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Whole Core Versus Plugs: Integrating Log and Core Data to Decrease Uncertainty in Petrophysical Interpretation and STOIP Calculations

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Abstract

Most carbonate reservoirs are commonly characterized by multiple-porosity systems that impart petrophysical heterogeneity to the gross of reservoir interval. Hence, the specific types and relative percentages of pores present, and their distribution within the rocks, exert strong control on the production and stimulation characteristics of carbonate reservoirs.

The impact of heterogeneity on core and log measurements is assessed. The challenge is to determine the reliability of relatively small scale properties measured by a log or core to the large scale reservoir property. A related question is one of reconciling the variability seen in high resolution (small volume of investigation) measurements (e.g. core plugs), with the variability in relatively low resolution (large volume of investigation) measurements (e.g. wireline log).

Routine and SCAL laboratory measurements on carbonate core samples from prolific reservoir in Abu Dhabi. The measurements were conducted on different scale samples ranging from small trims to full diameter whole core samples. Porosity and permeability obtained from small trims, plugs and whole core samples were compared with log data to study the impact of the measured volume on the results. Electrical property measurements were performed on 1.5" diameter plugs and 4" diameter whole core samples to evaluate the impact of heterogeneity and volume scale on cementation factors which are essential for proper petrophysical interpretation and saturation calculations.

Different scale measurements showed variations in both Routine and SCAL data and emphasized the importance of the whole core measurements in representing reservoir heterogeneity which could be used to better evaluate resistivity logs. Plug scale Poroperm data; however, were important in capturing higher degree of reservoir heterogeneity. The better integration between core and log data and the use of the right electrical parameters in petrophysical interpretation tends to minimize the uncertainty in STOIP calculations.

Introduction

Most sandstone reservoirs are typically single-porosity systems (i.e., inter-particle pores) of relative uniform (homogeneous) nature. However, most carbonate reservoirs are commonly characterized by multiple-porosity systems that impart petrophysical heterogeneity to the gross of reservoir interval (Mazzullo and Chilingarian, 1992). Hence, the specific types and relative percentages of pores present, and their distribution within the rocks, exert strong control on the production and stimulation characteristics of carbonate reservoirs (e.g., Jodry, 1992; Chilingarian et al., 1992; Honarpour et al., 1992; Hendrickson et al., 1992; Wardlaw, 1996).

Reservoir heterogeneity is the result of subsequent physical and chemical reorganization processes such as compaction, solution, dolomitization and cementation. Thus, heterogeneity is dependent upon the depositional environments and subsequent events in the history of the reservoir. This heterogeneity complicates the task of reservoir description where reservoir properties (e.g.

permeability, porosity, saturation and rock types) tend to vary as a function of spatial locations both in vertical and areal directions. Vertical heterogeneity has been shown to yield large impact on sweep efficiencies under water floods and conventional gas injection in mixed to oil-wet carbonate reservoirs as a result of large variations in permeability between different strata (Masalmeh et al, 2010). Permeability and other rock properties can also vary along the areal (lateral) direction of the reservoir which necessitates the establishment of accurate and detailed understanding of the geological heterogeneities and their impact on petrophysics and reservoir engineering.

The impact of rock heterogeneity becomes more pronounced when petrophysical properties are measured at various scales ranging from a small trim sample in the lab to log measurements in the field. Honarpour et al. reported permeability variation by three orders of magnitude that was detected over a distance of few centimeters in a carbonate core plug. This imposed severe variations in rock properties which were shown to have large influence on the spontaneous imbibition characteristics of that sample (Honarpour et al., 2003). Such a phenomenon in heterogeneous reservoirs introduces a real challenge in the prediction of reservoir performance through the acquisition of representative measurements. The challenge here would be to reconcile the variability seen in high resolution (e.g. trim or plug samples) and low resolution (e.g. wireline logs) measurements and to be able to quantify the technical and physical considerations at the various scale analysis.

In the present work, we performed Routine and SCAL laboratory measurements on carbonate core samples at various size scales ranging from small trims to full diameter whole core samples. The lab measurements were analyzed to detect any possible variability in rock properties influenced by the scale issue. The lab results were then interpreted with log data to study the impact of the measured volume on the results as a step towards reconciling the lab data with the logs. We have also studied the role of geology in identifying reservoir rock types in the core plugs under study.

Different Scale Measurements

Apart from numerical and digital rock analysis (e.g. Nur, 2009); laboratory measurements can be conducted on multi scale sample sizes with varying techniques and procedures. Each of those techniques has its own advantages and disadvantages with underlying estimations and assumptions. It is beyond the scope of this paper to discuss the details of the technical aspects of the available experiments at different scales but it is crucial to understand those facts and to take them into account at any attempt to reconcile rock property variations seen among the various scale measurements. Table 1 summarizes examples of different standard scales that are used in measuring petrophysical rock properties. "✓" indicates that the relevant sample size is appropriate for measuring that rock property; whereas "X" indicates that the sample size is inappropriate for such a measurement.

In table 1, "trim" refers to any small size, usually irregular rock sample taken from main core plug for the purpose of side analysis such as thin-section preparation, XRD, SEM or mercury injection. Out of the listed properties Poroperm data and primary drainage capillary pressure are usually considered from mercury injection experiments. Mercury derived permeability is calculated based on published research by Swanson (SPE 8234, 1978); and porosity is determined from sample bulk volume and total volume of mercury intrusion. Helium (He) porosity measurement is also possible if the sample is free of vugs. Mercury derived primary drainage capillary pressure curves are highly used in the oil industry and usually yield accurate results if proper protocols are applied (Masalmeh and Jing, 2006). Such a small and irregular trim sample is inappropriate for measuring relative permeability, electrical properties or non-water wet capillary pressures.

The sample size of 1"x1" plug should yield more accurate mercury derived poroperm and Pc data than the trim sample because of bigger pore volumes and in turn higher accuracy especially in heterogeneous or vuggy rocks. It is a standard practice to measure He porosity on this sample size. Absolute permeability is also measured accurately on 1" diameter plugs if the sample length is longer than 1" to minimize end effects. This sample size could also be used to obtain accurate formation resistivity factor and cementation exponent "m". However, Resistivity Index data and any other multiphase flow experiment is questionable due to the high uncertainty involved in the calculation of water saturations in such small pore volume samples.

The 1.5" diameter x 3" long plugs are widely used in the oil industry especially in special core analysis experiments. This sample size could be used to obtain all sorts of Routine and SCAL data in multiphase flow experiments. Composite samples composed of several core plugs are also used to increase the sample pore volume especially those multiphase flow tests involving miscible and immiscible gas injections.

The diameter of a whole core sample depends on the available cores which could range from 3" to 5". The length of the sample could be as long as 10 inches depending on the design of the core holder. This type of "big" rock sample is preferred in formations characterized by high degrees of heterogeneity which may not be properly represented by small plugs (Honarpour et al., 2003). As shown in table 1, whole core samples are appropriate to be used in all sorts of experimental measurements but they are not widely used in commercial laboratories because of difficulties associated with core handling and experimental design.

From the above discussions, it is obvious that a rock property (e.g. permeability) is obtained from similar (or different) techniques on various scales. Because of heterogeneity, varying results may be obtained on different sample sizes. This is apparent for instance when plugs versus whole cores are considered, and the local heterogeneity in the core is larger than the plug scale (e.g. figure 1(f)).

Reservoir Heterogeneity

It is perhaps important at this stage to identify heterogeneity in porous media which is responsible for the variations seen in the macro properties measured at different scales. As the word implies, heterogeneity means that in a rock sample under study there is a distribution of local rock properties at different locations. The following can help realize the causes of heterogeneity and hence the causes of the variations in rock properties at different locations (i.e. at different scales):

1. Surface mineralogy – the chemical composition of the rock surface. Variations in the mineral composition of the surface can yield different reactions between the fluid(s) and the rock surface which can have direct impact on the water film thickness and hence on the distribution of contact angles and wettability (e.g. Hirasaki, 1991). Performing measurements on different scales may alter the percentage of a certain type of mineralogy over another type of mineralogy present in the rock sample which may cause variations in the macroscopic results.
2. Surface roughness – the physical property of the rock surface. Roughness of rock surface has a direct effect on the water film thickness and hence on contact angle hysteresis, Wettability as well as irreducible fluid saturations (e.g. Dullien, 1992, Morrow, 1975).
3. Pore shape – the pore wall curvature. The relative presence and distribution of concave and convex pores plays a central role in the determination of wetting film thickness which is a direct cause of wettability alteration and hence fluid flow behavior (Kovscek et al, 1993).
4. Pore body/throat sizes. Variations in the distribution of pore/throat sizes within the sample create statistically different porosities and permeabilities at different locations. The distribution of different pore/throat sizes could also be viewed as variations in the distribution of vugs and/or micro-porosity which can cause severe degrees of heterogeneity.

Figure 2 serves as an illustration of the impact of heterogeneity on core measurements. Two adjacent core plugs were taken from a carbonate core and measured for helium porosity with uncertainty of ±0.5 porosity unit (p.u.). One plug has a porosity of 22.2%, while the other has 26.8%. This difference in porosity measurements is a result of formation heterogeneity. The effect of heterogeneity on core plug measurements is further illustrated by the conceptual diagrams in Figure 3 and Figure 4. Figure 3 shows a series of 11 core plugs and their measured porosity values taken from a heterogeneous carbonate (inset). The measured porosity at the core plug scale is highly variable, depending on whether an individual plug intersects a large hole (upper right of the inset) or a low porosity cemented region (light colors). A porosity measurement with a larger volume of investigation (such as a density tool) would read an average of a few plugs, thus having a smaller variance. The conceptual diagram in figure 4 shows a series of 11 core plugs and their measured porosity values taken from a homogeneous carbonate (inset). The measured porosity at the core plug scale does not vary. The impact of heterogeneity on core and log is concerned with the variability seen between high resolution measurements (e.g. core plugs) and relatively low resolution measurements such as whole core or density log (figure 5).

X-Ray CT Scanning

X-ray CT scanning provides the possibility of viewing the core without seeing it which is very crucial at instances where core exposure must be avoided or minimized. This technique allows for examining the internal structure of the core at different scales and for identifying the degree and distribution of heterogeneity in the core. It is often employed in the core characterization phase of core analysis for the selection of representative samples. Figure 1 presents examples of CT scan images for the identification of heterogeneity scale in addition to the overall core status which may not always be possible to visualize with conventional photography techniques.

Water Saturation Uncertainty

Water saturations calculated from open-hole resistivity measurements is a primary input to oil-in-place calculations. The fluid saturations very much depend on the accuracy of Archie cementation factor ‘m’ and saturation exponent ‘n’. Archie’s equation provides relationship linking measured resistivity with formation volume (i.e. porosity & saturation). A crucial component of the equation is the cementation exponent ‘m’. This parameter can have a dramatic influence on our understanding of the fluid distribution in the reservoir, and the use of unrepresentative ‘m’ values can yield to wrong estimations of the oil-in-place in the reservoir. Uncertainty analysis was done for the cored reservoir in this study in order to show which parameters have the most impact on the water saturation and the oil-in-place calculations. As illustrated in figures 6, 7 and 8, the Archie cementation exponent ‘m’ has the largest influence on the predictions of water saturation in the reservoir. The saturation exponent ‘n’ is the second most important parameter. Rt and Rw are the least important. These results pronounce the importance of having accurate core analysis measurements performed on representative core volumes (e.g. whole core samples in heterogeneous reservoirs) that can yield representative ‘m’ and ‘n’ values. The greatest advantages of electrical measurements on heterogeneous whole cores is obtaining representative ‘m’ factors that lead to better reservoir characterization, more confidence in volumetric, reserve estimate and simulation model initialization.

Experimental Measurements and Interpretations

A fit-for-purpose conventional and special core analysis program was carried out on a carbonate core from the Middle East. The objective of the program was to measure macroscopic rock properties on various scales in order to identify the effect of heterogeneity on different volume measurements.

Initial Sample Selection

X-ray CT scanning was first conducted on 4" diameter whole cores to identify appropriate locations in the core for the acquisition of representative 1.5” plugs and full diameter whole core samples. The aim was not to look for the most homogeneous intervals rather to look for sections which would best represent the heterogeneity in the reservoir at different scales and rock types. The decision was made to cut whole core samples with adjacent horizontal and vertical plugs. Such selection criteria would allow for direct comparisons of macro properties at different scales and would also give insight into reservoir anisotropy from vertical versus horizontal measurement analysis. In addition to this selection, extra plugs were cut in the core to confirm statistical distribution of rock properties along the length of the core. All samples were characterized by X-ray CT scanning, Poroperm data, mercury injection and thin-section preparation/description on corresponding trims.

Soxhlet Cleaning

Initially selected samples were cleaned in standard Soxhlet extractors. Such a conventional cleaning procedure is based on diffusion principles and may not be appropriate for whole core samples (Honarpour et al., 2003). It took three months to clean the whole cores, and the data presented in figure 9 confirmed conventional cleaning was sufficient to obtain reliable grain density data from plugs as well as whole cores. The grain density range of 2.70 to 2.73 indicates lime stone (calcite) rock nature which would have been measured much lower had the samples not been cleaned efficiently in Soxhlet.

Routine Plug Measurements

Figure 10 shows the orientation of vertical and horizontal plugs taken in or adjacent to a whole core. Figure 11 presents plug poroperm data where He porosity ranged from 10% to 30% and gas permeability varied between 0.1 to 1000 mD. Permeabilities were measured using steady state nitrogen injection technique. Some of the data is plotted from the dense zone in the reservoir where permeability and porosity dropped below 0.1 mD and 5% respectively. Two data points (with similar porosities and different permeabilities) were picked up to show their respective CT images and the effect of internal rock features they have on poroperm. The selected data points represent two different core plugs (3 feet away) having the same porosity of 23.75% but show large variations in permeability; one sample has high Kg of 245 mD and the other 5.4 mD.

In order to investigate anisotropy in the reservoir, horizontal permeability (Kh) data is compared to vertical (Kv) plug data in figure 12. For representative comparisons in heterogeneous carbonates both horizontal and vertical plugs should be taken from the same location in the core. This was not always possible and the average spacing between the horizontal and vertical plugs was 0.23 ft (less than 3 inches) for the samples presented in figure 12. Most data points, fall close to the equal line (y=x) indicating low degree of anisotropy. However, there is tendency towards lower gas permeability (Kg) in the vertical direction. The permeability differences seen in figure 12 may simply be due to differences in the rock types at different locations in the core, not necessarily anisotropy. Figure 13, however, plots the actual plug spacing between horizontal and vertical samples versus Kh/Kv. At a spacing of 0.25 ft (3 inches) there are large variations in Kh/Kv ranging from 0.57 (i.e. Kh<Kg) up to 12.65 (i.e. Kh>>Kv). Apparently, this set of data may not precisely be used to evaluate anisotropy because the horizontal and vertical plugs are not taken at the same core locations and because of the large macroscopic property variations along the core. This phenomenon will be further discussed with whole core measurements where both Kh and Kv are acquired on the same sample.

The distribution of all permeability data from horizontal and vertical orientation along the reservoir depth, in figure 14, also clearly indicates the minor degree of anisotropy in the permeability of the core. Figure 14 shows X-ray CT images at some locations where permeability was acquired on plug samples. There is a clear correspondence between the permeability value and the rock features seen in the X-ray CT image. Higher permeability values are obtained with more heterogeneous and vuggy core compared to lower Kg samples characterized with less heterogeneity and denser rock nature. The CT image in the dense reservoir zone captures the dense nature of the rock samples.

Routine Whole Core Measurements

Similar to plug porosity measurements, whole core porosities are acquired using helium gas in whole core holders. Whole core steady state gas permeabilities are measured in vertical and horizontal directions as indicated in figure 10. Two and up to four horizontal permeabilities can be performed on a whole core sample, each gas injection making 45 degrees with the following one. Two orthogonal horizontal permeability measurements were made; the higher value is called maximum horizontal permeability (Kh_{max}) and the lower one is referred to as 90 degrees horizontal permeability (K90). These two directional measurements are also shown in figure 10 as Kh and Kh(90°). Figure 15 presents WC poroperm data versus plug data. There is a clear general correspondence in poroperm between both sample sizes (Scale effect will be discussed later in more details). Figure 16 plots Kh (taken as Kh_{max} here) versus K90. There are only minor differences in orthogonal horizontal permeabilities in those WC samples, with maximum Kh/K90 factor of 1.61 and an average factor of 1.22.

Anisotropy can directly be checked by comparing Kv and Kh in each measured WC sample. Figure 17 depicts this comparison where most data points are very close to the equal line indicating minor differences in vertical and horizontal directional permeabilities. Anisotropy could be evaluated by the Kh/Kv factor. Average Kh/Kv was calculated to be 1.93, minimum is apparently 1.00 and maximum is of the order of 7.50. Maximum Kh/Kv was obtained on sample# 2A as shown in figure 17. That sample showed higher Kh values than Kv by 7.5 folds. By close look into the corresponding X-ray CT scan image of that sample one can easily see the variation in geological features which caused the high Kh/Kv factor (see figure 18). The top of the sample is very tight compared to its middle and bottom sections. This may cause reduction in vertical permeability but not in horizontal direction where gas would flow preferentially through the permeable heterogeneous and vuggy sections near the middle of the core sample.

High Pressure Mercury Injection (MICP)

This test uses mercury/air as the fluid system. The experimental setup is basically made to give primary drainage capillary pressure curves where gas is considered as the wetting phase. At ambient conditions, mercury injection pressure can go as high as 60,000 psi. Mercury is used primarily because of its high interfacial tension (485 mN/m) and high contact angle (140° measured through mercury) which make mercury almost spherical in shape. When mercury invades a porous medium it is then possible to calculate the pore throat radius of the sample by using the pressure drop across a spherical interface. As mentioned earlier both porosity and permeability (K_{Hg}) values can be derived from mercury injection data. Results from MICP can be used effectively to help in rock typing and sample selection.

In order to obtain representative MICP results, trim samples should be cut from the same plug or WC and should represent that plug or WC sample. Therefore, it is recommended to take the X-ray CT image on the plug or WC before trimming. This will allow for checking the sample together with end trims. This is extremely important in highly heterogeneous reservoirs where the end trims could be completely different from the main plug at the internal structural level. Because of the general variability seen between conventional plug and mercury trim data in heterogeneous reservoirs, there have been protocols applied to ensure the cut end trim is representative to the main plug or whole core sample. Such protocols would ensure representative data are obtained (from MICP tests) such as porosity, permeability, drainage Pc curve and pore throat size distribution. In this work, all plug samples were trimmed for MICP and thin-section preparation/description for proper rock typing and SCAL sample selection. Figure 19 presents the routine plug data and the mercury derived porosity and permeability from the corresponding end trims. One could see a general correspondence between plug and trim data in figure 19 but a close look at the differences between porosity values in figure 20 really reveals mercury data is generally lower than the plug data in all measured porosity range. Mercury derived porosity values are lower than plug porosities by maximum of 7.48% and average of 2.56% porosity unit.

There seems to be consistent relationship in figure 21 between plug Kg and trim K_{Hg}. However, there is no clear relative increase or decrease between the gas and mercury measurements in this core. Kg data were not corrected for gas slippage effect, and hence correction of Kg for Klinkenberg by multi-permeability measurements at increasing gas mean pressures may shift the data points in figure 21 higher than the equal line (opposite to the porosity trend seen in figure 20).

Plug Formation Resistivity Factor (FF,m)

Selected plugs underwent brine saturation for resistivity measurements at ambient and overburden stress. Plug selection was made such that samples would cover the whole range of poroperm data as seen in figure 22. Interpretation of cementation factor (m) and its inter-relationships with other rock properties is usually a difficult job especially in heterogeneous carbonate reservoirs. Cementation factor (m) is mainly a function of the shape and distribution of pores and can be influenced by many factors including shape, sorting and packing of the particulate system, pore size and configuration, constrictions existing in a porous system, tortuosity, type of pore system (intergranualr, intercrystalline, vuggy, fractured), compaction due to confining stress, presence of clay minerals and temperature. Consequently, the combination of these effects can produce a countless number of values of FF and m for a given porosity.

Figure 23 depicts FF versus porosity at confining stress for all selected samples. Samples are grouped with respect to composite m values ranging from 1.86 (one sample only) to 2.39 (two samples only). The composite m values were made to give maximum standard deviation of 0.04 and maximum range (maximum ‘m’ minus minimum “m”) of 0.10 ‘m’ unit. Figure 24 gives the percentage distribution of the m values among all samples. Most of the samples (13 plugs out of 30, 43.3%) have m values around 2.21; whereas 30% (9 plugs) of the samples have m values around 2.09. Only 5 samples have m values around 1.97. This variation in m values is a direct indication on the degree of heterogeneity in this reservoir. This is clear from figure 23 where data points (on each composite m line) cover the full range of measured porosity. Figure 25 emphasizes the influence of internal structure revealed by the CT images on the different composite m values. Heterogeneity and vuggy structure are responsible for the high m values obtained from sample# 4A&21A (composite m of 2.39) indicated on the plot of figure 23. Close look into the CT images of sample #3, #16A & #24A in figure 25 show respectively increasing m values with increasing degrees of heterogeneity. Figure 25 also depicts an interesting comparison between sample# 24A & #15 which both lie on the same composite m slope of 2.21. The CT image of sample# 15 reveals tight and vuggy structures (different/heterogeneous lithofacies) which gave lower poroperm data. Sample# 24A has more uniform distribution of vugs which gave rise to higher poroperm characteristics. These differences in CT images may influence the poroperm results but not the cementation factor m. This observation conspicuously emphasizes the complications involved in the diversified factors contributing to the determination of m exponents.

Figure 26 gives variations in rock properties (i.e. porosity – plot (a), permeability – plot (b), FF – plot (c) and m – plot (d)) along reservoir depth. Arrows are shown to emphasize the directional change of measurements. Negative slope arrows indicate reduction in measured properties whereas positive slope indicates an increase in rock property with depth. There is a general consistency in the directional change of porosity and permeability along the whole reservoir depth and this can be seen by the correspondence in positive and negative slope arrows in permeability and porosity plots in Figure 26 (a) & (b). Similarly, one can follow the data points and arrows in the FF plot in Figure 26 (c) to see completely opposite slope arrows compared to those in the porosity and permeability plots. This is expected as an increase in poroperm, for instance gives decrease in FF. A close look into the m plot in Figure 26 (d) shows that m follows the same directional change of poroperm when both porosity and permeability directional changes agree. When directional changes in porosity and permeability disagree as seen at an average depth of 9620 ft, m changes with permeability. At this reservoir depth, permeability in plot (a) and m in plot (d) both decrease with depth, while porosity in plot (b) increases. Only at a certain range of reservoir depth (9625 ft to 9630 ft) do we see a violation in the discussed variations in poroperm with m. At this depth interval both porosity and permeability decrease with depth while m increases. Figure 26 emphasizes the inherited inter-relationships among the various rock properties and the high degree of heterogeneity along the depth of this reservoir core. The follow up of these directional changes with emphasis on the influence of internal rock structures qualifies the obtained results and helps establish a profound basis for reservoir core characterization including proper rock typing and sample classification.

Whole Core Formation Resistivity Factor (FF,m)

Selected whole core samples underwent brine saturation for resistivity measurements at ambient and overburden stress. Whole core selection was made such that samples would cover the whole range of poroperm data as seen in Figure 27. A composite m exponent of 1.94 was obtained for all measured 6 whole core samples in Figure 28. However, the samples were split into three different m groupings based on the same criteria used for the plugs (see Figure 29). Figure 29 also depicts the corresponding CT images of all data points. The two samples which have a composite m value of 1.96 have got similar CT image characteristics. All the other data points have separate CT images given in Figure 29. One can immediately notice that samples with lower m values (i.e. 1.86 and 1.96) are more heterogeneous and vuggy than the single whole core sample which gave the highest m value of 2.08. Four out of six whole cores have got varying rock features and thus the corresponding data points in Figure 29 are represented by two CT images (one tight and one vuggy). Whole core samples showed much lower m values compared to measurements of plugs. It appears that local heterogeneity is better represented and averaged on the whole cores, and have such measurements should be more representative of the reservoir. The whole core measurements are consistent with the plug data in showing higher m values for more heterogeneous cores, and conversely lower m values for more well cemented and homogeneous samples.

Effect of Scale on Rock Properties

Honarpour et al., 2003 compared whole core and plug permeability measurements from Arun carbonate and tip top sandstone cores. They found that the average plug permeability was very similar to that of the whole core for the sandstone core. However, for the heterogeneous carbonate core the average plug permeabilities were much lower than the whole core data. Whole core measurement correctly averages the high and the low permeability zones into the overall volume, whereas, plug samples do not capture the 3D connectivity among the highest and lowest permeabilities appropriately.

Ehrenberg, 2007 compared laboratory measurements of porosity and permeability on coarsely bioclastic carbonate whole cores and plug samples. The plugs were cut from the same whole cores for direct comparison. He found that whole core porosities tend to be slightly lower than plug porosities. However, permeability differences between whole core and plugs varied greatly from sample to sample but whole core permeability tended to be higher in cases where larger differences were observed.

In this study we compare poroperm data measured on 14 whole core samples with measured poroperm data obtained from vertical and horizontal 1.5" plugs taken adjacent to the whole core samples. Figure 30 clearly shows that whole core porosities are lower than plug porosities. The comparison is made from both horizontal and vertical plugs which are cut adjacent to each and every whole core sample (The average difference is 2.50% porosity unit with maximum difference as high as 5.92% porosity unit). Figure 31 presents whole core versus plug permeabilities. Data points of "square" shapes present horizontal plug permeability versus whole core Kh, whereas, "rhombus" shape points present vertical plug data versus whole core Kv. Permeability differences between whole cores and plugs vary from sample to sample. However, the very tight rocks gave higher whole core permeabilities than the plug data. A more detailed look into the variations in permeability data between whole cores and plugs is shown in Figure 32 at a higher axes scale resolution. One can generally deduce that plugs with lower permeability range (< 10 mD) have lower permeabilities than the whole cores, and that plugs at the higher permeability range (> 10 mD) show higher permeabilities than the whole cores. This observation could be linked to the degree and distribution of heterogeneity present in the rock samples. There are different explanations for the permeability variations seen with scale (sample size). Small sample sizes (e.g. plugs) could overestimate permeability measurements by short-circuiting flow through porosity channels (e.g. vugs) with dimensions similar to plug length as compared to whole core samples. On the other hand, flow paths in the larger whole core volumes may exploit optimal connection pathways that tend to be unavailable within smaller subsets of the total rock volume.

In our case, the high permeability samples (i.e. >10 mD) are generally more heterogeneous and vuggy than the lower permeability samples as revealed through corresponding CT images. Such a high degree of heterogeneity would be more pronounced in smaller volume rocks which could easily overestimate permeability through relatively larger porosity channels. In the lower permeability range samples, larger rock volumes can enhance 3D connection pathways which can promote flow paths and yield higher permeability measurements. Figure 33 gives all plug porosities versus whole core porosities along reservoir depth. It can be observed that the whole core porosities are at the lower range of plug porosity distribution. This proves that with higher density measurements of plug porosity in the core one could get similar porosity measurements between plugs and whole cores. This is all due to the high degree of heterogeneity present in carbonate reservoirs. Nevertheless, whole core porosity data captures the reservoir porosity more correctly by averaging the different local rock properties in the larger whole core samples. It should also be noted that averaging plug data will not give correct porosity values as can clearly be induced from Figure 33. Comparing all horizontal plug permeability data with whole core Kh measurements in Figure 34 reveals what was concluded earlier about the dependence of the permeability difference variations on permeability range (i.e. heterogeneity). We see a general tendency of higher plug permeabilities over whole core permeabilities towards the top of the plot in Figure 34. As we go down in the reservoir permeability decreases and so does the difference between whole core and plug data. Figure 35 compares wireline porosity log data with porosity measurements conducted in the lab at three different scales. The match between whole core and log data is excellent and is actually the best among the other scale measurements. This result emphasizes the importance of whole core measurements in best representing the reservoir behavior by capturing the heterogeneity seen in the rock property. Figure 36 compares the measured cementation factor m from whole cores and adjacent plugs. It is very clear that all whole cores are giving lower m values than the corresponding plug samples. This result has a direct impact on saturations and estimations of oil in place. The figure plots all plug m values against the selected whole cores for Formation Resistivity Factor measurements. Adjacent plugs are shown with red circles in order to have direct comparisons. Figure 37 gives composite m values for plugs and whole cores. Whole core measurements give lower composite m value and this in turn will have a direct impact on the reservoir STOIP calculations.

Conclusions

- Whole core measurements are critical for obtaining core analysis data in heterogeneous and dual porosity systems such as fractured and vugular rocks where the scale of local heterogeneities is greater than the dimensions of the plug samples.

- Whole core porosity tends to be systematically lower than porosity of core plugs.

- Porosity from whole core samples gave much better match with log porosity than plug porosity.

- In low permeability samples (<10 mD), whole cores tend to have higher permeability values than plug measurements. However, in high permeability samples, the whole cores showed lower permeability values than the plugs. This phenomenon could be linked to the degree in heterogeneity and rock nature.

- In the low permeability samples, larger rock volumes can enhance 3D connection pathways which can promote flow paths and yield higher permeability measurements. In high permeability samples heterogeneity would be more pronounced in smaller volume rocks which could easily overestimate permeability through relatively larger porosity channels.

- Cementation exponents measured on whole core carbonates are lower than the measurements on the corresponding core plug samples. This would lead to more representative reservoir characterization, thus improved confidence in volumetric and reserve estimate.

- Local heterogeneity increases the experimentally derived cementation exponent on both plugs and whole cores. The impact of this increase is more pronounced on core plugs compared with whole cores, where the heterogeneity is better averaged out, and thus more representative of reservoir behaviour.

- The more representative measurements of porosity and electrical properties in whole cores decrease uncertainty in petrophysical interpretation and STOIP calculations.

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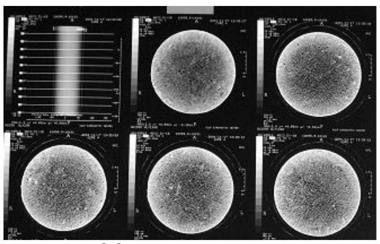
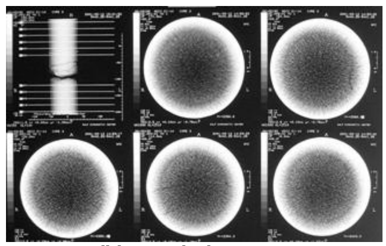
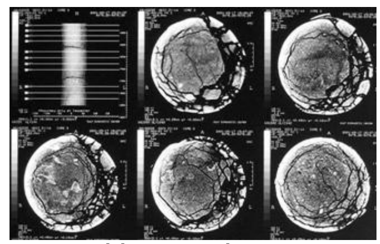
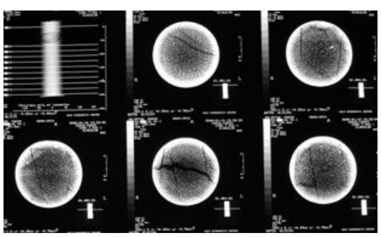
Sample Size (Scale)	Porosity & Permeability	Electrical Properties	Capillary Pressure (Pc)	Relative Permeability
Trim	✓	X	✓	X
1”x1” Plug	✓	✓ for FRF, X for RI	✓	X
1.5”x3” Plug	✓	✓	✓	✓
Whole Core	✓	✓	✓	✓

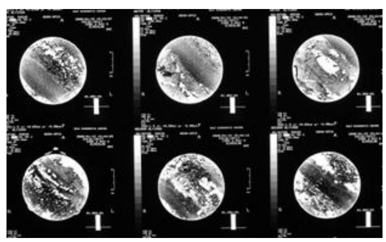
Table 1 Appropriate scales for relevant petrophysical measurements.


(a) Homogeneous core


(b) Invaded core


(c) Damaged core


(d) Fractured core


(e) Heterogeneous core

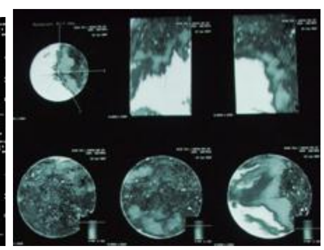

(f) Heterogeneous core

Fig. 1 Example CT scan images.

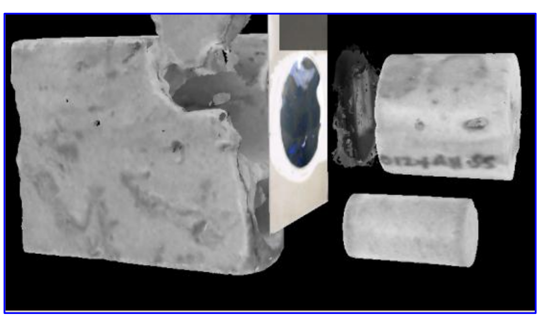


Fig. 2 Two adjacent plugs taken from a heterogeneous core.

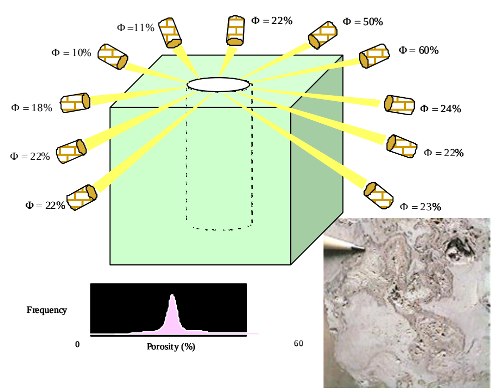


Fig. 3 Varying plug porosities taken from the same heterogeneous core.

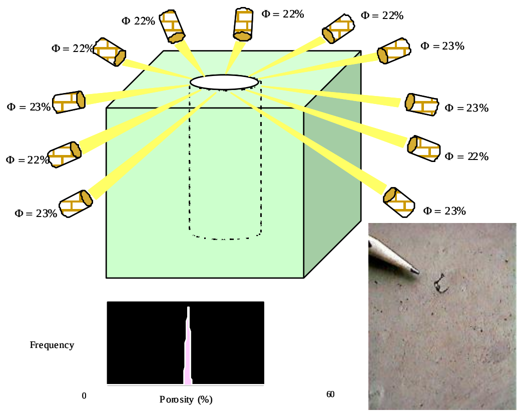


Fig. 4 Similar plug porosities taken from a homogeneous core.

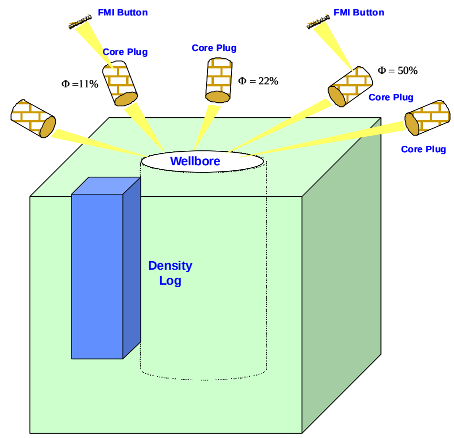


Fig. 5 Relative volumes of FMI measurement and the density log compared to well bore and core plugs.

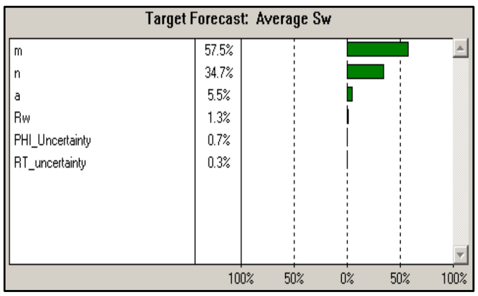


Fig. 6 Effect of m on water saturation.

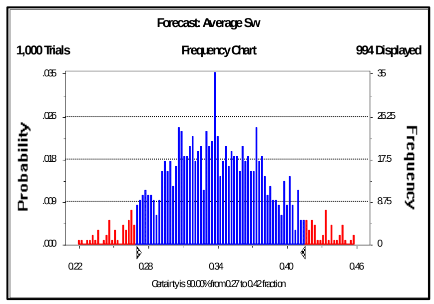


Fig. 7 Sw uncertainty due to Archie.

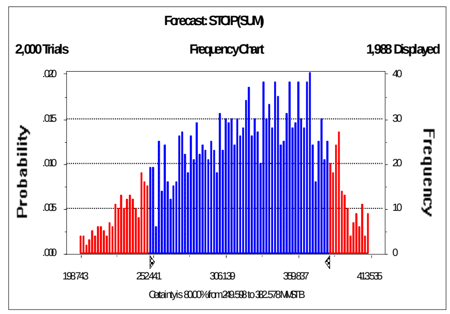


Fig. 8 STOIP uncertainty due to Archie.

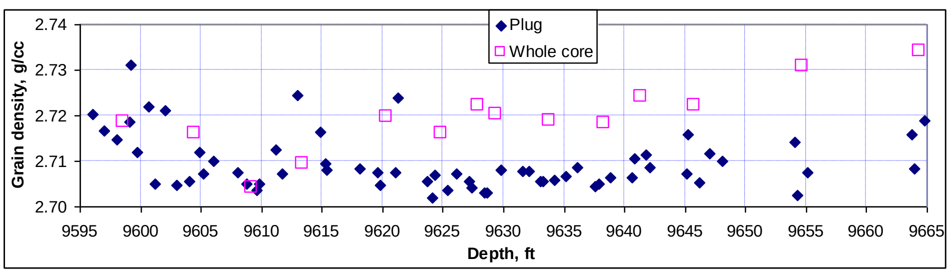


Fig. 9 Plug versus whole core grain density data with depth.

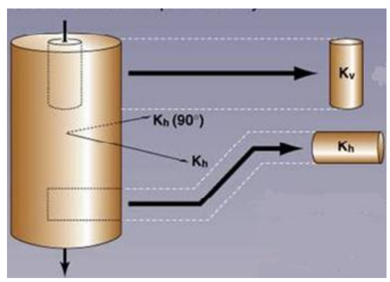


Fig. 10 WC with Kv and Kh plugs.

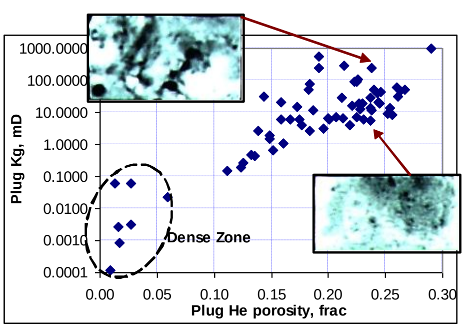


Fig. 11 Plug Kg versus plug He porosity.

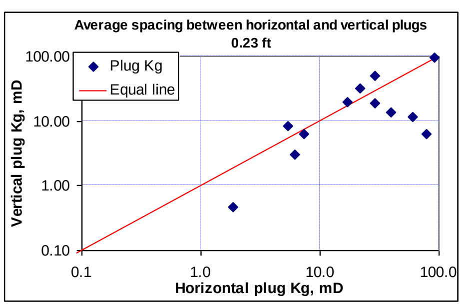


Fig. 12 Horizontal versus vertical plug Kg.

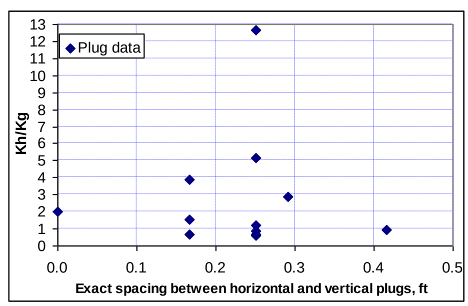


Fig. 13 Plug spacing vs Kh/Kv.

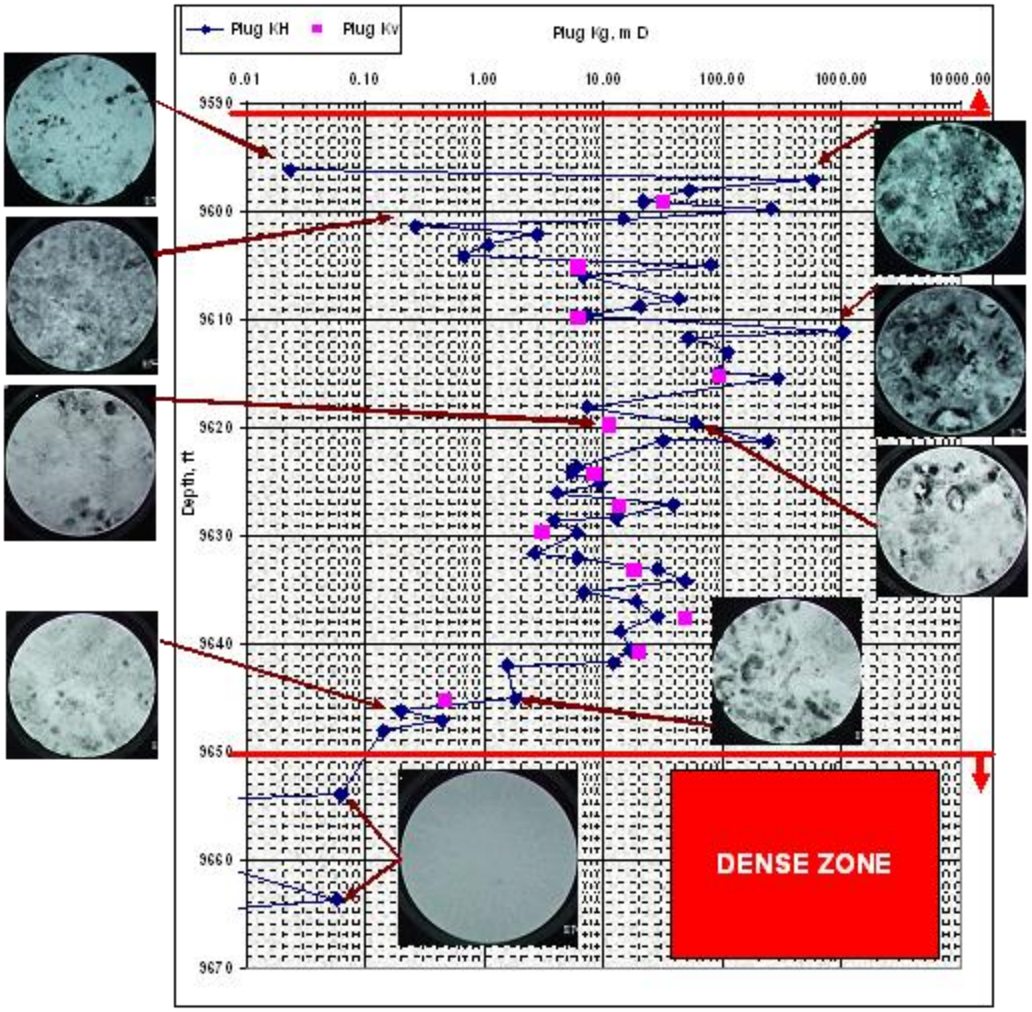


Fig. 14 Horizontal versus vertical plug Kg along reservoir depth with corresponding CT scan images in selected core locations.

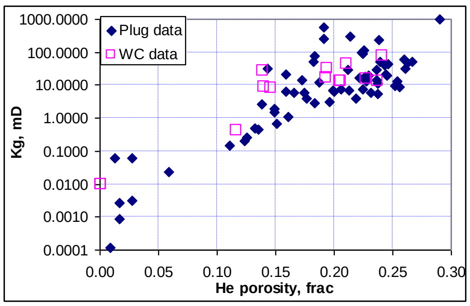


Fig. 15 Plug vs WC Poroperm data.

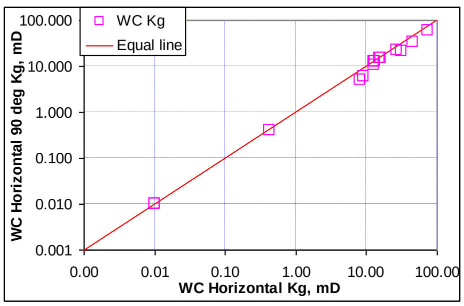


Fig. 16 Kh vs K90 WC Kg.

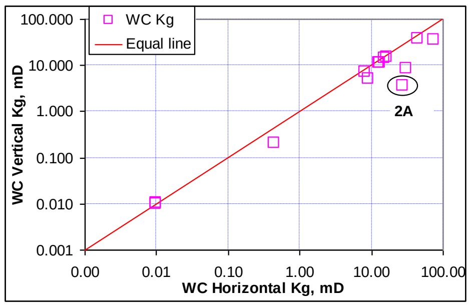


Fig. 17 Kh vs Kv WC Kg (Anisotropy) Sample#2A indicated with a circle.

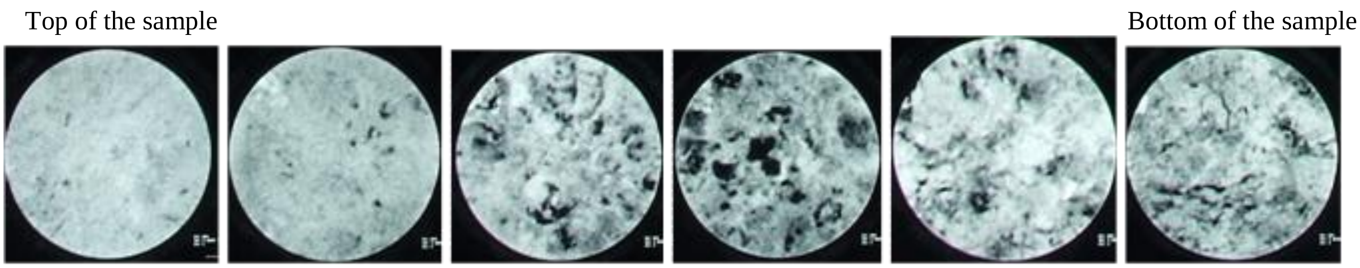


Fig. 18 Cross-sectional x-ray CT images along whole core sample# 2A.

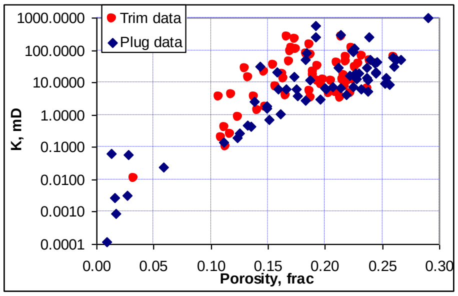


Fig. 19 Plug vs trim poroperm data.

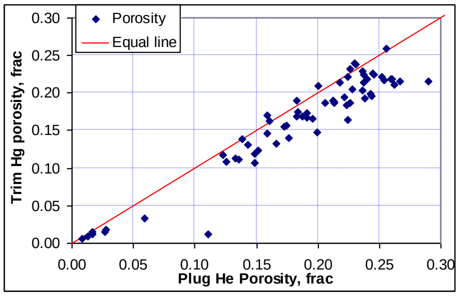


Fig. 20 Plug vs trim porosity.

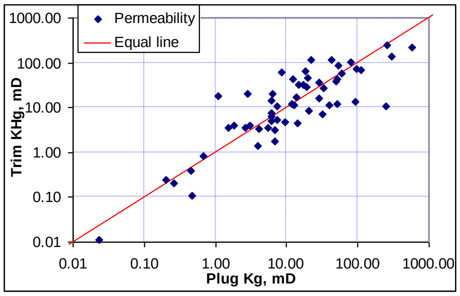


Fig. 21 Plug vs trim permeability.

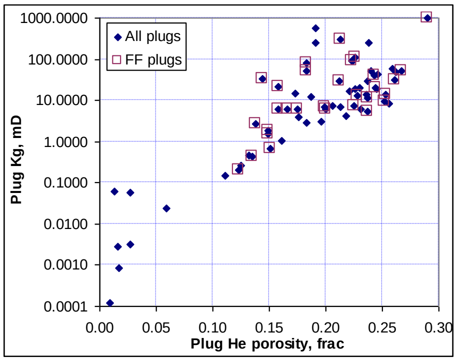


Fig. 22 Selected "FF" plugs vs all samples.

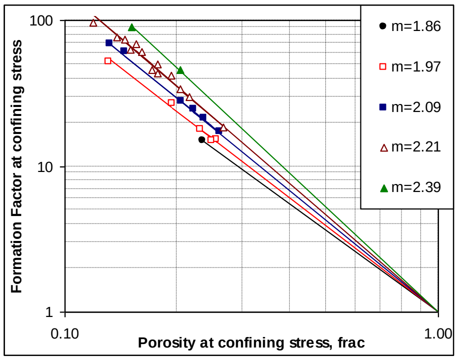


Fig. 23 Plug FF vs porosity.

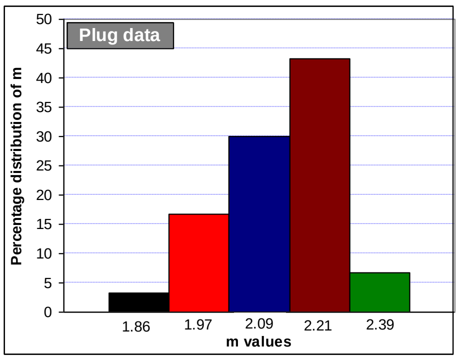


Fig. 24 Percentage distribution of m (plugs).

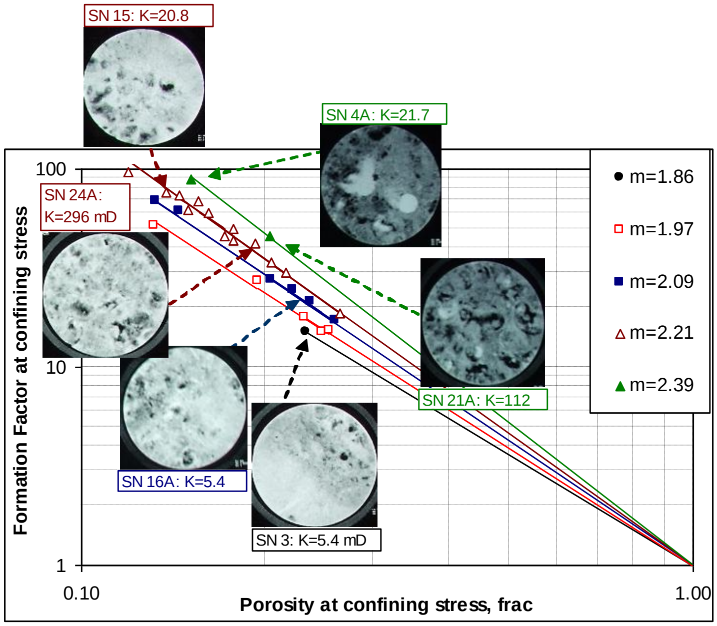


Fig. 25 Plug FF vs porosity with selected corresponding CT images.

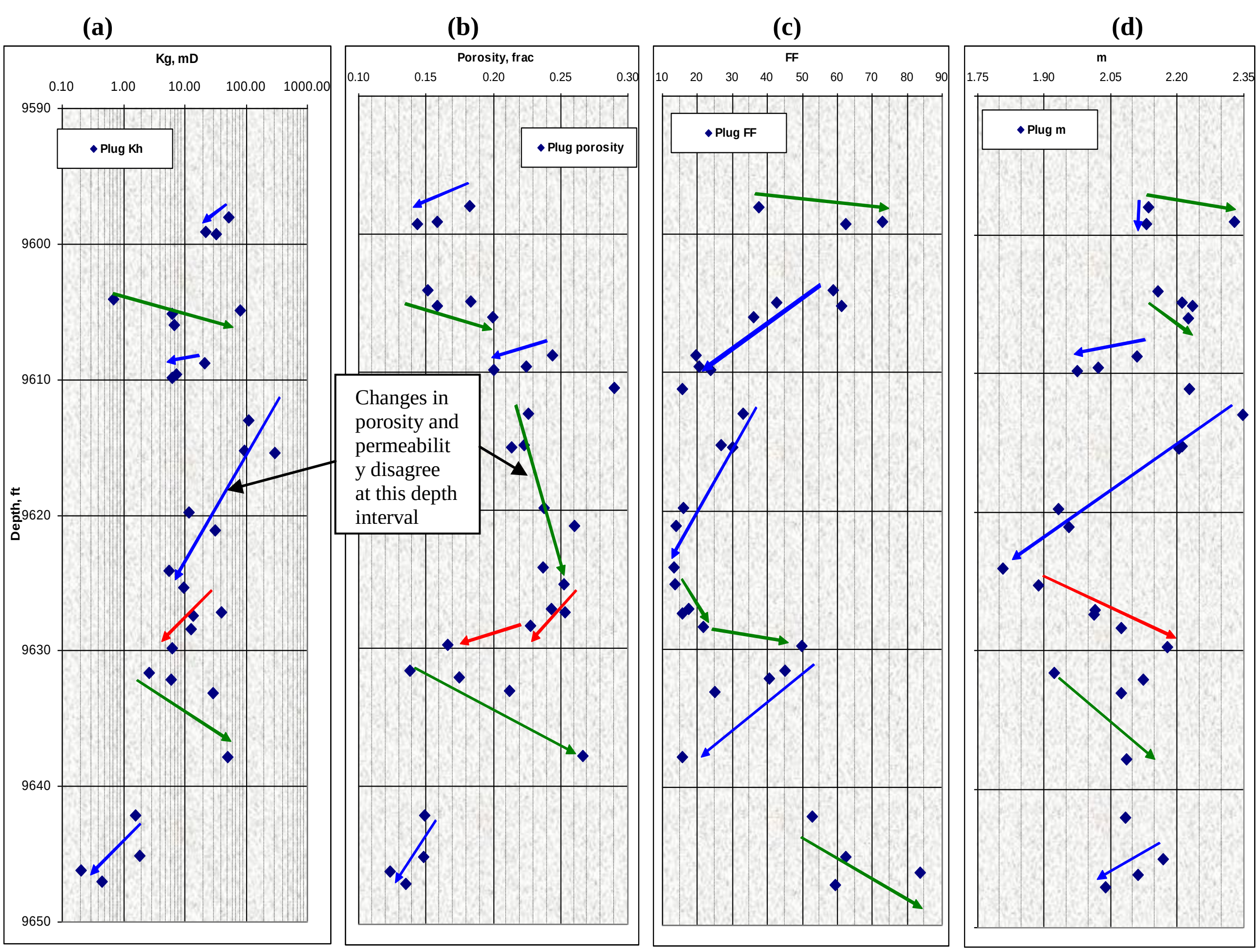


Fig. 26 Corresponding variations in permeability, porosity, FF and m values along reservoir depth – Arrows show directional change.

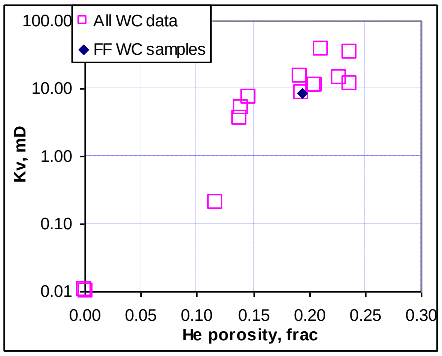


Fig. 27 "FF" whole cores vs all samples.

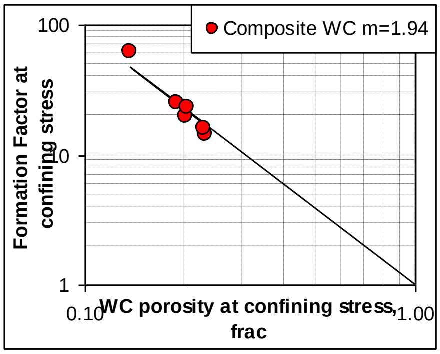


Fig. 28 WC FF vs porosity (single m).

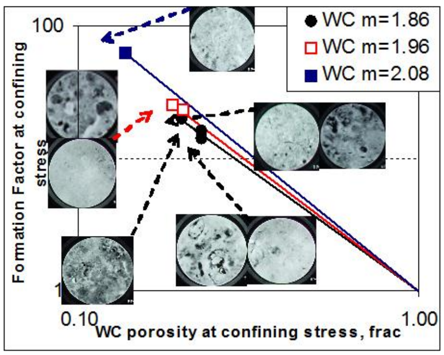


Fig. 29 WC FF vs porosity (different m).

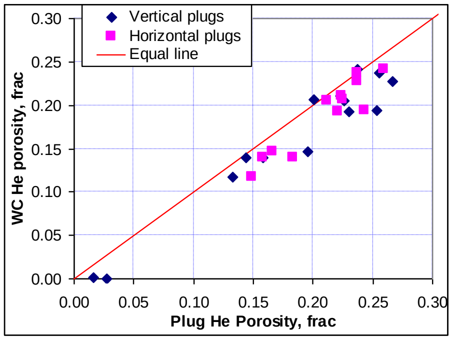


Fig. 30 WC vs plug porosity.

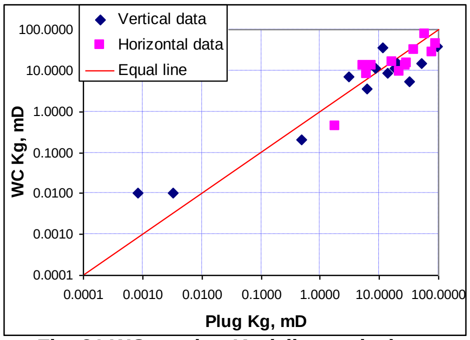


Fig. 31 WC vs plug Kg (all samples).

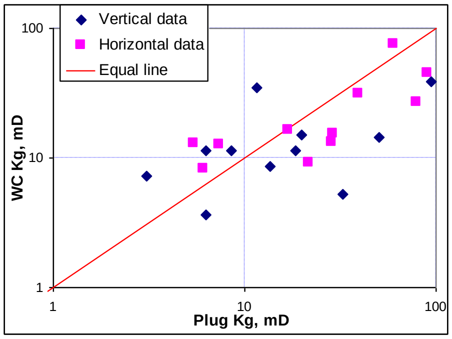


Fig. 32 WC vs plug Kg (>1 mD samples).

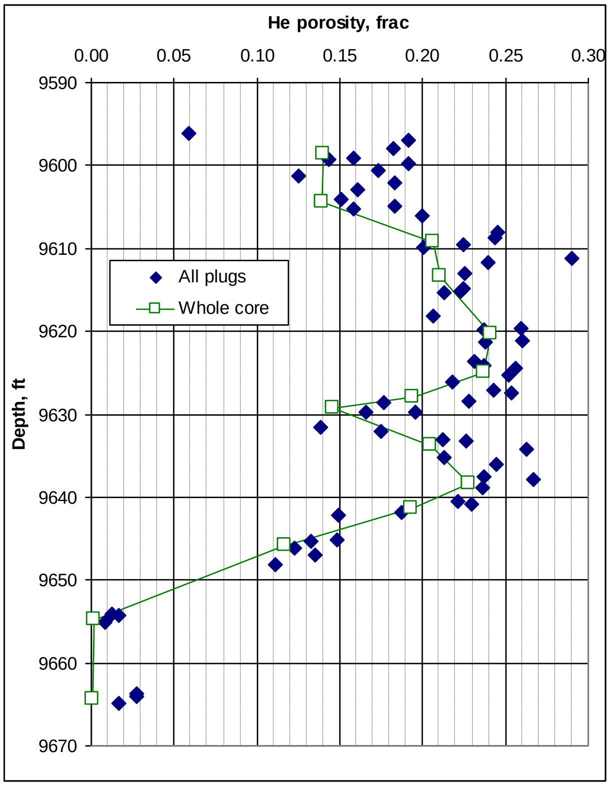


Fig. 33 WC and plug porosity along depth.

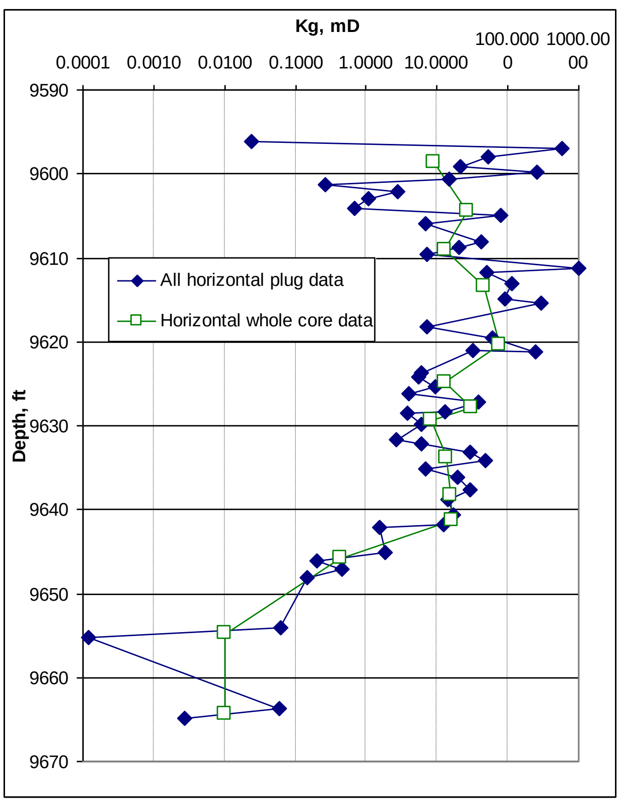


Fig. 34 WC and plug horizontal Kg along depth.

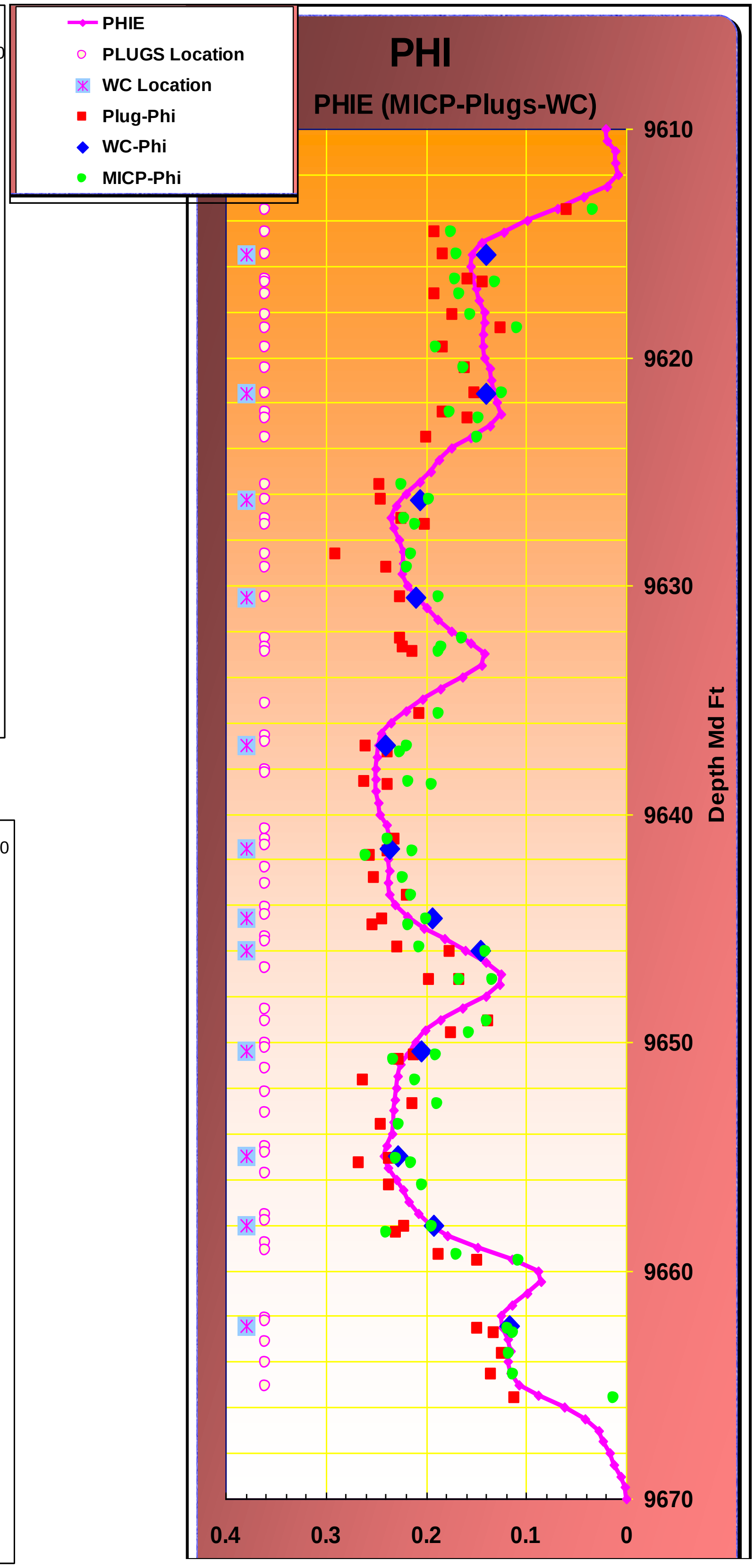
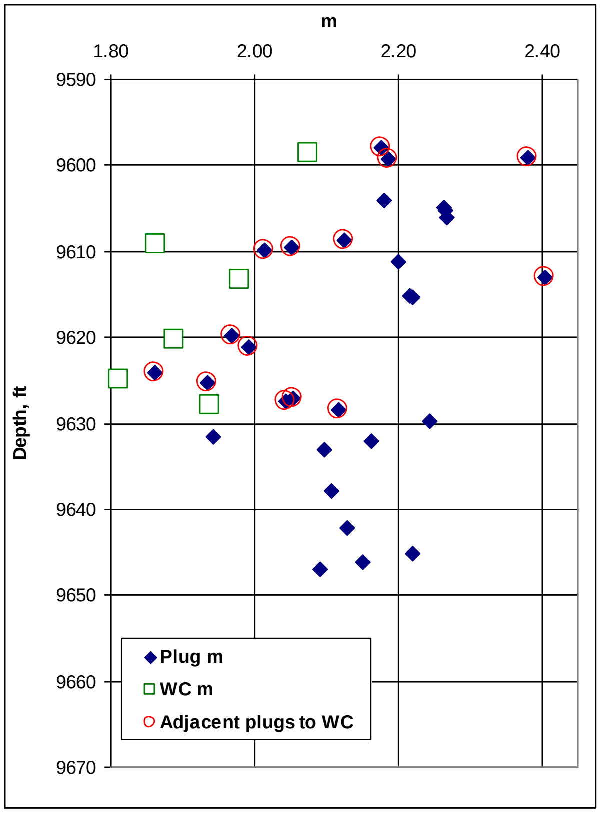


Fig. 35 Core porosity versus log data along reservoir depth.



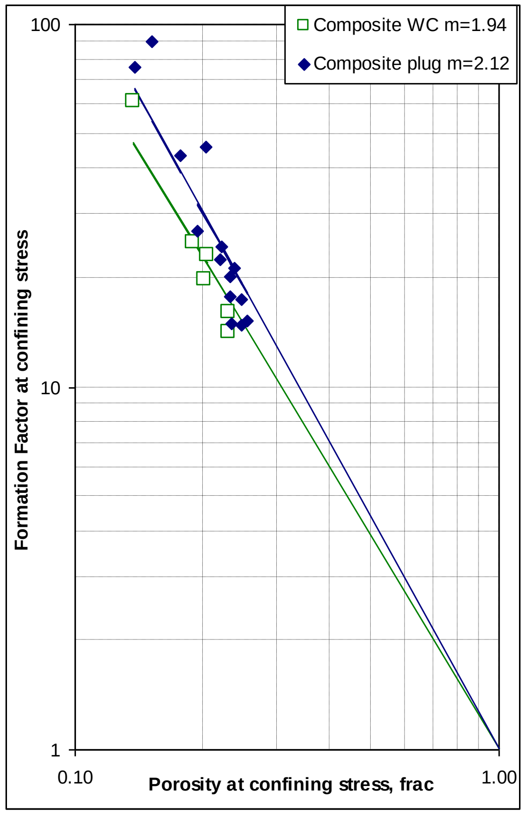


Fig. 36 WC and plug m along depth.

Fig. 37 FF vs porosity for both whole core and plug samples.