The Analysis of Injected Water into O-1 Formation of the Central Block of the Talakan Oil and Gas Condensate Field in Order to Identify and Predict Zones With High Risk of Salt Precipitation

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Abstract. The value of this research work involves the search for newer and best options of salt precipitation prediction in wells for fields in Eastern Siberia using the example of the Central Block of the Talakan oil and gas condensate field. The development of this block is complicated by the presence of salt impurities in a pore volume and highly mineralized formation water represented as calcium chloride brine while the source of gypsum deposits is injected water containing excess sulfate ion values. Prediction and control for scale during oil production is essential for practical tasks since the effectiveness of actions for elimination of salt sediments, prevention and protection of oilfield equipment depends on the prediction and timely detection of salt deposits in wells, on pumping equipment, in oil gathering and processing systems. If there is a problem, it is necessary to monitor it and prevent negative events leading to unproductive costs and losses in oil production, especially in the conditions of market relations, when the development of oil fields should be cost-effective.

1. Introduction
Currently, the number of discovered fields is increasing towards unproductive with hard-to-recover oil reserves, while giant and large fields are almost developed, and the development of new fields and additional development of old ones requires non-standard technical solutions, it is these conditions that have led to the special importance of the water factor affecting rational development and field exploitation.

Prospects that are being developed in Eastern Siberia at deep and average depth are associated with formation water of complex mineral composition and consequently with wider range of salt sediments during field development. The main source of salt precipitation is water produced together with oil. Water chemical composition constantly changes with the recovery of oil reserves what determines diversity and time-to-time variability of salt deposits composition. Oil production often comes with sedimentation of solid precipitations of non-organic substances accumulated on wellbore wells and tubing, in pumping equipment and surface oil gathering and processing systems.
2. Materials

2.1. Scaling of sulphates

In 2018 cases of sulphates deposition were found in two wells and oil gathering system as a gypsum with watering more than 50% (with sharp increase from 20 % to 50 % - 70 %). Sediments had layered structure. There is a layer of microcrystalline and organically bounded sediment directly on tubing wells. The sediment as it moves away from the surface, becomes surrounded by a layer of medium crystals with transformation to larger needle-shaped crystals. These shapes of mineral deposits are typical for low temperature conditions of scaling, it is not uncommon for druse building-up when large needle-shaped crystals of gypsum like “swallow tail” reach the size of 2-3 cm (Figure 1).

![Figure 1](image1.png)

**Figure 1.** Dense needle-shaped crystals in size up to 15 mm.

The researchers for evaluation of deposits solubility were done under conditions of research laboratory (Figure 2,3). Given sample does not dissolve either in organic solvents (toluene, alcohol-toluene mix (1:3), nefras, ethanol, acetic acid), or non-organic solvents (muriatic acid (diluted and concentrated), sulphuric acid (concentrated), alkalis (sodium hydroxide and potassium hydroxide of high concentrate, aqua ammonia)).

![Figure 2,3](image2.png)

**Figure 2,3.** Evaluation of gypsum deposits solubility in the research laboratory.

There is a complete absence of signs of a reaction. The deposits does not react. The deposits are destroyed under mechanical action (in a solution of concentrated sulfuric acid and sodium hydroxide), flakes appear, deposits become porous, but complete dissolution is not observed.

2.2 Composition and structure of salt deposits

In the crystallization kinetics, nucleation plays a greater role than in the growth of single crystals, which, being associated with secondary nucleation and agglomeration, is more complicated. There are two types of crystal nucleation: the heterogenous mechanism when crystal nuclei arise at interface and homogenous mechanism when crystal nucleation occurs spontaneously in the volume of the parent phase due to temperature changes and intermolecular interaction forces. As a rule, crystallization
occurs in a supersaturated solution, above the equilibrium concentration of the solute, and is determined by the inequality: $\mu_{\text{solid}}(T)<\mu_{\text{liquid}}(T)$, where $\mu_{\text{solid}}(T)$, $\mu_{\text{liquid}}(T)$ – chemical potentials of the solid phase and the dissolved component in solution, respectively [1].

2.3. Solubility conditions for solids

The solubility of salt compounds in solutions is judged by the magnitude of their solubility product. So, if a substance with the chemical formula $K_xA_y$ dissociates in solution according to the equation $K_xA_y \leftrightarrow xK^{+} + yA^{-}$, then its solubility product is:

$$L_{kxay} = (ak)^x(aA)^y,$$

where $aK$ и $aA$ – active concentration of cation and anion in a saturated solution, which are in equilibrium in the forming substance. The solubility product is usually determined experimentally using chemical analysis of saturated solutions of a substance in water of different salinity and composition at different temperatures and pressures [2].

Having studied the initial data on gypsum formation (protocols with quantitative chemical analysis of the component composition of both produced and injected water), it was found that the intensity of this type of sediment was observed in deposits with a high content of sulfate ion.

These are the sources of sulfate ion:
- water wells;
- sulfate-containing rocks.

During the interaction of anhydrite with water, gypsum precipitates, which means that the saturation of water with gypsum occurs even at 50-100-fold water exchange, that is, with gypsum formation throughout the development period, the water is completely saturated with calcium sulfate.

2.4 The effect of water cut on scaling

An analysis of the data on the watered well stock, taking into account the quality of water sampling and their chemical composition, showed that all the functional connections of the ionic composition of water on salinity, with the exception of salt-forming ions, mainly sulfate ion ($SO_4^{2-}$), hydrogen carbonate and ion carbonate ($HCO_3^-$, $CO_3^{2-}$), are linear.

The functional connection of the concentration of sulfate ion on the calcium content is represented by a power function. With a decrease in calcium cation, the content of sulfate ion increases. The absence of a linear relationship and a close bond suggests that the sulfate ion is a foreign component (Figure 4).

![Figure 4](https://example.com/figure4.png)

**Figure 4.** The functional connection of the concentration of sulfate ion on the calcium ion content.
Along with thermobaric conditions, an important reason for the formation of non-organic salt precipitation is the mixing of incompatible waters. The formation water of oil fields in the oil reservoir during contact with inclusions of salt deposits of the productive stratum acquire different salt saturations and are in thermodynamic equilibrium with gas-saturated oil [3]. If the factors contributing to the saturation of injected water by salts (water injection is needed to maintain reservoir pressure) can be attributed to natural factors, the formation of salt deposits is largely the result of anthropogenic impact. By exchanging with the reservoir rock and formation fluids, the water injected into the reservoir forms a certain chemical composition. When entering the well from heterogeneous interlayers, water of different chemical composition may be chemically incompatible. During the interaction of these waters, an ion exchange occurs, the result of which are gypsum and halite crystals.

### Table 1. Component composition of water samples from GPS-1, GPS-2, GPS-CT.

| Sampling place units | Sampling date | $\rho_b$ | SO$_4^{2-}$ | Cl$^-$ | HCO$_3^-$ | Ca$^{2+}$ | Na$^+$ + K$^+$ | Mineralization |
|----------------------|--------------|---------|--------------|------|-------------|------------|--------------|---------------|
| GPS-2, pump output   | 01.07.18     | 1.09    | 157          | 1331 | 244         | 1002       | 6400         | 23577         |
| GPS-1, pump output   | 01.07.18     | 1.02    | 562          | 1863 | 275         | 6012       | 1122         | 29379         |
| GPS-1, pump output   | 01.07.18     | 1.02    | 594          | 1686 | 287         | 6012       | 1139         | 27028         |
| GPS-CT               | 08.11.18     | 1.01    | 597          | 1287 | 236         | 3124       | 4106         | 22110         |

### Table 2. Component composition of water samples from WI-1, WI-2, WI-CT, WI-A.

| Sampling place units | Sampling date | $\rho_b$ | SO$_4^{2-}$ | Cl$^-$ | HCO$_3^-$ | Ca$^{2+}$ | Na$^+$ + K$^+$ | Mineralization |
|----------------------|--------------|---------|--------------|------|-------------|------------|--------------|---------------|
| WI-1                 | 12.10.18     | 1.00    | 304          | 81   | 506         | 132        | 106          | 1110          |
| WI-2                 | 03.11.18     | 1.00    | 843          | 24   | 258         | 281        | 30           | 1520          |
| WI-CT                | 19.11.18     | 1.00    | **1051**     | 21   | 278         | 337        | 34           | 1830          |
| WI-A                 | 13.11.18     | 1.00    | 80           | 22   | 244         | 66         | 21           | 460           |

Water injected into the reservoir contains high values of sulfate anions, other indicators are normal (Tables 1,2). The scaling comes from both produced water and injection water. The difference is that the formation water is initially in the reservoir in a brine state, and the injected water, passing through the salinized collector, gains mineralization to the state of a saturated solution. The rapid increase in water cut is associated with an increase in the permeability of the reservoir beyond the displacement front during salt dissolution (Figures 5,6).
Figure 5. The histogram of the distribution of water cut in production wells of the O-1 formation of Central Block of the Talakan oil and gas condensate field.

The formation water of the Central block of the Talakan field is highly mineralized - calcium chloride brine (the density is 1286 kg/m³, the mineralization is 419 g/l). In the reservoir, salt deposition is not expected because supersaturated solutions of water are in equilibrium. With an increase in water cut in wellstream there is a possibility for salt deposition on the working parts of pumping units. If deposits are detected by the composition of salts, it will be necessary to quickly select a scale inhibitor.

Figure 6. The distribution map of the current water cut values for the O-1 formation.
3. Methods
3.1. Dynamics of changes in the ion-salt composition of the produced fluid

If we turn to examples, then for wells №№ 1 and 2 there is a pattern in the growth and decrease of chemical elements, the density of produced water and spasmodic water cut of the product.

According to the chart of well № 1 we see that on 07/23/2016, 05/01/2017, 03/04/2018, 02/06/2019 there is a sharp increase in the concentration of salts, there is an increase in the number of calcium cations, as well as the density of produced water, which indicates the beginning of the development of processes scaling criterion (1.1). It should be noted that the growth maxima of salt-forming cations coincide with the density of produced water, and the maxima of the sulfate anion with water cut. On 09/04/2016, 06/01/2017, 06/20/2018 there is a decrease in the number of cations, as well as a decrease in the density of produced water, which is the maximum salt formation criterion (1.2). There is a cyclical nature in the development of the described processes. With the achievement of high water cut, calcium cations are washed out of reservoir rocks and react, what confirms a further increase in the density of produced water and a sharp decrease in water cut. It can also be predicted that soon enough calcium cations and sulfate anions will react and precipitate. This will lead to a decrease in their concentration and a decrease in the density of produced water and an increase in water cut.

![Figure 7](image_url): The content of ions \( \text{SO}_4^{2-} \) and \( \text{Ca}^{2+} \) in well № 1.

![Figure 8](image_url): The content of ion \( \text{SO}_4^{2-} \) and water cut of wellstream in well № 1.

![Figure 9](image_url): Density of produced water and water cut of production in well № 1.

On the chart for well № 2 we see that on 01/01/2015 there is a decrease in cations and anions, the water cut value is increasing, this indicates the first prerequisites for scaling (1.1). On 01/01/2017, there is a decrease in cations and anions, as well as a decrease in the density of produced water, which is the maximum salt formation criterion (1.2). The cycle ends on 05/11/2018 when the \( \text{SO}_4 \) values are outside the acceptable range, and the density of the produced water decreases to critical.
The formation and precipitation of calcium salts proceeds if two criteria are met:
1.1 A significant increase of sulfate anion, calcium cation, density and water cut of wellstream is the first sign of salt formation.

1.2 A sharp decrease of sulfate anion, calcium, density, and the invariability of water cut of wellstream, indicates that a chemical reaction and precipitation have occurred.

Salt formation and precipitation will not occur if one of the criteria is met:
2.1 An increase of sulfate anion, density, water cut and the immutability of the calcium cation leads to the fact that salt formation will not occur due to the lack of salt-forming calcium ion.

2.2 The increase of calcium cation, density, water cut and the immutability of sulfate anions, leads to the fact that salt formation will not occur due to the lack of salt-forming sulfate ion.

Derived patterns of changes in the ionic composition of produced water for various conditions of occurrence of oil helped to predict wells with a high risk of scaling.

After analyzing the data with constant sampling, it was possible to derive four levels of “salt hazard” from the content of the component composition of water, density and water cut. For further work, sampling with component analysis of water is required, and wells with an ultrahigh risk of scaling are put under control.
4. Results and discussion
1. The main factors of influence on the scaling of the East Siberian petroleum province were identified. The salt inclusions of the reservoir rock have a huge impact on the composition of water in the reservoir.
2. The injected water into the formation contains excess sulfate ion values, which increases the risk of scaling in the bottomhole formation zone and downhole equipment.
3. The selected criteria helped to analyze the well stock, give a forecast of salt formation, draw up technical solutions for selecting candidates for additional sampling.
4. In the northern part, sulfate salts predominate, in the central and southern parts - carbonate salts. This is due to the distribution of anhydrite, calcite and dolomite in the reservoir.
5. The next step is to propose the injection of chemicals into wells with an ultrahigh level of “salt hazard”. With the formation of halite, it is recommended to introduce the treatment of bottomhole formation zone with fresh water, and in the case of gypsum - with caustic soda.

5. References
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