Two-Phase Semi-Dynamic Method with Electrical Measurements: Determination of Relative Permeability and Capillary Pressure from a Single Experiment

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ABSTRACT

Relative permeability and capillary pressure are important petrophysical parameters for interpreting fluid flow in reservoirs and for calibrating appropriate reservoir simulation models. The parameters are conventionally determined in the laboratory using two separate and time consuming core flooding experiments. In addition to being time and labor intensive, the core properties can change during one of the measurements and adversely affect the results. In this work, a special core analysis program is used to obtain relative permeability, capillary pressure and resistivity from a single experiment. The method is based on the semi-dynamic method developed by the Institut Français du Pétrole IFP (Lenormand *et al.*, 1993) and electrical measurements.

A rock slab model, as described by Pairoys *et al.* (2012), was prepared to test the semi-dynamic method. Reliable capillary pressure *Pc* and relative permeability *Kr* of the injected phase were obtained at steady-state conditions. To determine the relative permeability of the displaced phase, a method similar to the one described by Li *et al.* (2007) for drainage and by Pairoys *et al*. (2013) for imbibition was used to derive the missing relative permeability from resistivity.

In this study, a full petrophysical rock characterization (FPRC) was obtained from a single and simple two-phase flow, semi-dynamic experiment. The method is attractive because it shortens the SCAL experimental program. Numerical simulations in imbibition using CYDAR software were also performed and compared with the experimental data (history-matching). The results are encouraging but further tests are planned to validate the generality of the overall workflow.

INTRODUCTION

In order to estimate oil reserves and to anticipate production scenarios in oil or gas reservoirs, two couples of parameters are requested. These are, respectively, the two Archie parameters, cementation factor *m* and saturation exponent *n* used for the estimation of water saturation *Sw*, and the two petrophysical relationships, relative permeability *Kr* and capillary pressure *Pc* used for production management.

All these parameters are determined independently in the lab using special core analysis. Because these measurements are made during different experiments, using time consuming methods, a full set of data on one single core plug can take up to one year and even more (Ma *et al.*, 2013). In order to run the different core flooding tests on the same sample, additional core cleanings are required, increasing the experimental time. It is generally preferred to run the complete experimental program on several core samples with similar properties, but it is difficult to make sure that they will behave similarly.

A review of the different methods for obtaining all the petrophysical parameters needs to be done to understand the core laboratories' challenge. Relative permeability is generally obtained either by unsteady or steady-state methods. Unsteady-state tests (constant flow rate/pressure injection or centrifuge) are easy to set up and fast, but data processing is complex. Steady-state data processing is much simpler but the test is more time consuming than unsteady-state. Another way to get relative permeability is the multi-rate unsteady-state method, which is very similar to the semi-dynamic one.

Capillary pressure on core plugs is generally obtained from centrifuge or porous plate techniques. The centrifuge method is fast but is not routinely performed at elevated temperature and leads to a saturation gradient along the sample. These effects can be taken into account using the Forbes or spline method. It is generally recommended to run a porous plate experiment to make sure that fluids are uniformly distributed in the porous space. But this method is time consuming due to the very slow invasion process.

With regard to electrical measurements, it is recommended to measure resistivity at equilibrium. This is generally done during a porous plate experiment, when capillary equilibrium is reached (at the end of each capillary pressure step). Pairoys *et al.* (2013) showed that it was possible to obtain reliable resistivity and relative permeability measurements during a steady-state experiment, taking resistivity measurements at stable states.

Even if interrelationships exist between all these parameters, there is, so far, no single experiment able to provide the full set of petrophysical parameters. The semi-dynamic method developed by IFP (Lenormand and Eisenzimmer, 1993) can directly measure capillary pressure and relative permeability of the injected phase. The relative permeability of the displaced phase is missing, but can still be obtained by numerical simulations and history-matching. Later, Lenormand and Schmitz (1997) proposed an integrated petrophysical workflow where capillary pressure, relative permeability of the displaced fluid, and resistivity can be determined.

An ambient experiment was designed in order to measure electrical response of a water-wet rock slab sample, as described by Pairoys *et al.* (2012), during a semi-dynamic two-phase, brine-oil, flow experiment. Considering the analogy between fluid flow in porous media and electrical flow in a conductive body, the missing water relative permeability *Krw* was derived from resistivity measurements using Li's model (2007) in drainage. Based on the same analogy, the missing oil relative permeability *Kro* was determined using the normalized resistivity index concept developed by Pairoys *et al.* (2013). In addition to *Kr* and *Pc*, the resistivity index *RI* curves in drainage and imbibition cycles are obtained and wettability indices *WI* can be determined.

In an acceptable time (less than two months), *Kr*, *Pc*, *RI* in primary drainage, imbibition and secondary drainage cycles were simultaneously measured on a single sample. Lessons learnt from this study led to a clear experimental program timing and workflow (experimental steps, stabilization time for production and differential pressure, electrical equilibrium state at the end of each step). Additional numerical simulations have been run and compared with the experimental data in imbibition. The results are encouraging but additional investigations such as imbibition model validation at various wettability stages will be necessary to validate the generality of the overall workflow.

BACKGROUND

The main objective of this study is to shorten the experimental time for a Full Petrophysical Rock Characterization (FPRC), which includes determination of relative permeability *Kr*, capillary pressure *Pc*, Archie's cementation factor *m* and saturation exponent *n*, and wettability index *WI*. FRPC can be obtained by running the semi-dynamic method, developed by IFP, with resistivity measurements taken at each equilibrium stage.

The principle of the semi-dynamic method is based on the balance between the capillary pressure and the viscous pressure drop:

- One fluid (fluid 1) is injected through the sample at the inlet face as in the unsteady-state method, with an additional recirculation of the second fluid (fluid 2) at the outlet of the rock. Different and increasing flow rates are applied.
- Similar to the steady-state experiment, data points (differential pressure and production) are taken at equilibrium, at the end of each flow rate step.
- The spontaneous positive imbibition and negative drainage Pc curves can also be obtained from this experiment.

In the following, fluid 1 is the injected fluid whereas fluid 2 is the displaced and recirculated fluid.

Inlet capillary pressure Pc_{inlet} calculation

Using the semi-dynamic method, the inlet capillary pressure Pc_{inlet} is directly obtained from the pressure drop in fluid 1. When the production of fluid 2 ceases, the pressure in this fluid is constant along the core sample and is equal to the outlet pressure, controlled by the pressure of the recirculated fluid 2. So the pressure drop of fluid 2 is zero. As a result, the pressure gradient in fluid 1 is equal to the gradient of capillary pressure; in other words, it means that the pressure drop ΔP across the sample is equal to the inlet capillary pressure Pc_{inlet}.

Inlet relative permeability Kr_{inlet} calculation

The relative permeability of the injected fluid at the inlet face can be directly determined from Darcy's law for two immiscible phase flow (Lenormand *et al.*, 1997):

$$Kr_{fluid1} = \frac{\mu_{fluid1} L}{KA} \frac{dQ_{fluid1}}{dPc_{inlet}} \qquad \text{Eq.1}$$

The inlet relative permeability of fluid 1 can be obtained from the slope of Q_{fluid1} plotted against Pc_{inlet}.

Inlet saturation $S_{fluid2inlet}$ calculation

The inlet saturation of the displaced fluid can be obtained from the Ramakrishnan and Cappiello expression (1991):

$$S_{fluid\,2\,inlet} = \left\langle S_{fluid\,2} \right\rangle + Q_{fluid\,1} \frac{d\left\langle S_{fluid\,2} \right\rangle}{dQ_{fluid\,1}} \qquad \text{Eq.2}$$

The inlet saturation $S_{fluid2inlet}$ of fluid 2 can be obtained from the slope of S_{fluid2} plotted against Q_{fluid1}. It has been shown that the analytical calculation of the saturation proposed by Ramakrishnan and Cappiello agrees with the local saturation obtained by an X-ray attenuation technique (Lombard *et al.*, 2002).

At this stage, the relative permeability of the displaced phase is still missing. The idea here is to use Li's model (2007) for primary drainage and the similar approach to the one described by Pairoys *et al.* (2013) for imbibition using the normalized resistivity index concept. Both approaches are based on rock electrical measurements. In this study, all rock resistivity measurements are performed at steady-state at the end of each step.

Brine-oil relative permeability in primary drainage

The rock is initially saturated with brine which is the conductive phase for electrical measurements. In the previous equations, brine is the displaced fluid 2 in drainage.

Because the conductive phase or brine relative permeability is inversely proportional to the Archie resistivity index RI (Archie, 1942), Li derived a relationship between relative permeability of the wetting phase and resistivity index *RI* during a primary drainage cycle:

$$Krw = Sw^* \frac{1}{RI} \qquad \text{Eq. 3}$$

where *Krw* is the conductive phase (brine) relative permeability, *RI* is the resistivity index, and *Sw** is the normalized saturation of the wetting phase in primary drainage defined as:

$$Sw^* = \frac{Sw - Swi}{1 - Swi - Sor} \qquad \text{Eq. 4}$$

where *Sw* is the water saturation conductive phase), *Swi* is the irreducible water saturation, and *Sor* is the residual oil saturation (non-conductive phase), equal to 0 in primary drainage.

By taking the base permeability equal to the absolute brine permeability *Kw*, the *Kr* end-points for the water phase are *Krw*=1 at *Sw*=1, and K*rw*=0 at *Swi*.

The relative permeability of the other phase (oil for instance) or injected fluid 1, *Kro*, is obtained from Equation 1:

$$Kro = \frac{\mu_o L}{KA} \frac{dQ_o}{dPc_{inlet}} \qquad \text{Eq.5}$$

Brine-oil relative permeability in imbibition

For the imbibition cycle, the injected phase (brine injection) relative permeability *Krw* is obtained from Equation 1:

$$Krw = \frac{\mu_o L}{KA} \frac{dQ_w}{dPc_{inlet}} \qquad \text{Eq.6}$$

For the displaced phase (oil) relative permeability *Kro*, the normalized resistivity index RI* concept described by Pairoys *et al.* (2013) is used:

$$Kro = (1 - Sw^{*})RI^{*} = (1 - Sw^{*})\frac{RI}{RI_{\max}} \qquad \text{Eq. 7}$$

where RI_{max} is the maximum resistivity value at the beginning of the brine injection.

By taking the base permeability equal to the effective permeability to oil *Ko(Swi)*, *Kro(Swi)*=1 and *Kro(Sor)*=0 are obtained.

ROCK AND FLUIDS

A water-wet Indiana limestone block was used for the preparation of the rock slab model as described in Pairoys *et al.* (2012). MICP was performed on two end chips (top chip S4T and bottom chip S4B) of the slab to assess the degree of heterogeneity of the rock (by comparing pore throat size distributions, Figure 1).

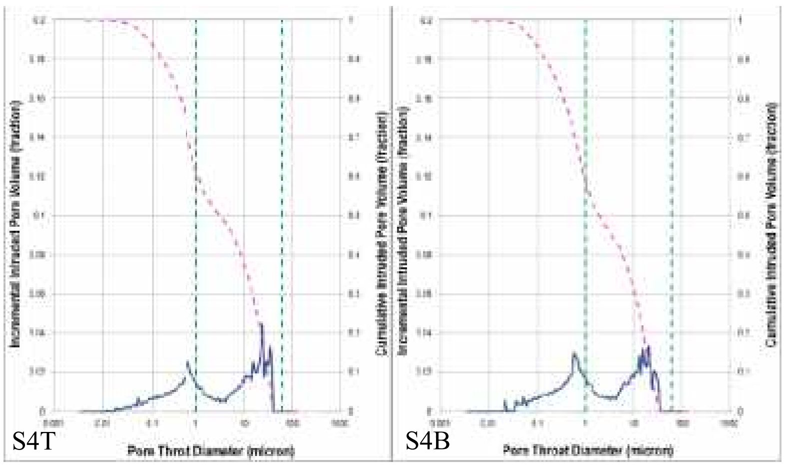

Figure 1: Pore throat size distribution for chips S4T and S4B

The rock chips have similar signatures with two distinct pore throat populations; one nanopore and one micropore population as described in Table 1.

Sample ID	Depth (ft)	Hg Inj Porosity (%)	Median Pore Throat Dia (micron)	Pore Throat Types: Nanopores 1nm<Dia<1 µm (%PV)	Micropores 1 µm<Dia<62.5 µm (%PV)	Mesopores 62.5 µm<Dia<4 mm (%PV)	Mercury/Air Entry Pressure (psi)	Air/Brine Entry Pressure (psi)	Swanson Air Permeability (mD)
S4T	NA	16.6	3.08	40.0	60.0	0.0	5.74	1.33	69.3
S4B	NA	15.8	1.90	42.7	57.3	0.0	6.24	1.44	35.7

Table 1: Rock properties from MICP

Even though porosity and Swanson air permeability vary from 15.8% to 16.6% and from 69.3 mD to 35.7 mD, respectively, properties such as porosity, pore throat types and entry pressures are very similar. Later it is considered that the rock slab has the same properties as the end-trims.

The rock slab, 12 cm length, with a rectangular cross section of 6 cm^2, was saturated with 200 kppm NaCl brine. The same brine was used for the imbibition cycle. Porosity and brine permeability of the limestone core plug S4 were also measured by the weighing method and Darcy's law respectively. Data results are listed in Table 2.

Rock	Porosity by weight ϕ (%)	Pore volume PV (cc)	Brine permeability Kw (mD)	Cementation factor m
Limestone S4	16.14	11.21	19.67	2.1

Table 2: Properties of the rock at ambient conditions

For the two-phase flow experiments, Soltrol 130 was used as the non-conductive oily phase. This paraffinic oil has no polar components; this ensures that the rock wettability will not change during the two-phase flow displacements. Fluid properties are listed in Table 3.

Fluids	Density ρ (g/cc)	Viscosity μ (cp)	Resistivity R (Ω.m)
200 kppm NaCl	1.15	1.4	0.047
Soltrol 130	0.75	1.7	X

Table 3: Fluid properties at ambient conditions

SEMI-DYNAMIC EXPERIMENTAL SET UP

The rock slab model set up is an ambient system; the two-phase flow experiments were run at ambient conditions (room temperature and atmospheric pressure). As explained before, a semi-dynamic method was chosen to run the two-phase flow test. In addition, resistivity measurements were performed at 1 KHz, with a 4-contact electrode configuration; stainless steel end platens were used as current electrodes, and two additional potential electrodes were placed on the rock, with a distance of 2.54 cm between them. A special 2-port end platen was designed for recirculating the displaced fluid at the outlet of the sample. Differential pressure ΔP and average water saturation $<Sw>$ were also monitored; an ambient video level tracker was used to monitor the effluent production. Oil-red dye was added to the oil to ensure a visible interface between brine and oil. A schematic of the set up in imbibition mode is shown in Figure 2.

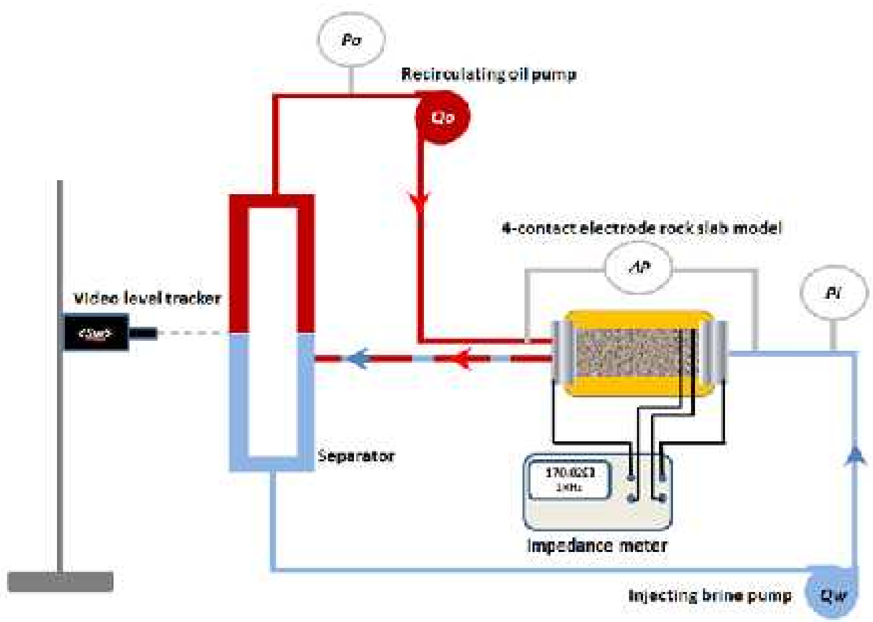

Figure 2: Set up for semi-dynamic method experiment with resistivity measurements

The schematic represents the experimental set up for running an imbibition cycle. It shows the oil recirculation (in red) at the outlet of the sample during the brine injection (in blue). The outlet pressure, controlled by the oil pump, was negligible (~0.1 psi) during the ambient test.

Because the test is run without back pressure, the inlet capillary pressure P_c is directly equal to the differential pressure ΔP, so equal to the inlet pressure Pi on Figure 2.

Note that all petrophysical properties are determined at the inlet of the sample; it is assumed here that the saturation between the two potential electrodes is close enough to the inlet saturation analytically calculated with the Ramakrishnan and Cappiello method. The two potential electrodes were placed at 2.54 cm from the inlet injection face of the rock, far enough from the outlet production face which can be affected by end-effects.

EXPERIMENTAL RESULTS

Primary drainage

In the following, all parameters, *Pc*, *Kr* and *RI*, are plotted against the analytical water saturation *Sw*. To obtain the calculated *Sw* value, the average water saturation <Sw>, measured by the video level tracker, was plotted against the oil flow rate *Qo*. An analytical function law (generally power or polynomial functions) was then used to fit the curve and the derivative was taken to calculate the inlet water saturation *Sw* (Equation 2).

Figure 3 represents respectively the water production and differential pressure, the capillary pressure *Pc*, the resistivity index *RI*, and the relative permeability *Kr* curves.

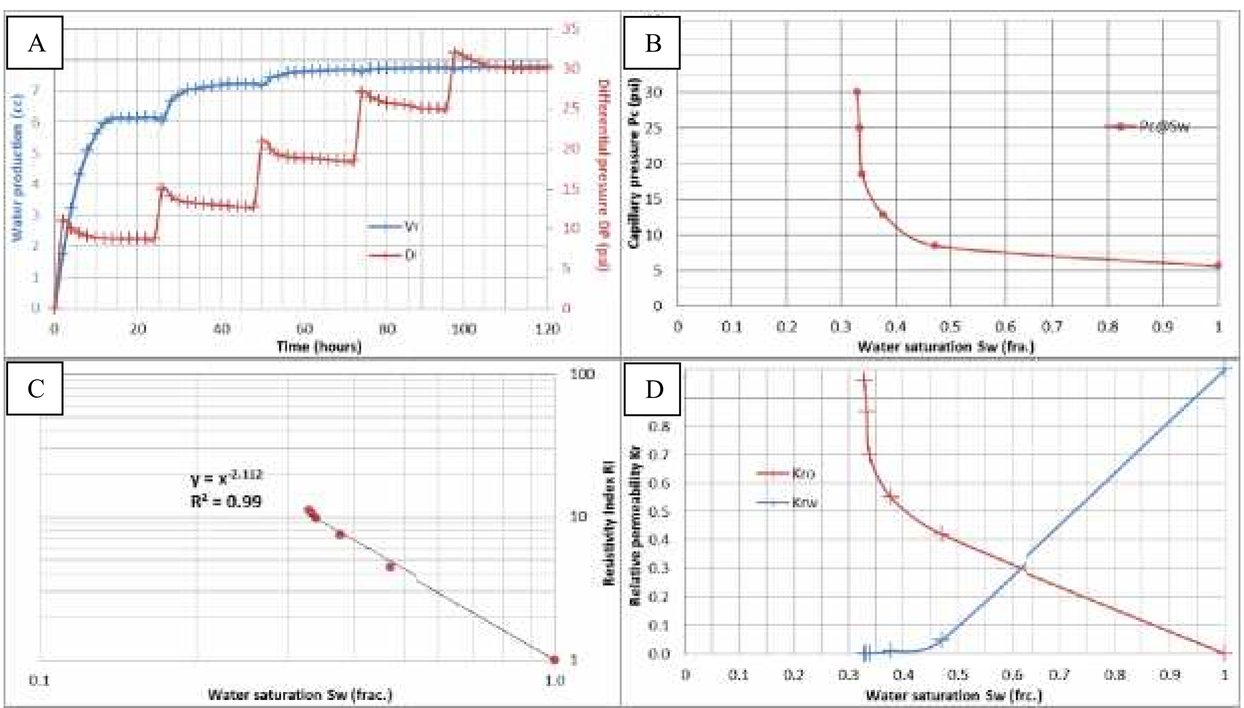

Figure 3: Petrophysical parameters in primary drainage

Graph A represents the differential pressure *DP* and water recovery *Vw* versus time; these two curves will be used later for history-matching and optimization. The multi-steps are clearly identified and equilibrium seems to have been reached at each step (plateaus). The production curve (in blue) does not directly correspond to the produced oil volume calculated by material balance; as a matter of fact, the measured production using the video level tracker was re-scaled to fit the end saturations *Sw* calculated at the end of each step with the Ramakrishnan and Cappiello method. This step is required for the latter numerical investigation (consistency).

Graph B represents the capillary pressure *Pc* curve; by plotting the Pc curve versus reduced saturation *Sw** in log-log scale, entry pressure *Pe* and pore size distribution index λ can also be determined; they are respectively equal to 5.6 psi and 3.5. The λ value indicates the degree of heterogeneity of the sample. The obtained entry pressure *Pe* is used as the first point of the capillary pressure curve at *Sw*=1 in graph B.

Resistivity data points were taken at the end of each step. The resistivity index RI curve (Graph C) was also plotted to get the Archie saturation exponent *n*: saturation exponent *n* equal to 2.1 was obtained. This value is common for water-wet rocks without clay content, like this sample.

Brine and oil relative permeabilities (Graph D) were calculated using Equation 3 and Equation 5 respectively. The oil relative permeability *Kro* at irreducible saturation *Swi* was found to be relatively high; the remaining water does not hamper the oil flow, leading to a high mobility of the oil phase.

At the end of the primary drainage, the average irreducible water saturation <*Swi*> calculated by material balance was equal to 45.3%. The irreducible water saturation derived from the Ramakrishnan and Cappiello method was found equal to *Swi*=32.9%. The spontaneous imbibition cycle came immediately at the end of the primary drainage.

Note that the significant irreducible water saturation *Swi* is due to the presence of brine-filled micro-porosity, which was not invaded by oil at the applied pressures in drainage.

<u>Spontaneous imbibition</u>

Figure 4 shows the capillary pressure Pc and resistivity index RI curves during spontaneous imbibition.

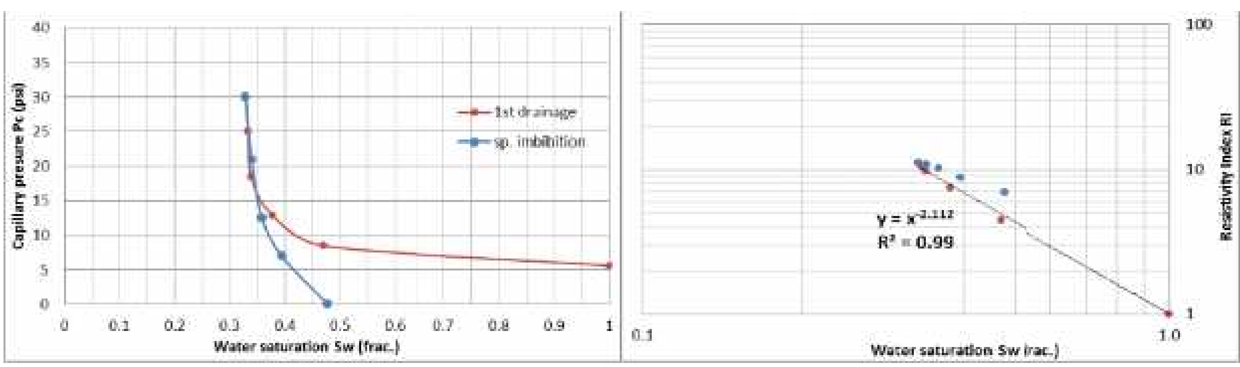

Figure 4: Petrophysical parameters in spontaneous imbibition

A total of 1.72 cc of brine were re-introduced in the rock; this confirms the water wetness of this sample. By increasing the water saturation *Sw*, the resistivity decreased as expected. Before starting the forced imbibition cycle, the water saturation *Sw* was equal to 47.7%.

Forced imbibition

Figure 5 represents respectively the oil production and differential pressure, the capillary pressure *Pc*, the resistivity index *RI*, and the relative permeability *Kr* curves in forced imbibition.

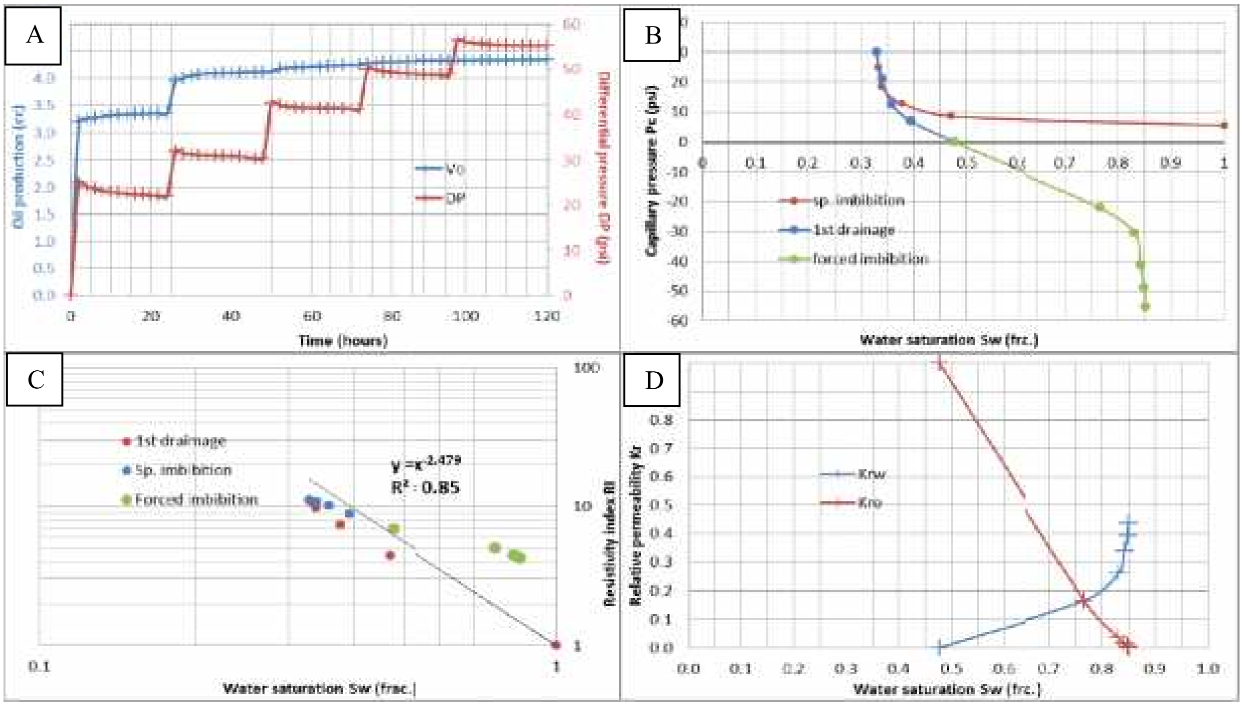

Figure 5: Petrophysical parameters in forced imbibition

Graph A represents the differential pressure *DP* and the oil recovery *Vo* versus time; as in the case of primary drainage, the multi-steps are clearly identified and equilibrium seems to have been reached at each step.

Graph B represents the capillary pressure *Pc* in forced imbibition (in green). The area under the curve does not reflect the water wetness of the sample – the area under the X-axis is significant.

The saturation exponent *n* equal to 2.48 in imbibition is higher than the one in primary drainage; even if this behavior was already observed in past studies, the question about the validity of Archie's method in imbibition remains open, particularly the forcing of the regression to cross [*Sw*=1; *RI*=1].

Brine and oil relative permeabilities (Graph D) were calculated using Equation 6 and Equation 7 respectively. The *Krw* end-point is equal to 0.44 which is a high value for a water-wet rock; an attempt to explain this behavior is given later.

At the end of the imbibition cycle, the average residual oil saturation <*Sor*> calculated by material balance was equal to 18.5%. The residual oil saturation derived from the Ramakrishnan and Cappiello method was found to be *Sor*=14.9%.

Spontaneous drainage

A slight water production and an increase in resistivity were observed during the spontaneous drainage cycle in which 0.25 cc of oil were re-introduced into the sample (Figure 6).

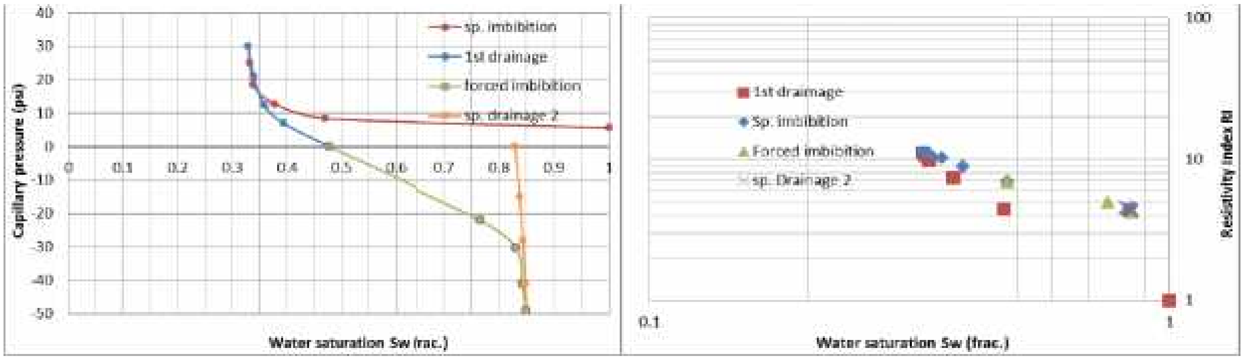

Figure 6: Petrophysical parameters in spontaneous drainage

At the end of the spontaneous displacement, the forced secondary drainage was performed.

<u>Secondary forced drainage</u>

The secondary drainage was essentially performed to calculate the Amott-Harvey and USBM wettability indices *WI* from the full capillary pressure curve *Pc* (Figure 7).

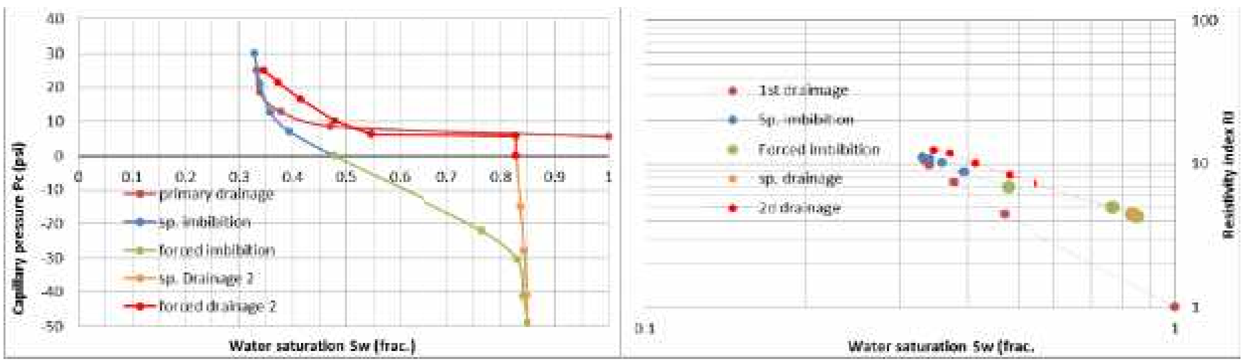

Figure 7: Petrophysical parameters in forced drainage

Using the trapezoid area technique to determine the area under the *Pc* curve, and using the end saturations after each cycle, wettability indices of WI_{USBM}=0.25 and WI_{A-H}=0.26 were found. These values are representative of a slightly water-wet rock; higher *WI* values would have been expected. Note that the slight water wettability of the rock is consistent with the significant mobility of the water phase observed in imbibition.

An additional study is currently ongoing in order to investigate the potential effect of the oil-red dye added in the oil phase to get a better color contrast between brine and oil in the video level tracker system; there are already some qualitative indications that dye was adsorbed onto the rock surface. This adsorption process may have caused a contact angle change and hence a change in the wetting relationships.

The saturation exponent *n* was found to be slightly higher in drainage than in imbibition.

<u>Numerical simulations using CYDAR</u>

To validate the FPRC experimental results, numerical simulations were performed using CYDAR software; the semi-dynamic module of the software was run for the forced imbibition. Direct numerical simulations were run using *Kr* and *Pc* obtained from the imbibition experiment.

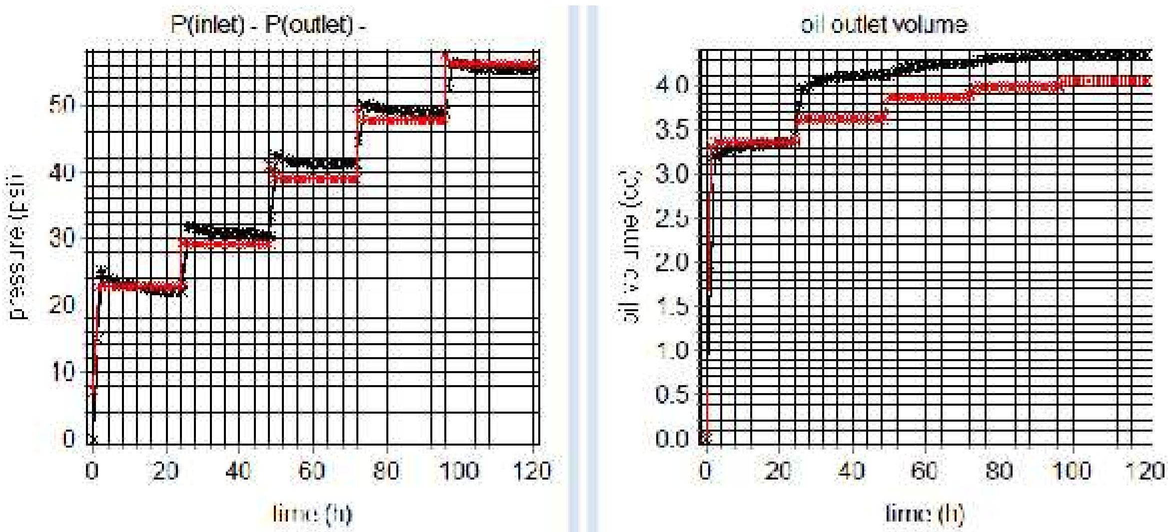

Figure 8: Experimental results (black) and numerical simulations (red) in imbibition

Figure 8 highlights the questionable agreement between the experimental and numerical results, mainly for the oil production match; it can be the result of the re-scaling method applied on the production curve. Another technique should be used to determine the inlet saturation, like in situ saturation monitoring at the inlet face of rock using an X-ray attenuation method for instance.

Then, the *Kr* and *Pc* curves were fitted with analytical functions (Corey's model for *Kr* and Log[beta] model for *Pc*) to run the optimization.

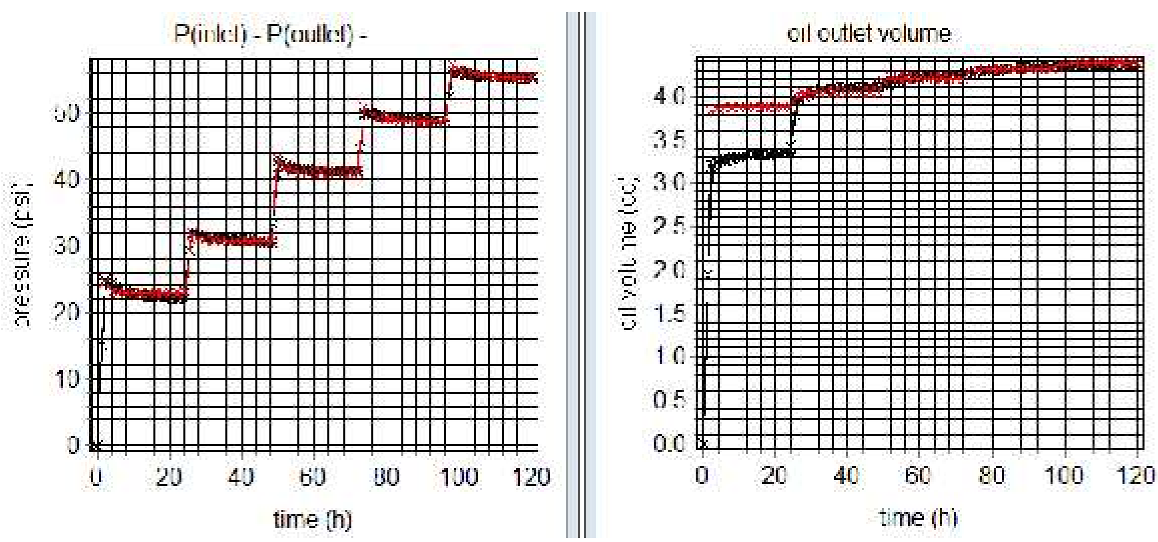

Figure 9: Experimental results (black) and numerical simulations (red) after optimization

The optimization results in a better but not perfect representation of the full dynamic features. This may be due to the choice of the fitting functions for *Kr* and *Pc*. To force the simulation to converge to the end value of the experimental oil production, 5 more % were added at the end saturation *Sw* (85% was replaced by 90%), confirming the need for an in situ saturation monitoring technique to avoid the use of the data reduction and re-scaling methods to get *Sw*.

CONCLUSIONS

Using a combination of a semi-dynamic experiment with electrical measurements, and using the Ramakrishnan and Cappiello differential data reduction method, a full petrophysical rock characterization (FPRC), including *Kr*, *Pc*, *m*, *n*, *RI* and *WI* measurements during water/oil displacement was obtained in less than two months. Lessons learnt from this study lead to a clear experimental program timing and workflow. Because the proposed model requires electrical measurements, this approach cannot be directly applied for gas/oil displacements.

In order to validate the results obtained with the FPRC method, numerical simulations using CYDAR software were performed using the imbibition data; a debatable agreement between experimental and numerical results was obtained. An optimization was run to get a better history-match between experimental and numerical data results. It showed that in situ saturation monitoring using an X-ray scanner at the inlet face of the rock is recommended.

Radial electrical configuration at the inlet face of the sample and history-matching of resistivity could be envisaged to improve and confirm the validity of the proposed set up and method. Because oil-red dye can alter the rock wettability during the two-phase flow, a floating disc could be used to clearly identify the brine-oil interface in the visual separator.

All the results of this study are very encouraging but additional investigations such as wettability effects on the proposed experimental method will be necessary to validate the overall workflow.

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