MATCHING EXPERIMENTAL SATURATION PROFILES BY NUMERICAL SIMULATION OF COMBINED AND COUNTER-CURRENT SPONTANEOUS IMBIBITION

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ABSTRACT

This paper describes numerical studies of two types of water displacing oil spontaneous imbibition: counter-current imbibition of water into a sample with one end in contact with water and the other end closed (OEOSI), and combined co-/counter-current spontaneous imbibition of water into a core sample with two ends open, free boundary geometry, as given by a sample with one end in contact with brine and the other in contact with oil (TEOSI). Both types of sample are initially fully oil saturated. The study uses an explicit simulator with an upstream differencing scheme, which allows flows of the oil in both directions without blockage because of zero water saturation grid cells. The boundary conditions are modelled using zero-width boundary cells with fixed saturations. For the OEOSI case, the saturation at the imbibition face is fixed at a value equal to the final mean saturation of the sample; this led to automatic history matching of the final saturation profile. For the TEOSI case, the saturation at the end face in contact with brine fixes the capillary bubble pressure (the pressure required to produce the oil) at this face. The experimental results were matched using an automatic search technique with both the capillary pressure and the relative permeability curves as the fitting parameters. Tabular values were used for all the curves, with six points in the curves and linear interpolation between points. Fits were achieved using *in situ* fluid saturation measurements as well as the oil production at the imbibition face for the OEOSI case and at the two faces for the TEOSI case. For the OEOSI case, the pressure at the closed face was also used. For the TEOSI case, three pressure taps were located along the core. However, data from these taps were not used in the history match. It was found that all the data could be fitted using comparable capillary pressure and relative curves.

INTRODUCTION

The problem of spontaneous imbibition is of major interest in the petroleum community because this is the mechanism whereby matrix oil can be produced into fractures in a reservoir [1,2]. Both experimental [3,4,5,6] and numerical simulation for various types of spontaneous imbibition are available in the literature [7,8,9,10,11].

The two problems presently under consideration are shown schematically in Figures 1 and 2. A sample, originally saturated with oil, is confined radially by a sealed surface. For the first type of problem, the left-face is exposed to a water reservoir while the right-face is sealed. This case will be termed one end open spontaneous imbibition (OEOSI). For the second type of problem, the sample is set up axially between two reservoirs, a reservoir that is filled with water and contacts the left-face of the sample and a reservoir that is filled with oil and contacts the right-face of the sample. This case will be termed two ends open (free) spontaneous imbibition (TEOSI). In the TEOSI experiment, the oil in the reservoir is identical to the oil that saturates the sample. It is assumed that the pressures of the fluids in all the reservoirs remain constant at a value of zero throughout the experiments. The sample is assumed to be strongly water-wet, and the porosity and permeability are assumed to be constant and uniformly distributed. In OEOSI, oil can only be produced at the left-face. In TEOSI, it is possible for water to spontaneously imbibe into the sample, displacing oil in both a counter-current fashion (causing oil production at the left-face of the sample) and a co-current fashion (causing oil production at the right-face of the sample). A pressure tap is located at the right-face of the OEOSI sample; three pressure taps are distributed along the length of the TEOSI sample.

Figures 1 and 2 also show the grid system that is used in the numerical simulations. The following description of the computer simulation model is taken from [11] and is included here for the convenience of the reader.

At both ends of the sample, zero-width grid blocks are located to facilitate the definition of boundary conditions. The sample is then divided into a number of equal-width grid blocks. The simulation determines changes in saturation in a grid block based on the difference between the flow rates across the boundaries. The flow rates at the boundaries are calculated using the two-component Darcy law equations. In the absence of gravity, these equations are:

$$\frac{Q_w\,\mu_w}{k\,A\,k_{rw}} = -\frac{dP_w}{dx} \quad (1)$$

$$\frac{Q_o\,\mu_o}{k\,A\,k_{ro}} = -\frac{dP_o}{dx} \quad (2)$$

$$Q_t = Q_w + Q_o \quad (3)$$

$$\frac{dP_c}{dx} = \frac{dP_o}{dx} - \frac{dP_w}{dx} \quad (4)$$

In these equations, Q is volumetric flow rate, μ is viscosity, k is permeability, A is cross-sectional area, k_r is relative permeability, P is pressure, and x is axial location. With regard to the subscripts, w denotes water, o denotes oil, t denotes total, and c denotes capillary. Equations 1 through 4 are combined to obtain the following equation for the flow of oil:

$$Q_o = \frac{Q_t\,\mu_w\,k_{ro}}{k_{ro}\,\mu_w + k_{rw}\,\mu_o} - \frac{A\,k\,k_{ro}\,k_{rw}}{k_{ro}\,\mu_w + k_{rw}\,\mu_o}\,\frac{dP_c}{dx} \qquad 5$$

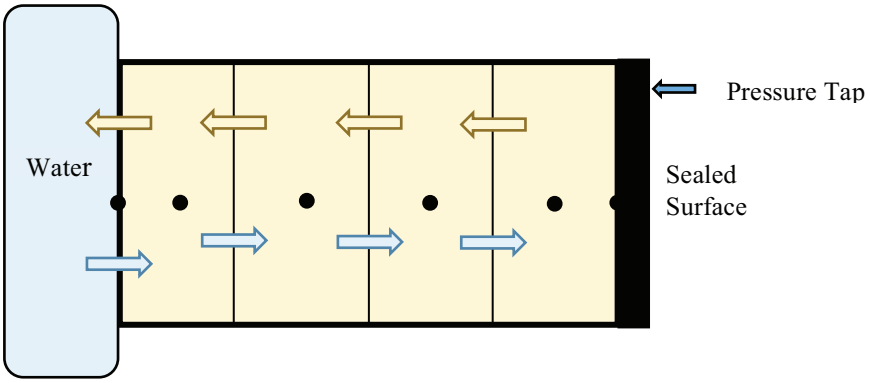

Figure 1. A schematic depiction of the problem of OEOSI.

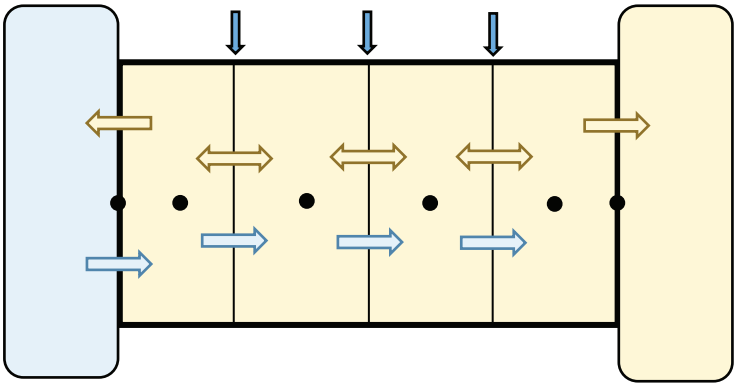

Figure 2. A schematic depiction of the problem of TEOSI.

Because the simulation depends on calculating saturation changes, it follows that saturations will be known for each grid block at any time. However, this does not allow direct evaluation of Equation 5 because the total volumetric flow rate is not known *a priori* for spontaneous imbibition problems. This shortcoming can be overcome by combining Equations 2 and 5 to obtain

$$-\frac{dP_o}{dx} = \frac{Q_t}{k\,A}\,\frac{\mu_w\,\mu_o}{k_{ro}\,\mu_w + k_{rw}\,\mu_o} - \frac{k_{rw}\,\mu_o}{k_{ro}\,\mu_w + k_{rw}\,\mu_o}\,\frac{dP_c}{dx} \qquad 6$$

The pressures in the water reservoir at the left-face of the sample (both cases) and the oil pressure at the right-face of the sample (TEOSI case) are known (they have been assumed

to have the same value and this value can arbitrarily be set to zero). Further, for the OEOSI case, the flow rate at the right-face is zero. The right-hand-side of Equation 6 is a function only of saturation with Q_t being a constant value throughout the sample at any given time. Knowing the saturation profile at any time, integration of Equation 6 (in the simulator this integration is performed numerically) yields the following equation for the total volumetric flow rate:

$$Q_t = \frac{(P_{or} - P_{ol}) - \int_l^r \frac{k_{rw}\,\mu_o\,dP_c}{k_{ro}\,\mu_w + k_{rw}\,\mu_o}}{\frac{1}{k\,A}\int_l^r \frac{\mu_w\,\mu_o\,dx}{(k_{ro}\,\mu_w + k_{rw}\,\mu_o)}} \qquad 7$$

Here the subscripts r and l refer to the right and left-faces of the sample.

A critical feature of the simulation is the assumption for the saturation used in calculating relative permeabilities for the flows across the grid-cell boundaries. In all cases, the saturation for a fluid is assumed to be the value for the upstream cell, the so-called "upstream-differencing" assumption. That is, if the flow rate of fluid crossing a cell boundary is left-to-right, the saturation of the left-hand cell is used. It follows that, for the case of counter-current imbibition at a grid-block boundary, the relative permeability of the water is calculated using the saturation of water in the left-hand cell while the relative permeability of the oil is calculated using the saturation of oil in the right-hand cell. The fundamental importance of this assumption can be seen by considering the left-hand sample face condition. Upstream-differencing means that the flow into the sample is controlled by the saturations of the fluids in the zero-volume surface cell. As this cell has zero-volume, it can instantly take on any saturation. For the present study, the saturation of the left-face is assumed to be the final average saturation of the sample. This means that there is a finite relative permeability for water to enter the sample despite the fact that the sample is fully saturated with oil. It is noted that a theoretical determination of the value of saturation and bubble pressure (the pressure required to produce oil) at the left-face in spontaneous imbibition problems is the most important unresolved issue in the prediction of spontaneous imbibition experiments.

The Program of Study

For the present study, the data for the OEOSI case has not previously been published; the TEOSI data is taken from [6]. As can be seen in Table 1, these tests used samples with similar petrophysical, water, and oil properties. The value of the permeability for the TEOSI case was published in [6]. The value for the OEOSI case was set to 10.0 md and the end-point relative permeability for oil was used as a fitting parameter. The resulting effective permeability value was taken to be the permeability of the sample.

Unlike the study published in [11], the history matches were achieved by varying both the capillary pressure and the relative permeability curves. For the OEOSI case, available experimental data were the saturations at five locations along the core, the production of oil at the imbibition (left) face, and the pressure in the oil at the right-face, all as functions of time. For the TEOSI case, the data were detailed saturation scans and the production

of oil at both faces of the sample, all as functions of time. Although pressures were available for three points along the sample, these values were not used in the history match. Comparison of the predicted and the experimental pressures provides an independent test of the quality of the analysis. The accuracy of the saturation profiles is in the range of 0.01-0.02 saturation units [12].

Table 1 The petrophysical characteristics of the two samples under study.

Sample	ϕ	L (cm)	D (cm)	ρ_w (kg/m^3)	μ_w (cp)	ρ_o (kg/m^3)	μ_o (cp)	k (md)
OEOSI	0.518	5.060	3.81	1050	1.09	730	0.92	10.0
TEOSI	0.468	12.00	5.08	1050	1.09	740	0.90	4.916

The simulations used data from the relative permeabilities and capillary pressures reported by [3] as a guide for initial curves. The history-matching process was straightforward. The curves were input as 6-entry tables. For the search, the saturations were kept constant and the values of the capillary pressures, the relative permeabilities, and the residual oil saturation were varied. For each variation, a simulation was run and the errors between the simulated and experimental data were computed. By using an exhaustive search technique (modifying values on a simple grid pattern), the curves that led to the minimum error were determined. This typically took several hundred search steps.

All simulations were run using a total of 60 grid blocks. Stability was controlled by limiting saturation changes in any one grid block to less than 0.0001. No stability problems were encountered and each test simulation ran in under 30 seconds.

RESULTS

Figure 3 shows the saturation function curves that lead to the best fit for both the OEOSI and the TEOSI cases. The dashed curves refer to the right-hand axis while the solid curves refer to the left-hand axis. The resulting capillary pressure curves are very similar except near the two ends. For the OEOSI case, the relative permeability curve for water determined by the history match is somewhat higher than the TOESI case. The flat shape of the low saturation portion of the oil relative permeability curve is an artifact of using the simulator to determine the permeability of the sample. If a permeability lower than the predicted value is entered and the relative permeability is restricted to values less than 1 this flat region can be reduced. It was observed that for the OEOSI case the saturation at the input face could be set independently from residual oil saturation used in the relative permeability curve. The water relative permeability curves for the two cases are very similar.

The quality of the curve fits for the OEOSI case is demonstrated in Figures 4 through 6. Both the left-face production and the right-face pressure are well predicted by the simulator. Theoretically, the right-face pressure should remain constant until the

imbibition front reaches this face [13]. The experimental data does not quite follow this pattern, possibly because of small scale heterogeneities in the sample. The simulation predictions for the water saturations are very good. In the legend of Figure 5, "E" and "S" indicate experimental and simulated, and the numbers are the fractional distances along the sample. At all locations, the experimental saturations show a "jump" at about 80 minutes. Before this time, the simulation and experimental data are very well matched. The reason for this jump is not clear. Because the jump appears in the experimental data, heterogeneities could again be the reason. However, this jump coincides with the arrival of the imbibition front at the sealed face, the time of which is indicated in the simulation by the end of the constant downstream pressure regime. The arrival of the front might be expected to lead to difficulties in measuring the pressure; however, there is no obvious reason why it should affect the saturation profiles. Figure 6 is based on the same data set as Figure 5 but in this figure saturation profiles at various times are shown. Comparison of experimental and simulated results for saturations less than 0.2 show how well the location of the imbibition front is predicted.

As noted above, in the OEOSI case, the saturation at the left-face could be set to a value and the simulation would produce final saturations that were equal to the left-face saturation regardless of the residual oil saturation used in the relative permeability curve. However, regardless of the value of saturation set at the left-face, it was found that the final saturation of oil for the TEOSI case would always correspond with the residual saturation for the relative permeability curves. This behavior needs further investigation.

The quality of the curve fits for the TEOSI case is demonstrated in Figures 7 and 8. The final production at the left-face is well simulated but the production history is not. The experimental data for the right-hand production appears to be retarded at early times. The observation of "induction" periods at the start of imbibition experiments is common [2]. These periods have been associated with the fluids establishing sufficient connectivity at the imbibition face and are therefore microscopic and stochastic in nature – they cannot be predicted by the simulator. The discrepancy between the experimental and simulated left-face production curves may also be due to this induction phenomenon. Experimental production at the left-face ends shortly after the induction period while simulated production ends much earlier. This observation is consistent with local phenomena that lead to production at the left-face but do not cause significant production at the right-face. After the induction period, the match between experimental and simulated production at the right-face is very good.

The saturation profiles shown in Figure 8 clearly show disagreement at early time. This is consistent with the phenomenon of an induction period. At later times both the shapes and the magnitudes of the saturation profiles are well predicted.

Figure 9 shows an example of the match between the experimental and simulated pressure responses at the internal pressure taps, in this case the tap located mid-length of

the sample. The trends in the pressure are similar but the magnitudes are clearly different.

DISCUSSION

The results presented above demonstrate that both production and *in situ* saturation data can be predicted by a history matching technique that varies both the capillary and the relative permeability curves. These curves are similar but not identical to each other in the cases of OEOSI and TEOS. The important issue of predicting the value of the saturation at the left-face of the sample in OEOSI experiments remains unresolved – this value was simply set to the final average saturation of the sample. A method to theoretically predict this saturation, and its detailed physical significance, in a unique manner is still the biggest challenge for research into spontaneous imbibition experiments. The only published theoretical method is by Arabjamaloei and Shadizadeh [14]. This method was applied to the present data but the tabular form of the data makes calculation of the required diffusion coefficient problematic. However, the theoretical value that was determined was approximately 0.6 which is similar to the experimental value of 0.685.

A major advantage of the present tests is that they provide both capillary pressure and relative permeability curves, simultaneously, for an imbibition process. Although spontaneous imbibition experiments are often performed, their utility is generally confined to finding production histories. With the availability of *in situ* fluid saturations, the data of most interest to reservoir engineers, both capillary pressure and relative permeability curves, can be determined from a single test.

CONCLUSIONS

The following conclusions can be made based on the present study:

1. The results of an OEOSI and a TEOSI experiment were successfully matched using reasonable capillary pressure and relative permeability curves. The resulting curves were comparable for the two experiments in both shape and magnitude.
2. Both productions and *in situ* saturations, as well as the right-face oil pressure in the OEOSI case, were well predicted by the simulations.
3. *In situ* pressures were not well predicted in the simulations for the TEOSI case.
4. It is possible to obtain both capillary and relative permeability curves from a single imbibition experiment if *in situ* saturation data is available.

ACKNOWLEGEMENTS

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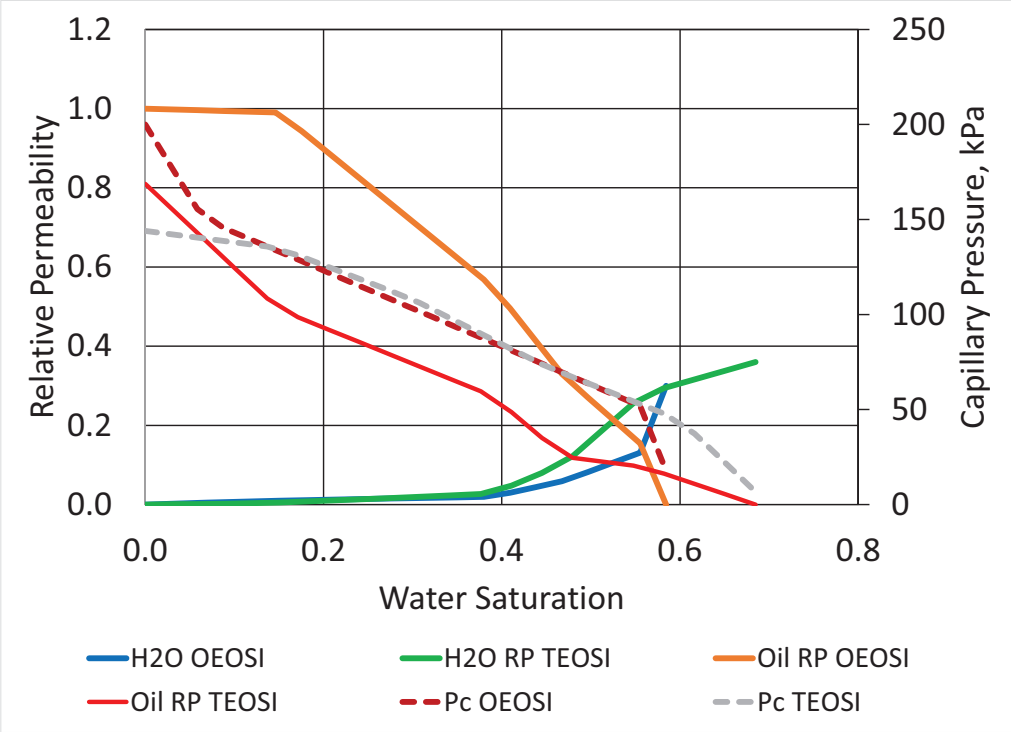

Figure 3. The capillary pressure and relative permeability curves predicted by the simulations.

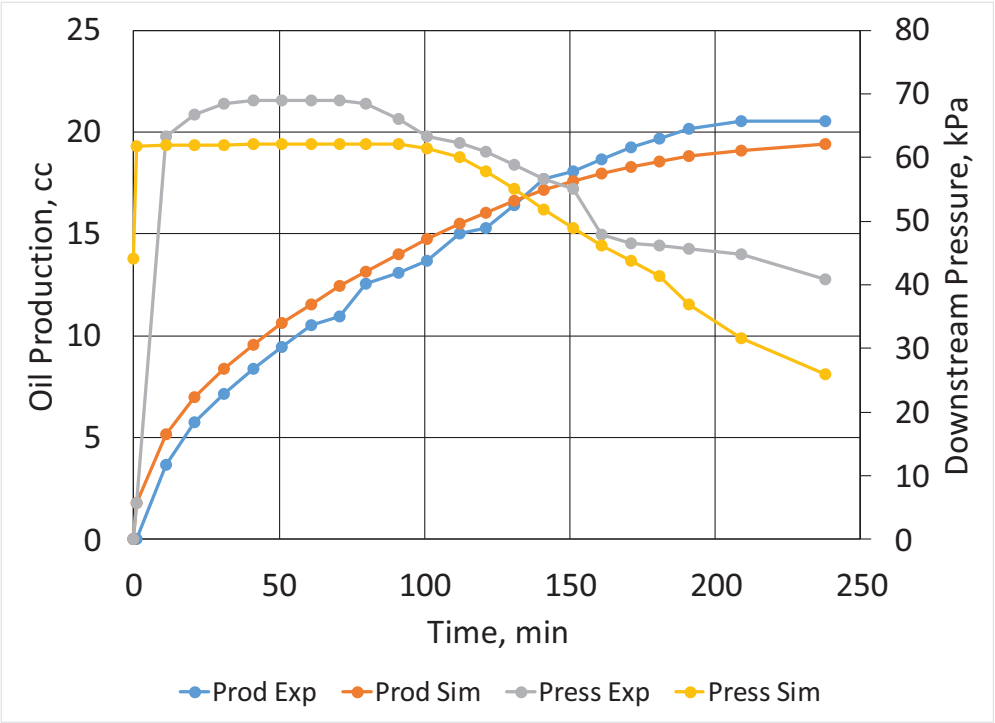

Figure 4. A comparison of experimental and simulated results for the OEOSI case.

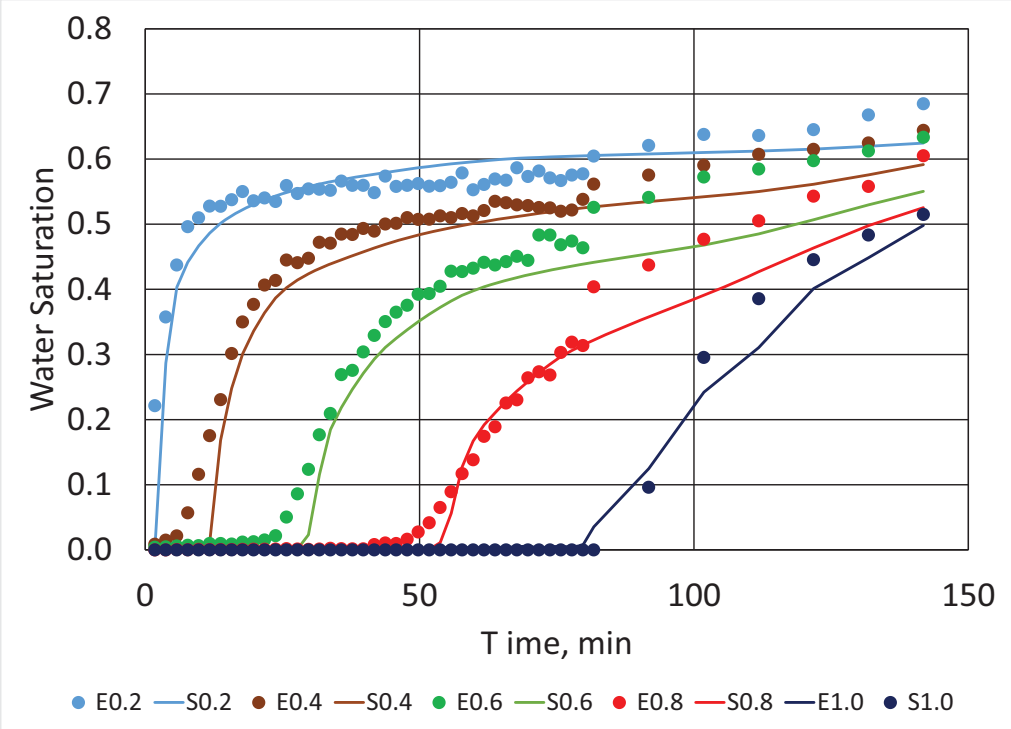

Figure 5. The water saturations for the OEOSI case. E and S indicate experimental and simulated; the number is the fractional distance along the sample.

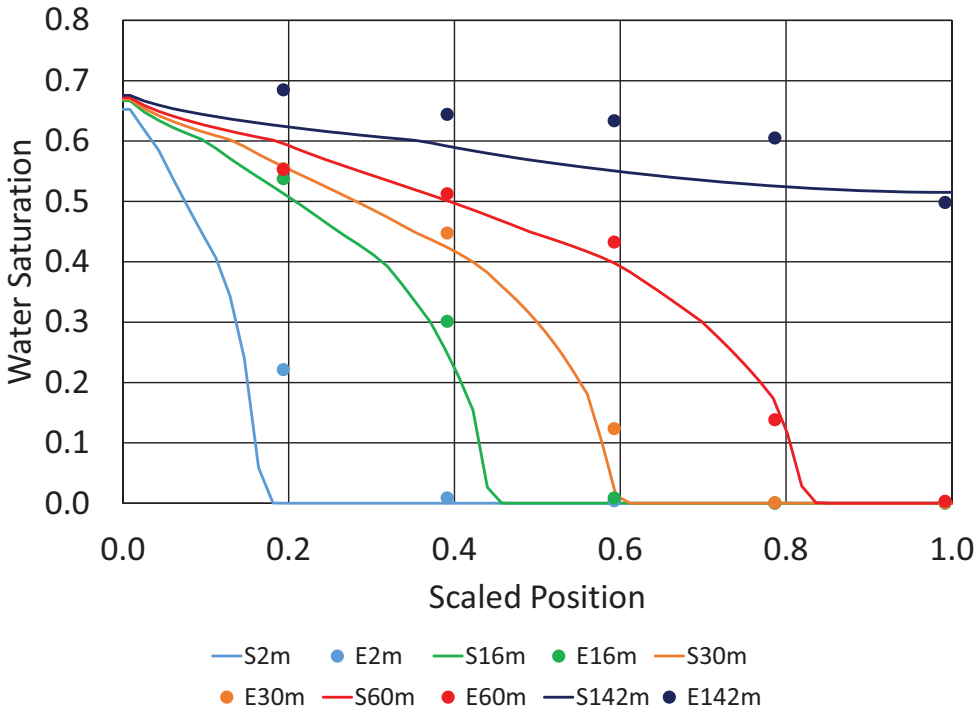

Figure 6. The water saturation profiles for the OEOSI case. E and S indicate experimental and simulated; the number is time in minutes.

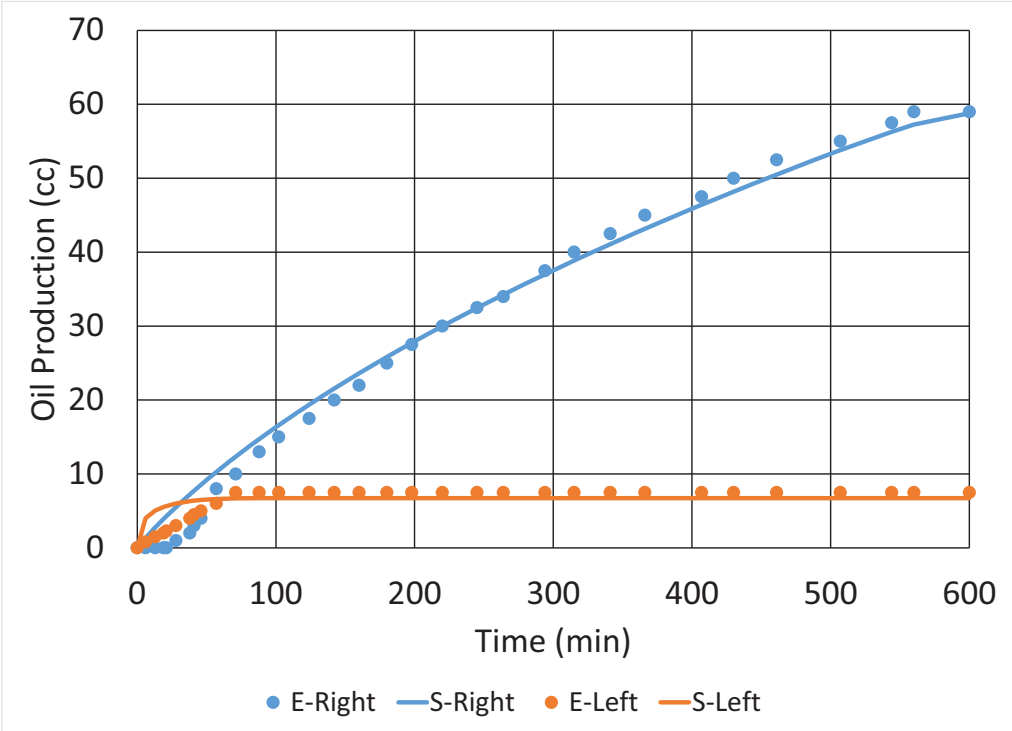

Figure 7. A comparison of experimental and simulated results for the TEOSI case.

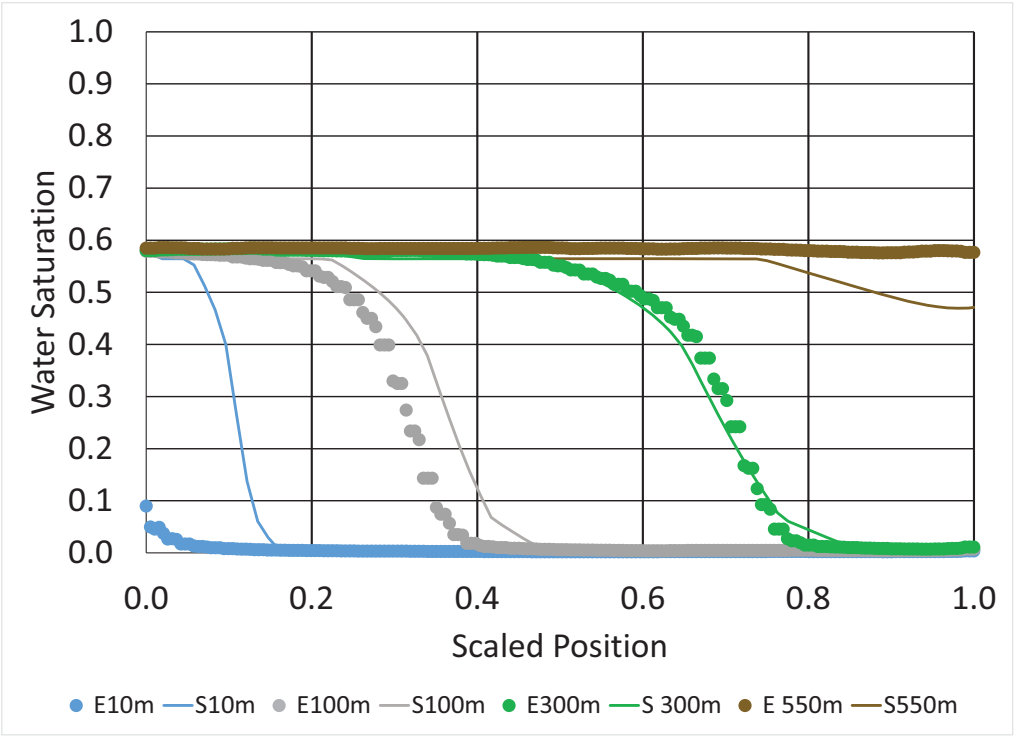

Figure 8. The water saturation profiles at four times for the TEOSI case. E and S indicate experimental and simulated; the number is time in minutes.

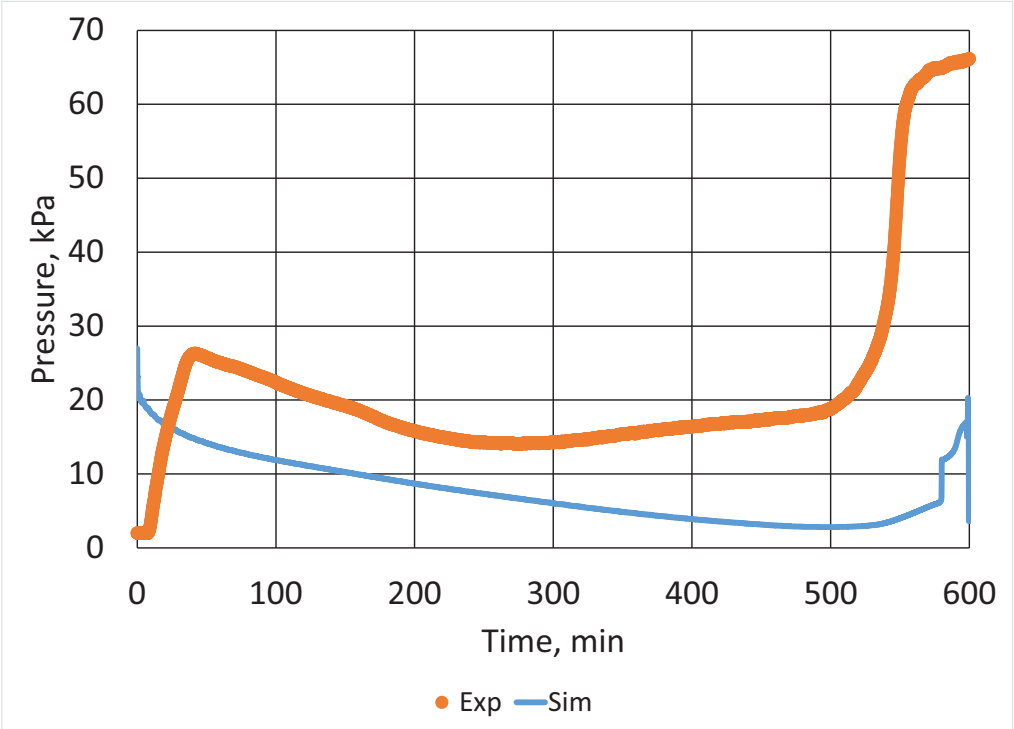

Figure 9. The pressure as a function of time at the mid-length of the sample.