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Field Application of a Modified Kozeny-Carmen Correlation to Characterize Hydraulic Flow Units

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Abstract

Hydraulic Flow Unit (HU) has been used extensively as a technique in permeability modeling and rock typing. Amaefule et al. (1993) introduced for the first time the concept of Reservoir Quality Index (RQI) and Flow Zone Indicator (FZI) by using the Kozeny-Carmen (K-C) model to characterize HU and predict permeability in uncored wells and intervals.

This technique has helped in enhancing the capability to capture the various reservoir flow behavior based on its respective characters. Yet, there are challenges in using the original correlation due to its inherent limitations and over simplified assumptions that prevent accurate HU definitions. This study highlights some of those shortcomings and proposes a modified K-C correlation that enhances the HU characterization.

It is found that the conventional K-C model ignores the inherent nonlinear behavior between the tortuosity and porosity. Hence, handling the tortuosity term in a more representative manner demonstrates a more rigorous correlation that extends the applicability of this powerful technique into more heterogeneous rocks - such as those found in carbonate reservoirs.

This paper presents a reservoir simulation case study that is conducted to validate the applicability of the proposed model as a rock typing technique in a heterogeneous carbonate reservoir in the Middle East region. Relative permeability curves, Leverett J-Function curves and initial water saturation distribution show good agreement within each HU generated using the proposed model.

It is recognized that modified Kozeny-Carmen technique give better matching of initial water saturation model than the conventional technique when compared to open-hole logs which, in turn; adds confidence to initial hydrocarbon-in-place calculations and reservoir behavior predictions. This result will ultimately enhance the prediction of reservoir performance under various scenarios in reservoir simulation.

Introduction

Several types of porosity-permeability transforms are available to determine permeability from well log-derived porosity in uncored oil and gas wells. Typically these transforms put emphasis on lithology or facies during reservoir characterization. In addition, several pore system dependent techniques are also published. Shenawi et al. (2009) have described commonly used porosity-permeability transform types, such as: i) transforms by facies, ii) by Winland technique, iii) by pore geometry, and iv) by geologic zones. Transforms by hydraulic unit approach provide way better results than those typical transforms.

Rock typing by hydraulic units can be defined as units of rock that have unique porosity-permeability relationship, capillary pressure profiles and relative permeability curves. It has many applications in reservoir characterization and simulation studies. Once the rock typing is done properly, it can lead to a reliable estimation of the permeability in the uncored wells, accurate generation of initial water saturation profiles and consequently, reliable reservoir simulation studies. (Davies et al., 1996; Guo et al., 2005; Shenawi et al., 2007)

Amaefule et al. (1993) HU Characterization Technique

In 1993, Amaefule et al. introduced for the first time the concept of reservoir quality index (RQI) and flow zone indicator (FZI) to identify HU based on the K-C model. In this regard, Amaefule's technique is recognized as a very simple, practical, and widely used established technique. This well-known approach classifies rock types using the original K-C model. The popular form of the original K-C model is given by:

$$k = \left(\frac{1}{f_g \tau S_{V_{gr}}^2}\right) \frac{\phi^3}{(1-\phi)^2} \tag{1}$$

where k is permeability in μm^2, f_g is the shape factor in the dimensionless unit, τ is the tortuosity in the dimensionless unit, $S_{V_{gr}}$ is the specific surface area of the grain in μm^{-1} and ϕ is the effective porosity in fraction.

The K-C correlation was developed based on the concept of average pore throat size. It was found that this correlation works best for synthetic porous media where pore systems are homogenous and easy to quantify; however, this equation does not work properly in heterogonous and complex pore systems (Ahmed et al., 1991; Babadagli and Al-Salmi, 2004; Francisco et al., 2009).

Further mathematical manipulation is carried on Eq.1 that leads to the following form:

$$0.0314 \sqrt{\frac{k}{\phi}} = \left(\frac{1}{\sqrt{f_g \tau}\ S_{V_{gr}}}\right) \frac{\phi}{(1-\phi)} \tag{2}$$

From Eq.2, the reservoir quality index (RQI) is defined as:

$$RQI = 0.0314 \sqrt{\frac{k}{\phi}} \tag{3}$$

The normalized porosity (ϕ_z) is defined as:

$$\phi_z = \left(\frac{\phi}{1-\phi}\right) \tag{4}$$

The flow zone indicator (FZI) is defined as:

$$FZI = \frac{RQI}{\phi_z} \tag{5}$$

When plotting RQI versus ϕ_z on a log-log scale, all core samples with similar FZI values will lie on a straight line with a unit slope (Amaefule et al., 1993). Other core samples that have different FZI values will lie on other parallel lines. Unfortunately, this is not always the case. In fact, Civan (2002) and Haro (2004) showed that natural rock systems tend to show various slopes rather than having a fixed slope as suggested by Amaefule et al., (1993) and the K-C-model.

Proposed Modification to the K-C Model

The proposed correlation is based on a modified Kozeny-Carmen model and has the advantage over the conventional approach of incorporating the tortuosity term in a more representative manner. The conventional model eliminates the inherent nonlinearity between tortuosity and porosity accordingly. The modified correlation is given by:

$$k = \left(\frac{1}{f_g a^2 S_{V_{gr}}^2}\right) \frac{\phi^{2m+1}}{(1-\phi)^2} \tag{6}$$

where, a is the lithology factor and m is the cementation exponent. Rearranging and taking the square root of Eq.6 results in the following form:

$$0.0314 \sqrt{\frac{k}{\phi}} = \left(\frac{1}{\sqrt{f_g}\ a\ S_{V_{gr}}}\right) \frac{\phi^m}{(1-\phi)} \tag{7}$$

The left hand side of Eq.13 is the reservoir quality index (RQI) where permeability (k) is in mD. The first part of RHS ($1/$

$\sqrt{f_g}\,a\,S_{V_{gr}}$) is the modified flow zone indicator (FZI_m). Since the normalized porosity index (ϕ_z) equals to ($\phi/(1-\phi)$), rearrangement of Eq.7 yields:

$$RQI = FZI_m * \phi_z * \phi^{m-1} \tag{8}$$

Taking the logarithm of both sides of Eq. 8 results in the following relationship:

$$\log(RQI) = \log(FZI_m) + \log(\phi_z * \phi^{m-1}) \tag{9}$$

It can be noticed that if the cementation exponent (m) equals to one, then Eq.9 becomes identical to Amaefule's et al. (1993) model. As (*m*) increases, the plot of RQI versus ($\phi_z * \phi^{m-1}$) on log-log scale gives higher slope lines. Each group of rocks having similar FZI_m will constitute a HU. It should be noted that Ohen et al (2002) used a very similar approach to characterize HU using a modified form of Kozeny-Carman correlation for fractured systems only. The modified correlation replaces tortuosity with cementation exponent, and *total porosity*. However, one of the primarily assumption of the K-C model is that the porosity is effective since it is closely related to permeability rather than total porosity that might not contribute to the flow at all.

In this paper, a case study is presented where the proposed model is used to characterize HUs in a carbonate reservoir in the eastern province in Saudi Arabia.

Case Study: Carbonate Reservoir

The study field is located onshore in the eastern province of Saudi Arabia. The structure is a NE-SW doubly-plunging and near domal anticline resulted from deep salt tectonics. The main reservoirs are Jurassic carbonates consist of 5 different units; Unit-A, Unit-B, Unit-C and Unit-D reservoirs. It has been determined from electrical property measurements on selected number of cores that the average cementation exponent (m) for these reservoirs is 2.00. Based on an earlier petrophysical study, six Petrophysical Rock Typing (PRT) electrofacies have been identified as shown in Table 1.

Hydraulic Flow Units Classification

All available cores from 10 wells were used to develop a representative training database for HU classification. The first attempt to classify HU was using graphical method by plotting the histogram of log FZI_m distribution (Figure 1), however, it is difficult to determine the HU from the histogram plot. Instead, the probability cumulative plot of FZI_m is used. The probability cumulative plot is the integral of the probability density function or histogram plot that a normal distribution is present in a straight line format. Figure 2 shows the core-derived probability FZI_m plot for both conventional and modified method which indicates 7 HUs based on the seven straight lines, respectively. The detail of each HU description is listed in Table 2.

Based on the HU definitions obtained from the cumulative probability plot, a log-log plot of RQI versus ($\phi_z * \phi^{m-1}$) were made as shown in Figure 3. For conventional method, cementation exponent (m) is assumed to be 1. The unit slop lines were drawn according to mean FZI_m values that intercept with the $\phi_z = 1$ vertical line. It is clearly demonstrated that the modified HU characterization improves the clustering significantly compare with the conventional model. Samples that lie on the same straight line have similar pore throat attributes and constitute a HU (Shenawi et al. 2009).

In addition, a plot of log permeability (*k*) versus ϕ (Figure 4) indicates a better correlation using the modified approach as a comparison to the conventional approach for each HU. For a given HU, it is obvious that the conventional method underestimates the permeability values by more than 50%, especially at high porosity values. Not only that, the proposed model generates HU that has narrower porosity range especially at low porosity which is a good indication of more accurate HU definition.

Figures 5 and 6 illustrate the differences between HU rock types generated by the conventional and proposed methods with the PRT rock typing (EFAC). The comparison has been made at the well level, as in Figure 5, as well as at simulation layers level, as in Figure 6. Results indicate that for each EFAC classification, there are more than one HU. This is mainly due to the fact that different pore throat sizes are present within the same EFAC. The HU generated by the proposed model is more sensitive to porosity as compared to the conventional model. On other words, each HU generated using the new equation has more correlation with porosity and less permeability variation with same porosity.

Model Validation

The modified approach described in this paper has been validated at the geological model level. The initial water saturation model is validated at many well locations. Plots of four of them are shown in figure 7. As shown in figure 7, the log measured water saturation profile is compared to the calculated initial water saturation profile from the geological model using both the conventional method and the modified one. It is apparent from this figure that an excellent overall match is achieved. Although

some discrepancies exist, the saturation model obtained from the modified approach adds a lot of confidence in all the subsequent estimations. It is also clear that the saturation model obtained using the modified approach is better than the saturation model from the conventional method especially at the transition zone.

Conclusion

In this paper, a reservoir simulation case study is presented where a modified K-C model is used to generate HU as a rock typing technique. This modified approach eliminates the inherent nonlinearity between tortuosity and effective porosity. Results demonstrate significant improvement in HU characterization using the proposed model that closely matches with field data sets in comparison with the conventional approach.

Results also show that HU obtained using the proposed model is more sensitive to porosity values. Consequently, for a given HU, the proposed model can capture a more representative range of permeability values for a particular range of porosities and resulted in higher range of permeability. This leads to the shortcomings of the classical model where underestimation of permeability values, especially at higher porosities, can occur due to the high variation in permeability.

The conducted case study confirms the applicability of HU, generated by the proposed approach, as a rock typing technique in reservoir characterization and the ability to provide better data integration between geology, petrophysics and reservoir engineering in determining Pc or J-function and Swc for saturation calculations.

This case study clearly shows that the rock typing using the modified RQI-FZI_m approach can be very effective in building a reliable simulation models. When properly done, this hydraulic unit rock typing can add confidence in predicting measurements in the uncored intervals of the reservoir, and hence will provide more accurate predictions.

Acknowledgments

Nomenclature

a	=	Lithology factor, dimensionless
$EFAC$	=	Electrofacies
FZI	=	Flow zone indicator, μm
FZI_m	=	Modified flow zone indicator, μm
f_g	=	Shape factor, dimensionless
HU	=	Hydraulic flow unit
J	=	Leverett J-Function
k	=	Permeability, mD
m	=	Cementation exponent, dimensionless
RQI	=	Reservoir quality index, μm
$S_{V_{gr}}$	=	Specific surface area of the grain, μm^{-1}
Sw	=	Initial water saturation, fraction
Swc	=	Connate water saturation, fraction

Greek Symbols

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ϕ	=	Porosity, fraction
τ	=	Tortuosity, dimensionless
ϕ_z	=	Normalized porosity index, fraction

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Electrofacies	Descriptions
EFAC_0	Very Low Quality Reservoir (VLQR)
EFAC_1	Low Quality Reservoir (LQR)
EFAC_2	Medium Quality Reservoir (MQR)
EFAC_3	Good Quality Reservoir (GQR)
EFAC_4	Very Good Quality Reservoir (VGQR)
EFAC_5	Extremely Good Quality Reservoir (EGQR)

Table 1: Petrophysical Rock Typing Classifications

HU	Qualitative Name
1	Extremely Good Quality Reservoir (EGQR)
2	Very Good Quality Reservoir (VGQR)
3	Good Quality Reservoir (GQR)
4	Medium Quality Reservoir (MQR)
5	Low Quality Reservoir (LQR)
6	Very Low Quality Reservoir (VLQR)
7	Extremely Low Quality Reservoir (ELQR)

Table 2: Hydraulic Flow Unit Classifications
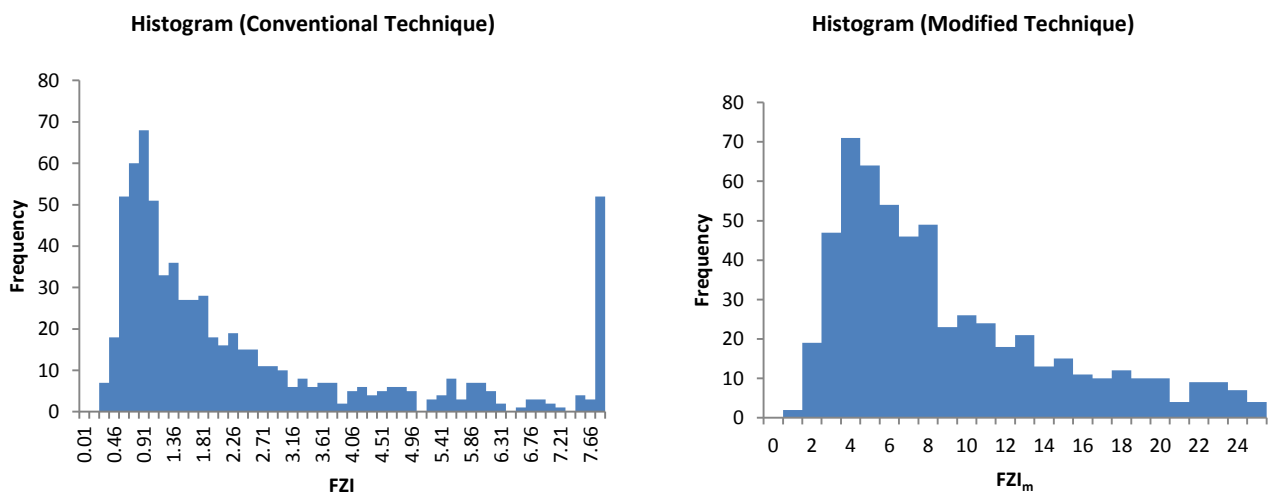
Figure 1: Histogram plot of *FZI* and *FZI$_m$* distribution
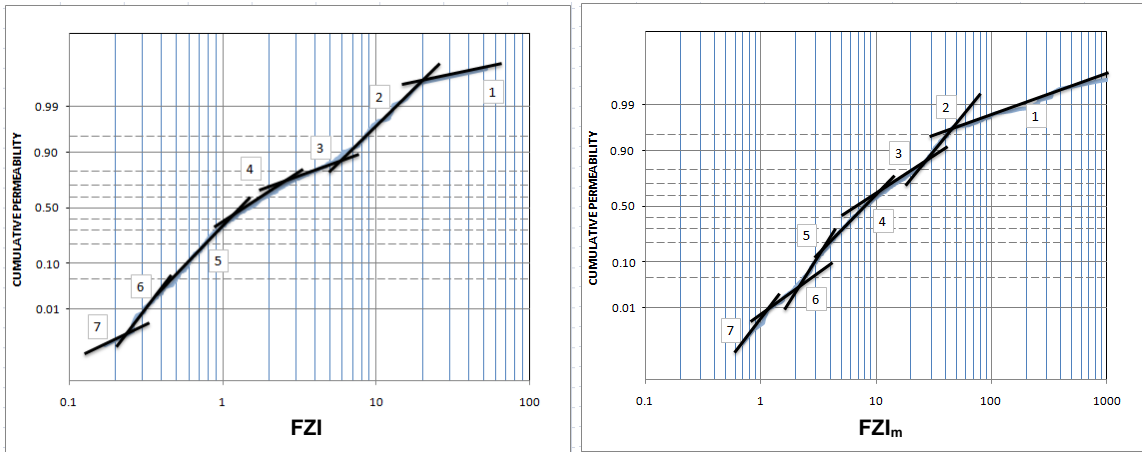
Figure 2: Cumulative Probability plot of FZI distribution for both conventional (left) and the modified technique (right)
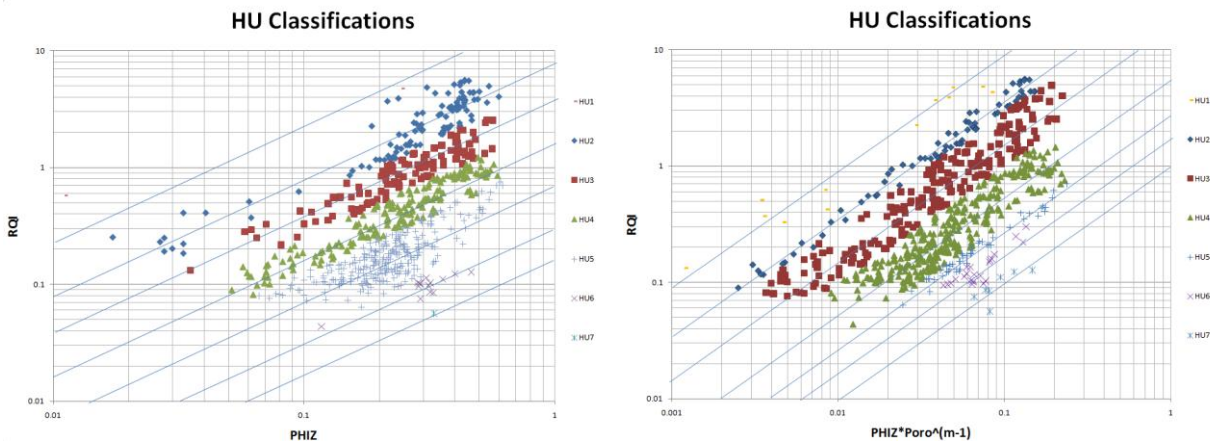

Figure 3: RQI versus PHIZ (ϕ_z) plot for the conventional technique (left) and RQI vs ($\phi_z * \phi^{m-1}$) for the modiftied technique (right)
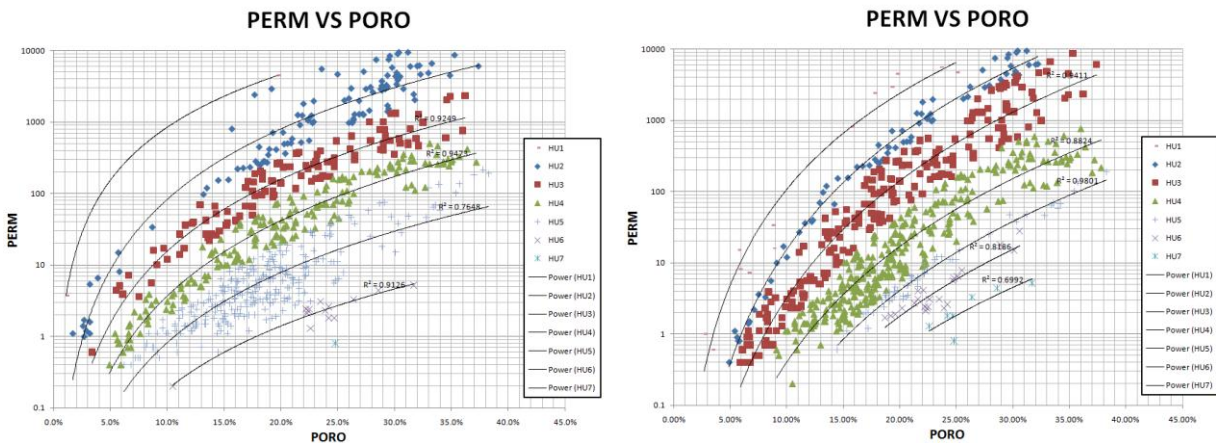

Figure 4: Log permeability (k) versus ϕ plot for both conventional approach (left) and the modified one (right)
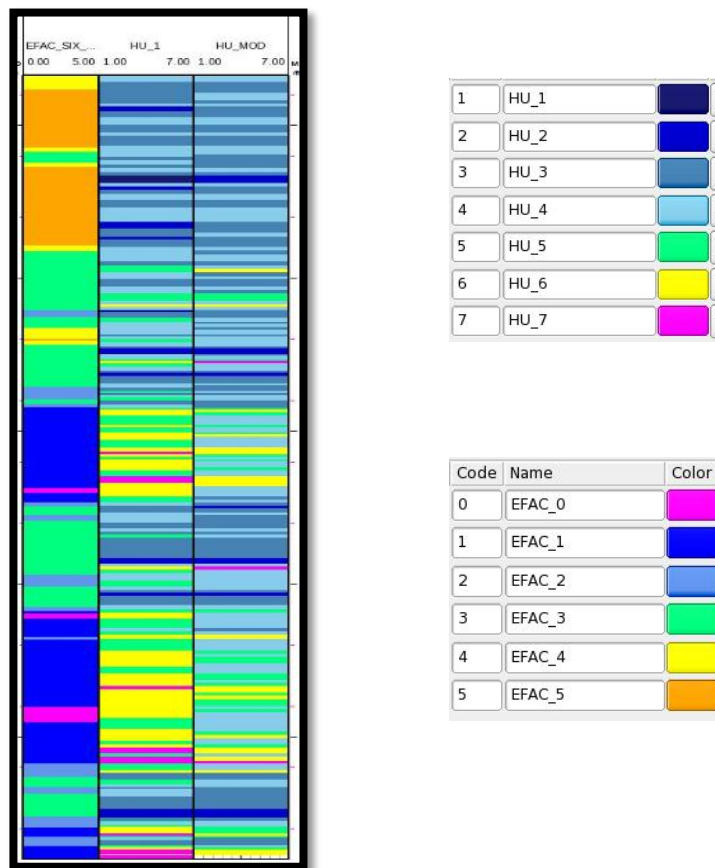
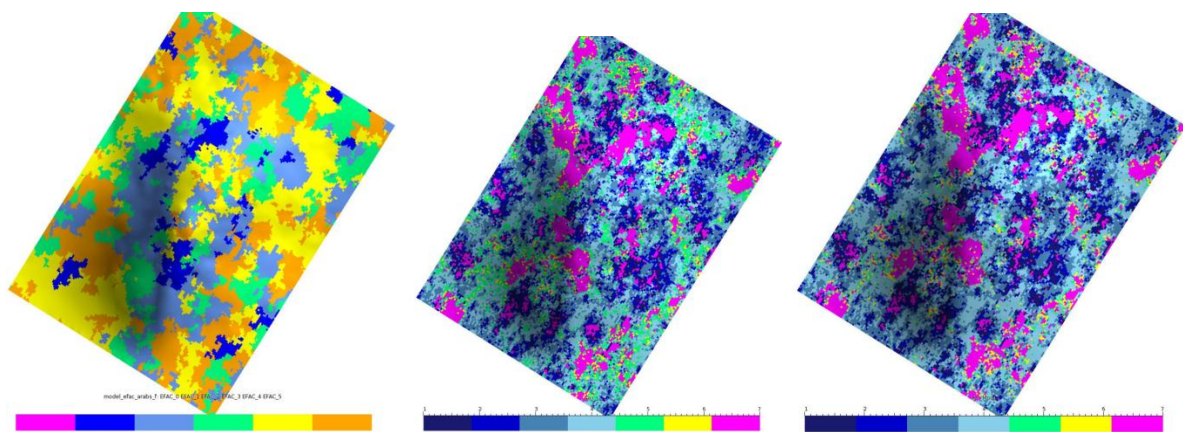Figure 5: Comparison of EFAC and HFU at well level

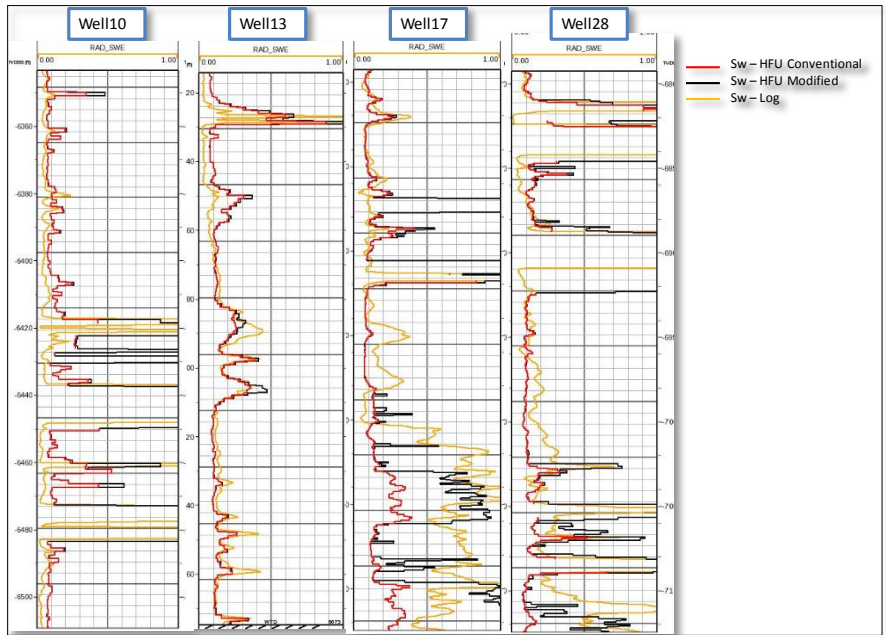Figure 6: Comparison of EFAC and HFU distribution at top layer

Figure 7: Water saturation profile comparisons between conventional HU and Proposed HU against open-hole logs