The simulation of high-pressure water vapor injection using core material

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Abstract. Effective reservoir development and economically viable development of high-viscosity oil require experience and comprehensive experimental studies on the physical modeling of oil recovery processes using various technologies and displacement agents. The article discusses the filtration processes occurring in the reservoir during the injection of high-pressure water vapor. The results of the filtration experiments show that increasing the temperature to 90 °C makes it possible to effectively displace viscous oil from the reservoir models, while the displacement coefficient reaches 76% after pumping 1.59 pore volumes of distilled water. It should be noted that the injection of low or demineralized aqueous fluids at reservoir temperature and pressure leads to rapid swelling of clay minerals of the formation rock, attenuation of filtration and loss of reservoir properties of the rock.

1. Introduction
In recent years, given the decline in oil production, much attention has been paid to the development of deposits with hard-to-recover reserves. Effective reservoir development and economically viable development of high-viscosity oil demand experience and comprehensive experimental studies on the physical modeling of oil recovery processes using various technologies and displacement agents. To date, thermal methods for increasing oil recovery are considered as the only industrial alternative.

2. Literature review
Thermal methods are oil recovery enhancement methods for productive formations based on additional heating of oil-saturated reservoirs. The thermal effect on the reservoir environment covers all its components (solid, liquid, gaseous); as a result, the reservoir filtration characteristics change due to the weakening of structural and mechanical properties. Improving the conditions for capillary impregnation, reducing the viscosity of oil, increasing its mobility, the transition of oil components to a gaseous state, improving the wettability of the displacing agent lead to an increase in the coefficient of displacement and final oil recovery [5, 6, 7, 9, 14, 18]. Thermal methods involving exposure to the reservoir are accompanied by phase transitions, as well as changes in the characteristics of the reservoir and its saturating fluids, the management of which in specific geological conditions is the most important task facing development specialists [1, 2, 10–13].

Currently, thermal methods are most effective in the development of high-viscosity oil fields and are priority among other methods; however, the development of such fields is currently complicated due to insufficient development of cost-effective technologies for the operation of such fields [8].
For cost-effective steam development on an industrial scale, two criteria systems were developed and published in 1984: one created at the University of Oklahoma under the name PDS (Petroleum Data System) [3]; the second was proposed at the Institute for Subsoil Development and Technology in Socorro, New York State [4].

Indeed, in the United States, commercial development using steam on an industrial scale is carried out in fields with oil viscosity of <7000 mPa·s, formation thickness of >15 m, and depth of >100 m.

But the quantitative values of the criteria for different authors do not always coincide, and sometimes significantly differ. V.D. Morozov and R.Kh. Safiullin (1988) analyzed data on 265 thermal projects in Venezuela, the USA, Canada and other countries [17]. Based on the results, it was found that the industrial development of high-viscosity oil and natural bitumen deposits is carried out in a rather narrow range of geological and physical parameters.

Thermal methods are based on a decrease in the viscosity of formation fluids due to their heating by heat transfer agents. Thermal methods of exposure based on the continuous injection of coolant into injection wells have a significant drawback. The heat supplied to the formation with a coolant is distributed in the formation between the rock forming the formation and the saturating fluids approximately in the ratio of 7–8 to 1. This heat distribution leads to low efficiency of such methods of exposure, since 70–80% of the heat introduced into the formation are heat losses to the skeleton of the saturated porous medium, as well as to the top and bottom of the formation [6, 9, 11].

The mechanism of the processes that occur during the injection of steam into the bottomhole formation zone is rather complicated. The effectiveness of thermal treatment depends on several factors. Increasing the temperature of the reservoir leads to a decrease in the viscosity of oil, a decrease in interphase tension and adsorption of the active components of oil. As a result of the dissolution of paraffin-tar deposits, the bottom-hole zone is cleaned and its initial filtration properties are restored.

During steam and heat treatments under conditions of a high degree of heterogeneity of the collectors, the activation of the processes of capillary absorption of condensate in the pores of oil-saturated low-permeability blocks also acquires special significance.

Steam is an ideal heat agent because it has a high heat content. For example, water at a temperature of 148.9 °C contains 630 kJ/kg, and saturated steam at the same temperature contains 2751 kJ/kg. Therefore, the heat transferred to the formation by steam is more than four times the heat transferred to the formation by hot water. If the reservoir temperature is 650 °C, then 1 kg of water heated to 148.9 °C will transfer 357 kJ to the reservoir, while 1 kg of steam under the same conditions will transfer 2478 kJ, i.e. almost 7 times more [6].

Despite the fact that the injection of hot water is the most technologically simple, it is less effective than the injection of steam. Due to the low specific heat content of hot water, heating up a typical formation to a temperature close to the temperature of the injected water may require 2.5 to 3 pore volumes of hot water.

Steam as a thermal agent has the following advantages:
- high specific heat amount due to latent heat of vaporization; with a degree of dryness of steam of 0.8 (80% of steam and 20% of water, by weight), significantly more heat can be introduced into the formation (calculated per unit mass of the injected agent) than when hot water is injected;
- can occupy a volume in the reservoir 25–40 times greater than water;
- can displace up to 98% of oil from a porous medium.

To quickly continuously increase the vapor zone, it is necessary to minimize heat loss in the wellbore. These losses during the steam injection process depend on the temperature of the injected steam and the equipment used [6, 11].

There are two ways to produce steam using steam generators and steam and gas generators. Steam and gas generators are characterized by good mobility, high efficiency, the possibility of layout for downhole applications, but relatively low productivity. Steam generators are usually massive plants that require complex water treatment systems with relatively low efficiency (to produce one ton of steam, you need to burn a lot of fuel), but with a sufficiently high productivity.
The principal physical mechanism for producing a thermal agent in a steam and gas generator is the injection of water into the fuel combustion products, followed by injection of the resulting mixture into the formation. The combustion process occurs at a pressure exceeding the reservoir, i.e. no additional devices are used to compress the resulting mixture to the required injection pressures. At the same time, unproductive heat losses are minimal, and useful heat can exceed 90%. The performance of modern steam generating units with respect to the thermal agent is small and amounts to 2 t/h.

With increasing formation depths and increasing injection pressure, it is technologically and economically feasible to inject high-temperature water into the formation without bringing it to boiling point, since at high pressures the enthalpy of steam, hot water or steam-water mixture are close in value. As shown in the work of Bourget et al, if the oil reservoir lies at sufficiently large depths, then with increasing injection pressure in a certain temperature range, the enthalpy of the steam-water mixture decreases. It is noted that when using high-temperature water as a heat agent, the operating characteristics of both ground and underground equipment are much higher than when using steam [11].

Of course, the efficiency of the hot water flooding process is lower than the steam-thermal effect, since the required volume of water must be twice as large as the pore volume of the collector to wash out a unit volume of the oil-bearing formation. However, the efficiency of hot water injection is much higher than normal water flooding and is used in cases where steam injection is unacceptable. This includes great depths, and the presence in the formation of clays that swell when in contact with fresh water, as well as the need to maintain temperature in the formation to prevent solid hydrocarbons from precipitating in oil, etc. [6].

3. Research methods
The considered stratum PK_{1-2} of the West Siberian deposit is the largest in area, represented by the alternation of sand, sandstone, siltstone with clays and clay siltstones, in the section of the stratum there are interlayers (up to 1.5 m) of rocks with calcareous cement. Oil and gas collectors are sands, sandstones and silts, gray loose or slightly compacted, fine, small- and medium-grained, clay interlayers. The formation is characterized by an average oil-saturated thickness of 8.6 m, gas-saturated thickness of 20.5 m, the depth of the formation is an average of 890 m. The viscosity of the oil in the reservoir is 377 mPa·s. The oil reserves of the facility are fully difficult to recover: the highly viscous oil rim is completely lined with water, the gas cap covers 82% of the oil area. The deposit has a block structure and is represented by a weakly cemented reservoir [15].

In order to determine further plans for the development of the PK_{1-2} formation, the task was set to simulate the filtration processes occurring in the formation as a result of injection of high-pressure water vapor.

The methodological basis for preparing samples and fluids for testing and for conducting experimental work on oil displacement is OST 39-195-86 [16].

In the studies described below, core material of the PK_{1-2} formation was used, which is characterized by the following reservoir properties: porosity – 0.34 units, permeability – 125 \cdot 10^{-3} \mu m^2, oil saturation – 0.63 units, sandiness coefficient – 0.57 units.

As a model of water vapor condensate, distilled (demineralized) water was used.

To prepare an isoviscose model of oil in the PK_{1} formation, dehydrated and filtered oil was used. For this purpose, purified kerosene in an amount of 8.5–9.0% was added to the oil, selecting the kerosene content so that the oil viscosity at 33 °C was equal to 204 mPa·s. The characteristics of the oil model are given in Table 1.

It was planned to conduct the entire study in the course of one experiment, and to use a stepwise increase in the temperature of the displacing agent and the reservoir model. However, the rock properties of the PK_{1-2} formation did not allow this study to be conducted as part of a single experiment. During the research on core material, clay particles of the rock swelled and dispersed, which led to attenuation of the filtration and made the ultrasonic separator fail to measure the amount of oil displaced, and the clay suspension blocked flow lines and disabled the pressure regulator valve.
Table 1. Oil model characteristics

| Parameter          | Measurement temperature [°C] |
|--------------------|-----------------------------|
|                    | 21                          |
| Viscosity [mPa·s]  | 560                         |
| Density [kg/m³]    | 938-939                     |
|                    | 33                          |
| Viscosity [mPa·s]  | 204                         |
| Density [kg/m³]    | 930                         |

The purpose of filtration experiments No. 1 and No. 2 was to develop a methodology for preparing reservoir models and saturating them with oil. The characteristics of the reservoir models are given in Table 2.

Table 2. Characteristics of models of reservoirs No. 1 and No. 2

| Experiment number (reservoir models) | Pore volume [cm³] | For gas | For mineralized water |
|--------------------------------------|-------------------|---------|----------------------|
| 1                                    | 155               | 1.50    | 0.408                |
| 2                                    | 153               | 1.20    | 0.371                |

In experiment No. 1, the following technique was used to saturate the reservoir model with oil. The installation was assembled, while the oil in the pressure vessel was heated to 55 °C, and the reservoir model, to reservoir temperature. After thermostating for 2 hours, we started pumping the isoviscous oil model into the reservoir model with a volumetric feed rate of 12 cm³/hour.

Initially, water was extracting from the reservoir model, which is typical for this type of experiment. However, after 0.2 porous volume of oil was filtered, at the exit of the reservoir model oil broke through. Such an early oil breakthrough is usually observed only in the case of a fractured core.

Subsequent oil filtration was accompanied by a gradual displacement of water (oil and water were simultaneously observed at the outlet). After pumping 1.38 of pore volume of oil, saturation reached 33 %. Then, the oil filtration rate was reduced to 6 cm³/h in order to equalize the displacement front. Subsequent filtration of 0.61 of pore volume of oil did not increase displaced water volume. The model oil permeability estimation yielded a value of 4.2 μm², which is significantly higher than gas permeability.

Subsequently, model No. 2 was saturated with oil. The saturation technique was changed. Initially, oil was pumped at a temperature of 23 °C (room temperature), which increased its viscosity from 204 to 560 mPa·S. The feed rate was 6 cm³/h. Oil breakthrough through the reservoir model occurred after pumping 0.28 of pore volume of oil, i.e. later than in experiment No. 1. After the oil breakthrough, the feed rate was increased to 12 cm³/h, which was accompanied by an increase in the rate of water displacement. After pumping 1.87 of pore volume of oil initial oil saturation reached 64 %.

After the experiments, when removing sandstone from the reservoir of the reservoir model, it was found that the oil is evenly distributed over the volume of core material, i.e. the porous medium is uniformly saturated.

The experiments performed made it possible to make the following assumption that the clayed sandstone of the PK1-2 formation has double porosity:

- intergranular porosity, i.e. the void space between the particles of the rock,
- intragrain porosity, i.e. clay particles contain capillary pores filled with water.

Initially, oil displaces water from the void space between the rock particles, which leads to a rapid breakthrough of oil, and then, at a higher filtration rate, oil is displaced from the capillary pores inside the particles of clay minerals. Perhaps this is partially due to a change in the wettability of some clay minerals under the influence of viscous oil.

At the final stage of the research complex of filtration experiment No. 1, the effect of distilled water injection (a model of water condensate) on the permeability of the porous medium from the core of the PK1-2 formation was tested. The average filtration rate was 30 cm³/h (1.8 m/day). The results of the last stage of experiment No. 1 are presented in Figs. 1 and 2.
Figure 1. Dependence of the differential pressure and pressure gradient on the time of injection of distilled water in experiment No. 1 (33 °C, back pressure is 9.8 MPa)

Figure 2. Dependence of the differential pressure and pressure gradient on the volume of injection of distilled water in experiment No. 1 (33 °C, back pressure is 9.8 MPa)

Figs. 1 and 2 show that in a very short time (3–4.5 hours), the clay components of the rock swell, which leads to a decrease in filtration. During the experiment, a pressure gradient of about 10 MPa/m was achieved, i.e. in the near-wellbore zone of the formation, as a result of the injection of demineralized fluid (water vapor condensate), an impermeable screen of high strength will form.
The disassembly of the reservoir model showed that the reservoir rock, as a result of interaction with demineralized water, turns into a viscous mushed mixture, i.e. actually loses reservoir properties [19].

When conducting filtration experiment No. 3, the reservoir model was also prepared and saturated with oil according to the previously described methodology. A feature of the reservoir model is that gas permeability is lower than oil permeability with residual water (Table 3).

The data obtained confirm the assumption that oil changes the structure of the void space and the wettability of clay minerals of the rock. The results of preliminary studies showed that prolonged injection at a reservoir temperature of demineralized water into a porous medium from a core of the PK1-2 formation is not possible. Therefore, the filtration of demineralized water at reservoir temperature was not carried out. The experiment was carried out according to the following procedure. After assembly, the installation was pressure-tested at reservoir pressure. Then, at the same time, distilled water was pumped into the reservoir model and the reservoir model was heated to 90 °C. The rate of temperature rise was 60 °C/h. The average filtration rate was 14.5 cm³/h, which ensured a linear displacement rate of 0.89 m/day. The results of the experiment are given in Table 3 and in Fig. 3.

Table 3. Results of filtration experiment No. 3

| Reservoir model characteristics | Indicator |
|--------------------------------|----------|
| Initial oil content, decimal units | 0.737 |
| Permeability [μm²]: | |
| for gas | 1.38 |
| for water | 0.426 |
| for oil (with residual water) | 1.53 |
| Water density [kg/m³] | 1012 |
| Pore volume [cm³] | 155 |
| Length [cm] | 39.5 |
| Diameter [cm] | 3.2 |

| Study of distilled water injection effect | Fluid | Pumped volume [pore volume] | Temperature, °C | Pressure drop in the end of experiment [MPa] | Oil displacement coefficient [%] | Average filtration rate [m/day] |
|------------------------------------------|-------|-----------------------------|-----------------|---------------------------------------------|-------------------------------|---------------------------------|
| Distilled water | 1.59 | 90 | 0.212 | 76 | 0.89 |

Water filtration began with a rapid increase in pressure drop to 0.154 MPa, which is explained by the fact that high pressure gradients are required to displace viscous oil. In the future, the pressure drop rapidly decreased, which is associated with the heating of oil and a decrease in its viscosity. A water breakthrough occurred after the injection of 0.425 of pore volume of distilled water. At the same time, an oil displacement rate of 57.6 % was achieved. Subsequently, the increase in the oil displacement coefficient continued at a slower rate and after pumping 1.59 of pore volume of distilled water, it reached 76 %. In general, the shape of the dependence of the oil displacement coefficient on the injection volume shows that the conditions for oil displacement at 90 °C are close to piston ones.
Figure 3. Filtration dynamics in experiment No. 3 at 90 °C

4. Results
Thus, increasing the temperature to 90 °C allows efficiently displacing viscous oil from the reservoir model. The dependence of the pressure drop on the injection volume is complex.

After the initial burst, the pressure drop decreases and stabilizes at sufficiently low values (about 0.023–0.030 MPa). However, after pumping 0.8 of pore volume of water the pressure drop begins to increase especially accelerating by the end of the experiment.

The obtained dependence indicates that clay minerals of the rock swell in distilled water and at 90 °C.

After pumping, approximately 1.1 of pore volume of water, the performance of the ultrasonic separator meter deteriorated, which determined the volume of the oil displaced from the model. Therefore, the experiment was temporarily stopped. At the same time, the inlet and outlet of the reservoir model were closed, and thermostating was continued. After cleaning the separator-meter and washing the discharge tank, the installation was pressure-tested at 9.8 MPa and prepared to continue the experiment. Initially, distilled water was started to be pumped through the reservoir model at 90 °C, but almost immediately the separator-meter again failed, the valve-pressure regulator at the outlet of the installation deteriorated (the back pressure began to fall). All this did not allow the experiment to continue in the region of higher temperatures.

Dismantling the reservoir model showed that the core material turned into a viscous mushed mixture ("quicksand"), as in experiment No. 1.

5. Conclusions
Thus, an increase in temperature to 90 °C makes it possible to effectively displace viscous oil from the reservoir models PK_{1-2} of the field. The displacement coefficient reached a value of 76 % after pumping 1.59 of porous volume of distilled water. When the formation is heated to a temperature of 90 °C, the clay minerals of the formation rock swell, but the swelling rate is lower than at the reservoir temperature [19].

Summing up the results of the experiments, it should be noted that the injection of low or demineralized aqueous fluids at reservoir temperature and pressure leads to rapid swelling of clay minerals of the PK_{1-2} formation rock, attenuation of filtration and loss of reservoir properties of the rock.
To preserve the reservoir properties of the PK$_{1,2}$ formation, it is necessary to prevent the use of desalinated water agents during the drilling, construction and operation of wells.

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