THE ROLE OF INTERSTITIAL WATER IN HYDROCARBON FLOW FOR TIGHT ROCKS

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ABSTRACT

Low porosity and permeability rocks such as seal and fault rocks have a significant impact in trapping and retaining hydrocarbons. The displacement (drainage) of oil and gas through these rocks has been the focus of many studies. However, the role of water during hydrocarbon trapping and flow is less understood and different hypotheses have been proposed to explain some of the experimental and field observations. The main aim of this paper is to improve the understanding of the role of interstitial water in reducing the hydrocarbon permeability and interruption to flow due to water blocking.

Steady state gas flow experiments performed in tight rocks, at constant saturation and different rates, showed non-Darcy behaviour. A positive pressure at which the gas stops flowing, here called water-blocking pressure, has been observed and its value determined at different saturations. The results presented demonstrate that relative permeability is difficult to determine in tight rocks and as a consequence misinterpretation of the results can easily occur. Also, the experiments clearly show that the water, even when not flowing, plays a crucial role in the observed behaviour, impeding the flow or trapping some gas.

INTRODUCTION

The primary control of hydrocarbon trapping in the sub-surface, low permeability, seal and fault rocks, and the sealing efficiency are crucial in petroleum exploration (oil and gas) and reservoir evaluation. Fault and tight rocks usually act as total or partial flow barriers. Leakage and trapping are also important in underground gas storage and liquid waste repositories.

Hydrocarbons migrate into reservoirs and fill traps during periods of active expulsion from source rocks. The hydrocarbon supply continues until deep burial of the source rock stops. A problem that is of common interest is the leakage from the trap, which can potentially decrease the size of the accumulation. Hydraulic-resistance seals fail when a leak becomes geologically significant, but the dynamics of oil flow in sealing rocks does not play any role in the determination of the sealing properties if a static assessment is used. However, the leak rate must be less than charge rate for the accumulation to exist.

Two vital elements of the dynamic of this problem are controlled by the water within the pore space: 1) the oil flow or leakage rate, controlled by the capillary pressure and hydrocarbon effective permeability and, 2) the pressure or hydrocarbon column height at which the seal reactivates when the supply stops and the pressure decreases.

There are many areas where the phenomena of trapping, leakage and seal reactivation play a crucial role, such as hydrocarbon accumulation (Brown, 2003), CO_2 storage (Chiquet *et al.*, 2005), or near wellbore gas flow and gas deliverability (Laroche *et al.*, 2000). The sealing and leakage of caprocks have been studied previously (Fisher *et al*. 2001; Underschultz, 2007). However, the condition at which the flow stops has not been experimentally investigated in detail. Remaining pressure after breakthrough or drawdown test, have been previously observed and reported. However, a range of terminologies and possible explanations has been used to refer to this phenomenon. For example, some researchers studying the threshold or breakthrough pressures mentioned a remaining pressure as “disconnection” due to rapid release of pressure; others attributed this effect to water imbibition (Smith *et al.,* 2005; Hildenbrand *et al.*, 2002). It has been also called “oil column after leakage” expressed as a percentage of the oil entry column height by Vassenden *et al.* (2003), or “apparent matric pressure” in clay when referring to spent nuclear fuel repositories (Horseman et al., 1999).

The main aim of this paper is to experimentally study the gas leakage flow in order to determine the effective permeability and improve the understanding of water blocking. The implications for relative permeability interpretation are also discussed.

EXPERIMENTAL METHODOLOGY

Sample preparation

Core samples from a gas reservoir were used in this study, Table (1). The reservoir rock is a low porosity well cemented fine grained quartz, of predominantly aeolian origin. The main diagenetic reaction responsible for reduction in pororosity is quartz cementation and pressure solution (Figure 1). The core plugs were scanned using an X-ray computer tomography (CT) system to identify their homogeneity and integrity. Full sample characterisation included: microstructure analysis using a scanning electron microscope (SEM), mercury porosimetry and NMR. All the core plugs were cleaned by Soxhlet extraction with toluene/methanol and dried before being tested. Porosity was measured using a helium expansion porosimeter. Brine (containing 5% NaCl, degassed and filtered through 0.45 μm) was used to saturate the core plugs. Four flow rates were used to obtain the absolute permeability, in order to select the rates to be used in subsequent experiments, and to check that no inertial effects exist in the flow range used. Further details of the equipment used can be found in Al-Hinai et al. 2006.

Table 1. Basic properties of the cores analysed in this study.

Sample	Length (cm)	Diameter (cm)	Porosity (%)	Brine Permeability (mD)
O2-62	4.68	3.79	8.5	0.068
O2-1	4.61	3.82	8.4	0.049
O3-5	4.63	3.82	5.6	0.0047

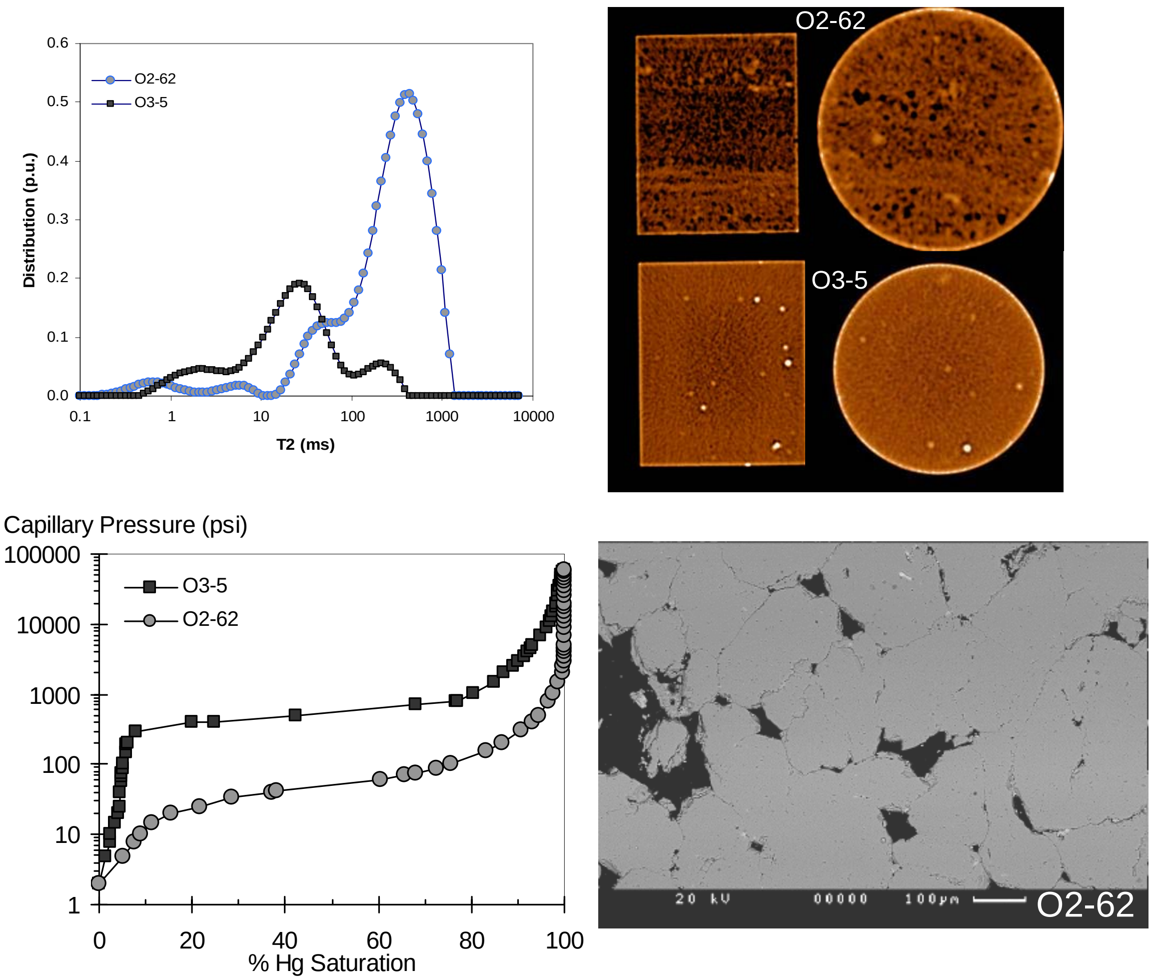

Figure 1. Sample characterization: NMR T_2 distribution, X-ray CT imaging, mercury capillary pressure and SEM. All the techniques clearly show that sample O3-5 is more homogeneous and presents smaller pore-throats than sample O2-62.

Methods

The experimental apparatus to conduct the test is conventional and consists of a hydrostatic core holder (PCRI MUS from Ergotech), syringe pumps (ISCO 100DM), differential pressure transducer (Validyne DP215-56) and a balance (Ohaus, Mentor) to monitor the water production. A schematic of the apparatus is shown in Figure 2. All the tests were performed at a constant confining pressure of 2000 psi and the gas was humidified before entering the sample.

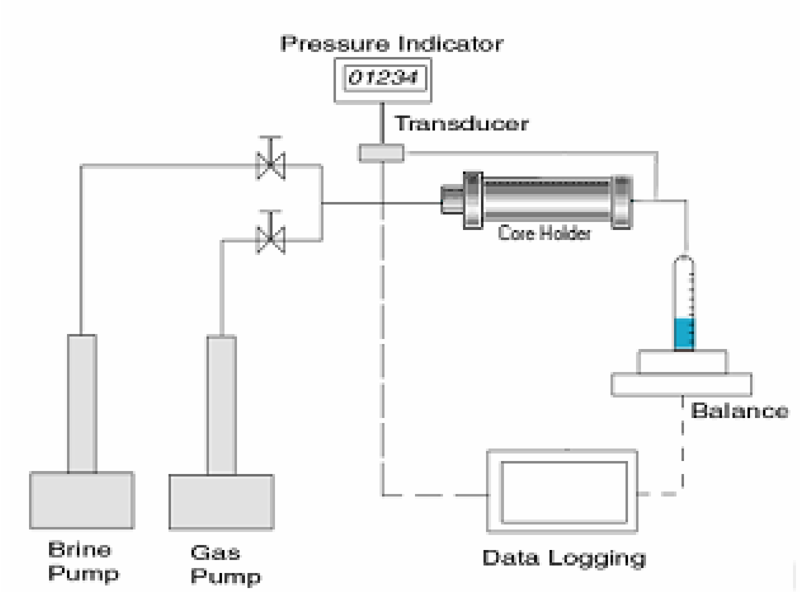

Figure 2. Schematic of the experimental set-up

Two separate experiments were performed on the same samples: 1) A modified version of residual capillary pressure (Hildenbrand *et al.*, 2002) with the objective of monitoring the water saturation and obtain the residual pressure at equilibrium or water blocking pressure. The main differences are that the downstream pressure was kept constant while the upstream decreased. 2) A series of steady-state gas flow tests at constant saturation in decreasing or increasing stepwise rate mode in order to determine the effective permeability.

RESULTS AND DISCUSSION

Water Blocking Pressure

In order to determine the water blocking pressure, a transient pressure decay test was performed with a declining pressure in the upstream side and constant pressure in the downstream. In high permeability cores upstream pressure drops rapidly and the pressure drop remaining across the sample is either zero or very small. However, this is not the case in tight rocks as the gas stops flowing before the pressure decays to a lower value, here called water-blocking pressure. An example of the pressure decline test is shown in Figure 3. It can be clearly seen that the pressure follows an exponential decay and does not decay to zero. When the test was performed at a lower saturation the water blocking pressure decreased, see figure 3-B. During previous experiments under different experimental conditions, we observed that an initial pressure was required to initiate the flow, which seems to be due to a similar effect. Water invasion or imbibition could be responsible for the observed effect (Hildenbrand et al, 2002); however, this mechanism can be eliminated in our experiments as all the water exiting the core has been removed. Additionally when the saturation is decreased the water-blocking pressure also decreases, as shown in Figures 3-B and 4.

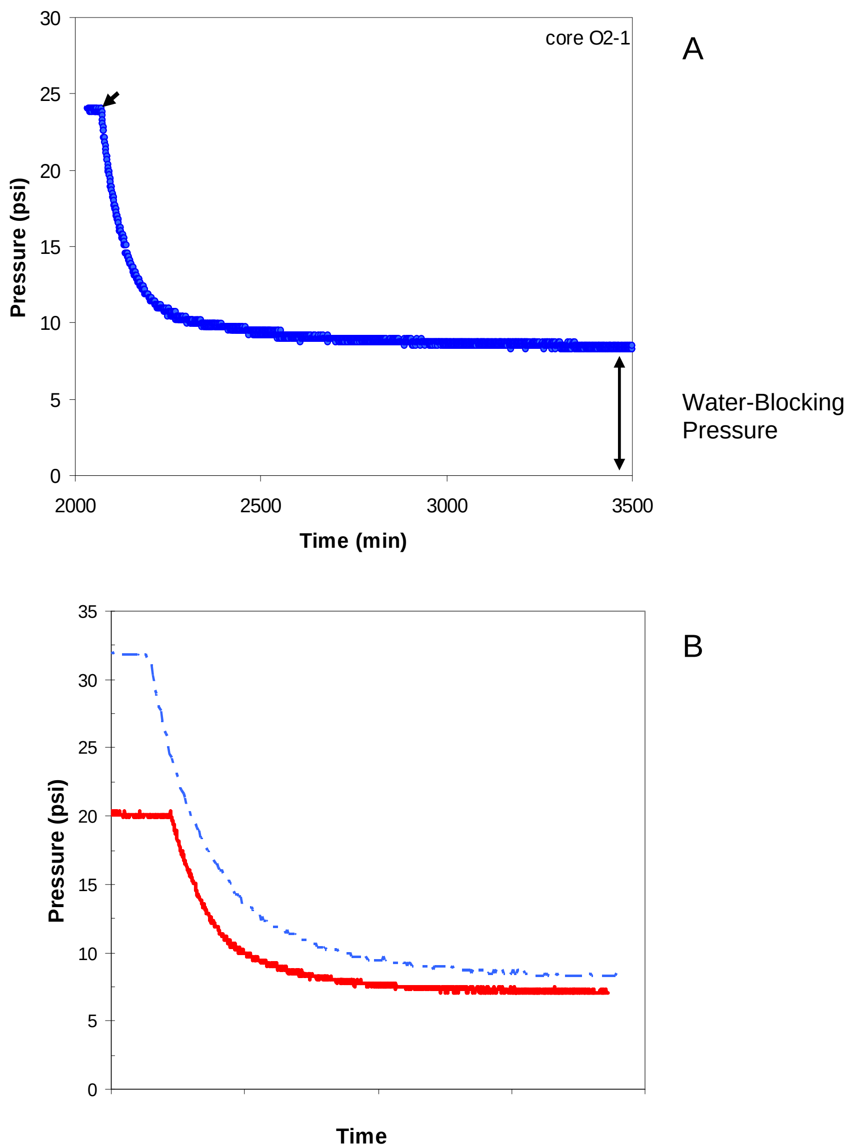

Figure 3. Pressure drawdown test showing the water blocking pressure.
A) sample O2-1 and B) sample O2-62 at different saturations.

This behaviour can be explained by water snap-off at pore level due to internal water redistribution. During gas flow the drag forces acting on the gas-water interfaces, mainly in the throats, maintains the gas pathways open and move some of the water to the pore bodies where the velocity is smaller, at the same time that a high capillary pressure is imposed. During the pressure decline phase the gas pressure decreases, so does the capillary pressure, thus water in pores, crevices and films redistribute changing the interface curvature and accumulating some water at the throats. Any fluctuation can cause a capillary instability that can lead to water snap-off in the smallest pores reducing the connectivity of the gas network and flow path. As the pressure decreases further, other throats get blocked until eventually the gas becomes disconnected. As a consequence no further gas can be produced and the pressure remains constant (water blocking pressure).

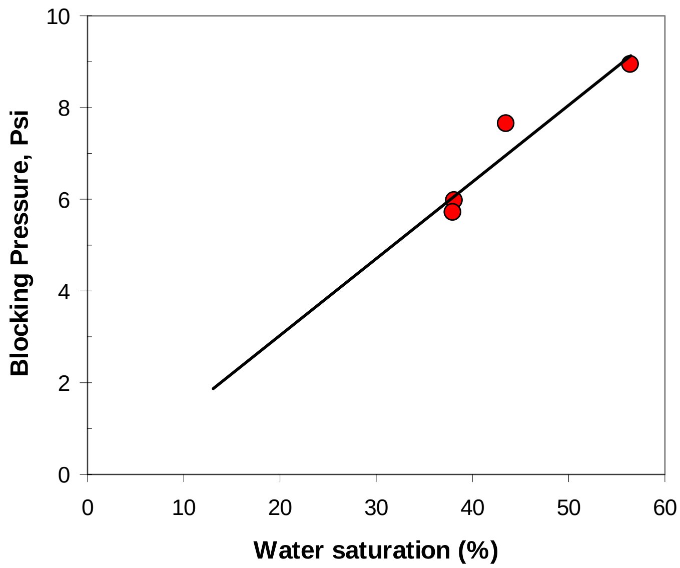

Figure 4. Water-blocking pressure at different saturations for sample O2-62.

<u>Brine and gas flow</u>

While the absolute permeability to brine by steady state was determined, inertial effects were noticed at higher flow rates. The pressure gradient versus brine flow velocity for sample O2-62 is shown in Figure 5A. Thus, the gas flow rates were selected to minimize Non-Darcy inertial effects.

During the experiments described in the previous section, the minimum water saturation obtained was 38 %. In order to determine the effective permeability and verify Darcy's law gas was injected at constant rate. The rate was decreased in stepwise stages and a series of successive steady state data was obtained. The results for sample O2-62 clearly show that the flow is non-Darcian, Figure 5B. A linear relationship can be observed between pressures and flow rates, but the intercept, at zero flow, corresponds to positive pressure. Normally for high permeability rocks a straight line going through the origin would be obtained, following Darcy's law. However, this was not the case for the low permeability cores tested here. The same results were obtained after recalibrating the pressure transducer and verifying the rate delivered by the pump. It is worth noting that the pressure gradient at zero velocity agrees very well with the water blocking pressure obtained during the drawdown test at the same water saturation.

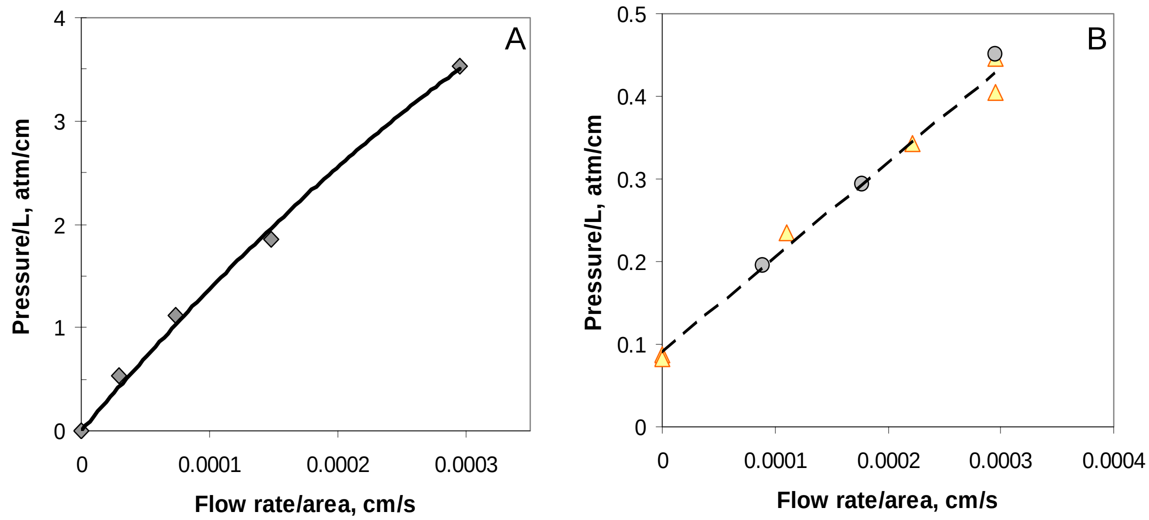

Figure 5. Behaviour of the flow-pressure relationship during steady state flow, sample O2-62. A) Brine flow in a fully saturated core, B) Gas flow in a partially saturated core at decreasing flow rates. Circles and triangles correspond to repeated experiments.

The interpretation and calculation of the effective permeability for these rock samples is thus non-unique and at least two interpretations are possible: 1) Assume that Darcy's law is valid and a linear relationship exist between each measurement point and the origin (0, 0); then effective permeability appears to be rate dependant. However, this approach ignores the water blocking pressure. 2) Before the flow through the core can start, the pressure needs to be higher than the water blocking pressure, which is a function of the initial saturation. Thus, the effective permeability (Darcy's law) can be obtained from the slope shown in Figure 5B. The latter scenario can be explained by capillary controlled snap-off. As the flow rate decreases so does the capillary pressure, thus the water redistributes within the pores and instabilities induce water snap-off. The pore blocking by water increases at lower flow rates. The process is similar to that previously described during the drawdown tests.

Horseman et al. (1999) also performed a descending history of flow rates in clay samples and they concluded that this produced variable gas permeability due to variable net stress and the tendency of the pathways to dilate with changes in the pore pressure. This is unlikely in our case as the core plugs used in this work are well consolidated and cemented. Additionally, confining pressure tests during pulse decay measurement of absolute permeability on our samples showed a very small effect of effective stress. This not so usual dependence for low permeability rocks may be due to grain-grain interlocking and the aspect ratio of the larger pores, shown in Figure 1, which are close to unity and have a lower stress dependency (Yale, 1984). On the other hand, Hildebrand (2002) suggested water invasion or imbibition for the variation of gas permeability in mudstones. However, these mechanisms have been eliminated in our experiments by removing all the produced water. Thus, water redistribution during flow due to drag forces acting on the gas-water interfaces, which are function of the local gas velocity, and water snap-off are the most likely mechanisms.

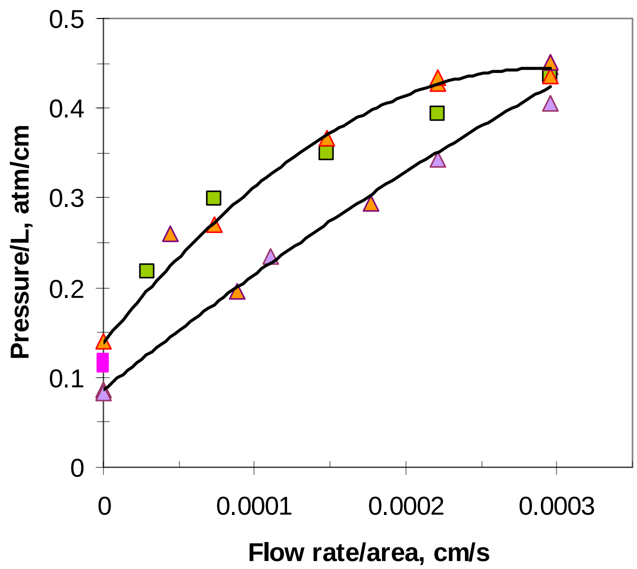

Figure 6. Hysteresis effect observed during stepwise increasing and decreasing flow rate.

In order to test this hypothesis an additional test was performed by increasing the pressure in steps to obtain a series of successive steady states. The results are shown in Figure 6. Water blocking effect and pressure hysteresis can be clearly observed. This effect is consistent with the water snap-off behaviour described in the previous section. Also it is worth noting that the pores entry pressure is always higher than the snap off pressure (Chambers and Radke, 1991; Vassenden *et al.*, 2003). Also as the connectivity of the gas network and flow path increases smaller pores get incorporated into the network. However, the contribution of smaller pores to permeability is nonlinear and proportional to the throat size, thus inducing a non-linear behaviour.

Assuming Darcy's law is valid and that the blocking pressure is a function of water saturation, the flow equation can be written as:

$$\frac{\Delta P}{L} = \frac{\mu\, Q_g}{K\, k_{rg}(S_W)\ A} + \frac{P_{wb}(S_w)}{L} \tag{1}$$

were $\Delta P/L$ is the applied pressure gradient, μ the gas viscosity, Q_g the gas flow rate, K the absolute permeability, K_{rg} the relative permeability, which is function of water saturation (S_w), A the core cross sectional area, L core length and P_{wb} water blocking pressure. The blocking pressure at different water saturations combined with gas steady state flow can be used to obtain the gas relative permeability as a function of water saturation. A summary of results is shown in Figure 7. The sharp decrease in gas permeability with water saturation is consistent with previous results presented by Al-Hinai *et al.* (2006).

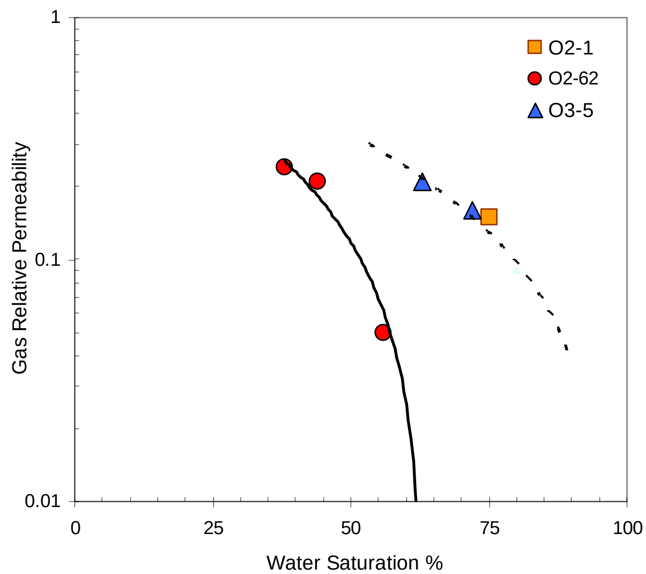

Figure 7. Gas relative permeability for the tight cores calculated using Eq. 1.

CONCLUSIONS

The experiments performed closely represent the main processes occurring during hydrocarbon leakage, which can potentially decrease the size of the accumulation, as well as secondary migration of oil. Water blocking due to snap-off seems to be an important mechanism for secondary hydrocarbon migration, leakage and seal reactivation. Otherwise, if the leak does not stop no hydrocarbon will remain in the initial trap.

The effective gas permeability at various flow rates and water saturations for tight rocks was determined and the controlling role of water interpreted. From the results it can be concluded that the water controls the effective permeability even when it is not being produced. At low flow rates during pressure decline the water can block completely the gas flow, even when a pressure gradient exists across the rock. This water blocking phenomena was observed under different experimental conditions. Water snap-off due to internal water redistribution is the most likely mechanism producing the observed phenomena.

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