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Construction of Capillary Pressure and Relative Permeability by Using NMR Data for Sarvak Formation in SW Oil Fields of Iran

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Abstract

Determining and estimating reservoir properties such as capillary pressure and relative permeability are always challenging in reservoir studies. The current research has been done in the Sarvak Formation in the southwestern oilfields of Iran, focusing on applying Nuclear Magnetic Resonance (NMR) logging in synthesizing capillary pressure and relative permeability. In this study, the Sarvak Formation in the studied well was divided into three flow units using the Hydraulic Flow Unit method. Then, for each separate flow unit, the capillary pressure curves were calculated and illustrated from the NMR T2 distribution data. Next, the calculated capillary pressure curves were corrected concerning the laboratory capillary pressure data derived from SCAL. Then, the conversion factor to calibrate well log-derived Pc curves to SCAL Pcs was determined for each flow unit. Afterward, mathematical functions for capillary pressure curve estimation were written using MATLAB software. Next, the relative permeability for oil and water phases was calculated and plotted in MATLAB software based on the functions determined in the previous step. Finally, the representative capillary pressure curve and relative permeability curve of the oil and water phases were determined for each flow unit. The results showed an increasing trend in the reservoir quality from flow units 1 to 3. Flow unit 3 had the lowest capillary pressure with the highest relative permeability and, consequently, better reservoir quality. In contrast, flow unit 1 had the highest PC levels, the lowest relative permeability, and the lowest reservoir quality.

Keywords: Nuclear Magnetic Resonance, NMR, Relative Permeability, Capillary Pressure, Sarvak Formation.

Introduction

The construction and usage of the NMR tools in oil studies caused a vast revolution in reservoir studies and the calculation of important reservoir quality parameters. The NMR logging is based on the nuclear response of the atoms to the magnetic field of the drilling tool, which is tracked and recorded as measurable signals by the drilling tool. Compared to other atoms, the hydrogen atom, having only one proton in its atomic nucleus, produces the most prominent measurable signal, which can be easily recorded and measured by magnetic resonance imaging tools [1]. The NMR data are independent of the well conditions, lithology, and matrix; as a result, the curves obtained from the measurements of this log represent the body of the pores and the type of fluids in those pores. On the other hand, well-logs such as sonic, neutron, and density are sensitive to the matrix of formations and are affected by well and mud cake conditions. Therefore, the response recorded by such tools needs environmental corrections, and they are not fully representative of the studied Formation's porous media [1]. As a result, compared to conventional logs such as neutron, density, and resistance, the NMR log provides researchers with a more reliable estimate of the essential properties of a reservoir, such as porosity, permeability, water saturation, characteristics of pores filled with fluid, and pore throats. On the other hand, due to the special conditions of some wells, especially those drilled in loose formations, and the high cost of coring with a time-consuming process, there are many limitations in the accessibility of core and SCAL data from all wells in one field. Therefore, for calculating the reservoir parameters of the target sequences, the Nuclear Magnetic Resonance log is one of the most important tools for this aim due to the different nature of its output data compared to the mentioned logs.

Extensive studies have been conducted on the calculations of capillary pressure [2-4]. The studies conducted by the mentioned researchers focus on the different methods of calculating the capillary pressure using the NMR logging

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data. In another research conducted by Volkitin et al. in 2001 and Eslami et al., the capillary pressure curves were calculated using both NMR and conventional logging data such as resistance, neutron, and sonic [5, 6].
Studies conducted by Kadkhodaie et al. and Hosseinzadeh et al. in recent years also focus on the methods of NMR data to calculate capillary pressure and relative permeability [7, 8]. The independence of NMR output data from the effects of well conditions and lithology of the Formation, and the continuous recording of the properties of the studied Formation along the entire length of the drilled well, are the advantages of using this log for capillary pressure and relative permeability calculations. On the other hand, the capillary pressure and relative permeability data have been accessible from SCAL. Still, the possibility of recording the well data along the entire length of the drilled wells makes it possible to record and measure these important reservoir properties completely. Therefore, the main goal of this study is to focus on the calculation of capillary pressure and relative permeability using NMR logging data in one of the wells of the Anaran Block.
This study aims to determine flow units and calculate each flow unit's capillary pressure and relative permeability using NMR logging data. Flow units were first determined using core porosity and permeability data to achieve this goal. Then, for each separate flow unit, the capillary pressure curves were calculated and illustrated using the NMR T2 distribution data. In the following, the calculated capillary pressure curves were correlated with those obtained from SCAL to correct the calculated curves. After correcting the calculated capillary pressure curves, the Conversion factor (C) was determined for each flow unit.

Geological Setting

The Anaran block is one of the exploration areas of the National Iranian Oil Company, which is spread along the Iran-Iraq border and from the northwest of Cheshmekhosh field to Mehran city, with a length and width of approximately 140 and 40 kilometers. In terms of topography, this block is in the western areas of the mountainous Zagros region (Anaran Mountains) with a height of 1900 meters to the flat lands of Mesopotamia with a height of fewer than 100 meters. In 2013, with the drilling of exploratory well No. 2 (the drilling of well No. 1 was not successful in this field) by Hydro Zagros Company of Norway, the presence of oil-type hydrocarbons was proved.
The studied oilfield is an anticline with a northwest-southeast trend in the northwest end of the mentioned block and is a shared oilfield with Iraq, known as the "Badra" field (Figure 1). The surface outcrop of this field is Aghajari Formation, and its reservoir is the Bangestan Group, including upper and lower Sarvak. According to the latest studies, this field's hydrocarbon is estimated to be 2.4 billion oil barrels with an API of 31.48 and a GOR of 1100 [9].
Sarvak Formation is one of the limestone formations of the Bangestan group, and in the past, it was known as rudist limestone and Lashtakan limestone. This Formation has shallow facies in the type section and Coastal Fars and deep facies in the Lorestan region [10]. Sarvak has two members including Maudod and Ahmadi Shale. The Maudod limestone unit in Iran is a thick layer of Orbitolina-bearing limestone overlying the Kazhdumi formation. The Ahmadi shale section in Iran is a gray shale of the Cenomanian age, which is inclined on the Maudod limestone section and alternately underlies the Ilam Formation [10].
The surface outcrop of the target area includes the Lahbari member of the Aghajari formation and the Bakhtiari conglomerate. Subsurface units include the Bangestan group (Sarvak, Surgah, and Ilam Formations) and Gurpi, Pabdeh, Asmari, Gachsaran, and Aghajari Formations [9].

Methodology

Rock Types

Determining rock types in reservoirs is the process of generalizing reservoir characteristics (dynamic behavior) to geological facies [11]. In this process, geological facies are described and characterized by their dynamic behavior [12]. Combining sedimentary characteristics of reservoir rocks with their petrophysical and dynamic features, such as capillary pressure, relative permeability, and wettability, rock types representing the same ability to store and transfer fluids are defined as flow units.

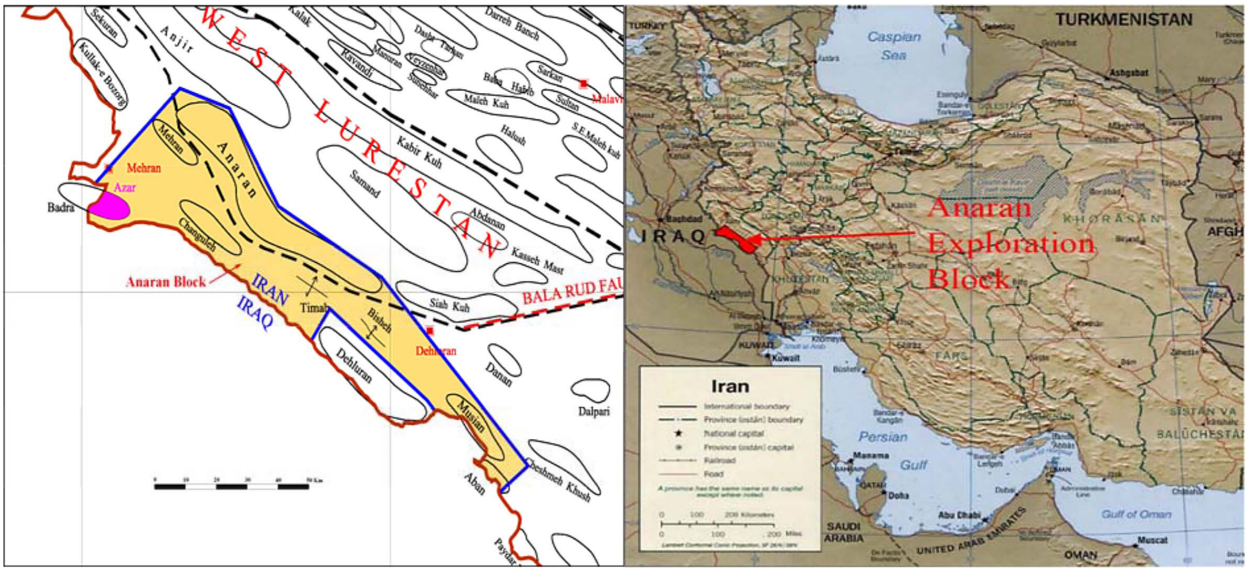

Fig. 1 The location of the Anaran block in the west of Iran [10].

The Hydraulic Flow Unit Index method, is one of the most widely used methods for determining rock types. Amaefule and his colleagues introduced the concept of reservoir quality index to define the pattern of flow units [13]. It is possible to define adaptable flow units in the reservoir in terms of the relationship between the pore volume (ε) and the reservoir quality index (RQI) [14] (Equation 1):

$$\log RQI = \log FZI + \log \varepsilon \quad (1)$$

$$\varepsilon = \frac{\varphi}{1-\varphi} \quad (2)$$

$$RQI = 0.0314\sqrt{\frac{k}{\varphi}} \quad (3)$$

$$FZI = {}^{RQI}\!/_{\varepsilon} \quad (4)$$

where φ is porosity (frac.), k is permeability (mD), and ε is the ratio of pore volume to matrix volume.

Capillary pressure curves estimation

The concept of capillary pressure can be used to evaluate reservoir rock quality, fluid saturation and fluid boundary depth, gradient zone thickness, barrier capacity, and the net-to-gross ratio [15]. In addition, capillary pressure is also one of the essential parameters in reservoir recovery, especially fractured reservoirs [16].

Capillary pressure is created due to the curvature of the wetting and non-wetting fluid interface and is defined as the pressure difference at the interface of two immiscible fluids [16] (Equation 2):

$$P_c = P_{nonwettingfluid} - P_{wettingfluid} \quad (5)$$

Capillary pressure reflects the mutual effect of rock and fluids, which is affected by pore geometry, pore size distribution, surface tension, and wettability. According to the Young-Laplace equation [17], capillary pressure is directly proportional to surface tension (σ) and is inversely proportional to the effective radius (r) of the interface between two fluids. Capillary pressure also depends on the wetting angle (θ). The vertical capillary pressure is expressed as follows:

$$P_c = \frac{2\sigma\cos\theta}{r} = gh(\rho_1 - \rho_2) \quad (6)$$

where g is the gravitational acceleration, h is the height of the liquid column, and ρ1 and ρ2 are the fluid densities.

In Figure 2, the comparison of the T2 distribution of the rock saturated with brine with pore size distribution related to the mercury injection test can be seen. As is seen, after effective surface relaxivity and transferring the pore size distribution obtained from the mercury injection test, it matches well with the NMR T2 distribution.

T2 distribution curves obtained from NMR represent the volume of the pore body, while laboratory capillary pressure curves represent the pore throats. The concept of surface relaxivity is also defined based on this difference. This difference in larger pores is less than in smaller pores. Therefore, by applying a constant coefficient, the measurements of NMR-derived capillary pressure and capillary pressure from SCAL can be matched with the lowest error [18]. In this way, it is possible to use NMR data in zones where SCAL data is unavailable.

According to T2 surface relaxivity:

$$\frac{1}{T_2} = \frac{1}{T_{2B}} + \rho_2\left(\frac{s}{v}\right) + \frac{D(\gamma GTE)^2}{12} \quad (7)$$

where T2B is the transverse relaxation time of pore fluid (ms), ρ_2 is surface relaxivity (mμ/ms), S/V is the ratio of pore surface to fluid volume, D is the molecular diffusion coefficient (mμ²/ms), G is the field-strength gradient (gauss/cm), TE is inter-echo spacing (ms), and γ is gyromagnetic ratio of a proton. Due to the uniformity of the value of G and the shortness of TE as well as T2B>>T2, the first and third terms in the above equation can be omitted and rewritten as follows.

$$\frac{1}{T_2} = \rho_2\left(\frac{s}{v}\right) \quad (8)$$

According to the above equation, the transverse relaxation time depends on the surface-to-volume of the pore body ratio. If the pore body is considered a describable geometric shape, the equation would be:

$$\frac{1}{T_2} = \rho_2\left(\frac{s}{v}\right) = \rho_2\frac{F_s}{r_c} \quad (9)$$

where Fs is the shape factor, and rc is the pore radius.

On the other hand, according to the capillary pressure equation:

$$P_c = \frac{2\sigma C\,os\theta}{r_c} \quad (10)$$

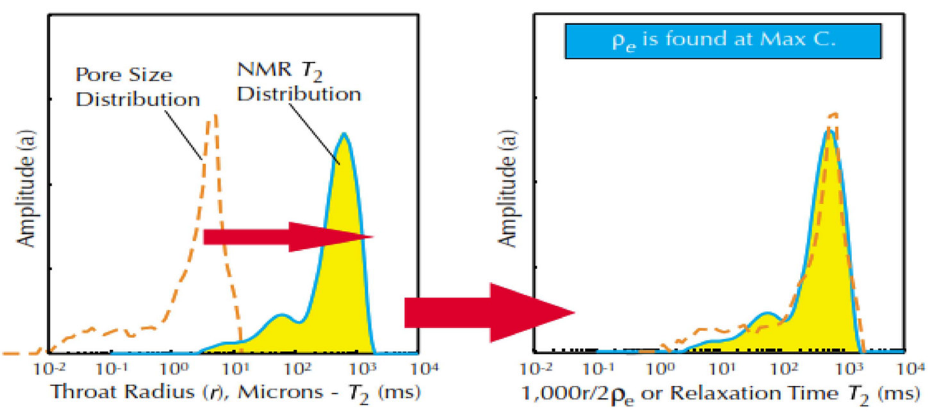

Fig. 2 Through applying an appropriate conversion factor, NMR-Dervived T2 distibution can be concerted to core-derived caplillary pressure or its corresponding pore throat size distribution [18].

$$P_c = \frac{2\sigma C\,os\,\theta}{r_c} \approx \rho_2 \times T_2 \times F_s \tag{11}$$

As a result:

$$P_c = C \times \frac{1}{T_2} \tag{12}$$

The coefficient C in the above equation is called the calibration or conversion factor [19 - 21].

First, the cumulative sum of all 30 T2 distribution bins was calculated to obtain NMR-derived capillary pressure curves. Next, cumulative sums obtained for all depths were normalized between zero, and 100The curves obtained in this step are the initial and uncorrected curves that should be corrected in the following steps with laboratory capillary pressure data and curves.

Relative permeability curves estimation

The first step to calculate the relative permeability is to obtain the mathematical functions of the modified capillary pressure curves in the previous step using MATLAB software. These functions are different and unique for each sample. Still, the shape of the curves was similar. Therefore, a type of function with different and unique variables was used for each sample for ease of calculation. The functions of the capillary pressure curves obtained in the following formulas [22] must be calculated. The following formulas were coded in MATLAB and Excel software for this purpose. The relative permeability was calculated for each sample at the depth from which the data of core tests were available.

$$K_{rw} = \left(\frac{S_w - S_{wc}}{1 - S_{wc}}\right)^2 \times \frac{\int_{S_{wc}}^{S_w} \frac{1}{P_c^2} dS_w}{\int_{S_{wc}}^{1} \frac{1}{P_c^2} dS_w} \tag{13}$$

$$K_{rnw} = \left(\frac{1 - S_w}{1 - S_{wc}}\right)^2 \times \frac{\int_{S_{wc}}^{1} \frac{1}{P_c^2} dS_w}{\int_{S_{wc}}^{1} \frac{1}{P_c^2} dS_w} \tag{14}$$

where Sw is the water saturation, Swc is the connate water saturation, Pc is the capillary pressure, Krw is the relative permeability of the water phase, and Krnw is the relative permeability of the oil phase.

The binomial, exponential function was used to calculate the relative permeability in MATLAB software, which had the best compatibility with the available data. The general equation is as follows.

$$f(x) = a * \exp(b * x) + c * \exp(d * x) \tag{15}$$

where f(x) is equivalent to capillary pressure (Pc), x is equivalent to water saturation (Sw), and *a*, b, *c*, and d are constant numbers.

Afterward, NMR-derived relative permeability curves were calibrated to core-derived Kr curves. Finally, the synthetic Kr curves for oil and water were calculated for the whole interval for which NMR data were available. After calculating the relative permeabilities, a representative curve was determined for each flow unit by averaging all computed permeability curves.

Results and Discussion

The Sarvak Formation in the studied well was divided into three flow units using the method of hydraulic flow units to reduce the effect of heterogeneity and obtain homogeneous groups for performing calculations in the following steps. According to the porosity and permeability curve shown in Figure 3, all three calculated flow units have a high coefficient of determination indicating the homogeneity of the flow units. Therefore, the more homogeneous the flow unit is, the accuracy of calculations related to capillary pressure and relative permeability will also improve.

Based on calculations, flow unit 1 has the highest permeability to porosity ratio, while flow unit 3 has the lowest value. Therefore, flow unit 1 has the best reservoir quality. In the following, the reservoir quality of these units is examined based on the saturation versus mercury injection pressure curves.

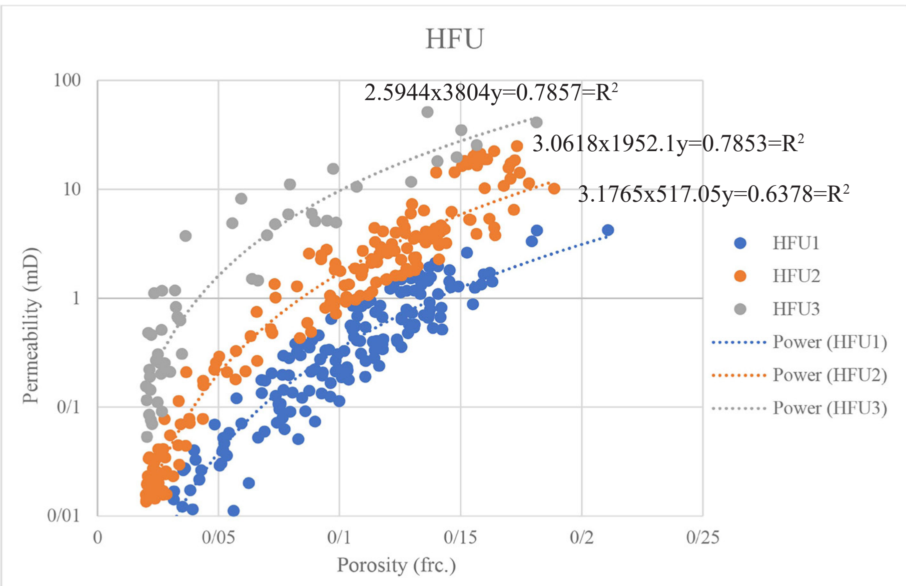

Fig. 3 The permeability vs. porosity for three flow units with a high coefficient determined by the HFU method.

The capillary pressure curve was calculated and illustrated using NMR logging data for all three flow units. Then, each flow unit's representative capillary pressure curve was correlated and corrected with the corresponding capillary pressure curves obtained from SCAL. The correction of NMR-derived capillary pressure curves was done to reduce the difference between the calculated curves and the SCAL data. As mentioned earlier, the NMR data represent the pore properties of the Formation, while the SCAL data indicate the condition of pore throats. Therefore, it is necessary to correct the calculated curves to reduce the difference between the data and increase the accuracy of calculations. After correcting the curves, a conversion factor is determined, equal to 370, 435, and 620 for flow units 1 to 3, respectively. As shown in Figure 4, the closer the capillary pressure curve is to the letter L, the better the reservoir quality is. Also, with the decrease of the transition zone, the permeability of the units increases. The closer the shape of the capillary pressure curve is to the letter L, and the smaller the gradual zone, the higher the quality compared to other curves. The capillary pressure curve of flow unit 3 after correction, compared to the capillary pressure curves of flow units 1 and 2, is most similar to the letter L. Also, this flow unit has the lowest transition zone and irreducible water saturation. As a result, the reservoir quality increases from flow unit 1 to flow unit 3. These results are consistent with the core porosity and permeability data results showing flow unit 3 has a higher quality than the other two flow units.

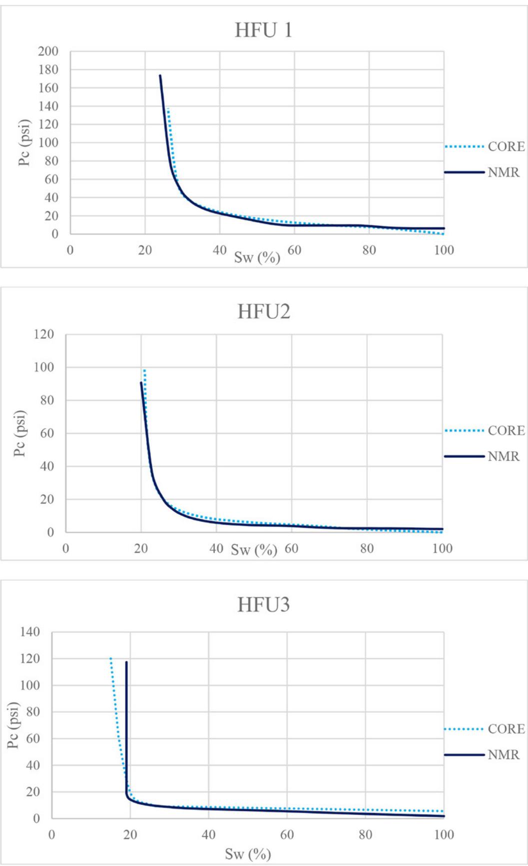

Fig. 4 The compatibility of the capillary pressure curves, obtained from SCAL and the NMR-derived capillary pressure curves, with corresponding calibration coefficients (C) of 620, 435, and 370 calculated for each sample flow unit.

In the next step, the equation of corrected curves was determined to calculate relative permeability using MATLAB software. Finally, the relative permeability for oil and water phases was calculated and plotted for each flow unit (Figure 5). According to the calculated and illustrated curves, the quality of relative permeability increases from flow units 1 to 3. And the intersection points of the water phase's relative permeability curve and the oil phase's relative permeability curve in flow unit 3 are at lower water saturation values than flow units 1 and 2. Therefore, flow unit 3 has the highest relative permeability and reservoir quality compared to flow units 1 and 2.

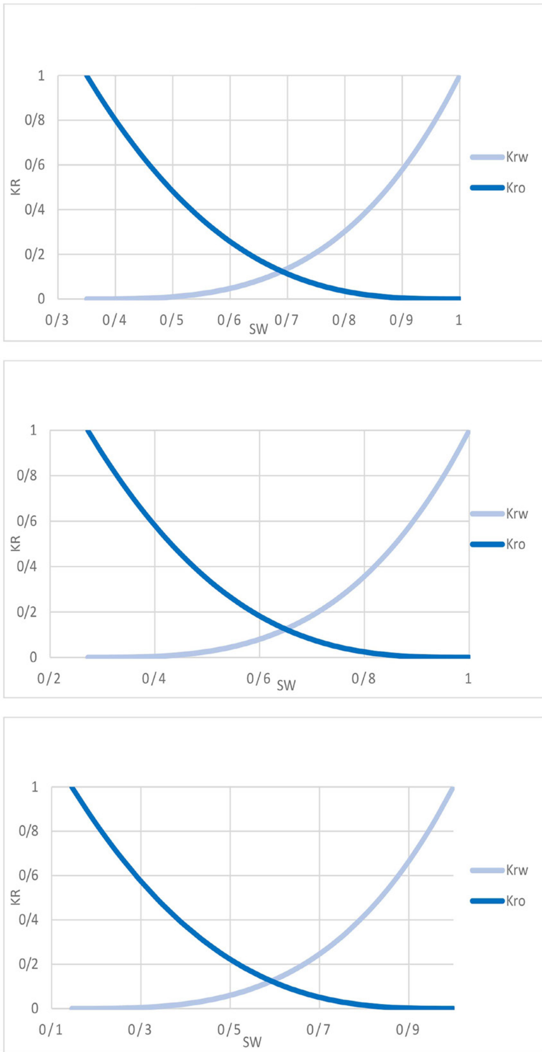

Fig. 5 Relative permeability curves calculated using MATLAB software.

Conclusion

The Sarvak Formation in the studied well was divided into three flow units by hydraulic flow unit method. Then the capillary pressure curves were calculated and illustrated using NMR data for each flow unit. Next, the curves obtained from NMR were corrected with laboratory capillary pressure curves for a more accurate estimation of the required function in the stages of relative permeability calculation. Then, the function of illustrated curves was extracted using MATLAB software. In the next step, the relative permeability of the oil and water phases for each flow unit was calculated with MATLAB software.

According to the results, the reservoir quality increased from flow unit1 to 3. Furthermore, based on the shape of the calculated capillary pressure curves, the closer the shape of the capillary pressure curve was to the letter L, the better the reservoir quality was. Also, with the decrease of the transition zone, the permeability of the flow unit increases.

Finally, according to the results of the calculations, it can be concluded that NMR successfully estimated capillary pressure and relative permeability curves for the Sarvak reservoir. The methodology described in this study can be used to estimate Pc and Kr curves for all carbonate and clastic reservoirs.

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