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# Study of the thermal influence on the displacement of high-viscous oil by reservoir water from the Bashkirian core of Akanskoe field

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The article discusses the results of physical laboratory modeling of nonisothermal oil displacement by formation water on model composite core samples of the Akanskoe field, performed on a VINCI CFS-700 filtration unit.

In the work, the influence of the permeability of composite core samples on the results of nonisothermal oil displacement by formation water was studied. An analysis of the performed experiments shows that the influence of the temperature regime on the displacement coefficient manifests itself to varying degrees on samples of different permeabilities. The change in the displacement coefficient at various temperature conditions occurs most strongly in low-permeability rock samples, in high-permeability rocks the changes are less significant. Use for displacing produced water with a temperature below the initial formation water (within 2-5ºC) provokes a greater decrease in the displacement coefficient than the use of slightly heated water (within 7ºC).

The presence of highly differentiated rock samples by permeability revealed when drilling productive formations significantly complicates the processes of oil displacement. The local highly permeable sections available in the context of productive formations can act as intensifying the process of displacing the zone with the right choice of temperature and exposure technology.

**Keywords**: core, heterogeneity, laboratory experiment, formation conditions, simulation of thermal influence, displacement coefficient

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Analysis of the causes of low current oil recoveries and search for new technological solutions to optimize field development operations are issues of current importance. Waterflood development of the Bashkirian reservoirs of the Akanskoe field was found to have poor efficiency. This is attributed to the presence of fractures of various origins; in particular, the presence of larger vertical and subvertical fractures of tectonic origin amid small fractures of different genesis (Muslimov, 2015).

Optimization of Akanskoe field development strategy is a complex task, which requires integration of various formation stimulation mechanisms.

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Laboratory-scale experimental modeling of subsurface processes provides the theoretical foundations for finding new solutions to optimize field development. One of the priority areas is heat treatment of productive formations.

Results of simulations of formation treatment under nonisothermal conditions provide the basis for development and improvement of new integrated formation treatment technologies.

In the present research, experimental and simulation data have been used to assess waterflood performance in the Bashkirian reservoirs of the Akanskoe high-viscosity oil field at various temperatures. Studies of oil displacement processes began from joint research efforts of Almetyevsk State Oil Institute, Institute TatNIPIneft Tatneft PJSC and Kara Altyn CJSC (Khayrtdinov, 2018).

This research effort facilitated selection of a set of 12 samples from Well No. 2060 of the Akanskoe field.

Preparation of core samples for further research involved hot solvent cleaning and drying in a desiccator at 105°C.

Gas permeability, connected porosity, and irreducible water saturation were determined for each core sample (Table 1), followed by vacuuming of the samples and saturation with kerosene until constant mass was reached.

Figure 1 presents variability of reservoir properties based on laboratory core testing data.

Characteristic changes in porosity and irreducible water saturation, as well as permeability variations of rocks along the wellbore cause challenges associated with reservoir management and bringing into development multiple pay zones within productive reservoir section.

Based on variability of reservoir properties along the wellbore, irreducible water saturation increase from 8.96 to 43.89 % results in significant changes in permeability (more than 33 times, Fig. 2).

Considering the location of the samples relative to each other and rock characteristics, core material was grouped into composite core models, including 3 samples with similar reservoir properties.

The resultant core samples were further used in coreflood experiments. Table 2 characterizes the properties of composite core samples.

Table 3 provides the characteristics of Bashkirian-stage crude oil and formation brine of the Akanskoe field used in coreflood experiments.

Simulation of in-situ conditions in composite core samples during the experiment involved: applying confining pressure (to simulate overburden load) of 30 mPa, creation of pore pressure (to simulate reservoir pressure) of 11.5 mPa, simulation of reservoir temperature of 19°C. Composite core samples were flooded at a rate of 0.5 ml/min until complete displacement of kerosene, indicated by steady-state flow conditions at constant pressure drop.

| Coring intervals, m | | Core recovery, m | Sampling point, m | Connected porosity, % | Irreducible water content, % | Effective porosity, % | Gas permeability, $10^{-3}\mu m^2$ |
|---|---|---|---|---|---|---|---|
| from | to | | | | | | |
| 1335.6 | 1342 | 6.4 | 3.00 | 26.11 | 12.48 | 22.85 | 1491 |
| 1335.6 | 1342 | 6.4 | 3.10 | 24.64 | 13.12 | 21.41 | 1896 |
| 1335.6 | 1342 | 6.4 | 3.35 | 24.78 | 12.89 | 21.59 | 673 |
| 1335.6 | 1342 | 6.4 | 5.30 | 23.58 | 10.30 | 21.15 | 2203 |
| 1335.6 | 1342 | 6.4 | 6.00 | 22.67 | 8.96 | 20.64 | 2405 |
| 1335.6 | 1342 | 6.4 | 6.30 | 21.59 | 9.11 | 19.62 | 1894 |
| 1342 | 1346 | 3.5 | 1.80 | 14.92 | 43.89 | 8.37 | 73 |
| 1342 | 1346 | 3.5 | 3.00 | 19.26 | 41.05 | 11.35 | 236 |
| 1346 | 1351 | 5.0 | 1.05 | 18.96 | 11.87 | 16.71 | 381 |
| 1346 | 1351 | 5.0 | 1.90 | 11.91 | 21.15 | 9.39 | 71 |
| 1346 | 1351 | 5.0 | 1.40 | 19.10 | 12.77 | 16.66 | 220 |
| 1346 | 1351 | 5.0 | 1.60 | 12.79 | 19.33 | 10.32 | 96 |

*Table 1. Results of porosity and permeability measurements of core samples from Well No. 2060 of the Akanskoe field*

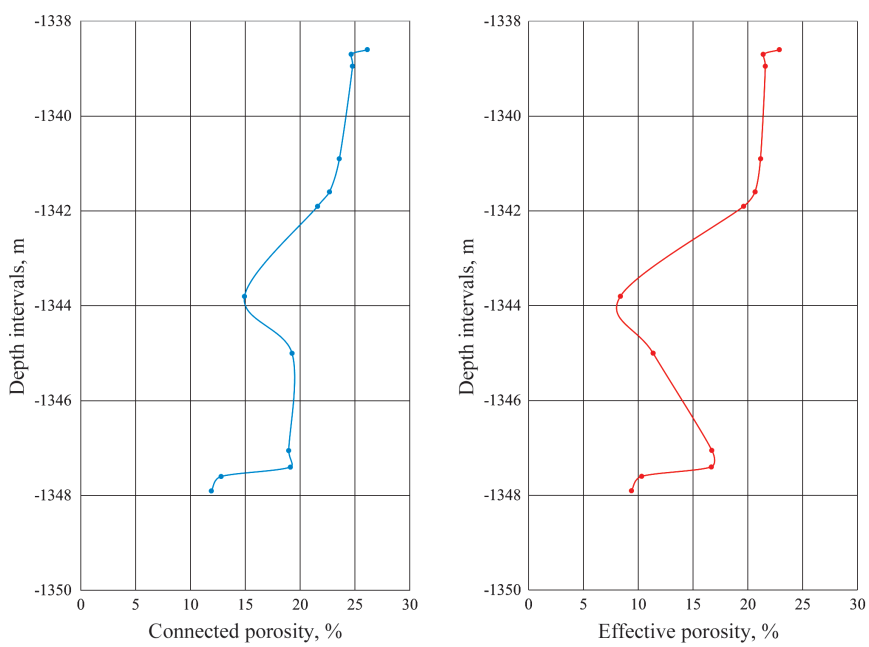


*Fig. 1. Vertical variations in porosity of core samples recovered from Well No. 2060 based on laboratory analysis data*

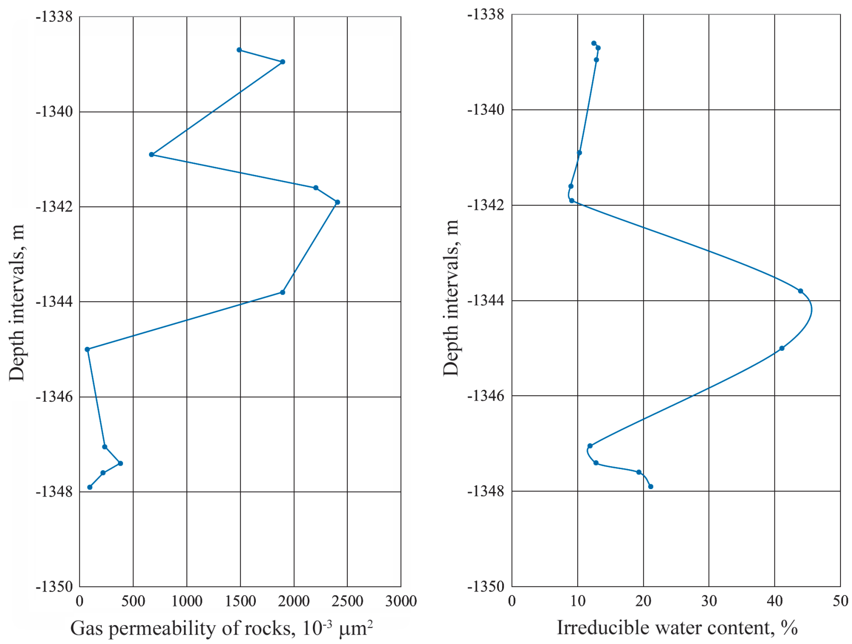


*Fig. 2. Vertical variations in permeability and irreducible water content in core samples from Well No. 2060 based on laboratory analysis data*

| Composite sample | Dimensions (Ø × length, mm) | Gas permeability, μm$^2$ | Connected porosity, % | Pore volume, ml | Initial oil saturation, % |
|---|---|---|---|---|---|
| 1 | 30 × 120 | 0.263 | 19.1 | 16.11 | 78.08 |
| 2 | 30 × 120 | 1.117 | 25.2 | 21.36 | 87.18 |
| 3 | 30 × 120 | 2.146 | 22.6 | 19.16 | 90.53 |

*Table 2. Properties of composite Bashkirian core samples of the Akanskoe field*

| Parameter | Crude oil | | Formation brine |
|---|---|---|---|
| Dynamic viscosity, mPa·s | 231 | 172 | 1.73 |
| Density, kg/m$^3$ | 20.926 | 0.924 | 1.172 |
| Measurement temperature, °C | 19 | 23 | 19 |

*Table 3. Properties of Bashkirian crude oil and formation brine of the Akanskoe field*

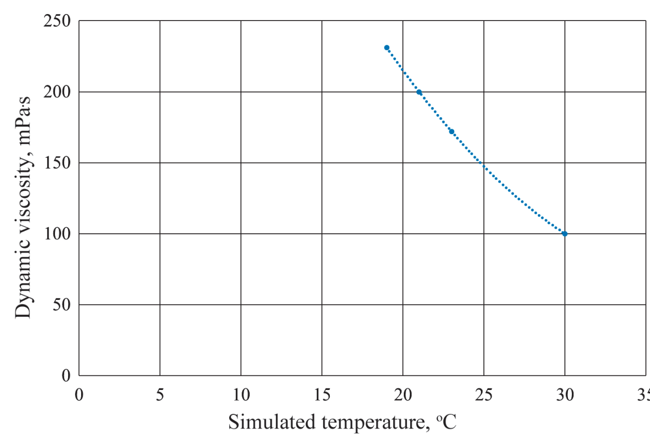


*Fig. 3. Temperature effects on viscosity of crude oil from the Akanskoe field in the targeted temperature range*

Composite core samples were soaked in oil under reservoir temperature and pressure conditions for 2 days to reproduce surface properties of rock samples with cyclic top-down and bottom-up injection of new batch of oil.

To study water displacement of oil from variable permeability composite core samples under nonisothermal conditions, a series of experiments with consistent changes in the temperature of displacing agent was carried out. Temperature conditions simulated reservoir temperature decrease by 4°C and 2°C, reservoir temperature of 23°C and reservoir temperature growth up to 30°C. Fig. 3 presents oil viscosity behavior within the targeted temperature range.

The experiment entailed estimation of required displacement rates for each sample, recording pressure changes at the faces of composite core samples while injection of the required displacement volumes, monitoring displaced fluids volumes, measurements of residual oil saturation and displacement efficiencies.

Table 4 provides experimental conditions and estimated parameters. Pressure drop behavior in each temperature range is demonstrated in Fig. 4-6.

Reservoir cooldown simulations provided for injection of at least ten pore volumes of formation brine at a temperature of 19°C and measurement of displaced fluids volumes. Further experiments implied stepwise increase of temperature up to 21°C, 23°C and 30°C during injection of approximately six pore volumes of displacement fluid while monitoring and measuring the amount of fluid displaced. Once the desired volume of oil

| Number of composite sample | Input and estimated parameters | Initial parameters and experimental data for various temperature conditions | | | |
|---|---|---|---|---|---|
| | | 19 | 21 | 23 | 30 |
| Composite sample №1 $K_{pr}$=0.263 μm$^2$ | Displacement fluid injection rate, ml/min | 0,765 | | | |
| | Displacement fluid volume, ml | 122,0 | 64,2 | 77,04 | 64,2 |
| | Water saturation, $S_w$, fraction | 0,444 | 0,559 | 0,621 | 0,753 |
| | Oil saturation, $S_o$, fraction | 0,556 | 0,441 | 0,379 | 0,247 |
| | Displacement efficiency, fraction | 0,287 | 0,435 | 0,514 | 0,684 |
| Composite sample №2 $K_{pr}$=1.117 μm$^2$ | Displacement fluid injection rate, ml/min | 1,017 | | | |
| | Displacement fluid volume, ml | 155 | 83,7 | 93 | 93 |
| | Water saturation, $S_w$, fraction | 0,396 | 0,470 | 0,469 | 0,613 |
| | Oil saturation, $S_o$, fraction | 0,604 | 0,530 | 0,531 | 0,387 |
| | Displacement efficiency, fraction | 0,307 | 0,392 | 0,462 | 0,556 |
| Composite sample №3 $K_{pr}$=2.146 μm$^2$ | Displacement fluid injection rate, ml/min | 0,912 | | | |
| | Displacement fluid volume, ml | 131,4 | 78,8 | 74,5 | 83,2 |
| | Water saturation, $S_w$, fraction | 0,415 | 0,430 | 0,460 | 0,468 |
| | Oil saturation, $S_o$, fraction | 0,585 | 0,570 | 0,540 | 0,532 |
| | Displacement efficiency, fraction | 0,354 | 0,37 | 0,404 | 0,412 |

*Table 4. Results of the non-isothermal flooding on the Bashkirian stage of the Akanskoe field*

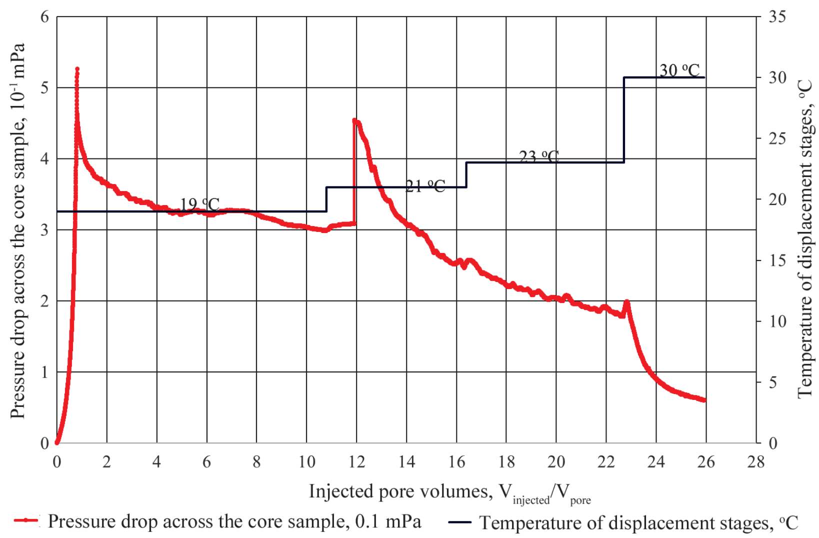


*Fig. 4. Pressure drop across composite core sample with initial gas permeability of 0.263 μm² during nonisothermal water-oil displacement at various temperatures*

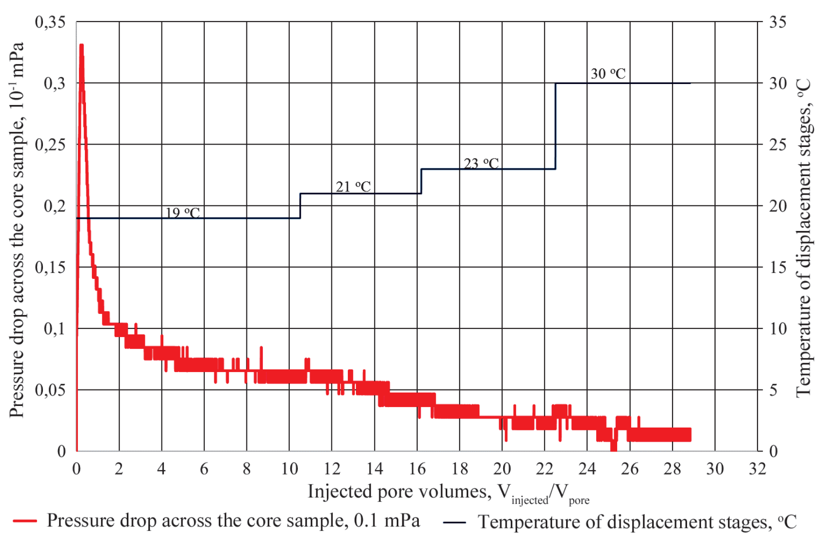


*Fig. 5. Pressure drop across composite core sample with initial gas permeability of 1.117 μm² during nonisothermal water-oil displacement at various temperatures*

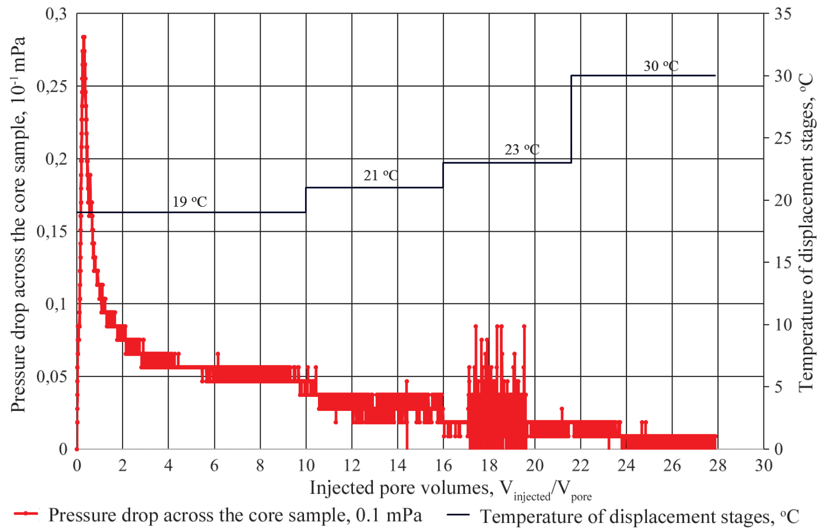


*Fig. 6. Pressure drop across composite core sample with initial gas permeability of 2.146 μm² during nonisothermal water-oil displacement at various temperatures*

had been pumped through the core sample, displacement continued. Following injection of 6 pore volumes of formation brine across the composite core sample at specified temperature, steady-state displacement conditions were reported, and by the end of this stage, no oil trace was noticed in the displaced fluid.

Fig. 7 demonstrates the results obtained in experimental studies on the influence of initial gas permeability and original oil saturation on residual oil saturation trends during nonisothermal displacement and final oil saturations after displacement.

Experimental data suggest that initial gas permeability of core samples affects residual oil saturation during nonisothermal displacement. Furthermore, this effect is the most pronounced in the low permeability range.

The difference in residual oil saturations after nonisothermal displacement of oil from composite core sample with initial gas permeability of 0.263 μm² reaches 0.309, varying from 0.247 (displacement with formation brine at 19°C) to 0.556 (displacement with formation brine at 30°C.)

For permeabilities above 2.146 μm², the difference in residual oil saturations after nonisothermal displacement at 19°C to 30°C does not exceed 0.053.

Fig. 8 confirms dependence of displacement efficiency on gas permeability. For composite core samples with initial gas permeability below 0.263 μm², displacement efficiencies range from 0.287 at brine temperature of 19°C to 0.684 at 30°C.

One of the factors contributing to increase of oil recovery in fractured formations during injection of heat carriers is water-imbibition oil displacement. Temperature increase enhances capillary imbibition processes due to viscosity reduction, improved water-wettability of the rock and permeability growth resulting

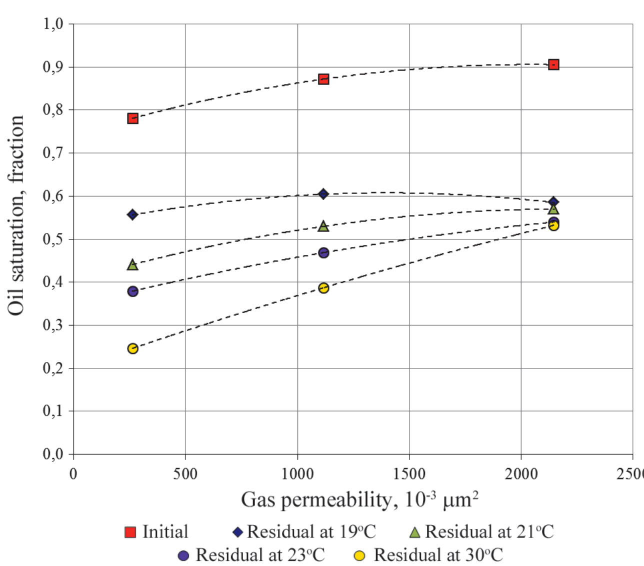


*Fig. 7. Effects of initial permeability and saturation on residual oil saturation during nonisothermal displacement*

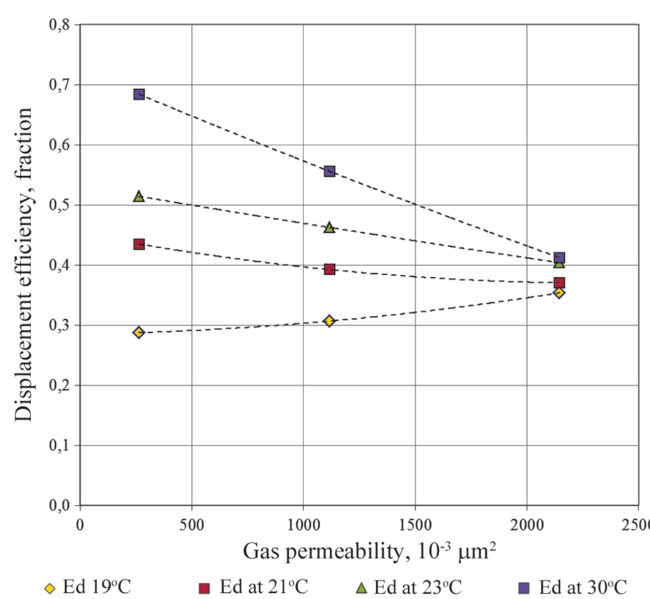


*Fig. 8. Initial gas permeability effects on displacement efficiency during nonisothermal displacement*

from desorption of surface-active components and rupture of oil films (Ametov, 1985).

For the composite core sample with gas permeability exceeding 2.000 μm$^2$, fluid flow during nonisothermal displacement is associated with mobilization of large flow channels with relatively low flow coefficients. As seen in Figs. 7 and 8, temperature growth from 19°C to 30°C within gas permeability range in the order of 2.150 μm$^2$ leads to 0.058 (or 16.3 %) increase in final displacement efficiency (from 0.354 to 0.412), which is significantly lower compared to oil viscosity changes observed in the similar temperature range (relative viscosity change exceeded 95.6 %).

Increase in temperature of heat carrier and composite core sample does not facilitate involvement of small pores in the displacement process due to predominant fluid flow through large channels.

Temperature increase does not lead to substantial improvements in oil displacement efficiency.

In composite core samples with gas permeability of 0.250 μm$^2$, the pore space is relatively homogeneous, thus ensuring a uniform displacement of oil and improved reservoir sweep efficiency. Displacement efficiency increases from 0.287 to 0.684, i.e. by 138.3 %, which far exceeds the relative oil viscosity change (95.6 %).

If reference temperature is assumed equal to 23°C (initial reservoir temperature of 23°C), then temperature reduction by 4°C in a composite core sample with gas permeability of 0.263 μm$^2$ leads to 44.2% decrease in the displacement efficiency compared with the reference value (Fig. 9). For the composite core sample with gas permeability of 2.146 μm$^2$, displacement efficiency decreases by 12.4 % under similar conditions.

Temperature rise of 7°C leads to increase in the displacement efficiencies by 33.1% and 2 % for composite samples with permeability of 0.263 μm$^2$ and 2.146 μm$^2$, respectively.

For adequate assessment of the impact of nonisothermal fluid flow in composite core samples with various permeabilities on displacement efficiency, comparative analysis of displacement efficiency with viscosity behavior was performed.

Integrated assessment of the extent of changes in viscosity and displacement efficiency enables, primarily, evaluation of displacement mechanism and the influence of rheological characteristics of oil on displacement process in heterogeneous environment. The analysis shows that oil temperature increase from 23°C (in-situ conditions) to 30°C results in 41.9 % decrease of oil viscosity, while increment in displacement efficiency under similar conditions is much smaller; particularly, 2% for the composite core sample with high permeability (k = 2.146 μm$^2$) and 33.1% for the composite core sample with low permeability (k = 0.263 μm$^2$).

The following conclusions can be drawn from the present study.

Different displacement efficiency growth trends in composite core samples with gas permeability above 2.0 μm$^2$ and below 0.5 μm$^2$ are attributed to structural differences in the pore space.

Relative oil viscosity changes with temperature are generally consistent with changes in final nonisothermal displacement efficiency, however, for samples with different permeabilities, the rates of displacement efficiency changes differ significantly. On the whole, reduction of injected water temperature (compared to reference temperature) by 4°C diminishes the efficiency of the displacement process. Particularly, oil displacement efficiencies for composite core samples with permeability of 0.263 μm$^2$ and 2.146 μm$^2$ decrease by 44.2 % and 12.4 %, respectively. Displacement efficiency improves generally with increase of injected water temperature by 7°C (compared to reference temperature). Particularly, oil displacement efficiencies for composite core samples with permeability 0.263 μm$^2$

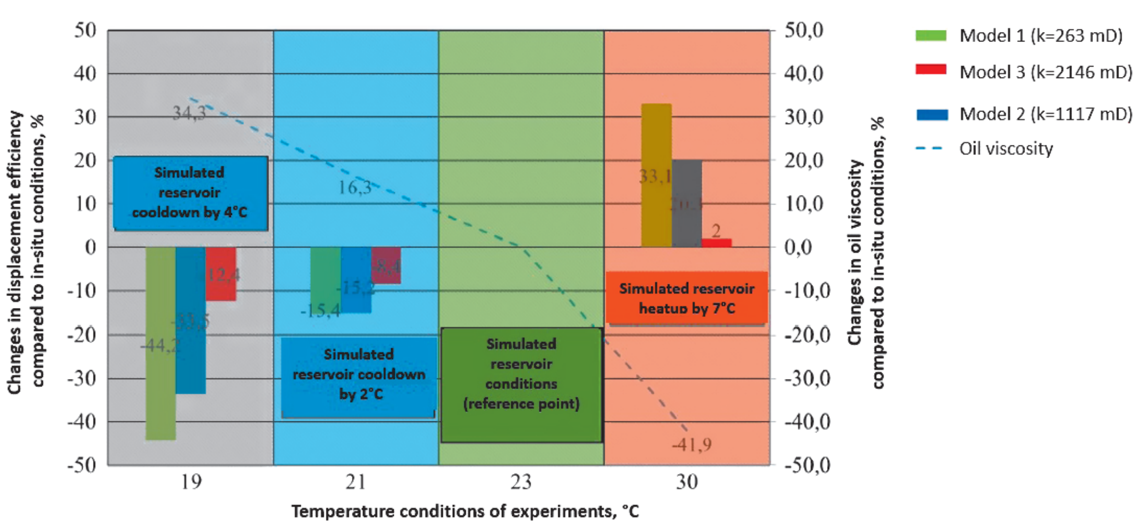


*Fig. 9. Comparison of displacement efficiency changes in composite core samples with changes in oil viscosity compared to in-situ conditions during nonisothermal displacement*

and 2.146 μm$^2$ increase by 33.1 % and 2 %, respectively, while the absolute value of oil viscosity change is 41.9 %.

Tentative identification of zones with simulated permeability along the wellbore and interference of processes (due to absence of natural barriers between high- and low permeability zones) suggest that high permeability reservoir intervals contribute more to enhancing the displacement efficiency. Moreover, rapid advance of temperature front to the region of low flow resistances at the initial stage requires accurate monitoring of the displacement process to prevent propagation of thermal front outside the target zone.

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