DISPLACEMENT OF HIGH-PARAFIN OIL FROM FORMATIONS BY INJECTED COLD WATER

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Abstract. When cold water is injected into reservoirs, the reservoir temperature near the injector wells decreases and becomes lower than the wax saturation temperature of the oil. As a result, wax is precipitated from the oil in the porous medium of productive horizons, negatively impacting the development of oil reservoirs. The need to take into account the characteristics of oils and reservoir systems when designing the development of oil fields applies both to deposits of high-viscosity oils, in which, with increasing the reservoir temperature, viscosity decreases and oil mobility increases, intra-reservoir hydrodynamic resistances decrease, which improves the flow of fluids to producing wells, and to deposits of low-viscosity oils saturated with paraffin. The article addresses the question of the effectiveness of hot water injection. Hot water injection is only meaningful when the oil (or gas equivalent to oil) consumption for heating the water is less than the potential oil losses during cold water injection. The problem of research on cold water injection is relevant and necessary to optimize oil production processes. Changes in the reservoir pressure and temperature are important in assessing the effectiveness of the flooding method to increase oil recovery at the Uzen field of the Republic of Kazakhstan. The paper presents theoretical models based on real data that were used for calculations. The criteria for the effectiveness of hot water injection include such indicators as an increase in oil production, increase in the reservoir pressure efficiency, decrease in oil viscosity to improve its flowability, as well as a reduction in production costs.

Keywords: waterflooding, paraffin, oil, oil field.

Introduction

When flooding oil reservoirs, the temperature of the injected water is usually lower than the reservoir temperature. For reservoirs containing highly paraffinic oils, this leads to a sharp decrease in oil recovery [1; 2]. Today, the extraction of heavy oil from a powerful natural reservoir is a difficult task. An unfavorable mobility coefficient leads to an early water breakthrough and a low oil recovery coefficient. During flooding, the initial stress distribution changes due to two main factors. Firstly, the injected water changes the distribution of the reservoir pressure. Secondly, the temperature difference between the injected liquid and the initial reservoir temperature causes additional changes in the form of thermal stress.

The effect of cold water injection on the thermal state of productive horizons raises the problem of studying the degree of influence of the reservoir cooling on changes in the productivity compared with the productivity at the initial reservoir temperature.

Flooding is an important method for extracting heavy oils worldwide. In Western Canada, over 200 flooding operations extract more than 24% of the approximately five billion cubic meters of heavy oil available in Alberta and Saskatchewan [3].

During flooding of oil reservoirs, the temperature of the injected water is typically lower than that of the reservoir. In the case of highly paraffinic oils, this leads to a sharp decrease in oil recovery [4; 5]. The physical mechanism behind the reduced efficiency of displacing highly paraffinic oil with water at a temperature lower than the reservoir temperature involves the precipitation of paraffin as a solid phase, consequently impairing the reservoir fluid mobility [6]. Accordingly, injecting hot water into such deposits is recommended at both early and later stages of flooding.

Under these conditions, the selection of the optimal temperature regime is based on mathematical modeling within the framework of non-isothermal two-phase flow.

Analysis of oil recovery from reservoirs involves assessing the physical and chemical properties of the reservoir, evaluating the production well activity, forecasting changes in production considering time and investments, as well as analyzing the effectiveness of the oil extraction methods from reservoirs.

The Uzen deposit is located in the southern steppe part of the Mangyshlak peninsula of the Republic of Kazakhstan, known in the geological literature as the South Mangyshlak trough. The Uzen deposit

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was put into commercial development in 1965. In total, 12 gas-bearing Cretaceous horizons (1-12) and 13 oil and gas-bearing Jurassic horizons (18-25) have been identified at the field.

One of the main provisions was to maintain the reservoir pressure and temperature from the beginning of field development; delineation of four production objects of the upper oil and gas horizon: object I- 13 + 14 horizons, object II -15 + 16, III-17, IV-18.

Materials and methods

In [7], the Murphy Oil Seal field in the Peace River oil sands area in northwestern Alberta, Canada, has remarkable opportunities for enhanced oil recovery (EOR). Two potential candidates that have been evaluated for this site include traditional cold water flooding and hot water flooding. The results of core analysis, logging, detailed seismic and petrophysical studies, as well as reservoir modeling and forecasting, taking into account historical data, show that cold water flooding is superior to hot water flooding.

There is some literature supporting the concept that enhanced oil recovery due to gas displacement is an important factor in flooding projects [8] and that, contrary to popular belief, the reaction of the field to the injection of immiscible gas is very positive [9]. However, there are very few published works on the displacement of heavy oil by gas with a sufficient degree of detail that could lead to practical application in the fields.

Sahni et al. [9] conducted an excellent analysis of the foamy oil data, in which they summarized the results of several researchers and included some of their own experiments. They presented a common framework for interpreting experiments with foamy oil, in which pore physics was linked to macroscopic experimental observations. There are also two recent reviews from Firuzabadi [10] and Maini [11] which examine in detail the various mechanisms associated with the flow of foamy oil. Although there are some differences between the two authors, it is obvious that the main driving force of the foamy oil flow is the pressure gradient, and not the rate of decrease in the average reservoir pressure. Oil foaming is really a separate process, and it should not be excluded as a separate term or marked as a process of supplying a solution gas.

The complex thermobaric conditions, high paraffin and asphaltenes content, sharp zonal and permeability heterogeneity of reservoir-collector formations, and a large number of reservoirs in a single object (up to 10-14) require a special approach to field development. Various technologies have been implemented over the years to increase oil recovery.

These technologies involve extensive use of hydrodynamic methods to impact oil reservoirs and increase reservoir productivity, as well as the involvement of low-permeability reservoirs in development. Among these technologies are: hot water injection, stepwise thermal flooding, pattern flooding, differential injection pressure, selective injection of cold water into high-productivity formations, methods for involving low-productivity zones, and others.

Field development technologies and their efficiency. From new technologies provided for by the development project, they were introduced:

1. Stepped thermal flooding – STF (carried out on 42 fields).
2. Figured flooding FF (implemented in 11 fields).
3. Area flooding in low-productivity zones (in 7 areas).

The effectiveness of these development technologies was influenced significantly by organizational and economic factors and the overall state of the industry. Due to economic instability during the years of implementing these technologies, the techno-economic assessment of their effectiveness was ambiguous (due to changes in costs, introduction of new taxes and fees, increases in wholesale oil prices, etc.).

By 1994, about half of the producing well stock was covered by new technologies. The total oil production from all areas where new technologies were implemented in 1993 amounted to 1540.2 thousand tons or 40.6% of the field production. In areas where the system was implemented according to project requirements, the introduction of new technologies was quite successful (see Table 1).

Table 1

Oil production through implementation of new technologies at the Uzen field

Technology	**Oil production, thousand tons**									
	1981		1985		1990		1991		1992	
	for the year	accum-ulated	for the year	accum-ulated	for the year	accum-ulated	for the year	accum-ulated	for the year	accum-ulated
Injection of hot water	989	4760	1073	8961	956	14014	737	147	662.0	154
Staged thermal flooding	279	279	335.0	1617	810.4	5066.4	685.7	5752.1	624.4	6376
Figure flooding	-	-	40	40	21.7	466	166.9	632.9	148.7	781.6
Separate development of low-productivity zones	-	-	11.5	11.55	18.0	71.0	34.8	105.8	30.2	136.0
Total	1268	5039	1459.5	10629.5	1997.1	19617.4	1624.4	21241.8	1464.9	22706.7

Let us delve deeper into the implementation process and effectiveness of displacing highly paraffinic oil from reservoirs using cold water injection.

In oil reservoirs characterized by significant permeability heterogeneity of collector layers, cold water injected into the reservoir moves more rapidly through the most permeable layers, thereby cooling the adjacent, less permeable oil-saturated layers. As a result, the oil reserves contained in these layers are not effectively involved in production, leading to uneven advancement of injected water both in thickness and across the area of the reservoirs. This reduces the effectiveness and coverage of the flooding process, decreases the period of water-free well operation, lowers oil production (all other being equal), and increases the water cut of the produced fluid. Consequently, the development status of oil reservoirs deteriorates, and both the current and ultimate oil recovery factors decrease.

At the onset of development at the field, two types of flooding were employed: intra-contour block (horizons 13-16) and contour (horizon 17); horizon 18 was developed under natural conditions. Water injection began in 1968; however, the project volumes were achieved only by 1972.

Displacing highly paraffinic oil from reservoirs through cold water injection is a method commonly used to increase production and reduce oil viscosity. This process is based on the fact that water introduced into the reservoir reduces the viscosity of oil by diluting and wetting the paraffinic components.

The typical methodology for cold water injection often includes the following stages:

1. Study and analysis of the reservoir and oil properties.
2. Development of the injection plan, including well distribution, etc.
3. Injection of cold water into the reservoir to displace oil.
4. Monitoring the process, including changes in pressure, temperature, and the composition of displaced oil.
5. Evaluation of the effectiveness of methods and adjustment of the strategy as necessary.

The method can be effective for increasing oil production from reservoirs with high viscosity, such as those containing highly paraffinic oil.

In multi-layered reservoirs with highly paraffinic oil and significant permeability heterogeneity of collector layers, lowering the reservoir temperature below the oil saturation temperature by injecting cold water may result in paraffin precipitation and cessation of oil filtration in relatively low-permeability layers. Therefore, the question arises about the effectiveness of injecting hot water, as injecting hot water only makes sense when the oil (or gas equivalent to oil) consumption for heating the water is less than the potential loss of oil reserves when injecting cold water.

To develop the basic differential equations of the temperature field, we assume that energy is convected with a volumetric fluid flow. During the flow, an instantaneous thermal equilibrium is assumed between the liquid and the solid grains [12]. We also believe that heat is transferred to the boundary of the reservoir, the retaining layer, and transferred to the retaining layers through both conduction and thermal dispersion. This leads to a two-dimensional heat transfer problem.

Theoretical calculations have been conducted using actual data from the Uzen field [13-14]. The initial data for the calculations are presented in Table 2. To heat the water, a certain portion of the extracted oil or an equivalent amount of gas needs to be burned, while the volume of commercial production, equal to the volume of extracted oil minus the volume burned, should increase. The criterion for the effectiveness of injecting hot water should take this into account. Thermal extraction processes are methods used to reduce the viscosity of oil and increase oil recovery by supplying heat to the underlying reservoirs. Hot water injection is a thermal extraction method in which water is injected into hydrocarbon reservoirs. Injection of hot water reduces the viscosity of heavy oil and creates a driving mechanism for moving heavy oil to producing wells. In this work, the application of hot water injection into the Middle East reservoir with large deposits of heavy oil was investigated.

The criterion for the effectiveness of injecting hot water is characterized by the following formulas (1):

$$W(X_{**})\frac{F}{K_r} > \left[\left(1-\frac{K_r}{F}\right)\cdot\frac{\left(\frac{\mu_a}{K_{ac}}\right)_H + \mu_{oil}}{\left(\frac{\mu_a}{K_{ac}}\right)_{oil} + \left(\frac{\mu_a}{K_{ac}}\right)_{ef}} + \frac{K_r}{F}\right] y_* g \frac{F}{K_r}. \tag{1}$$

After some transformations, the criterion for the effectiveness of hot water injection takes the form (2):

$$W(X_{**}) > \left[\left(1-\frac{K_r}{F}\right)\mu_0 + \frac{K_r}{F}\gamma_*\right] g, \tag{2}$$

where x_{**} – represents the maximum value of normalized permeability for a set of less permeable layers subject to the dangerous change in the reservoir temperature ΔT_*.

During the displacement of highly paraffinic oil by cold water injection, a dangerous change in the reservoir temperature ΔT_* occurs, which may lead to paraffin precipitation from the oil and its solidification, turning it into an immobile solid substance. Water with constant physical and thermal properties and constant temperature is injected at a constant rate. Such assumptions make it possible to take into account the axisymmetric fields of pressure, velocity and temperature of stress in mathematical developments. Since all fields are symmetrical, the resulting stresses around the borehole arising from the injection of a non-isothermal liquid are solved by assuming simple deformation conditions around a hollow cylinder located in an infinite matrix. First, the transient pressure and temperature distributions are calculated. Then, solutions for pressure and temperature distribution are included in the output of the transient voltage field for the conceptual model.

A specific flushing factor corresponds to this dangerous change in the reservoir temperature ΔT (Formula 3):

$$v_* = \frac{v_T}{\ln\frac{\Delta T_O}{\Delta T_*}}. \tag{3}$$

The flush multiple is equal to the product of the calculated flushing factor v_{**}, which could have been achieved with equal mobility of the displacing agent and oil, and a corrective coefficient that accounts for the difference in their mobilities, typically with the displacing agent having higher mobility (4):

$$v_* = v_{**}\left[\left(1-\frac{K_r}{F}\right)\cdot\frac{\left(\frac{\mu_a}{K_{ac}}\right)_H + \mu_{oil}}{\left(\frac{\mu_a}{K_{ac}}\right)_{oil} + \left(\frac{\mu_a}{K_{ac}}\right)_{ef}} + \frac{K_r}{F}\right]. \tag{4}$$

In the provided formulas, $\Delta T_o = (T_a - T_o)$ represents the maximum possible change in the reservoir temperature observed near (at the wall of) the injection well; T_o – initial reservoir temperature; T_a – temperature of the displacing agent injected into the oil reservoir (injection water); v_T – represents the thermal front lag behind the oil displacement front by the agent (water), determined by formula (5):

$$v_T = \frac{\frac{1}{\Delta} + \delta 0.5}{\delta 1.5}, \tag{5}$$

where Δ – proportion of effective thickness in the total thickness of the oil reservoir;
δ – proportion of the cross-sectional area of the effective thickness of the oil reservoir occupied by the injected water, equal to the product of the porosity fraction, initial oil saturation, and displacement coefficient;
1.5 – ratio of the specific heat capacities of the injected water and the porous rock saturated with oil and water;
K_r/F– calculated average oil fraction in the total liquid production;
K_r – coefficient of recovery of mobile oil reserves;
F – calculated total liquid production in fractions of mobile oil reserves.

The values of K_3 and F are determined considering the specified values of v_*^2 – the indicator of layer-by-layer heterogeneity in the permeability of the oil reservoir, and A – the calculated maximum possible fraction of the displacing agent in the production of the oil reservoir at the time of cessation of production from the producing well. The calculated maximum fraction of the agent A is determined based on the specified value of A_2 – the maximum mass fraction of the agent in the production of the oil reservoir (A_2 = 0.98) taking into account μ_o – the coefficient of difference in physical properties between the oil and the displacing agent (water) (6):

$$A = \frac{A_2}{(1 - A_2)\mu_0 + A_2}. \tag{6}$$

After determining v_{**}, the proportion of less permeable layers $Y(x_{**})$ adjacent to more permeable layers, differing in permeability by v_{**} and more, is defined. For cases where v_x^2 and $v_x^2 = 0.5$, $Y(x_{**})$ it is calculated using formulas (7):

$$Y(X_{**}) = \frac{1}{1 + v_{**}} \text{ and } Y(X_{**}) = \frac{1 + 3v_{**}}{(1 + v_{**})^3}. \tag{7}$$

For other values of v_x^2 and $Y(x_{**})$, they are determined respectively through interpolation and extrapolation and are provided in Table 2.

Table 2

v_x^2 and $Y(x_{**})$

Horizon	Heterogeneity index of permeability by layers	Equation	Maximum value of normalized permeability
13	$v_x^2 = 1.32$	$Y(x_{**}) = 0.14001705 \cdot v_x^2 - 0.044246$	$x_{**} = 0.151$
14	$v_x^2 = 1.36$	$Y(x_{**}) = 0.1262871 \cdot v_x^2 - 0.0438983$	$x_{**} = 0.137$
15	$v_x^2 = 1.16$	$Y(x_{**}) = 0.1262051 \cdot v_x^2 - 0.0438913$	$x_{**} = 0.109$
16	$v_x^2 = 0.91$	$Y(x_{**}) = 0.111643 \cdot v_x^2 - 0.0419126$	$x_{**} = 0.062$
17	$v_x^2 = 1.71$	$Y(x_{**}) = 0.121843 \cdot v_x^2 - 0.0434513$	$x_{**} = 0.179$

Based on the known values of v_x^2 and $Y(x_{**})$, the values of x and $W(x_{**})$ are determined, where $W(x_{**})$ represents the proportion of less permeable layers in the overall productivity of the reservoir in the initial period, before the water breakthrough of the producing well. In this case (8):

$$\begin{aligned} &Y(X_{**}) = 1 - e^{-x_{**}} \\ &W(X_{**}) = 1 - (1+x)e^{-x_{**}} \\ &A = (1+x)e^{-x} \\ &K_r = \frac{1}{x}\left(1 - e^{-x}\right) \\ &F = \frac{1}{x}, \frac{K_r}{F} = 1 - e^{-x}. \end{aligned} \tag{8}$$

In this case, the criterion for the effectiveness of hot water injection takes the form (9):

$$1-(1+x_{**})e^{-x_{**}} > \left[\left(1-\frac{K_r}{F}\right)\mu_0 + \frac{K_r}{F}\gamma_*\right]g \text{ or } 1-(1+x_{**})e^{-x_{**}} > \left[1+\left(\frac{\mu_0}{\gamma_*}-1\right)e^{-x}\right]\gamma_* g\ . \tag{9}$$

Results and discussion

The results of the calculations are presented in Table 3.

Table 3

Results of calculations of the criterion for the effectiveness of hot water injection

Horizon	13	14	15	16	17
Calculated maximum fraction of the agent A, is determined as follows:	0.952	0.960	0.960	0.957	0.954
Ratio of the permeability of the layer under consideration to the average permeability of all layers, is given by *x*	0.347	0.315	0.315	0.327	0.339
Calculated total liquid production in terms of the mobile oil reserve fraction, is determined as follows (according to formula 8) *F*	2.879	3.179	3.179	3.062	2.948
Coefficient of recovery of mobile oil reserves, is given by (according to formula 8) K_3	0.845	0.858	0.858	0.853	0.848
$1-(1+x_{**})e^{-x_{**}}$	0.0104	0.0086	0.0055	0.0018	0.0143
$\left[\left(1-\frac{K_r}{F}\right)\mu_0 + \frac{K_r}{F}\gamma_*\right]g$	0.0171	0.0148	0.0149	0.0156	0.0164
Recoverable oil reserves lost during cold water injection	3.53%	3.18%	2.03%	0.65%	4.97%
Amount of extracted oil that is burned to prepare hot water is given by:	5.84%	5.49%	5.52%	5.59%	5.71%

As seen from Table 3, recoverable oil reserves lost during cold water injection are as follows for each horizon: 13 – 3.53%, 14 – 3.18%, 15 – 2.03%, 16 – 0.65%, 17 – 4.97%. The amount of extracted oil or its equivalent burned to prepare hot water is as follows for each horizon: 13 – 5.84%, 14 – 5.49%, 15 – 5.2%, 16 – 5.59%, 17 – 5.71%.

Conclusions

The water temperature at the faces of injection wells should be from plus 81-90 ºC, therefore, at the mouth of the order of 100 ºC (designed water heating units are designed for 100 ºC) and insufficiently heated water was pumped – mainly hot water was pumped with a temperature at the outlet of the furnaces plus 55-70 ºC, the temperature at the wellheads ranged from 40 up to 58 ºC, the temperature at the bottom of injection wells plus 51-56 ºC.

By discontinuing the use of hot water injection, the total hydrocarbon production increases by 1-3.5%. Additionally, significant savings are achieved by avoiding the construction of additional or repair of existing furnaces for water heating, as well as reducing technological and economic losses due to corrosion in pipelines. This is because the corrosion intensity decreases by 2-4 times when using cold water compared to hot water. This study strongly confirms that engineering changes in thermoelastic stresses deserve further comprehensive study using numerical models.

Author contributions

Author contributions are included in the manuscript. Formulation of the idea and objectives of the study, R.B. and A.T.; writing – preparation of the initial draft, monitoring the conduct of research activities, R.B.; conducting and collecting information, attracting funding, A.J. and M.S. All co-authors saw and approved the final version of the article and agreed to submit it for publication.

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