CORE PETROPHYSICAL SYNTHESIS CARRIED OUT AT A SCALE OF A BASIN, SOME EXAMPLES FROM TERTIARY OFFSHORE RESERVOIRS

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ABSTRACT

The robustness of a static reservoir model is often dependent on the amount and quality of available core data. Petrophysics must be well documented for each reservoir, each sedimentary facies.

When performing such a study at a scale limited to a reservoir or to a single field, there is a big risk of biases introduced by 1) a limited sampling 2) a limited acquisition program 3) data quality and accuracy, especially in the early phase of exploration/appraisal of several structures within a new block.

In a recent study performed over tertiary turbidites deposits, core tests results on more than 1800 samples from 22 wells and 8 fields were reviewed Several examples of the interest of multi field petrophysical synthesis are illustrated, including:

- Identification of very strong multi field trends between permeability and key features of the grain size distribution and initial water saturation,
- Identification of outlier reservoirs in a multi field trend,
- Improved integration of the core data to well logs by a greater availability of appropriate core results.

INTRODUCTION

Core data synthesis is usually required 1) For individual wells to tie back interpreted, porosity, permeability and saturations to core data 2) At a field scale, as an input of a geological or reservoir model construction. This paper illustrates that it may also integrate data from several wells belonging to different fields, at an early stage of the exploration/appraisal of several structures within the same block. The objective is to gain a wider and earlier insight into the reservoir characteristics. If this synthesis is limited to a targeted field, some biases might be introduced by the lack of some data, by a limited core sampling or by selective acquisition programs. This risk can be reduced by accounting for data from neighboring fields, as soon as they belong to the same geological formation and that this approach confirms that they are reservoir-type analogs.

During the last years, we performed core data synthesis at the scale of a basin. In this paper we describe a workflow based on a recent study performed over tertiary turbidites deposits giving good example of the interest of a multi field petrophysical synthesis.

PROCEDURES

This study includes core data on more than 1800 samples from 22 wells and 8 fields (see details Table 1). This formation consists of unconsolidated to fairly consolidated sands. This study involved an iterative intervention of several specialists (sedimentologist, log analyst, core petrophysicist). Its scope of work can be described as follows:

Data Set Construction:

The first step is the collection of all available core data in a unique global tabular form. It incorporates: conventional core petrophysical data as porosity, permeability, grain density, cementation exponent, Archie exponent, cation exchange capacity; lithological description, mineralogy by XRD and grain size distribution, special core data such as capillary pressure curves, in-situ water saturation from Dean –Stark extraction.

Based on the observations of the cores and thin sections, the sedimentologist assigned a sedimentary facies to each core sample,.

Specific procedures were used for the core measurements due to the absence of rock consolidation for a big part of the set of samples. Some of them were cohesive enough to be treated with the conventional procedures for consolidated sands. The permeability was either gas or water permeability or both. 70% of the cementation exponents were corrected for the clay conductivity effect. Three types of drainage capillary pressure experiments were carried out: mercury injections (MICP), oil/water centrifugations (centriOW) and oil/water with porous membrane (pcOW).

The resulting data set is wide and non homogeneous: incomplete information, various experimental conditions, various experimental procedures, various rock characteristics and various core qualities. Therefore, core data must be prepared prior to any interpretation. This step is described in the next paragraphs.

Conversion to Reservoir Conditions:

Porosity and permeability measurements were generally carried out under stress close to the initial effective reservoir stress (initial effective reservoir stress may vary from one reservoir to another from 60 bars to 160 bars). As previously said, some samples were treated with conventional procedures for consolidated sands (very low effective stress). Some other ones were measured under low stress pressure (20 bars to 50 bars).

It is obvious that these various experimental conditions result in a non homogeneous data set, porosity and mainly permeability being not directly comparable from one reservoir to another because of their sensitiveness to the stress level applied during their measurement.

It was therefore decided to correct all porosity and permeability values towards a median reservoir stress (giving a minimum correction), the equations used being determined from the 42 available compressibility tests, after their grouping by field or by reservoir or by burial depth.

In order to reduce the correction at the minimum possible, a 125 bars average effective stress was selected. The ranges of magnitude of the corrections obtained are:

- Correction for the porosity: 0.0035 to 0.02 porosity unit (in fraction) for 100 bars of stress variation

- Correction factor for the permeability: 10% to 38% for 100bars of stress variation

Quality Control of All Analytical Information:
This analysis consists of the control of the coherency between the mineralogical data, the grain sizing data and the petrophysical data taken by well or by reservoir type. Some outliers were disregarded after data inspection; they were identified based on several usual cross-plots such as: porosity to permeability, porosity to mean grain size, permeability to quartz content.
We also checked the presence of heavy mineral from the mineralogy analysis by XRD or from the rock density (shaly sands matrix). For instance, the core samples exhibiting a too large fraction of of siderite or pyrite nodules are deemed not representative of the reservoir.
Finally, the control of the CT scan images helped us identifying some heterogeneous core samples which were removed from the data set.
After this quality control, 200 core samples (out of the 1800) were discarded; they are mainly samples with low data confidence or poor representativity.

Interpretation of Petrophysical Behaviors by Wells or By Reservoirs:
After the conversion to median reservoir conditions and quality control, the data set is now homogeneous and clean. It allows the comparison and the interpretation of petrophysical behaviors by wells, reservoirs or fields.
<u>Main Correlations on Unconsolidated Turbidites Formations</u>
One of the characteristics of the unconsolidated turbidites formations is the absence of global correlation between porosity and permeability [4]. For the medium to coarse sands and conglomerate, the permeability is globally higher than 500 mD and is not correlated to porosity. But in fact, figure 1 also shows that for shaly silts, silts and fine sands, a correlation exists.
Similar observation appears from figure 2 where porosity is plotted against the mean grain size:

- For sands with low clay content, the best porosities are measured on the finest grained and better sorted ones; as mean grain size increases, the porosity decreases due to the increase of grain size heterogeneity (progressive filling of the pores by the finest grains).
- For shaly sands and silts, the porosity decreases due to a progressive filling of the pores by clay material.

The poor to medium correlation factors mentioned on figure 2 are a result of: 1)the increase of grain size heterogeneity as the mean grain size increases for medium to coarse sands, 2)the presence of some fine grains for shaly sands and silts.

<u>Sedimentary Facies and Petrophysics:</u>
The goal is to investigate the core data by groups of sedimentary facies. We look for trends or specific behaviors as a function of wells or reservoir data.

Mud Turbidites:
This facies group consists of silts with various amount of clay. The clay fraction is represented by the particles smaller than 5µm, the progressive filling of the pores leads to a reduction of both porosity and permeability as shown by figure 3. Porosity, permeability and clay fraction are well correlated whatever the field.
Fine Sands:
This facies group consists of very fine to fine sands with various amount of clay. In figure 4 the clay fraction corresponds to the total clay measured by XRD. We observe a trend between porosity and permeability whatever the field, the apparent scatter being controlled by the amount of clay.
Medium To Coarse Sands:
This facies group consists of medium grained to coarse grained sands with low amount of clay. In figure 5 the clay fraction corresponds to the total clay measured by XRD. We observe a trend between porosity and permeability whatever the field, the apparent scatter being controlled by the amount of clay as shown figure 5b.
Figures 4, 5 and 5b illustrate that the scatter in poroperms data from fine to coarse sands within each sedimentary facies is controlled by the clay fraction. This observation allows a refined assignment of poroperms data to the reservoirs, provided that the geological trends of clay fraction within the different geological units can be assessed.

Analogy between the fields, putting Outliers in evidence:
This preliminary review put in evidence several noticeable trends, after a correction of both porosity and permeability to the same stress level, valid for several fields together. During this study we observed that almost all reservoirs had similar behavior regarding petrophysics, mineralogy and grain sizing.
One reservoir (named Res X) exhibited a different behavior. This reservoir mainly consists of medium grained sands with low clay content (2 to 3 %).
Its specific behavior can be put in evidence from permeability, porosity and grain size data (see figure 6). Compared to others reservoirs with similar grain size characteristics, reservoir “X” has lower porosity (-7 s.u.) and lower permeability. This reservoir is deeper than others and an explanation is reinforced by thin sections observations showing the presence of a partial cementation by quartz overgrowth and a little of calcite.

Water Saturation Model
Three kinds of drainage Pc experiments were carried out on 14 wells: Oil/Water with porous membrane (44), Mercury injections (16) and Oil/Water centrifuge tests (24). Looking at the sedimentary facies distribution, we observe a large predominance of fine grained to coarse grained sands as the capillary pressure tests were carried out on reservoir intervals. As a consequence the great part of the core samples used for the capillary pressure tests have a good porosity and low clay content.
The 84 Pc curves are the result of different types of experiments, conducted with different fluids systems, at different operating conditions, i.e. at different interfacial tensions (IFT). In order to allow the direct comparison of the results, all curves have been

corrected to a normalized capillary pressure: $Pc_{normalized} = Pclabo / (IFTlabo*\cos\theta)*(IFT_{normalized}=1)$.
After a quality check, 15 tests were disregarded due to suspected experimental issues or samples heterogeneity.
Specific case of the mercury injections: they have been performed on dried core samples containing clay, which is a limitation of this method, and we observe that the capillary pressure curves exhibit a bimodal behavior. Therefore, the capillary pressure curves have been truncated towards the highest capillary pressure in order to consider only the part of the curve representing the sand fraction. The remaining part of the curves describes a 500m tall oil column which is appropriate for these reservoirs (see figure 7).
The data exploration put in evidence a good trend between the water saturation derived from Pc curves and the permeability (r^2=0.86), but no clear trend with porosity (r^2=0.3).
A good coherency is also evidenced between the three types of experiments (see figure 8).
It is really interesting to plot the data by field. This shows how a study conducted at a scale of a single field may lead to biased results. For instance figure 8 shows that if we considered the field “AK” alone, it would not be possible to build any sound water saturation model.
The association of experiments from several analogous fields results in a good control of the water saturation model derived from the Pc curves over a wide range of rock quality.
A single regression would be valid for all facies and all reservoirs; the water saturation model was established following the WWJ method [1] with very good correlation coefficients varying from 0.64 to 0.86 (this model has been preferred to the well known Leverett [2] [3] model due to poorer results as could be anticipated from the poor Swi-porosity relationship).
The final equation is:

$$\mathrm{Log}_{10}(SW) = A * \log_{10}(K) + B \qquad (1)$$

With:

$$A = a1 * PCn^{n1} \qquad (2)$$

$$B = a2 * PCn^{n2} \qquad (3)$$

$$PCn = PC / IFT = (FWL - Z) * \Delta\rho * g / IFTres \qquad (4)$$

Comparison with Dean-Stark Data:

251 water saturation measurements by extraction (Dean-Stark) were available. We can compare directly these water saturation results (samples cored at less than 30m above their respective WOC are disregarded) with Pc experiments (Sw at around 100m above FWL) by plotting the water saturation as a function of permeability. Figure 9 shows the evidence of a very similar behavior between the two techniques whatever the well. This is a good cross validation of the two data sets. This quality control of core data is a prerequisite for any further comparison with other sources of data such as logs or well tests, and any comparison between data sets from other wells to put in evidence reservoir-type analogs or outliers.

Comparison with Well Logs:

The studied wells experienced an extended coring. They might be considered as key wells, where the log interpretation procedure must be validated, to be later exported to uncored wells. The comparison between porosity and water saturation inferred from cores and from log interpretation raises the issue of scale of measurement. This issue is tackled through the construction of a petrophysical log. This approach has been detailed by Levallois [4] . It is a three steps approach: 1) the cored zone is subdivided into homogeneous, self consistent intervals using the visual and CT scan inspection and various continuous measurements (natural or attenuation gamma-ray, sonic velocity) 2) a value of porosity, permeability, grain density and clay content is assigned to each cored interval and later to intervals without core measurements 3) An upscaled value of porosity, permeability is calculated all over the well reservoir zone using sliding window averaging. In this study, a petrophysical log of permeability was constructed on each well, giving the permeability profile all along the cored sections. This allowed calculating a core derived water saturation. This process benefited from the well defined saturation model, derived from the extended, multi-field data set. A good agreement was observed between the water saturation profile (after averaging at log sampling scale) and the saturations inferred from well logs interpretations. Figure 10 shows a histogram of the difference between core derived Sw and well logs estimate.

This is illustrated by the figure 11 where dots correspond to core samples data, dashed lines correspond to core petrophysical log and solid lines and shaded areas correspond to well logs results. This example comes from a reservoir composed of interbedded sands and shale. We observe, for instance, that between 3728m and 3736m the rapid facies change is well accounted for by the core petrophysical logs, even on the small intervals where core permeability data were missing on this well but were available on another well for the same facies. After upscaling to well logs scale we obtain a good agreement in hydrocarbon-filled porosity from cores and logs but in the intervals composed of a rapid facies variation some differences remain, they are responsible of the biggest discrepancies (more than +/-10 s.u.) seen on figure 10. In fact, the core petrophysical logs were upscaled using a 50cm wide window which is appropriate for the nuclear tools scale but too small compared to the vertical investigation of the induction tools.

CONCLUSIONS

A core petrophysical synthesis may integrate data from several wells belonging to different fields, at an early stage of the exploration/appraisal of several structures within the same block. The objective is to gain a wider and earlier insight into the reservoir characteristics.

The following workflow proved to be successful:

1. Construction of a comprehensive data set, including porosity, permeability grain density, grain size distribution, mineralogy, water saturation data, drainage capillary pressure curves, compressibility, cementation factor, Archie exponent, cation exchange capacity, sedimentary and geological data,
2. Transfer to comparable reservoir conditions
3. Quality control of all analytical information. Simple cross checks allow probing the reliability of experimental data acquired with various experimental techniques.

4. Putting in evidence reservoir-type analogues or outliers through the comparison of various petrophysical properties,
This process requires iterative involvements of several specialists (sedimentologist, log analyst, core petrophysicist)

This approach was found very helpful in finding reservoir-type analogs and therefore in:
1. Best engineering approach for extrapolation of neighboring fields results at an early phase of appraisal of different structures
2. Improving the integration of the core data to well logs by a greater availability of appropriate core results, once the required upscaling of core data has been carried out.

A multi-fields core synthesis also improves the robustness of the static reservoir model by:

- Allowing a safer guess of data in case of incomplete information that could be introduced by the selective acquisition programs, poor core recovery, biased core sampling, and/or by technical problems during the experiments (see example of reservoir X or field AK)
- Putting in evidence off-trend fields or reservoirs.

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Table 1

Number of fields	8
Number of cored wells	22
Total number of samples with CCAL	1810
Core samples with mineralogy by XRD	1493
Core samples with grain size measurements	1358
Core samples with capillary pressure tests	84
Core samples with water extraction (Dean&Stark)	251
Core samples with compressibility tests	42

Table 2: symbols used in equations 1 to 4

SW	Computed water saturation in fraction
K	Permeability in mD
PCn	Normalized capillary pressure in bars: PCn = PC / IFT * 1
IFT	Experimental oil-water interfacial tension in dynes/cm
FWL	Free water level (PC = 0) in m
Z	Depth in m
$\Delta\rho$	Difference between water density and oil density in g/cm^3
g	Gravity g= 0.0981
IFTres	Oil-water interfacial tension at reservoir conditions in dynes/cm

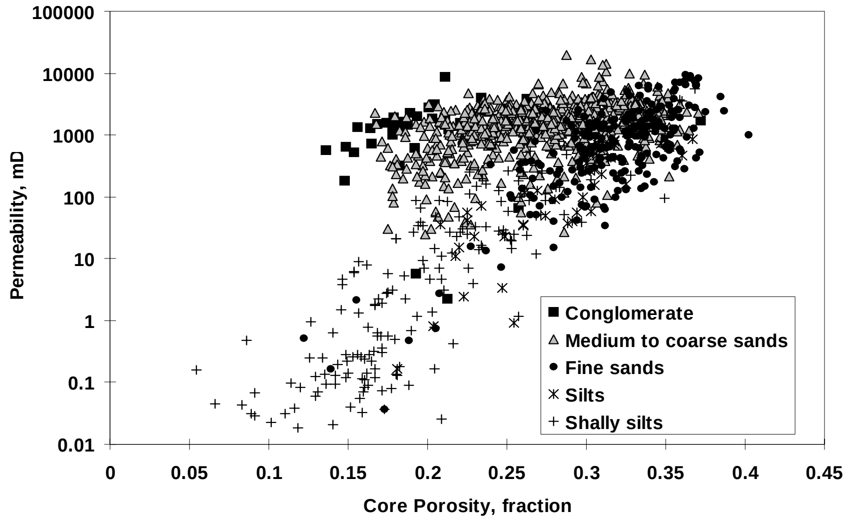


Figure 1: porosity and permeability by sedimentary facies.

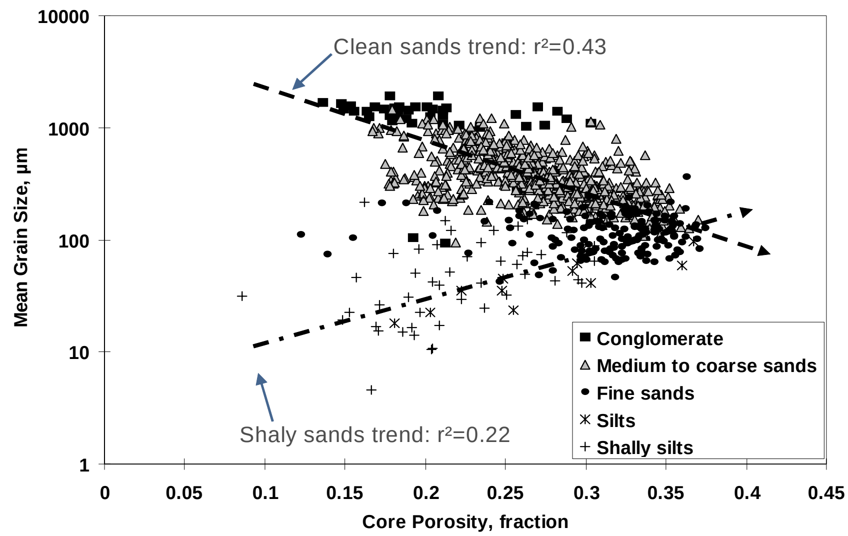


Figure 2: porosity and mean grain size by sedimentary facies.

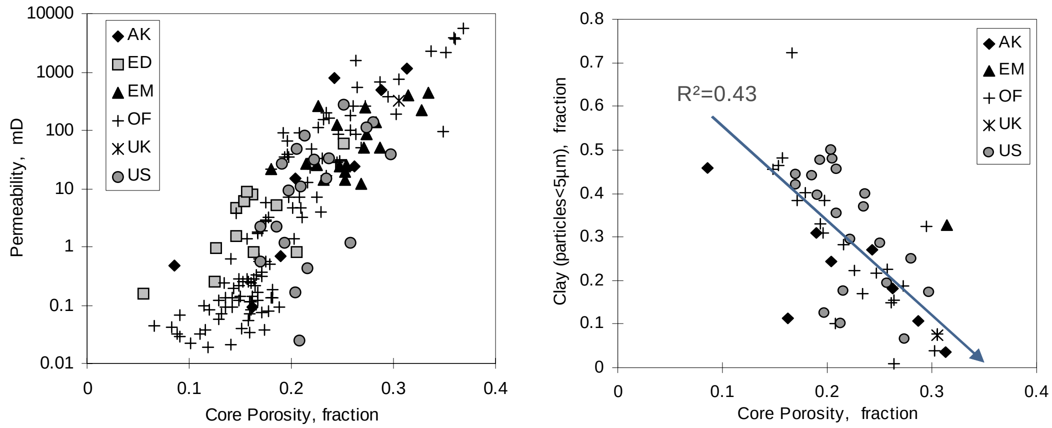


Figure 3: permeability (left) and clay fraction (right) versus porosity and field name, on mud turbidites.

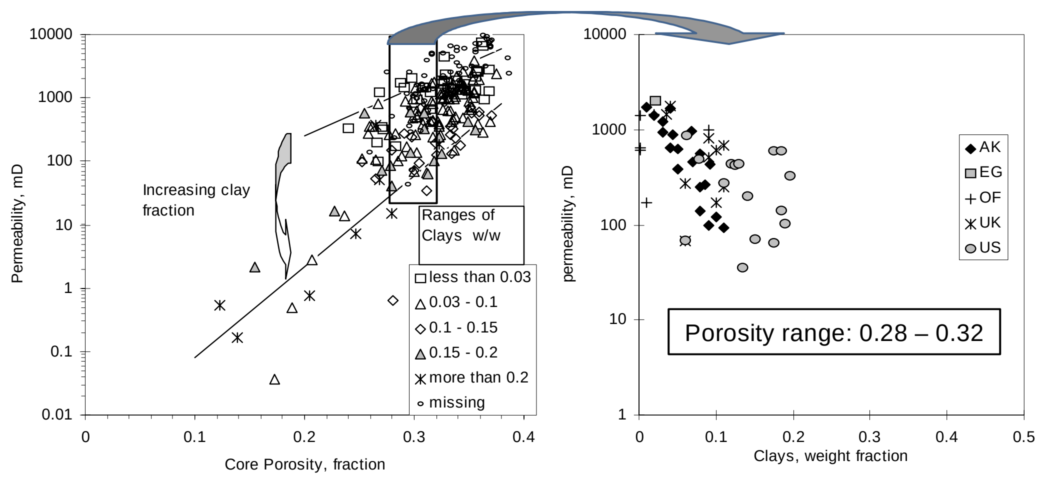


Figure 4: permeability versus porosity and clay fraction (left), permeability versus clay fraction for a limited porosity range (right), on fine sands.

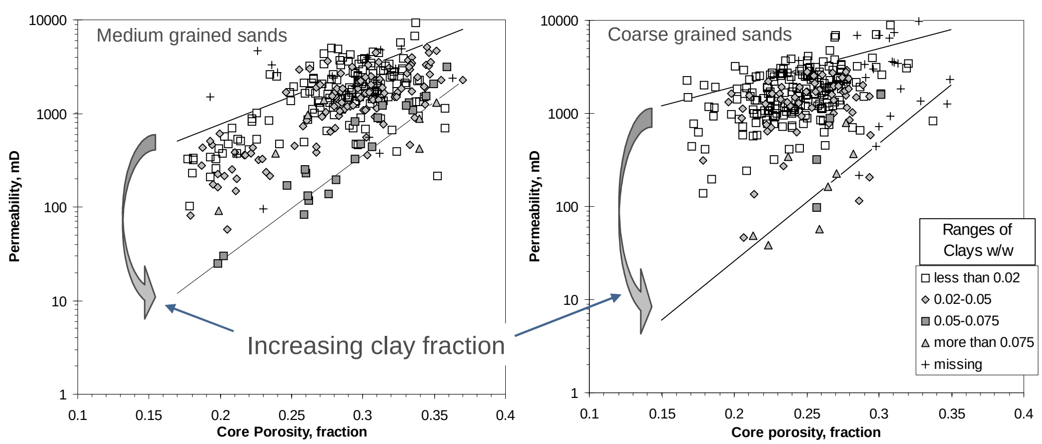


Figure 5: permeability versus porosity by ranges of clay fraction from XRD, medium grained sands (left) and coarse grained sands (right)

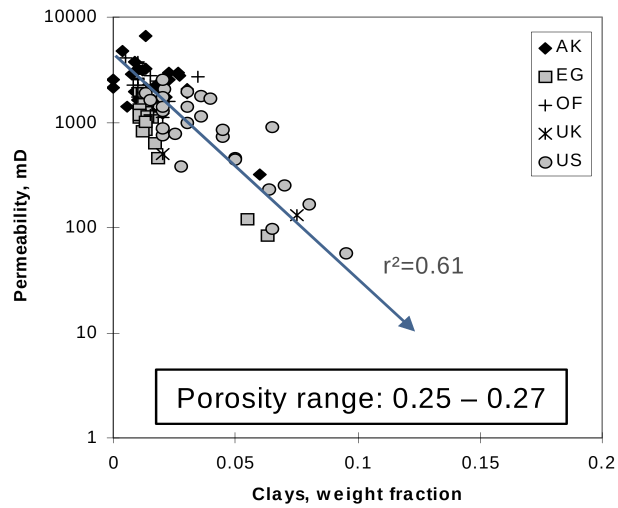


Figure 5b: permeability versus clay fraction from XRD, medium grained sands to coarse grained sands

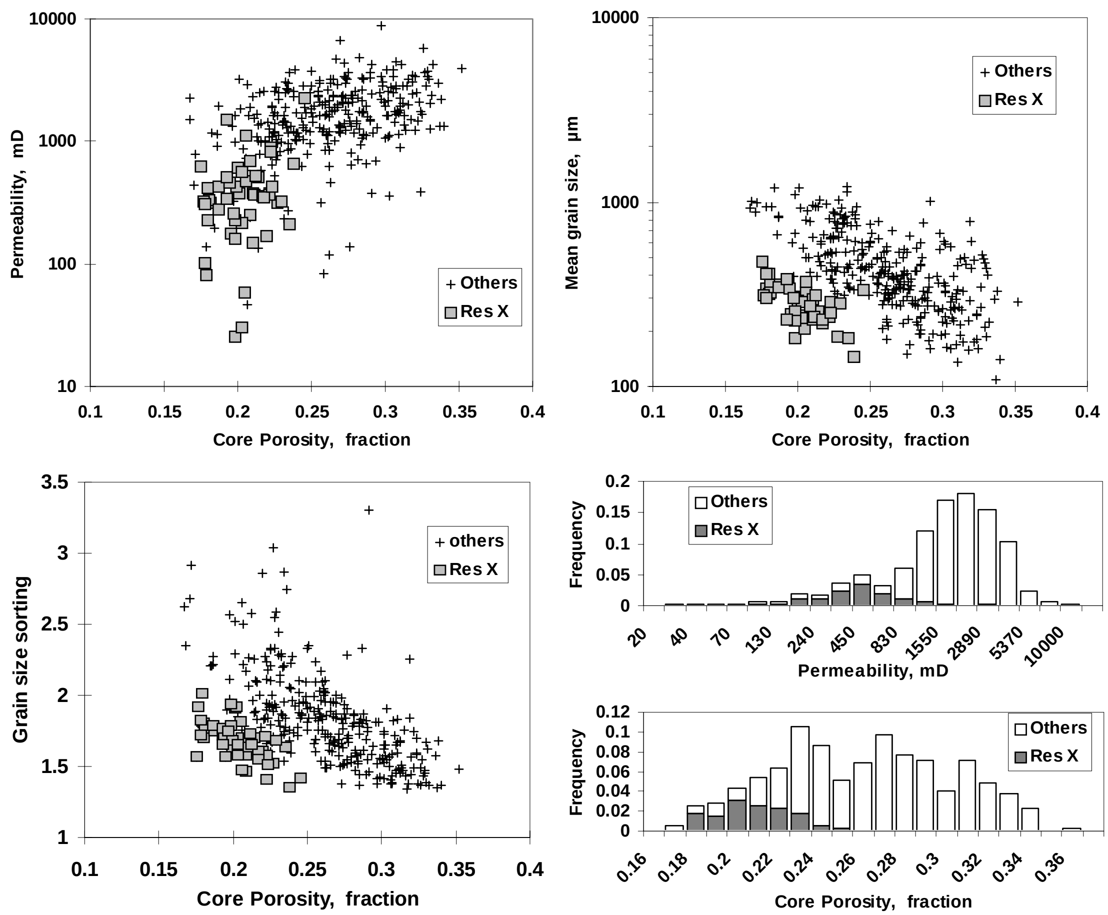


Figure 6: Reservoir "X" has a different behavior.

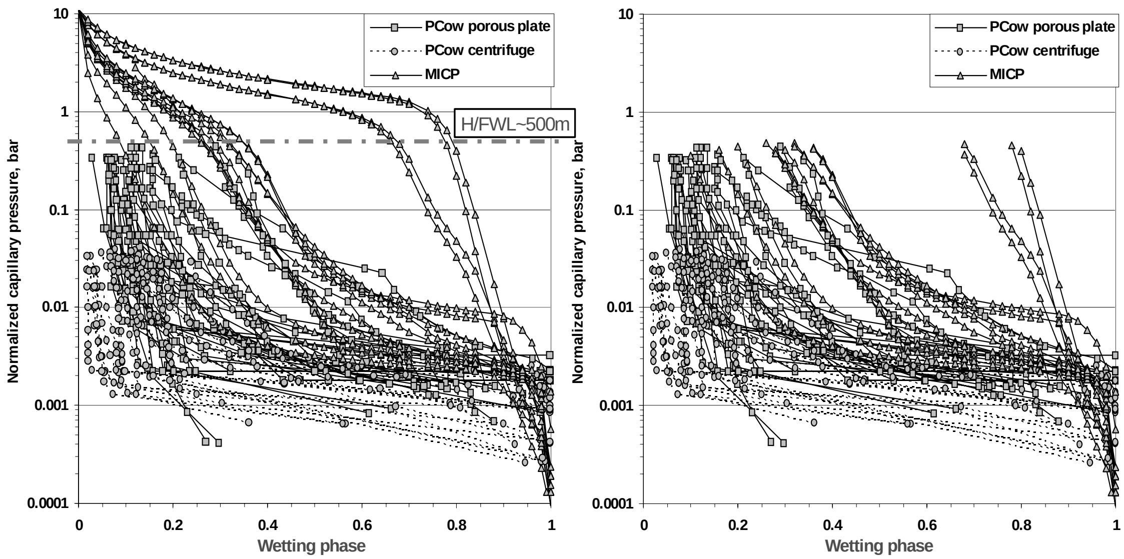


Figure 7: Capillary pressure curves, raw data (left), truncated MICP (right)

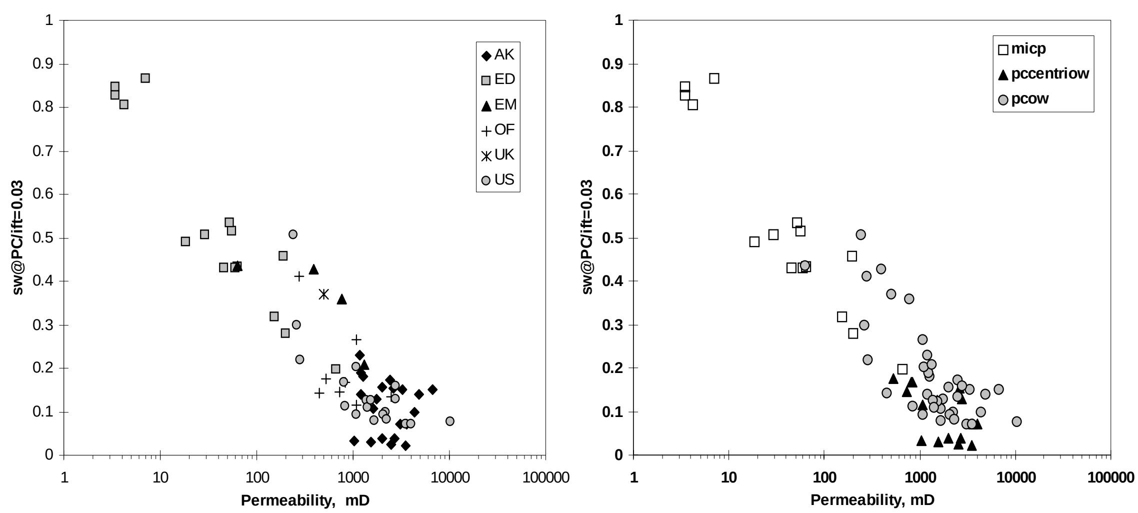
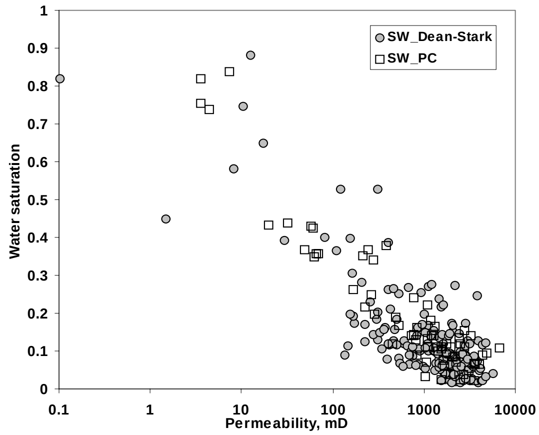


Figure 8: PC derived water saturation at 30m above FWL, correlated with permeability by field (left) or by experimental procedure (right).



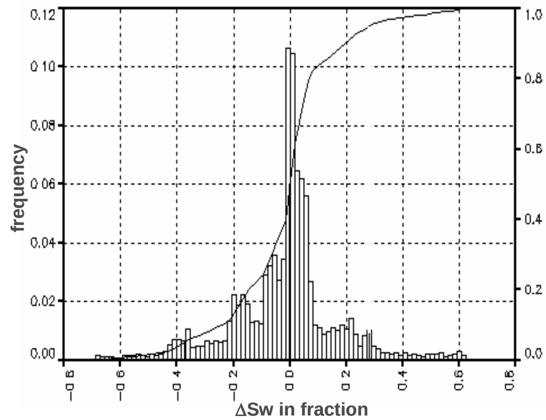


Figure 9: Comparison between Dean-Stark and capillary pressure tests.

Figure 10: Comparison between core derived Sw and well logs estimate

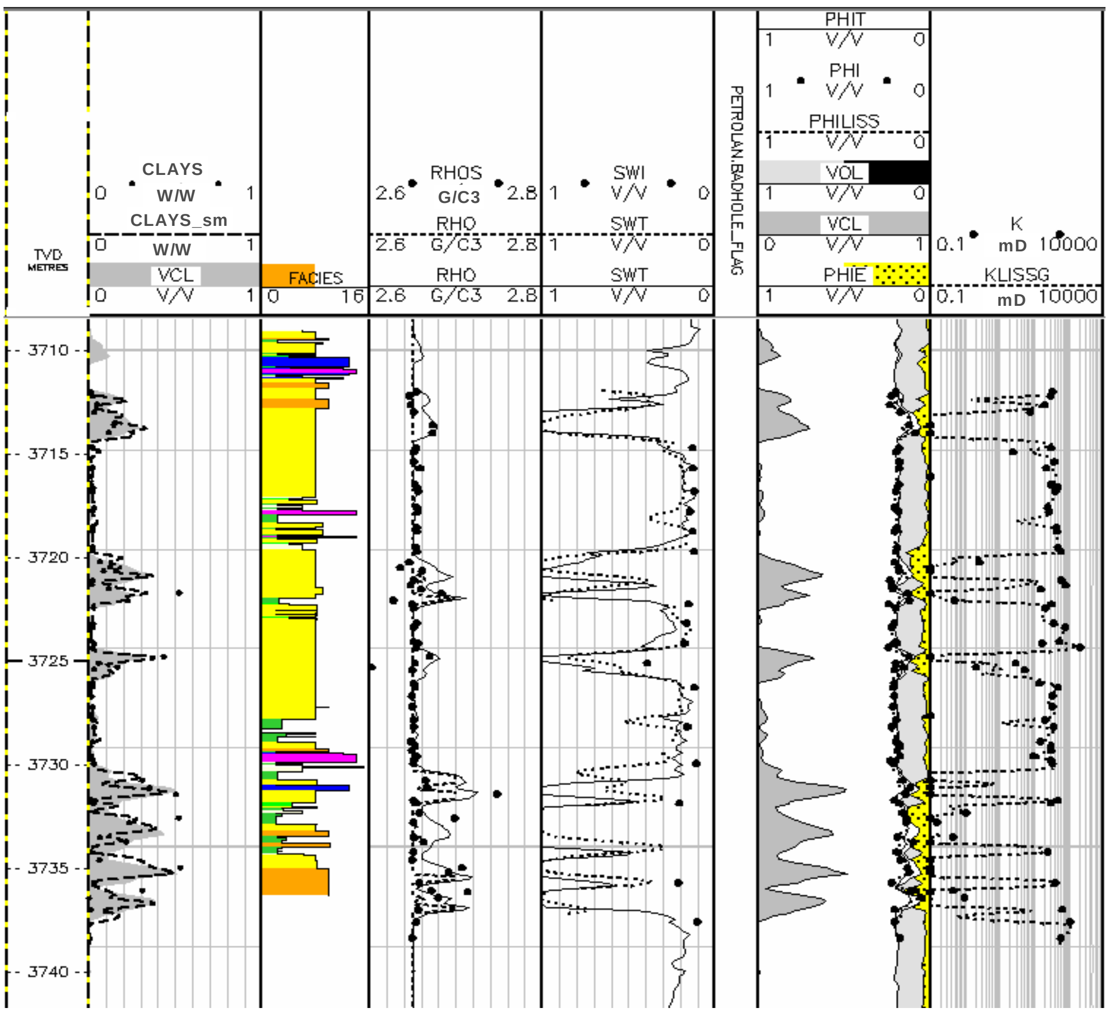


Figure 11 Core data to well logs comparison