CASE STUDY FOR REPRESENTATIVE WATER SATURATION FROM LABORATORY TO LOGS AND THE EFFECT OF PORE GEOMETRY ON CAPILLARITY

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ABSTRACT

A detailed laboratory study to determine water saturation in representative reservoir cores (a range of reservoir rock types) as well as remaining oil in water flooded regions has been completed using Porous Plate measurements at reservoir temperature and reservoir overburden pressure conditions for a huge carbonate field. Representative reservoir core samples were selected based on whole core and plug X-ray CT, NMR T2, high pressure mercury injection (MICP), porosity, permeability and Thin Section analyses. The results of Primary Drainage (PD), Spontaneous Imbibition (SI) and Forced Imbibition (FI) experiments are presented in this work which capture the capillary pressure (Pc) behavior and the electrical resistivity (RI-Sw) changes all the way to irreducible brine saturation (Swi) for drainage and residual oil saturation (Sor) for imbibition. The ensuing water saturation (Sw) and Sor results are validated with appropriate logs and sponge core measurements. The impact of both drainage and imbibition laboratory results for the field and hysteresis in RI-Sw measurements are also considered.

The initial water saturation was estimated using the RI-Sw curves in drainage. Very low saturation was reached covering the range of saturation of interest in the field. The saturation exponents ‘n’ appear to be around 2 for the reservoir rock types (RRT) containing most of the STOOIP while the tighter RRT’s show lower values. Capillary pressure and Resistivity Index data when grouped according to geological lithofacies confirm the distinct RRT characteristics. The remaining oil saturation was estimated using the RI-Sw curves in the imbibition mode. Interesting capillary pressure behavior has been observed in the spontaneous imbibition cycle which can directly be linked to the pore throat size distribution curves obtained from mercury injection data on corresponding sample ends. Small hysteresis has been noticed in the imbibition cycle which tends to increase the saturation exponent ‘n’ above 2. Obtained Sor values have shown little variations amongst the reservoir rock types, except for the tightest RRT s which show comparatively higher values.
Integration of the capillary pressure, water saturation and resistivity index results together with the basic Petrophysical data including porosity, permeability**,** NMR, CT scans, mercury injection and Thin Section images confirm the validity and consistency of the collected data. The value of the well defined laboratory data and its integration to logs is

presented. Despite the reservoir zone of interest being classed as intermediate to oil wet conditions, 'n' values are lower than the previously assumed value of 2, and much lower than that expected for pseudo oil wet conditions. The case study presented reduced the uncertainties in the oil in place estimations and allowed a realistic evaluation of the water flooding performance.

INTRODUCTION

Previous studies (Kalam et. al., 2006 and Efnik et. al., 2006) detail the reservoir rock characterization phase involved in the SCAL study including sample selection, preparation and cleaning methodology employed. The results were focused to primary drainage measurements only. In this work, we present additional Porous Plate measurements involving spontaneous imbibition and forced imbibition experiments (as continuation to the primary drainage cycle) with an emphasis on the effect of pore geometry on core property. The calibration of the log response in imbibition mode is also considered (Fleury et. al., 2004).

EXPERIMENTAL PROCEDURES, RESULTS & DISCUSSIONS

Reservoir Core Description

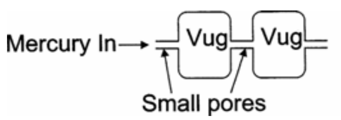
Thin Section descriptions were carried out on selected plugs representing typical reservoir rock types (RRT). Plate 1 shows the Thin Section images. Two main categories can be identified which have similar features and characteristics. Group1 representing RRT1, RRT2 and RRT4 are commonly composites mainly of rudist, skeletal, peloid rudstone and peloid floastone, foraminifera and echinoderms which formed in a shallow subtidal to intertidal, high energy open platform above fair weather wave base. Porosity fluctuates around the value of 30% (+/- 10%) with permeability ≥ 500mD, 100-500mD and 25-100mD, respectively. White areas represent the pore-filling cement. The second group, describing RRT6 and RRT7 contain mud (clay and fine silt-size carbonate) and therefore classified as wackestone and mudstone. The images show preserved intra-particle porosity (8-25%) within Lithocodium/Bacinella grain and pore-filling cement with permeability ≤ 0.1 mD.

NMR Analysis

NMR T2 relaxation times were measured on brine-saturated samples using an echo-spacing of 200 micro seconds. The T2 distribution obtained from rocks saturated with a single fluid phase wetting the surface of the pores reflects the pore size distribution of the rocks where pore size is measured as the ratio between its surface area and volume (Kenyon et. al., 1986). It is interesting to note that there is a good correlation between permeability and mean T2 values indicating that the shape and position of the T2 distributions for the saturated samples, is dependent on the size and distribution of the main flow channels within the pore space. All samples had NMR porosity values within 1.1 porosity units (p.u.) of the helium porosity.

Comparison of T2 with Mercury Injection Derived Pore Throat Distributions

A comparison of mercury injection pore size distributions and saturated sample T2 distributions can help evaluate if a pore network contains 'shielded' pores. RRT 6-7 samples in general, show an excellent match between T2 distributions and mercury injection pore size distributions. Figure 1 represents one sample from this RRT group. This indicates that the pore geometry for these samples approximate the capillary tubes model. On the other hand, the comparison of the two forms of distribution for RRT 1-5 samples show a mismatch. Such an example is shown in Figure 2. If pores are arranged such that the entrance to a large pore is through a small restriction, the capillary pressure required to fill the large pore will have to be high enough to fill the small entrance pore, as shown schematically:



This may lead to an over estimation of the small pore volume in the mercury injection pore size distributions. This may explain why the observed mercury injection pore throat distribution is centered on smaller pore sizes compared with the T2 distribution derived pore size distribution. The disparity between the two types of pore size distribution may indicate the existence of shielding of large pores by small pores, in addition to experimental artifacts arising from use of different samples in the two tests.

Primary Drainage Cycle

Figures 3 and 4 show the primary drainage capillary pressure curves for the examined samples. The results are consistent with the expected trends for higher permeability multi-modal RRT in Figure 3, and conversely with lower permeability uni-modal RRT in Figure 4. The J function for these RRT's were presented earlier (Kalam et. al., 2006), confirming the assertion of (Masalmeh and Jing, 2004) complex pore structure/pore size distribution of high permeability carbonate samples, and hence possible inapplicability in correlating rock behavior.

Spontaneous Imbibition Cycle

The spontaneous imbibition (SI) measurements were performed as a continuation of the primary drainage cycle at the same experimental conditions of reservoir temperature and net overburden pressure. The spontaneous imbibition cycle started after the cores had been in contact with reservoir crude oil at reservoir temperature for about 5 months (end of primary drainage cycle). The SI cycle took approximately 2 months to complete. This means that the rock samples under study had been in crude oil at reservoir conditions long enough to alter (or restore) their wettability towards intermediate or oil wetness. The core plugs were saturated with simulated formation brine (SFB) spontaneously by decreasing the capillary pressure in steps (from max Pc of 7 bars to zero) and recording resistivity and imbibed water on a daily basis.

Figures 5 and 6 depict the spontaneous imbibition of high permeability (and comparatively more heterogeneous) RRT 1-4 samples and the low permeability (almost homogeneous) RRT 5-7 samples, respectively. RRT 1-4 samples did not show any significant spontaneous imbibition, and some of those samples did not show any spontaneous imbibition at all. However, the low permeability samples (RRT 5-7) showed unexpectedly large imbibition of brine during capillary pressure reduction except one sample (plug # 43) from RRT 6. This is an interesting behavior which could be linked to the microscopic pore structure parameters of the rock samples as well as the rock-fluid interaction over the length of aging time. The impact of latter is beyond the scope of current investigations. An interesting observation is the capillary behavior of sample # 1. This sample had the largest imbibition in the SI cycle. Mercury injection data showed the sample to be narrowest and most uniform PSD amongst all imbibing samples, reflecting high capillary forces associated with presence of numerous small pores.

Forced Imbibition Cycle

Since the reservoir investigated was under water flooding, capillary pressure (Pc) and resistivity index (Sw-RI) measurements were required under imbibition cycle. The forced imbibition experiment is a key element in evaluating hydrocarbon reservoir performance through the shape of the Pc curve, saturation exponent and residual oil saturation (Sor) (Masalmeh and Jing, 2006). The measurement cycle of 3-4 months was a continuation of the spontaneous imbibition cycle at the same experimental conditions and fluid system by increasing water pressure in constant capillary pressure steps and recording resistivity and imbibed water on a daily basis.

Figure 7 shows the real time transient non-equilibrium RI data for drainage, spontaneous imbibition and forced imbibition on a typical plug sample along with the corresponding equilibrium data in Figure 8. In such experiments, it is important to collate both the transient and the equilibrium data for improved fits and data confidence. The small hysteresis that can be observed in some of the test samples with transient data may not be evident if only equilibrium RI-Sw data is used.

The Full Cycle Involving PD, SI and FI

Figures 9 and 10 show the full cycle of PD, SI and FI for each of the samples tested. The two plots demonstrate the potential contribution of different pore sizes and permeability in addition to the (embedded) non-quantified impact of rock-fluid interactions on the capillary pressure behavior of the current reservoir cores. The corresponding RI-Sw plots are shown in Figures 11 and 12, respectively. It should be noted that Porous Plate is the ONLY available technique to measure both the parameters (Pc and RI-SW or ‘n’) on same reservoir core samples under representative test conditions for all the three measurement cycles. Previous studies (Kalam et. al., 2006) have also established the robustness of the technique in minimal experimental uncertainty compared with other capillary pressure techniques as well as Sw-RI determinations to low target Swi. In addition, conventional Porous Plate is known to depict fluid movement behavior that generates uniform saturations mimicking typical distribution of fluids in reservoir rocks under typical drainage and imbibition scenarios, compared with centrifuge and other laboratory techniques for Pc and RI-Sw measurements (Kalam et. al., 2006).

All the RRT 1-4 samples which had comparatively higher permeability compared with RRT 5-7 samples showed convergence in the imbibition Pc behavior down to Sor values of around 20% with the maximum applied capillary pressures of 80 psi (limited by use of available Porous Plate). RRT 5 samples also gave similar range of Sor (Figure 10) unlike the very low permeability (micro Darcy) RRT 6 and RRT 7 cores which converged to Sor values of around 27 to 30%. The RI-Sw behavior which determines typical saturation exponents 'n' confirm the above capillary pressure trends. The higher permeability reservoir cores with comparatively more local heterogeneity, comprising samples of RRT 1-5 show 'n' to increase from 1.99 to 2.28 (from PD to FI), while the tighter (less than 1 mD) and more homogeneous RRT 6-7 samples show 'n' to increase from 1.56 to 1.82 (from PD to FI). Such test results have important implications on both the STOOIP calculations and the remaining oil saturation for reservoirs under water injection schemes, as discussed in the next section.

LOG CALIBRATIONS

Previous studies have established laboratory evaluation of saturation exponent 'n' during primary drainage, and consequent calibration of relevant logs (Efnik et. al., 2006). The new RI-Sw data for forced imbibition is used to calibrate the log response in the water injection wells, and capture the Sor as accurately as possible. Considering the imbibition cycle, the best fit line for the resistivity index data gave an average 'n' value of 2.28 for the good quality rock types (RRT 1 to RRT 5). The comparatively poor rock quality rock types (RRT 6 and RRT 7) show a lower value of saturation exponent of 1.82. There were no significant variation of cementation factor for all the rock types; an average value of 2.08 was used in the calculations.

Two wells, one with low water influx (study well) located in the crest part of the field, and one with high water influx in the reservoir located in mid dip of the field are used to calibrate the water saturation using the new SCAL data. Figure 13 shows the application of the new Petrophysical parameters on the study well, and their impact on the water saturation calculation across the reservoir. The left hand side track shows three water saturation (Sw) curves; the black curve is the original Sw curve that was calculated using the old SCAL data (m=2.15 and n=1.79). The middle sky blue curve shows the calculated Sw curve using an average 'n' value of 1.82 representing the low quality rock types 6 & 7. Insignificant changes between the original Sw and the one calculated for RRT 6&7 is observed. A higher amount of Sw is calculated when the Petrophysical parameters for the good quality rock types (RRT 1 to RRT 5) are used. An average 'n' value of 2.28 is used in this calculation (dark blue line) and shows less amount of remaining oil existing in the reservoir.

Figure 14 illustrates the impact of using different parameters to calculate Sw in a mid dip producer where more water influx has swept the reservoir due its closer distance from the injectors. Again, the difference between the Sw values is insignificant when old data with ‘n’ value of 1.79 is compared with the new ‘n’ value of 1.82 for RRT 6&7. However, a large reduction in the remaining oil saturation (higher Sw values) is observed when Sw is calculated (dark blue curve) using ‘n’ of 2.28 for RRT 1 to RRT 5.

Review of the two wells show the amount of reduction in remaining oil saturation (higher Sw) is more pronounced in the case where more water has already swept the reservoir, and thus is consistent with expected results. Less separation between the old Sw curve and the new Sw curve for RRT 1 to RRT 5 in the study well with little water influx is compared with the separation between the same curves where water has swept the reservoir. In the later example, the separation is much wider although the same Petrophysical parameters are used in both cases. Hence the impact of properly evaluated ‘n’ value under forced imbibition is critical in determining ROS for water injected and/or water swept wells. Drainage ‘n’ values that are conventionally used to assess water saturation in logs (and thus the ROS) are thus not applicable to water injected or swept reservoir sections.

CONCLUSIONS & RECOMMENDATIONS

Based on findings of this study, the following are our conclusions and recommendations for carbonate reservoir cores.

a) Porous Plate at reservoir temperature and reservoir overburden pressure is an excellent laboratory technique for water-oil Pc and RI-Sw measurements during primary drainage, spontaneous imbibition and forced imbibition cycles of carbonate reservoir cores. Minimal experimental artifacts and/or corrections are required in such measurements, and more importantly rock-fluid interactions are usually more representative of reservoir situations.

b) Interesting observations of reservoir rock type dependency on RI-Sw behavior is confirmed in the primary drainage, spontaneous imbibition and forced imbibition cycles. Saturation exponents show little difference between PD and SI, but can be quite different during FI cycle.

c) Non-linear RI-Sw behavior in primary drainage and imbibition is not observed despite presence of local heterogeneity such as vugs and rudists, and samples having a wide range of permeability (0.01 to 10,000 mD) and porosity (10 to 33%).

d) Insignificant hysteresis in RI-Sw between drainage and spontaneous imbibition modes, and very small hysteresis between drainage and forced imbibition were evident in the Porous Plate tests with the current carbonate reservoir core samples.

e) Large spontaneous imbibition was clearly seen in the reservoir core samples having very low permeability (less than 1 mD) and uniform pore throat size distribution despite long aging time with crude oil at reservoir temperature (121ºC). This behavior in capillarity may be directly linked to pore-network geometry and rock-fluid interactions.

f) Log Sw calibrations need to be carefully scrutinized from appropriate laboratory tests; drainage 'n' value is not always applicable to imbibition 'n' expected in water swept wells.

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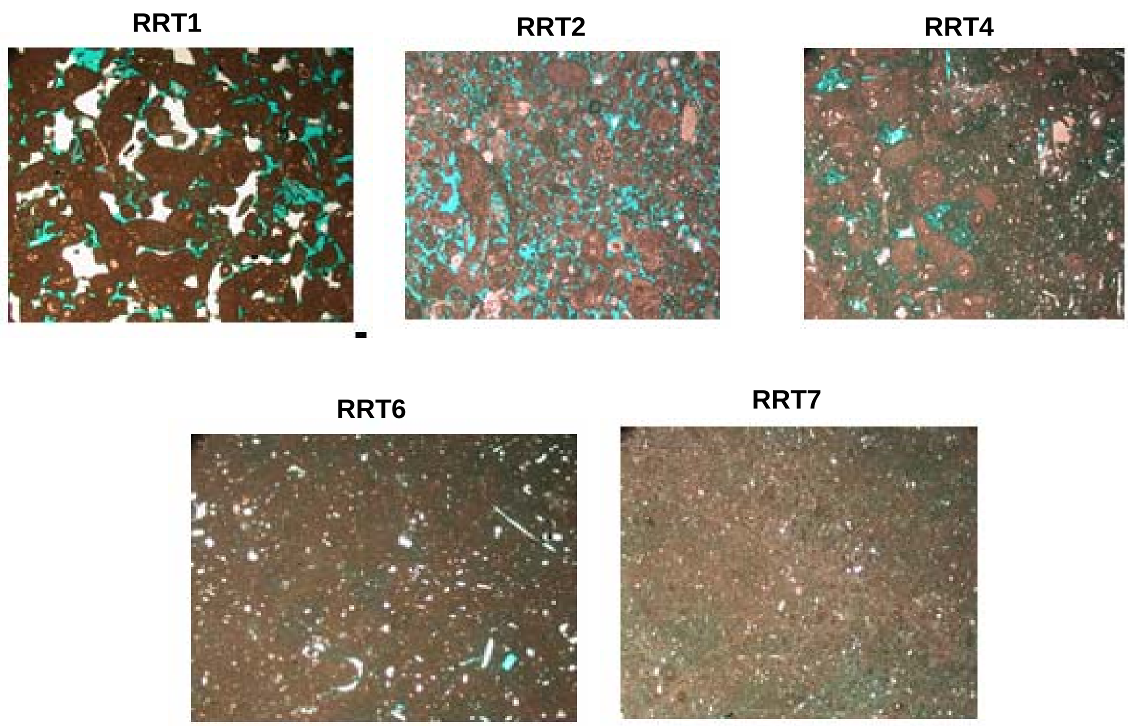

Plate 1: Thin Section Images of selected reservoir rock types

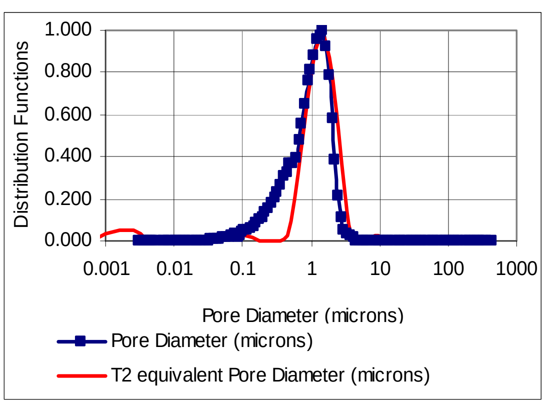

Figure 1. T2 (Fully saturated) vs MICP-Derived Pore Diameter. SN 34

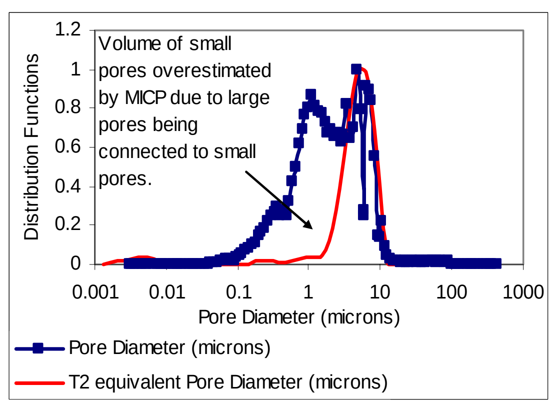

Figure 2. T2 (Fully saturated) vs MICP-Derived Pore Diameter. SN 19

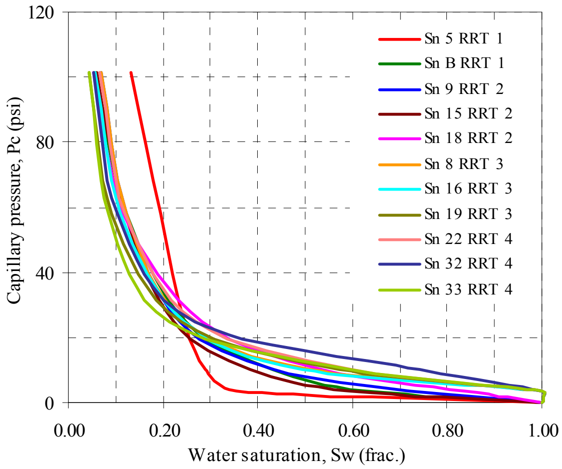

Figure 3. Pc curves for RRT 1-4 plugs

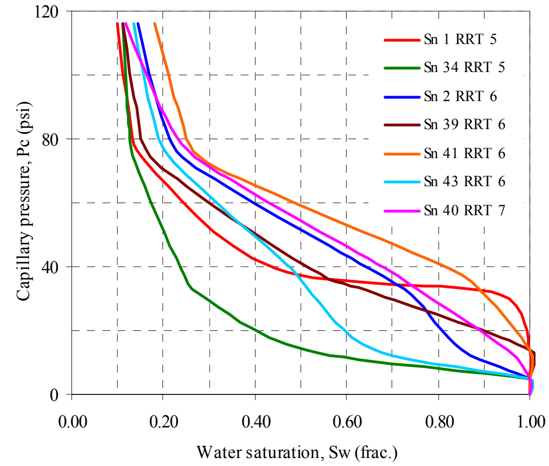

Figure 4. Pc curves for RRT 5-7 plugs

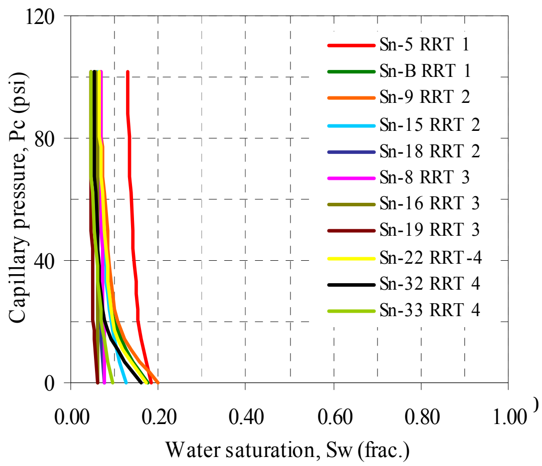

Figure 5. SI Pc curves - RRT 1-4

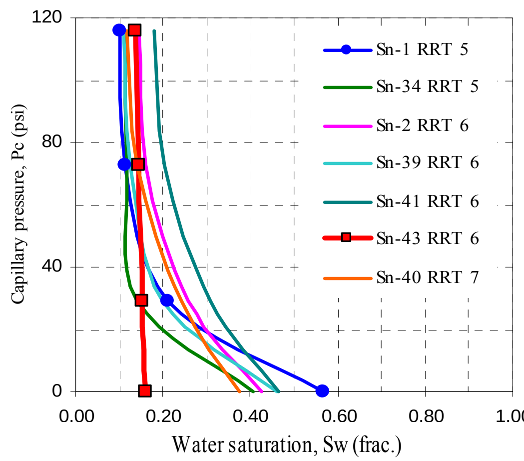

Figure 6. SI Pc curves - RRT 5-7

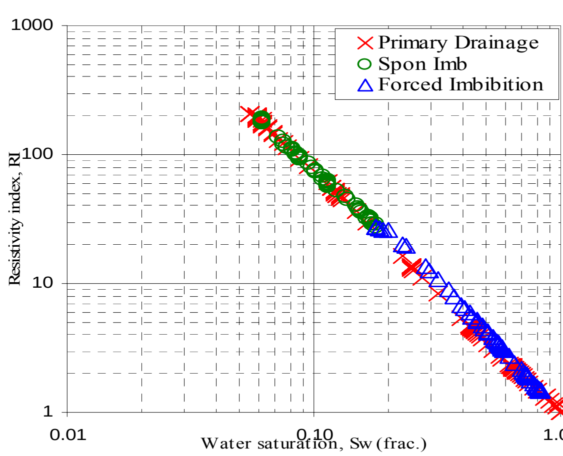

Figure 7. RI-Sw Plots (Transient data)

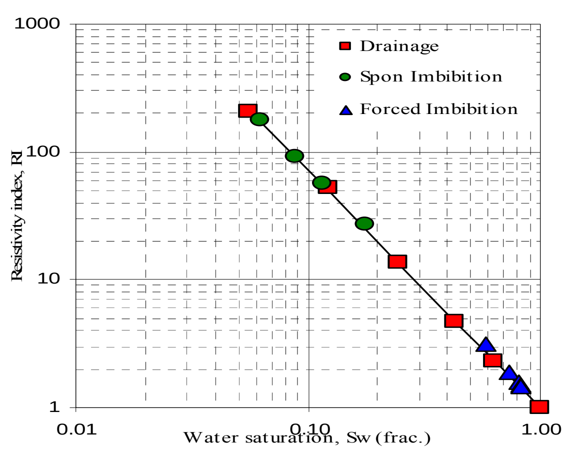

Figure 8. RI-Sw Plots (Equb. data)

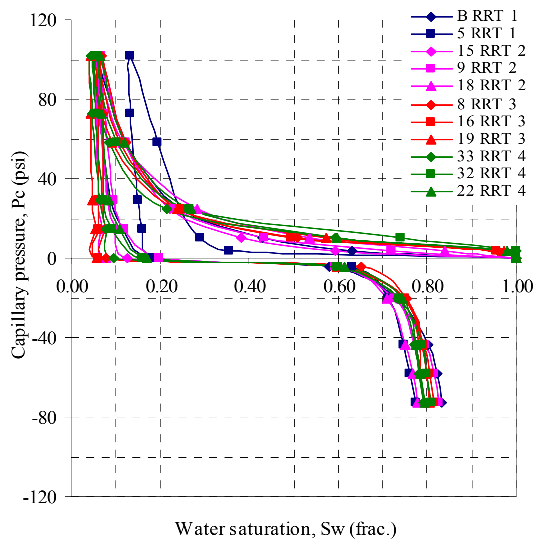

Figure 9. Pc Vs Sw for RRT 1-5

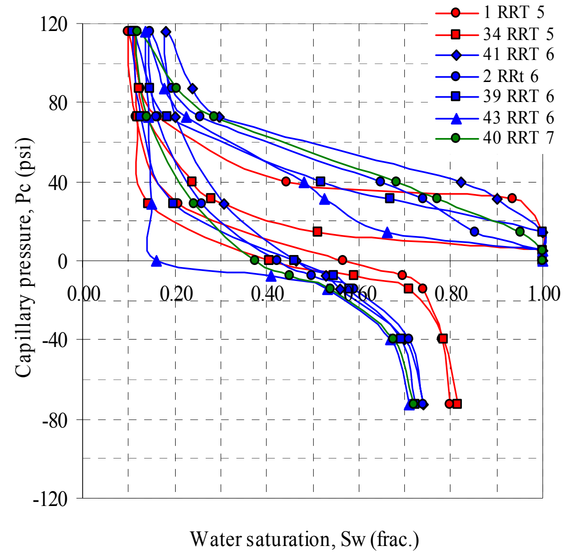

Figure 10. Pc Vs Sw for RRT 6-7

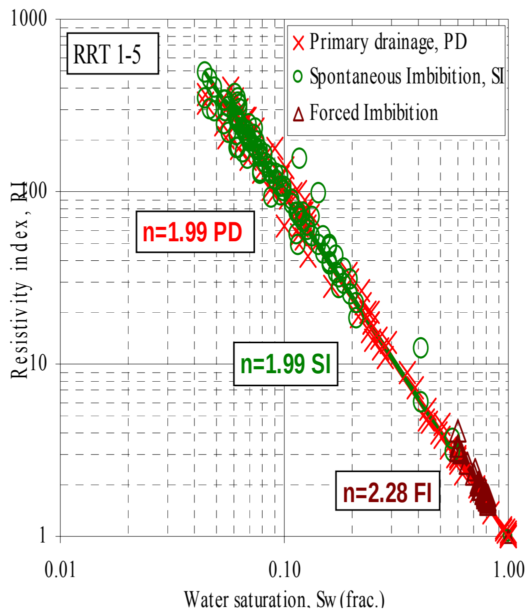

Figure 11. RI-Sw for RRT 1-5

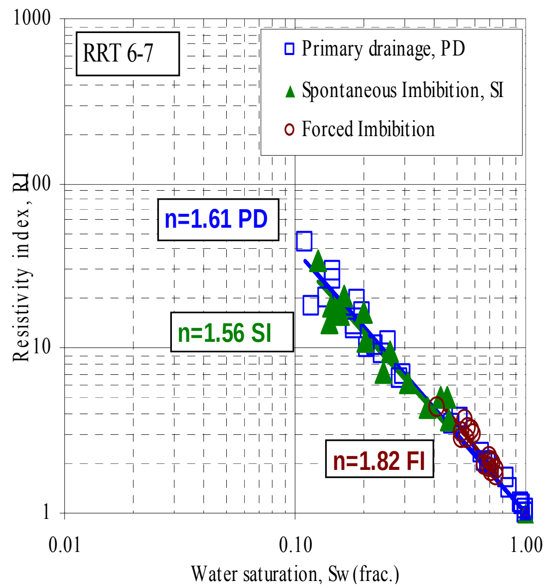

Figure 12. RI-Sw for RRT 6-7

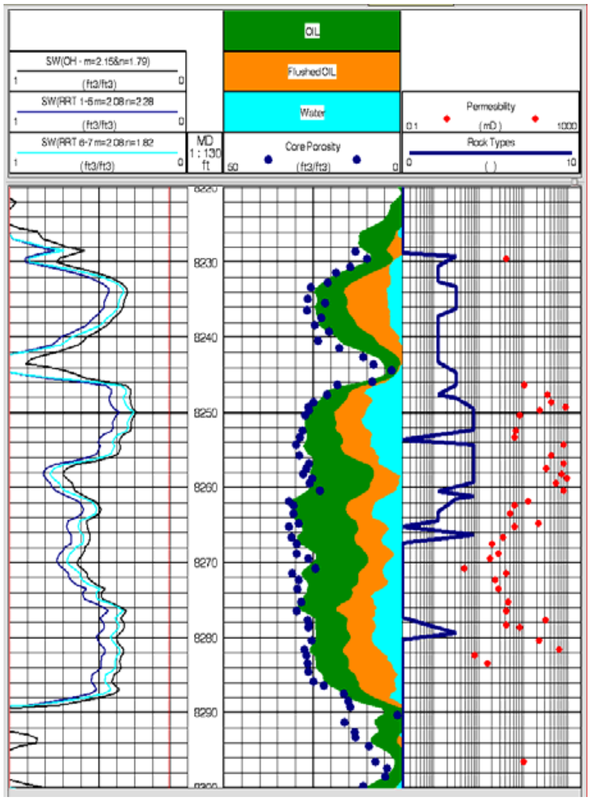

Figure 13. Impact of using different Petrophysical parameters to calculate water saturation (Sw) in the study well. Black line is for Sw original, sky blue line is for RRT 6 and 7, and dark line represent Sw for RRT 1 to RRT 5. Core porosity (circles), log porosity, and calculated volumes are plotted in the middle track, whereas RRT's and core permeabilities are plotted in the right hand side track.

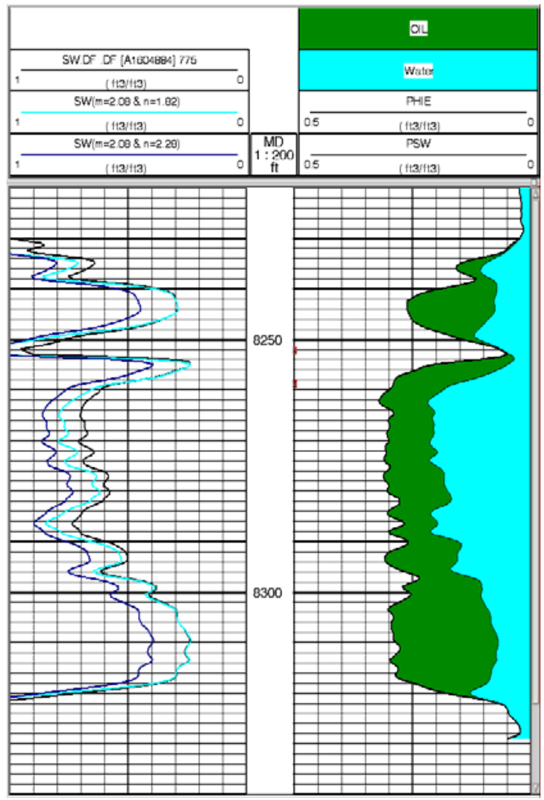

Figure 14. Impact of using different Petrophysical parameters to calculate water saturation (Sw) in the mid dip producer. The Left hand side track is different Sw curve using different parameters. Black line is for Sw original, sky blue line is for RRT 6 and 7, and dark line represent Sw for RRT 1 to RRT 5. Log porosity, and calculated volumes are plotted in the middle track