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Permeability Predication by using Capillary Pressure data in Carbonate Reservoir from Southern Iraqi oil field

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Abstract: Permeability and capillary pressures are important petrophysical properties. Permeability is one of the most important parameters for reservoir management and development. Capillary pressure data have been widely used in evaluating reservoir rock, sealing capacity, transition zone thickness, pay versus non pay, and absolute and relative permeability. We are working in this study modification two empirical models: First, Empirical model using capillary pressure curve, this empirical model that is based on Swanson proposed a simple correlation between the permeability and mercury capillary pressure, after determined the point on the mercury injection curve that represents a continuous, interconnected pore system through the rock. This model is used to prediction of permeability for each sample in the laboratory from capillary pressure data.

Second, the model is based on correlation between permeability with capillary pressure, porosity, and water saturation from well log, using well log data to derive estimates of permeability is the lowest cost method.

This correlation is same work Brown and Husseini (1977), and fitted to data from a carbonate reservoir of one Iraqi field to find the best method for estimation of formation permeability from well logs included a term of capillary pressure (Pc) in addition to water saturation (Sw) and porosity (φ). Good results are achieved through integration of Empirical models using capillary pressure curve in the laboratory and well log data in the field.

Introduction

Knowledge of reservoir porosity, permeability, and capillary pressure is essential to exploration and production of hydrocarbons. Although porosity can be interpreted fairly accurately from well logs, permeability and capillary pressure must be measured from core. Estimating permeability and capillary pressure from well logs would be valuable where cores are unavailable.This study is to correlate Core permeability with capillary pressures and other petrophysical properties to predict permeability from capillary pressure curve without measurement permeability and in well where cores are unavailable. A new proposed correlation is based on previous study after fitted to data from a carbonate reservoir in this study, and other empirical model which be used in this study to prediction of permeability from capillary pressure curve without measurement of permeability. The carbonate formation (Mishrif Formation) from one Iraqi field and two wells, which have available data, were chosen in this study, as the case study in this research, this formation sub-divided into three reservoir units: MA, MB1, and MB2.

Relationship between Capillary Pressure and other Petrophysical properties

When a capillary pressure tube is placed in a wetting fluid, pressure difference exists across the interface between wetting phase and nonwetting phase in the capillary tube. This pressure difference is called "capillary pressure" (Leverett, 1942)[1]. The capillary pressure of a reservoir increases with decreasing pore size or, more specifically, pore-throat diameter. The permeability and fluid saturations are linked through pore-size, [$k=f(r_p)$, where r_p is the effective pore radius]. Pore-size is related to the size and sorting of the particles that make up the fabric of the rock as well as to the porosity. Fluid saturations, such as water and oil saturations, are function of pore size. Permeability is a function of porosity and pore-size, Fig. (1).[2] The water saturation of a reservoir rock is therefore a function of Capillary Pressure (P_c), which in turn is controlled by pore-geometry, wettability and the height of the hydrocarbon column.

Permeability correlation with porosity and water saturation

The correlations of permeability with porosity and water saturation are limited because of the portion of the porous media that dominates permeability; porosity and water saturation are different. Permeability is dominated by the nature of the restrictions to flow, the pore throats. Porosity and water saturation are dominated by the volume within the pore bodies, not

the pore throats. Hence, correlations for permeability are inherently limited when correlated to porosity and water saturation or any other rock property that is strongly influenced by any part of the porous media other than the pore throat.[3]
In oil-bearing reservoirs the irreducible water saturation (S_{wirr}) is dependent on the pore geometry, wettability of the rock and the capillary pressure. The capillary profile leads to a transition zone between 100% S_w and the S_{wi}; this will create a gradient between R_o and R_t. If this is expressed per foot of depth then it can be related to the overall permeability of the zone.[4]

Permeability Correlation with Capillary Pressure

Washburn (1921)[5] first suggested the use of mercury injection as a laboratory method for determining the pore aperture size distribution in porous rocks, the Washburn equation can be expressed as:

$$P_c = \frac{-2\,\sigma\cos\theta}{r} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \text{(1)}$$

Thus, r (μm)= 107/P_c (psia).
The determination of permeability from electric logs and from their relation to capillary pressure are suggested by many workers.[1, 6, 7]
A mathematical expression was developed by Leveret (1942) [1] for a general relation between capillary pressure (P_c) and general properties of a porous media:

$$P_c = \left(\frac{\varphi}{k}\right)^{1/2} j(S_w)\,\sigma\cos(\theta) \quad \ldots\ldots\ldots\ldots \text{(2)}$$

When water saturation (S_w) is unity, a suitable relation was proposed by Rose and Bruce (1949).[6]

$$Pd = \sigma/(k\,F_s\,\varphi)^{1/2}\,\tau \quad \ldots\ldots\ldots\ldots \text{(3)}$$

The general relationship between P_c and Pd for all porous media is undoubtedly complex, but as a first approximation, the relationship derived by Rose and Bruce (1949) may be used. This relationship states that:

$$Pd = P_c\,S_w^{1/2} \quad \ldots\ldots\ldots\ldots \text{(4)}$$

It then follows that: [6]

$$P_c = \left(\frac{1}{k}\right)^{1/2} \frac{\sigma}{\tau\varphi^{1/2} Fs^{1/2} S_w^{1/2}} \quad \ldots\ldots\ldots\ldots \text{(5)}$$

or that,

$$k = \frac{\sigma^2}{P_c^2 F_s \tau^2 \varphi S_w} \quad \ldots\ldots\ldots\ldots \text{(6)}$$

In Eq. (6) σ may be assumed constant (50 dyne/cm^2 for gas/water and 30 dyne/cm^2 for oil/water), and since the term $F_s\tau^2$ which is known as the Kozeny constant, is usually between 5 and 100 in most reservoir rocks. The porosity (φ), S_w and P_c are calculable from log data. Thus, in terms of the parameters that are obtainable from appropriate logs, the permeability may be expressed as: [6]

$$k = \text{cons.}\ \frac{\varphi^{2m-1}}{{P_c}^2 S_w} \quad \ldots\ldots\ldots\ldots \text{(7)}$$

The above equation is modified by Brown and Husseini (1977) [7] and fitted to data from a carbonate reservoir of Lower Cretaceous age in Shaybah field in Saudi Arabia to find the best method for estimation of formation permeability from well logs included a term of capillary pressure (P_c) in addition to water saturation (S_w) and porosity (φ) where:

$$k = 57\frac{\varphi^{0.86}}{P_c^{0.89} S_w^{1.26}} \quad \ldots\ldots\ldots\ldots \text{(8)}$$

The existing other correlations from Winland-Pittman[8], Swanson[9] and Katz-Thompson[10] are tested to predict the West Texas samples permeability. The basic concept of the permeability model from capillary pressure is to use a characteristic throat size that governs the flow at the percolation threshold of the porous medium and each model uses a different method to estimate that characteristic throat size. Winland developed a power law models that relates permeability with porosity and pore throat radius and later published by Kolodzie (1980):[8]

$$k = 17.6\varphi^{1.47} r_{35}^{1.701} \quad \ldots\ldots\ldots\ldots \text{(9)}$$

Pittman (1992)[11] found that most pay zones have r_{35} values greater than 0.5µm, while most non-pay zones have r_{35} values less than 0.5um. He also extended the Winland equation by correlating pore-throat radius with porosity and permeability at different mercury saturations ranging from 10% to 75% by 5% increments. The best correlations occur at 20%-30% mercury saturation, and the accuracy decreases as saturation of mercury increases.
Swanson (1981)[9] proposed a simple correlation between the permeability and mercury capillary pressure as follow:

$$k=399\left(\frac{S_b}{P_c}\right)_{max}^{1.69} \quad \ldots\ldots (10)$$

Starting from percolation concept, Kataz and Thompson (1986)[10] have related the permeability of a porous medium to a length scale I_c , i.e.,

$$k=226\frac{{I_c}^2}{F} \quad \ldots\ldots (11)$$

where I_c is diameter of the "critical" pore-throat size that controls permeability. This pore size is inferred to correspond to the inflection point on a MICP curve or a diameter corresponding to displacement pressure (Katz and Thompson, 1986)[10].
The Winland-Pittman [8] model is modified as follow:

$$k = 102.36\frac{r_{35}^2}{F} \quad \ldots\ldots (12)$$

Swanson (1981) [9] determined the point on the mercury injection curve that represents a continuous, interconnected pore system through the rock. Swanson mentioned that at this point, "the mercury saturation expressed as percent of bulk volume is indicative of that portion of the space effectively contributing to fluid flow." Thus, this point can be used as the cutoff between microporosity (non-effective) and macroporosity (effective).

Methodology and Results

- **Capillary Pressure Measurements**

Capillary pressure cannot be measured directly in a reservoir. It can be inferred from information that indicates the height of a transition zone, such as well log information. Capillary pressure is usually determined in the laboratory that provides a relationship between capillary pressure P_c and water saturation S_w. A typical P_c vs. S_w curve has the following features, see Figs. (3 and 4):

- **The drainage P_c curve starts at S_w = 100%.**
- **Water saturation S_w decreases as oil is forced into the rock.**

The pressure required to force the first droplet of oil into the rock is called entry pressure (or threshold pressure). Thus, high permeability rocks have lower P_c than lower permeability rocks containing the same fluids.[13]
The porosity, permeability, and capillary pressure measurements were available for the plug samples. Figs. (3 and 4) depicts a plot of water saturation S_w versus capillary pressure P_c for each value from permeability for the core samples of the well NR18 and NR19.
Capillary pressure in laboratory can be converted to reservoir capillary pressure by using equation (Hartmann, 1997):[14]

$$P_{c\,Res} = \frac{P_{c\,lab}\,(\sigma.\cos\,\theta)_{Res}}{(\sigma\,.\cos\,\theta)_{Lab}} \quad \ldots\ldots (13)$$

Thus, the term $(\sigma.\cos\theta)_{Res}$) in (oil- water) equal to 26 and the term $(\sigma.\cos\theta)_{lab}$) when mercury injection equal to 367 and Eq.(13) became:

$$P_{c\,Res} = P_{c\,lab}\left(\frac{26}{367}\right) = P_{c\,lab}\,(0.071) \quad \ldots\ldots (14)$$

The results of values of capillary pressure that is convert from laboratory conditions to reservoir conditions are shown in Table (1).
The capillary pressure in a hydrocarbon reservoir is a function of the difference between the pressure in the water and hydrocarbon phases. The reservoir elevation (depth) above the free water level may be converted to capillary pressure values through the application of the equation: [15]

$P_c = h\,(\rho_w - \rho_h)\,(3.281)\,(0.433)$ ………………………………….. (15)

We need to identify the oil water contact which is characterized by an increase in resistivity and the Rxo-Rt departure in logarithmic scale in the other cases.[15]

- **Prediction of permeability from Capillary pressure data:**

Prediction of permeability in this study from two models:
First, Empirical model using capillary pressure curve:
Swanson (1981) determined the point on the mercury injection curve, this point corresponds to the apex of the hyperbola of a plot of log –log Pc vs. Sb. Fig.(3 and 4) show the results of the plot P_c vs. S_w from core data for wells in this study and determined the point corresponding to the apex of the hyperbola, from this point we can be used modified Swanson's model to prediction of permeability for each sample after using regression analysis to determine the coefficients and fitted to the data carbonate reservoir in this study. Table (2) shows the coefficients of the modified Swanson's model for each well in this study and Table (3) show results of permeability values that determined from modified Swanson's model and core permeability values.
Second, empirical model using well log measurements data:
One benefit of using wireline log data to estimate permeability is that it can provide a continuous permeability profile throughout a particular interval.

The modified of the following relationship that be used to predict the permeability in carbonate reservoir in this study:

$k = a\,\frac{\varphi^b}{P_c^d S_w^c}$ …………………………………………….. (16)

Using water saturation S_w, capillary pressure P_c, and porosity(φ) as independent variables, and permeability as the dependent variable, nonlinear estimation using regression analysis was employed to find the optimum equation for permeability prediction for each reservoir unit in the carbonate formation for wells of the case study.
Table (4) shows the coefficients for each unit in the carbonate formation (Mishrif Formation).
Figs. (5 and 6) show the profile between calculated permeability from modified Eq. (16) for each reservoir unit in this study and that give good results and good matching.

Conclusions

- We can be converting the depth above the free water level (FWL) to capillary pressure after determined water and hydrocarbon density and detecting oil- water contact.
- From point the apex of the hyperbola of a plot of P_c vs S_w, we can be used modified Swanson's model to prediction of permeability for each sample in the laboratory without measured permeability in the laboratory after using regression analysis to determine the coefficients and fitted to these samples.
- Using wireline log data to estimate permeability after converting the depth above the free water level (FWL) to capillary pressure, that it can provide a continuous permeability profile throughout a particular interval.

Symbols

r: is the pore-size (μm),
k: is the permeability (μm^2; 1 md = 9.871 x 10^{-4} μm^2)
φ: is the porosity (fraction).
P_c = capillary pressure ($dynes/cm^2$),
σ= surface tension of Hg (480 dynes/cm),
θ = contact angle of mercury in air (140^o), and,
$j(S_w)$ is the Leveret's capillary pressure function.
Pd: is the displacement pressure (psi),
τ: is the tortuosity,
F_s: is the effective pore throat shape factor,
r_{35} is the pore radius corresponding to 35% mercury saturation.
S_b is the mercury saturation in present bulk volume.

P_{cRes} : reservoir capillary pressure .
P_{cLab} : laboratory caplilry pressure.
ρ_w: is the formation water density (g/cc),
ρ_h: is the hydrocarbon density (g/cc),
h: is the height above the free water level (FWL) in m (difference between free water level and depth of the sample).

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Table (1): Results of the laboratory capillary pressure converted to reservoir conditions.

NR18		NR19	
Pc Lab.	Pc Resev.	Pc Lab.	Pc Resev.
0	0	0	0
1.6	0.1136	1.6	0.1136
2.5	0.1775	3	0.213
4	0.284	5	0.355
8	0.568	8	0.568
15	1.065	15	1.065
30	2.13	30	2.13
45	3.195	45	3.195

Table (2): The coefficients of the modified Swanson's model

NR18		NR19	
a	b	a	b
396	1.88	392	2.61

Table (3): Results of the permeability from the modified Swanson's model and compared with core sample permeability.

Well NR18			Well NR19		
apex	k cal.	k meas.	apex	k cal.	k meas.
0.16347	13.2512	13	0.16693	3.47314	2.2
0.22161	23.48	25	0.18349	4.46234	3.2
0.23408	26.0251	28	0.21534	6.81937	6.8
0.27874	36.1368	32	0.25467	10.6366	10.7
0.35654	69.8303	72	0.30587	17.2834	18
0.41338	89.6596	93			
0.48451	117.258	119			

Table (4): The empirical parameters for equation (16)

	Unit-MA				Unit-MB1				Unit-MB2			
Well No.	a	b	c	d	a	b	c	d	a	b	c	d
NR18	2436	2.2	0.7	0.37	2422	2.1	0.65	0.7	2427	3.3	0.72	0.5
NR19	2520	3.1	0.78	0.56	2480	2.8	0.9	1.02	2360	2.9	0.8	0.96

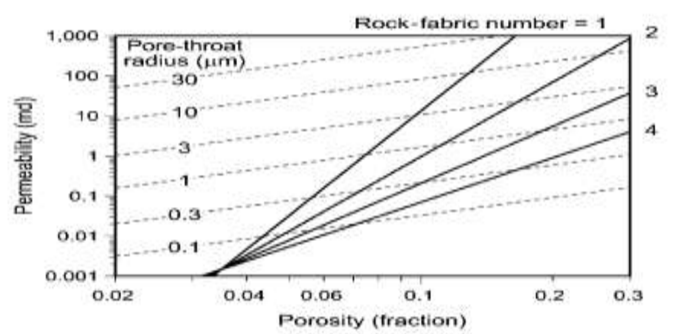
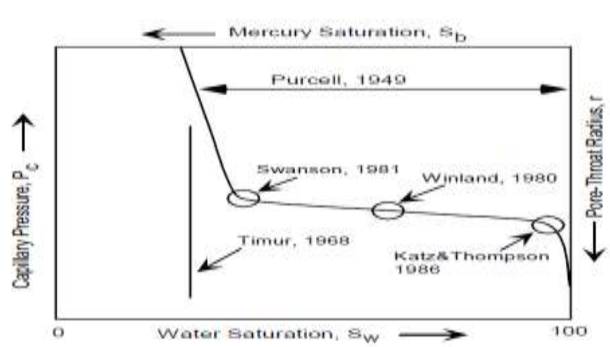


Figure (1): Variations of pore-throat size with permeability and porosity. (After Lucia, 2007) [2]



Figure(2): An idealized capillary pressure curve showing used by different aurthors for determination of characteristic pore dimension (modified from Nelson,1949).[12]

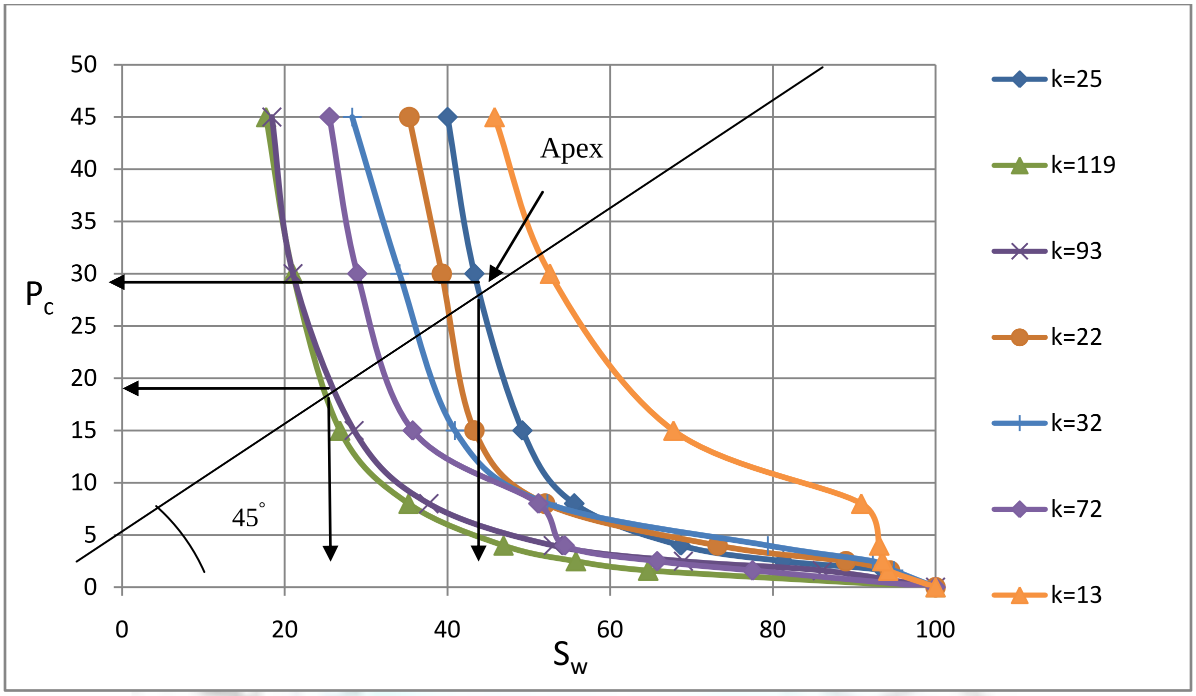


Figure (3): Capillary Pressure Relation with Water Saturation for well NR18

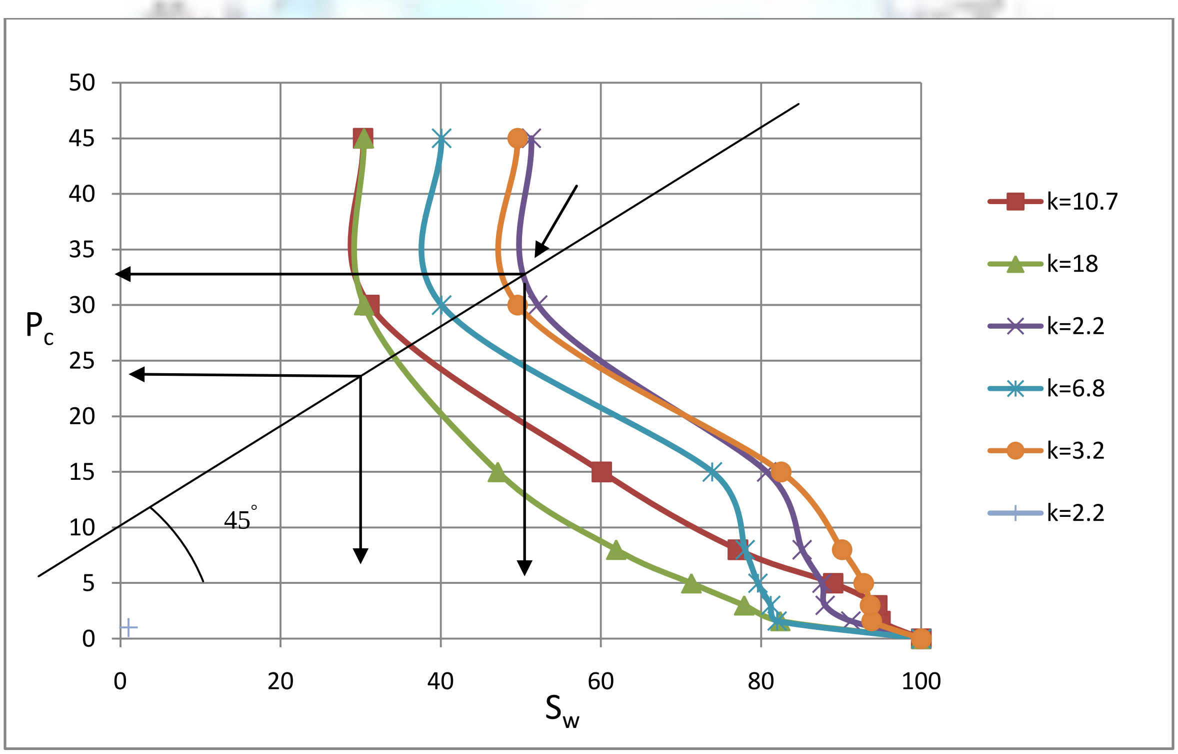
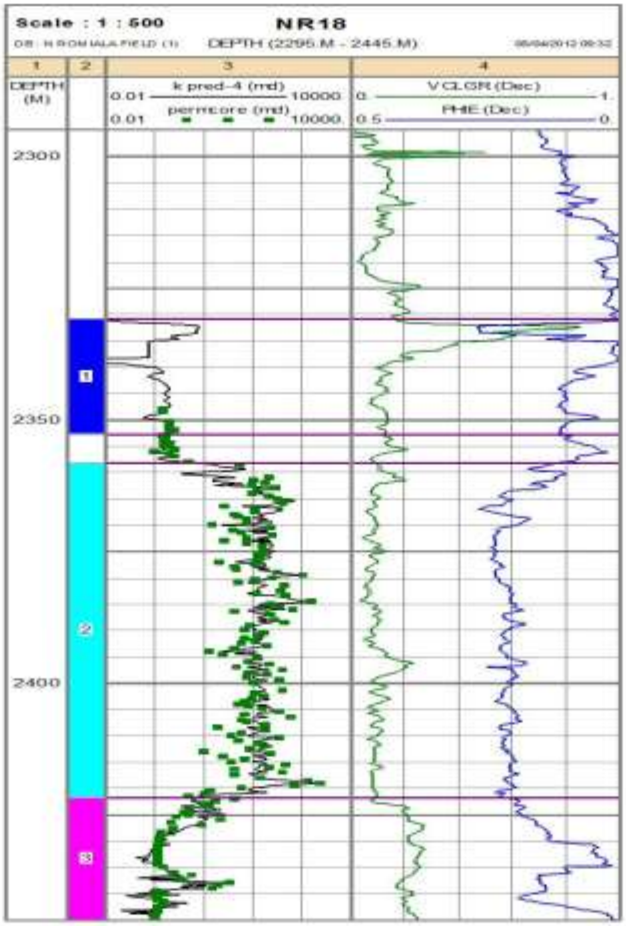
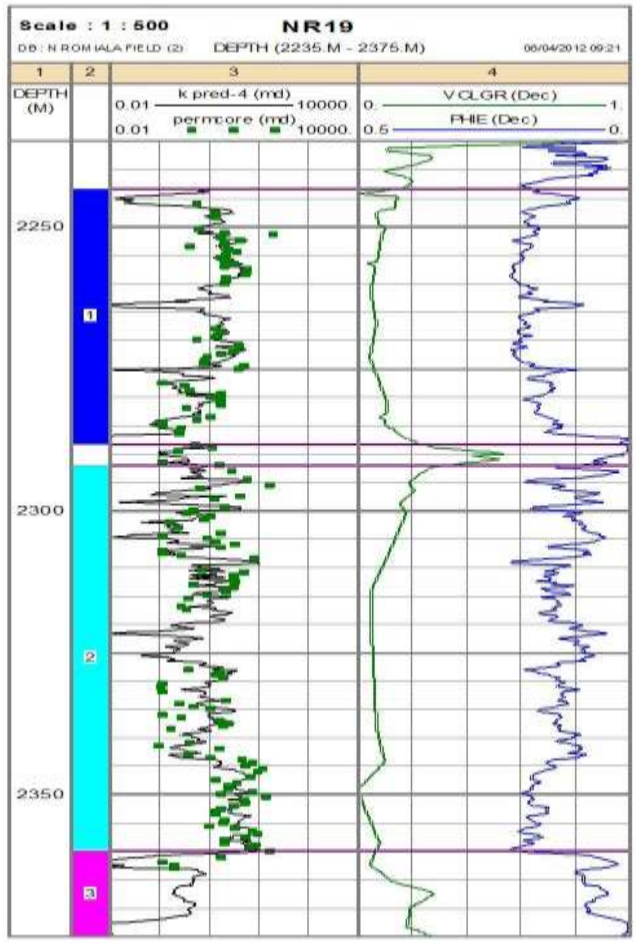


Figure (4): Capillary Pressure Relation with Water Saturation for well NR19





Figure(5): Predicted and measured permeability for wells: NR18 and NR19, by using Eq.(16) with coefficient in the table (4).