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Laboratory and Numerical Study of the Dissolution Process of Salinization Clastic Reservoirs

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Abstract

This paper discusses risks of fresh water injection in the terrigenous reservoir of the Verkhnechonsky producing horizon where interstitial space is fully or completely filled with halite (naturally occurring salinization).

Strata of salinized sandstone are believed to be a potential ″super″ reservoir since when fresh water is injected in the layer it washes out salts and induces a manifold increase in the effective porosity and permeability. Such flooding may accelerate water breakthrough into the producing wells, creating water absorption zones and changing the displacement front. All that reduces sweep efficiency and, with that, oil recovery.

The work has focused on flow experiments with core samples to assess the dynamics of change in the permeability and porosity of the rock and arrived at important conclusions on the characteristics of desalination process. A mathematical model of multi-phase filtration has been built to account for the interaction of water with the reservoir salt which brings about changes in the reservoir properties of the porous medium and rheology of injected water. Numerical experiments have been conducted to study the impact of desalination on viscous displacement of oil.

The paper offers systematic information about the injection experiments with salinized core samples from the Verkhnechonsky formation. It offers a description of the mathematical model of filtration of oil, gas and mineralized water which serves as the basis for hydrodynamic simulation at different levels (from core models to a full-scale model of the Verkhnechonsky horizon).

The results obtained give insight into key factors that accompany dissolution of reservoir salt in the injected fresh water, as well as their effect on the efficiency of water-flooding of salinized reservoirs.

The study will be of interest for specialists at oil companies which have in their portfolio oil fields with subsalt and inter-salt oil deposits.

Introduction

The Verkhnechonsky oil and gas field today is the largest producing oilfield in Eastern Siberia. Most of its hydrocarbon reserves are concentrated in terrigenous deposits of the eponymous Verkhnechonsky producing horizon (reservoir VC). The Verkhnechonsky horizon is a unique naturally occurring reservoir formed by dissimilar and lithologically highly heterogeneous rocks.

As it is typical of the subsalt oil deposits in the Irkutsk circus, reservoir VC shows natural salinization of interstitial pores with halite (rock salt, NaCl). Deposits of the salt mineral on the surface of the rock is the product of secondary processes in the formation of the reservoir, and halite fills in interstitial spaces both partially, taking up fractions of the pore space, and fully, sealing the pores completely and making the rock impermeable. It results in high differentiation of porosity and permeability in the reservoir resulting in a broad range of values of total porosity (0.2÷27.6%) and permeability (0.002÷10 D).

Numerous studies have shown that the degree of salinization is highest in the coarse-grain lithological varieties that originally have had better natural porosity and permeability: gravel conglomerates, gravel sandstones and coarse-grain sandstones. Halite content across salinized segments of the Verkhnechonsky horizon is estimated to range between 30 and 100% of the pore volume, or from 10 to 35% of the total volume of the rock.

Initial desalination experiments with rock samples from the VC horizon demonstrated significant changes in the structure of pore spaces and reservoir properties of the samples, with porosity and permeability increasing tens and hundreds of times.

The issue of desalination of reservoirs as a result of flood displacement of oil is quite relevant for the Verkhnechonsky project. The Verkhnechonsky producing horizon is injected with water in order to maintain reservoir pressure and compensate for the uptake of oil. The water resources available at the oilfield include fresh water which, when injected, initiates dissolution of the reservoir salt. It is supported by data obtained through the monitoring of mineralization and chemical analysis of the water produced from the wells in the net oil pay zones (zones with initial critical oil saturation). With less than 10g/l of salt in the injected water, mineralization of the water produced reaches 260 – 300 g/l. The relic reservoir water is represented by ″hard″, heavily metamorphosed and highly mineralized brines (in excess of 400 g/l), which by their composition belong to the calcium chlorine type, whereas the water produced from the wells, judging by the composition of metal ions, is of the sodium chlorine type.

In addition, bottom holes and borehole equipment in production wells accumulate deposits of halite: to fight it, it is necessary to use inhibitors, and well bores have to be cleaned with fresh water two to four times a month.

There is a fairly large body of work devoted to the effect of mineralization for oil displacement efficiency [10-20]. However, its main thrust has to do with the mineralization of water in water injection facilities at the developed offshore oilfields where there is no shortage of sea water but fresh water resources are, by contrast, limited and expensive to use.

Papers concentrating on core-based studies of water mineralization suggest a somewhat higher degree of oil displacement by fresh or weakly mineralized water, compared to displacement by highly mineralized water only (low-salinity technologies), and offer possible explanations. The key working hypothesis is that the effect may be due to the changing degree of wettability of the rock affected by the injected fluid. The changing wettability is attributed in these studies to the following reasons:

- lower surface tension as a result of higher pH;
- due to the concept of the double electric layer of multivalent cations in clay minerals (Ca +2, Mg+2, Fe+2, and Sr+2);
- due to ion exchange between oil, water and rock.

The issue of interstitial salinization by halite has been touched upon in part in [17], but this publication deal primarily with the need to minimize the discharge of salt deposited on borehole equipment.

In [20] authors refer to successful displacement of oil with high-mineralized water. Higher mineralization of water is achieved through the injection in the border zone where the water is high in salt. As a result, the displacement front advanced evenly, and in the course of the first three years, 66% of wells achieved water free production.

This paper uses a holistic approach to the study of desalination process and its effect for oil production. At the first stage, laboratory experiments with salinized rock samples have allowed us to assess characteristics of water interaction with halite deposits, and have served as the basis for further research. At the next stage, a mathematical model was developed describing filtration of oil, gas and mineralized water and taking into account the change in reservoir properties of the porous medium and water rheology in the process of dissolution of reservoir salt deposits. The mathematical model was used to conduct computations that describe the effect of desalination for oil displacement in models of different level – from core models to a full-scale model of the Verkhnechonsky horizon.

The key findings of the studies are summarized in this paper.

Experiment

The first experiments on desalinization of rock samples were implemented on the apparatus, the hydraulic circuit diagram of which is presented in Figure 1. The experiments were mainly focused on developing the methodological basis for the salinized core samples testing.

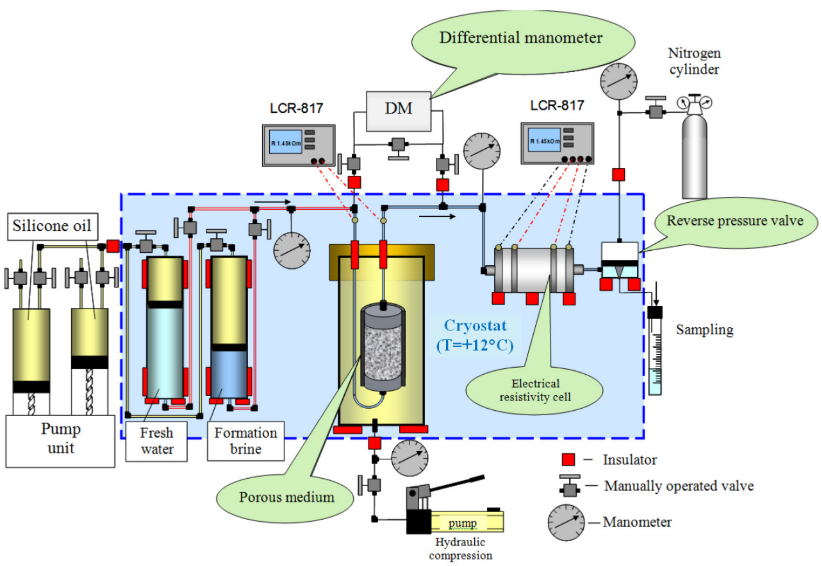

Figure 1—Hydraulic circuit diagram of the apparatus for core study on salt dissolution in the reservoir pore space

The rock is initially saturated with extremely saline formation brine. During the experiment conducted under thermobaric reservoir conditions the brine is displaced by distilled water. Having passed through the core, the aqueous solution of salt enters a flow-through four-electrode resistometer and subsequently passes through a block of pore pressure maintenance to glass burets designated for probe collection.

The flow-through resistometer was designated to permanently monitor the electrical resistivity of the filtering solution by 4-electrode classic circuit. From the electrical resistivity of the solution the viscosity of water was determined, which was required for the calculation of dynamic permeability. The dependence of viscosity and measure of water salinity on electrical resistivity was determined before the experiment, see Figure 2.

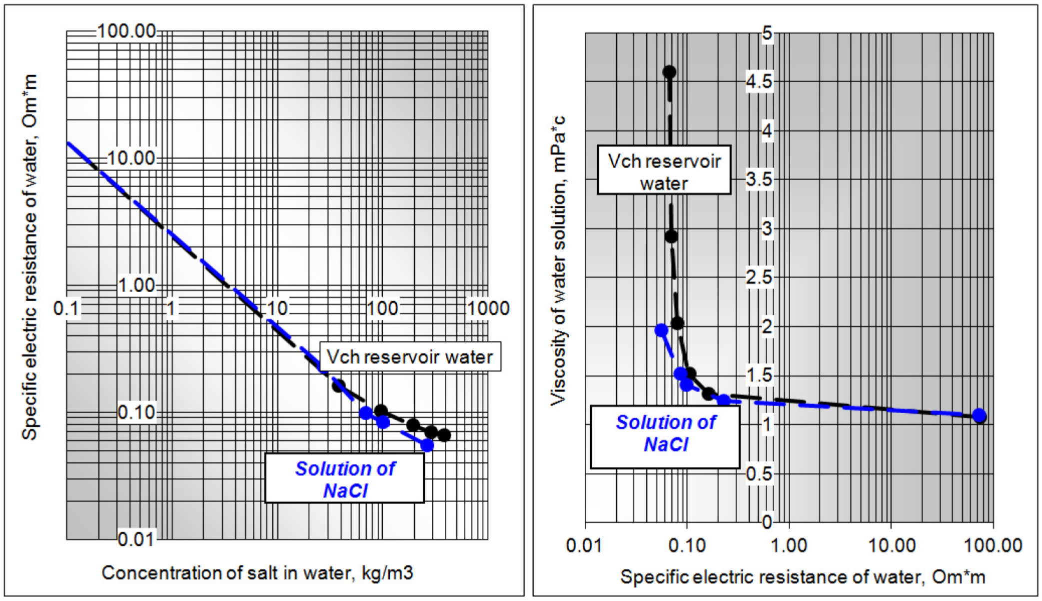

Figure 2—Dependences between characteristics of water solutions of NaCl salt and VC reservoir water under different concentrations (t=+12° C, P=16MPa).

According to chemical composition, the VC formation brine relates to chloro-calcium-magnesium type. The dependence in Figure 2 demonstrates that the formation brine and its solutions exhibit high electrical resistivity in comparison with NaCl solutions at equal concentrations; this fact is a characteristic feature, which allows to differentiate these liquids in case of piston interreplacement.

To estimate the actual drained porosity change with time, the electrical resistivity of the rock was measured by two-electrode bridge method using LCR-meter Instek-817 on the alternating current frequency 1kHz. Porosity was estimated from rock and solution electrical resistivity through the formation factor.

Based on X-ray photoelectron spectrometry (XPS) and X-ray diffraction (XRD), salinized rock of the VC reservoir is either poor in clay fraction or, more often, has none (in 95% samples); it therefore may be concluded that porosity depends not on the mineralization of water in pores but only on the porosity ratio and the structure of interstitial space. This simplifies our calculations as it is possible to rely on a simple dependence between the porosity parameter and the porosity ratio.

The porous media stack consisted of three core plugs with a diameter of 3cm, length of 3cm, porosity lower than 10%, permeability to gas lower than 50 mD, and with Na percentage about 20% according to the X-ray phase analysis. The lithology of the porous reservoir was represented by medium-coarse-grained sandstones of predominantly quartz composition, without visible clay fraction and anhydrite inclusions. To avoid the washout of salts, the samples were extracted in pure toluene and subsequently in benzene with soaking in chloroform.

The experiment was carried out in several stages of displacement. On each stage the rate of fresh water was set as constant. On the first stage the rate was equal to 0.1-0.3 ccm/min, subsequently it increased progressively with salts dissolution and washout, changes in the internal structure and in the filtering area and, correspondingly, decrease in the differential pressure (hydraulic resistance). On the final stage of the experiment the rate was equal to 4-5 ccm/min, because at the lower rate of filtering the observed pressure gradient between the end faces of the core samples stack is negligible.

The permeability was calculated using Darcy’s Law at the moment of constant differential pressure establishment for the mode.

Three experiments were conducted using this methodology.

In the beginning of the experiments the displacement of highly-saline formation brine from the core samples can be observed. In this period the interaction of the injected fresh water with salts is quite low or completely absent; the processes of mixing of two salt solutions with different values of salinity become of first importance. Thus, it can be expected that at reservoir conditions the injected water will primarily enrich in salts through the mixing with connate formation brine, and the water-rock interaction will start only after the significant dilution or total replacement of the formation brine.

The evidence of that is the profile of permeability change (Figure 3), where the rapid increase in permeability can be observed after the injection of 1.5-2 pore volumes of fresh water (Experiments 1 and 2) or when the formation brine is significantly diluted with fresh water (cumulative flow volume is close to pore volume, Experiment 3).

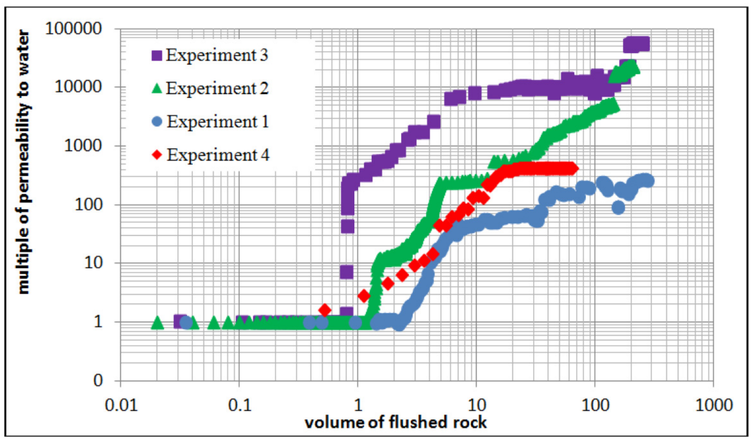

Figure 3—Change in permeability depending on the volume of water flushed through pore spaces of the core stack

The volume of water required for complete desalinization of pore space and process duration depend on the time of contact between the solvent and saline portions of rocks. In the experiments conducted the complete washout of salts took place after the flowing of 38-40 pore volumes. Absolute permeability of completely washed samples in the experiments amounted to 23.6, 12.9, and 7.98 D, with the pre-experiment values of permeability equal to 26, 0.3, and 0.02 mD correspondingly.

While reservoir permeability to water grows rapidly after displacement of reservoir water, porosity increases less rapidly. The change in the structure, curvature and roughness of pore canals, and their exposure to the solvent happen three times as fast as it takes to clear the space of the solid phase. It follows then that rock desalination by fresh water leads primarily to the formation of well washed canals, which, undoubtedly, will affect oil displacement efficiency.

Figure 4 shows a comparison of the pore radius distributions of the samples before and after desalination experiments. As can be seen, before the experiment predominate pore size of 2.5 - 10 microns experiment after distribution pore radius shifted towards high values of 30 - 100 microns.

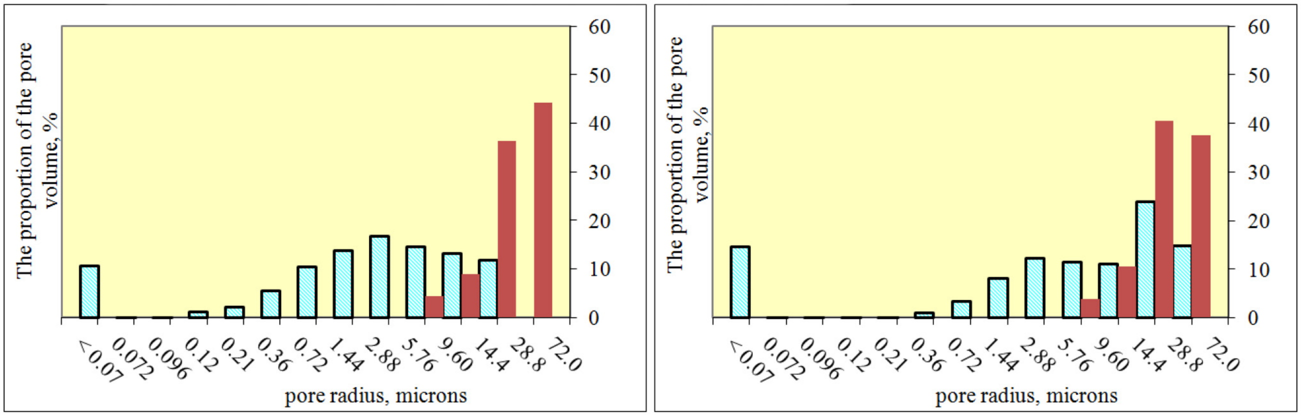

Figure 4—The distribution of pore radius of the samples before and after the experiment desalinization.

After obtaining the first results of the experiments with the dramatic increase in permeability the methodics of the experiments was modified.

The characteristic feature of the VC reservoir is the fact that the surface of the rock framework regardless of salinization is oil-wet and preferentially oil-wet. Therefore, there is a layer (possibly with high-molecular weight hydrocarbon compounds) in oil-saturated medium that limits the contact between water and rock surface and thereby evens, reduces the rate and the scale of salt dissolution.

In the subsequent experiment 4 the pore space was filled with oil, and also the changes in structure and properties of porous medium were estimated when fresh water flushing through the samples.

Samples were fully saturated with oil (100%, without residual water), because the experiment was focused on the estimation of kinetic coefficient of intrapore salt dissolution. Absence of the formation brine, which contains large amount of salt, in the experiment allows uniquely determine the change in salt mass in the rock, because all salt output represents the washed out mass of halite. From the salt mass change in the rock it is possible to determine the kinetic coefficient of dissolution, which is commonly referred to in literature as reaction constant (similar to chemical reactions).

Besides that, the results of the experiment on the samples 100% saturated with oil can be considered as a lower estimate of fresh water interaction with intrapore halite, whereas first experiments on core samples fully saturated with water can be considered as an upper estimate of the interaction.

The design of apparatus for the experiment on oil-saturated samples is nearly similar to that of used in first experiments. The difference is absence of flow-through resistometer in the cirquit, because the presence of oil phase precludes from working with this gauge. In the new experiment water mineralization was measured directly by collecting the entire water volume at the end face of the core, weighting and subsequent evaporating of this solution.

For the experiment the reservoir model was stacked composed of standard plugs of consertal sandstone with higher matrix density equal to 2.55 g/ccm.

On the first stage of the experiment the permeability of reservoir stacked model to oil was determined on seven modes of steady-state liquid flow. The obtained values turned out to be close enough to each other at average permeability of 1.35 mD.

Subsequently fresh water was injected in fully oil-saturated samples. At the same time at the other end face of the model through the block of reservoir pressure maintenance the collecting and measuring of water volume was carried out, and after water breakthrough its volume and salinity were measured.

The injection was carried out with the volumetric flow rate which ensured the designed speed of ″oil-water″ front propagation. Water rate on the first stage of oil displacement amounted to $Q = 0.78$ ccm/hr.

After water breakthrough and fixing of ″quasi-constant″ values of salinity, the water rate was increased three times up to Q = 2.34 ccm/hr in order to accelerate the exchange processes and to shift the equilibrium of salinity of collected water into the zone of constant undersaturation of its ionic composition.

After interpretation of results of first water samples, collected in this mode, it was found that they are sufficient for the estimation of dissolution constant, however with the significant error and only for one rate. Therefore the water flow rate was decreased and subsequently terminated to restore the chemical equilibrium in the system ″rock matrix-salt-water″.

After 38 hours the water filtering was resumed, with the rate increased up to Q = 3.9 ccm/hr, and all further workflow of the experiment remained unchanged.

The dynamic desalinization of reservoir core samples allowed to the estimate water salinity and amount of salt washout in time and volumes of filtered liquid.

After water breakthrough the oil inflow from the stack completely stopped. Three-times and five-times increase in injected water flow rate did not significantly change the oil recovery.

According to the X-ray phase analysis, the salt washed out in the experiment was represented only by NaCl (halite) without any impurities. As a result, when calculating the instantaneous permeability, the water viscosity determined from the dependency of NaCl solution viscosity on its electrical resistivity was used.

After the end of the experiment the samples were moved to the extraction and subsequent determination of reservoir properties. Based on change in porosity of the samples during the experiment, the degree of the initial salinization of the pore volume was estimated.

When inspecting the samples after the experiment, it was noticed that each sample has a clear zone of significant desalinization and of change in rock framework structure in the lower parts of the samples. This is especially visible in the middle sample of the stack, which was partially destroyed during the experiment (Figure 5). The zone of intensive desalinization starts from wide part of the flow entry face of the core and then decrease with an angle to the outflow end face of the core.

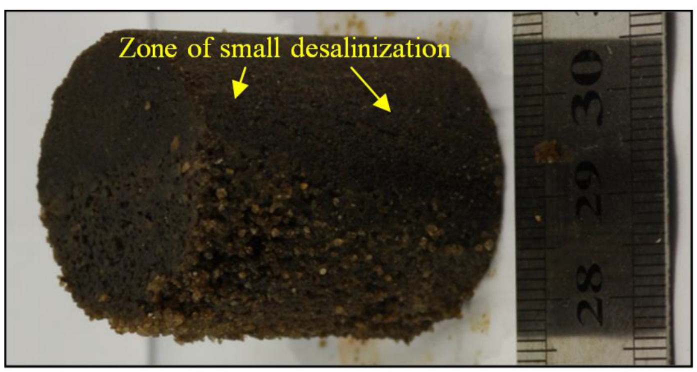

Figure 5—Photography of middle core sample from the core sample stack after the Experiment 4 on desalinization.

Zones of the core samples with different degrees of desalinization had also different colors, which indicated the different values of residual oil saturation. More bright saturation zone corresponded to more washed out zones of the samples.

Obviously, at low initial filtration rate gravity segregation of fluids played a part. The injected water advanced primarily through the lower parts of the samples, increasing the permeability in these zones and forming the zone of the maximum washout of salt. Subsequently the permeability increased even more, the main water flow was filtering mainly through this zone, leaving the upper part of the rock almost untouched by waterflooding. This is the reason of low flood displacement efficiency, which was estimated as 41%.

Therefore, even in core scale it can be seen that the oil sweep efficiency in saline reservoir is non-uniform. The non-uniformity of oil displacement increases due to the increase in water density when dissolving salt and to the development of low filtration resistance channels.

The scale of permeability change in fully oil-saturated core is comparable with the results of the first three experiments, which is demonstrated in Figure 3. Similarly to first experiments, the active phase of desalinization, accompanied by the increase in the permeability of the porous medium, starts after the reservoir fluid (in present case it is oil) is replaced by the working agent.

Oil stopped to outflow after the flowing of 1.7 pore volumes; the permeability to water during oil displacement increased insignificantly from 1.35 mD up to 2.56 mD. For the end of the first stage of the experiment, six pore volumes were flowed through the core, the permeability to water increased 27 times, from 2.57 mD up to 70 mD.

On the basis of the experiments on fully oil-saturated and fully water-saturated samples it can be concluded that the presence of oil in oleophilic porous medium reduces the contact between injected fresh water and salt, and mixing of the injected water with the formation brine increases the salinity of the injected water and decreases its solving activity.

Water salinity and the amount of salt washed out during the experiment were estimated using three independent methods:

- Electrical resistivity of the outflow water solution;
- Volume-weight method, through measuring the solution density;
- Amount of salt evaporated from the liquid samples of known volumes.

The methods of water salinity estimation based on specific electric resistance and on the mass of salt evaporated from the solution have produced similar results, Figure 6.

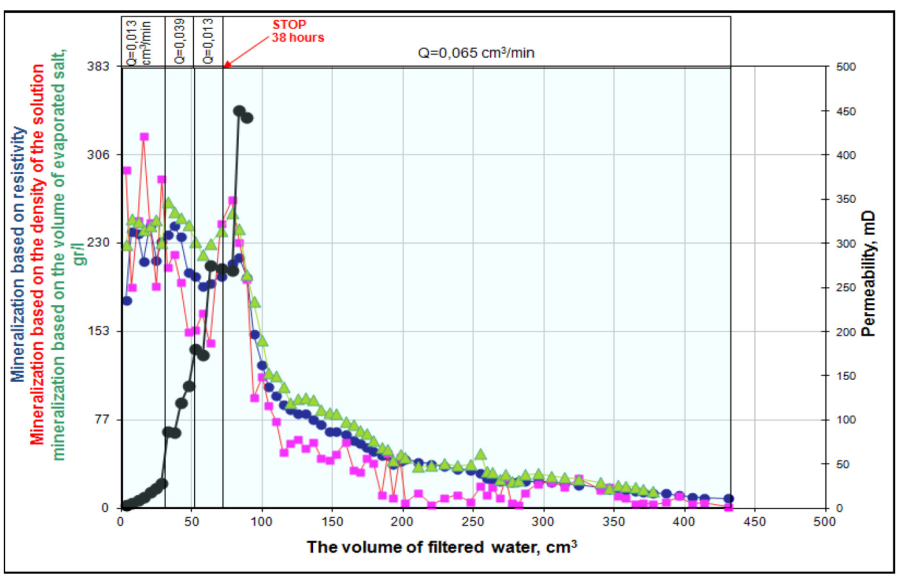

Figure 6—Dynamics of salinity of the produced water in the experiment 4 for desalination of oil-saturated core samples of fresh water

On the basis of the measurements the plot of relative change in salt mass in rock was constructed in Figure 7.

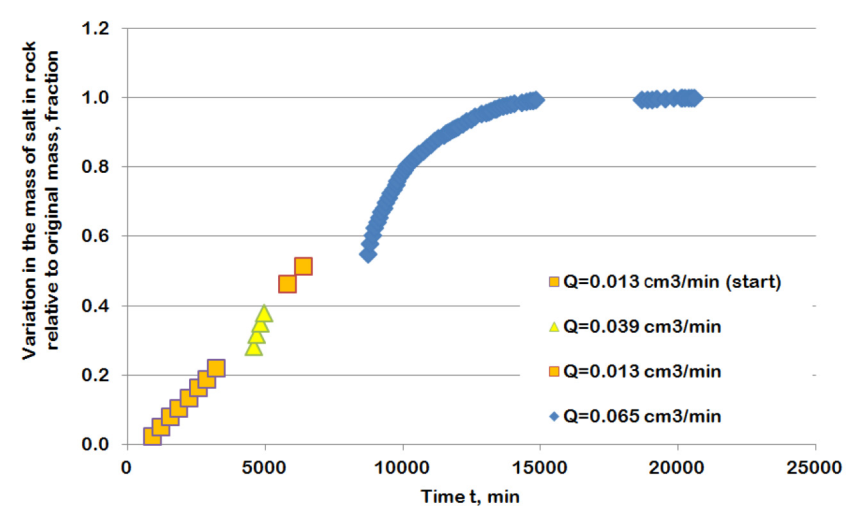

Figure 7—Experimental kinetic curves of salt dissolution.

As can be seen from the Figure 7, the experimental points have a good fit to some functional relationship. Erofeev and Kolmogorov proposed for this relationship the approximating function [7]: $\alpha(t) = 1 - \exp(-b(t^n))$, the parameters of which have physical meaning.

In particular, the parameter n, referred to as order of reaction, characterized the ratio of diffusion and kinetic processes, which accompany the salt dissolution. Diffusion processes are conditioned upon different concentrations of salt in the solution near the surface of salt crystals and inside the pore channel. At $n > 1$ the dissolution reaction rate is controlled by kinetic process; at $n = 1$ the reaction rate is comparable with the diffusion rate (1^{st} order reaction); at $n < 1$ the reaction rate is controlled by the diffusion of substance in the solution.

The kinetic coefficient of reaction K is estimated from the Sakovich relation: $K = n \cdot b^{1/n}$, where b is a constant adjusted in the approximating the relationship to fit the experimental data.

The slope of the kinetic curve characterizes the initial rate of dissolution – the higher the slope of the initial section of the curve, the higher the initial rate. In our case steeper kinetic curve corresponded to the periods of intensive water injection into the samples.

Gradually with the decrease in mass of the reagent the reaction rate smoothly decreases. Curve shape analysis showed that the more the water rate is, the faster the curve flattens out.

The results of the actual data approximation and kinetic coefficients are presented in Table 1.

Table 1—Values of kinetic characteristics of formation salt dissolution.

Stage of experiment	Water rate, ccm/hr	Salt mass in rock in the beginning of the stage, g	Order of reaction n	b constant	Kinetic coefficient of reaction K, 1/day
1	0.78	37	1.901	5.36E-08	0.41
2	2.34	28.2	4.717	1.79E-18	1.17
3	0.78	22.3	3.150	7.42E-13	0.64
4	3.9	18.4	3.599	5.17E-15	0.56

On all modes of the experiment the order of reaction n is above 1, which indicates the dominant role for the processes dependent on the filtration rate. This simplifies the modelling of salt dissolution process.

The values of kinetic coefficient of dissolution on all modes of filtration were close to each other, therefore it is allowable to take the average value of the parameter K equal to 0.54 1/day.

Based on the results of core flooding experiments the following characteristics were estimated for the purposes of modelling: kinetic coefficient of reaction, which determines the rate of formation salt dissolution, permeability change during salt removal from pore space, water viscosity and density change during the increase of water salinity. These parameters are the main characteristics of the desalinization process

Mathematical model

We have taken the multiphase isothermal black oil model in 3D as the basis for our model [1]. The salt solution is considered as addition to the water phase, changing its density and viscosity. The mass conservation equation (in moles) for component ″c″ is the following:

$$\frac{\partial}{\partial t}(\phi\, N_c) = div \textstyle\sum_{P=W,O,G} x_{c,P}\xi_P v_P + q_c \quad c = 1 \dots n_c, \tag{1}$$

where the phase flow velocity is given by Darcy's law:

$$v_P = k\frac{k_{r,P}}{\mu_P}(\nabla p_P - \rho_P g\Delta D).$$

In the framework of the considered model, we will assume that water viscosity and density are functions of C_{salt} – salt concentration. Porosity and permeability changes during elution are taken into account by setting the reservoir porosity and absolute permeability dependence on the amount of diluted formation salt. The functions f_{sol}^{por} and f_{sol}^{perm} are introduced, describing the resulting porosity and permeability as: $\phi = \phi_0 f_{sol}^{por}$, $k = k_0 f_{sol}^{perm}$, where ϕ_0 and k_0 are the initial reservoir porosity and permeability.

Thus, Darcy's law for water phase can be formulated as:

$$v_W = k\frac{\kappa_{r,W}}{\mu_W(C_{salt})}(\nabla p_W - \rho_W g\Delta D).$$

The salt solution transfer equation takes the following form:

$$\frac{\partial}{\partial t}(\phi\, N_W \cdot C_{salt}) = div(\xi_W v_W \cdot C_{salt}) + q_W \cdot C_{salt} + v_{sol}. \tag{2}$$

In this case, the flow equation solution algorithm will be the following: knowing C_{salt} at current step, we solve the initial flow equations (1), and calculate new values of p_W and N_W, then inserting them into equation (2), we get C_{salt} value for the new time step. To take the elution process into account, the initial formation salt mass distribution should be set, and the solution speed constant K should be defined. In this case, the formation salt dilution speed formula in a given water volume V will be the following:

$$v_{sol}^{V} = K(m_{max} - m_{salt}) \tag{3}$$

where m_{salt} is current saluted salt mass in volumeV, and m_{max} is the mass of salt that would be diluted in the saturated solution of volume V. Using formula (3), the functions f_{sol}^{por} и f_{sol}^{perm} are recalculated at each time step. Note that in the framework of the considered model, function f_{sol}^{perm}, characterizing reservoir permeability change dynamics during dilution, is supposed to be known an analytic, and f_{sol}^{por} и f_{sol}^{perm} is recalculated on the basis of the assumption that pore size increases by the volume of diluted salt.

For the equation (2) numerical solution, a fully implicit scheme is applied. To describe changes in the displacement characteristics, depending on displacing the agent rheology, the phase relative permeability end-point scaling dependant on water salinity is used.

Numerical computations

The first computations were made for synthetic models: synthetic models with their small grid spacing make it possible to gain a detailed insight into the effect that desalination has on oil displacement by water.

Geometrically, the synthetic models represented the two-dimension area between the injection and producing boreholes 1000 m long (in line with the actual spacing between Verkhnechonsky oil wells) and 20 m high (in line with the average thickness of the reservoir). The grid cells were 10 m long and 1 m high.

Different options were considered for the distribution of salt over thickness: uniform, layered and ″quasi″ random salinization. In the latter option, salinization over thickness has a qualitative correspondence with the geological and statistical distribution of salt within the VC reservoir; however within separate layers values in the cells have random distribution.

Synthetic models simulations showed that during water propagation the least salinized zones of the reserovoir are washed. The zones with the salinization exceeding 20% of rock volume due to their extremely low permeability provide the development of non-uniform front of displacement.

Based on the results of synthetic models runs, three zones of injected water salinization were determined (Figure 8):

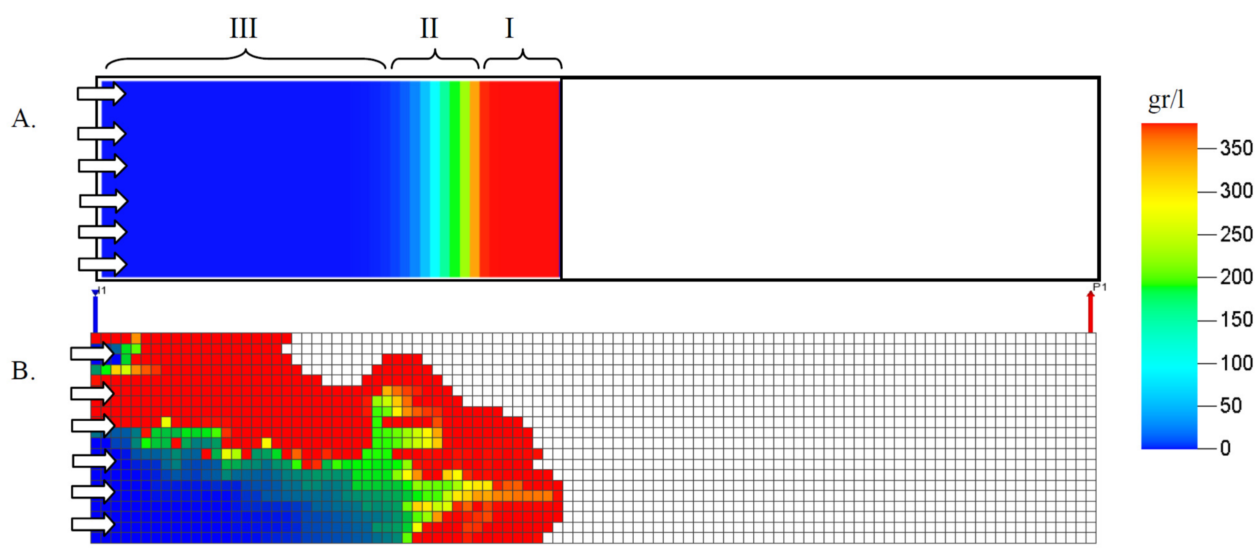

Figure 8—Allocation zones of the salt concentration in the injected water during the displacement for the homogeneous (A) and quasirandom (B) initial salt distribution in the formation.

I. Zone of extreme saturation, which develops initially due to salt dissolution in the bottom-hole zone of injection well and mixing with saline formation brine. The zone of extreme saturation is preserved along the entire path of oil displacement front propagation that is responsible for the lag of ″desalinization front″ from the displacement front, as formation salt dissolution nearly does not occur in the zone of extreme saturation.

II. Transition zone, which forms next to the zone of extreme salinity and represents the zone, where the major formation salt dissolution occurs with multiple increase in porosity and absolute permeability of the reservoir.

III. Flushed zone. In this zone, dissolution is weak and water mineralization corresponds more or less to the salinity of the injected water. Water propagates through formed channels of low filtration resistance dissolving the residual salt.

The major oil displacement occurs in highly-saline water rim (zone I), therefore it is absolutely admissible to ignore the difference in shapes of relative permeability curves in ″oil-saline water″ and ″oil-fresh water″ systems in the model and to consider only relative permeability curves in ″oil-saline water″ system.

The dimensions of the zones depend on filtration rate and degree of salinization. At the salinization of more than 10% of rock volume the linear size of extremely saline water rim is 150-300 m. At lower degree of salinization the rim length is several tens of meters.

Overall, water interaction with reservoir salt is the factor that slows water advance across the reservoir, together with the growing water viscosity and density, whereas oil to water mobility ratio for Verkh-nechonsky horizon conditions is close to one.

There are thus two key factors which in their relation produce the net effect from desalination for the oil displacement process:

1. mineralization of the injected water where a higher viscosity solution fringe emerges at the displacement front. As a result, the water to oil mobility ratio decreases, which, in turn, straightens up the displacement front and increased the time of water-free production from wells. Salt deposits in this case act as a natural thickener for the injectant;
2. formation of zones of lower filtration resistance controlled by heterogeneity of geological salinization of the reservoir. As a result, the displacement front becomes more uneven. In addition, the water that is continued to be injected moves along the flushed zones, reducing the sweep.

Calculations for the full-scale oilfield model were preceded by calculations for the reservoir's sectoral model. The purpose of these calculations was to scale the dependence of relative change in absolute permeability versus relative change in the volume of salt in the reservoir. This dependence was charted in flow experiments, and it corresponds in scale to the rock samples. It would be incorrect to apply this dependence directly to the reservoir filtration model where the size of grid cells is in large excess over the length of the core.

A filtration model was built for a separate segment of the reservoir where the first development wells in the oilfield were established and which has currently a long production history. The water-cut of the wells production in the area averages more than 90%.

For the first approximation, the model explored the experimental dependence between the change in permeability and the change in the volume of salt in rock. During the computation of the sectoral model this dependence was verified by approximating estimates of the produced water salinity to actual data, see Figure. 9.

The monitoring of associated water salinity was carried out constantly in the field; however, the results of measurements are influenced by regular bottom-hole flushing with fresh water during the removal of salts from downhole equipment. This shows itself in the disturbance of actual values on the salinity charts. Nevertheless, the quantity and quality of the measurements are sufficient for making the needed estimates of salt concentration in the produced water.

Actual data on water salinity presented in Figure 9 demonstrate the behavior similar to that observed in the oil-saturated core flooding experiment (Figure 6). This indicates the similarity of the conducted experiments to real processes.

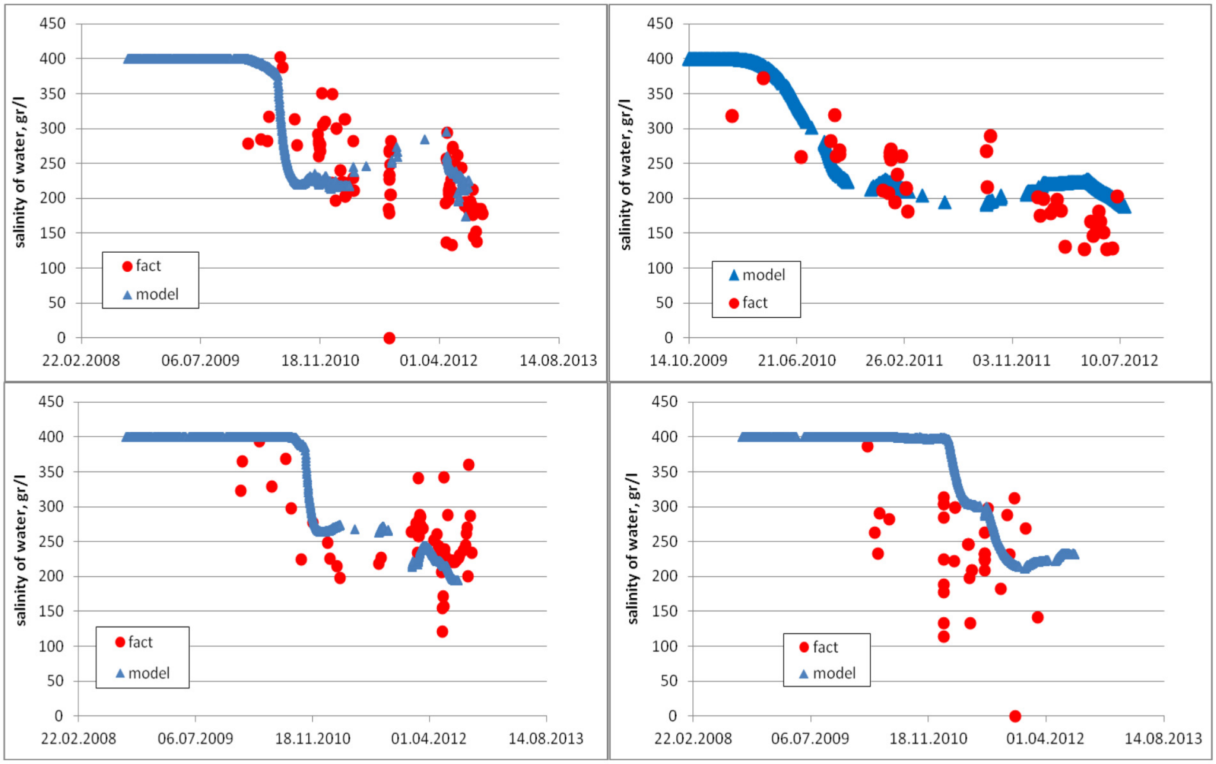

Figure 9—Calculation versus actual mineralization of produced water in the sector model

According to the sector model runs, the water salinization profile is non-monotonic due to several reasons. One of the reasons is that the displacement front propagation is non-uniform, which is caused by the initial non-uniform reservoir salinization. Another reason is that water from injection wells arrives at different times. It was shown that when the highly mineralized fringe which is next to the front arrives, it briefly increases mineralization of all produced water.

With the introduction of the desalination factor in the sectoral model, it became possible to produce a more accurate calculation of the water front movement across the reservoir and the dynamics of water-cut in the wells of the sector. Increase in the viscosity and density of the injected fresh water due to salt dissolution decreases the rate of the displacement front propagation, resulting in the later breakthrough in comparison with the model, where the factor of water interaction with formation salt is ignored.

Behind the displacement front, as it was shown above, the active salt dissolution and development of low filtration resistance zones takes place. Subsequent injected water propagates faster through the zones freed from salt, with the rheological properties of the injected water not changed or changed slightly. This reflects in more rapid increase in water cut in comparison with the results of model simulation without desalinization (Figure 10).

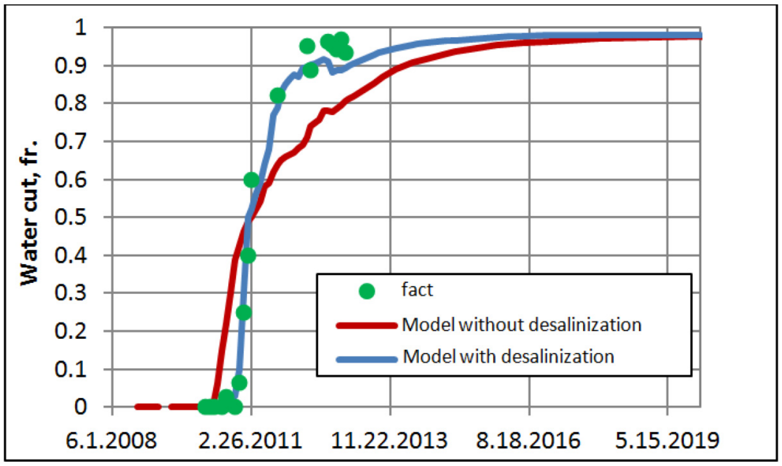

Figure 10—Water cut profile for the wells in the models with and without the account of desalinization.

The full-scale simulations of VC reservoir showed that in general the desalinization negatively affect the oil production. According to the computations, the cumulative oil production for 40 years of production from the VC reservoir in the model with desalinization is by 3.6% (or 4,700 kt) lower than in the model without desalinization.

At that it is need to be noticed that in the first stage of reservoir development, drilling-out, and pressure maintenance system organization the oil production in the model with desalinization exceeds, although slightly, the oil production computed without the desalinization option. Development of high-saline water slug at the displacement front favors oil production, because water and oil viscosities in this case equalize and the oil water displacement is near to the piston-like displacement. This is the positive impact of desalinization on oil production.

Along with that, the increase in water density leads to the oil displacement preliminary through the bottom zone of the reservoir that leads to the decrease in the displacement efficiency. The formation of low filtration resistance zones behind the displacement front makes further water injection low-effective. This is the negative impact of desalinization on oil production, which after all prevails above the positive aspect of the process.

According to the model simulation results, the negative impact of desalinization on the operation of Verkhnechonsky horizon takes place since 2013. A kind of ″point of no return″, when the further injection of fresh water will result in irreversible negative effect, is a period after 2020.

The impact of desalinization on the waterflooding efficiency non-uniformly and significantly depends on the degree of the initial salinization. In the zones with maximum degree of salinization the oil production loss can be as high as 20%.

The negative manifestation of desalinization can be reduced by increasing the salinity of the injected water. This will make possible to increase the size of the first zone and hyper-saline zone (Figure 8) and reduce the scale of desalinization and of the increase in absolute permeability in the second zone.

Model simulations with the account of desalinization showed that the saline water injection in the field from 2016 will make possible to neutralize the negative factors of desalinization, in this case the injected water salinity is required to be not lower than 100 g/l.

This measure can be optimized by targeted injection of saline water in the zones where the desalinization has the most negative impact of oil production. For this purpose the reservoir zones with maximum predicted loss in oil production were found and the option of saline water injection with water salinity 200 g/l was simulated. The obtained results demonstrated that this method gives the opportunity to not only neutralize the negative impact of desalinization, but also to increase the oil production by 8%.

Conclusions

The research has looked into the impact of desalination factors for viscous displacement of oil with water. The study did not consider issues of possible change in wettability of rock with the changing concentration of salt in the injected water, or physico-chemical interaction between salts of different metals among themselves or with rock minerals, or salting which happens with the change in temperature or pressure, or other aspects of geochemical processes.

At the same time, assessments made in this study are based on experimental data and have been confirmed by field data from the wells.

The results of study show the significant influence of the desalinization process on oil water displacement. Dissolution of salts in the reservoir has a complex effect and may help to make an important contribution in the development of those segments of the oilfield where salt concentration in the reservoir is high.

First of all, the dissolution of formation salt (halite) increases the injected water salinity, changes the rheological properties of displacing agent. The zone of increased salinity develops at the displacement front, where water and oil viscosities under the conditions of VC horizon are nearly similar.

The type of oil displacement is near to piston-like displacement that increases the time of water-free wells operating and, correspondingly, the oil production in the water-free period.

Desalinization processes change the pore space structure, multiply increasing reservoir porosity and permeability. Low filtration resistance zones develop behind the displacement front, resulting in the increase in the encroachment rate, decrease in sweep efficiency and oil recovery.

Generally for the entire Verkhnechonsky horizon the desalinization negatively affects the ultimate oil recovery. The decrease in oil recovery factor for 40 years of development is expected to be equal to 3.6%. The impact of desalinization on oil production is non-uniform and depends on the degree of the initial lateral and vertical reservoir salinization.

Negative factors of desalinization can be reduced by targeted (local) injection of saline water after the injection of low-salinity water.

Ignoring factors of desalination and relying on standard simulation techniques may lead to errors in projections of the technological parameters of the reservoir and overstated estimates of recoverable oil reserves in salinized oil reservoirs.

Nomenclature

B_w = formation volume factor for water
C_{salt} = the salt concentration in the solution, gr/l
ϕ = porosity
K = kinetic coefficient of dissolution, 1/time
k = tensor of absolute permeability, mD
$k_{r,P}$ = relative permeability phase P
μ_P = dynamic viscosity phase, cP
p_P = pressure phase P, Pa
ρ_P = density phase P, kg/m3
$x_{c,P}$ = the molar ratio of the component c in phase P
N_c = molar density component c
q_c = rate of component c,
ξ_P = molar density phase P
V_P = flow rate phase P
V_{sol} = the rate of dissolution of salt formation

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