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The Use of Tracer Based Dynamic Production Profiling in Estimating Hydrocarbon Recovery in Directional Wells

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Abstract

Production surveillance in the producing wells has been an important task for many years in oil and gas development since it provides relevant information useful for the effective management of the HC production. The main objective pursued by operators is to increase the production volume and enhance the oil recovery rate, which often requires some additional well interventions in the existing producing wells. For this purpose, it is necessary to understand how and where to perform stimulations and properly select adequate EOR technologies in order to avoid the risks associated with premature complications of well operation. Usually, production surveillance can be performed using standard logging methods (PLT complex), aimed at the inflow profile monitoring in a well. There are many factors, however, that may complicate the data recording and affect the reliability of the study results. In addition, it is not always possible to shut down the well for production logging purposes. As an alternative approach, it is proposed to consider a technology that involves the placement of special marker-reporters in the bottom-hole zone of the well [3]. The inflow tracers are gradually washed out in the course of production, thus providing the possibility to directly assess the current flow rate, while different codes of productive intervals enable quantification of the production with a phase-wise analysis (hydrocarbon and water) [5].

This paper presents the results of the analysis of reserves recovery in a multi-layer reservoir characterised by relatively low porosity and permeability parameters by means of a tracer-based technology designed for production profiling in directional wells. Surveillance of each productive interval's performance over time was conducted by taking reservoir fluid samples from the mouth of several wells during stable production without well shut-down.

INTRODUCTION

Production surveillance in the producing wells has been an important task for many years in oil and gas development since it provides relevant information useful for the effective management of the HC production. The main objective pursued by operators is to increase the production volume and enhance the oil recovery rate, which often requires some additional well interventions in the existing producing wells. For this purpose, it is necessary to understand how and where to perform stimulations and properly select adequate EOR technologies in order to avoid the risks associated with premature complications of well operation. Usually, production surveillance can be performed using standard logging methods (PLT complex), aimed at the inflow profile monitoring in a well. There are many factors, however, that may complicate the data recording and affect the reliability of the study results. In addition, it is not always possible to shut down the well for production logging purposes. As an alternative approach, it is proposed to consider a technology that involves the placement of special marker-reporters in the bottom-hole zone of the well [3]. The inflow tracers are gradually washed out in the course of production, thus providing the possibility to directly assess the current flow rate, while different codes of productive intervals enable quantification of the production with a phase-wise analysis (hydrocarbon and water) [5].

This paper presents the results of the analysis of reserves recovery in a multi-layer reservoir characterised by relatively low porosity and permeability parameters by means of a tracer-based technology designed for production profiling in directional wells. Surveillance of each productive interval's performance over time was conducted by taking reservoir fluid samples from the mouth of several wells during stable production without well shut-down.

SUBJECT FIELD DESCRIPTION

Long-term production surveillance in the production well stock is performed at the tested oilfield located in the Nizhnevartovsky District of the Khanty-Mansi Autonomous Okrug of the Tyumen Region.

The field was discovered in 1974, and its commercial development began in 1978. Oil accumulations were found in a number of formations: AB1 of the Alym Formation, AB2, BV5, and BV6 of the Vanden Formation, BV8, BV9, BV10, Ach1, Ach2, and Ach3 of the Megion Formation, YUV0 of the Bazhenov Formation, and YUV1 of the Vasyugan Formation. The main oil-bearing strata are the Achimov deposits, and the key geological feature of the oilfield is the extensive expansion of the so-called anomalous section of the Achimov strata [1]. Currently, the geological service largely focuses on the Ach group layers, which is determined by high expectations of boosting oil production throughout Western Siberia.

The geological section of the oilfield is represented by terrigenous deposits of the Mesozoic and Cenozoic sedimentary cover, occurring on heterogeneous formations of the Paleozoic basement and effusive sedimentary rocks of the Turin series, forming an intermediate complex [2]. Tested oilfield has a complex geological structure. The section is represented by interlayed terrigenous sand, aleurolite, and clay rocks. The reservoir properties are non-uniform both laterally and vertically. On average, the porosity values vary in the range of 16—17%, and the permeability is below 1 mD. There are wedge-outs and facies substitutions. The deposits of the Achimov strata stratigraphically pertain to the Berriasian stage of the Lower Cretaceous. In the Late Jurassic and Early Cretaceous, the study area had favourable conditions for the formation of reservoir rocks and fluid-resistant rocks that later turned into natural oil and gas reservoirs. Tectonically, the Achimov Formation of the oilfield is located in the Nizhnevartovsky Arch system. There is a system of pinchouts, grooves, and depressions. A clinoform structure is observed. The reservoir rocks mostly consist of polymictic sandstones and siltstones. The fluid-resistant layer right above the Achimov deposits consists of mudstones.

Tested oilfield has been in commercial development for more than 35 years. The main oil reservoirs are found in the Achimov deposits of the Megion Formation of Early Cretaceous age. The reserves have been assigned the categories B, C1 and C2. The Achimov deposits are considered complex, represented by clinoforms. Most of the production wells were drilled in the central part of the oilfield within the reservoirs of the layers Ach1, Ach2, and Ach3.

Efficient recovery of the Achimov strata reserves requires a comprehensive approach to the control and production at the reservoirs. In other words, when interpreting the obtained inflow intensity distributions for each productive interval, it is very important to take into account not only the specifics of the subject field itself, but also to analyse the current and historical well performance indicators, the results of the conducted well interventions, as well as to keep in mind the possible interference with the neighbouring wells. All this can help justify the further strategy of field development and enhancing oil recovery.

DESCRIPTION OF THE TECHNOLOGY USED FOR TRACER-BASED PRODUCTION PROFILING IN DIRECTIONAL WELLS

The tracer-based production profiling technology used in directional wells involves the use of quantum dot marker- reporters that are high-precision indicators of the reservoir fluid inflow [3]. Within this approach, high-precision inflow tracers of reservoir fluid are placed in man-made fractures. After completing the hydraulic fracturing operation and the subsequent commissioning of the well, reservoir fluid samples are taken from the wellhead. Then, the markers of each code are quantified, their number corresponding to the distribution of each type of fluid among intervals.

Marker-reporters are polymer microspheres made of quantum dots (Figure 1). Various combinations of quantum dots form a marker code (signature).

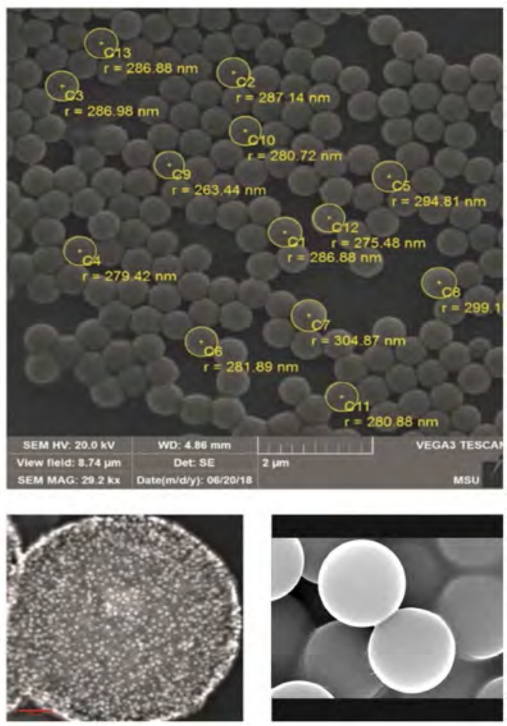

Figure 1—A photo of marker- reporters in the scanning election microscope

The technology consists in placing markers in a polymer cover of proppant injected into the reservoir [4]. Figure 2 shows a marked proppant grain that contains markers in its polymer cover.

Proppant marked with a certain code is pumped down into each productive stage during hydraulic fracturing as the last proppant pack to ensure maximum contact when the proppant is washed by the reservoir fluid coming from the reservoir into the well. Marked proppant may have three types of polymer cover: oleophilic, i.e. absorbing oil, and hydrophilic, i.e. absorbing water.

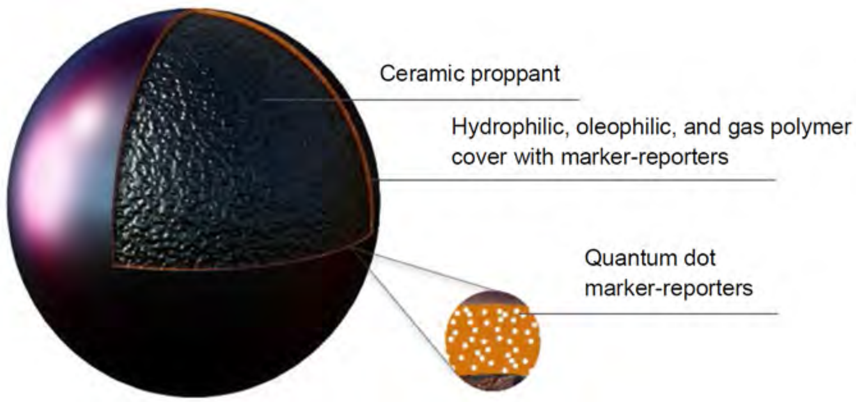

Figure 2—A grain of the marked polymer-covered proppant with quantum dot marker-reporters

As per the work plan, the necessary amount of marked proppant is injected into each frac stage, which is a uniform 50:50 mixture of hydrophilic (targeting the water phase) and oleophilic (targeting the hydrocarbon phase) proppant. This amount is defined individually for each well, depending on the type of reservoir, its pay zone, permeability, and PT conditions. According to empirical evidence, at least 15 tons of proppant must be injected into each stage of hydraulic fracturing for reliable quantification of the inflow profile and composition.

In the subsequent long period of well operation, the marker-reporters are gradually washed out by water or hydrocarbons and are carried by the reservoir fluid to the wellhead. Marker-reporters are released into both the HC and water phases of the reservoir fluid.

Upon completing the hydraulic fracturing operations and bringing the wells into production, fluid samples are taken from the wellhead on a regular basis and are further sent to the research laboratory for analysis. During the first stage, i.e. sample preparation, water and hydrocarbon phases are separated in the lab and then each phase is analysed separately using analytics equipment and a software package. In this analytical complex, a small-diameter fluid stream like a thin jet is formed (Figure 3). The markers are lined up in a row and irradiated with a laser as they flow, which helps identify markers of each code individually based on the scattered light signal, direct and lateral. Thus, the analysis of the total volume of delivered samples helps identify the contribution of each port by phase (water and HC) to the total flow rate.

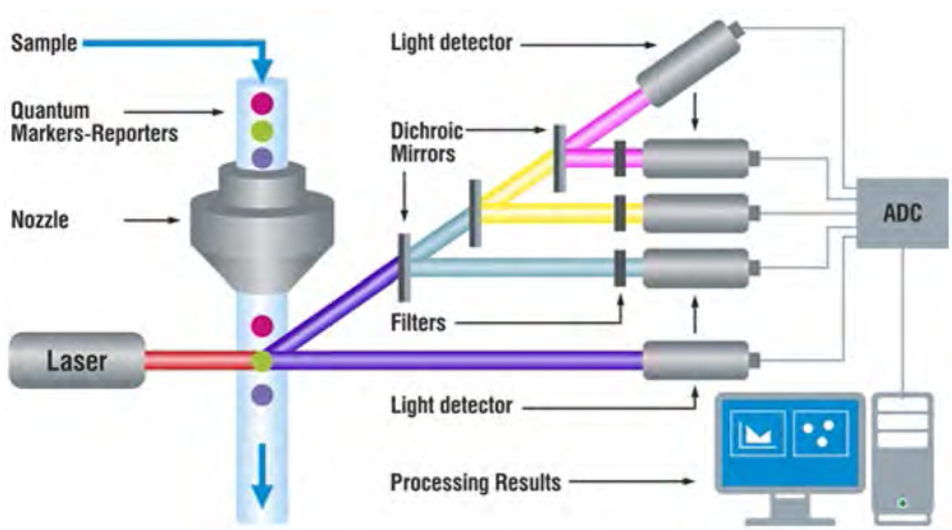

Figure 3—Analytical complex based on the flow cytometry method

The key elements of the technology include machine learning algorithms, in which learning occurs as a result of implementing solutions for many similar problems. Production surveillance in producing wells requires processing of large data arrays. For example, the data on the identification of each marker- reporter is a 15-dimensional point cloud, so manual calculations would be very time-consuming. For this reason, tracers-based production surveillance technology is supported by custom-tailored machine learning-based intelligent software using the Random Forest algorithm.

The basic working principle can be described as follows: initially, the neural network is trained using reference samples of marker-reporters to build a "decision tree", wherein the evaluated parameters are sorted at each level. A huge number of such trees are generated. As a result, a marker with a specific code passes through this tree and gets into a strictly predetermined directory. Trained algorithms "know" which directory shall be the destination for each specific code. Then a mixture of many markers passes through the entire tree and is sorted out, i.e. the algorithm counts the exact number of each marker code in the mixture (Figure 4).

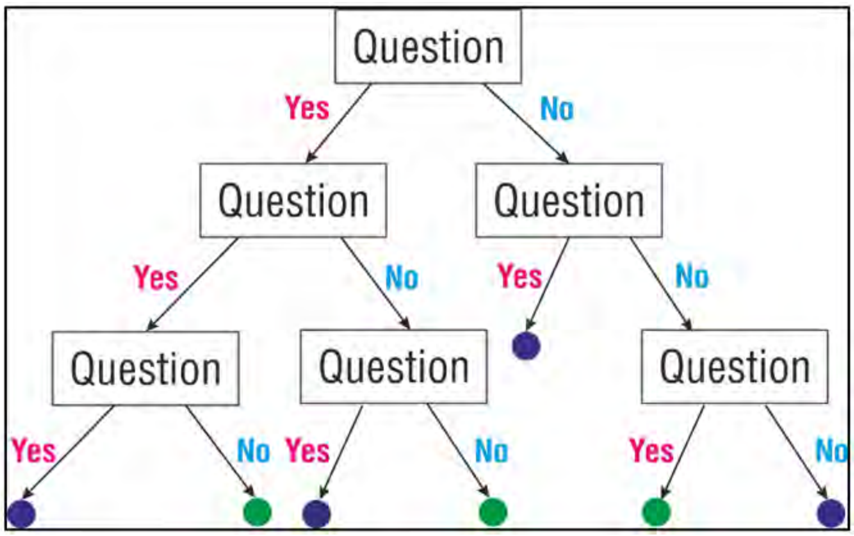

Figure 4—Machine learning and decision tree building algorithm

In general, machine learning algorithms enable processing large data arrays with a certain accuracy within a short time frame, while avoiding incidental human errors. Thus, this algorithm is a highly accurate and fast method for analysing the received samples.

After that, the inflow profile itself is visualised split into phases, taking into account the initial data, such as the production history for the period of reservoir fluid sampling, as well as geological and technical data on one or several subject fields. Regular sampling and subsequent analysis provide information on the recovery and extraction of hydrocarbons over time by evaluating the cumulative production volumes individually for each productive interval along the borehole.

TRACER-BASED PRODUCTION SURVEILLANCE IN DIRECTIONAL WELLS

To study the efficiency of reserves recovery in the productive layers Ach2 and Ach3 of the oilfield, two wells were selected to perform hydraulic fracturing with injection of proppant.

Well No. 59P has two perforation intervals that penetrate the pay zones of Ach2 (2,844 —2,881 m) and Ach3 (2,897 —2,910 m). In well No. 34P, two intervals were also perforated in the zones Ach2 (2,669 — 2,689 m) and Ach3 (2,700 —2,719 m).

Figure 5 shows a fragment of the current sampling map, where the subject wells are marked. As is seen on the map, well No. 59P is located near injection wells No. 5I and 53I that can affect the inflow profile dynamics, which was taken into account in the further analysis. Well No. 34P is neighboured by injection wells No. 1I, 42I, and 24I, which can also affect the subject well performance.

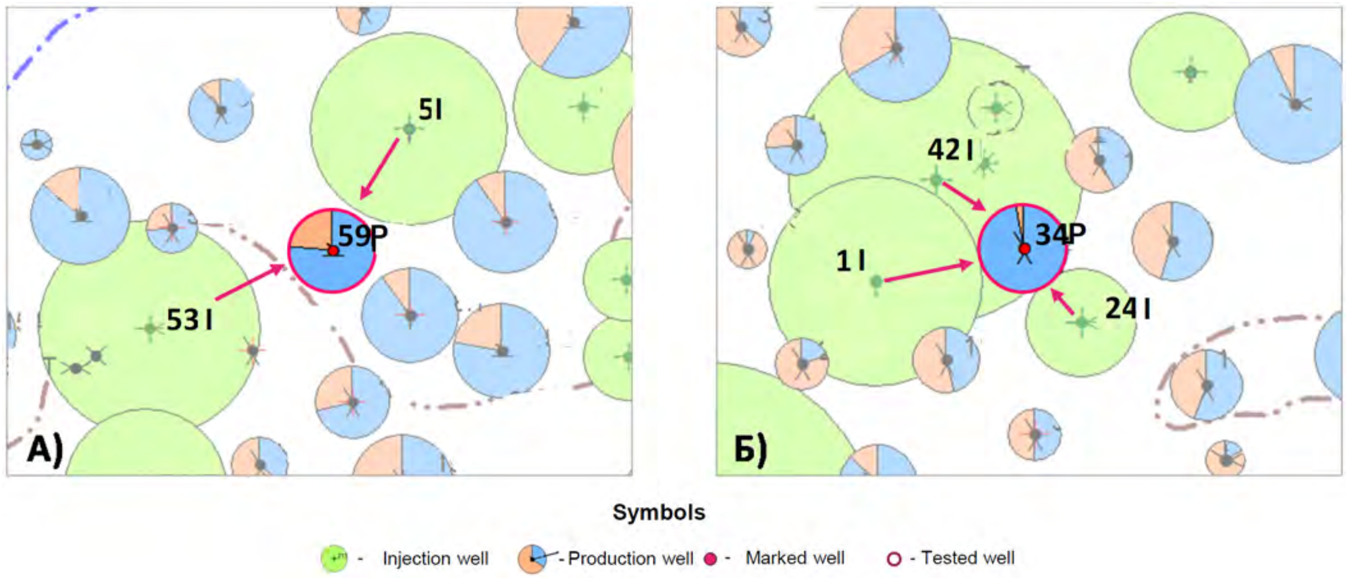

Figure 5—Bubble Map with the location of tested wells No. 59P (A) and No. 34P (B)

During the hydraulic fracturing, 30 tons of proppant were injected into the first interval (formation Ach3) of well No. 59P, including 15 tons of GEOSPLIT proppant. In the second interval (formation Ach2), 50 tons of proppant were injected, including 15 tons of marked proppant. The consumption rate during the hydraulic fracturing in both intervals was 3.5 m^3/min. The net pay of the Ach3 formation is 6.1 m, and the net pay of the Ach2 formation is 24.4 m.

During hydraulic fracturing, 40 tons of proppant were injected at both intervals of well No. 34P, including 15 tons of GEOSPLIT injected to each stage. The consumption rate during the hydraulic fracturing at the first interval (Ach3) was 3.8 m^3/ min, and at the second interval (Ach2) - 3.5 m^3/ min. The net pay of the Ach3 formation is 11.5 m, and the net pay of the Ach2 formation is 17.1 m.

The dynamics of the productive intervals' performance for the producing wells was monitored during 6 surveillance periods. Figure 6 shows the interval performance dynamics for well No. 59P in comparison with the reservoir saturation according to the data yielded by the open hole logging. The dynamics reflect the changes in the inflow intensity of different directional well intervals in the course of well operation.

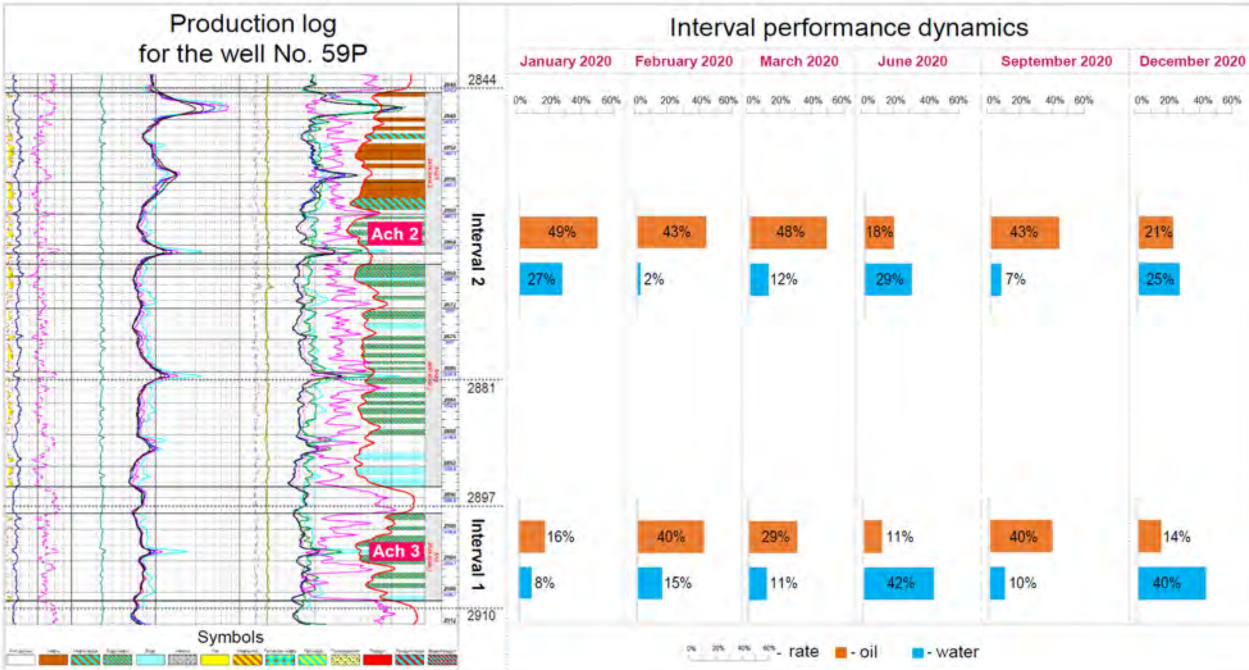

Figure 6—Comparison of the production profile of well No. 59P with the reservoir saturation based on the open hole logging

During the entire period of the study, the highest oil recovery is observed in Interval 2, which is compared with the results of the open hole logging. The water cut in the extracted reservoir fluid shows quite a significant amplitude over 6 surveillance periods — from 2 to 29% for Ach2 and from 8 to 42% for Ach3.

Table 1 below presents the data on average daily cumulative fluid, water and oil production for each interval of well No. 3159. The cumulative oil and fluid production from the Ach2 formation significantly exceeds the production from the Ach3 formation. This, most likely, can be attributed to the greater formation transmissibility of the Ach2 due to a thicker pay zone. The cumulative production of reservoir water from Interval 1 slightly exceeds the same parameter of Interval 2. This fact is not confirmed when comparing with open hole logging results.

Table 1—Average daily cumulative production of fluid, water and oil at well No. 59P

Producing zone	Average daily cumulative production of fluid, water and oil by the intervals of well No. 59P for 6 surveillance periods (1 year of well operation), m^3		
	Fluid	Oil	Water
Interval 1 (Ach3)	81.6	48.9	32.7
Interval 2 (Ach2)	105.0	75.4	29.6

Figure 7 below shows the historical performance of well No. 59P, as well as the injectivity parameters for injection wells No. 5I and 53I. The graph shows the periods of reservoir fluid sampling for analysis in the laboratory of GeoSplit.

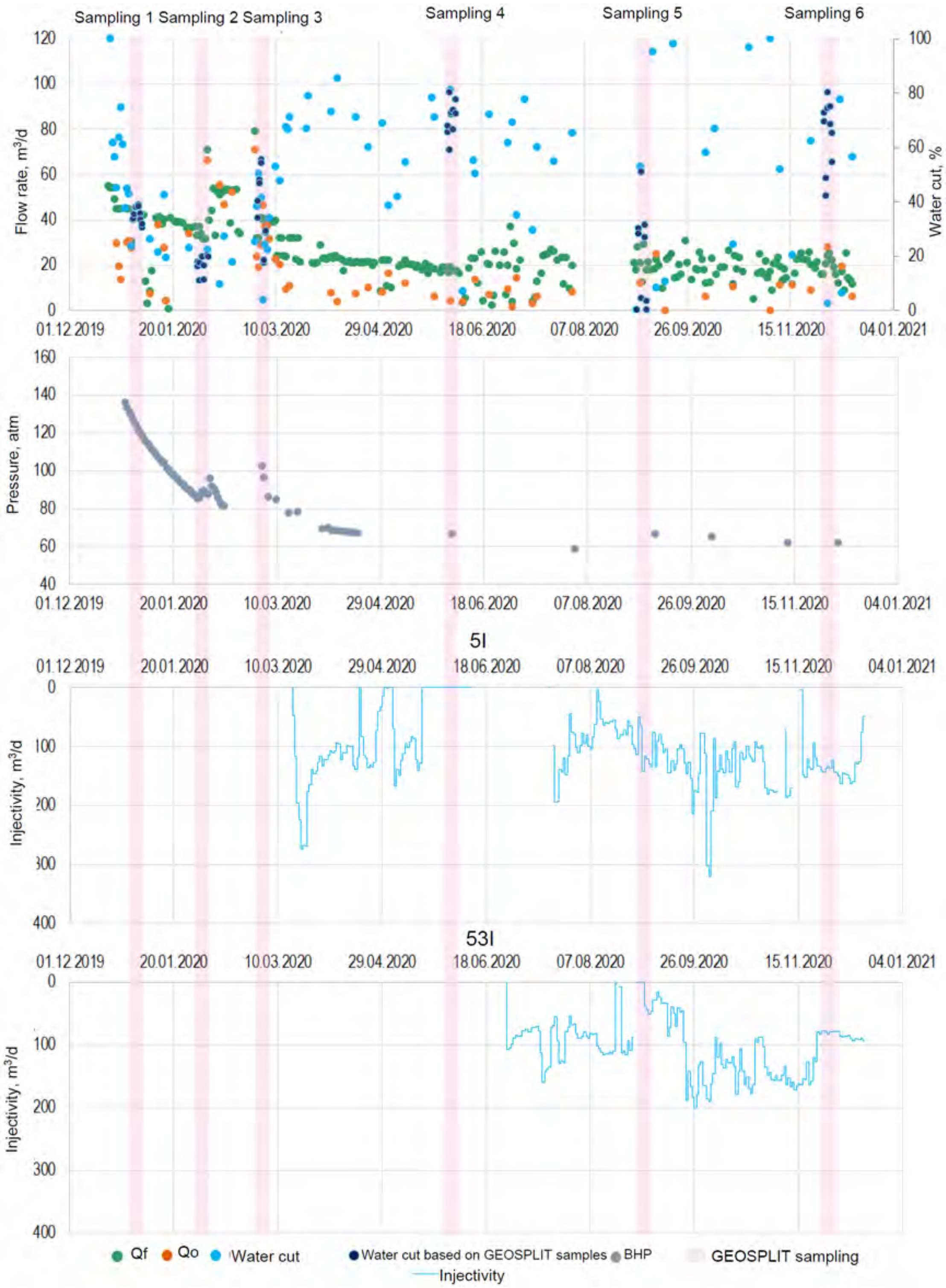

Figure 7—Production and injection history of wells Nos. 59P, 5I, and 53I in the period from December 2019 to December 2020

As can be seen from the historical data of well No. 59P, the water cut decreases dramatically from 100 to 40% during production after well launch. It deals with the hydraulic fracturing gel clean-up. Up to April 2020, the water cut varies from 10 to 50%.

In mid-March 2020, injection well No. 5I was launched, in which the target injection was made into the Ach2 formation. Later, in April 2020, there was a sharp increase to 70% in the water cut of reservoir products at well No. 59P. Further, it was observed that as the injectivity of the injection well No. 5I decreased, there was a decrease in water cut at well No. 59P, while growing injectivity was accompanied be an increase in water cut. During sampling period 4, there is a significant increase in the water cut for both the Ach2 and Ach3 formations. This fact suggests that hydraulic fracturing has led to frac coalescence, as a result of which the water injected into the formation of Ach2 leaks into the formation Ach3.

Before the 5th sampling, the well was put in an intermittent short-term operation mode, as a result of which the water cut of the samples decreased significantly. However, the fow rate of well No. 5I was also reduced to 50 m^3/day in this period.

It should be noted that injection well No. 53I was launched in July 2020 (injectiion into both production intervals). Most likely, this is the reason of better profile conformance during sampling period 5.

During the 6th sampling period, after increasing injection of well No. 5I to 150 m^3/day, water cut in the fuid rate increased significantly with a predominant contribution of Interval 1.

Figure 8 shows the interval performance dynamics of well No. 34P versus the reservoir saturation according to the data obtained using the open hole logging results.

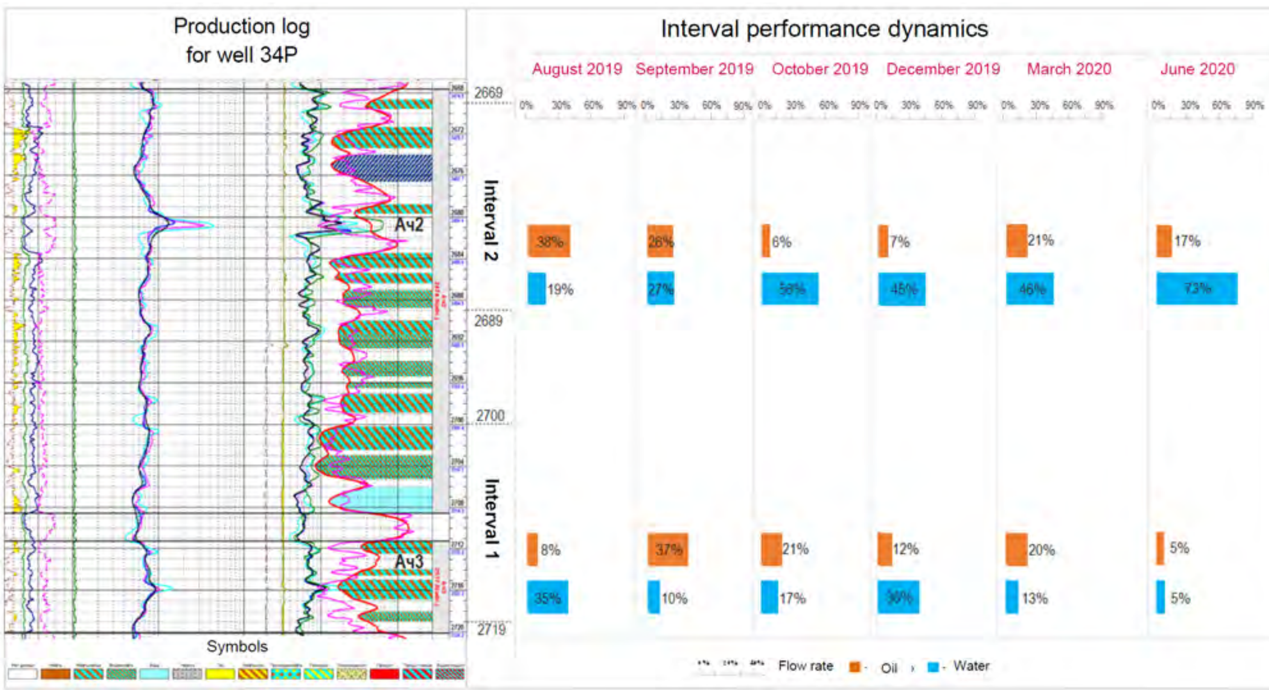

Figure 8—Comparison of the production profile of well No. 34P with the reservoir saturation based on open hole logging results

During all tested period, significant reserves recovery is observed in the Ach2 productive formation (from 52 to 90%). The contribution of Interval 1 during 6 sampling periods varies from 10 to 48%.

Table 2 below presents the data on average daily cumulative fluid, water and oil production for each interval of well No. 34P. The cumulative oil and fluid production from the Ach2 formation significantly exceeds the production from the Ach3 formation. This, most likely, can be attributed to the greater reservoir transmissibility of the Ach2 formation due to a thicker pay zone. The cumulative oil production from Interval 2 also exceeds that of Interval 1.

Table 2—Average daily cumulative production of fluid, water and oil at well No. 34P

Producing zone	Average daily cumulative production of fluid, water and oil by the intervals of well No. 34P for 6 surveillance periods, m³		
	Fluid	Oil	Water
Interval 1 (Ach3)	57.9	27.4	30.5
Interval 2 (Ach2)	91.9	33.5	58.4

Figure 9 below shows the historical performance of well No. 34P, as well as the injectivity parameters for injection wells No. 1H, 42I, and 24I. The production and ijection history plots show the periods of reservoir fluid sampling for analysis in the laboratory.

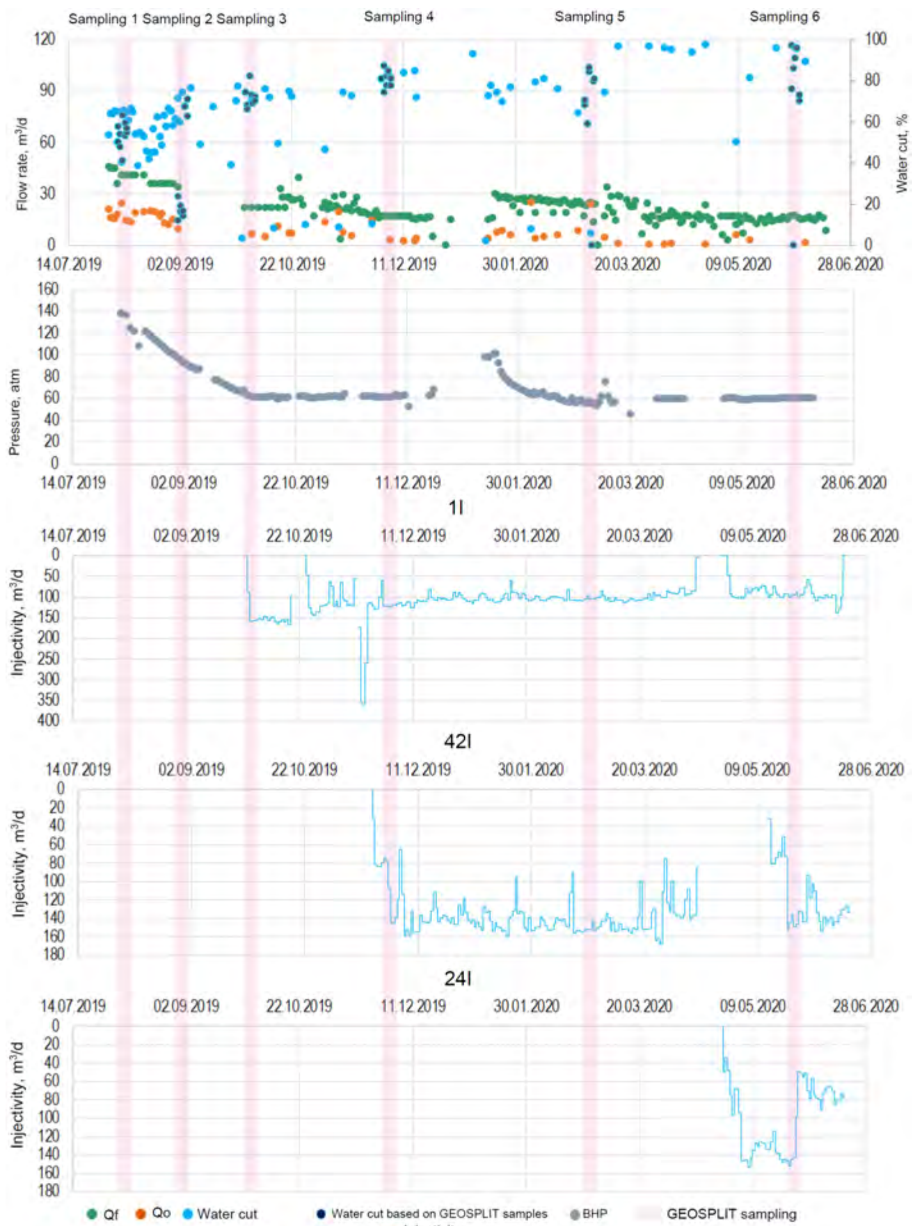

Figure 9—Production and injection history of wells Nos. 34P, 1I, 42I, and 24I in the period from August 2019 to June 2020

As evidenced by the historical data of well No. 34P, the water cut of fluid in the first two months of well production is quite stable and keeps at the level of 60%. By the third sampling period, the well had reached a steady-state flow (bottom-hole pressure stabilised).

On September 30, 2019, injection well No. 1I was launched (targeted injection into the Ach2 and Ach3 layers) with flow rate of 150 m^3/day, which resulted in a significant increase in the proportion of water coming from Interval 2 during the third sampling period, most likely due to greater reservoir transmissibility. Before the fourth sampling period, the injection of well No. 1I was increased to 350 m^3/day, which resulted in an increase in the water proportion in Interval 1 and the preservation of a high water cut in the products from Interval 2. Then, after reducing the injectivity to 100 m^3/day, the proportion of water from Interval 1 decreased.

Also, before the fourth sampling period, injection well No. 42I was put in operation. After that, a gradual increase in the water cut of reservoir products up to 100% was observed. During the shutdown of well No. 42I from mid-April to mid-May 2020, the water cut of reservoir products at well No. 34P decreases, but once it was brought into operation, the water cut increases again.

Before the sixth sampling period, injection well No.24I (targeted injection into Ach2) was launched. Most likely, this was the reason of dramatic increase in the water-cut trend in Interval 2 to 73%.

Thus, having studied the data yielded by tracer-based production surveillance and the historical production data of the tested well and the neraby wells, it was confirmed that hydraulic fracturing in two productive intervals of the directional well resulted in the fracs propagating selectively for each layer, which is confirmed by the results of tracer-based surveillance — the contribution of Interval 2 (Ach2) significantly exceeds the contribution of the lower one (Ach3), both for the produced reservoir fluid in whole, and separately for the water and oil phases.

CONCLUSION

A series of studies were conducted at an oil field located in Western Siberia to assess the reserves recovery and monitor the current state of recovery using an alternative method for inflow profile surveillance in two producing directional wells. The application of the tracer-based production surveillance technology helped:

- identify the influence of injection wells on the performance of productive intervals of production directional wells;
- analyse and measure the reserves recovery rate in productive layers;
- monitor the inflow composition dynamics during a long-term production period and identify intervals of potential water breakthrough;
- detect the probability of the hydraulic fracture coalescence (at well No. 59P) and take into account the causes thereof when planning future hydraulic fracturing designs in order to prevent this phenomenon.

The study conducted has led us to the following conclusions:

1. The highest reserves recovery takes place in productive layers with greater reservoir conductivity (with greater pay zone);
2. A slight decrease is observed in the reservoir pressure (according to the drop in production rates), and in addition, higher water content in the reservoir fluid is seen in the subject wells. These observations may implicitly indicate inefficient compensation due to the current injection modes.

Thus, tracer-based studies aimed to monitor reserves recovery yield data to assess the current state of production in the production well stock at any time and find how certain factors determine the results obtained. In addition, the technology does not require deploying costly equipment, and there is no need for the temporary well shutdown. To address the objectives set, the technology implies only timely sampling of reservoir fluid from the wellhead. This advantage provides a significant cost-saving effect to the operator company.

Moreover, the large-scale deployment of this technology over the entire field area will open up new opportunities not only for the micro-level surveillance of the current production state but also for highly efficient management of the field development process [5, 6], consisting in selecting the optimal operating conditions for the production and injection wells, as well as adequate well interventions.

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