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Complex Using of Conventional Production Logging and Indicator Technologies in Tight Oil Reservoir Study

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Resume

Constant growth of commercial hydrocarbon (HC) consumption requires for the oil and gas industry to be involved into exploitation of unusual oil and gas reserves, preventing HC supply shortage on the global market. The fields with conventional reservoirs being actively developed during the last century have a tendency now to reduction of routine parameters of HC production.

Now more and more attention is being attracted to tight reserves, which have to be studied in unconventional ways. This article focuses precisely on complex reservoirs, in which reserves are classified as tight. A complex quantitative assessment using several different technologies for long-term monitoring under difficult conditions has shown favorable results.

Introduction

Vertically integrated oil companies (VIOC) have to engage more resources for searching and putting new oil and gas sites into operation every year. Otherwise they shall switch to exploitation of hard-to-recover reserves (HTR) or unconventionals.

The technology growth in the oil industry, introduction and adoption to the mass operation of such methods as horizontal drilling and hydraulic fracturing enabled to consider commercial and economically recoverable exploitation of shale sites that are unique by its structure.

The Shale Revolution started in the USA at the end of 2010s and enabled the USA to recover colossal hydrocarbon resources from unconventionals was a breakthrough for shale production technology advancement.

The Figure 1 shows the volume of oil production from the main shale rocks: Permain, Bakken, Eagle Ford. The fairly large volume of reserves was planned to be recovered within next 10 years in accordance with the suggested scenario. However, the present situation involving HC price collapse has updated the plans of shale site exploitation (figure 2), but even in the present circumstances the production output is at the level consistent with the volume of whole oil produced in the RF.

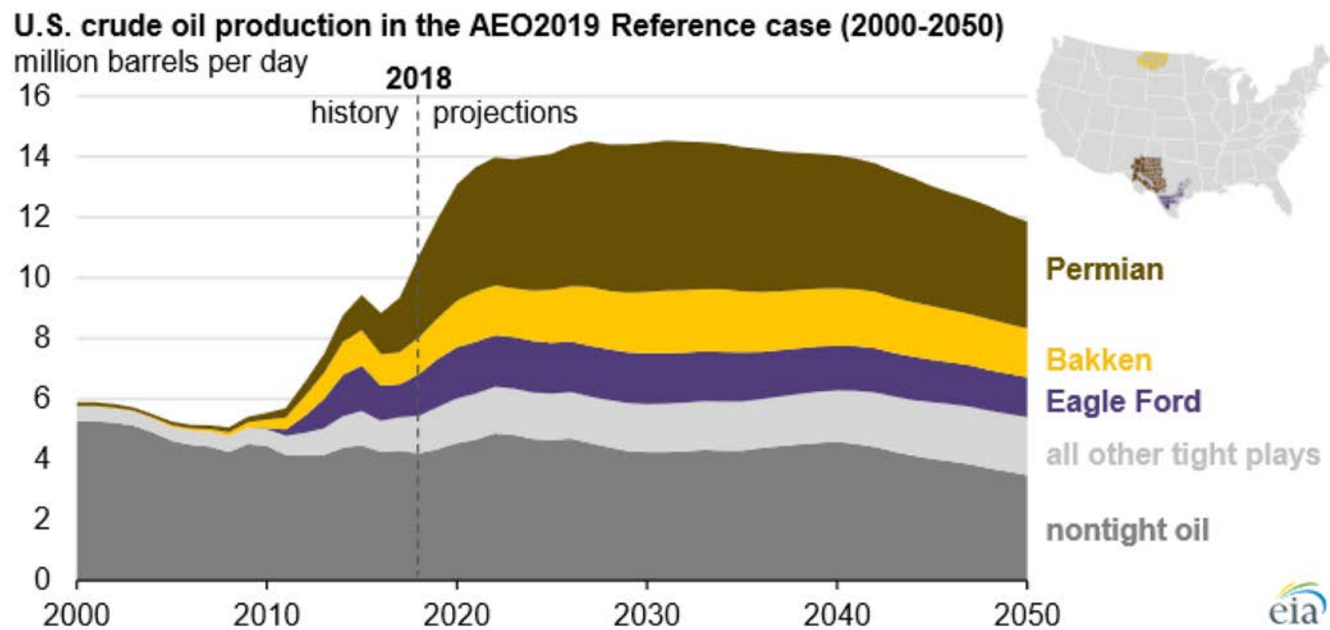

Figure 1—US oil production

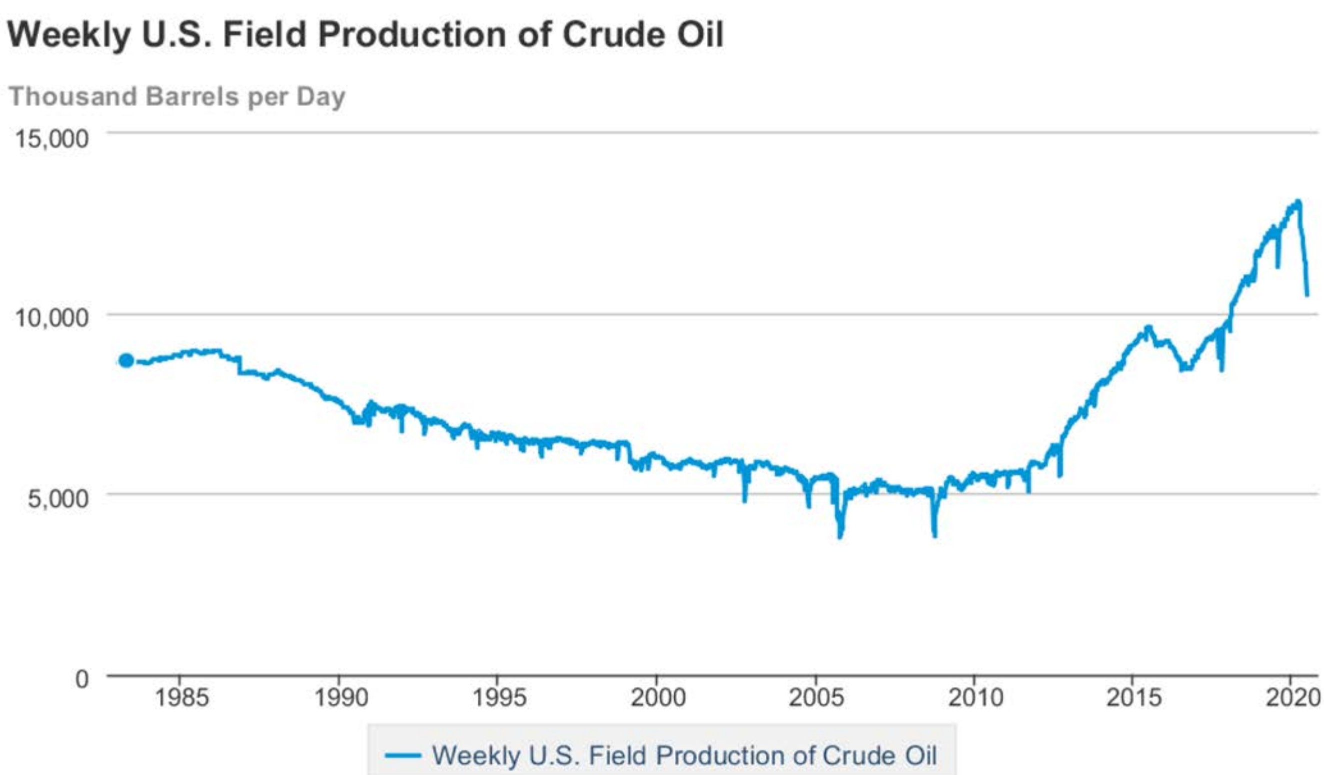

Figure 2—US oil production as a result of price collapse in 2020.

The Russian analogue of the US shale sites is Bazhenov formation (BF is a source rock assemblage bedding in Western Siberia from Kazakhstan border to Kara Sea covering about 1 mln. km^2). Extremely low values of matrix formation permeability ~ 0.01 mD and average BF depth about 30 m are typical for BF. Due to the low permeability as well as small oil saturated thickness of the bed ~10 m, exploitation of BF was unprofitable for the longest time to achieve commercial oil inflows.

Multi-stage hydraulic fracturing (MSHF) is the main effective method of HC recovery from the source rocks. HTR are fractured due to complexity of geology structure of the site under study, presence of natural fracture zones, abnormally high reservoir pressure (AHRP), low porosity & permeability (RQ), variable along the horizon distribution of wells with dramatically different production rate i.e. sweet spots, as well as high decline rates during the year after MSHF and so on. It differs fundamentally from operations in conventional formations. The application of specialized treatment plans for MHF to generate a stimulated reservoir volume (Fig. 3 - 4) or long half-length hydraulic fractures involves the use of high-speed injections (Q~15 m^3/min) and a large volume of low-viscosity fluid used with small fraction proppants. Such measures are required for potential initiation and further solidification of natural fracturing which makes it possible to multiply the area of drainage thereby increasing HC production (Fisher M.K. et al., 2002), (Kashapov D. V. Et al., 2019)

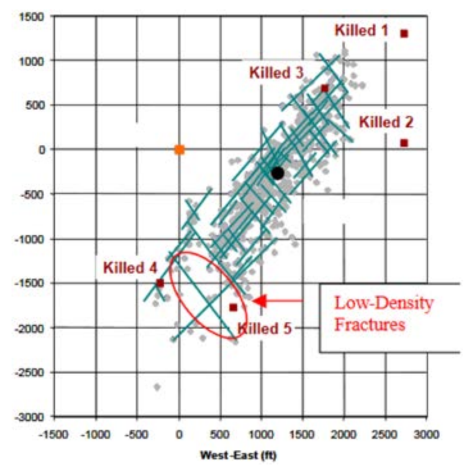

Fig. 3—an example of MHF with SVR development which has shut down the operations of the adjacent production wells

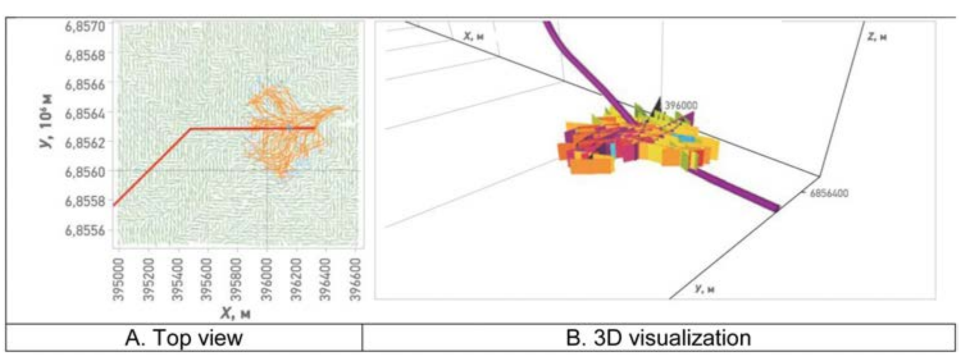

Figure 4—an example of MHF with SVR development for Bazhenov formation wells a - top view; b - 3D visualization

Petrophysically, the Bazhenov formation in the Palyanovsk zone where Gaspromneft set up a facility to test MHF is comprised of five packs shown in Fig. 5 (Alekseev A.D. et al, 2019). Pack No. II has the highest rates of movable oil and porosity therefore a horizontal well must be drilled in this pack along with a perforation interval.

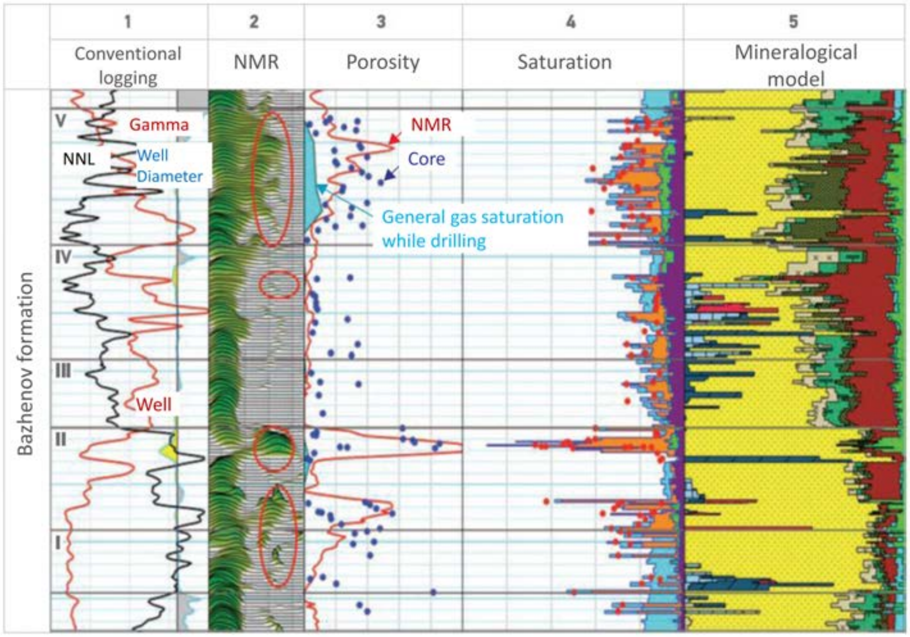

Figure 5—Petrophysical log of the Bazhenov formation (vertical grid step is 1 m): I-V – pack number; GC – gamma-ray logging; DS – caliper measurements; NNC – neutron-neutron logging; T2 – transverse relaxation time; saturation profile: 1 – movable oil (loss of volatile oil components from the core); 2 – movable oil preserved in the core (parautochthonous hydrocarbons); 3 – bound oil (autochthonous hydrocarbons); 4 – water; integrated petrophysical model: 5 – silica; 6 – calcite; 7 – dolomite; 8 – phosphorite; 9 – argillaceous admixture; 10 – siderite; 11 – feldspar; 12 – pyrite; 13 – kerogen along with solid heteroatomic compounds (resins, asphaltenes); 14 –oil; 15 – water

The complexities of using traditional production logging tests at unconventionals

Aside from the complexity of identifying and stimulating good rocks in the Bazhenov formation, operators engaged in developing unconventionals face the task of performing a subsequent assessment of both well performance and individual ports/clusters in order to assess the carried out MHF operation and subsequent adjustments in order minimize various problems such as breakthroughs into the underlying/overlying non-target gas/water-saturated intervals, low irregular production rate of certain sections in the horizontal well, etc. (Ding Zhu et al., 2018), (Pang Wei et al., 2016).

The complexities associated with conducting surveys in a horizontal well due to the stratified liquid flow, the presence of a gas component in the flow, the presence of flow recirculation zones and others which cause major problems in the assessment of recorded parameters often failing to provide sufficient measurement accuracy. Apart from the complexity of determining multi-phase flow properties, there are specified parameters to inflow assessment operations: the necessity of performing a well kill, operations of running and pulling special-purpose equipment which ultimately results in downtime for wells and clogging of the bottom-hole region which leads to reduced hydraulic fracture conductivity in the well-bore area, and, consequently, to a decrease in the performance of the fracture and the well in general. Considering the structure of the BF as a source rock (the wells operate in depletion mode because of the absence of an RPM system), an intervention in the operation of wells may yield a significant reduction in the liquid flow rate following PLT operations.

Well survey methods employed to determine the inflow profiles following a completed hydraulic fracturing operation and to evaluate the physical and chemical properties of the fluid, can be divided into three main groups:

- Production logging tests (PLT);

- Fiber-optic sensors put in place for online monitoring mounted throughout the wellbore (with additional software);
- Marker technologies of well inflow dynamic monitoring

Comparison of inflow test and monitoring methods is shown in table No. 1.

Table 1—Comparison of the characteristics of various types of monitoring of well inflows

Type of monitoring	Classical set of PLT using CT	Distributed fiber optic sensors for online monitoring	Marked proppant
Monitoring period	A few hours	Up to several years (depending on the quality of the optical material and the number of removal of solid particles from the rock)	Hydrophilic, oleophilic, gas - more than 3 years (depending on conditions)
The need to stop or change the well operation mode	Yes	No	No
Bench tests	Yes	No	Yes
Number of studies per year	1-2	Continuous monitoring	6-12 (selectively upon customer request)
Laboratory	Not applicable	Not applicable	Yes
Multi-hole, multilateral wells or wells with a large distance of the bottom from the vertical	Yes	Yes	Yes
Use in cemented shanks	Yes	No	Yes
Applicable for old/new wells	Yes	For new wells	Yes
Use in open holes	Yes (there are restrictions)	No	Yes (there are restrictions)
Assessment of the quality of bottom-hole or hydraulic fracturing	No	KO - Yes Hydraulic fracturing-limited	Yes
The possibility of increasing the efficiency of field development based on the results	Yes	Yes	Yes
Method limitations	Availability of a horizontal shaft; Risks of downhole operations;	The complex process of running in hole; Repair and maintenance is required; Not a mass decision;	Limited use in high-viscosity oil Depends on the success of the hydraulic fracturing operation;

Object of research

In September 2018, a 16-stage hydraulic fracturing was carried out in one of the BF wells of the II petrophysical pack, which included a high-speed operation with a large volume of injected fluid, the presence of "slug" packs, marked proppant for each processing stage, the use of low-viscosity fluid – Slickwater at the initial stages of the operation, followed by the transition to high-viscosity systems to enable the transfer of proppant with high concentration and the creation of high conductivity in the well bore zone.

The Customer agreed to conduct the MSHF address operation summarized in Table 2. Figures 6 and 7 show data on the flow, concentration, and supply of propane.

Table 2—MSHF implementation Plan

Stage No.	Flow, m³ / min	V_{fluid}, m³	$Proppant_{Mass}$, t	40/70	30/50	30/50 (marked)	Flow, concentration kg/m³
2 - 4	12-8	1200	70	35	20	15	350-450
5 - 6	10	1100	100	40	45	15	150-200
7 - 16	10	1100	100	40	45	15	350-450

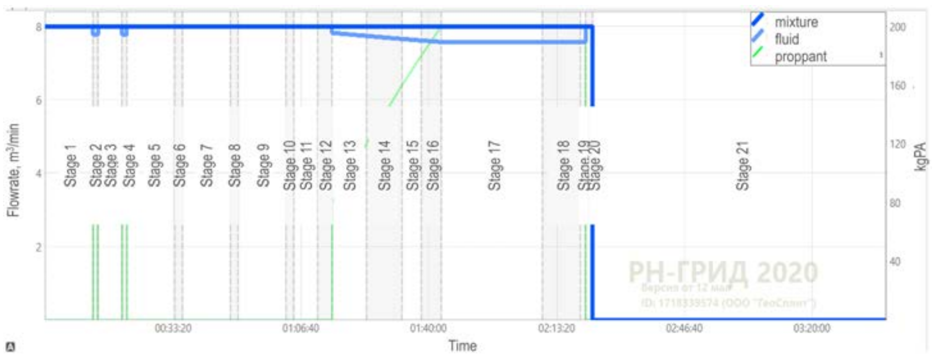

Figure 6—Hydraulic Fracturing Processing Plan for Stages 2-4

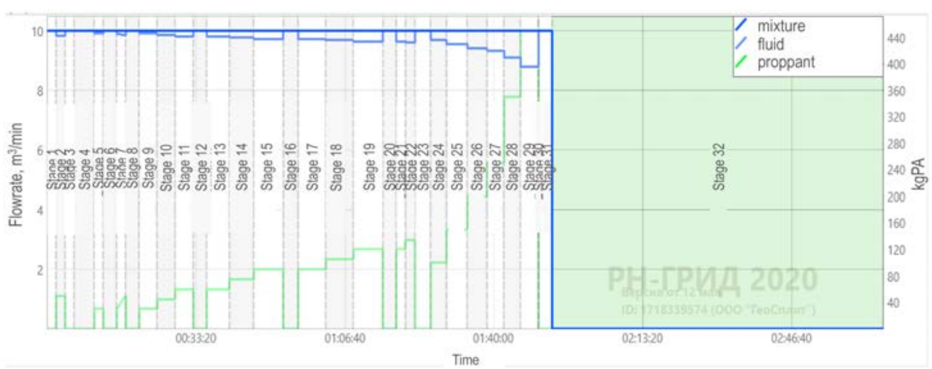

Figure 7—Hydraulic Fracturing Operation Plan for Stages 6-16

The processing plan for stage 1 included a hydraulic fracturing weighing 15 tons with the aim of cleaning the wellbore and checking the downhole equipment, so this stage will not be considered in further analysis.

The geometry of hydraulic fracture and the proppant placement for the actually performed operation for stages 2-5 are shown in Figure 8. The marked proppant was supplied at the last stage of MSHF.

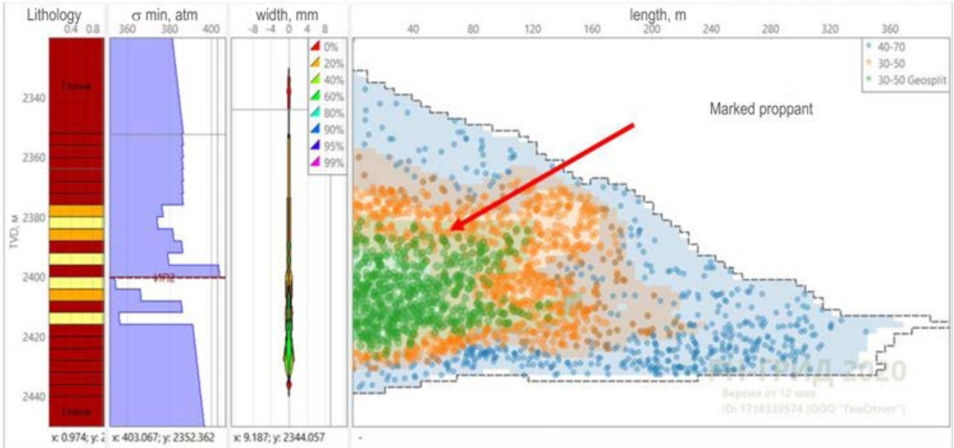

Figure 8—Geometry of Hydraulic Fracture and Proppant Placement for Stage 4

Stages 5 and 6 are shown in Figure 9. In these designs, the marked proppant was supplied at medium proppant stages, followed by the flush by usual ceramic proppant of the 30/50 fraction weighing 35 tons in order to transfer the proppant inward to increase the area of its contact with the reservoir.

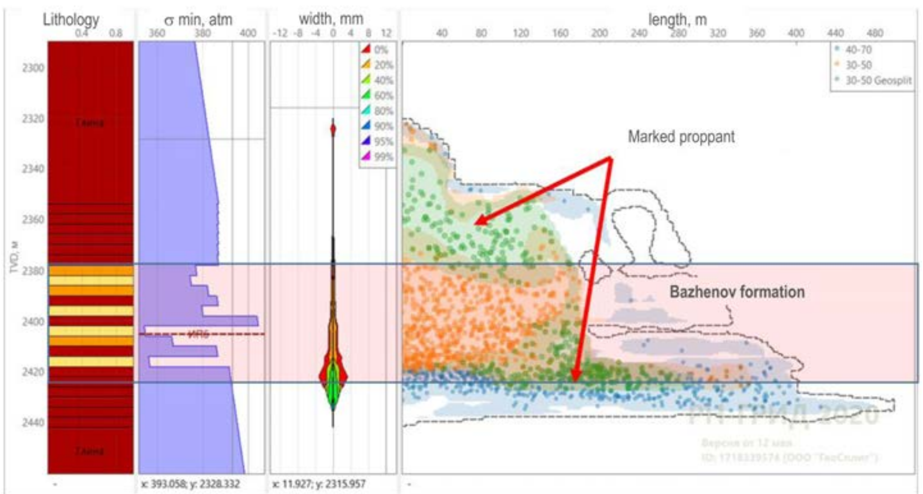

Figure 9—Geometry of Hydraulic Fracture and Proppant Placement for Stages 5 and 6

However, according to the result of simulation and adaptation of the actual pressure data with the simulated ones, it was found that part of the marked proppant is located in over/underlying impermeable barriers, which affects the quality of marker diagnostics and can lead to serious distortions in assessing the flow profile.

Stages 7-16 are shown in Figure 10. In these designs, the marked proppant was supplied at penultimate stage, followed by the flush by usual proppant of the 30/50 fraction weighing 5 tons. With this type of processing, the marked proppant is located in a semicircle within the exploitation target. The post-simulation results showed that this arrangement is the best of all offered.

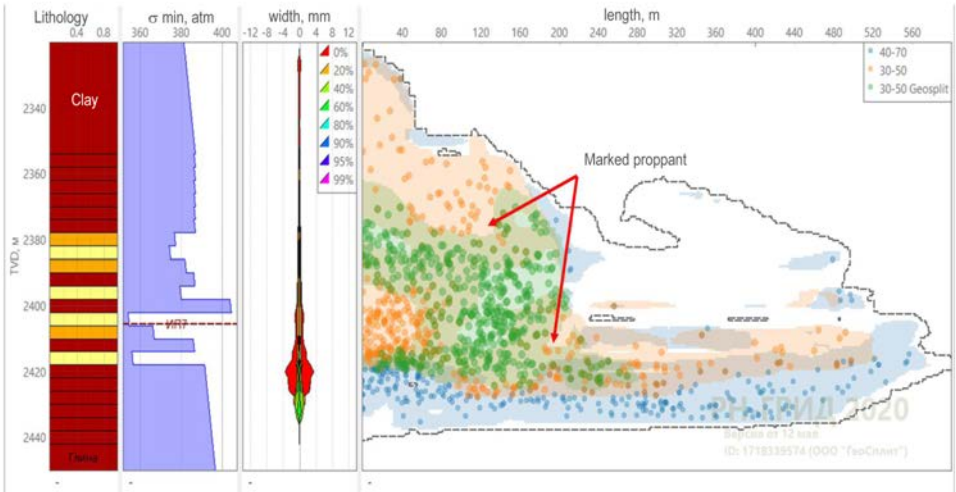

Figure 10—Visualization of the hydraulic fracture geometry and proppant location for stage 7

During the multi-stage hydraulic fracturing operation, an individual signature (coding number) was used at each stage to identify the information on the functioning of each hydraulic fracture: the flow rate for each of the fractions.

It should be noted that due to the complexity of the sidetrack well structure, as well as the presence of restrictions during the multi-stage hydraulic fracturing operation, the hydraulic fracturing stages were carried out with certain adjustments to the approved processing plan. These adjustments were made during the main works and minimized the risk of complications such as a STOP, due to reaching the maximum level of processing pressure (Figure 11). The adjustments include reducing the flow rate of injected hydraulic fracturing fluid, reducing/increasing the number of "slug" packs, bringing down the volume of injected fluid, etc.

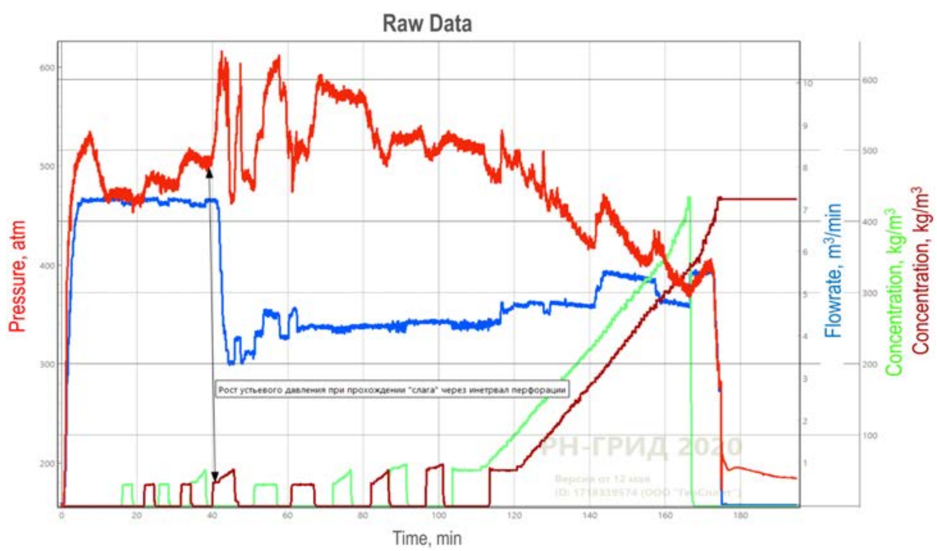

Figure 11—Actual data of stage 1

In general, despite the adjustments introduced during the process of conducting selective stimulation of the bed, field hydraulic fracturing operations were carried out routinely and the entire planned volume of proppant was placed in the bed formation.

The well was connected to the bed formation by applying Pump down Plugs / Perforators technology. This technology provides for the installation of insulating plugs and carrying out perforation in a single bed stimulation operation. The advantages of this technology are that conducting hydraulic fracturing does not require a large number of resources: in fact, only a geophysical party and a hydrofrac fleet are required. Boring machines and plugs are lowered on a geophysical cable drawn by gravity and then pumped by pumps of the hydraulic fracture fleet out of the planned areas of perforation. Then, by the efforts of the geophysical party, the perforators are set at the required intervals using the collar locator, a shut-off plug is installed, and perforation is initiated. Upon completion of the multistage hydraulic fracturing process in the well under consideration, the plugs were drilled out using coiled oil well tubing.

Marked proppant located in the hydraulic fracture, as well as the planned field geophysical tests provided an opportunity to evaluate both the operation of the well on the whole and the individual stages of multistage hydraulic fracturing. It should be noted that when interpreting the data obtained by using both technologies for estimating the inflow profile (marked proppant and standard piping & instrumentation field-geophysical complex), there are risks of ambiguity in the quantitative determination of the flow rate from local areas of formation fluid entry. Using only one of the inflow evaluation methods leaves a number of uncertainties for experts involved in the development of nonstandard reservoirs. An integrated approach, on the contrary, gives a chance to get a more complete picture without distortion, leveling the shortcomings of interpretation characteristic of each method.

Marker diagnostics technology and inflow profile evaluation

50 samples of formation fluid were studied for the purpose of marker diagnostics; the monitoring period was about 6 months, during which three marker diagnostics studies were performed — in June, July and November 2019. It should be noted that some of the samples taken in November 2019, presumably, do not reflect the real way the formation works, due to lengthy repairs carried out in order to clean the bottom-hole with the help of the drilling junk basket immediately before taking fluid samples. Significant losses of fluid into the bed formation occurred during the downhole operation.

A set of studies was conducted for all samples of reservoir fluid in order to extract quantum reporter markers from the oil and water phases separately (Guryanov A.V., 2019). The method for determining the inflow profile is based on placing reporter markers containing quantum dots in the polymer coating of proppant. Quantum dots (several nanometers in size) are placed inside insoluble microspheres (markers the size of one micron) and then those microspheres are placed in the polymer coating of ceramic proppant. After that the markers are washed out of the coating by bed formation fluid during a long period of time, after which samples are taken at the wellhead and sent for laboratory analysis.

Analytical determination of reporter markers is based on the instrumental procedure: flow cytofluorometry (Ovchinnikov K.N. et al, 2017). The principle of its functioning is as follows: inhomogeneities (including markers) that the sample contains are lined up strictly one after another using pressing fluid and a finely tuned hydrodynamic system. Then they are irradiated by several lasers, the signals after irradiation are registered by various detectors. 15 different parameters are recorded for each point, the most informative of which are fluorescence channels in different wavelength ranges. Reporter markers are microspheres containing quantum dots inside that can fluoresce in different colors depending on the signature number or marker code (Kawasaki et al., 2005). Each productive range of a horizontal well is marked with a unique code, which makes it possible to evaluate the contribution of each such range to the well operation. Each sample, divided into phases, is examined using a special analytical hardware and software system.

A relative content of marker-reporters of various signatures is determined based on the findings of sample analysis and its interpretation resulting in moving to percentage expression of flows for each range (Figure 12).

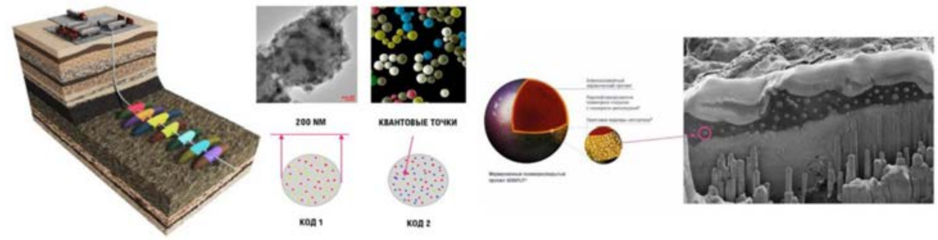

Figure 12—The principle of marker diagnostic technology functioning

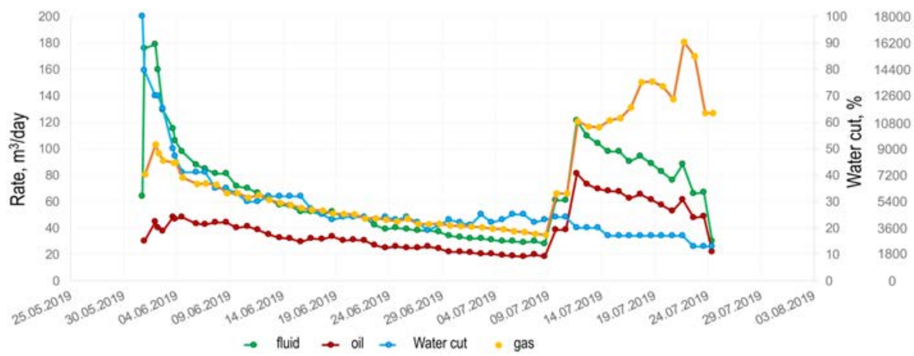

Figure 13—Dynamics of well operation prior to the stop for repair works

After the hydraulic fracturing operation was completed in June 2019, the well was put into operation by free-flow production method, due to the presence of abnormally high formation pressure. The well flow rate was maintained by an adjustable wellhead nozzle. Since August, scheduled works to extract the bottom-hole pressure gauge, plug milling, fishing and emergency works, etc. have been started in the well. Since the end of October the well operation was resumed, alongside with preparations for field geophysical tests due in November 2019.

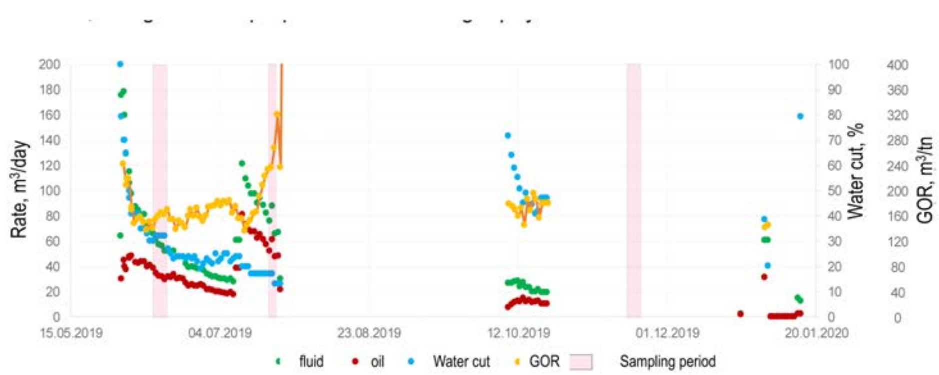

Figure 14—Dynamics of well operation during the period from June 2019 to January 2020

Analysis of fluid samples taken in June 2019 showed that stages 5, 8, 11, 13, 15 differ in the maximum values of oil and water inflow.

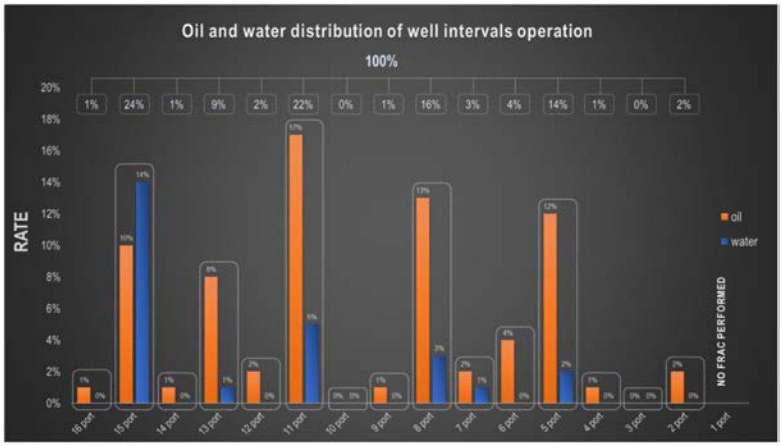

Figure 15—Distribution of oil and water flow rates by stages during the period from June,11 2019 to June,16 n2019.

Stages 2, 4, 6, 7, 9, 12, 14, 16 bring minimum values into the well operation. Stages 3 and 10 – according to the findings of marker diagnostics are registered as non-functioning.

From the results of modeling and proppant placement operations, the following interesting features have been noted:

- at stages 2 to 4, with the marked proppant pumped at the last stage, the markers were actually not detected. Most likely, this is due to the fact that a smaller mass of proppant was used and the injection of a large volume of cross-linked gel (56 of 70 tons) was done.
- Stages 5 to 6 (Figure 9) – marked proppant was supplied at the middle injection step, this range makes a significant contribution to the operation of the well. A likely cause is the formation of a complex network of fractures.

The results of re-sampling and diagnostics carried out in July 2019 are presented in Figure 16.

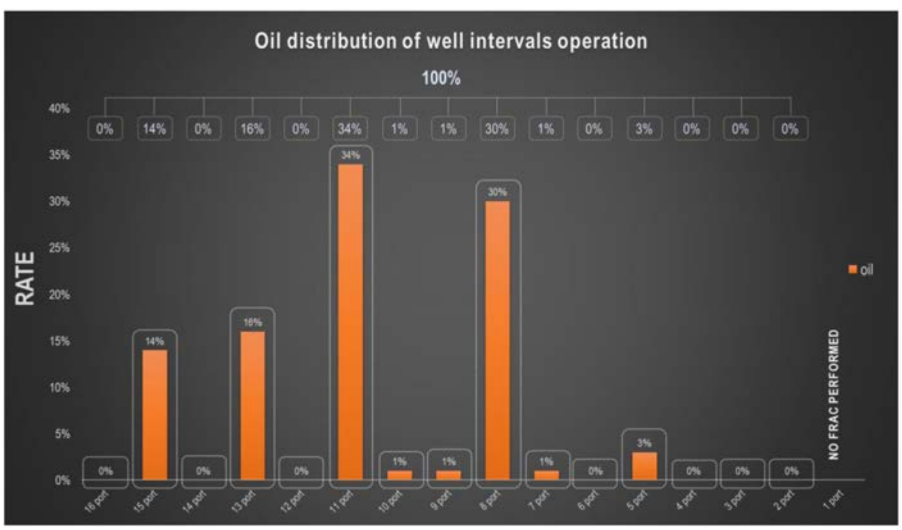

Figure 16—Distribution of accumulated oil flow rates by stages during the period from July, 22 2019 till July, 23 2019.

The drop in the flow rate at port 5 is likely due to the location of proppant in the non-target zone of the formation, and, as a result, the absence of fluid movement along the fracture through the marked proppant.

The most positive dynamics of the change in operation is demonstrated by stage 11, oil inflow values increased up to 34% by the first period of testing; stages 15 and 13 also show a small increase in oil production.

The number of stages that do not contribute oil inflows increased to 7 — stages 2, 3, 4, 6, 12, 14 and 16.

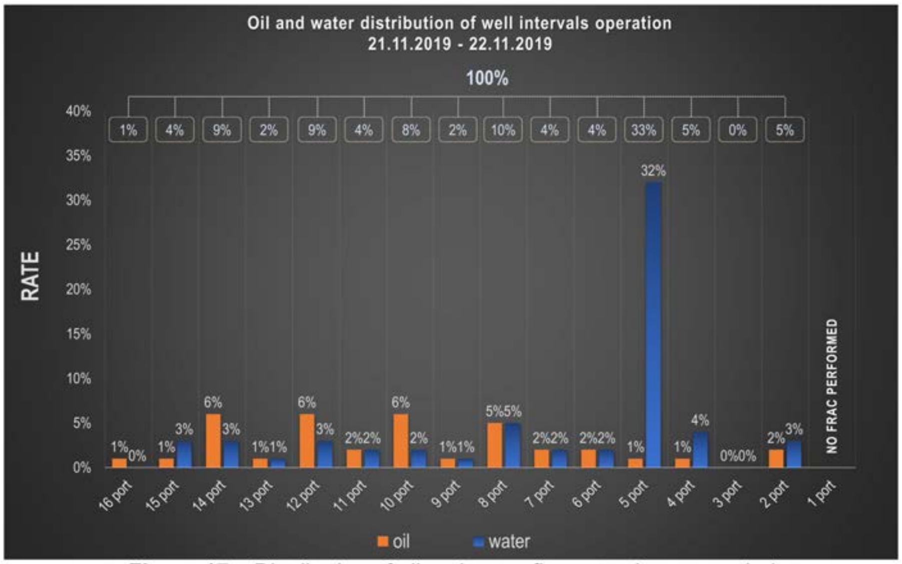

Figure 17—Distribution of oil and water flow rates by stages during the period from Nov. 21 2019 till Nov. 22 2019.

Based on the results of marker analysis, during the period from November 21 to November 22 2019, functioning of all stages in multi-stage hydraulic fracturing (with the exception of 3 ports) for oil and water was noted. Appearance of water is associated with constant flushing of the well during the cleaning works in the horizontal section of the wellbore with the help of the drilling junk basket in the period from November, 12 to November, 20 2019. The probable reason for high water reading at port 5 is related to the complications that arose in the well toe and the tight pull of the tools.

Field geophysical tests. Based on a set of tests done in the inflow mode at a 6 mm nozzle, working ranges of the YuKO reservoir were identified, and a detailed quantitative inflow profile was obtained based on thermodynamic modeling.

According to wellhead measurements data, the total fluid flow rate (carbonated oil-water emulsion) amounts to ~45 m^3/day.

According to the data of spectral noise logging in the inflow mode and the data obtained by a set of methods, functioning of all hydraulic fracturing ports: port 2 to port 15 was noted. Hydraulic fracturing port 2 is partially covered by studies. Hydraulic fracturing port 1 is not covered by studies.

According to the data of spectral noise logging in the inflow mode the following facts were noted:

- the ranges of YuKO reservoir associated with the operation of hydraulic fractures are active, which is determined by the intense broadband high-amplitude signal in the spectrogram (Figure 18);
- hydraulic fracturing ports 2, 4, 5, 6, 7, 8, 10, 11, 12, 14 and 15 are characterized by the operation of all perforation ranges;
- perforation ranges of 3,570–3,572 m (port 13) and 3,775–3,777 m (port 9) do not function.

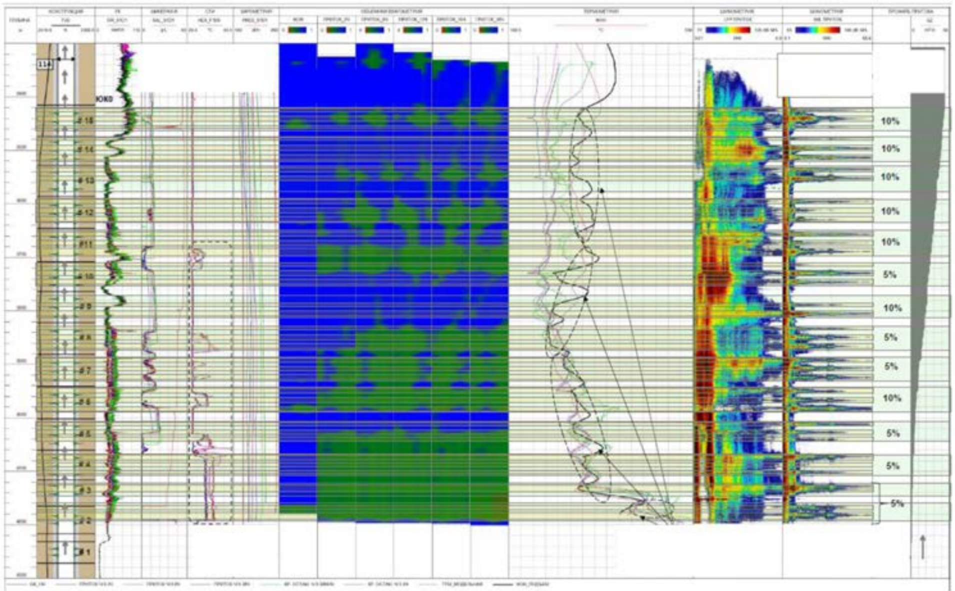

Figure 18—Spectral noise logging, high accuracy thermometry and thermal modeling data in the range of detailed studies

Temperature modeling was carried out taking into account the volume of injected fluid at each stage of hydraulic fracturing in order to analyze temperature disturbances (cooling anomaly) associated with previously injected fluid during hydraulic fracturing opposite each stage.

A characteristic slope is observed between the stages of hydraulic fracturing, due to convection heat transfer (Figure 18). Gradient in the thermograms on the inflow between the stages of hydraulic fracturing corresponds to the fluid flow rate, with a lower gradient corresponding to a higher flow rate.

The inflow profile was calculated based on the performed set of temperature modeling operations. According to the results of inflow profile modeling the following facts can be noted (Table 3):

- a relatively uniform fluid inflow throughout the entire wellbore;
- the main fluid inflow from hydraulic fracturing ports 6, 9, 11, 12, 13, 14 and 15 (10% of the total inflow volume from each hydraulic fracturing port);
- operation of hydraulic fracturing ports 4, 5, 7, 8, and 10 is characterized by average intensity (5% of the total inflow volume from each hydraulic fracturing port);
- ports 2 and 3 are characterized by weak functioning rate (the aggregate contribution of these ports to the total flow rate is estimated as 5%);
- functioning of port 1 is estimated as 3%.

Table 3—Ranged inflow profile for the YuK0 reservoir according to the results of thermodynamic modeling and spectral noise logging

top M	bottom M	Fr, kHz	Noise, dB	port	Noise type	Inflow profile	
						%	accuracy %
3424	3426	3.9 ~ 57.5	67 (high)	15	Frac flow	10	5
3439	3442	3.8 ~ 57.7	69 (high)				
3455	3458	3.8 ~ 57.1	65 (high)				
3475	3480	4.1 ~ 57.5	64 (high)	14	Frac flow	10	5
3493	3498	3.8 - 58.3	73 (high)				
3511	3516	4.0 - 58.3	71 (high)				
3534	3538	4.0 - 58.3	71 (high)	13	Frac flow	10	5
3551	3555	3.9 - 58.3	71 (high)				
3594	3597	3.9 - 58.1	67 (high)	12	Frac flow	10	5
3610	3613	3.8 ~ 38.9	67 (high)				
3625	3631	4.0 ~ 41.0	68 (high)				
3655	3659	4.0 - 58.3	70 (high)	11	Frac flow	10	5
3672	3675	3.8 ~ 58.2	67 (high)				
3685	3691	3.8 ~ 58.2	67 (high)				
3713	3715	3.8 ~ 20.0	67 (high)	10	Frac flow	5	3
3727	3733	3.8 ~ 58.3	71 (high)				
3744	3748	3.9 ~ 58.5	67 (high)				
3787	3791	4.1 ~ 43.0	66 (high)	9	Frac flow	10	5
3803	3808	3.9 - 58.3	70 (high)				
3831	3534	3.9 ~ 57.2	67 (high)	8	Frac flow	5	3
3847	3852	4.0 - 58.4	70 (high)				
3864	3868	4.1 ~ 58.3	70 (high)				
3890	3595	3.9 ~ 58.3	68 (high)	7	Frac flow	5	3
3905	3910	3.9 ~ 58.3	71 (high)				
3922	3927	3.9 - 58.3	68 (high)				
3949	3953	3.8 -51.1	67 (high)	6	Frac flow	10	5
3965	3970	3.9 - 58.3	68 (high)				
3979	3986	3.9 - 58.3	73(high)				
4010	4014	4.0 - 58.3	69 (high)	5	Frac flow	5	3
4026	4029	3.8 - 48.4	67 (high)				
4040	4043	3.9 - 41.9	68 (high)				
4070	4076	4.0 - 58.3	71 (high)	4	Frac flow	5	3
4087	4090	3.9 - 40.9	63 (high)				
4100	4104	3.9 - 51.5	69 (high)				
4127	4129	4.0 - 58.3	74 (high)	3	Frac flow	5	3
4133	4135	4.1 - 58.3	73 (high)				
4166	4170	3.9 - 58.2	69 (high)	2	Frac flow		
4180	4184	3.9 - 58.3	69 (high)				

top M	bottom M	Fr, kHz	Noise, dB	port	Noise type	Inflow profile	
						%	accuracy %
Below test interval (frac №1)						Less then 3%	-

Results of comparative assessment of marker diagnostics and field geophysical tests complex.

- For most of the studied intervals of the well, there is a convergence at a qualitative level of the results of marker diagnostics and the results of field geophysical tests interpretation with inclusion of spectral noise metering (Figure 19);
- The discrepancy has been observed when assessing the contribution of stage 5.

Figure 19—Field geophysical tests research data

The probable reason for the discrepancy between the results of field geophysical tests and marker diagnostics on port 5 may be the repair work during field geophysical tests, as well as collection of fluid samples.

To confirm that the proppant placed in the fifth stage has the same marker release intensity as the proppant in the other stages, a procedure was carried out to compare the degree of leaching of marker substances from proppant arbitration samples.

The procedure for verification of proppant arbitration samples obtained from the field after multi-stage hydraulic fracturing was carried out to establish the correctness of marked proppant injection of the required signature in accordance with established work program. In addition, the obtained data are used for training and calibration of the design model within the framework of a software package as part of a special analytical hardware-software complex.

The methodology of arbitration test procedures for considered interval (port No. 5) consisted of the following steps:

1. Based on arbitration samples of code 4 proppant (port No. 5), standardized samples were prepared for further shooting on a fluorescence-based flow cytometry device.
2. Based on the data of fluorescence-based flow cytometry device, the marker code found in the aliquot was determined to correspond qualitatively with the one stated in description of arbitration samples and work program.
3. When the signature number of certain arbitration sample directly matches the list specified in the work program, an operation was performed to configure and calibrate machine learning algorithms.
4. Using the machine learning algorithms, a qualitative and quantitative assessment of arbitrage proppant properties was carried out.

Subsequently, when analyzing the formation fluid samples, a corrected mathematical model based on arbitration samples, which allowed to level out possible calculated errors was applied.

Thus, it was possible to obtain the most objective and accurate data in analysis of real samples, as well as confirm the markers release degree under given conditions (well operating mode during the study).

Conclusion

Following on the results of marker research and PLT data comparison a satisfying convergence in inflows coming from MSHF ports has been obtained. The data of both tests show steady performance of all ports after a few months of production. An important part of work is that using conventional monitoring technology and inflow profile quantitative evaluation only would hardly give a trustworthy result. In this case a mix of several methods made it possible to obtain distribution of operation of all MSHF intervals along the borehole of the horizontal well being studied, in addition we were able to differentiate every running interval by a blend composition of the produced fluid, having found the ports that had no contribution at all. Furthermore, insignificant differences in producing interval performance rate factors (assuming the change of the produced fluid composition) have been found by dynamic evaluation of the inflow profile when comparing with conventional geophysical techniques. We managed to relate the discovered effect for the well under examination to a number of historical events that were hold at the well, proving the value of the integrated monitoring under complex conditions at low irregular inflow. Nonetheless, the question of the reasons of possible test result divergence is still one of the areas being constantly under study.

The information obtained is a tool to make a decision on improvement production of complex exploitation sites and to plan further field operations including selective stimulation of the target formation at the higher level.

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