A NEW METHODOLOGY TO EVALUATE THE IMPACT OF THE LOCAL HETEROGENEITY ON PETROPHYSICAL PARAMETERS (KR, PC): APPLICATION ON CARBONATE ROCKS

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ABSTRACT

This paper presents an innovative methodology to integrate the local heterogeneity characterized by the local saturation measurements in the history matching procedure of the relative permeability (kr) and also to evaluate the impact of this rock local heterogeneity on the petrophysical parameters (kr, Pc).

The saturation profiles are routinely measured during SCAL experiments. Several ways exist to use this information in the inversion procedure for the determination of the kr data. To date, the local saturation profiles are either included in a global objective function that is minimized during the inversion process, or smoothed and used as input data in the simulation, which leads to non-smoothed simulated pressure drop. None of these methods permit the reproduction of the local saturation fluctuations that are often measured on carbonate samples. Our approach has the advantage in that it incorporates these fluctuations to characterize the petrophysical properties for a given rock-type. The proposed method uses upscaling techniques that are routinely applied in reservoir simulation and that are based on the pressure data. Both the stabilized and transient saturation profiles are analyzed to evaluate the local properties.

Several examples conducted on carbonate samples with either gas/oil or water/oil systems are shown. The results demonstrate that it is possible to reproduce very accurately both the production data and the local saturation profiles. The output of the proposed methodology is not only a set of kr, Pc curves but an interval of best confidence for kr and Pc since the petrophysical properties are calculated at every section where the local saturation is measured. The spreading of the kr, Pc data due to the heterogeneity within a given rock-type can then be assessed from only one experiment and can be used to perform uncertainty studies at the reservoir scale.

INTRODUCTION

Petrophysical parameters assessment

Both the relative permeabilities (kr) and the capillary pressure (Pc) curves are key factors for assessment and prediction of the hydrocarbon recovery of a field. Representative curves are routinely obtained through SCAL (Special Core Analysis Laboratory) studies, which permit the reproduction as close as possible of the reservoir conditions. These conditions mainly concern the thermodynamics conditions (Pressure, Temperature), the reservoir stress (overburden pressure), the nature of the fluids (synthetic reservoir brine, live oil), the initial saturation state (low S_{wi} value) and the in-situ wettability (preserved samples or restored wettability through an aging process at S_{wi}).

Relative permeabilities are usually determined from flow experiments performed on core samples using either the Unsteady Steady State (USS) or the Steady State (SS) method, where either one or two fluids respectively are injected. The centrifuge technique can also be used but not at full reservoir conditions [18]. Whatever the approach followed, the experimental results must be interpreted using capillary pressure curves. Virsnosky et al. [21] proposed an analytical method to correct the SS data for capillary pressure. However, numerical simulations are needed for both USS and SS because a complete analytical solution does not exist. The kr curves can either be optimized in order to history match the experimental data knowing the Pc curve (from another experiment) or both kr and Pc curves can be optimized simultaneously [; 12].

More recently, it has been shown that both kr and Pc curves can be determined at reservoir conditions using the semi-dynamic approach [14]. The main advantage of this method is to establish several equilibrium states between the viscous and the capillary forces within the sample by injecting one fluid while the other circulates at the outlet face. These equilibrium states enable the analytic of both the kr of the injected phase and the Pc curve. The kr of the displaced phase can also be obtained by history matching of the transient evolution of the pressure drop.

The in-situ saturation monitoring, which is now widely implemented in SCAL studies, brings a significant added value to the interpretation process because it enables the direct identification of the influence of the capillary effects on the experimental data. Several ways exist to use this information in the inversion procedure of the kr data. To date, the local saturation profiles are either included in a global objective function (in addition to the production and the pressure drop data) that is minimized during the inversion process, or smoothed and used as input data in the simulation, which leads to non-smoothed simulated pressure drop. Local saturation fluctuations often take place in carbonate samples during coreflood experiments. These saturation fluctuations cannot be anticipated during the preliminary core selection process because they are due to small-scale local variations of the petrophysical properties. Therefore, none of the available methods permit the accurate reproduction of both the production data and the heterogeneous saturation profiles in an automatic way.

Background on rock heterogeneities

Because the core heterogeneities can severely affect the determination of the petrophysical parameters, a SCAL study always begins by a preliminary selection and sampling process in order to retain the best cores within a given rock-type. Various techniques can be used and combined to finalize the selection: CT-scanner, NMR, HPMI, tracer tests [4]. Whatever the techniques and the methodology, the petrophysical parameters (k, ϕ, kr, Pc) are seldom homogeneous within the entire core.

Graue [9] reported an interesting study on an eolian sandstone originally considered as homogeneous, which showed unexpected saturation profiles during coreflood experiments. The saturation fluctuations were successfully interpreted as a result of permeability and capillary pressure heterogeneities. Honarpour *et al.* [13] showed through several displacement experiments conducted on cross or parallel bedding cores, that the structure of the heterogeneity itself played a major role in the relative permeability curves shape. These conclusions were confirmed by Mannseth et al. [16], who interpreted synthetic experimental data with different heterogeneity structures : tilted lamina, unstructured heterogeneity distribution and flow barriers. Hamon and Roy [11] explored the influence of the coreflood design as a function the heterogeneity type, along or across bedding samples. They generated numerical experiments through a finely, well characterized model and the interpreted kr curves were compared to the input curves. One of their conclusions is that the USS experiment is very sensitive to along-axis heterogeneities.

Saad *et al.* [19] succeeded in history matching both the production data and the heterogeneous saturation profiles presented by Honarpour *et al.* [13] by introducing a limited number of kr, Pc models in the simulation code. Fincham and Gouth [7] presented an interesting analysis of a multi-rate coreflood experiment, which showed heterogeneous saturation profiles. Because the stabilized profiles result from an equilibrium between the viscous and the capillary forces, they observed that the saturation profiles tend to become more homogeneous at the highest bump flow rates (higher viscous forces). It was possible to reproduce all the experimental data by implementing a single set of kr curves and two sets of Pc curves accounting for low and high permeability facies.

Outline

This paper presents an innovative methodology to fully account for the local heterogeneity characterized by the saturation measurements in the history matching procedure of the petrophysical parameters (kr, Pc). The proposed approach takes advantage of these fluctuations to characterize the petrophysical property variability within a rock-type due to the rock local heterogeneity. The method is derived from upscaling techniques that are routinely applied in reservoir simulation and that are based on the pressure data, which are, contrary to the saturation data, already a smooth function even when the heterogeneity level is significant. Both the stabilized and transient saturation profiles are analyzed to evaluate the local properties.

The first part of the present paper is devoted to the presentation of the proposed approach. A literature review on the use of local saturations in SCAL and the background about upscaling techniques in reservoir engineering is first presented. The principle of the approach is then illustrated through a synthetic case and the general workflow to interpret an USS experiment is described. Several applications of the method are then described in the two next parts on carbonate samples with either gas/oil or water/oil system. The results and the utilization of the petrophysical parameters obtained through this approach for field simulation purposes are discussed in the last part.

THE PROPOSED HETEROGENEOUS APPROACH

As described in the introduction, the rock heterogeneity affects the experimental saturation profiles very frequently. Several experimental techniques exist to identify this heterogeneity, and results from these techniques can be accounted for in the numerical simulation. Nevertheless, the heterogeneity is seldom taken into account in the interpretation process although several studies demonstrated that significant improvements can be made using local petrophysical parameters. The mathematical approach based on numerical inversion of the problem is too complex and time consuming to be handled. The trial-and-error method is too subjective and only applicable on a limited number of petrophysical models. Therefore there is a need to develop a physical approach to assess these parameters directly from the experimental data in a consistent manner.

Use of local saturations

Undoubtedly, the local saturation profiles bring a significant improvement in the interpretation of coreflood experiments by a better accounting of the capillary pressure effects during the relative permeabilities determination. But, do we use all the information?

The most conventional approach is to use an homogeneous numerical model, a single set of kr-Pc curves, and the saturation data added to the production data to calculate the objective function. At each iteration step, this function is then minimized by adjusting kr (and Pc) curve(s). Several papers showed that the inclusion of the saturation data considerably improved the determination of kr, Pc curves especially at low injected fluid saturation [3]. Nevertheless, the optimized simulated saturation profiles pass through the experimental data in only an average sense but cannot reproduce the local heterogeneities. Mejia and Mohanty [17] proposed to improve this procedure by incorporating local end-point saturation in the inversion procedure. They found a better match of the saturation profiles but the large number of parameters to be considered makes the optimization process very time consuming.

Another approach consists in processing directly the local saturation data [6; 8]. The particularity of this approach is to get rid of the local heterogeneity effects by smoothing the saturation profiles and to use them as input data for the numerical simulator. This leads to simulated pressure profiles that are not smooth, which is not in agreement with the reality that the pressure drop curves should be always smooth whatever the level of heterogeneity inside the core. Therefore, this approach permits the reproduction of the saturation data in all the cases (input data in the model) but it fails to take into account the heterogeneity and produces non-realistic pressure drop responses.

The latest approach is the one followed by Graue , Ficham and Gouth and Saad et al. [7; 9; 19]. It consists in implementing several kr, Pc models in the simulator to account for the local heterogeneities. These existing studies demonstrated that this approach permits significant improvements in the quality of the history match but is only applicable with a limited number of kr, Pc models.

Pressure based approach

Upscaling techniques in reservoir engineering

A tremendous amount of work has been published on flow in heterogeneous porous media in the reservoir numerical simulation community. The geological codes often provide fine description models of millions of cells, which account for the complexity and the heterogeneities of the reservoir. Because the fluid flow simulations cannot be conducted on these high resolution grid, an upscaling (or averaging) technique is needed to reach reasonable calculation times. The conventional method is to coarsen the grid by doing a static upscaling before the flow simulation but it can lead to significant errors due to the averaging of the saturation profile. The principle of the Dual Mesh Method (DMM) is to solve the pressure equation on the coarse grid and the saturation equation on the fine grid. The pressure data are then interpolated on the fine grid in order to better reproduce the saturation profile evolutions [10]. From a mathematical point of view, the DMM approach justifies itself by the parabolical (or elliptical) nature of the pressure equation (long range forces) compared with the hyperbolical nature of the saturation equation. It makes the pressure profiles to be smoother as compared to the saturation profiles [20].

Principle of the method

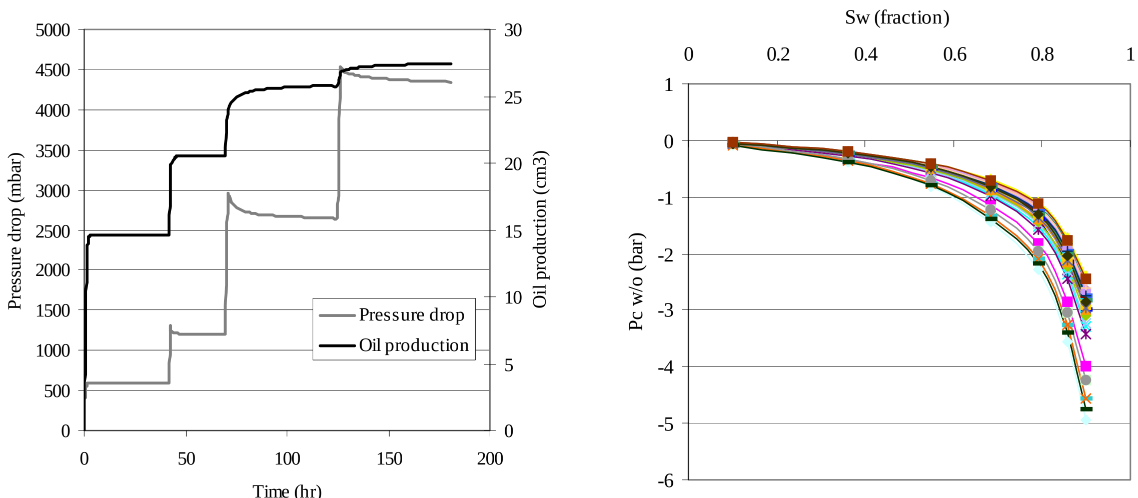
The main findings of these upscaling studies is that the pressure data are less sensitive to the heterogeneity than the saturation data. Therefore, it suggests that the pressure can be reasonably approximated with numerical simulation at every saturation measurement locations without the need for local pressure taps. Synthetic data have been generated by simulation to illustrate this point on a conventional USS coreflood imbibition experiment. ATHOS™, the IFP developed IFP simulator, has been used with a 1D geometry and 30 cells. The core properties are presented in

Table 1. We consider a multi-rate brine injection in a core originally at S_{wi} (10, 50, 200, 400 cm^3/hr). The same viscosity was considered for both fluids (1 cP) and a unique set of kr curves was used. The Corey exponents and kr end-point values are equal to 2 and 0.6 for the water phase, and, 4 and 0.9 for the oil phase respectively.

Table 1. Core properties

Length	Diameter	Phi	Kmin	Kmax	K average	S_{wi}	S_{orw}
8 cm	5 cm	25 %	11 md	47 md	24.5 md	0.1	0.1

Two sets of data were generated using either a homogeneous or a 1D heterogeneous core with non-uniform permeability and Pc curves. The permeability values range between 11 and 47 md and distributed at random along the sample. The local Pc curves were obtained using the Leverett function. The set of Pc curves is shown in Figure 1 and corresponds to an oil-wet case. The permeability of the homogeneous core is the average permeability of the heterogeneous core with a unique Pc curve based on this average permeability value.



a b

Figure 1. Synthetic experimental data with small-scale heterogeneities: (a) production data and (b) the set of Pc curves implemented in the simulator at each location

The production data (Figure 1) are very similar to real experiments performed in the laboratory in an oil-wet core. Each increase of the injection rate leads to production of additional oil due to the increase of the viscous forces. As expected, many fluctuations are observed in the saturation profiles with the heterogeneous core (Figure 2) due to local variations of oil trapping. The amplitude of the saturation fluctuations (10-15 % saturation units) is in good agreement with real experimental data. The fluctuations also tend to minimize at higher rates because of the balance between the viscous and the capillary forces establishes at a higher value. This behavior is also observed in experimental data [5; 7]. The saturation profiles obtained with the homogeneous core pass on average through the heterogeneous saturation points but the saturation differences can be locally as high as 10 % (Figure 2). The picture is completely different for the pressure profiles. Some small amplitude fluctuations can be detected on the profiles derived from the heterogeneous core but they remain very comparable with the homogeneous case (Figure 2).

This example illustrates and confirms that the pressure is less prone to fluctuations due to small-scale heterogeneity (in the order of the centimeter scale) compared to the saturations. Now, we consider that the heterogeneous core data set has to be interpreted with nothing else than the average core properties. A preliminary history match of the production data will first be done using a homogeneous model. According to the previous part, the simulated pressure profiles at the end of each injection rate can be used in addition to the "experimental" saturation data to derive, without any inversion procedure, several local Pc values.

When the stabilization is reached, it is important to mention that the pressure in the displaced phase is uniform along the sample and equal to the outlet pressure. The local pressure of the injected phase corresponds to the capillary pressure (plus the outlet pressure) like in a semi-dynamic experiment. In the case where the stabilization is not completely achieved, it is also interesting to note that pressure profiles in the two phases are smooth. Therefore, the simulated capillary pressure profiles before rate changes can be used in addition to experimental saturation to deduce the local parameters.

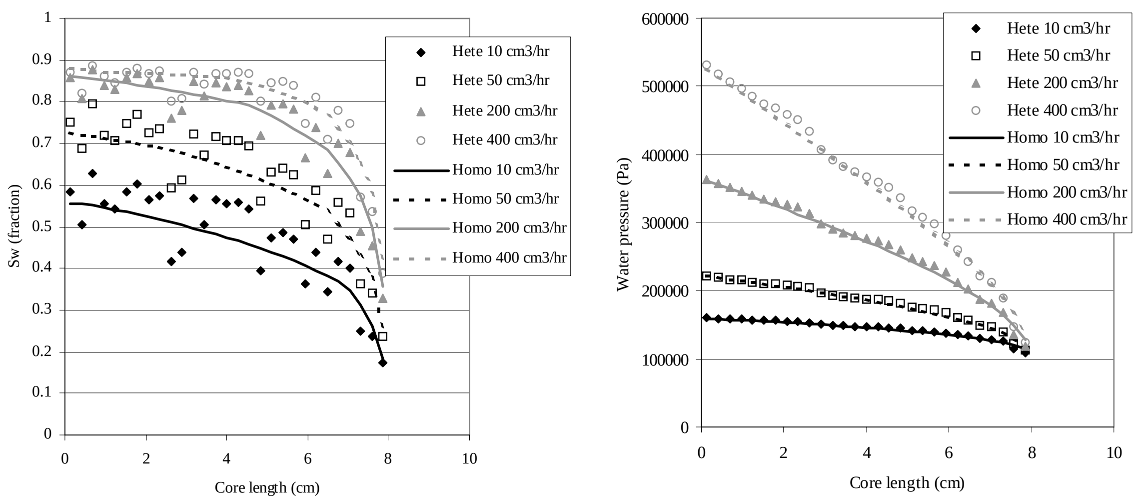


Figure 2. Saturation and pressure profiles for the homogeneous (solid or dotted lines) and the heterogeneous cores (points)

General workflow for interpretation

In this part, the general methodology to account progressively for the heterogeneities is described. The general workflow is given in Figure 3 and includes several steps.

Experimental data and analytical interpretation

At this step, it is worth reminding the added value to perform a multi-rate USS experiment. Because each stabilization state results from an equilibrium between the viscous and the capillary forces, this type of experiment enables a level of analytical interpretation prior to conducting the numerical history match of the experiment.

Both Pc and kr of the injected phase values can be calculated using the equilibrium states and the following analytical expressions with full account for capillary effects:

$$S_{inlet}(\Delta P_i) = \bar{S} + q\frac{d\bar{S}}{dq}$$ (q is the flowrate, $\bar{S}$ is the average saturation)

(1)

$$kr^{inj} = \frac{\mu L}{KA}\frac{dq}{d\Delta P_i}$$ (ΔP_i is the pressure drop)

(2)

The calculation procedure is identical to the one followed in a semi-dynamic experiment and described in a previous SCA paper [14]. The capillary pressure points correspond to the ΔP_i, $S_{inlet}(\Delta P_i)$ values because the stabilized pressure drop is measured at the inlet (pressure profile in the displaced phase is uniform, equal to the outlet at equilibrium).

Homogeneous approach

This corresponds to the conventional procedure excepted that some Pc and kr values are known. A Pc curve obtained from a companion plug is often used as input in the numerical simulation after correction with a Leverett function to account for permeability or porosity variations between the two plugs and for IFT if the fluids are not the same. Because some "true" Pc values are calculated from the experiment to be interpreted, the Pc curve can be directly rescaled in amplitude according to these points. These local values of Pc can also be very valuable to assess and quantify the nature of the local heterogeneity using a Leverett function. The initial set of krs before optimization can be better estimated using the analytical calculated values (injected phase) but also the shape of the curves obtained through the JBN interpretation. A coreflood simulator is then used to history match the experimental data by tuning the kr curves only. At this stage, we derive a first set of optimized krs and simulated pressure profiles (Figure 3).

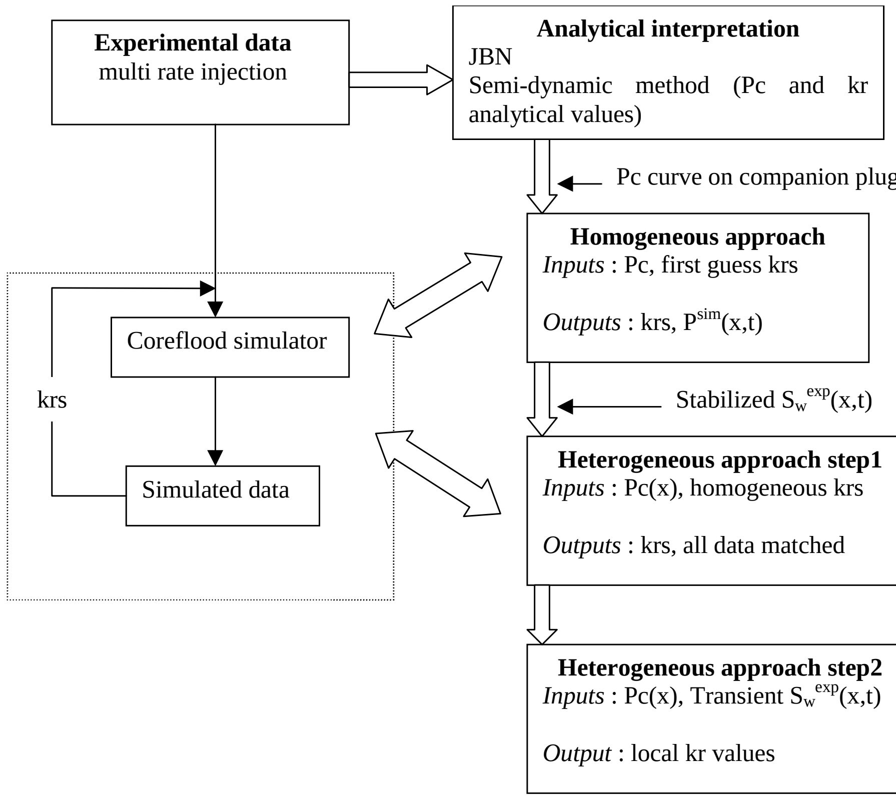


Figure 3. General workflow to interpret an USS multi-rate experiment

Heterogeneous approach: step 1

We apply in this part the pressure based approach by combining the experimental saturation measurements with the simulated pressure profiles at the equilibrium points. This enables derivation of several values of Pc at each location where a saturation measurement was performed. These calculated values are then used to rescale the original Pc curve for each position. These different curves are introduced as inputs in the simulator in addition to the set of krs obtained through the homogeneous approach before going to the optimization process again (Figure 3). This procedure can be repeated several times to improve also the simulated pressure profiles but our experience suggests that one iteration is often enough to considerably improve the match of all the data. It has also to be pointed out that this approach permits a very fast inversion process since no capillary pressure data are included in the optimization problem.

Heterogeneous approach: step 2

This step does not require simulations. It consists in taking advantage of the transient evolution of the saturation profiles to calculate local values of the fractional flow and derive the relative permeability for the displaced phase. We used the following expression taking into account the local variations of Pc deduced from the previous part:

$$f_w = \frac{1 - \frac{k\, k_{ro}}{u_t\ \mu_o} \frac{\partial P_c}{\partial L}}{1 + \frac{\mu_w}{\mu_o} \frac{k_o}{k_w}} \qquad \text{(gravity is neglected in this expression)} \qquad (3)$$

APPLICATION CASE 1: GAS/OIL SYSTEM

Experimental data

The experiment was performed in a composite core built with four reservoir plugs selected from the same rock type (carbonate rock with porosity and permeability around 30 % and 10 md, respectively). S_{wi} was first established and the wettability was restored by aging at reservoir conditions with live oil. Then, the live oil was replaced by dodecane using several successive miscible displacements prior to injection of nitrogen at ambient conditions.

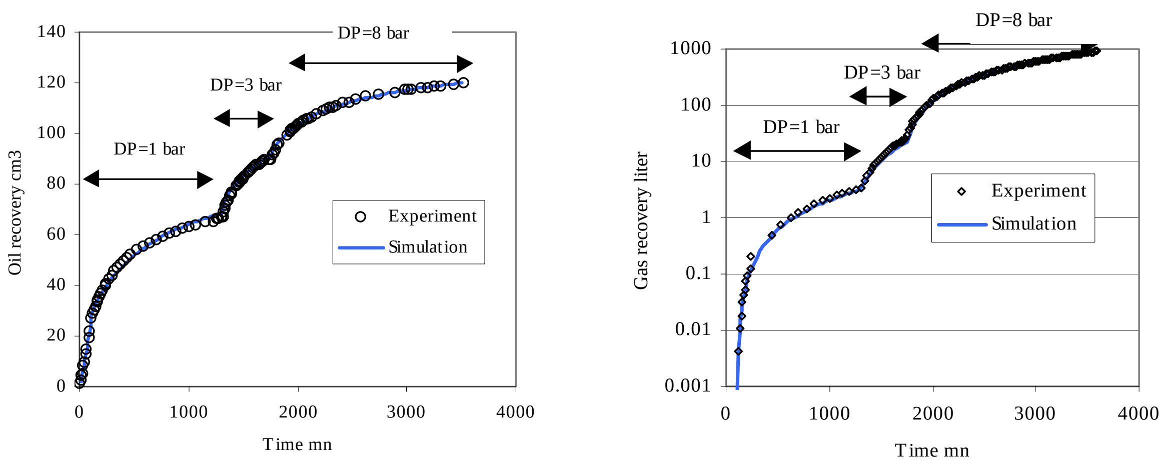


Figure 4. History matching of the production data (gas/oil system)

The gas injection experiment was conducted with a medical CT-scanner (voxel $0.12\times0.12\times1\ mm^3$) to follow the evolution of the saturation profiles as a function of time (1 acquisition every second). The oil and gas productions were recorded and CT-profiles were measured regularly during the experiment (Figure 4 and Figure 5). A differential pressure of 1 bar was first applied, then 3 bar, and finally a high flow rate bump (P = 8 bar) was applied. The experiment was held horizontal. Further details on the experiment can be found in a previous paper dedicated to gas injection processes [5].

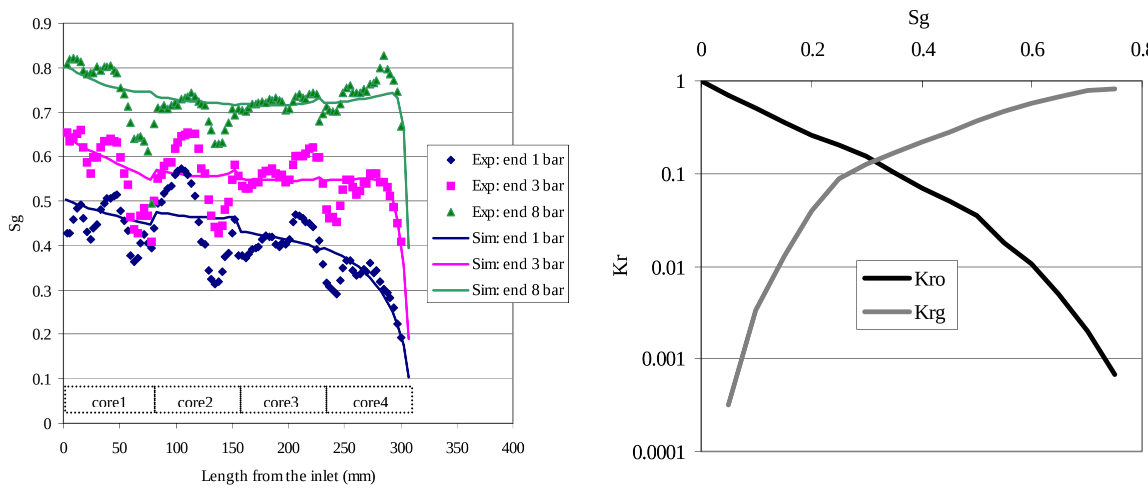


Figure 5. Saturation profiles and kr curves obtained through classical approach

Interpretation

Homogeneous approach

The set of krs deduced from the homogeneous approach is given in Figure 5. The corresponding production data history matching is very good. Concerning the saturation profiles, the simulation reproduces the general shape but not the local fluctuations. These fluctuations, which occur within the plugs, are attributed to the heterogeneities rather than an interfacial effect between the plugs (Figure 5a).

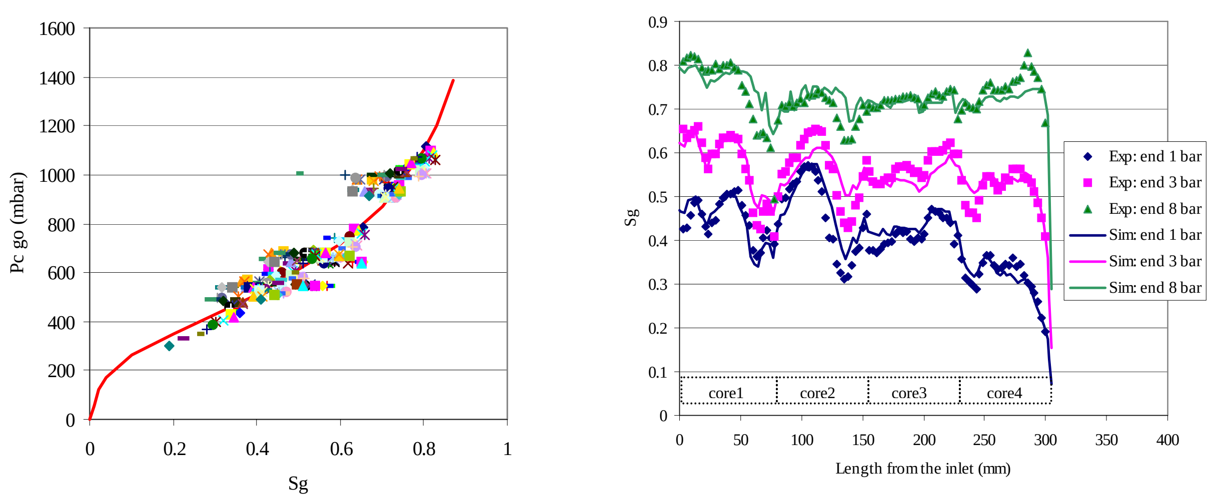


Figure 6. Application of the heterogeneous approach in terms of capillary pressure data

Heterogeneous approach

Figure 6 shows the Pc values that have been obtained from the hundred locations where the local saturation was measured. All the values spread around the Pc curve (solid line) that was introduced in the homogeneous approach with a level of scatter that reflects the heterogeneities. Figure 6 (right) must be compared to Figure 5 to evaluate the degree of improvement in the history match of the saturation profiles. Only one iteration of the process was needed to obtain these results, which demonstrates the ability of the pressure data to account for the heterogeneities.

Another interesting result concerns the relative permeabilities. Only slight modifications of the set of curves obtained through the homogeneous approach were necessary to keep a good match of the production data with the heterogeneous simulation (Figure 7). An illustration of the local calculation of k_{ro} is also provided in Figure 7. All the calculated values are spreading around the k_{ro} curve that was obtained though the global history match and reflect the impact of the heterogeneities on this parameter. The impact of heterogeneity on k_{rg} was neglected because it is calculated from the pressure data that are smooth towards heterogeneity.

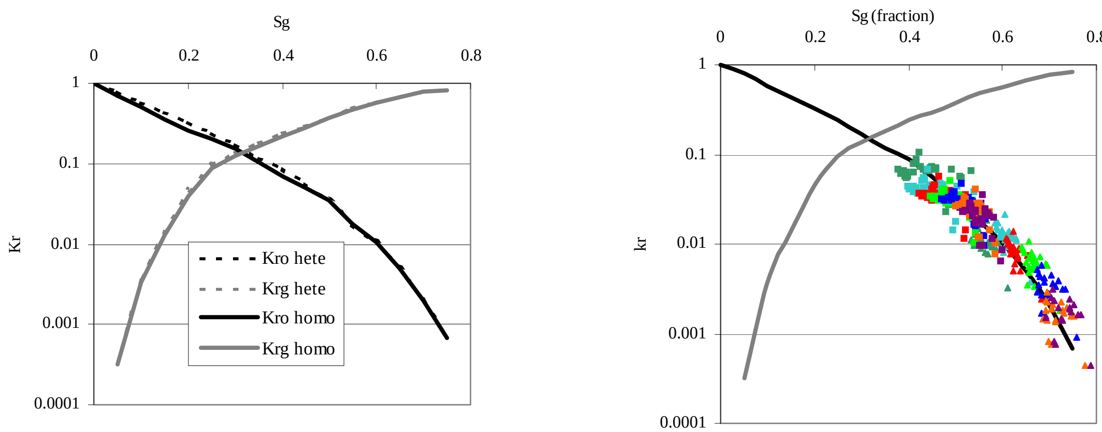


Figure 7. Application of the heterogeneous approach in terms of relative permeability data

APPLICATION CASE 2: WATER/OIL SYSTEM

Experimental data

This second example corresponds to the results of a multi-rate imbibition experiment, which was published recently [6]. The coreflood was conducted in a carbonate core (29% porosity and 14.8 md) using a single plug (6 cm).

Interpretation

The Figure 8 shows the results obtained in terms of capillary pressure and saturation profiles. Because the saturation profiles cover a large range of saturation at the end of the lowest injection, it was possible to calculate Pc points even at low water saturations. The shape of the Pc curve obtained suggests the sample is rather oil-wet (negative values over the whole range of saturation). The corresponding simulated saturation profiles reproduce very well the experimental saturation fluctuations that were measured.

DISCUSSION

Comparing to other existing methods, the added value of this approach is to provide a consistent match of the whole experimental data set, including the true saturation profiles, and to define an interval of confidence for kr and Pc due to the heterogeneities. This latest point is particularly interesting for reservoir engineers, who need such data to conduct uncertainty analyses at the reservoir scale to help decision making in field development strategies [15].

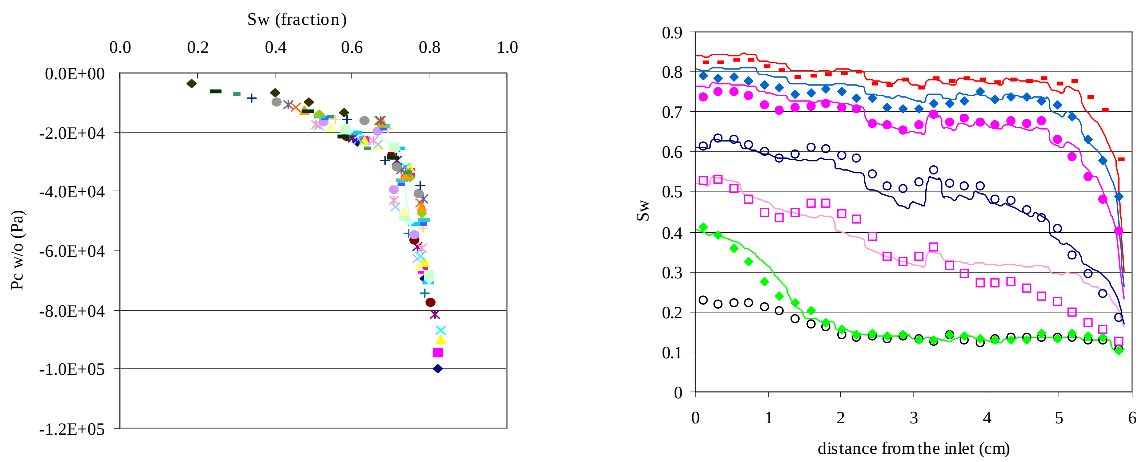


Figure 8. Application of the heterogeneous approach for a single plug (water/oil system): (a) calculated Pc values and (b) the simulated S_w profiles

CONCLUSIONS

A novel approach was successfully developed and tested to take into account the rock heterogeneities that impact the coreflood experimental data mainly in terms of saturation profiles. The methodology is based on the calculation of the pressure profiles in the core, which are less prone to fluctuations due to heterogeneity compared to the saturations. Multi-rate injection experiments are recommended to get analytically both Pc and Kr data prior to the start of the simulation process. The method does not require a special coreflood simulator and can be applied with existing tools. The method enables the reproduction of the saturation fluctuations by calculating analytically the local Pc attributes using the stabilized saturation profiles. The local values of kr can also be obtained using the transient profiles between two consecutive rates. The method was successfully applied on experimental data related to intermediate permeability carbonate samples (composite or single plug) for a gas/oil and a water/oil system. It is possible to follow this method to reinterpret existing experiments that were affected by small-scale heterogeneties. The spreading of the kr, Pc data due to the heterogeneity within a given rock-type can also be assessed from only one experiment and can be used to perform uncertainty studies at the reservoir scale.

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