much bigger local heterogeneity and pore throat distributions (as evident from MICP and NMR data) reflect the same with more diffused saturation response. Hence, the packstone samples of RRT 4 and RRT 5 with narrower pore throat distributions show sharper saturation changes with the Pc measurements. Such consistencies in the current measurements add confidence to the measured data.
The relative permeability (kr) tests were performed on carefully selected composite samples of each RRT to minimise the impact of local heterogeneity and improve the overall volumetric, and thus a more accurate mass balance. The tests were performed on 30 cm long composites of four to five individually butted plugs at Unsteady State conditions with live reservoir fluids and simulated formation brine. Reservoir advance rates (representative of reservoir conditions) were chosen during the initial displacements, followed with couple of bumps to reach end points close to the residual oil saturation, Sor. The full details of the calibrations, QA/QC and consistency checks on the measurements have been reported by Spearing et al (2004) and Kalam et al. (2006 and 2007). These involved history matching of each measured core composite data set with production, pressure drop and in situ saturation monitoring profiles along with relevant capillary pressure corrections for possible end effects.

Figure 11 shows the interpreted imbibition kr data in both linear and semi-log forms for the six rock types, and like before, the data of RRT 6 were suspect due to its very low permeability and experimental limitations using current technique. It is clear that in general (based on our preliminary measurements), the kro increases with rock types containing the skeletal packstones and /or wackstones when compared with oolitic grainstones, and this enhancement is consistent with the reducing permeability. Conversely the krw curves, show a reduction at similar saturations from oolitic grainstones to skeletal packstones, as the overall permeability increases. The higher RRT number reflect lower permeability with correspondingly lower pore size distribution, and hence during imbibition displacements water is less mobile for the higher RRT reservoir cores, i.e. those containing oolitic grainstones. Figure 12 shows the same consistent behaviour when the fractional flow rates are plotted with respect to each RRT and cross plots of krw/kro with RRT. A major observation is the shift in the kr cross over plots for each rock type. As observed earlier, oolitic grainstones comprising the heterogeneous bimodal RRT 1 and RRT 2 have lower cross over points indicating pronounced oil wet behaviour. Similarly, the packstones comprising RRT 3 and RRT 4 show shifts to the right and thus less oil wet behaviour compared with RRT 1 and RRT 2, while RRT 5 with dominant packstones and wackstones show a consistently more water wet tendencies. Hence, in terms of wettability characteristics, one can conclude from this limited data set that the rock types containing oolitic grainstones are strongly oil wet while skeletal packstones are intermediate wettability (or less oil wet) and combination of packstones/wackstones make the RRT comparatively water wet.

Conclusions

- Reservoir rock typing is a process by which geological facies are characterized by their dynamic behaviour.
- There is a clear distinction between facies, petrophysical groups, and reservoir rock types.
- The dynamic behaviour of the facies is established by studying the rock fabric, the diagenetic processes which overprinted the initial fabric, and the interaction between the rock itself and the fluids.
- Porosity, permeability and pore throat radius/pore size characterize the rock fabric while Pc, Kr, wettability describe the rock-fluid interaction. In other words, rock typing is a synergetic process between geology and SCAL.
- Rock types should be characterized by integrating SCAL data with the fluid model and the sampling for SCAL should take into consideration the distribution of the petrophysical groups within the fluid model, i.e., rocks from the same petrophysical group should be sampled in the oil leg as well as in the water leg to assess wettability variations and, therefore, account for variations in the relative permeabilities.
- SCAL conducted on carbonate rocks from a Middle East reservoir with a geological setting similar to the example of Fig 2, indicate dependence of imbibition capillary pressure on reservoir rock types, with oolitic grainstones showing definitive oil wet tendencies and thus minimal spontaneous imbibition of brine. Also, the shift in fractional flow curves and water-oil relative permeability from a clear oil wet behavior in oolitic grainstones to less oil wet characteristic in skeletal packstones, and weakly water wet tendencies in mix of wackstones and packstones.

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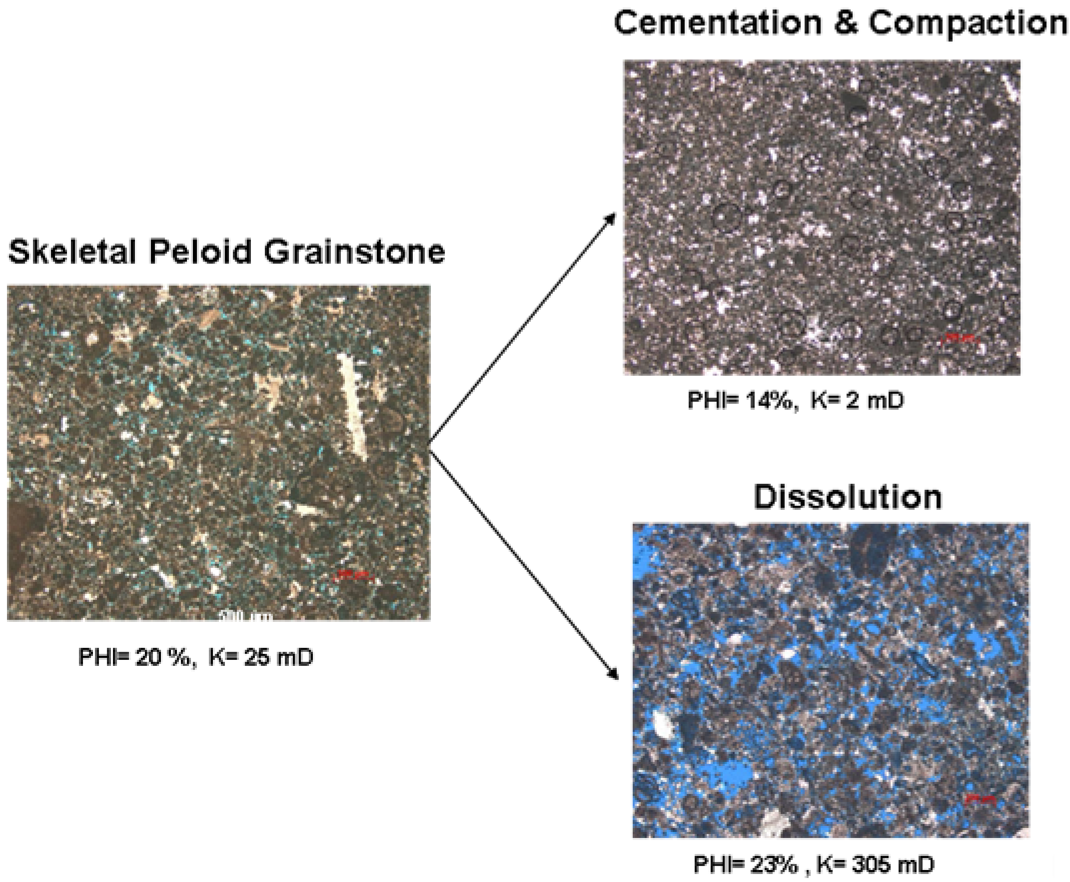


Figure 1 – Impact of diagenesis (cementation and dissolution) on the rock fabrics and petrophysical properties

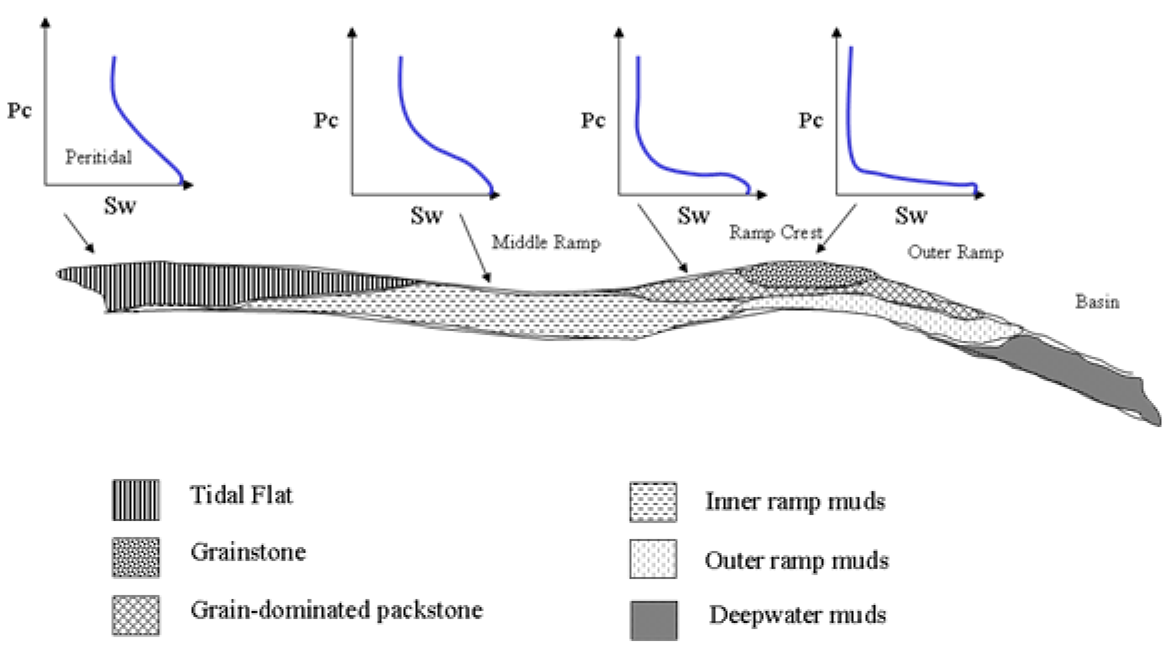


Figure 2a – The link between facies, depositional environment and capillary pressures for a system not affected by diagenesis.

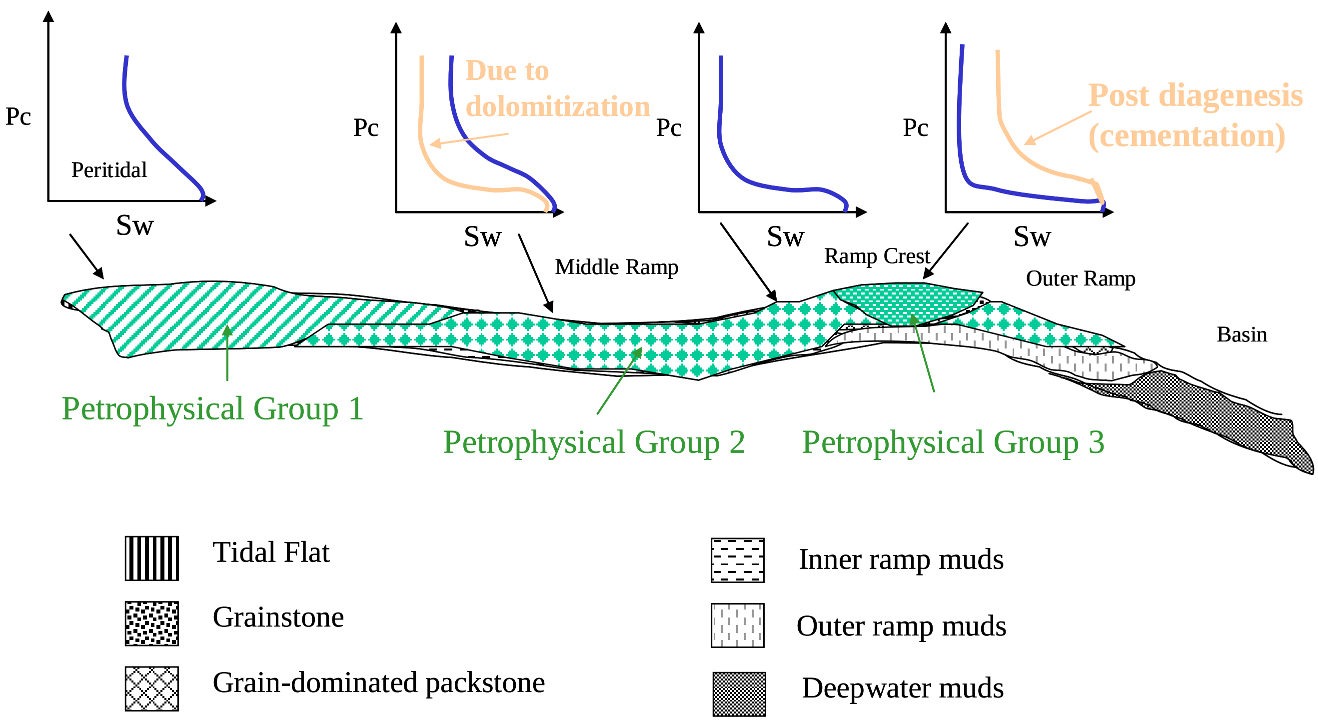
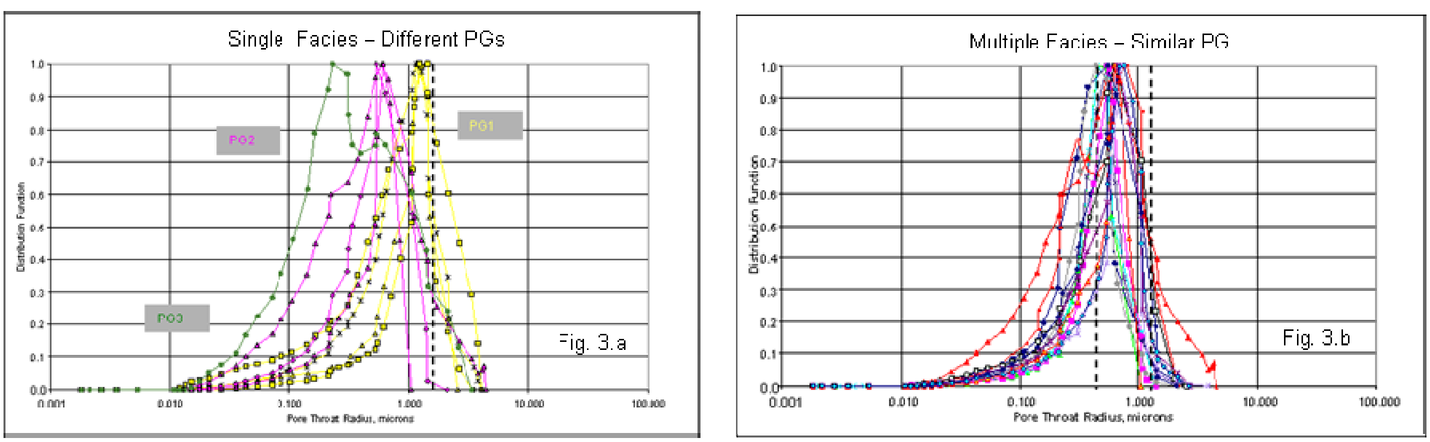


Figure 2b – The impact of diagenesis on the capillary pressure behaviour of different facies (Refer to Figure-2a).



Figures 3a & 3b – Impact of diagenesis on pore throat radius distributions of geological facies

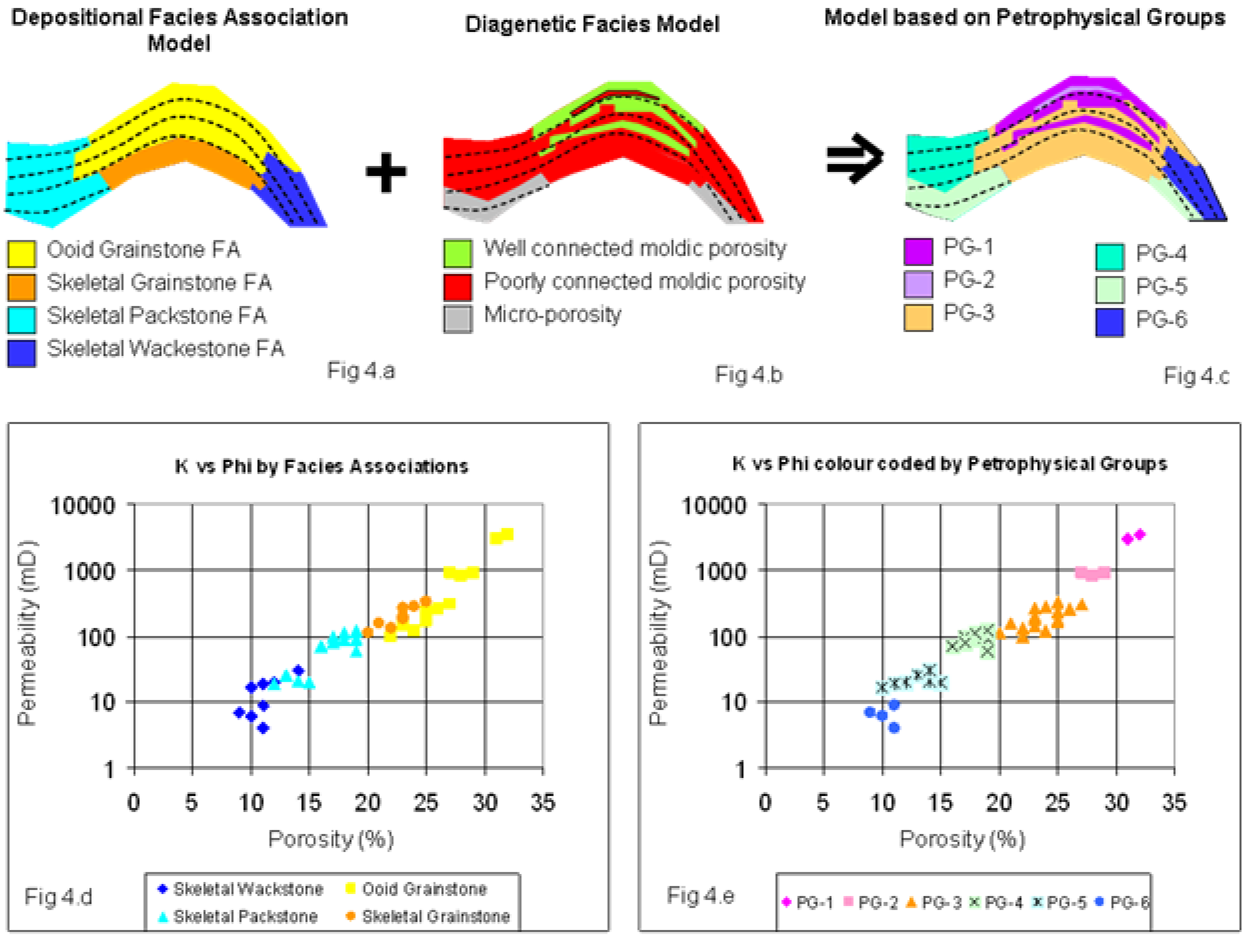


Figure 4 (a-e)– The link between depositional facies, diagenesis and petrophysical groups exhibited in a conceptual model (Figs 4a-4c) and the correspondente Φ- k cross-plots by facies and petrophysical groups (Figs 4d-4e).

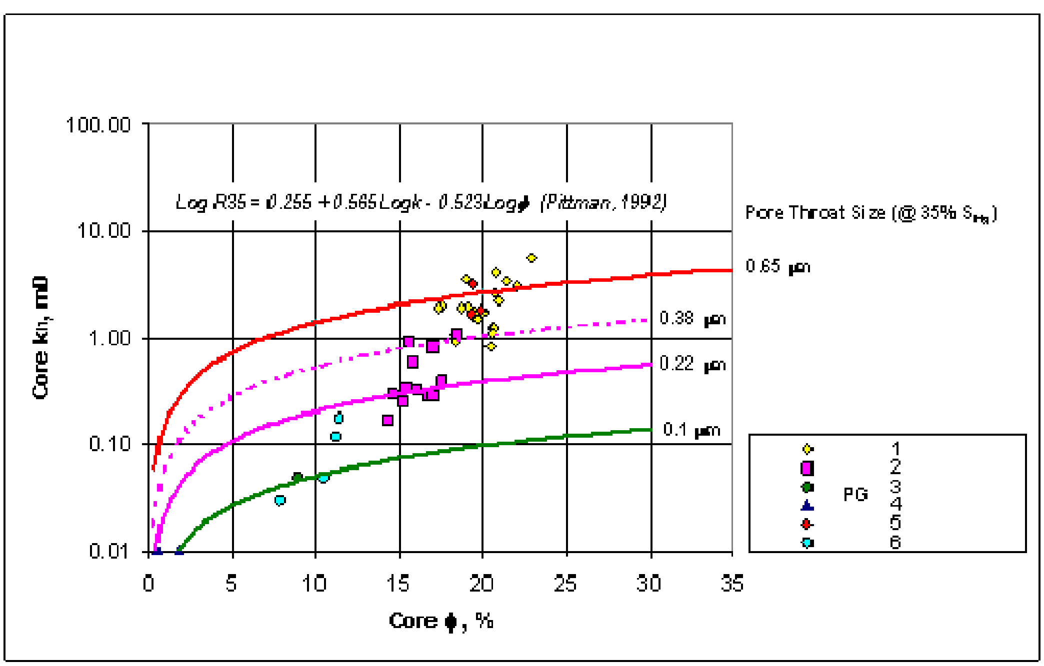


Figure 4f – Pittman Plot establishing the relationship between porosity and permeability for different petrophysical groups.

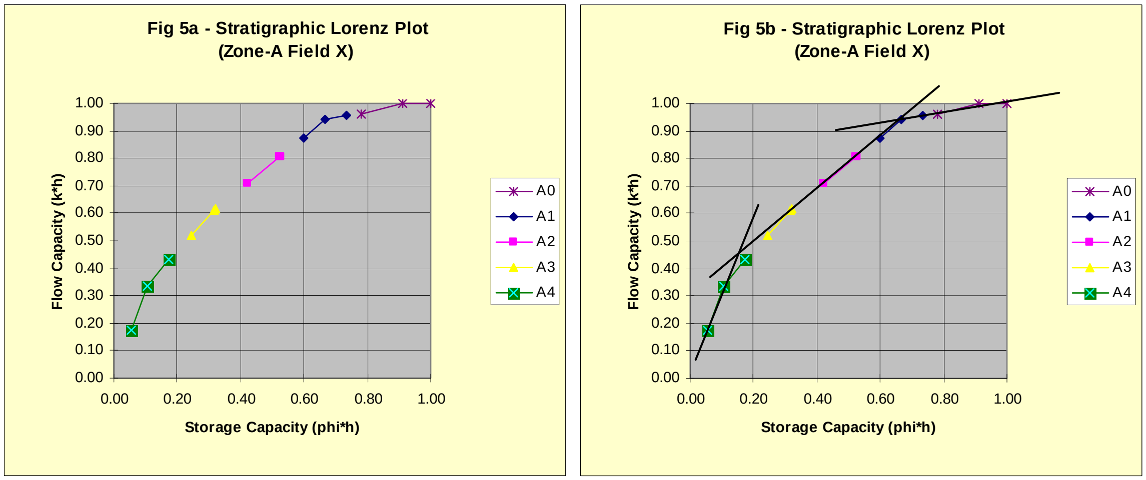


Figure 5 – Stratigraphic Modified Lorenz Plot for flow unit identification.

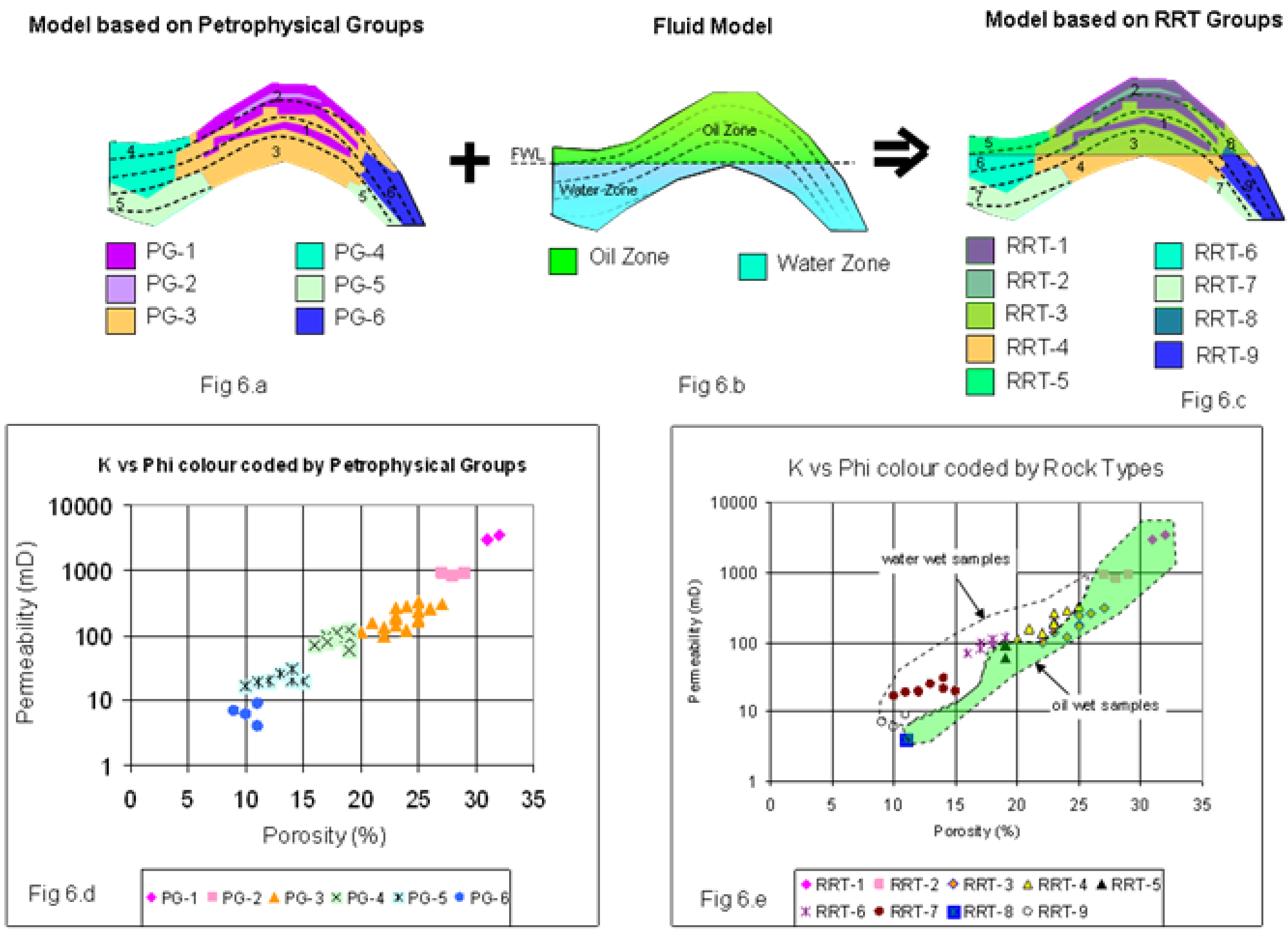


Figure 6 – The link between petrophysical groups and rock types by integrating SCAL and a fluid model

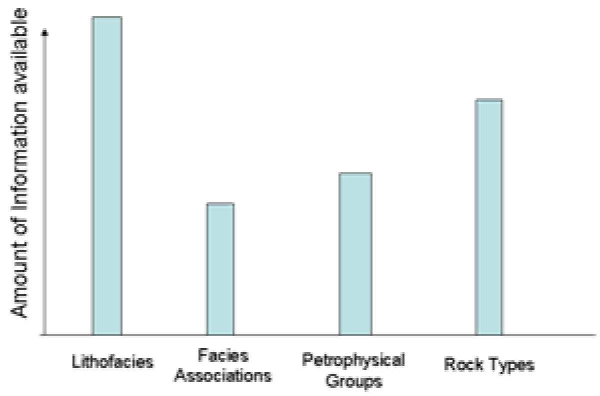


Figure 7 – The amount of information available and the resultant model granularity during a rock type study.

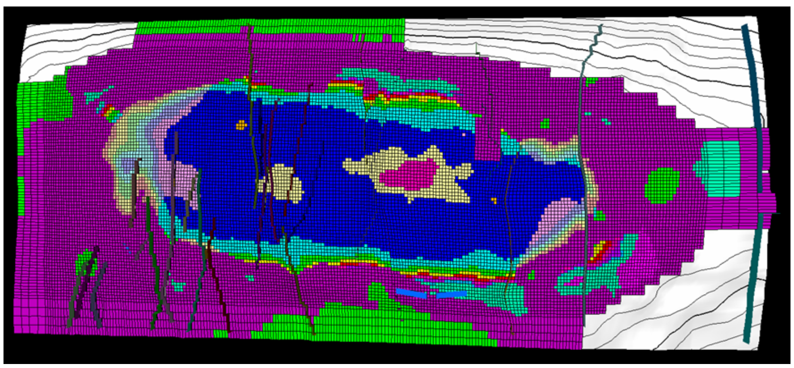


Figure 8 – Representation of different rock types in the simulation model

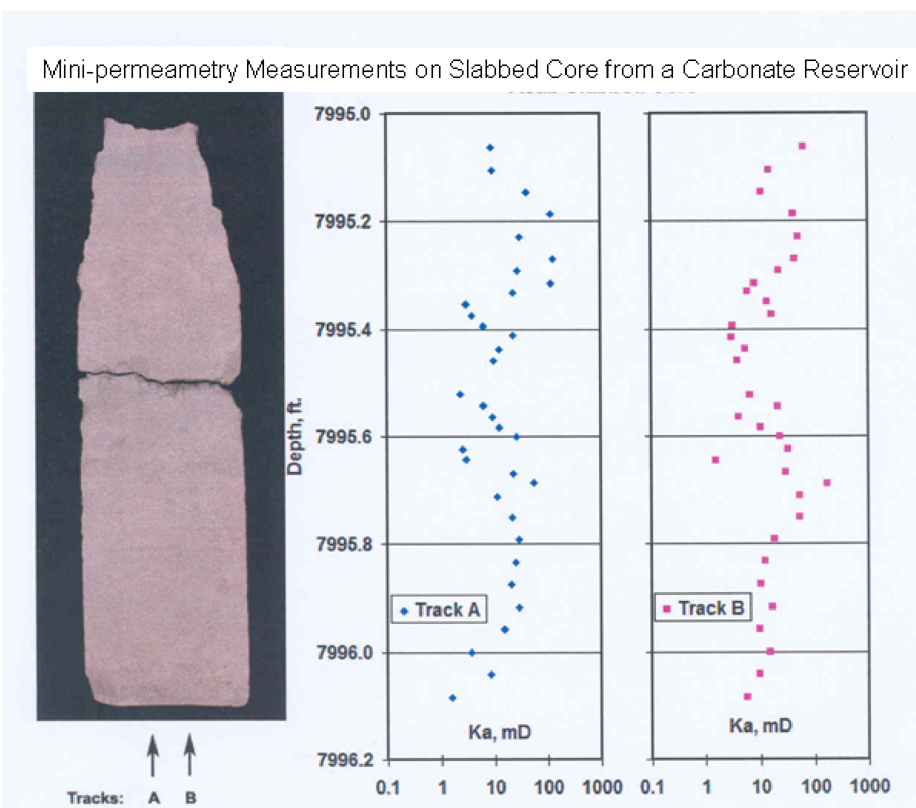


Figure 9 – Probe-permeametry across one foot slabbed core of Middle East carbonate.

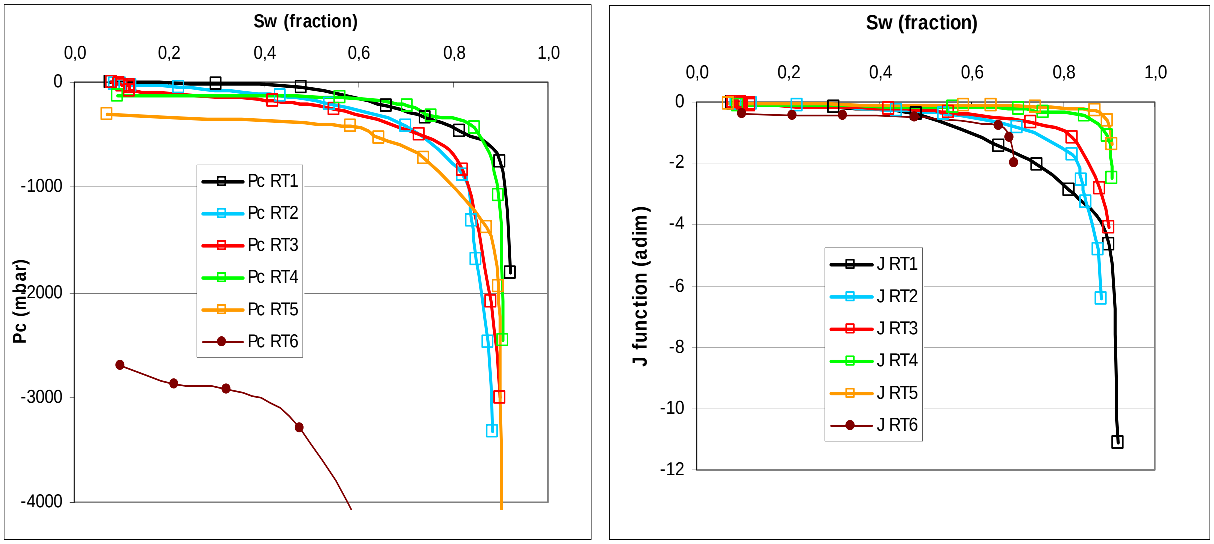


Figure 10 Capillary pressure and J-function curves of the SDM samples

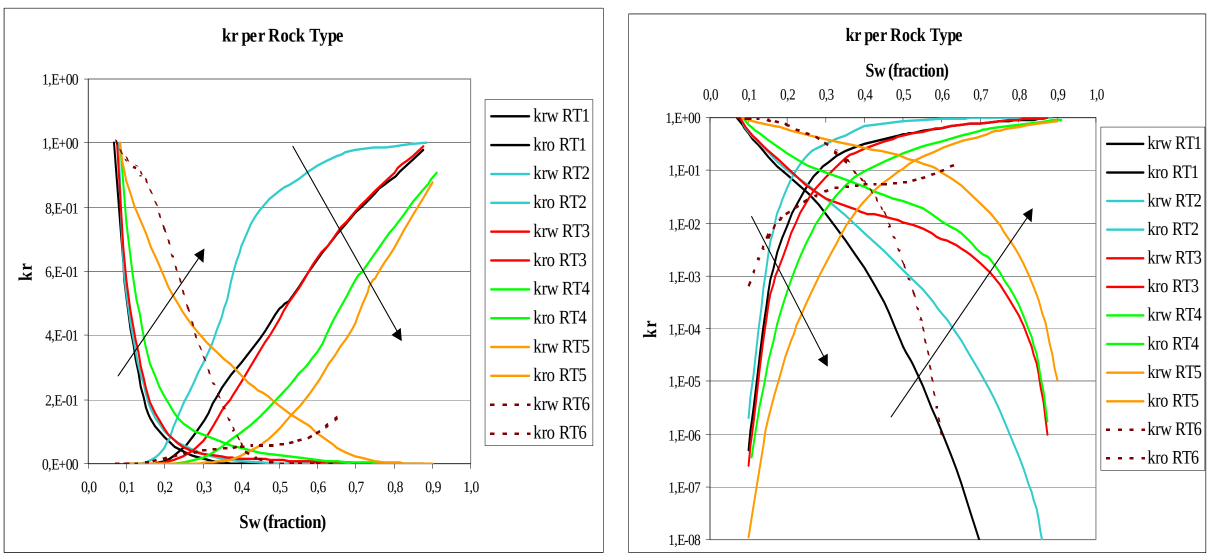


Figure 11. Imbibition Relative Permeability of carbonate rock types

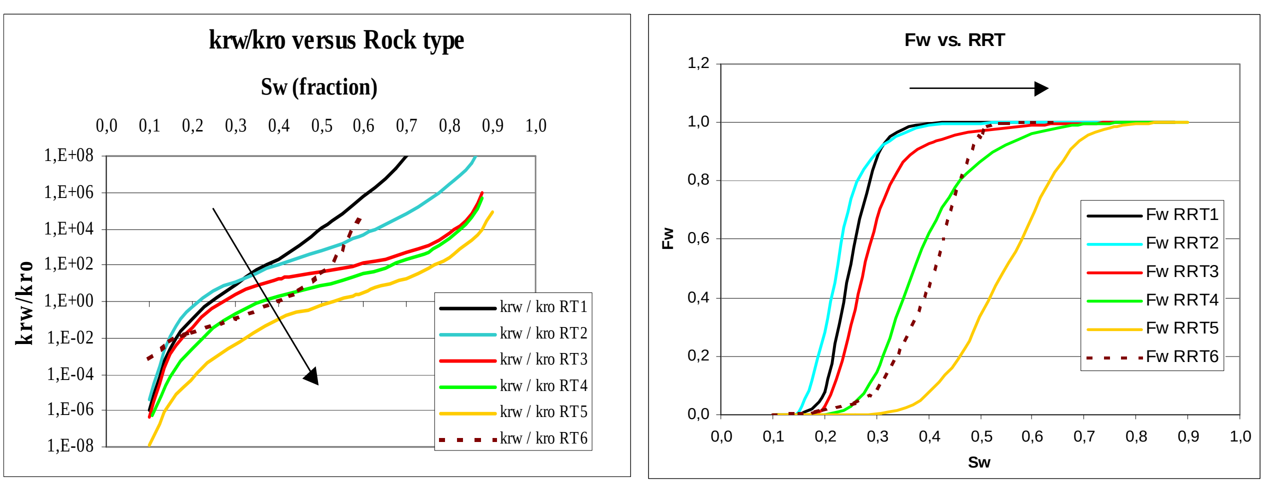


Figure 12. Fractional Flow Curves and krw/kro behavior in carbonates

Facies	Porosity Class	Permeability Class	Petrophysical Group
Oolitic grainstones	> 30%	> 5000 mD	1
Oolitic grainstones	25% - 30%	1000 mD	2
Oolitic grainstones	20% - 28%	100-300 mD	3

Table-1: Petrophysical grouping based on porosity and permeability distributions within the same facies

Layers	iso (ft)	phi (%)	k (md)	k/phi	phi*h (1)	k*h (2)	Cum (1)	Cum (2)	Storage Capacity	Flow Capacity
A4	1.2	17.00	16.00	0.94	20.40	19.20	20.40	19.20	0.06	0.17
A4	1.1	17.00	16.00	0.94	18.70	17.60	39.10	36.80	0.11	0.33
Dense	3.0	8.00	3.50	0.44	24.00	10.50	63.10	47.30	0.17	0.43
A3	1.9	14.00	5.20	0.37	26.60	9.88	89.70	57.18	0.24	0.52
A3	1.9	14.00	5.20	0.37	26.60	9.88	116.30	67.06	0.32	0.61
Dense	0.2	9.00	3.20	0.36	1.80	0.64	118.10	67.70	0.32	0.62
A2	2.3	16.00	4.50	0.28	36.80	10.35	154.90	78.05	0.42	0.71
A2	2.3	16.00	4.50	0.28	36.80	10.35	191.70	88.40	0.52	0.80
Dense	0.1	12.00	3.50	0.29	1.20	0.35	192.90	88.75	0.53	0.81
A1	2.0	13.00	3.70	0.28	26.00	7.40	218.90	96.15	0.60	0.88
A1	2.0	13.00	3.70	0.28	26.00	7.40	244.90	103.55	0.67	0.94
Ao	4.9	5.00	0.30	0.06	24.50	1.47	269.40	105.02	0.73	0.96
Ao	4.1	4.00	0.10	0.03	16.40	0.41	285.80	105.43	0.78	0.96
Ao	6.1	8.00	0.70	0.09	48.80	4.27	334.60	109.70	0.91	1.00
Ao	8.0	4.00	0.02	0.01	32.00	0.2	366.60	109.86	1.00	1.00

Table 2 – Example of dataset used for the Stratigraphic Modified Lorenz Plot exhibited in Figure 5. The low permeability zones are highlighted in grey

Facies	Porosity Class	Permeability Class	Petrophysical Group	Wettability	RRT Group
Oolitic grainstones	> 30%	> 5000 mD	1	Oil wet	1
Oolitic grainstones	25% - 30%	1000 mD	2	Oil wet	2
Oolitic grainstones	20% - 28%	100-300 mD	3	Oil wet	3
Oolitic grainstones	20% - 28%	100-300 mD	3	Water wet	4

Table-3: Rock type grouping based on petrophysical properties, facies and position in the fluid column (variations in wettability).

Key Parameters	Characterization	Outcome	Applications
Sedimentary structures, grain types, % mud vs grain, fossils, mineralogy etc	Facies	Facies Association (FA)	Static Model (STOOIP)
porosity, permeability, MICP, PSD, NMR T2	Rock Fabric	Petrophysical Groups (PG)	
All of the above plus, wettability, Swi, high above FWL, % IOC, Kr curves	Rock-Fluid Interaction	Reservoir Rock Types (RRT)	Dynamic Model (Recovery Factors)

Table-4 : Summary of the key data used for the characterization of facies, petrophysical groups and rock types and their respective applications

RRT	d (cm)	L (cm)	ϕ	Kw (mD)	Swi
1	4.88	7.87	0.296	451	0.083
2	4.87	7.94	0.295	44.9	0.09
3	4.84	7.14	0.329	24.6	0.089
4	4.86	6.0	0.310	13.0	0.090
5	4.91	8.16	0.290	4.02	0.069
6	4.90	7.36	0.151	0.14	0.099

Table 5 Reservoir core characterization data of SDM plugs