Towards faster Amott index measurement: Amott Express Technique

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Abstract.

Wettability of oil reservoirs is a crucial parameter influencing hydrocarbon recovery. The Amott and USBM index are commonly used to evaluate the wettability of reservoir rocks. However, traditional methods often require cell loading/unloading operations between different phases of the experiment, which imposes handling and therefore more errors and uncertainties. In this paper we present the Amott Express technique, which uses a single cell designed to be compatible with Nuclear Magnetic Resonance (NMR) imaging to perform all stages of the experimental cycle from spontaneous imbibition to forced secondary drainage. The use of D2O brine instead of conventional H2O brine allows the monitoring of oil saturation changes during the different phases. NMR provides a precise evaluation of saturation variations along the rock sample enabling the calculation of a far more precise Amott index, as it helps to deal with the presence of capillary end effects. Another benefit is reducing the experimental duration due to less handling and using viscous sweeping for forced steps. The proof of feasibility of the Amott Express is confirmed with the results obtained on a reservoir rock sample. In addition, keeping the same rock inlet throughout the corefloods allows the approximation of inlet pressure to Capillary pressure, which is then associated with inlet face saturation (evaluated thanks to NMR). This approach provides Pc curves for each step, allowing the evaluation of the USBM index. The Amott Express Technique offers a practical and reliable solution for obtaining Amott and USBM indices while minimizing errors and uncertainties associated with cell exchange.

1 Introduction

Wettability is a key factor controlling multi-phase flow in porous media, significantly influencing the behaviour of oil reservoirs. While it is generally recognized that most clean rock-forming mineral surfaces are strongly water-wet, interactions with components in crude oil can alter this wetting condition. Consequently, the most likely wettability condition in oil reservoirs is often something other than strong water wetness. An extensive body of literature has emerged addressing the questions of reservoir wettability and the optimal methods for its measurement. Among these methods, the Amott Wettability method, introduced in 1959 [1], stands out as an excellent technique for determining rock wettability. Early literature on this topic has been thoroughly reviewed by Anderson [2], with more recent developments covered by Morrow [3], Cuiec [4], and Buckley [5].

The standard and well-established laboratory procedures used to characterize the wettability of an oil/brine/rock system in the oil and gas (O&G) industry are the Amott and USBM tests. These tests provide wettability indexes based on a combination of spontaneous and forced displacement properties of the oil/brine/rock system. They are highly valuable for petrophysicists and reservoir engineers but are time-consuming, often taking several months or even more than a year to complete. As a result, they frequently come too late during reservoir pre-development evaluations.

In the experimental procedures, cylindrical cores are cut using a diamond core bit with tap water for cooling. These cores are then dried in an oven at 80°C for several days, after which nitrogen permeabilities are measured. Selected core plugs are saturated under vacuum in degassed brine and allowed to equilibrate in the brine phase for one week at ambient temperature. Following this equilibration period, absolute permeability to the brine is measured. Synthetic and outcrop cores prepared in this manner are strongly water-wet and ready for various experimental applications.

To alter the wettability of the cores, the brine-saturated samples are flooded with crude oil to establish an initial

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water saturation, followed by an initial measurement of oil permeability. The extent of wetting alteration is influenced by variables such as initial water saturation, ageing time, and ageing temperature. The cores, containing oil and connate water, are submerged in crude oil in a sealed beaker and stored at the designated ageing temperature. After the ageing period, the oil in the core is displaced with fresh oil, and permeability to oil is remeasured with connate water in place.

The use of imbibition measurements to characterize wettability in cores has been common since Amott [1] proposed a test comparing the amount of a phase imbibed spontaneously with the amount taken up by the same core in a forced displacement. The procedure used here is similar to that suggested by Cuiec [4], combining spontaneous imbibition with viscous forced displacement in a core flood, as opposed to the gravity-driven centrifuge displacement recommended by Amott.

The main drawback of the so called Amott test are the following: it is quite a long process, and it requires lots of core handling. Authors like Regaieg [6] and Repina [7] have proposed ideas to accelerate the wettability assessment, using high resolution 3D CT scanning on very small samples (4mm diameter).

In this work we propose to accelerate the wettability evaluation, but to keep the standard sample size of 1,5inch.

2 Rock and fluid properties

The aim of this article is to bring the proof of concept of the experimental procedure proposed. An experiment was performed on one reservoir rock sample in order to test the setup and the protocol described in the section 3.

2.1. Rock

Properties of the rock are presented in Table 1 below.

Table 1. Reservoir Rock properties.

Properties	Sample
D (mm)	37.88
L (mm)	51.23
Poro-NMR (frac)	0.185
Poro-Vt-Vs (frac)	0.181
KgKl (mD)	1.9
RhoG (g/cc)	2.679

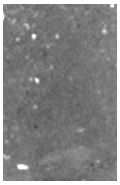


Fig. 1. Rock sample CT-Scan: Strike Gray Scale 1200-2400.

Qualitatively, the Fig. 1 CT scan is not showing any significant visual heterogeneity for this rock sample. It is also possible to define a quantitative heterogeneity cut off if needed as described by Maas [8]. Fig. 2 is showing the Pore Throat Radius (PTR) distribution obtained thanks to Mercury Injection Capillary Pressure experiment (MICP) on a twin sample and a Nuclear Magnetic Resonance (NMR) T_2 relaxation time distribution. Both acquisitions exhibit a bi-modal behaviour with two peaks associated to two pore throat sizes for MICP and two pore sizes for NMR T_2.

In this experiment, heavy water replaces brine and is not seen by NMR. Therefore, the reference NMR measurement is then the 100% oil saturated measurement. This point is explained in detail in the following parts (2.2 Fluids and 2.3 Initialization).

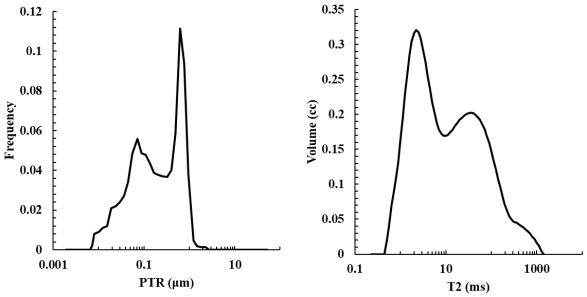


Fig. 2. On the left PTR distribution obtained by Mercury Injection and on the right T_2 NMR Distribution of the sample 100% saturated with brine.

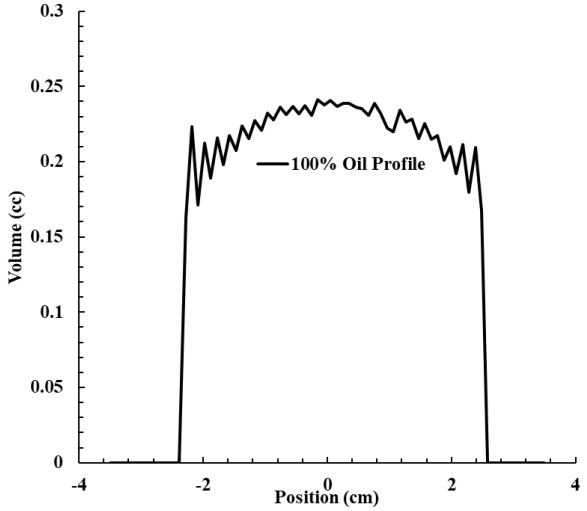


Fig. 3. Oil volume profile of the rock sample obtained from NMR acquisition.

Fig. 3 shows the volume profile of the rock sample at 100% saturation with the oil used for the experiment. In terms of volume repartition the rock sample is homogeneous. Even if the acquired volume profiles are not perfectly squared shaped and may exhibit a slightly rounded shape, the process of calculating saturations involves dividing a given profile by the 100% oil saturated profile, therefore removing this effect. Furthermore, the entire Amott Express process happens in the NMR magnet and the sample position remains the same.

2.2 Fluids

The proposed approach is based on NMR saturation measurements. One convenient way to perform NMR based saturation measurements in laboratory experiments is to use a brine based on heavy water (D_20). This makes the water phase invisible to NMR. Table 2 and Table 3 describes respectively the brine composition and oil properties used in this experiment.

Table 2. Brine (D2O Based) salt composition.

Salts	C° (g/L)
NaCl	59
KCl	7.52
MgCl2	1.47
CaCl2	5.14

Table 3. Oil properties

Dead Oil Properties	Value
Wax Appearance Temperature	19
Saturates (%wt)	82.3
Aromatic (%wt)	17.2
Polars (%wt)	0.5
Total Acid Number (mgKOH/g)	0.1
Total Base Number (mgKOH/g)	0.1

2.3 Initialization

As for each special core analysis, the initial point is to set the rock sample at the right saturation and wettability conditions prior to perform the experiment wanted. So, before measuring wettability, the sample has to be set at a given saturation and aged, according to the restored state technique. The following process describes how our rock sample has been prepared to measure wettability following the Amott Harvey Index experiment. We also describe how the continuous NMR saturation monitoring and the reduction of handling contribute to accelerating the experiment.

Cleaning of the received sample with hot Soxhlet extraction (Toluene – Isopropanol – Mix of both solvent – 2 cycles)

- Drying in oven at 80°C for 6 days (weight monitoring to ensure stability)
- Saturation of the rock sample with Dead oil. The aim is to obtain a reference NMR T_2 and Volume profile.
- Cleaning again with the same process as the first point
- Saturation 100% in D_2O based brine.
- Primary drainage to set Swi in centrifuge following the UFPCRI technique by Faurissoux [9] with mineral oil.
- Replacing Mineral oil by Dead Oil and obtain the Swi profile in NMR, see Fig. 4 for the T_2 at Swi of Res-1 sample.
- Ageing with Dead oil during 4 weeks under controlled temperature (80°C) and constant oil refresh.

Mineral oil was used for setting Swi for convenience, a protocol using crude oil for the first drainage would be completely equivalent.

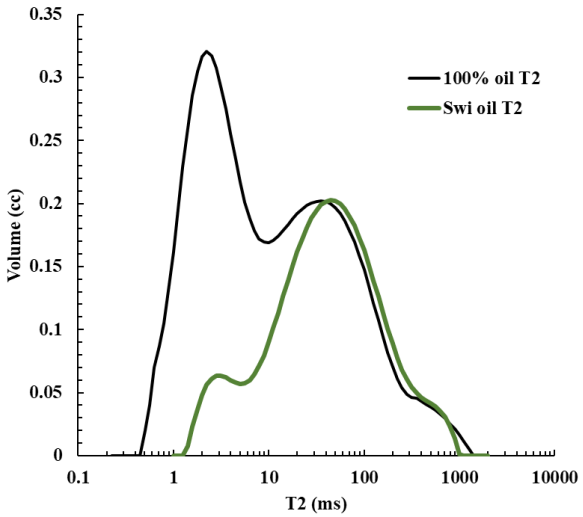


Fig. 4. T_2 relaxation time NMR at 100% oil saturation in black and the T2 of the rock sample with oil and D2O at Swi after ageing in green.

From Fig. 4, it is possible to compute the average Swi of the rock sample with the following equation:

$$Swi_{T2} = 1 - \left(\frac{Vo_{T2-100\%} - Vo_{T2-Swi}}{Vo_{T2-100\%}}\right) \quad (1)$$

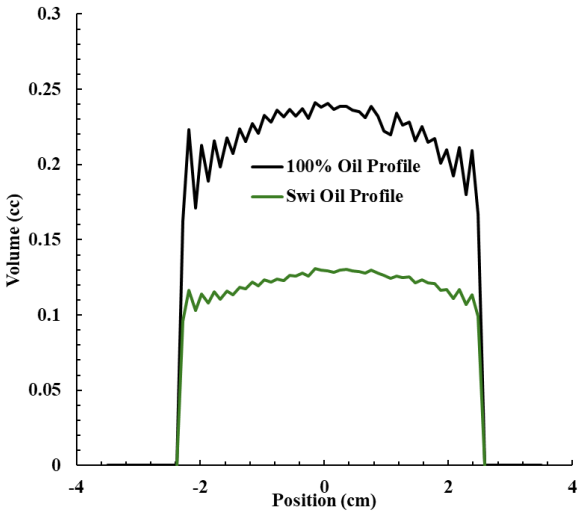


Fig. 5. Oil volume profiles in NMR at 100% oil saturation and at Swi.

Equation (1) can also be used in the 70 discrete points composing Volume profiles of Fig. 5 to compute the saturation profile presented in Fig. 6.

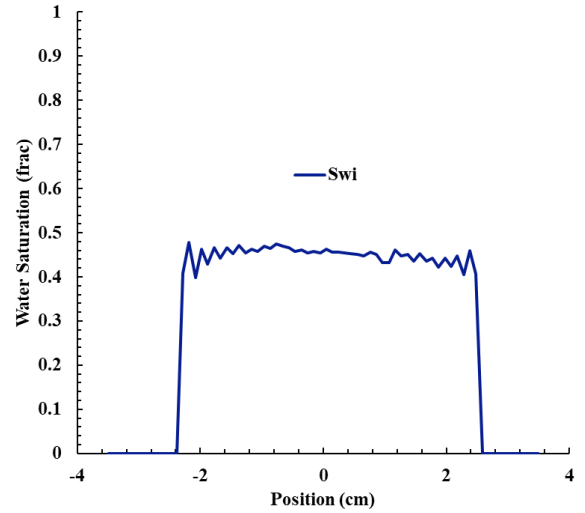


Fig. 6. Water saturation profile computed from Oil volume profile at Swi and at So = 100%.

Saturation profile at Swi is almost perfectly flat. No reversal was used to avoid any re-imbibition possibility as described by Nono [11], but no capillary end effects are observed here. Capillary end effect issues in centrifuges have been discussed by some authors like Sharma [12]. In laboratory conditions, some discrepancies between theoretical capillary pressure at the outlet of the sample (Pc=0) and measured experimental results appear. Explanations are not well established. For this study the main advantage of a flat profile is to provide a homogeneous initial point for the study and increase the probability to obtain homogenous wettability alteration and then wettability index all along the rock. In case of a non-homogenous irreducible saturation profile, the Amott Express should be one of the most robust techniques available because saturation can be computed each millimeter of the rock sample with NMR profile acquisition. This challenge is tackled in the discussion part.

3 Amott Express Technique

3.1. Setup

The experimental device used for the validation of the Amott Express principle is illustrated in Fig. 7. The confining pressure was maintained by an Interchim pump connected to the cell. The confining fluid should not appear in NMR measurements. Fluids like D_2O, dry air or nitrogen or fluorinated oil are suitable. Drainage and imbibition phases were carried out by injecting fluids thanks to a piston pump capable of maintaining low constant flow rates (as low as 0.1 cc/h).

The NMR device consists of a GeoSpec 12 MHz low-field DRX spectrometer from Oxford Instruments, equipped with magnetic field gradients on the vertical axis. This equipment made it possible to monitor saturation profiles thanks to quantitative evolution of volumes during injection phases, respectively by 1D saturation profile NMR pulse sequences and T_2 relaxation time distribution.

The cell containing the sample and the injection tubes are made of PEEK. This cell produces an NMR signal clearly differentiable from the rock sample signal as shown in part 3.3 (Data Analysis). This overburden cell was first used and described by Fernandes [10] with few modifications. In the Amott express technique presented here the diffuser at the top and bottom of the rock samples are "double spiral" diffuser (Fig. 8) to ensure a maximum surface sweeping of the rock samples

In addition to NMR data, differential pressure (ΔP), flowrate (Q) and produced volume are all recorded.

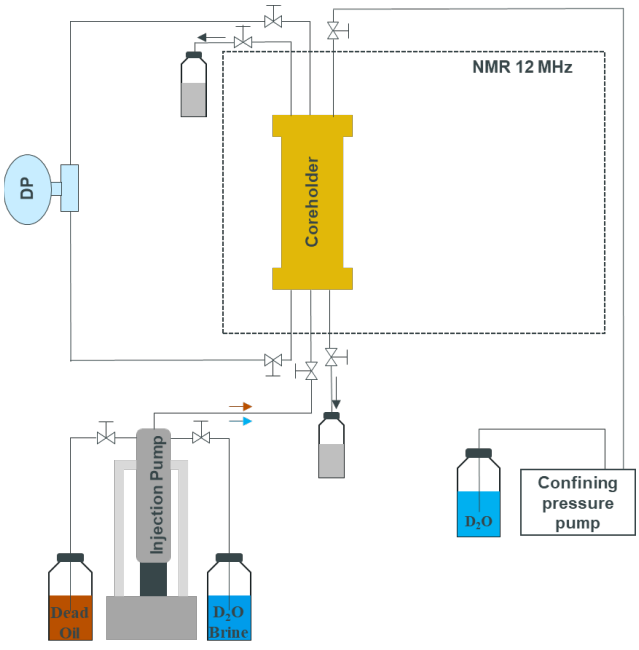


Fig. 7. Schematic representation of the Amott Express experimental setup.

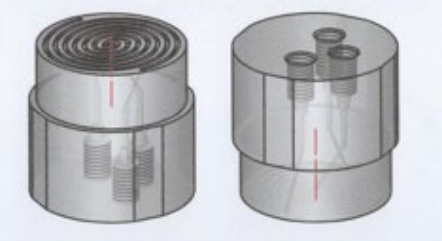


Fig. 8. Schematic representation of the double spiral diffuser used to sweep the sample faces in Amott Express Technique.

3.2. Procedure

A complete Amott express test requires the 5 following steps:

- Ageing: The ageing phase is performed in the Amott Express cell in oven at 80°C. During the ageing, a continuous refresh was performed with a monitoring of Oil permeability (Ko) at Swi. The Ageing process duration is conventionally 1 month but a regular Ko monitoring can help to define the end of this phase (if there is no evolution of the Ko).

- Spontaneous imbibition: An inspiration from the experimental program described by Regaieg [6] and Repina [7] is used here to apply a sweeping at 0.1cc/h of one extremity of the rock. The inlet and oulet lines are both on the same side of the rock and no pressure increase is allowed. Saturation monitoring is done by NMR acquisition with a time-step of 4 hours between each acquisition (a lower or higher time step could be used if necessary). The constant tracking of the produced volume in NMR is a key factor in reducing experimental time. If no, or low evolution (as low as 0.1 s.u. for 24 or 48 hours) is shown then the step could be stopped to move on the next one.

- Forced imbibition: The sample is now flowed by brine at a constant flow rate. Injection line at the bottom of the sample and production line at the top. (closing the production line at the bottom and opening the one at the top) NMR monitoring is maintained, as well as the measurement of the differential pressure between the two faces. When oil production no longer changes, the flow rate is increased. If no produced volume is observed with a flow rate increase the forced imbibition is over.

- Spontaneous Drainage: After saturating the injection lines with dead oil, this step is carried out on the same principle as spontaneous imbibition: sweeping the inlet face (bottom face) at a low flow rate (0.1cc/h) with NMR monitoring each 4 hours. As for the Spontaneous Imbibition, the end of this process occurs when there is no NMR volume evolution.

- Forced drainage: the exact same procedure as for forced imbibition is repeated with dead oil injection. Monitoring and step change conditions are kept the same as Forced imbibition.

During the entire experiment the injection line is positioned at the bottom of the rock sample. This choice has been made to ensure that the same inlet of the rock sample is kept and if any saturation profiles are observed then the inlet face of the rock sample always experiments the highest capillary pressure possible (the entry pressure). Doing so helps with the assumptions made in the 5.1 discussion part about USBM obtention. The only drawback of this choice could appear in the spontaneous drainage. It is linked to gravitational effect due to the differential densities between fluids (oil being lighter that Heavy water, if injected by the bottom it creates a pressure to "go upside"). Considering the densities of the fluids used and the length of the sample the pressure implied here is lower than 1.5 mb (also lower than the uncertainty of the ΔP sensor). It was considered negligible.

3.3. Data Analysis

Each step described in the above section (3.2 procedure) corresponds to a computation of saturation thanks to continuous NMR acquisition. The analysis begins with cutting the NMR signal provided by the cell from the NMR signal of the rock sample. Fig. 9 is the schematic representation of the cut-off used in our experiment. The T_2 of the rock sample is comprised between 1 and 2000 ms while the cell signal is below 0.5 ms. On the right side of the T_2 plot Fig. 9, after 6000 ms, a new signal appears linked to the other equipment used for this experiment as diffusers and injections or production lines).

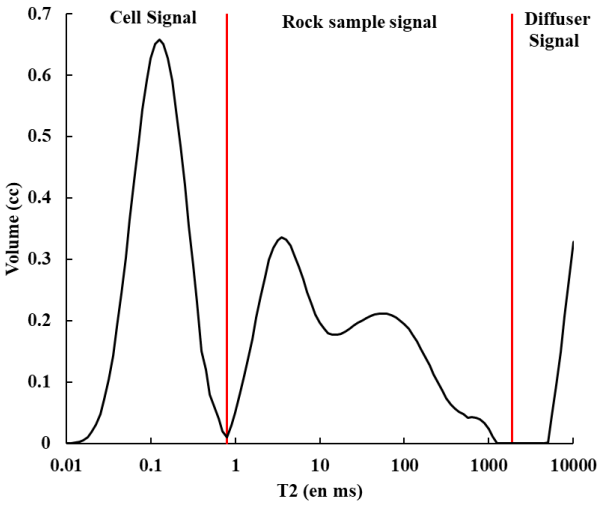


Fig. 9. Schematic representation of an NMR T_2 volume acquisition at 100% Oil saturation with cell signal in black and cut off applied between red lines.

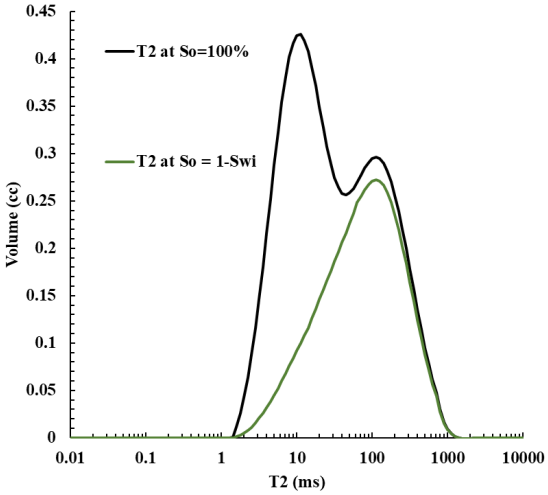


Fig. 10. Schematic representation of an NMR T_2 volume acquisition at 100% Oil saturation and Swi.

After the cut off analysis, NMR T2 are usable to compute irreducible saturation. For example, Fig. 10 shows T2 volume at 100% oil saturation and the T2 at the irreducible saturation state (with D2O as brine). Then, during the Imbibition (Fig. 11) it is also possible to monitor the decrease in oil volume both in spontaneous and forced phase. It leads to an increase of Sw and thus evaluate the water Index as follows:

$$Iw = \left(\frac{Sw_{si} - Sw_i}{Sw_{fi} - Sw_i}\right) \qquad (2)$$

with Sw_{si} the water saturation after spontaneous imbibition and Sw_{fi} the water saturation after forced imbibition.

These water saturations are derived from oil volume acquired in NMR as follows:

$$Sw_{si} = \left(\frac{Vp - Vo_{si\,NMR}}{Vp}\right) \text{ and } Sw_{fi} = \left(\frac{Vp - Vo_{fi\,NMR}}{Vp}\right) \quad (3)$$

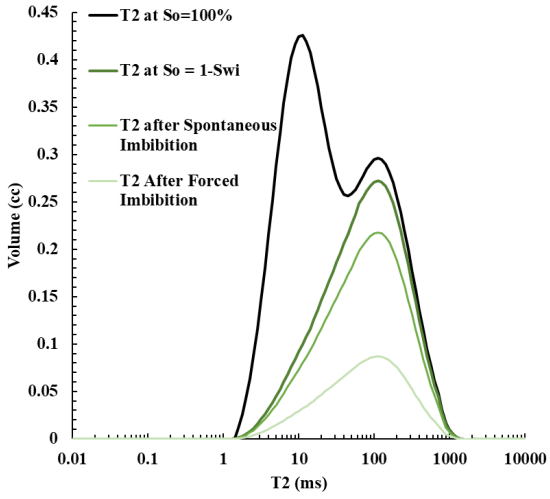


Fig. 11. Schematic representation of an NMR T_2 volume acquisition at 100% Oil saturation, Swi, Sw at the end of spontaneous Imbibition and Sw at the end of Forced imbibition (i.e. Residual oil saturation).

The same saturation evaluation can be done during the secondary drainage (Fig. 12) and permits the evaluation of the Io with the following equation:

$$Io = \left(\frac{Sw_{sd} - Sw_{fi}}{Sw_{fd} - Sw_{fi}}\right) \qquad (4)$$

Sw_{sd} being the water saturation after spontaneous drainage and Sw_{fd} the water saturation after forced drainage.

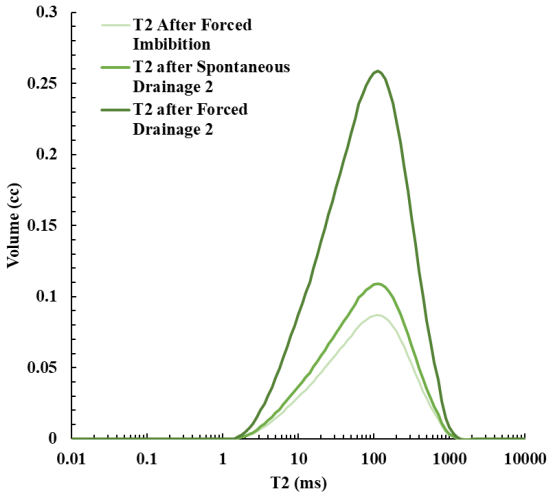


Fig. 12. Schematic representation of an NMR T_2 volume acquisition at residual oil saturation, end of spontaneous drainage and end of forced secondary drainage (Swi2)

At the end of this complete cycle and NMR T_2 computed Amott Harvey Index (I) is available:

$$I = Iw - Io \qquad (5)$$

4 Results

4.2. Spontaneous Imbibition

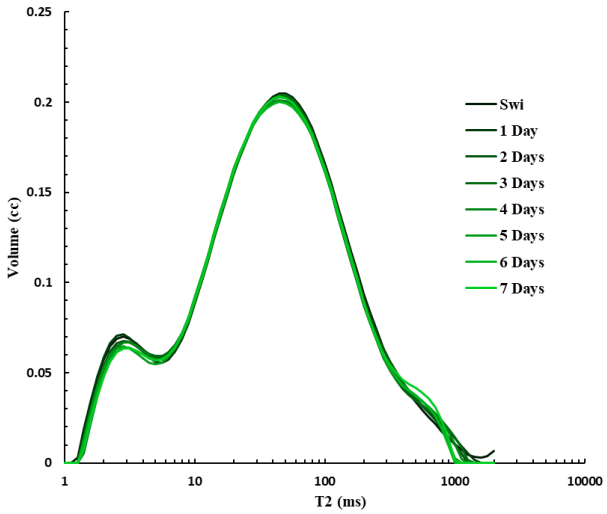


Fig. 13. evolution of T_2 distribution with time during spontaneous imbibition.

As shown on Fig. 13, during the spontaneous imbibition, very few oil production is observed. It leads to a small increase in saturation with quick stabilization. Fig. 14 represents the saturation evolution computed from the T_2 distributions. It highlights the small production of 3 saturation units (s.u.) and the stabilization after 5 days of experiment (Sw change <<< 0.1 s.u./day).

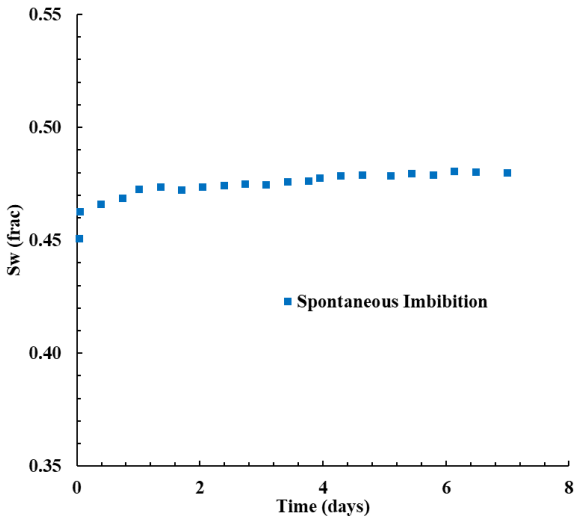


Fig. 14. Average NMR saturation evolution during the spontaneous imbibition.

4.3. Forced imbibition

During the experiment, 7 flow rates from 0.1 cc/h up to 9 cc/h were applied for a total duration of 21 days. The water saturation increased from 48 s.u. to 83 s.u. during this phase (representing a production of 35 s.u.).

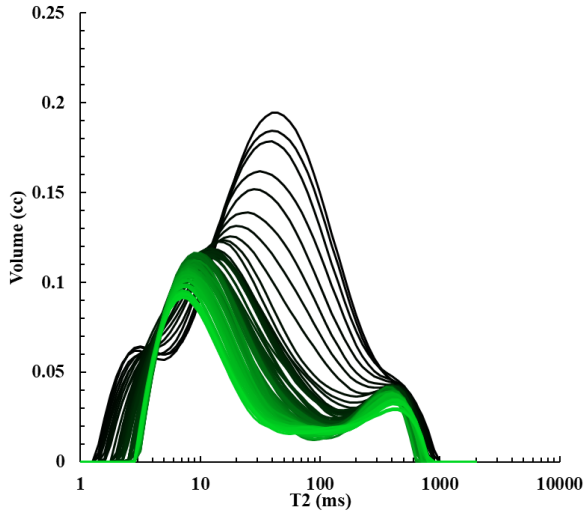


Fig. 15. T_2 evolution monitored by NMR during the forced imbibition.

In Fig. 15 the T_2 distributions are recorded with 4 hours interval. The diminution of volume is clearly visible and the gap between T_2 distributions every 4 hours is reducing with time (sign of stabilization).

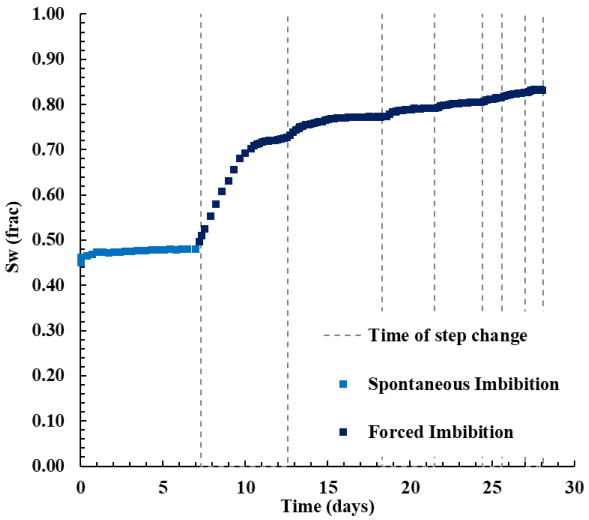


Fig. 16. Average NMR saturation evolution during the spontaneous and forced imbibition.

Fig. 16 is a summary of water saturation evolution against time. For the forced imbibition, the stabilization criterion was met for all steps (saturation evolution inferior to 0.1 s.u. for 24 hours). A significant increase in Sw is observed from the first injected flow rate, followed by a more gradual progression in next steps, to finally reach a Sw of 83 s.u. At this stage the residual oil saturation is obtained (1 – 0.83 = 0.17 = 17 s.u.) and water index is calculated.

$$Iw = \left(\frac{0.48 - 0.45}{0.83 - 0.45}\right) = 0.08$$

The low production in spontaneous phase (3 s.u.) induces the low water Index Iw. Monitoring this evolution with NMR T_2 is a strong advantage here. In this particular case of a bi-modal rock sample the irreducible saturation obtained at the end of primary drainage is fairly high (45 s.u.). At Swi, NMR T_2 clearly shows that oil is mainly present in the biggest pores (pores responding at $T_2 > 5$ ms). The smallest pores (pores responding at $T_2 < 5$ ms) seems to be still filled with D_2O at Swi (invisible in NMR). Iw is then representative of only one pore size of this rock, the biggest ones.

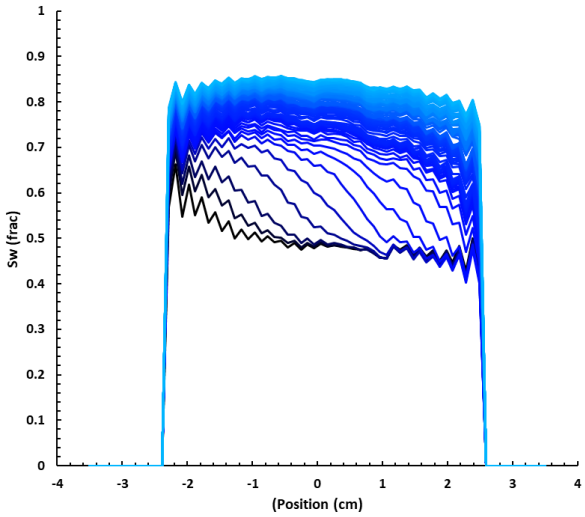


Fig. 17. Saturation profiles obtained by NMR during the forced imbibition.

In Fig. 17 the water saturation profile is monitored throughout the sample. The waterfront is clearly visible at the beginning of D_2O injection (bottom black line on Fig.16). As in relative permeability experiments, this acquisition helps to see the breakthrough (BT) and also the end effects on the saturation all along the rock. Increasing the flowrate helps to reduce this end effect and the superposition of the curves also indicates the stabilization of Sw. The saturation profile is also used to evaluate wettability. It is tackled in the discussion part.

4.4. Secondary Spontaneous Drainage

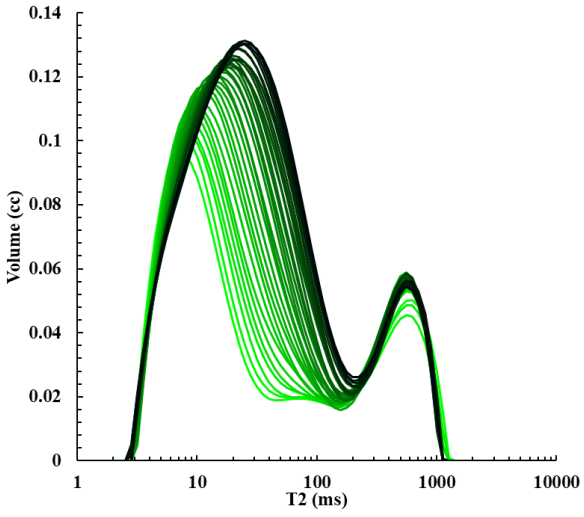
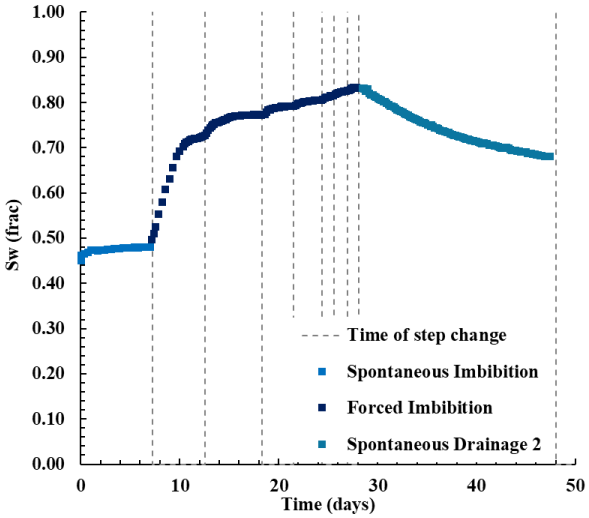


Fig.18. T_2 evolution monitored by NMR during the spontaneous secondary drainage – from light green line for the T_2 at the beginning of forced imbibition to the black line at the end.

During this phase, pores responding at T_2 > 5ms are increasing in oil signal, meaning that oil volume is increasing in this part of the porosity. This behaviour is in line with the previous observations. "Big pores" were mainly filled by oil at Swi while small pores where still filled by water. Ageing could only be efficient where oil is present and thus a spontaneous oil replacement is expected in the big pores and clearly visible on Fig 18.

Fig. 19. Average NMR saturation evolution during the spontaneous imbibition, forced imbibition and spontaneous drainage in green.



The saturation obtained at the end of 20 days of spontaneous drainage is 67.9 s.u. (15.1 s.u. produced during this phase).

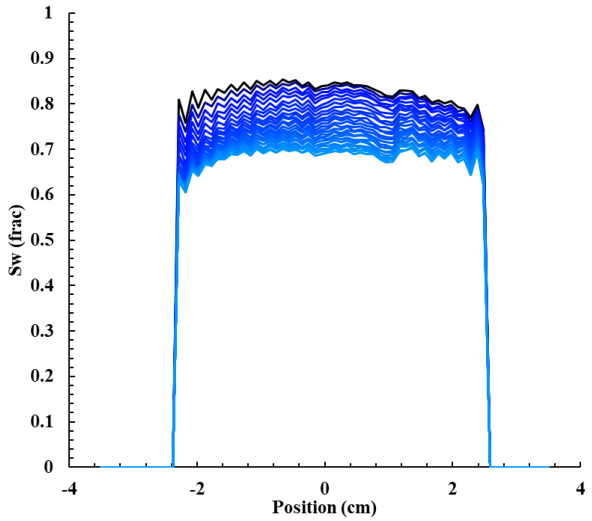


Fig. 20. Saturation profiles obtained by NMR during the spontaneous drainage.

For the spontaneous drainage, the stabilization criterion was not completely fulfilled with a production of 0.2 s.u. on 24h for the last 48 hours of spontaneous drainage. Considering that the suggested time of 480 hours of spontaneous drainage by Reed [13] was reached, and saturation evolution was close to our criterion, the process has been accelerated, and the next phase was launched.

4.5. Forced Secondary Drainage

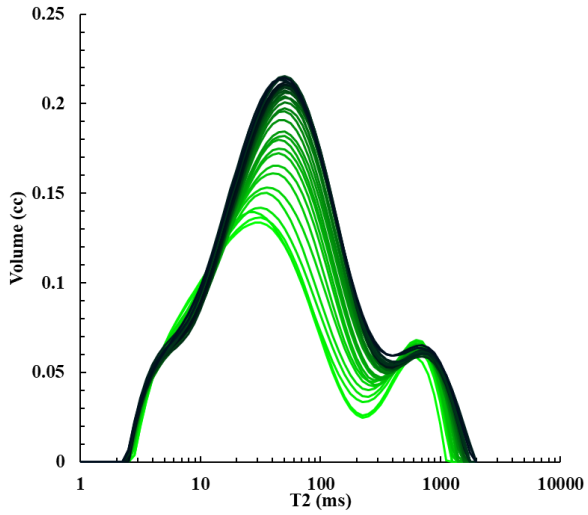


Fig. 21. T_2 evolution with time during forced secondary drainage.

For experimental necessities it was impossible to perform more than two steps of forced drainage. The main objective here is to obtain the Amott Harvey Index and the Swi at the end of secondary drainage is the only parameter needed. Fig. 22 shows that Swi-2 = 47 s.u. was obtained. Even if the acquisition was too quick, stabilization of produced volume was obtained at the same differential pressure as the pressure obtained at Sor. (Amott Harvey evaluation is best used when pressures obtained in imbibition and secondary drainage).

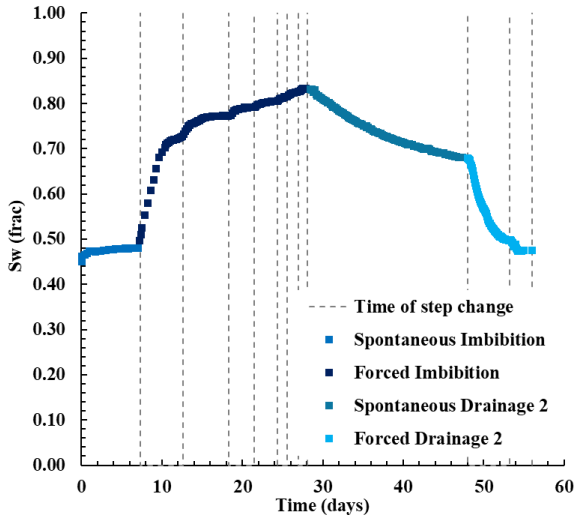


Fig. 22. Average NMR saturation evolution during the 4 phases of Amott Harvey experiment.

The resulting irreducible saturation at the end of secondary drainage is equal to the Swi primary drainage *i.e.* 47 s.u.

$$Io = \left(\frac{0.68 - 0.83}{0.47 - 0.83}\right) = 0.42$$

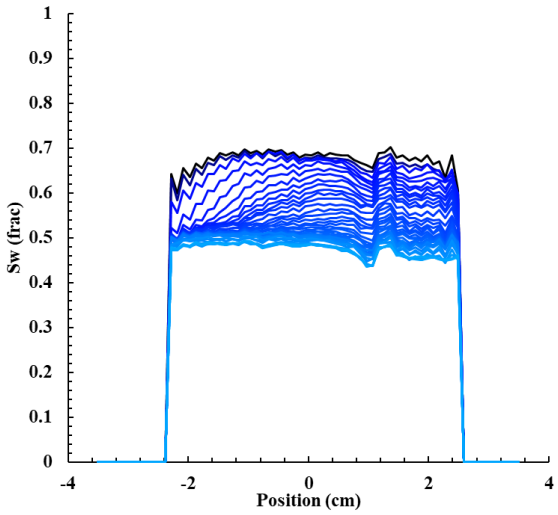


Fig. 23. Saturation profiles obtained in NMR during the forced drainage.

$$I = Iw - Io = 0.08 - 0.42 = -0.34$$

At this stage of the experiment, the global Amott Harvey index is equal to -0.34 and provides a "slightly" oil wet behaviour. The T_2 measurement is an average for all the sample, therefore the resulting Amott index represents the average wettability of the rock sample. Again, it is more representative of what is happening in the "big" porosity of the sample than of the entire porous network (small T_2 pores have not been filled by oil). The following part will show how Amott Express technique allows a second way of evaluating Amott Index but also an USBM evaluation of wettability.

5 Discussion

5.1. Obtaining AMOTT & USBM from NMR profiles data during Amott express

The recorded saturation profiles during the entire Amott Express techniques contains a lot of information. Fig. 24 shows the profiles obtained at the end of each phase. Even when stabilization for a flowrate is reached, a saturation gradient exists along the sample. The average saturation evaluated from T_2 in the result part is different from the local saturation experienced by the rock. As a result, the wettability index can be evaluated all along the rock and wettability variations are plotted against the position on Fig. 25.

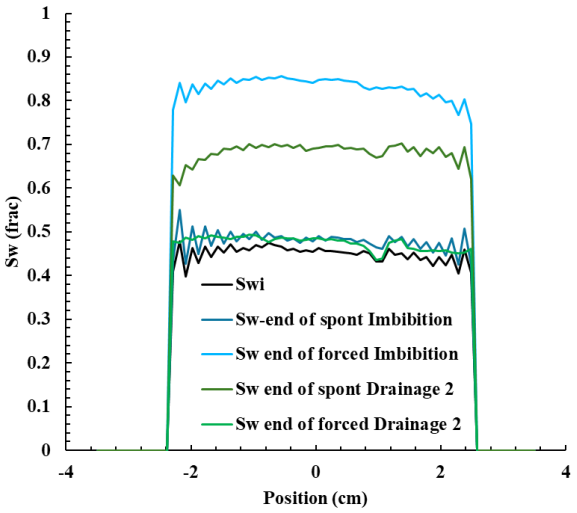


Fig. 24. NMR saturation profiles obtained at the end of each step (Swi, spontaneous and forced Imbibition and Drainage 2).

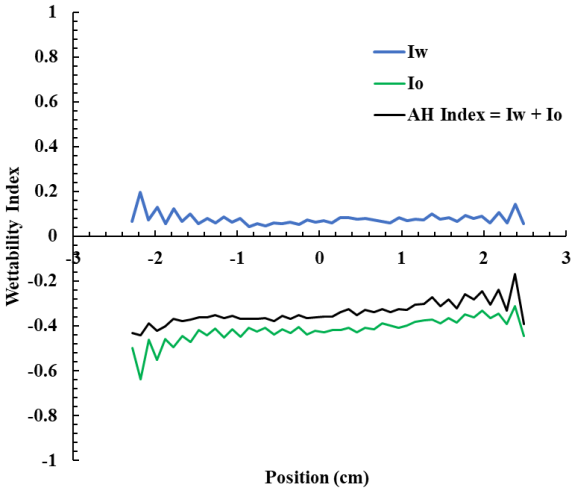


Fig. 25. Corresponding wettability index computed from saturation profiles in Fig. 24.

Fig. 25 shows the Amott Index (and its components Iw and Io) computed from saturation profiles. In this particular case, the profiles are mainly flat at the end of each phase and thus, the global Amott Harvey (I = -0.34) is in good agreement with the one observed on Fig 25 varying from -0.44 and -0.24.

Because the injection of fluid has been done by the bottom of the rock sample and kept the same during the entire experiment (Position = -2.5 cm highlighted by red crosses in Fig. 26) the highest saturation variations are experienced by the rock at or near the inlet face. For example, it is possible to evaluate the inlet face saturation for multiple flow rates (red crosses) for imbibition in Fig. 26 and secondary Drainage Fig. 27.

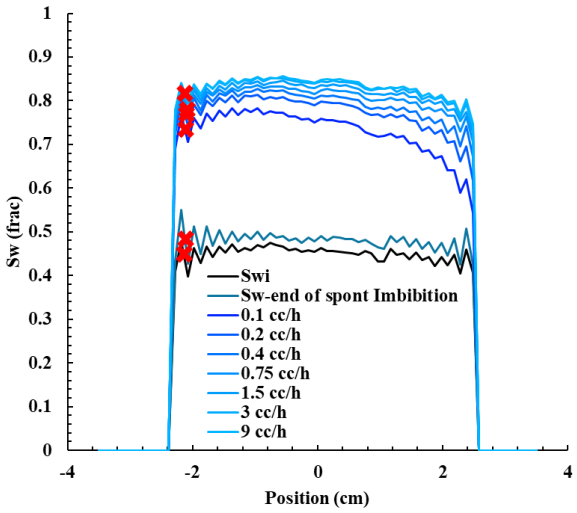


Fig. 26. Saturation profiles obtained in NMR at Swi, end of each step (Swi, spontaneous and forced Imbibition).

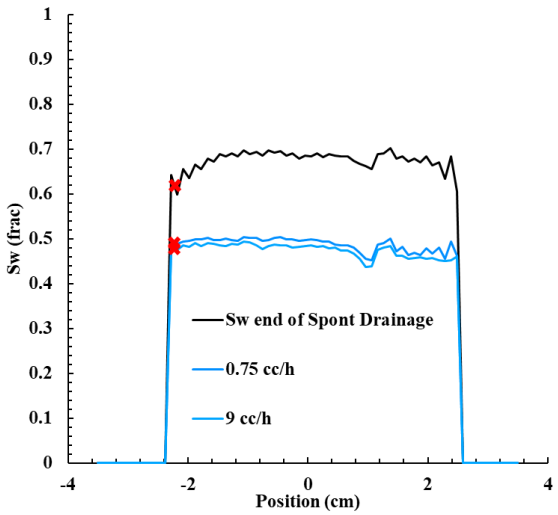


Fig. 27. Saturation profiles obtained in NMR during the secondary drainage.

A common practice in the interpretation of relative permeability curves is to assume that capillary pressure (Pc) at the inlet face is equal to the ΔP once there is no more production for a given flowrate. In our case, this assumption allows to plot inlet face saturation versus Pc(=ΔP) for both imbibition and secondary drainage (Fig. 28). Flow-rates, corresponding ΔP and inlet Sw are summarized in the two tables (4 and 5) below.

Table 4. Imbibition end points

Flow rate (cc/h)	ΔP (bar)	Inlet Sw (frac)
0 (Swi)	0	0.47
0 (end of spontaneous imbibition)	0	0.51
0.1	-0.34	0.75
0.2	-0.41	0.78
0.4	-0.53	0.79
0.75	-0.71	0.80
1.5	-1.01	0.81
3	-1.42	0.82
9	-3.36	0.82

Table 5. Secondary Drainage end points

Flow rate (cc/h)	ΔP (bar)	Inlet Sw (frac)
0 (Swi)	0	0.82
0 (end of spontaneous drainage)	0	0.68
0.75	0.33	0.45
9	3.05	0.43

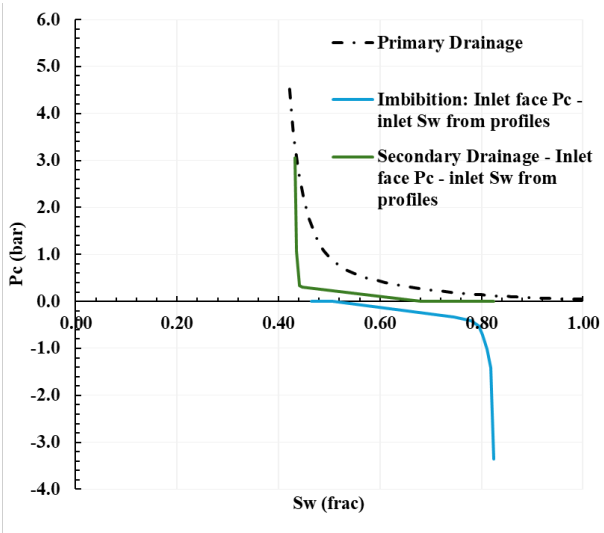


Fig. 28. Capillary pressure curves obtained with NMR profiles during the full Amott Cycle.

Given that both Pc curves are available, the USBM index calculation is possible as provided by Donaldson [14]. Areas below Pc imbibition and Pc secondary drainage are computed, resulting in USBM = -0.27.

This result is in agreement with the global Amott Harvey index obtained from T_2 acquisitions (I = -0.34) and is providing the same insight about wettability of this rock: a slightly oil wet behaviour.

5.2 Accelerating Spontaneous acquisitions.

The spontaneous phase is defined as the saturation at Pc=0. In classical Amott test, this is obtained by waiting for a complete spontaneous phase. If we could ensure that Pc=0 at the outlet during a flooding experiment, the saturation information at the outlet face would then directly give the desired information. This would accelerate the measurement by removing the spontaneous phases.

In our experiment the outlet face saturation changes with various flow rates (Fig.26). This proves that the Pc=0 condition is not perfectly met in our experiment. Further developments of the Amott Express technique will concentrate on this effort, for example sweeping the outlet face as recommended by Lenormand [15]. This will allow to further accelerate the measurement, avoiding approximatively 20 to 30 days of experiment in imbibition and the same time in secondary drainage.

Conclusion

In this paper the Amott express technique is presented with a real case application to show the actual possibilities given by this technique. This experimental setup is able to provide a massive amount of data. Acquisition of NMR volume and saturation from T_2, saturation profiles with 1mm resolution along the rock sample every 4 hours or less are used to monitor the evolution of saturation and accurately determine stabilization.

The amount of handling needed to perform the full Amott is divided by 4: a single cell is used for the entire process, avoiding multiple tedious mounting and unmounting of samples in various spontaneous and forced cells. This amount of handling could further be reduced by including the primary drainage in the same test.

Reduction of handling and accurate monitoring of stabilizations times can already reduce the entire experimental time by two months.

This paper is a proof of concept on the experimental setup. It demonstrates the tremendous advantages of the technique. However, several improvements are possible and going to be evaluated.

For example, the Amott Express technique with accelerating spontaneous acquisition as expressed in part 5.2 could reduce the acquisition time by two extra months (one for each avoided spontaneous phase) and provide both Amott and USBM indexes in half the conventional time.

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