

PAPER • OPEN ACCESS

## Numerical simulation of the oil displacement process from a porous medium by nanofluid

To cite this article: A V Minakov *et al* 2019 *J. Phys.: Conf. Ser.* **1382** 012115

View the [article online](#) for updates and enhancements.



**IOP | ebooks™**

Bringing together innovative digital publishing with leading authors from the global scientific community.

Start exploring the collection—download the first chapter of every title for free.

# Numerical simulation of the oil displacement process from a porous medium by nanofluid

A V Minakov<sup>1,2</sup>, E I Mikhienkova<sup>1</sup>, M I Pryazhnikov<sup>1,2</sup> and V A Zhigarev<sup>1</sup>

<sup>1</sup>Siberian Federal University, 79 Svobodny pr., Krasnoyarsk, 660041, Russia

<sup>2</sup>Institute of Thermophysics SB RAS, 1 Acad. Lavrentiev pr.,  
Novosibirsk, 630090, Russia

E-mail: tov-andrey@yandex.ru

**Abstract.** Numerical simulation of the oil displacement process from a porous medium by nanofluid was carried out. To describe this process a flow model of two immiscible fluids taking into account the surface tension forces and the wetting angle was used. The simulation results of the penetration of fluid with nanoparticles into a porous medium are obtained using the example of the oil displacement. The nanoparticles addition to the displacing fluid affects the process of oil displacement from porous medium significantly. SiO<sub>2</sub> particles with a size of 5 nm were used as nanoparticles. The concentration of nanoparticles ranged from 0 to 1 wt.%. The main reason for the increase in ORF (oil recovery factor) during oil displacement by nanofluid is the improvement of rock wetting.

## 1. Introduction

The efficiency of oil recovery from oil-bearing strata by modern industrially methods in all oil-producing countries is considered unsatisfactory today, despite the consumption of petroleum products is increasing worldwide from year to year. The average final oil recovery in different countries and regions ranges from 25 to 40% [1-2]. Residual or non-recoverable oil reserves reach an average of 55–75% of the original geological reserves in the subsurface. Traditionally, to increase the oil recovery coefficient, the aqueous solutions of various surfactants are used. In recent years, studies show that the nanosuspensions significantly increase the ORF of the reservoir [3-7]. Nanosuspensions have approximately the same characteristics in reducing the interfacial tension at the boundary with oil and reducing the contact wetting angle. Authors of [8-9] showed that the nanoparticles addition to the displacing fluid can significantly increase the oil recovery factor. In work [8], SiO<sub>2</sub> nanoparticles with sizes of 20–70 nm were used for these purposes. A 5% NaCl solution with a density of 1.05 g/cm<sup>3</sup> and viscosity of 1.09 cP served as a reservoir water model. The displacing nanofluid was prepared by adding to this solution nanoparticles with a concentration of 4 g/l. The displacement of natural oil with a viscosity of 11.014 cP and a density of 859.3 kg/m<sup>3</sup> from cores of the carbonate reservoir was investigated. The use of nanofluids makes it possible to increase the ORF from 47% to 76% compared to reservoir water. The authors explained this effect by the adsorption of nanoparticles: the rock acquires the properties of water wetting, which contributes to the leaching of both film and capillary-retained oil. In another paper [9] TiO<sub>2</sub> nanoparticles with an average size of 50 nm were used for oil displacement. The heavy natural oil with a density of 920 kg/m<sup>3</sup> and dynamic viscosity of 41.21 cP was used for the experiments. The measurement results show that the ORF increases at least 1.3 times using nanofluids.



In our study numerical simulation of the oil displacement process from a porous medium by nanofluid was carried out. To describe this process, a flow model of two immiscible fluids taking into account the surface tension forces and the wetting angle was used.

## 2. Numerical simulation

### 2.1. Mathematical model of oil displacement process

To simulate the oil displacement process by nanofluid, we used a numerical method based on the fluid in cells method, which is good for calculating macroscopic flows with a free surface [10-11]. The idea of the Volume of Fluid (VOF) method is that fluids are considered as a single two-component medium, and the spatial distribution of phases within the simulation domain is determined using a special function of the marker  $F(x, y, z, t)$ , the value of which defines the volume fraction fluid phase in the simulation cell as follows:  $F(x, y, z, t) = 0$  if the cell is empty,  $F(x, y, z, t) = 1$  if the cell is completely filled with fluid.

Since the free surface moves with the fluid, the movement of the free boundary in area is monitored by solving the transfer equation for the volume fraction of the fluid phase in the cell:

$$\frac{dF}{dt} + V \cdot \nabla F = 0 \quad (1)$$

where  $V$  is the velocity vector of a two-phase medium, found from the solution of hydrodynamic equations system consisting of the mass conservation equation or the continuity equation

$$\frac{d\rho}{dt} + \nabla(\rho \cdot V) = 0 \quad (2)$$

and motion equations or the momentum conservation law:

$$\frac{d\rho V}{dt} + \nabla(\rho V \times V) = -\nabla p + \nabla(\tau) + F \quad (3)$$

where  $\tau$  is the viscous stress tensor,  $F$  is the volume force vector,  $p$  is the static pressure,  $\rho$  is the density of the two-phase medium.

The components of the viscous stress tensor  $\tau_{ij}$  are defined as:

$$\tau_{ij} = \mu \left( \frac{\partial u_i}{\partial x_j} + \frac{\partial u_j}{\partial x_i} - \frac{2}{3} \delta_{ij} \frac{\partial u_k}{\partial x_k} \right) \quad (4)$$

where  $\mu$  is the dynamic viscosity of the two-phase medium,  $u_{ij}$  are the components of the velocity vector  $V$ .

The density and molecular viscosity of the two-component medium are defined by the fluid volume fraction in the cell according to the mixture rule, where  $\rho_1, \mu_1$  are the density and viscosity of one fluid, respectively  $\rho_2, \mu_2$  are the density and viscosity of the other:

$$\rho = \rho_1 F + (1-F)\rho_2 \quad (5)$$

$$\mu = \mu_1 F + (1-F)\mu_2 \quad (6)$$

### 2.2. Mathematical model of surface tension

When considering two-component fluid flows in a porous medium it is necessary to take into account the surface tension phenomena. The study of flows controlled by surface tension forces is a difficult task. Therefore, another advantage of the VOF method is the relatively simple consideration of the influence of surface tension forces. To simulate the surface tension within the VOF method the CSF

(Continuum surface force) algorithm was used [10]: the addition of the surface force  $F_s$  into the motion equations:

$$F_s = \sigma k \nabla F \quad (7)$$

where  $\sigma$  is the coefficient of surface tension,  $k$  is the curvature of the free surface defined as the divergence of the normal vector  $n$ :

$$k = \nabla \left( \frac{n}{|n|} \right) \quad (8)$$

The normal to the free surface is calculated as the gradient of the volume fraction of the fluid phase in the cell:

$$n = \nabla F \quad (9)$$

On a solid wall the normal vector is determined from the wetting angle  $\theta$ , where  $n_w$ ,  $\tau_w$  are the normal and tangential components of the vector:

$$n = n_w \cos \theta + \tau_w \sin \theta \quad (10)$$

The method is described in detail in [12]. We note the main points of the numerical simulation. The difference analogue of convective-diffusion equations is found using the finite-volume method for structured multi-block grids, the conservativeness of the resulting scheme is automatically performed. The connection between the fields of velocity and pressure is implemented using SIMPLEX procedures on the combined grids.

### 3. Results and discussion

The experimental data on the interfacial tension at the oil / nanofluid boundary and the wetting angle at the oil / water / rock boundary were used for simulation. The viscosity increases by 8%, the interfacial tension decreases by 10%, the contact angle increases from 70 to 145° with nanoparticles addition to a displacing fluid at concentration of 1 wt.%. Silicon oxide nanoparticles of 5 nm in size were used as additive to suspension. The concentration of nanoparticles ranged from 0 to 1 wt.%. The viscosity of the oil was set equal to 10 cP, the density was 800 kg/m<sup>3</sup>. The measured interfacial tension at the water / oil boundary was 22.5 mN/m.

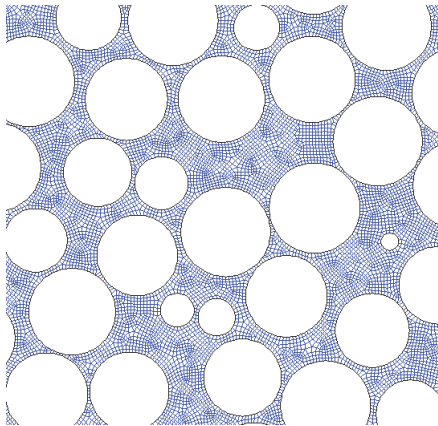
A sandstone model was used as a rock model. The core porosity was 30%. The average soil size was 100 microns.

To simulate the displacement process, a three-dimensional simulation core model was created. In this model the rock particles are in the form of spherical balls. The porous medium in this model is the form of random filling of balls. The balls sizes were randomly distributed. The minimum soil size was 50 μm, the average size was 100 μm, and the maximum was 200 μm.

The simulation was carried out in a two-dimensional formulation. The simulation domain was obtained by cutting a three-dimensional region in the central plane. A simulation grid consisting of 350000 nodes was used for calculations (see Fig. 1).

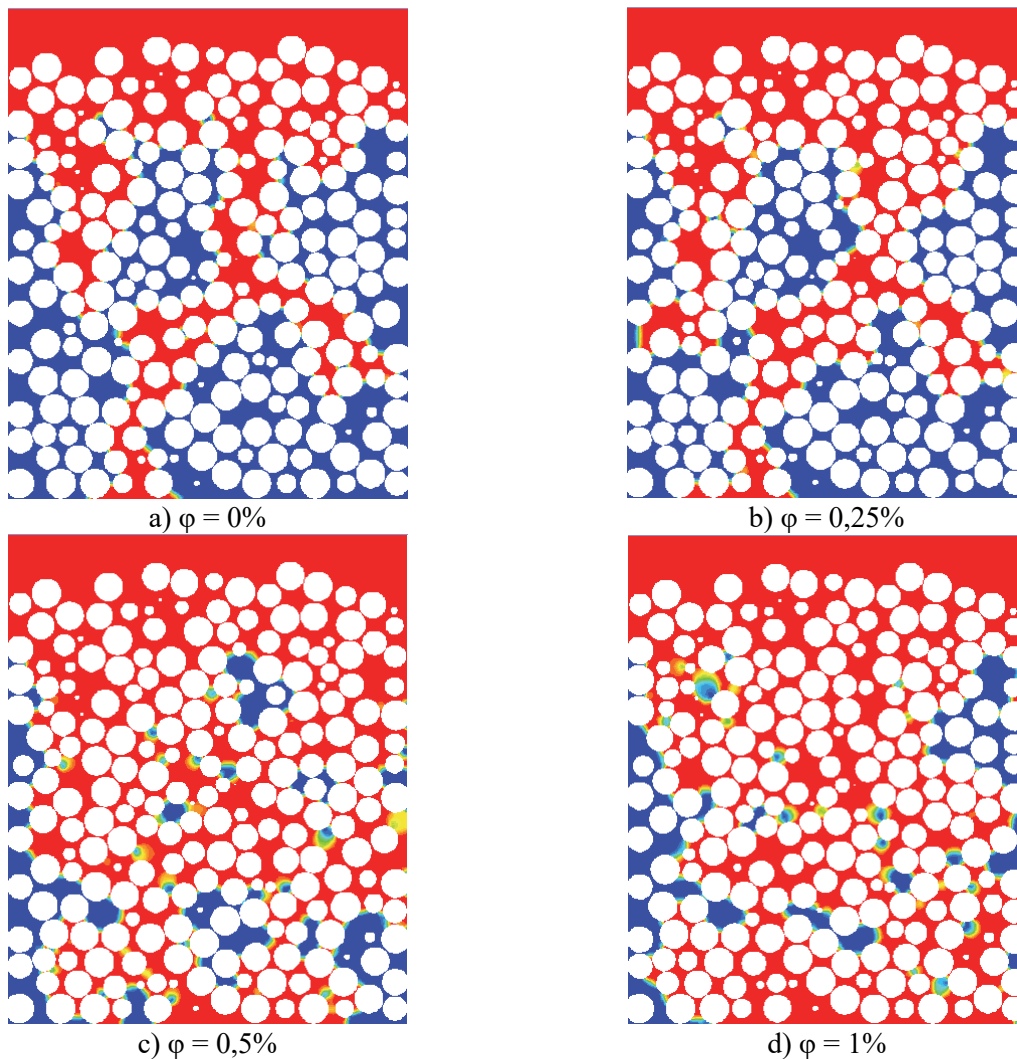
The nanofluid velocity of 0.0002 m/s was set as the boundary conditions at the entrance to the simulation domain. Such velocity value corresponded to the conditions of a standard experiment on flooding the core of 3 cm in diameter with a flow rate of 10 ml/min. Neumann conditions were specified at the exit from the simulation domain. The sticking condition was set on the channel walls.

At the initial moment the simulation domain is completely filled with oil. In the process of calculation the displacement fluid fills the free volume of the simulation domain and displaces oil. The ORF and the magnitude of the pressure drop during fluid injection were determined by the calculation. The ORF was defined as the ratio of the displaced oil volume to the original oil volume in the porous medium.



**Figure 1.** The simulation grid.

First, the effect of nanofluid concentration on oil displacement efficiency was studied. A calculations series with the nanoparticle concentration from 0 to 1 wt.% was carried out. The oil displacement process (blue) by nanofluid (red) over time is shown in Fig. 2.

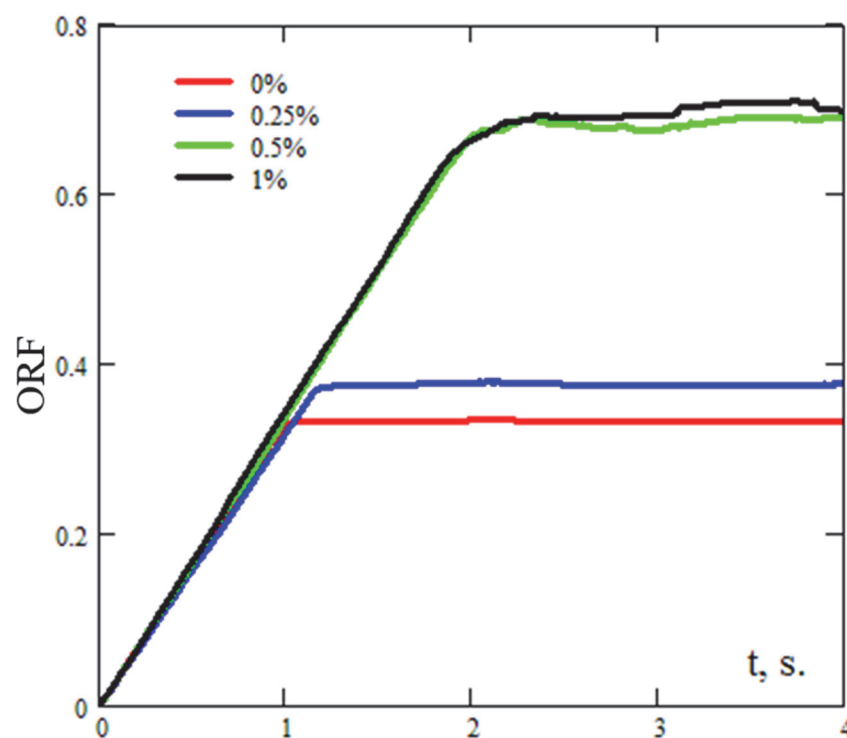


**Figure 2.** Distribution of oil (blue) and nanofluid (red) in a porous medium for various concentrations of nanoparticles at time  $t = 5$  sec. after the start of displacement.

Analysis of the simulation results shows that the nanoparticles addition to the displacing fluid significantly affects the process of oil displacement from a porous medium. The displacing fluid moves through the oil-saturated rock in the form of separate streams or streams with a low nanoparticles concentration in the case of pure water or nanofluid. The displacing fluid moves through the channels in a porous medium, where the hydraulic and interfacial resistances are minimal. Such water streams break quickly through to the exit from the simulation domain. Further water flow occurs through this channel, and the water distribution throughout the volume of the porous medium actually stops. At the same time, most of the porous medium volume remains filled with oil. In the simulation water displaced is about 30% of oil. Further flushing of such rock is not effective. The flow process becomes stationary. Figure 2 shows the steady-state distribution of the flow rate modulus. The water moves in the form of thin streams.

The process of oil displacement by nanofluid is significantly different. At high nanoparticles concentrations the nanofluids do not move in separate streams, but in a more uniform front throughout the entire simulation domain (Fig. 2 c,d). As a result the breakthrough of the displacing fluid occurs much later. So, if water breaks through to the exit from the simulation domain in approximately 1 second from the moment of the start of flooding, then a nanofluid with a particle concentration of 1 wt.% does this in about 1.8 seconds. As a result, a much more volume of the porous medium is covered by the movement of the displacing fluid. And, accordingly, a significantly more oil is flushed out of the rock.

The dependence of oil recovery efficiency on displacement time at various nanoparticles concentrations is shown in Fig. 3. The ORF increases with increasing nanoparticles concentration in the displacing fluid significantly. As a result of simulation, a 1 wt.% concentration of silica nanoparticles of 5 nm in size allows an increase in ORF by about 2.15 times as compared to water. The dependence is non-monotonic. Saturation of the ORF occurs at nanoparticles concentrations of more than 0.5 wt.%, and a further increase in the concentration is impractical.



**Figure 3.** The dependence of the oil recovery factor from on time at various concentrations of silica nanoparticles with an average size of 5 nm.

### Conclusion

The results of a numerical study of the nanofluid penetration into a porous medium are obtained at an example of the oil displacement. Analysis of the simulation results showed that the nanoparticles addition to the displacing fluid significantly affects the process of oil displacement from porous medium. In contrast to the displacement of oil by water, which moves through the oil-saturated rock in the form of separate streams, nanofluid displaces oil by a uniform front. As a result, the oil recovery factor increases significantly. The 1 wt.% nanoparticles concentration of silicon oxide with a size of 5 nm makes it possible to increase ORF by about 2.15 times as compared to water. The main reason for the increase in ORF with oil displacement by nanofluid is the improvement of rock wetting.

### Acknowledgments`

The reported study was funded by Russian Science Foundation to the research project №17-79-20218.

### References

- [1] Surguchev M L 1985 *Secondary and tertiary methods of enhanced oil recovery* (M.: Nedra) p 308
- [2] Amelin I D, Surguchev M L and Davydov A V 1997 *Forecast development of oil deposits at a later stage* (M.: TOO "GISA") p 308
- [3] Bera A and Mandal A 2014 *JPST* **5** (3) 255–68
- [4] Bera A and Belhaj H 2016 *J Nat Gas Sci Eng* **34** 1284–1309
- [5] Qiu F 2010 *Experimental Study of Solvent Based Emulsion Injection to Enhance Heavy Oil Recovery* (MSci. Thesis, Texas A&M University, USA) p 95
- [6] Mandal A and Bera A 2012 *WASET* **6** (7) 21–6
- [7] Santanna V C, Curbelo F D S, Castro Dantas T N, Dantas Neto A A, Albuquerque H S and Garnica A I C 2009 *J Petrol Sci Eng* **66** (3-4) 117–20
- [8] Roustaei A and Bagherzadeh H 2014 *J Petrol Explor Product Tech* **5** (1) 27–33
- [9] Ehtesabi H, Ahadian M M and Taghikhani V 2015 *Energy and Fuels* **29** (1) 1–8
- [10] Brackbill J U, Kothe D B and Zemach C 1992 *J. Comput. Phys* **100** 335–54
- [11] Hirt C W 1981 *J Comput Phys* **39** 201–26
- [12] Minakov A V 2014 *Comp Math Math Phys* **54**(10) 1560–70