Scientia Iranica C (2015) 22(6), 2373–2378

Sharif University of Technology
**Scientia Iranica**
*Transactions C: Chemistry and Chemical Engineering*
www.scientiairanica.com

*Research Note*

# Experimental observation and mathematical modeling of immiscible displacement in oil wet reservoirs

**E. Kamari***

*Department of Petroleum Engineering, Research Institute of Petroleum Industry (RIPI), Tehran, Iran.*

Received 22 September 2014; received in revised form 27 January 2015; accepted 4 August 2015

**KEYWORDS**
Breakthrough;
Fracture reservoir;
Front;
Heterogeneous;
Immiscible displacement;
Oil recovery.

**Abstract.** Here, a series of immiscible displacement processes have been performed on the fractured porous medium developed on glass micro-models in order to investigate the role of fracture characteristics in oil displacement efficiency during the immiscible displacement process. Oil recoveries were determined from image analyses of continuously recorded pictures during different flooding schemes. A clear bypassing of displacing fluid which results in premature breakthrough of injected fluid due to the fracture has been observed. Moreover, the results showed a decrease in oil recovery when fracture's length increased. In contrast, an increase in fracture orientation from flow direction increased oil recovery. The results of this work may be useful in gaining a thorough understanding of the immiscible displacement process as well as the optimal field development plans.



## 1. Introduction

Fluid flow in porous media is of great interest in many industrial applications, such as oil recovery, geological sequestration of carbon dioxide, imbibition, and underground pollutant remedy application. The dynamics and stability of immiscible fluid-fluid displacements in porous media is a subject of interest, both from a fundamental point of view as a dynamical non-equilibrium process and from a technological point of view in industrial and environmental problems such as oil recovery, irrigation, and filtration. This is particularly true in the context of oil recovery enhancement from underground reservoirs. Such an enhanced oil recovery typically involves displacement of in-situ oleic phase by continuous injection of another fluid phase which may be immiscible (e.g. water injection) or miscible (e.g. $CO_2$ or solvent injection) to the former. Stability considerations partly affect the degree of effectiveness of these methods [1-3].

Experimental [4-6] and theoretical [4,7-13] studies have revealed that the transient growth pattern of the displacement of a non-wetting fluid by a wetting one (imbibition), and vice-versa (drainage) depends strongly on various factors such as pore morphology, capillary number, viscosity ratio, and wettability.

There is strong evidence that the so-estimated relative permeability and capillary pressure curves are correlated strongly with capillary number and viscosity ratio [12,14-21]. Such correlations have occasionally been attributed to the interactive effects of various local forces (e.g. capillary, viscous, gravity, etc.) on the displacement propagation pattern at the pore network scale [10,12,15,18,21,22].

Many researchers have used micro-models, which have been proved to be useful for studying a variety of oil recovery processes and for obtaining a better understanding of transport mechanisms during enhanced oil recovery phenomena [23-35].

In this study, the micro-model is used for quantitative measurements as well as qualitative investigations. Therefore, a series of experimental tests were conducted in order to investigate the role of

*. *Mobile: +98 912 4147996; Fax: +98 21 44739746*
*E-mail address: kamarie@ripi.ir*

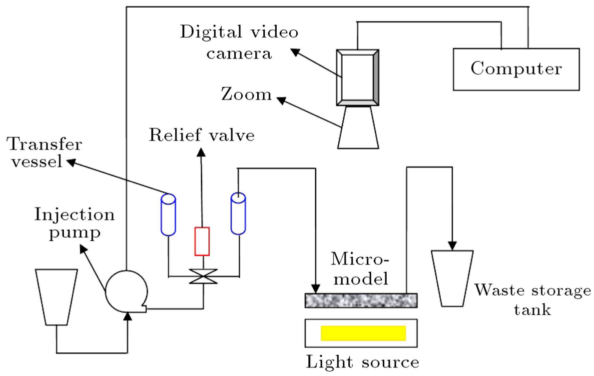



**Figure 1.** Schematic diagram of the experiment setup.

single fracture characteristics (length and orientation) in oil recovery during the immiscible displacement process. For this purpose, distilled water was used as an injection fluid to displace $n$-Decane in glass micro-models with different fracture geometries.

## 2. Materials and experiments

Schematic diagram of the micro-model apparatus is shown in Figure 1. Description of experimental setup and micro-model patterns construction can be found elsewhere [32-35].

### *2.1. Experimental procedure*

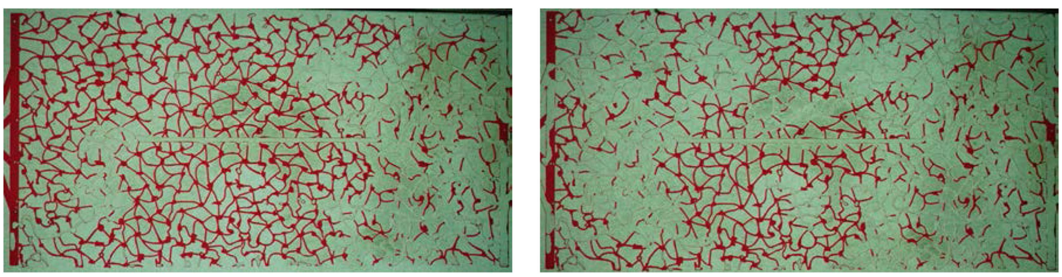
All of the tests were carried out at a temperature of 21 $\pm$ 0.5°C. At the first step, before starting the experiments, the micro-model was cleaned with toluene/ethanol and then de-ionized water to be removed of any extra material trapped inside the model. A low flow rate, high-pressure pump was used for cleaning purposes. At the second step, micro-models were saturated with n-C10. At the last step, the distilled water was injected through the inlet port of the micro-model at a pre-selected flow rate. During the experiments, a digital video camera captured images from the process and saved them in the computer every 30 seconds. The fractional flow versus pore volume injected at the output of glass micro-model was calculated using the captured images and the data from injection pump; for example, two images of one of them is shown in Figure 2. Experiments in some of the patterns were repeated to check the reproducibility of results.

To change the wettability of micro-models to strongly oil-wet, the following procedure was conducted:

1. Rinse micro-model thoroughly with NaOH solution for 1 h;
2. Rinse micro-model thoroughly with distilled water to remove all residues, and then dry in an oven at 200°C for at least 15 min;
3. Prepare a diluted solution of 2% Three Chloro Methyl Silane (TCMS) and 98% dehydrate toluene by volume (this solution should be prepared fresh daily);
4. Saturate the micro-model with the diluted solution for at least 5 min. A thin film immediately coats the internal surface of micro-model making it water repellent;
5. Rinse the micro-model with methanol to remove excess siliconizing fluid;
6. Dry the micro-model in an oven at 100°C for 1 h to cure the silicone coating.

## 3. Experimental results

When capillary trapping experiments are performed in the laboratory studies, care must be taken to insure that laboratory flow conditions are representative of the subsurface conditions. The ratio of capillary to viscous forces is quantified by a dimensionless number, the capillary number by which flow phenomena in porous media can be scaled. For systems without gravity, we expect different flow regimes depending on the capillary number [4]. In this study, the displacement experiments have been carried out in a horizontal mounting to ignore the effect of gravity. For evaluation of the viscous and capillary forces through the porous medium used in these experiments, we calculated the capillary number for some of the



(a) (b)

**Figure 2.** Flow pattern of glass micro-models for $L_{\text{FD}} = 0.5$ and $\theta = 0°$: a) 0.47 injected pore volume; and b) 1.20 injected pore volume.

tests. For the range of experiments performed here, the capillary number varies from $10^{-4}$ to $10^{-3}$ and as a result, the effect of capillary force can be neglected.

### *3.1. The effect of fracture length on recovery factor*

To investigate the effect of fracture length on recovery of an immiscible oil displacement, micro-models with different fracture lengths of 3, 4, 5, 6, 8, 10, and 11 cm with 0° fracture orientation to flow direction were used. The results are shown in Figure 3. The dimensionless fracture length is defined by the length of fracture divided into injection length, which is the distance between the injection-production face or the length of the pattern. Having oil-wet micro-models, distilled water tends to go to the big pores and as a result, front goes inside the fracture and causes earlier breakthrough time; also, it needs more pore volume injected of distilled water to displace trapped $n$-Decane and reach to a recovery factor of one. In addition, Figure 3 shows that the longer fracture in the micro-model causes the earlier breakthrough time and needs more pore volume injected of displaced fluid to attain ultimate recovery.

### *3.2. The effect of fracture orientation on recovery factor*

To observe the effect of fracture inclination (the angle of fracture with respect to flow direction) on the immiscible displacement process, several micro-model patterns with the same length of fracture and with different orientations of fracture to the flow direction were used. The results of the immiscible displacement tests conducted on the above micro-models for $L_{\mathrm{FD}} = 0.5$ are shown in Figure 4. This figure shows that by increasing the fracture orientation to flow direction, the breakthrough time increases and therefore the porous media will act homogenously. Therefore, if the fracture orientation is 0°, it causes earlier breakthrough time and lower recovery factor curve versus pore volume injected of distilled ware; and if fracture orientation is

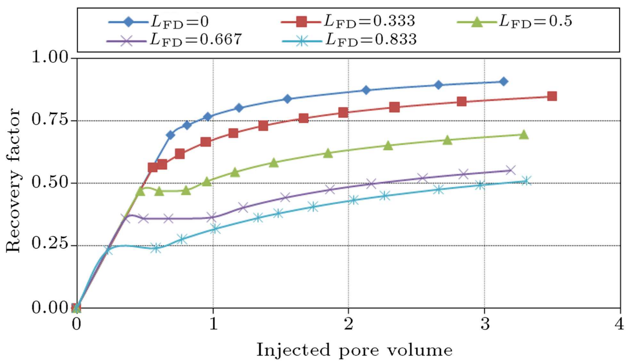



**Figure 3.** Effect of fracture length on recovery factor curves.

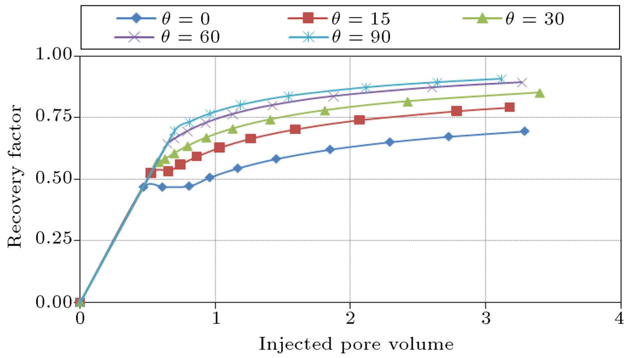



**Figure 4.** Effect of fracture orientation on recovery factor curves for $L_{\mathrm{FD}} = 0.5$.

90°, it acts like homogeneous porous media (as shown in Figure 4).

## 4. Modeling: Calculation of recovery factor

The fractional flow model for a fractured porous media, where the capillary and gravity effects are neglected, can be written as follows [33]:

$$f_d = \frac{1}{1 + \left(\frac{k_{ro}}{k_{rd}}\right)\left(\frac{\mu_d}{\mu_o}\right)\left(\frac{1}{H}\right)}. \tag{1}$$

Correlations of Corey were used for relative permeability calculations:

Relative permeability to oil:

$$k_{ro} = \alpha_1(1 - s_{dD})^m. \tag{2}$$

Relative permeability to displacing fluid:

$$k_{rd} = \alpha_2 s_{dD}^n. \tag{3}$$

Normalized saturation of displacing fluid:

$$s_{dD} = \frac{s_d - s_{id}}{1 - s_{or} - s_{id}}, \tag{4}$$

where $f_d$ is fractional flow of displaced fluid, $k_d$ is relative permeability to displaced fluid, $k_o$ is relative permeability to oil, $\mu_d$ is viscosity of displaced fluid, $\mu_o$ is viscosity of oil, $s_d$ is displaced fluid saturation, $s_{id}$ is initial displaced fluid saturation, $s_{or}$ is residual oil saturation, $m$ is exponent in relative permeability correlation for oil, and $n$ is exponent in relative permeability correlation for displaced fluid. $m$ and $n$ are dimensionless parameters. Also $H$ is heterogeneity factor which represents the heterogeneity of a porous medium in fractional flow model for immiscible displacement due to the presence of the fractures.

Substituting Eqs. (2), (3), and (4) into Eq. (1) yields:

$$f_d = \frac{s_{dD}^n}{s_{dD}^n + A\left(\frac{1}{H}\right)(1 - s_{dD})^m}. \tag{5}$$

Taking the derivative of Eq. (5), with respect to normalized saturation, gives us:

$$\frac{\partial f_d}{\partial s_{dD}} = \frac{1}{pv_i}$$
$$= \frac{A\left(\frac{1}{H}\right)\left[ns_{dD}^{n-1}(1-s_{dD})^m + ms_{dD}^n(1-s_{dD})^{m-1}\right]}{\left[s_{dD}^n + A\left(\frac{1}{H}\right)(1-s_{dD})^m\right]^2}, \tag{6}$$

where $pv_i$ is pore volume injected and $A$ is defined as:

$$A = \frac{\mu_d}{\mu_o}. \tag{7}$$

Before breakthrough, recovery factor is equal to the injected pore volume of displacing fluid; however, after breakthrough of displacing fluid, the recovery factor is calculated as follows:

$$\text{R.F.} = (pv_i)_{bt} + \int_{(pv_i)_{bt}}^{pv_i} (1 - f_d)d(pv_i), \tag{8}$$

where R.F. is recovery factor and $(pv_i)_{bt}$ is injected pore volume of displacing fluid at the breakthrough time.

## 5. Results and discussion

In this study, more than 40 experiments were conducted on several glass micro-model patterns with different fracture lengths and orientations. The $H$ values for each of these micro-models have been calculated by the Kamari et al. [33] method.

In this study, the values of other parameters in Eq. (8) are shown in Table 1.

The integration in Eq. (8) was calculated numerically by Simpson's rule. The curve of recovery factor versus injected pore volume for different values of $H$ is shown in Figure 5. The higher value of $H$-factor is corresponding to the lower recovery factor, and the effect of fracture in higher $H$ value is much more profound.

### 5.1. *Comparison between experimental results and the model*

For two cases of the micro-models, the comparisons between experimental results and the model have been done.

**Case 1:** The micro-model with fracture length of 6 cm ($L_{FD} = 0.5$) and orientation of 0°. For this case, the $H$ value was 2.295 and the breakthrough time occurred at 0.469 injected pore volume. For this case, the recovery factor versus injected pore volume is shown in Figure 6. The doted points and solid line were attained from experimental data and the model, respectively. In Figure 6, the effect of fracture on recovery factor is visible in the experimental data and the approached model.

**Table 1.** Physical and hydraulic properties that are used in Eq. (8).

| Property | Value |
|---|---|
| $M$ | 2.5 |
| $n$ | 1 |
| $s_{id}$ or $s_{iw}$ | 0 |
| $\mu_d$ or $\mu_w$, (cp) @ 21°C | 0.9776 |
| $\mu_o$ or $\mu_{n-C10}$, (cp) @ 21°C | 0.8998 |

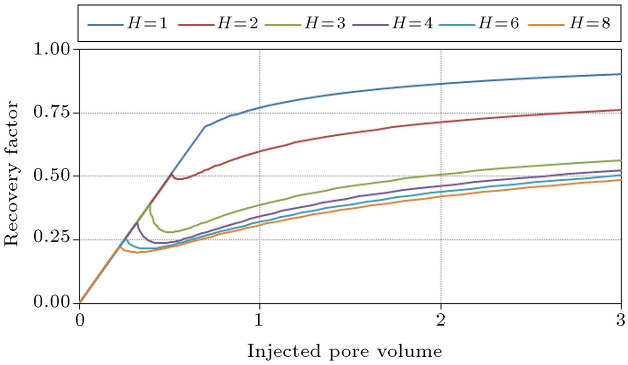



**Figure 5.** Representative graph of Eq. (8) for different $H$ values.

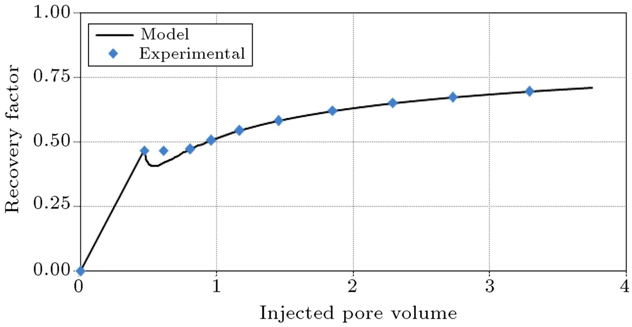



**Figure 6.** Comparison between experimental data and the model for Case 1.

**Case 2:** The micro-model with fracture length of 8 cm ($L_{FD} = 0.667$) and orientation of 45°. For this case, the $H$ value was 1.685 and the breakthrough time occurred at 0.557 injected pore volume. For this case, the recovery factor versus injected pore volume is shown in Figure 7.

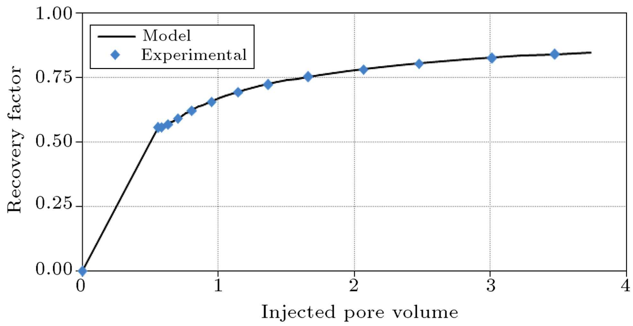



**Figure 7.** Comparison between experimental data and the model for Case 2.

In general, when a fracture exists in porous media, the main part of injected fluid passes through the fracture, and consequently, the displaced fluid will be trapped to some extent. As a result, recovery factor of a fractured porous media is much lower than that of the homogeneous porous media.

## 6. Conclusions

The obtained results show that longer fracture in line drive micro-models causes lower recovery factor. Also, increasing the angle of fracture orientation, with respect to the mean flow direction of displacing fluid, leads to increment of oil recovery factor. In addition, in models with only one fracture, after breakthrough time, the effect of fracture is noticeable and the recovery factor will be decreased due to the displaced fluid being trapped. As well, the proposed model is in good agreement with the obtained experimental data.

## References


1. Craig, Jr. F.F. "The reservoir engineering aspects of waterflooding", *SPE Monograph Series*, **3**, Society of Petroleum Engineers (1993).
2. Daripa, P., Glimm, J., Lindquist, B. and McBryan, O. "Polymer floods: a case study of nonlinear wave analysis and instability control in tertiary oil recovery", *SIAM J. Appl. Math.*, **49**(2), pp. 353-373 (1988).
3. Stalkup, F.I. "Miscible displacement", *SPE Monograph Series*, **8**, Society of Petroleum Engineers (1983).
4. Lenormand, R., Touboul, E. and Zarcone, C. "Numerical models and experiments on immiscible displacement in porous media", *J. Fluid Mech.*, **189**, pp. 165-187 (1988).
5. Tzimas, G.C., Matsuura, T., Avraam, D.G., Van der Brugghen, W., Constantinides, G.N. and Payatakes, A.C. "The combined effect of the viscosity ratio and the wettability during forced imbibition through nonplanar porous media", *J. Colloid Interface Sci.*, **189**(1), pp. 27-36 (1997).
6. Vizika, O., Avraam, D.G. and Payatakes, A.C. "On the role of the viscosity ratio during low-capillary number forced imbibition in porous media", *J. Colloid Interface Sci.*, **165**(2), pp. 386-401 (1994).
7. Aker, E., Maloy, K.J. and Hansen, A. "Simulating temporal evolution of pressure in two-phase flow in porous media", *Physical Review E*, **58**, pp. 2217-2226 (1998).
8. Aker, E., Maloy, K.J., Hansen, A. and Batrouni, G.G. "A two-dimensional network simulator for two-phase flow in porous media", *Transp. Porous Media*, **32**, pp. 163-186 (1998).
9. Blunt, M. and King, P. "Relative permeabilities from two- and three-dimensional pore-scale network modeling", *Transp. Porous Media*, **6**, pp. 407-433 (1991).
10. Constantinides, G.N. and Payatakes, A.C. "Effects of precursor wetting films in immiscible displacement through porous media", *Transp. Porous Media*, **38**, pp. 291-317 (2000).
11. Goode, P.A. and Ramakrishnan, T.S. "Momentum transfer across fluid-fluid interfaces in porous media: a network model", *AIChE J.*, **39**(7), pp. 1124-1134 (1993).
12. Hughes, R.G. and Blunt, M.J. "Pore scale modeling of rate effects in imbibition", *Transp. Porous Media*, **40**, pp. 295-322 (2000).
13. Singh, M. and Mohanty, K.K. "Dynamic modeling of drainage through three-dimensional porous materials", *Chem. Eng. Sci.*, **58**(1), pp. 1-18 (2003).
14. Beliaev, A.Y. and Hassanizadeh, S.M. "A theoretical model of hysteresis and dynamic effects in the capillary relation for two-phase flow in porous media", *Transp. Porous Media*, **43**, pp. 487-510 (2001).
15. Constantinides, G.N. and Payatakes, A.C. "Determination of the effects of capillary number, viscosity ratio and wettability on the capillary pressure-saturation relation using an advanced pore network simulator", *SPE Paper No 78518, Presented at the 10th Abu Dhabi International Petroleum Exhibition and Conference*, Abu-Dhabi (Oct. 13-16, 2002).
16. Hassanizadeh, S.M. and Gray, W.G. "Thermodynamic basis of capillary pressure in porous media", *Water Resources Research*, **29**(10), pp. 3389-3405 (1993).
17. Hassanizadeh, S.M. and Gray, W.G. "Toward an improved description of the physics of two-phase flow", *Advances in Water Resources*, **16**(1), pp. 53-67 (1993).
18. Hassanissadeh, S.M., Celia, M.A. and Dahle, H.K. "Dynamic effect in the capillary pressure-saturation relationship and its impacts on unsaturated flow", *Vadose Zone Journal*, **1**, pp. 38-57 (2002).
19. Singh, M., Mani, V., Honarpour, M.M. and Mohanty, K.K. "Comparison of viscous and gravity dominated gas-oil relative permeabilities", *Journal of Petroleum Science and Engineering*, **30**(2), pp. 67-81 (2001).
20. Tsakiroglou, C.D. "Correlation of the two-phase flow coefficients of porous media with the rheology of shear-thinning fluids", *Journal of Non-Newtonian Fluid Mechanics*, **117**(1), pp. 1-23 (2004).
21. Tsakiroglou, C.D., Theodoropoulou, M. and Karoutsos, V. "Non-equilibrium capillary pressure and relative permeability curves of porous media", *AIChE Journal*, **49**(10), pp. 2472-2486 (2003).
22. Aker, E., Maloy, K.J., Hansen, A. and Batrouni, G.G. "A two-dimensional network simulator for two-phase flow in porous media", *Transport in Porous Media*, **32**, pp. 163-186 (1998).
23. Wang, J., Dong, M. and Asghari, K. "Effect of oil viscosity on heavy-oil/water relative permeability curves", In: *SPE/DOE Symposium on Improved Oil Recovery*, Tulsa (2006).

24. Sohrabi, M., Tehrani, D.H., Danesh, A. and Henderson, G.D. "Visualization of oil recovery by water-alternating gas injection using high-pressure micromodels", *SPEJ*, **9**(3), pp. 290-301 (2004).

25. Sohrabi, M., Danesh, A., Tehrani, D.H. and Jamiolahmady, M. "Microscopic mechanisms of oil recovery by near-miscible gas injection", *Transport in Porous Media*, **72**(3), pp. 351-367 (2007).

26. Soudmand-asli, A., Ayatollahi, S.S., Mohabatkar, H., Zareie, M. and Shariatpanahi, S.F. "The in situ microbial enhanced oil recovery in fractured porous media", *Journal of Petroleum Science and Engineering*, **58**(1-2), pp. 161-172 (2007).

27. Bai, B., Liu, Y., Coste, J. and Li, L. "Preformed particle gel for conformance control: transport mechanism through porous media", *SPE Reservoir Evaluation & Engineering*, **10**(2), pp. 176-184 (2007).

28. Romero-Zeron, L. and Kantzas, A. "The effect of wettability and pore geometry on foamed-gel-blockage performance", *SPE Reservoir Evaluation & Engineering*, **10**(2), pp. 150-163 (2007).

29. Ghazanfari, M.H., Rashtchian, D., Kharrat, R. and Voussughi, S. "Capillary pressure estimation of porous media using statistical pore size function", *Chemical Engineering & Technology*, **30**(7), pp. 862-869 (2007).

30. Hatiboglu, C.U. and Babadagli, T. "Pore-scale studies of spontaneous imbibition into oil-saturated porous media", *Physical Review E*, **77**(6), 066311 (2008).

31. Niasar, V.J., Hassanzadeh, S.M., Pyrak-Nolte, L.J. and Berentsen, C. "Simulating drainage and imbibition experiments in a high-porosity micromodel using an unstructured pore network model", *Water Resources Research*, **45**(2), W02430 (2009).

32. Kamari, E., Rashtchian, D. and Shadizadeh, S.R. "Micro-model experimental study of fracture geometrical effect on breakthrough time in miscible displacement process", *Iranian J. Chem. Chem. Eng.*, **30**(3), pp. 1-7 (2011).

33. Kamari, E., Rashtchian, D. and Shadizadeh, S.R. "Immiscible displacement of a wetting fluid by a non-wetting one at high capillary number in a micro-model containing a single fracture", *Transport in Porous Media*, **94**(1), pp. 289-301 (2012)

34. Kamari, E., Shadizadeh, S.R. and Rashtchian, D. "Effect of fracture geometrics on breakthrough time in immiscible displacement process through strongly oil wet fractured porous media: experimental investigation", *Energy Sources, Part A*, **34**, pp. 867-876 (2012).

35. Kamari, E., Shadizadeh, S.R. and Rashtchian, D. "Improvement of fractional flow model for miscible displacement process: an experimental investigation in single fractured porous medium", *Journal of Porous Media*, **16**(3), pp. 255-266 (2013).

## Biography

**Ehsan Kamari** holds a BS degree from the Petroleum University of Technology and MS and PhD degrees from Sharif University of Technology, all in Reservoir Engineering. His academic experience includes research on experimental and simulation studies of different EOR processes, micro-model experiments, and properties of petroleum fluids. He has authored/co-authored more than 20 technical papers, which have been presented and/or published in international conferences and journals. He is a member of SPE. He is now a project manager in Department of Petroleum Engineering, Research Institute of Petroleum Industry (RIPI). He has served as the Manager of Graduate Students and several research projects.