In situ estimation of relative permeability from resistivity measurements

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ABSTRACT: Relative permeability is one of the key parameters governing fluid flow through porous media. Determination of relative permeability is traditionally conducted in the laboratory using either recombined reservoir oil or laboratory oil at simulated reservoir conditions, or simply at laboratory conditions. This is because it is expensive to sample representative uncontaminated reservoir fluids and extremely difficult to cut reservoir cores without altering their surface properties. Restoring rock properties to their original reservoir conditions has been a technical challenge to the industry. Upscaling laboratory special core-analysis data to reservoir scale is also a concern. Consequently, the industry has been researching new methods to extract relative permeability *in situ*, including the utilization of specially designed permanent downhole electric resistivity array, pressure and flow rate measurements. In this study, a different approach was taken. A semi-analytical model, developed to infer relative permeability from resistivity, was verified using experimental and field data. Relative permeability and resistivity were measured simultaneously in the laboratory. The results demonstrated that relative permeability derived from measured resistivity was close to the measured relative permeability. Relative permeability calculated from resistivity logs in two wells was compared to measured relative permeability with encouraging results.

INTRODUCTION

Relative permeability is required in almost all aspects of reservoir engineering dealing with fluid flowing through porous media. However, relative permeability is expensive, difficult and time-consuming to measure in the laboratory. It is also difficult to maintain exact reservoir conditions in taking a core or a fluid sample from the reservoir and bringing it to surface, and it is almost impossible to conduct the measurements in real time (DiCarlo *et al.* 2000; Hui & Blunt 2000). Consequently, there has been a decades-long research effort to develop methods and procedures to infer relative permeability using network modelling (Fatt 1956; Bryant & Blunt 1992; Heiba *et al.* 1992; Blunt 1997; Dixit *et al.* 1998; Mahmud *et al.* 2007) or from other parameters, such as capillary pressure (Purcell 1949; Brooks & Corey 1966; Li & Horne 2006) and resistivity data (Pirson *et al.* 1964; Li 2008, 2011). Recently, the industry has researched new methods to extract relative permeability *in situ* by using specially designed permanent downhole electric resistivity array measurements (Kuchuk *et al.* 2008).

In contrast to measurements of relative permeability, it is relatively uncomplicated to measure resistivity in both the laboratory and reservoirs (Li & Williams 2006). A great many resistivity measurements are available from well logs, even in real time (Ali *et al.* 2007). Obviously, it would be helpful if relative permeability could be inferred from resistivity log data so that enhanced reservoir engineering studies, such as reservoir characterization, based on flow units (Amaefule *et al.* 1993) could be performed. A brief literature review is presented here.

Pirson *et al.* (1964) proposed models to calculate relative permeability from resistivity and tested their models using experimental data. They found that the originally derived models did not fit the experimental data and then tuned the models with different correction coefficients in different cases. For example, the models for gas–liquid were different from those for oil–water. Toledo *et al.* (1994) discussed the theoretical models of water relative permeability and electrical conductivity as a function of the wetting-phase saturation, but did not verify the models using any experimental data. Li (2008) derived a model to infer relative permeability from the resistivity index. The relative permeabilities calculated from resistivity were close to those calculated from capillary pressure for Berea Sandstone and a limestone. Later, the relative permeability models proposed by Li (2008) were verified directly by comparing them to laboratory measurements (Li 2011).

In this article, we measured both resistivity and relative permeability simultaneously in core plugs from an oil well at a specific series of depths. Then we calculated the relative permeability with the models proposed by Li (2008), using both laboratory resistivity measurements and resistivity logs from the same well. Finally, we compared the modelled relative permeability with the experimental data in order to verify further the approach to inferring relative permeability from resistivity data. The novelty of this study over the earlier paper (Li 2008) is stated briefly as follows. It is the first time that relative permeability has been computed using field data (resistivity log data) and compared with the experimental relative permeability data

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measured in the rocks sampled from the formation where the resistivity logging was conducted. Previously (Li 2008), it was only verified that the values of relative permeability inferred from resistivity index data are almost equal to those calculated from experimental capillary pressure data, rather than measured relative permeability data. In the current study, however, both oil and water relative permeability data were directly measured using the unsteady-state method, instead of being calculated indirectly from the capillary pressure data.

CALCULATION OF RELATIVE PERMEABILITY FROM RESISTIVITY

In this study, water relative permeability was calculated from resistivity using the model reported by Li (2008). This model correlates the wetting-phase relative permeability, k_{rw}, with the wetting-phase saturation (water in this study), S_w, and resistivity index, I (for the nomenclature used in this paper see Appendix Table 1). Relative permeability is the ratio of the effective permeability of one phase to the absolute permeability of the porous medium. Resistivity index is defined as the ratio of the resistivity of the rock partially saturated with water to that of the rock completely saturated with water. The model reported by Li (2008) is expressed as:

$$k_{rw} = S_w^* \frac{1}{I} \tag{1}$$

where S_w^* is the normalized wetting-phase saturation, defined as:

$$S_w^* = \frac{S_w - S_{wir}}{1 - S_{wir}}. \tag{2}$$

Here, S_{wir} is the residual wetting-phase saturation. From equations (1) and (2), k_{rw} can be calculated as a function of S_w if S_{wir} and I are given.

The similarity between fluid flow in a porous medium and electricity flow in a conductive body is the main theory on which equation (1) is based (Li 2008). According to equations (1) and (2), k_{rw}=1 at S_w=100% and k_{rw}=0 at S_w= S_{wir}, which is as expected. Li (2008) demonstrated that the values of the non-wetting-phase relative permeability, inferred from the resistivity index data, are almost equal to those calculated from the experimental capillary pressure data. For the wetting-phase relative permeability, the values inferred from the resistivity index are close to those calculated from capillary pressure in most of the cases studied by Li (2008). The approach to calculating the wetting-phase relative permeability from capillary pressure was the Brooks–Corey capillary pressure model (Brooks & Corey 1966). Later Li (2011) verified that the water relative permeability data calculated from resistivity index data, using equation (1), were almost equal to the experimental data at the same water saturation. The detailed theoretical derivation of equation (1) was reported in Li (2008).

From Purcell (1949) and Li & Horne (2006), k_{rw} may also be expressed as:

$$k_{rw} = (S_w^*)^{\frac{2+\lambda}{\lambda}} \tag{3}$$

where λ is the pore size distribution index. The value of λ can be determined using equation (3) once the wetting-phase relative permeability data are calculated using equation (1) with resistivity data.

Based on Brooks & Corey (1966) and Li & Horne (2006), the non-wetting-phase (oil in this study) relative permeability in the drainage process, k_{rnw}, can be calculated using the following equation:

$$k_{rnw} = (1 - S_w^*)^2[1 - (S_w^*)^{\frac{2+\lambda}{\lambda}}]. \tag{4}$$

The values of the non-wetting-phase relative permeability can then be determined using equation (4) with the data of λ determined using equation (3). One can see that both oil and water relative permeabilities can be obtained from equations (1)–(4) once the resistivity data as a function of water saturation are available.

The relationship between I and wetting-phase saturation, S_w, is defined by the Archie equation (Archie 1942):

$$I = \frac{R_t}{R_o} = S_w^{-n}. \tag{5}$$

Here, n is the saturation exponent, R_t the true resistivity at S_w, and R_o is the resistivity at S_w=100%, which is related to porosity, φ, and water resistivity, R_w, by the following relationship:

$$F_R = \frac{R_o}{R_w} = \varphi^{-m} \tag{6}$$

where m is the cementation exponent and F_R the formation factor.

Note that equation (1) has the same assumptions as Archie's law (equation 5), which postulates that the rock matrix is non-conductive to electricity. This assumption implies that equation (1) is suitable in rocks without a significant amount of clay minerals. There are also two associated assumptions, including Archie's law: (1) hydraulic and electrical conductance are correlated directly with each other; and (2) resistivity index and water saturation are correlated directly with each other. It is known that these assumptions are not universally valid. However, it has been found that these assumptions are valid in many cases. In general, the method is suitable for: (1) rocks without a significant amount of clay; and (2) rocks without multimodal pore distribution systems. It was found through the experimental measurements of resistivity versus water saturation (as presented and analysed in the following sections) that Archie's law applies to the carbonate rock samples analysed from the Arab-D Formation reservoir targeted for research in this study. Thus, equation (1) is suitable for the carbonate rock samples investigated in this article because of the correlation between equation (1) and Archie's law.

EXPERIMENTAL DETAILS

Rock and fluids

The core plugs used in this study were sampled from Well 1 across a light oil reservoir operated by Saudi Aramco. The core plug used for the relative permeability test had a length of 4.93 cm and a diameter of 3.78 cm. The values of porosity and permeability of core sample 1 were 25.9% (corresponding pore volume was 14.33 ml) and 494.0 mD, respectively. The core samples used in this study were from the Arab-D reservoir, which is the main pay zone. The lithology of the Arab-D is mainly limestone and dolostone (or dolomite). The Arab-D Formation in this

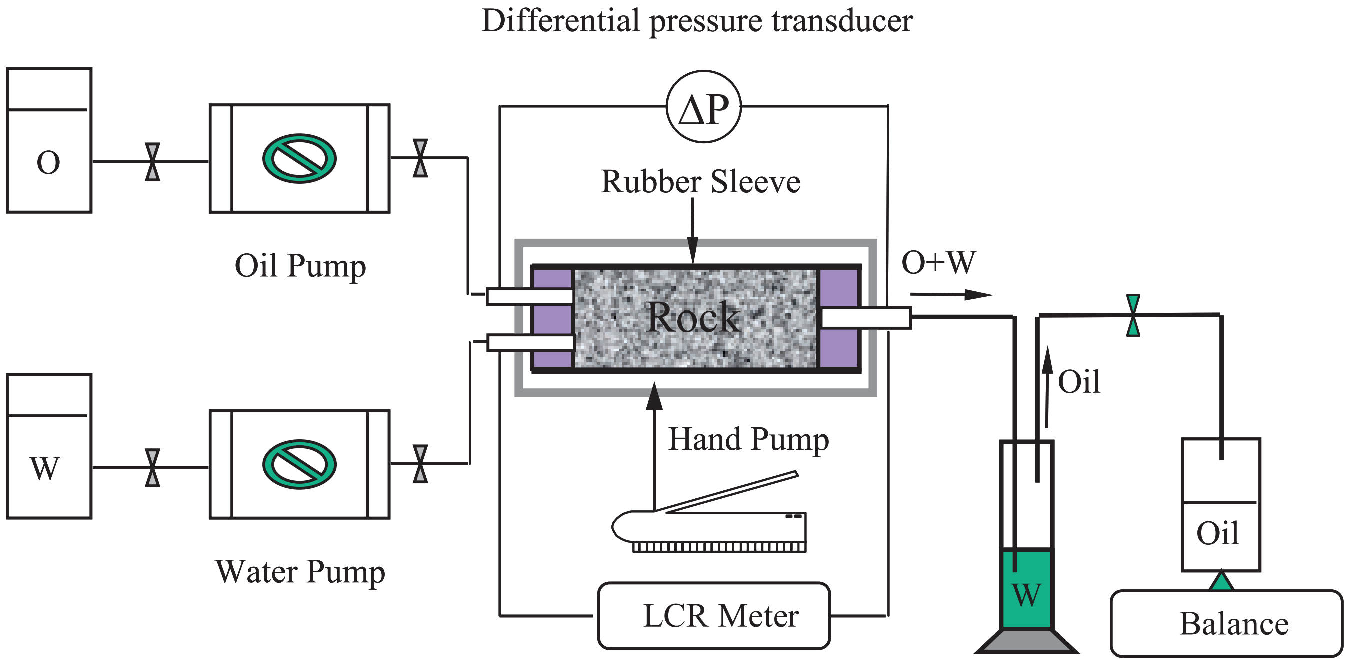

Fig. 1. Schematic of the apparatus used for relative permeability and resistivity measurements.

field is an upwards-shoaling sequence of the marine carbonate capped by anhydrite. The porosity and matrix permeability of the formation show a strong vertical variation, and increase in the upwards direction from the base of the formation. Although it is described by means of five different primarily limestone and dolomite stratigraphical sequences, the formation exhibits a much finer vertical stratification that is normally described by a much greater number of geological flow units (Ma *et al.* 2002). Okasha *et al.* (2007) reported that the Arab-D rocks had a general trend of slightly oil-wet to intermediate wettability behaviour. However, most of the results demonstrated a slightly water-wet behaviour (see fig. 8 in Okasha *et al.* 2007).

In the experiments, brine with 1.0% NaCl was used as the water phase, which had a viscosity of about 1 cP at room temperature. The crude oil from the same well was used as the oil phase, with a viscosity of 6.59 cP at room temperature.

Apparatus

The oil and water relative permeabilities were measured using an unsteady-state method. Figure 1 shows a schematic of the apparatus for the measurements of relative permeability and resistivity. The core holder was designed specifically for measuring resistivity. An LCR meter with an accuracy of 0.2% was used to measure the resistivity of the core sample at different water saturations. Differential pressure transducers with an accuracy of 0.25% were used to measure the differential pressure across the rock. The amount of water produced by oil flooding was measured using a glass cylinder with a minimum reading of 0.05 ml. The total liquid production (oil and water) was measured by a balance with a readability of 0.01 g. Using crude oil as the test fluid was helpful to avoid other problems from using refined oil. It was feasible to use the true crude oil as the test fluid in this study because of its low viscosity.

Procedure

The experimental procedure for measuring oil and water relative permeability and resistivity index in core sample 1 is described briefly here. It was not very difficult to clean the rock because the crude oil was light and had a low viscosity. The cleaned core sample was first saturated with the brine; the absolute permeability was then measured by water flooding. After that, oil flooding using crude oil was conducted. Production of oil and water, resistivity, and pressures at the inlet and outlet of the core sample were measured as a function of time. Oil and water relative permeabilities were calculated using the JBN method (Johnson *et al.* 1959). Note that all of the experimental measurements were conducted at room temperature and atmospheric pressure.

According to Sandler *et al.* (2009), there was almost no effect of frequency on the resistivity measurement in rocks without fractures for frequencies in the range 100–10 000 Hz. Therefore, 10 000 Hz was used to measure resistivity in this study. Note that the measurements of resistivity were conducted across the core sample (at the inlet and the outlet of the core) during the displacement by using the LCR meter (Fig. 1).

RESULTS

We measured oil and water relative permeability in the carbonate rock samples from the Arab-D Formation, an unsteady-state displacement approach in order to provide the experimental data for the comparison with model data. Using equations (1) and (4), we then inferred oil and water relative permeability separately from both resistivity logs and laboratory resistivity measurements during the oil displacement. Finally, we compared the modelled relative permeability with the laboratory measured relative permeability. The procedures to calculate relative permeability from resistivity are outlined below.

Procedures to calculate relative permeability from resistivity measured on cores

The procedures to infer oil and water relative permeability data from resistivity measured in laboratory are described briefly as follows:

(1) Determine S_{wir} of the core based on experimental data for core flooding (oil displaces water to residual water saturation).
(2) At each S_w,

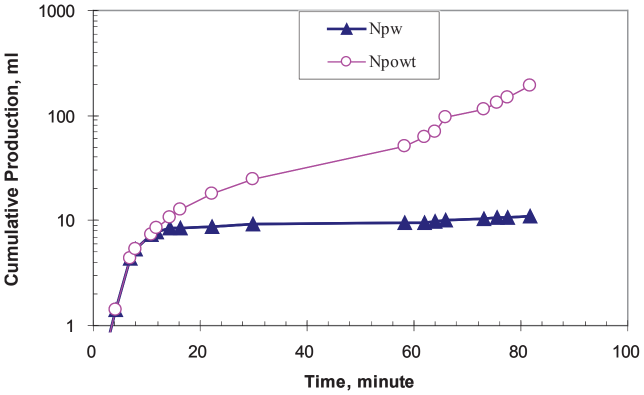

Fig. 2. Cumulative water (solid triangle) and total production (open circle) versus time in core sample 1.

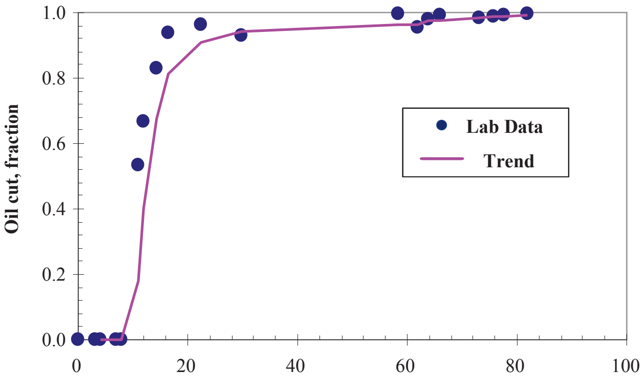

Fig. 3. Oil cut versus time in core sample 1. The solid line is the moving trend of the oil cut obtained by a three-point moving average.

(a) Calculate S_w^* using equation (2) with S_{wir}.
(b) Determine I.
(c) Compute k_{rw} (S_w) using equation (1).
(d) Plot k_{rw} (S_w) v. S_w^*.
(e) Estimate λ according to equation (3).
(f) Calculate k_{ro} (S_w) using equation (4).

Procedures to calculate relative permeability from resistivity logs

It is assumed that the rock type in the specific section of the formation is the same for the determination of relative permeability from the resistivity logs. The procedures to infer oil and water relative permeability data from resistivity log data are described briefly as follows:

1. Assess S_{wir} from log-analysed S_w (a full description of this log analysis is provided by Asquith & Krygowski 2004) or from the experimental data of core flooding (oil displaces water to residual water saturation).
2. Evaluate the values of R_o (a full description of this routine log analysis is provided by Asquith & Krygowski 2004).
3. Using the values of R_o, determined in the above step (2), convert the R_t log into an I log with equation (5).
4. Cross-plot S_w and I.
5. At each S_w:

(a) Compute S_w^* using equation (2).
(b) Determine I, then k_{rw} (S_w) using equation (1).

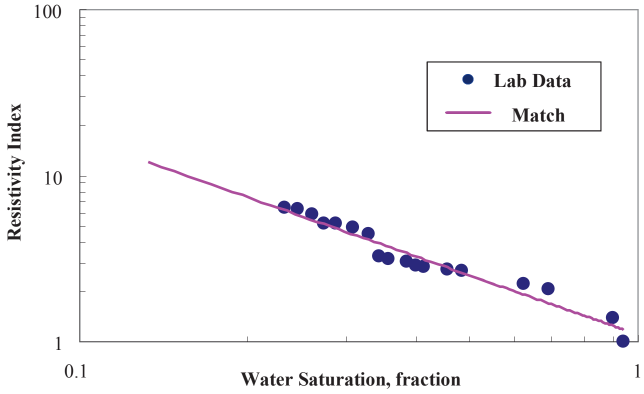

Fig. 4. Resistivity index versus average water saturation in core sample 1. The solid line is obtained using the regression analysis (n=1.27).

(c) Plot k_{rw} (S_w) v. S_w^*.
(d) Estimate λ according to equation (3).
(e) Calculate k_{ro} (S_w) using equation (4).

Note: Instead of utilizing the resistivity index from the laboratory resistivity measurement or logs, as done in this paper, water relative permeability can also be calculated with the data obtained by regression using the Archie equation (equation 5).

OIL–WATER RELATIVE PERMEABILITY MEASURED USING AN UNSTEADY-STATE APPROACH

The water production v. time during drainage for core sample 1 is shown in Figure 2 (solid triangles). Also shown in Figure 2 is the total production of oil and water (open circles). N_{pw} and N_{powt} represent cumulative water production and cumulative total (oil and water) production, respectively. The solid lines in Figure 2 are just the connection between data points. The change of oil cut with time during the drainage process is shown in Figure 3 (the solid line is the moving trend of oil cut obtained by the three-point moving average). Resistivity index was measured simultaneously in the core as a function of average water saturation, and is shown in Figure 4. The solid line is the moving trend of oil cut obtained by a three-point moving average. Note that Archie's law requires a uniform distribution in theory, but this is rarely achieved in practice in the laboratory or in the field.

The primary drainage oil–water relative permeability data were calculated from the experimental measurement using the JBN method and separately inferred from the resistivity data using the procedure outlined in the previous section. The results of both experimental and modelled oil–water relative permeabilities are plotted in Figure 5. One can see that the modelled water relative permeability agrees very well with that measured, indicating that equation (1) works well. However, the agreement between the modelled and measured oil relative permeability is relatively poor; that is, equation (4) does not work as well as equation (1). Several factors might contribute to the differences between model and experimental data of oil relative permeability. These include differences in wettability, non-uniform distribution of water saturation and other experimental errors. Note that the solid lines in Figure 5 are just the connection between data points (not shown) to show the model and experimental data clearly.

It is known that capillary pressure is ignored in the JBN method to calculate oil–water relative permeability. The effect

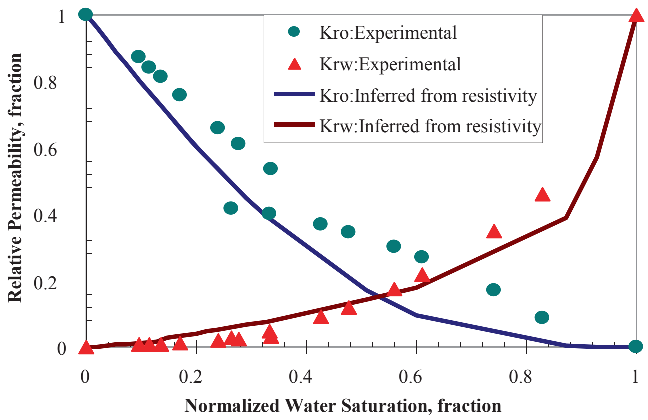

Fig. 5. Comparison of experimental (individual data points) and modelled (solid line) relative permeability in core 1. Note that relative permeability and resistivity were measured simultaneously in the same core sample.

of capillary pressure on the calculation of oil–water relative permeability was neglected in this study. Qadeer *et al.* (1988) demonstrated that there is almost no effect of capillary pressure on the relative permeability of the wetting phase (water phase in this study). Li *et al.* (1994) proved this theoretically. Therefore, it might be reasonable to ignore capillary pressure to calculate the water relative permeability. Considering the high permeability of the core sample, the effect of capillary pressure on the calculation of oil relative permeability is expected to be small.

COMPARISON OF MEASURED RELATIVE PERMEABILITY WITH THOSE INFERRED FROM WELL LOGS

From the last section, in the laboratory, relative permeabilities inferred from resistivity measurement have similar trends to those measured on a core, especially the water relative permeability. A more important concern is whether the relative permeability inferred from the well logs has similar characteristics. Figure 6a shows the resistivity index data calculated using the well resistivity logs (see Fig. 6b, the second track from the right) from Well 1 at a depth from X054 to X070 ft, in the vicinity of where Core 1 was taken. The solid line is obtained by using regression analysis with the Archie equation (equation 5). Note that the regression analysis was conducted by fitting a regression line through the data set to obtain the value of n using the Archie equation. From Figure 6, it is clear that the relationship between the resistivity index and average water saturation derived from logs (Fig. 6) is noisier than that derived from cores (Fig. 4). This observation is especially true in the high water saturation region, where log-derived water saturation may carry larger uncertainties owing to low true formation resistivity. The noisier log-derived relationship may also reflect geological heterogeneity, which might cause different values of n for different rock types in this formation. Note that the core samples used in this study were from the Arab-D reservoir. The lithology of the Arab-D rock is mainly limestone and dolostone (or dolomite). Usually this type of reservoir is characterized by a large degree of geological heterogeneity.

Based on the procedures outlined here, the oil and water relative permeabilities calculated from logs (depth from X072 to X102 ft in Well 1, covering Core 1 depth) are plotted in Figure 7. Also shown are the measured relative permeabilities and those inferred from laboratory measured resistivity (measured on Core 1, labelled as ‘Lab Log’ in Fig. 7). Note that the laboratory resistivity logs shown in Figure 7 were measured using natural evaporation techniques, as reported by Sandler *et al.* (2009).

The reason for using a different technique to measure resistivity index was to test whether the relative permeability inferred from resistivity measurements using this approach was close to the JBN relative permeability. From Figure 7, relative permeabilities estimated from well and laboratory logs are close to those measured directly in the laboratory, with a band of uncertainty. Relative permeability estimated from resistivity logs correlates better with relative permeability estimated from laboratory resistivity measurement than relative permeability measured directly in the laboratory, probably due to data quality. One can also see in Figure 7 that the water relative permeability values estimated using well logs are slightly greater than the experimental data, while the oil relative permeability values predicted from well logs are less than the experimental data. There might be some difference in wettability conditions between the lab resistivity tests and the well logs, which might also affect the data quality. However, the core sample used in the laboratory may not representatively sample geological heterogeneity that influences relative permeability in the wellbore region. The relative permeability values estimated from resistivity well logs and those estimated from laboratory resistivity measurements are considered to be a satisfactory match considering the potential sources of discrepancy described above.

RELATIVE PERMEABILITY INFERRED FROM WELL LOGS IN WELL 2

We also calculated the oil–water relative permeability using resistivity logs from Well 2. Calculations were made for three different sections with different depths in this well. The depth of Section 1 was chosen from X603 to X740 ft, and the corresponding resistivity index calculated is shown in Figure 8. Similarly, oil and water relative permeabilities were estimated, and the results are shown in Figure 9. The data points of water-phase relative permeability are scattered, but the main trend is clear. The reason for the scattering of the data points shown in Figures 8 and 9 might also be because of the geological heterogeneity in the rocks.

The depth of Section 2 was chosen from X740 to X745 ft, and the derived resistivity index values are plotted in Figure 10. The relative permeability curves inferred are shown in Figure 11. The depth of Section 3 was chosen from X803 to X807 ft, and the resistivity index is depicted in Figure 12. The water relative permeability curves inferred are shown in Figure 13. One can see from Figures 8–13 that reasonable results of relative permeability could be inferred from resistivity logs. Core samples from Well 2 were not available, so the comparison between experimental and modelled relative permeability data cannot be performed. Note that the solid lines in Figures 8, 10 and 12 are obtained by using regression analysis with the Archie equation (equation 5), and the solid lines in Figures 7, 9, 11 and 13 are moving average trend lines.

The values of n are different at different sections of the formation. The reason for this is complex because the values of n depend upon several factors, including rock types, pore structures and even wettability. The reason for the small values of n is speculatively attributed to the limestone and dolostone lithologies of the reservoir studied here. These rock types may contain fractures that could reduce the values of n significantly (Rasmus 1987).

DISCUSSION

In this study, only results from Well 1 have been verified owing to the lack of core samples from other wells. The reason was that the main purpose of this study was to compare the relative permeability data measured in the laboratory with those inferred

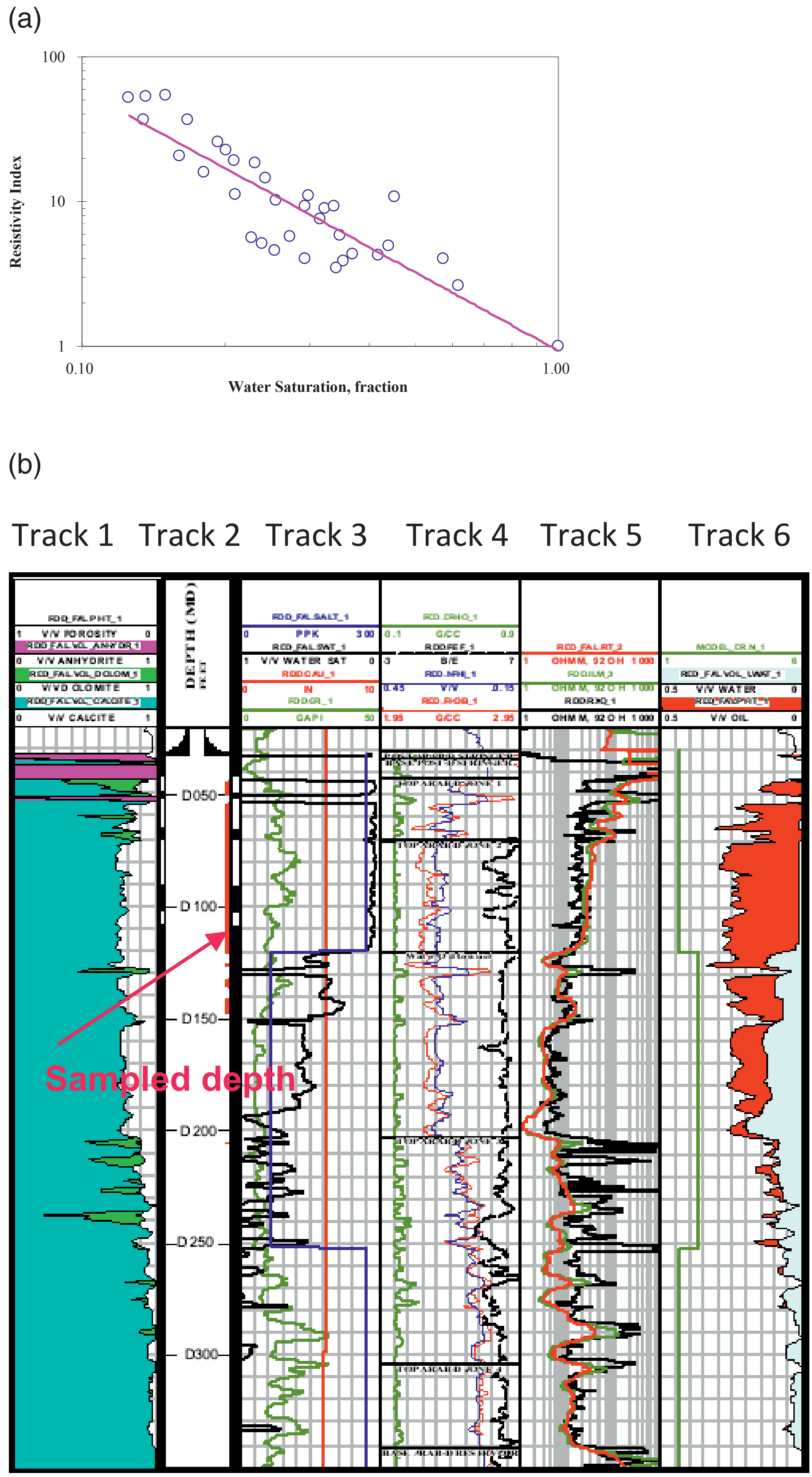

Fig. 6. (**a**) Resistivity index derived from log (depth: X054–X070 ft) in Well 1. The solid line is regression based on equation (5) (n=1.89). (**b**) Resistivity and other logs in Well 1. Track 1 – lithology, limestone (blue), dolomite (green) and anhydrite (pink); Track 2 – measured depth in ft; Track 3 – GR (green), Caliper (red), Sw (black) and salinity (blue); Track 4 – bulk density (red), neutron porosity (blue), Pef (black) and delta rho (green); Track 5 – resistivities: shallow (black), medium (green) and deep (red); Track 6 – volumetrics (oil in red and water in blue) and n (green).

from the well logs. To test the approach, the core plugs were required to be sampled from the same depth and position as where the resistivity logs were taken in the oil wells, which was difficult and very expensive. Hence, only a single well was used (but worked very well). Note that this is the first field test of the method for inferring relative permeability from resistivity data. The following discussion will explain the reasons for discrepancies between laboratory and field results.

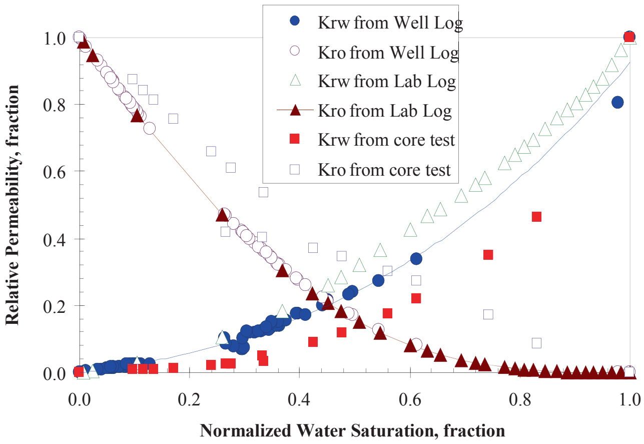

Fig. 7. Comparison of experimental and modelled relative permeability inferred from resistivity; core (lab logs) and reservoir (well logs).

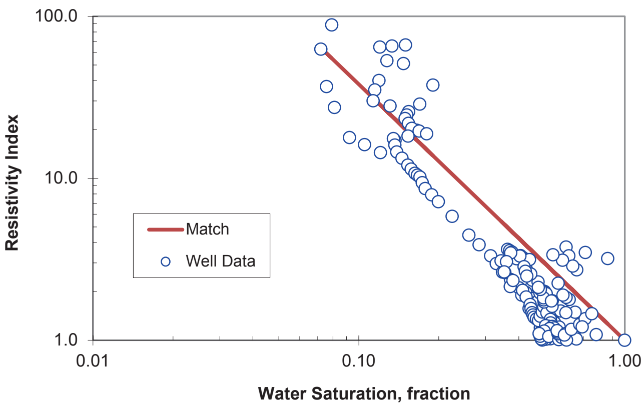

Fig. 8. Resistivity index data from well log (depth of Section 1: X603–X740 ft) in Well 2. The solid line is obtained using regression analysis with the Archie equation (equation 5) (n=1.58).

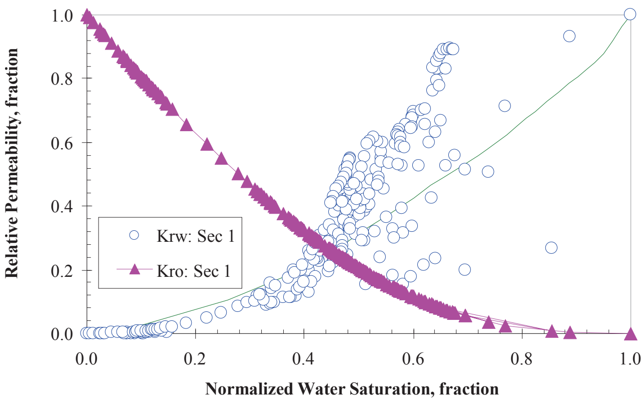

Fig. 9. Relative permeability for Section 1 in Well 2, depth: X603–X740 ft (solid lines are moving-average trend lines).

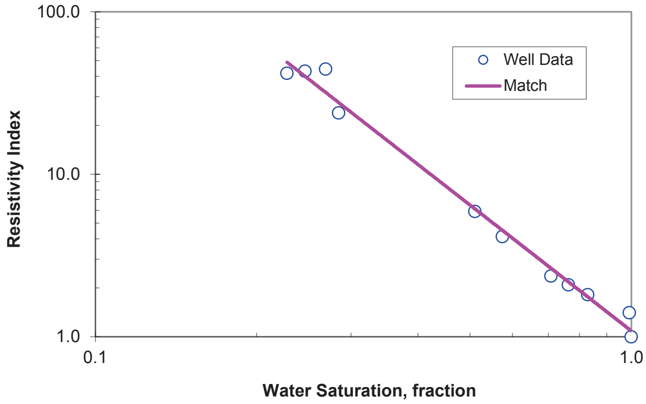

Fig. 10. Resistivity index data from well log (depth of Section 2: X740–X745 ft) in Well 2. The solid line is obtained using regression analysis with the Archie equation (equation 5) (n=2.57).

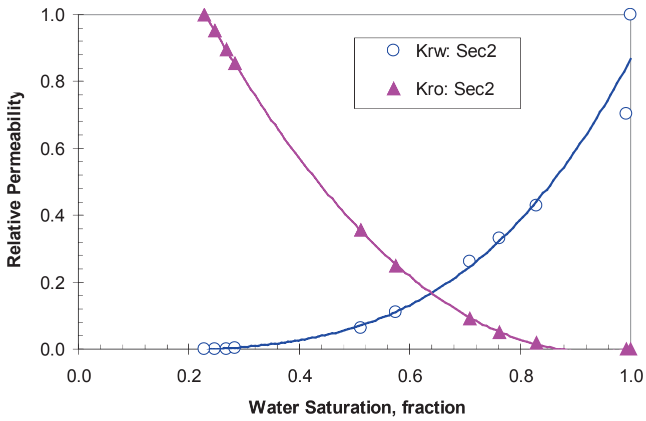

Fig. 11. Relative permeability curve for Section 2 in Well 2, depth: X740–X745 ft (solid lines are moving-average trend lines).

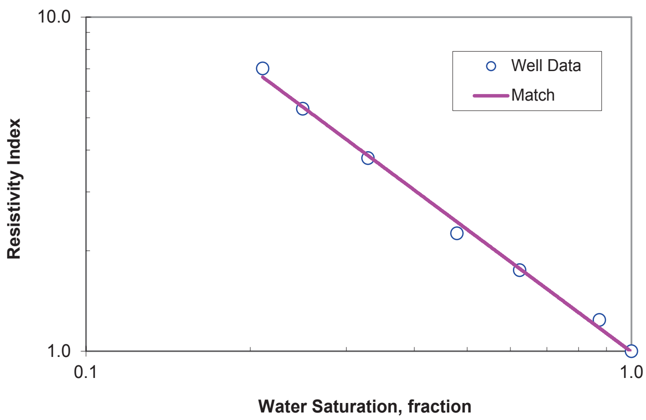

Fig. 12. Resistivity index data from well log (depth of Section 3: X803–X807 ft) in Well 2. The solid line is obtained using regression analysis with the Archie equation (equation 5) (n=1.22)

A frequency of 10 000 Hz was used to measure the resistivity of core sample in this study. The selection of frequency was based on the report by Sandler *et al.* (2009), which indicated that there was almost no effect of frequency on resistivity measurement in rocks without fractures for frequency in the range from 100 to 10 000 Hz. Note that we do not imply that this frequency could be suitable for all types of rocks. Determining the best frequency for a specific type of rock would be a subject for further research.

The experimental data in this study are all based on oil displacing water. That is, the drainage relative permeability data were obtained from the laboratory tests and the resistivity index data. The reason for this was because the Brooks–Corey model (Brooks & Corey 1966) was used to calculate the relative perme-

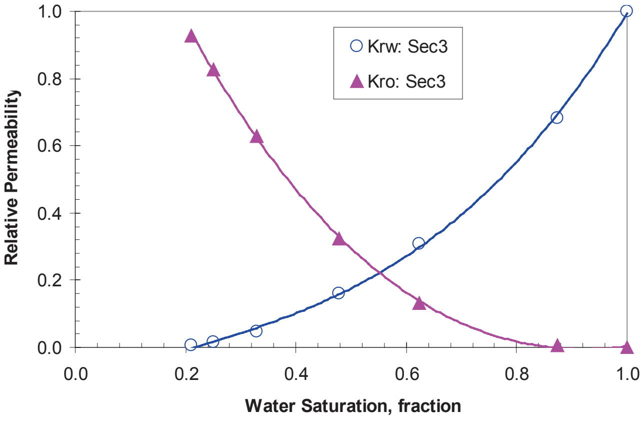

Fig. 13. Relative permeability curve for Section 3 in Well 2, depth: X803–X807 ft (solid lines are moving-average trend lines).

Appendix Table. *1. Nomenclature*

F_R	Formation factor (equation 6)
I	Resistivity index (equation 1)
k_{rnw}	Relative permeability of the non-wetting phase (equation 4)
k_{rw}	Relative permeability of the wetting phase (equation 1)
m	Cementation exponent (equation 6)
n	Saturation exponent (equation 5)
N_{powt}	Cumulative total (oil and water) production (ml)
N_{pw}	Cumulative water production (ml)
S_w^*	Normalized wetting-phase saturation (equation 2)
S_{wir}	Residual water saturation (equation 2)
R_o	Resistivity of rock at a water saturation of 100% (ohm m) (equation 5)
R_t	Resistivity at a specific water saturation (ohm m) (equation 5)
R_w	Resistivity of water (ohm m) (equation 5)
S_w	Water saturation (equation 2)
λ	Pore size distribution index (equation 3)

ability of the non-wetting phase (equation 4), and it is known that the Brooks–Corey relative permeability model is only appropriate to the drainage case. Note that relative permeabilities are often used in water displacing oil (imbibition) mode, and imbibition relative permeability curves of the non-wetting phase may differ from the drainage curves. One question arises: can the approach proposed in this paper still work satisfactorily in the imbibition case? It is also known that the relative permeability curves of the wetting phase in the imbibition cases are almost equal to those in the drainage cases (Qadeer *et al.* 1988; Li & Horne 1999). In fact, Li *et al.* (1994) proved this theoretically. Comparing experimental data with the modelling data, Li & Horne (2006) also found that equation (3) could best fit to the experimental data of the wetting-phase relative permeability for both drainage and imbibition processes. However, the derivation of equation (1) (Li 2008) does not require the assumption of displacing modes (drainage or imbibition). Therefore, based on the above analysis, the method proposed in this study may work satisfactorily in both the primary drainage and the imbibition cases for calculating the relative permeability of the wetting phase. However, it may not work well for calculating the relative permeability of the non-wetting phase in the imbibition case. In summary, the method proposed in this study may be more valid for rocks with a water-wet condition and the primary drainage cycle.

Several assumptions, including the lack of knowledge of capillary pressure in calculating relative permeability, were made in this study. These assumptions may cause some errors and uncertainties, and some of the poor correlation between directly measured and inferred relative permeability values may be related to these assumptions. It would be worth investigating these issues further in the future.

Another possible source of discrepancies between laboratory and field results may be the poor representation of geological heterogeneity in the studied Arab-D reservoir, which is important in determining and explaining such potential discrepancies. The presence of clays in rocks means that hydraulic and electrical conductance are not directly correlated, pore distributions are multimodal such that water saturation is not uniformly distributed, and that geological heterogeneity at length scales and in locations that are not sampled in the wellbore region implies that well logs (and core plugs) may not sample the reservoir in a representative way. The method for inferring relative permeability from resistivity well logging data, however, works for the studied Arab-D reservoir according to the results obtained in this study. The main reason for this may be due to the relatively high-permeability values of the rock samples from the studied Arab-D reservoir. The effects of clay, pore size distribution and wettability on the experimental results of relative permeability and resistivity may be reduced in such high-permeability rocks.

Estimated relative permeability characteristics from well logs may be used to enhance reservoir-engineering studies, such as reservoir characterization, using flow units. However, this requires more study to cover more core samples with different rock types and different pore systems; for example, rocks with different clay types, and bimodal and multimodal pore size distributions.

CONCLUSIONS

Based on the present study, the following conclusions are reached:

- Relative permeabilities inferred from both well resistivity logs and laboratory resistivity measurements were close to those measured directly on the cores, which verified, to some extent, the methodologies of estimating relative permeabilities from either laboratory or well log resistivity data.
- The quality of the predicted water relative permeability is better than that of the predicted oil relative permeability in the cases in which the laboratory resistivity data were used.
- The water relative permeability values estimated using well logs are slightly greater than the experimental data, while the oil relative permeability values predicted from well logs are less than the experimental data.

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