Resource-Efficient Technologies

Research Paper

ESTIMATION OF FIELD PRODUCTION PROFILES IN CASE OF ASPHALTENE DEPOSITION

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Abstract

In this work, we aimed to predict possible field production scenarios in case of asphaltene deposition based on field data as well as recommend remediation and stimulation measures to mitigate the risks of asphaltene deposition in the reservoir. We considered the influence of asphaltene formation in the near-wellbore of producers on the production data without reservoir pressure maintenance system in one of the oil fields. The asphaltene envelope in the reservoir oil was obtained, and the operating conditions of the field were evaluated under the possibility of asphaltene deposition. According to the results of dynamic modeling, the pressure map was plotted and the low-pressure areas in the near-wellbore were shown, which contributes to the aggravation of the problem associated with the asphaltene envelope. Based on the geometrical features of the low-pressure area, the dependence of the permeability reduction in the near-wellbore of the production well on the operating time was obtained using the asphaltene deposition model proposed by Wang and Civan. Based on the Buckley-Leverett theory, the field production profiles were calculated with and without asphaltene deposition. A decrease in the oil rate and consequently, the decrease in cumulative oil production in the field is expected due to the damage formation by solids. Maintenance of the production level will be facilitated by treating the near-wellbore with aromatic solvents and maintaining the reservoir pressure above the asphaltene onset pressure.

Keywords: formation damage; asphaltene deposition; asphaltene onset pressure; reservoir oil; permeability reduction.

1. Introduction

During the field production, the reservoir pressure and temperature, as well as the properties of reservoir fluids constantly change. The field development during primary oil recovery, the use of gas methods to enhance oil recovery, and acid treatments may be accompanied by the disequilibrium of asphaltenes in oil. As a result, the solubility of oil decreases according to asphaltenes, resulting in their precipitation in oil. The precipitation increases as the reservoir pressure decreases from the upper onset pressure to the bubble-point pressure. Such phenomenon can be observed even though asphaltenes are in the equilibrium state in oil [1]. Asphaltenes are primarily known as components that can precipitate in oil at low pressure and high temperature. In the reservoir, this leads to a decrease in effective porosity (asphaltene scales may accumulate on rock surfaces), wettability alteration, decrease in the phase permeabilities of the reservoir, and mobile oil reserves. The oil industry faces a similar issue in many oil fields, such as the Hassi Messaoud oil field (Algeria), the Ventura oil field (California), the Prinos oil field (the northern Aegean Sea), the Thunder Horse oil field (deepwater Gulf of Mexico), offshore fields in the lake Maracaibo (Venezuela) among many others [2].

Damage caused by asphaltene deposition is extremely important due to huge costs associated with remediation. A number of fields in Venezuela, the Middle East, China, the United States, Canada, and other countries face asphaltene deposition-related complications, which can turn conventional reserves into hard-to-recover reserves and challenge the profitability of the project.

Asphaltene precipitation can extensively occur during the implementation of gas-enhanced oil recovery (EOR) projects. In Russia, pilot projects of this technology started in the 1980s. One of the first projects of carbon dioxide (CO_2) injection in the Samara region (Russia) were initiated in Radaevskoye and Kozlovskoye oil fields [3] in 1984. Approximately 790,000 and 110,000 t CO_2, respectively, were injected in the fields by the middle of 1989. However, shortly after CO_2 breakthrough in producers, gas injection projects were terminated. Notably, JSC RITEK resumed field trials of the carbon dioxide flooding technology as an EOR method [3] at heavy oil reservoirs in Samara (Russia). Nearly 150 oil fields were analyzed in the Samara region [4]. They found that the downhole pressure of many wells in some fields dropped below the bubble point. Some studies [5] showed that oils with similar characteristics under such conditions tend to precipitate asphaltenes when interacting with CO_2. Therefore, asphaltene deposition is a major concern for oil companies. Nowadays, interest in CO_2 EOR has re-emerged in Russia so that the pilot projects with CO_2 injection are implemented as needed. There were about 136 active CO_2 EOR projects in the United States in 2014. The first two large-scale projects were the Scurry Area Canyon Reef Operators (SACROC) flood in Scurry County and the North Crossett flood in Crane and Upton Counties (Texas) that were implemented in 1972 and are active to date [6]. The discovery of large CO_2 reserves led to further growth in the use of CO_2 EOR in the USA. The maximum growth in the use of this technology in the USA was achieved in the late 1980s despite low oil prices. Other CO_2 EOR projects are ongoing in Canada (Weyburn oil field, Saskatchewan), Turkey (Bati Raman heavy oil field), and other areas in the world [7].

During oil production and transportation, stabilization of water-in-oil emulsions, reduction in cross section of tubing, flow lines, and upstream pipelines take place in case of asphaltene deposition [8]. During oil processing, catalysts are poisoned with nick-el, which is present in asphaltenes [9]. Clogging the pore volume of the reservoir rock with asphaltenes and organic scale deposition in tubings and flow lines lead to a decrease in production rates, reduction in the workover period of wells, and extra costs associated with asphaltene removal and remediation techniques [10]. One of the methods used to obtain reliable information about asphaltene precipitation in oil is the use of asphaltene envelope. Laboratory results and field surveys suggest that asphaltene precipitation and deposition take place at a specific depth in the well. Then, the required dosage of the inhibitor is estimated, the capillary tube is run in the hole to the depth of deposition to inject the reagent, and injection is started. However, asphaltene begins to precipitate in the near-wellbore area. This reduces well productivity, making inhibitor injection into the tubing inefficient, and results in the involvement of more sophisticated and expensive control methods. Prevention of this complication can be carried out using various methods (technological, mechanical, electromagnetic, physical, chemical) with limited success, but formed scales are difficult to remove and negatively impact the economics of projects.

With the use of reservoir pressure maintenance systems in oil fields, a decrease in reservoir temperature is observed due to the injection of cold water during the winter and autumn-spring period. Thus, during the field production, the thermal front in the reservoir must be controlled to prevent reservoir cooling. Controlling well operation conditions to minimize the risks associated with organic scale deposition in the field becomes substantiated if the field development monitoring is carried out and well survey and laboratory studies with calculations are simultaneously provided. The challenge in modeling formation damage is that the pore space in a reservoir has a very complex structure. Previously, simplified models [12] were obtained with the pore space represented by parallel pathways. That model included empirical correlations between permeability reduction and concentration of solids in a fluid. Later, another model was created [13] that took into account the adsorption of asphaltenes on the surface of pore throats and their plugging. One of the most responsible and accessible methods is a simplified analytical model for formation damage in single-phase state proposed by Leontaritis [14]. He proposed the following assumptions: reservoir pressure and asphaltene onset pressure remain constant; asphaltene precipitation occurs in the near-wellbore

area, uninvaded area remains unaffected, and the decrease in permeability occurs due to plugging pore throats by asphaltenes.

This work provides accurate estimation of production profiles in case of asphaltene deposition and the effects of well treatments on incremental oil production in the examined oil field.

2. Oil field overview

The pay zone of the field is represented by limestone with a thickness of 10 m. The formation is characterized by medium reservoir properties: a porosity of 16 % and a permeability of $11 \cdot 10^{-3}$ μm^2. The formation development is provided by the natural drive. The reservoir pressure maintenance system in the field at the current date is not implemented.

The reservoir pressure has decreased by an average of 60 % during the last few years of production and is close to the asphaltene onset pressure in oil (37 MPa). The initial reservoir temperature is 121 °C. Oil is characterized as low-wax content of 1.5 % by weight, low tar of 2.5 % by weight and average specific gravity of 0.870 g/m^3. The asphaltenes content of 1 % by weight.

In situ oil is in a single-phase state. High reservoir pressure makes the possibility of long-term reservoir development without oil flashing in the formation in the absence of the reservoir pressure maintenance system. However, the reservoir has a low dynamic relationship with the aquifer, and the development history of neighboring fields shows that, in the natural drive, the recovery factor does not exceed 6–10 %.

The oil production in the field is complicated by asphaltene deposition in the pore volume of the rock and downhole equipment, which is confirmed by field data and special oil analysis (asphaltene precipitation and deposition tests). The most intensive formation of asphaltene scales is observed at the bubble-point pressure. The asphaltene scales formation is carried out in the pressure range from 7.6 MPa above to 4 MPa below the bubble-point pressure. Analysis of the producer's operation showed that the most likely area for asphaltene scale formation in the well is the perforation. Although the company operator tried to bring the asphaltene scale formation from the reservoir into the well by replacing the choke at the wellhead to increase the downhole pressure, this operation led to a two-fold decrease in flow rates (via the use of choke with smaller diameter) and underuse the reservoir potential, which is economically unviable.

Successful remediation to improve well productivity in the field is the treatment of the near-wellbore by aromatic solvents. In addition, the operator plans to provide hydraulic fracturing on certain wells to create filtration channels through affected areas and slow the expansion of the drawdown cone deep into reservoir to remove asphaltene deposition from the near-wellbore and use the asphaltene inhibitor at the bottom of the wells.

2.1. Causes of complications

The causes of the asphaltene scales formation during the field operation include the following:

1. Change in oil composition during production.
2. Reduction in reservoir pressure below the asphaltene onset pressure [1].
3. Reduction in reservoir temperature, which leads to a decrease in solvent power of oil to asphaltenes.
4. Injection of hydrocarbon gas or CO_2 into the reservoir, as well as the use of a gas lift, which increases the upper asphaltene onset pressure (UOP) in oil due to the increase in the gas-to-oil ratio and, as a result, the asphaltene deposition in the near-wellbore [15].

According to field data, one of the neighboring fields in the oil of the underlying formation has a high content of hydrogen disulfide. Hydrogen disulfide pollution of the overlying reservoir in which this gas was previously absent indicates a dynamic relationship between formations. Thus, during the field operation, it is possible to change the oil composition, which can lead to a decrease in its solvent power to asphaltenes and, as a consequence, the organic scale formation.

In the future, when implementing the reservoir pressure maintenance system in the field, it is necessary to be leery of the selection of a flooding agent. Formation water with salinity exceeding 200 g/l, due to the high concentration of ions, destabilizes the asphaltenes, which are the polar components of oil. A flooding agent is selected based on its compatibility with both the reservoir water and oil.

2.2. Prevention and correction methods
of the asphaltene scales formation

Effective methods for prevention and correction of the asphaltene scale formation in the field include the following:

1. Utilization of nonorganic and asphaltene scale inhibitors in the composition of water flooding agents: A necessary condition is the preservation of the initial temperature of formation. It is necessary to rely on the laboratory studies of the compatibility of water, nonorganic and asphaltene inhibitors, and oil selection reagents.

2. Injection of chemicals through capillary tubes into the well, which slows asphaltene scale formation: This chemical prevention method may not be effective because it takes a lot of time for the interaction of inhibitor and asphaltenes. Thus, the inhibitor must be preliminarily supplied to the oil before asphaltene precipitation, which imposes special requirements for the selection of injection technology.

3. Injection of chemicals into the reservoir (conventional squeeze treatment): The inhibitor must have an optimal adsorption capacity with respect to the surface of the pore volume of the rock to ensure the required dosage in the well for a long term of production. A brief description of the technology is given below.

The treatment procedure of the near-wellbore with an activator and inhibitor of asphaltene scale formation is described in detail [11]. At the first stage, the well is cleaned and reverse-circulated, followed by the injection of the activator and buffer solution. The activator is adsorbed by the formation. At the second stage, the injection of an asphaltene inhibitor is carried out, at the third stage, well flushing with oil, and at the fourth stage, shutting in of the well for 12–24 hours of soaking so that the activator and the inhibitor have time to interact. After this, the well is put into production. The use of activator increases the squeezing time of the inhibitor into the well.

According to a previous study [11], the use of this technology has increased the workover period of the well compared with the conventional solvent treatment of the near-wellbore from 1 to 3 months. Re-treatment was more effective since a certain amount of inhibitor remained in the porous media after the first treatment. Accordingly, the workover period increased to 9 months [11].

2.3. Remediation methods

The field operation can be accompanied by the use of physical and chemical stimulation techniques. Each of the following methods causes a certain effect and can be used both individually and in combination with other techniques.

1. The ultrasonic treatment disperses asphaltene aggregates and leads to an increase in the mobility of asphaltene scales in a porous media.

2. The near-wellbore treatment with asphalt-free oil or low-asphaltene oil leads to the washing of the pore volume of the rock from asphaltene scales.

3. The near-wellbore treatment with hot oil leads to an increase in the mobility of asphaltene scales in a porous media but requires additional research as complications are possible.

4. The use of hydrocarbon solvents (aromatic) and surfactants with the addition of asphaltene inhibitors prevents the asphaltene precipitation in the near-wellbore, remediates its reservoir properties, and contributes to the weakening of the non-Newtonian oil properties.

2.4. Measures before putting well into production and recommencing

New wells (without frac) that are put into production at which the forecast oil rate is not reached, and wells restored to production are subjected to an acid treatment. The purpose of the treatment is the cleaning of the near-wellbore, perforations, wellbore from clays, mud, and solids.

The acid can contain all necessary additives (corrosion inhibitor, stabilizer, surfactant, demulsifier). Since the oil of this field is susceptible to the asphaltene scale formation, the use of an asphaltene inhibitor is recommended as an additive of the acid composition.

Before treatment, laboratory tests must be performed on core and oil samples. First, the rock mineralogy must be investigated to select the process fluid. Then, the compatibility of the process fluid and oil should be studied to ensure that mixing will not lead to the formation of emulsions or solids.

To remediate the relationship of the near-wellbore with a marginal reservoir area (to create filtration channels in the affected area), it may be recommended to provide hydraulic fracturing with the addition of asphaltene inhibitors.

In the presence of intensive organic scaling, it is recommended to create a protective film on the surface of downhole equipment via tubing circulation of a water-in-hydrocarbon emulsion with a nonionic surfactant or asphaltene inhibitor. This reduces the adhesion power of organic scales to the steel surface. Additionally, it is possible to use this emulsion as preserving and packer fluids for producers.

2.5. Sampling recommendations for downhole oil samples in the field

Downhole oil samples collected in wells located in the low reservoir pressure area were subjected to the evaluation of asphaltene content. The oil field is characterized by low coverage of downhole oil samples, and one of the samples was collected with a partial loss of asphaltenes. However, such oil samples can be extremely useful in assessing the occurrence of complications in the field. It is worthwhile to compare the original oil properties and oil sampled at the current date to understand how many asphaltenes precipitated and remained in the reservoir and evaluate the plugged radius. For complete coverage of the field by fluid studies, it is recommended to collect samples from wells located on profiles directed perpendicular and parallel to the main axis of the field. So, samples will be collected and examined both from the marginal and roof reservoir areas. The location of faults must be considered during well selection. High-amplitude faults may divide the reservoir into a number of unconnected areas in which the reservoir oil differ in properties.

Downhole oil samples should be collected under a pressure above the UOP, which is higher than the bubble-point pressure. Collection of downhole samples must be carried out in samplers with nitrogen pressure suppression (in the sampler, extra volume of sample is loaded under pressure exceeding the asphaltene precipitation pressure by 30–50 %).

3. Calculation of production profiles in case of asphaltene scale formation in the porous medium

Asphaltene scale formation was predicted by studying asphaltene flocculation, adsorption, and desorption. In calculations, the asphaltene deposition model was used based on the asphaltene mass balance equation and asphaltene precipitation model and takes into account the porosity and permeability reduction during field operation [1]. The asphaltene deposition model was obtained by Wang et al. on the basis of core test results and scaled up to petroleum reservoirs.

According to the asphaltene mass balance equation [16], asphaltenes can be partially dissolved in oil, partially suspended (in solid phase), and adsorbed [17] onto the surface of the pore volume:

$$\frac{\partial}{\partial t}(\varphi S_o C_A \rho_A + \varphi S_o \rho_o w_{AL}) + \frac{\partial}{\partial x}(\rho_o u_o w_{SAL} + \rho o u o w A L = -\rho A \partial E A \partial t \tag{1}$$

Darcy equation was used to describe the superficial velocity of oil:

$$u_o = -\frac{k k_{ro}}{\mu_o} \frac{\partial P}{\partial x} \tag{2}$$

Asphaltene precipitation models are based on two conventional approaches: the thermodynamic the colloidal theory. According to the thermodynamic theory, asphaltenes are completely dissolved in oil at the original state. By changing thermodynamic conditions, asphaltenes go to the disequilibrium state and precipitate in oil. According to the colloidal theory, asphaltenes are presented in oil as colloidal particles with the resins adsorbed onto their surface. By changing pressure and temperature conditions or oil composition, resins desorb from asphaltenes, and the latter form flocs and aggregates.

The asphaltene precipitation model [18] used in this paper can be represented by the following equation:

$$\varphi_A = exp\left[\frac{V_A}{V_L} - 1 - \frac{V_A}{RT}(\delta_A - \delta_L)^2\right] \tag{3}$$

$$\delta_A = 20{,}04 \times (1 - h_o T) \tag{4}$$

$$\delta_L = \left(\frac{\Delta U_w}{V_L}\right)^{0,5} \tag{5}$$

The asphaltene deposition model [19] allows asphaltene particles adsorbed on pore throats to occupy a small fraction of pore volume and block oil flow (Figure 1), resulting in a decrease in flow rate. The asphaltene deposition rate can be represented as follows [19]:

$$\frac{\partial E_A}{\partial t} = \overbrace{\alpha_A S_o C_A \varphi}^{adsorption} - \overbrace{\beta_A E_A (v_o - v_{cr,o})}^{desorption} + \overbrace{\gamma_A u_o S_o C_A}^{clogging} \tag{6}$$

$$v_o = \frac{u_o}{\varphi} \tag{7}$$

The first term in Equation (6) describes the adsorption of asphaltenes on the surface of pores. The second term represents asphaltene desorption from the surface of pore throats when the interstitial velocity of oil is larger than the critical one. The last term describes the pores clogged with asphaltenes:

$$\gamma_A = \gamma_{Ai}(1 + \sigma E_A) \tag{8}$$

The following conditions are assumed in the calculations:

At the initial time, the volume fraction of asphaltenes adsorbed on the surface of the pore volume and suspended in oil is zero (asphaltenes are completely dissolved in oil);
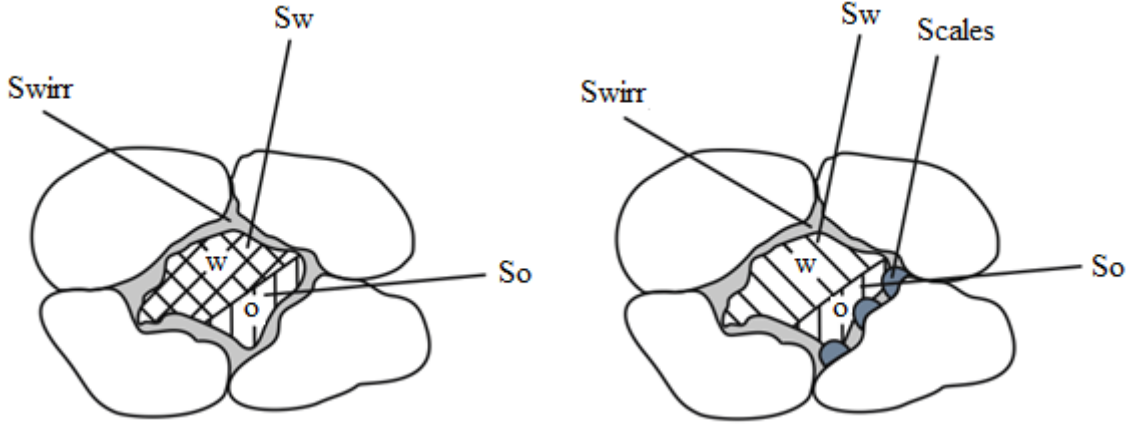
Porosity and permeability correspond to the initial values.

Fig. 1. Scheme of scale formation in the pore volume

The calculation technique requires determining the amount of pore volumes of oil with suspended asphaltenes passed through a porous media. The distribution of the concentration of suspended asphaltenes in oil from the inlet to the outlet of the core is described by an exponential relationship. With an increase in the number of passed pore volumes of oil, the volume of asphaltene scales in the porous media increases. Thus, asphaltene precipitates undergo the entrainment and deposition in the formation like fine solid particles [19].

The adsorption and desorption coefficients can be estimated based on flooding experiments. At the first stage, the oil is injected into the core at the interstitial velocity below the critical interstitial velocity, which is determined empirically. Then, the concentration of suspended asphaltenes in the oil outlet of the core is measured by available methods [20], while the concentration inlet of the core remains constant. The concentration of asphaltenes in oil outlet of the core is lower than the inlet concentration as long as the asphaltenes are adsorbed onto the surface of pore throats. From flooding experiment, the following data are obtained: number of injected pore volumes of oil, concentration of suspended asphaltenes in oil outlet of the core in time, initial porosity of the core, and duration of the experiment.

The porosity and permeability reduction model allows to predict the change in reservoir properties due to asphaltene deposition and to provide the forecast of the field production profiles before and after the implementation of remediation technologies.

The local porosity is calculated as the difference between the initial porosity and the volume fraction of asphaltenes adsorbed on the surface of the pore volume [16]:

$$\varphi = \varphi_i - E_A \quad (9)$$

The local permeability is presented as a function of porosity and calculated as follows [21]:

$$k = k_i \left(\frac{\varphi}{\varphi_i}\right)^3 \left(\frac{1-\varphi_i}{1-\varphi}\right)^2 \quad (10)$$

The permeability damage factor is introduced to estimate the relative change in reservoir permeability, which is calculated by

$$Kdf = 1 - \frac{k}{k_i} \quad (11)$$

The Buckley-Leverett theory was used to determine the field production profiles in case of waterflooding (to model two-phase flow in porous media). The calculation technique determines water cut over time upon which the production profiles are calculated.

The water-free oil production period is calculated by the following equation:

$$t^* = \frac{\pi \cdot h \cdot r_k^2 \cdot \varphi}{q \cdot f`(S_w)} \quad (12)$$

$$f`(S_w) = \frac{f(S_w)}{S_w - S_{irr}} \quad (13)$$

The water saturation on the wellbore wall is calculated over time t by the following equation:

$$\frac{f`(\bar{S})}{f`(S)} = \frac{t^*}{t} \qquad (14)$$

$f(\bar{S})$ is calculated and the water cut is made equal to the Buckley-Leverett function.

4. Results and discussion

4.1. Complications (asphaltene scale formation) in downhole equipment

A Pressure-Volume-Temperature (PVT) model of oil was created based on the PVT studies of reservoir oil, as well as data on special studies (asphaltene precipitation, deposition tests). After tuning the model to the asphaltene onset pressure, an asphaltene envelope was obtained (Figure 2). Based on the asphaltene envelope, the range of the field operation conditions was observed at which the oc-currence of asphaltene scale formation was possible in the field. Above the red line in the graph (UOP), asphaltenes completely dissolve in oil. At the UOP, asphaltenes begin to precipitate in oil, and the maximum precipitation rate is observed at the bubble-point pressure. Below the green line (lower asphaltene onset pressure – LOP), asphaltenes begin to dissolve in oil at a special rate.

The producer located in the low reservoir pressure area (Figure 3) was considered in further analysis. According to the calculated pressure and temperature profiles along the wellbore (Figure 4) in the depth interval from 5000 m (bottom) to 3600 m, the pressure varies from 29 to 22 MPa, and the temperature varies from 121 to 95 °C.
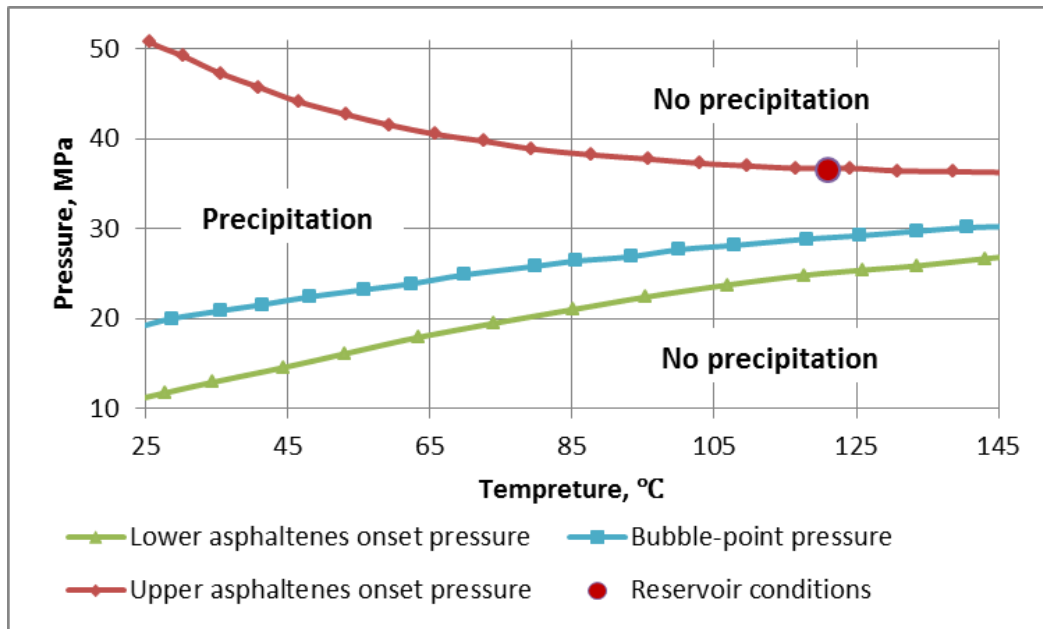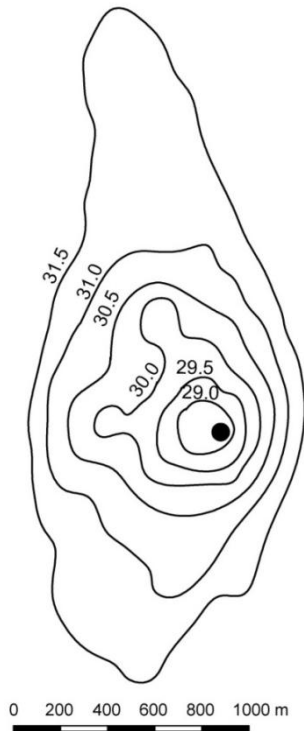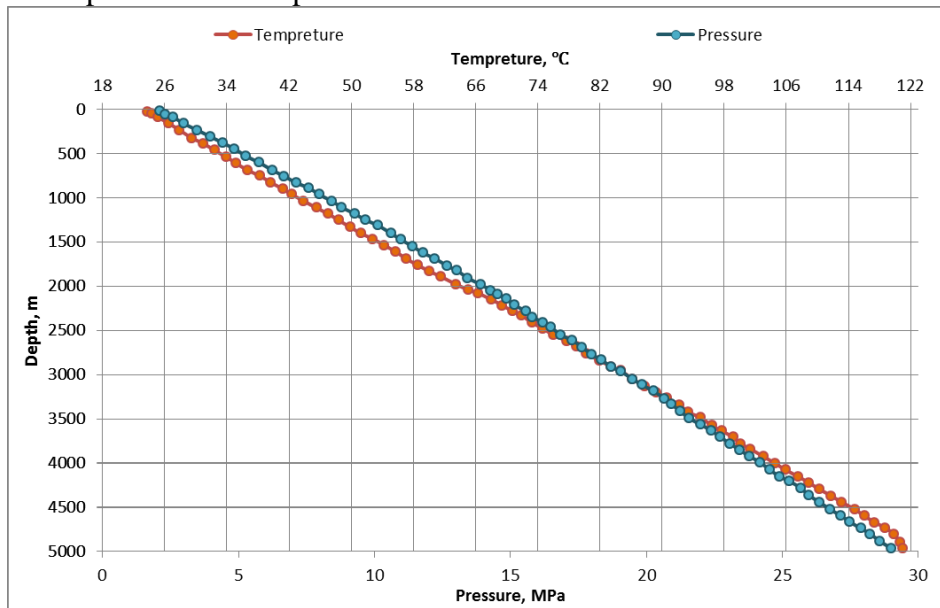

Fig. 2. Asphaltene envelope in reservoir oil

close to the bubble-point pressure. Thus, in the depth range from 5000 m to 3600 m, the asphaltene scale formation most likely occurs in the downhole equipment. There are numerous examples where asphaltene scales can block tubing and flow lines [11].

4.2. Complications (asphaltene scale formation) in the near-wellbore

The instantaneous reservoir pressure presented in Figure 3 is obtained via dynamic simulations. By taking into account the asphaltene envelope, the figure confirms the possibility of asphaltene scale formation in the near-wellbore area of the producer. Based on the geometry of the low-pressure area, as well as using the asphaltene deposition model proposed by Wang and Civan [22], we obtained the dependence of the permeability damage factor in the near-wellbore of the producer *Kdf* on the well operation time (Figure 5).
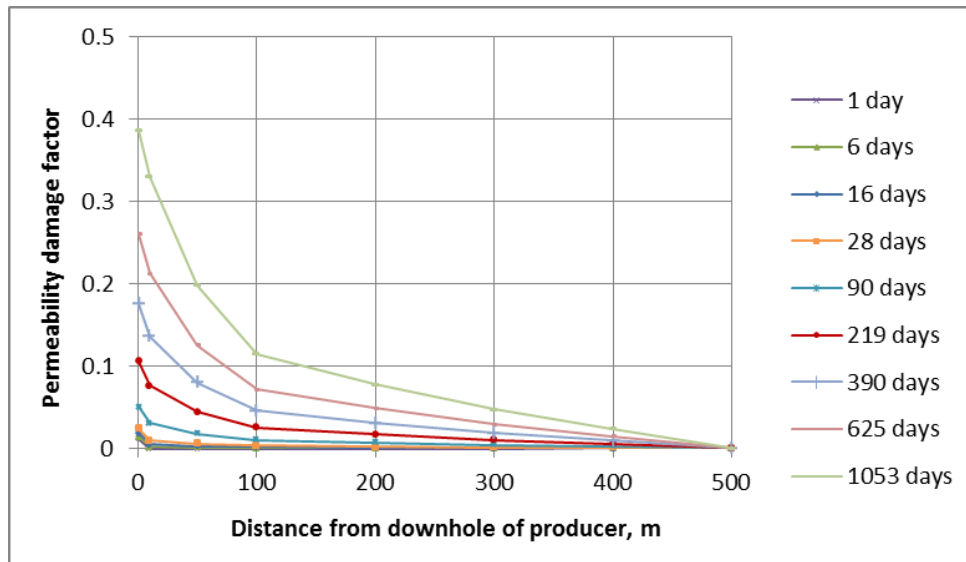

Fig. 3. The instantaneous reservoir pressure in the near-wellbore of the producer

The figure shows that the downhole pressure is 7.6 MPa below the asphaltene onset pressure and

Fig. 4. Pressure and temperature profiles along the wellbore

Fig. 5. The permeability damage factor along the radius *(r)* on the well operation time

Since the permeability damage most likely occurs in the first year of production, the near-wellbore treatment with aromatic solvents is proposed as a remediation method in the field. The calculation results can provide determining treatment schedules in the field.

4.3. The field production profiles

The field production profiles were calculated without asphaltene scale formation in a porous media to estimate possible complications caused by asphaltene deposition. The flow rate and cumulative oil production were selected as targets. The calculation of production profiles in the case of water drive using the Buckley-Leverett theory evaluates water cut over time.

Oil and water relative permeabilities used in the calculations are shown in Figure 6.

Figure 7 shows the curves $f(S)$ and $f'(S)$ plotted based on relative permeabilities. The curve $f(S)$ shows the water saturation at the displacement front (S_w), and then, $f(S_w)$ is estimated.

Figures 8 and 9 show the cumulative oil production and production profile by well based on the schedule of the near-wellbore treatments (dotted curve indicate the dates of treatments). The re-treatment efficiency decreases due to the low solvent penetration into the formation. For example, well treatment in a volume of 1 m^3 of solvent per 1 m of perforated interval causes a penetration depth of 1.4 m. Within the treatment area, the effective porosity can be remediated to the initial value; however, outside of this area, the effective porosity remains unrestored. After putting into the production of the well, the porosity in both areas continues to decrease over operation time. So, the calculations showed that after the treatment of the fifth well, only a slight effect in production can be achieved (Figure 9).
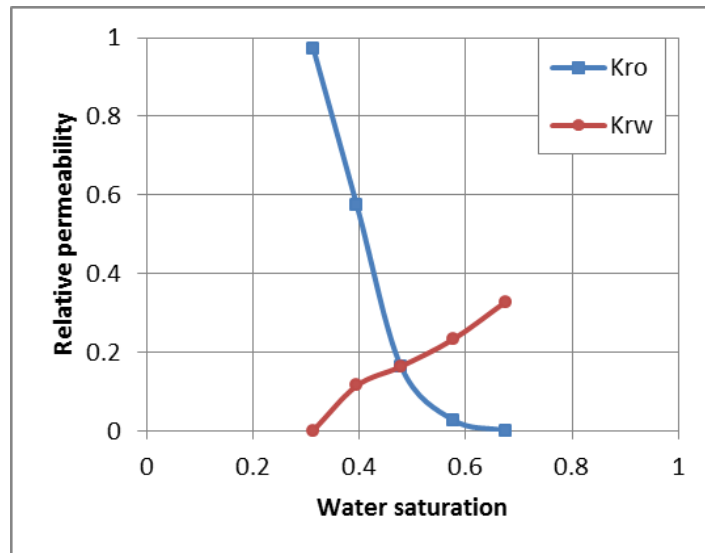
Fig. 6. The dependences of oil (k_{ro}) and water (k_{rw}) relative permeabilities on water saturation
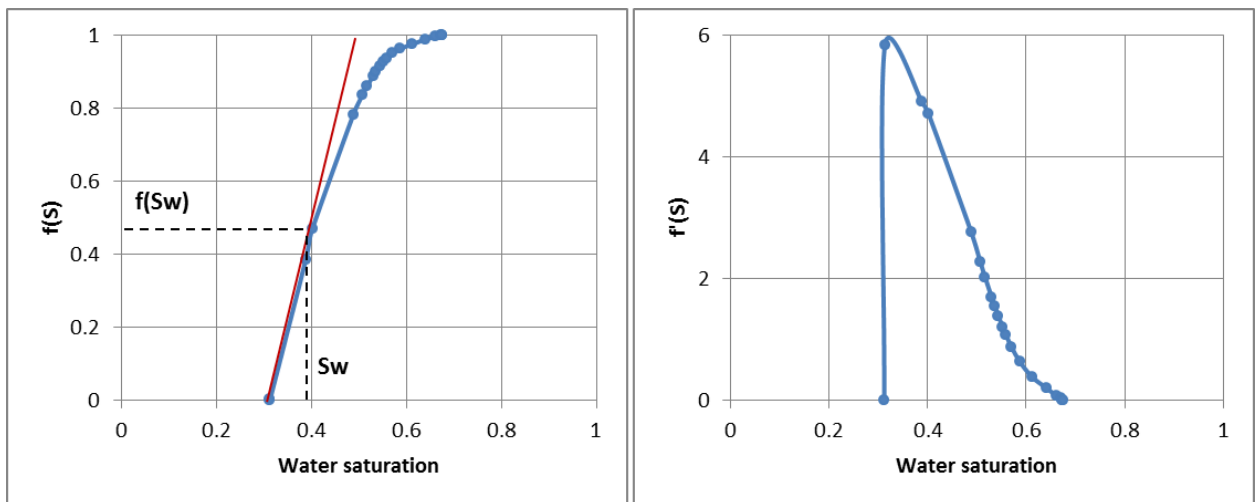

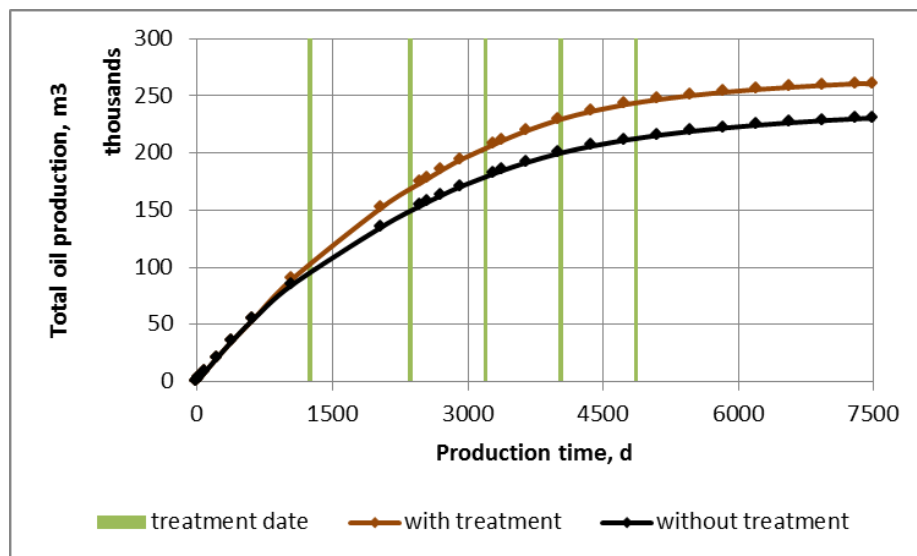**Fig. 7.** Buckley–Leverett function (left) and its derivative (right)

Fig. 8. Cumulative oil production (by well) without and with the near-wellbore treatments
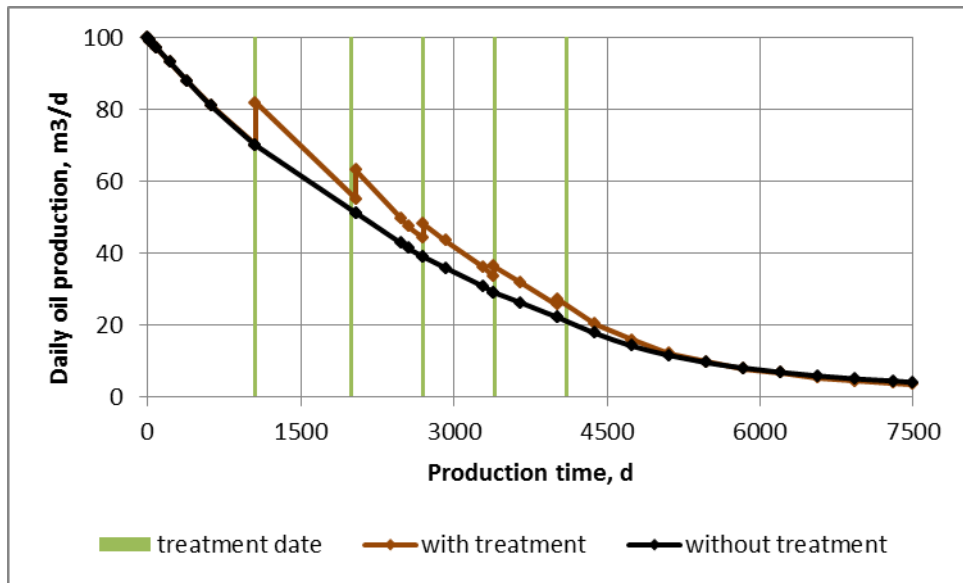
Fig. 9. Oil production profile (by well) without and with the near-wellbore treatments

Figure 9 shows that the well oil rate is reduced by 30 % relative to the start value within 1053 days of production as a result of the asphaltene deposition in the near-wellbore. The near-wellbore treatments are planned after this date.

The field is operated as the water drive reservoir, so low reservoir pressure areas in the near-wellbore of the majority of producers are expected. Since the implementation of the reservoir pressure mainte-nance system in the field is not provided, the sched-ule of the near-wellbore treatments was made to all producers. Figure 10 shows three curves of the field cumulative oil production calculated in accordance with the Buckley-Leverett theory without asphaltene deposition and with asphaltene deposition without and with near-wellbore treatments.
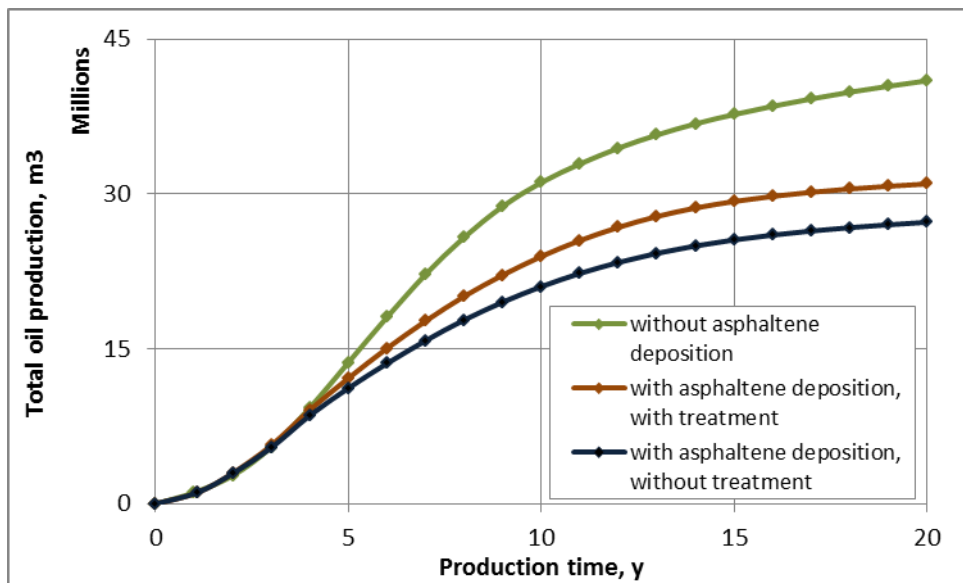

Fig. 10. The field cumulative oil production without and with near-wellbore treatments

The asphaltene deposition in the near-wellbore leads to a 33 % decrease in the field cumulative oil production (blue and brown curves in Figure 10), and this is consistent with several studies [22]. The proposed schedule of the near-wellbore treatments will increase the field cumulative oil production by 15 % (red and blue curves in Figure 10).

The implementation of the reservoir pressure maintenance system in the field may cause an altera-tion of the temperature scenario. In the field, it will provide the injection water from surface source, the average annual temperature of which is about 20 °C. Accordingly, the average temperature of the injected water equaled 20 °C. The Chekalyuk equation was used to estimate the downhole temperature:

26

$$T_d = T_0 - \frac{2GQC_p}{2\pi r_0 \alpha(t)} \times \left(1 - exp\left(-\frac{2\pi r_0 \alpha(t)}{QC_p}h\right)\right) +$$
$$T_w \times exp\left(-\frac{2\pi r_0 \alpha(t)}{QC_p}h\right) \tag{15}$$

The calculated temperature profile at the downhole of the injector over the well operation time with an injection rate of 100 m^3/d is shown in Figure 11.
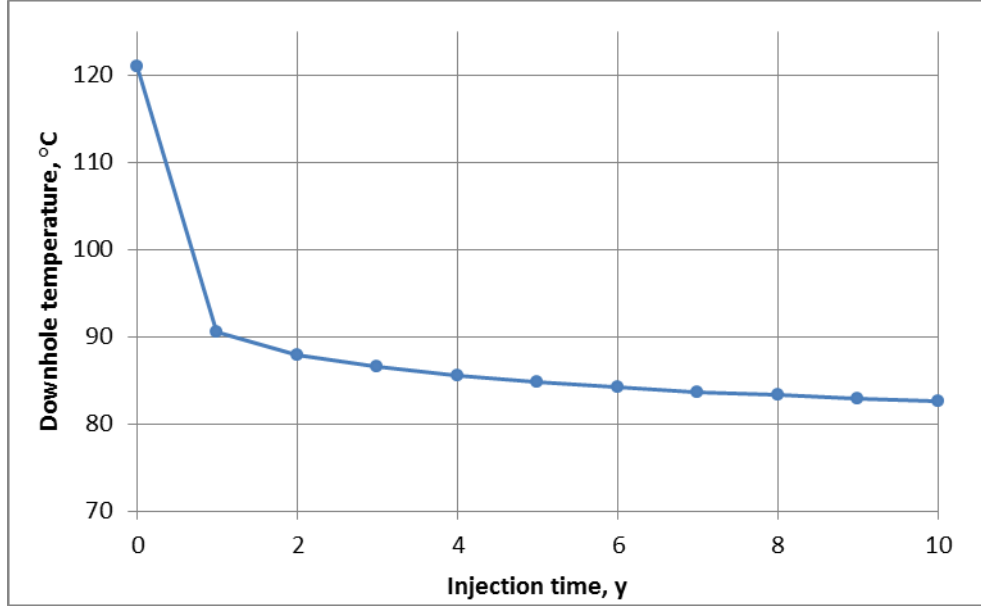

Fig. 11. Temperature profile at the downhole of the injector over time

The temperature field in the reservoir in case of cold-water injection can be calculated based on the Lauwerier's concept [24]. The concept involves the calculation of heat transport in the reservoir with uniform thickness, porosity, and permeability. The main assumptions and simplifications are as follows: the vertical reservoir temperature gradient is neglected; the lower boundary of the reservoir is sealed for water and heat, and the upper boundary is sealed for only water. The equations were proposed by Lauwerier for the calculation of the temperature distribution in the reservoir as a function of time and position during the hot water injection. Further, based on the Lauwerier's concept, Barends [25] proposed a calculation technique for the temperature field distribution in hot reservoirs during the cold-water injection. The Lauwerier's concept is appropriate for calculating the thermal front when water is injected into the reservoir in a wide range of initial reservoir temperatures. The obtained dependence must be taken into account when developing fields in more favorable initial pressure and temperature conditions. Without controlling the temperature of the injected water, it is difficult to accurately predict the rate of reservoir temperature reduction and the probability of clogging of the pore volume. The extended Lauwerier's concept for convective-conductive heat transfer with bleeding to adjacent layers was proposed by Saeid and Barends [25]. The extended Lauwerier solution is presented below:

$$T_0 = T_d erfc\left[\frac{\xi}{2\sqrt{\tau - \xi(1-\delta)}}\right] U[\tau - \xi(1-\delta)] \tag{16}$$

$$\xi = \frac{xh_cD'}{v_cH^2} \tag{17}$$

$$\tau = \frac{th_cD'}{H^2} \tag{18}$$

$$\delta = \frac{h_cDD'}{v_c^2H^2} \tag{19}$$

The calculated temperature field in the reservoir over the well operation time is shown in Figure 12.

Figure 12 shows that one year after the start of injection, the decrease in reservoir temperature will appear 50 m above from the bottom of the injector. 10 years after the operation of the injector, the thermal front will move to 125 m. Thus, reservoir cooling and, accordingly, organic scale formation and deposition in the pore volume of the interwell space take place.

However, it is known that the thermal front velocity significantly lags the displacement front velocity due to the heat exchange with the surrounding rocks. The thermal front velocity can be estimated by the following equation:

$$U_{DF} = \frac{\gamma C_p}{\gamma C_p \varphi + C} \times U_{TF} \tag{20}$$
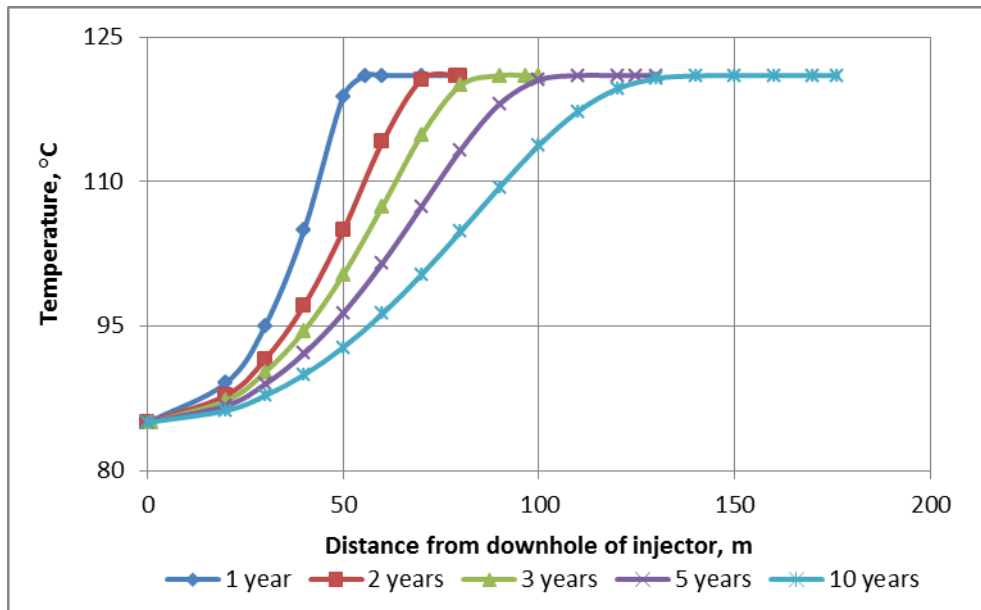
Fig. 12. Temperature field in the near-wellbore of the injector

The calculations showed that the thermal front velocity is 3.5 times lower than the displacement front velocity in the field. Thus, in the areas of the reservoir behind the thermal front, only residual oil (areas washed by several pore volumes of water) will remain in the porous media. Consequently, the asphaltene and wax precipitation in the pore volume with residual oil during cooling will not affect the water relative permeability and injection rate, as suggested by other studies [26].

5. Conclusions

According to the field data and PVT studies of reservoir oil and calculations, the problem of asphaltene scale formation in the field was confirmed.

We obtained the asphaltene envelope, which enables the estimation of the range of field operation conditions, creating the risk of asphaltene scale formation. The calculation results showed that asphaltene precipitation occurs in a pressure range of 36–25 MPa at the reservoir temperature.

The permeability damage factor in the near-wellbore over the well operating time was obtained based on the pressure map and the asphaltene deposition model proposed by Wang and Civan. The volume of clogged pores is determined mainly by the pore volume of flowing oil with precipitated asphaltenes. Due to the law of continuity and mass balance, there is less oil flow in the uninvaded area of the well compared to the area adjacent to the well; therefore, less volume of clogged pores is observed.

The calculation results showed that permeability in the area adjacent to the well decreased by approximately 40 % in less than 3 years. Calculations indicate a reduction in the well oil rate by 30 % after 1053 days as a result of asphaltene deposition in the near-wellbore area.

The field production profiles with and without asphaltene deposition are calculated using the Buckley-Leverett theory. A comparative analysis of the results suggests that due to the asphaltene deposition in the near-wellbore, the field cumulative oil production may decrease by 33 %. The forecast calculations based on the field data will allow to maintain suitable conditions of the field production, prevent formation damage, as well as design well treatments. Providing the near-wellbore treatments of producers with aromatic solvents may contribute to an increase in cumulative oil production by 15 %. The application of remediation technologies will significantly increase the workover period of wells and improve the profitability of the project.

The implementation of the waterflooding system aimed at maintaining reservoir pressure above the asphaltene onset pressure will reduce the risk of asphaltene deposition in the porous media. The alteration of the temperature scenario of the reservoir in case of the cold-water injection is required.

Future work will address an uncertainty analysis when assessing formation damage induced by asphaltene deposition using experimental design techniques and data analysis methods discussed in detail. This will allow to estimate probable production scenarios and uncertainty in the results.

Nomenclature

S_o	oil saturation, unit fraction
C_A	concentration of suspended asphaltenes in oil, unit fraction
ρ_A and ρ_o	density of asphaltene and oil, respectively, kg/m^3
w_{SAL} and w_{AL}	mass fraction of the suspended and dissolved asphaltenes in oil, respectively, unit fraction
E_A	volume fraction of asphaltenes adsorbed on the surface of the pore volume, unit fraction
u_o	superficial velocity of oil, m/s
k_{ro}	relative oil permeability, unit fraction
μ_o	oil viscosity, mPa·s
P	pressure of oil in the pore volume, Pa
x	linear coordinate, m
φ_A	volume fraction of dissolved asphaltenes in oil
V_A	molar volume of asphaltenes, l/mol
V_L	molar volume of the liquid phase, l/mol
R	universal gas constant, J/(mol·K)
T	absolute temperature, K
δ_A	solubility parameter of asphaltenes
δ_L	solubility parameter of the liquid phase
h_o	a specific constant for oil
ΔU_w	the internal energy change during the vaporization of a unit mole liquid
$\dfrac{\partial E_A}{\partial t}$	the asphaltene deposition rate
α_A	the asphaltenes adsorption coefficient
β_A	the asphaltenes desorption coefficient
v_o	the interstitial velocity of oil, m/s
$v_{cr,o}$	the critical interstitial velocity of oil, m/s
γ_A	the clogging deposition rate coefficient
γ_{Ai}	the instantaneous clogging deposition rate coefficient
σt	the snowballing deposition constant
φ and φ_i	local and initial porosity, respectively, unit fraction
k and k_i	local and initial permeability, respectively, μm^2
q	the water injection rate, m^3/s
r_k	radius of the circular section of reservoir, m
h	the reservoir thickness, m
$f(S_w)$	Buckley-Leverett function, unit fraction
$f'(S_w)$	derivative of the Buckley-Leverett function
S_w	water saturation at the displacement front, unit fraction
S_{irr}	irreducible water saturation, unit fraction
$\bar{S}$	water saturation on the wellbore wall, unit fraction
T_d	the downhole temperature of injector, °C
T_0	reservoir temperature, °C
G	geothermal gradient, °C/m
Q	mass injection rate, kg/s
r_0	wellbore radius, m
$\alpha(t)$	heat transfer coefficient, W/(m·°C)
C_p	specific heat of water, J/(kg·°C)
T_w	the wellhead temperature, °C
γ	water density, kg/m^3
C	volumetric specific heat of rocks, J/(kg·°C)

U_{DF}	displacement front velocity, m/d
U_{TF}	thermal front velocity, m/d
Erfc(x)	complementary error function
x	distance from the injection well, m
U(x)	the unit function
h_c	the heat capacity ratio
D and D'	the reservoir and the adjacent layer thermal diffusivity, respectively, m^2/s
v_c	heat convective velocity, m/s
t	time, s

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