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Abstract

The work is devoted to improving the technology of drilling and well completion at the Prirazlomnoye field. Provides the basic information about the field, the geological structure of the field, well design. A comparative calculation of the parameters of the drilling mode and technical and economic indicators for the basic and advanced drilling technology is done. Calculation of the drill string and hydraulics program of the well is performed and the well completion systems were considered.

The purpose of this work: Improving the efficiency of the development of the Prirazlomnoye field by improving the technology of drilling and completion of wells. Production increase, as well as a decrease in the cost of drilling wells, will be the determining factor in increasing the development of the field. This paper provides an example of how this can be achieved.

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1. Introduction

Exploration and development of oil and gas fields on the shelf of the Arctic, Far Eastern and Southern seas is one of the most promising areas for the development of the oil and gas industry in Russia. I want to note that a lot of money is spent on the development of offshore fields. Sometimes the amount can reach several billion US dollars.

The most effective way to drill such fields is cluster directional, horizontal and multilateral drilling of wells with a large deviation of the wellbore from the vertical with the possibility of covering the entire area of the field.

The Pechora Sea is a natural reference for the Arctic water area, which is under the threat of rapid and possibly irreversible environmental changes as a result of human activities, large-scale prospecting, exploration, oil and gas production both in its water area and on adjacent land. The Pechora Sea lies on the continuation of the Timan-Pechora oil and gas province with a high density of initial total hydrocarbon reserves.

The study of the Pechora Sea deserves special attention, where the first (and so far the only) offshore oil field is being developed among the Arctic seas of the Russian Federation.

In this paper, we consider the improvement of drilling and completion technology for directional and horizontal wells in an offshore oil and gas field. Let's consider what role rotary steerable systems (RSS) and positive displacement motor (PDM) can play in well construction, and also consider the role of well completion.

2. General information about field

2.1. General information about the Pechora Sea

The Pechora Sea is the shallowest southeastern region of the Barents Sea, whose area reaches 81 263 km^2, located beyond the Arctic Circle. This coastal sea is bordered by the coast of only one government - Russia. The reservoir should be looked for on the map between two key islands called Kolguev and Vaygach. There are several bays within the Pechora Sea: Ramenka, Kolokolkova, Pakhancheskaya, Bolvanskaya, Khaipudyrskaya, Pechora. The largest formations of them are two bays - Pechora and Khaipudyr. As for the rivers, the most abundant source of fresh water is Pechora, after which the water area was named. For map, see Figure 1.

The Pechora Sea belongs to the peripheral seas of the Polar Basin, which are characterized by arctic species of flora and fauna. There is a complex dynamic of waters with the presence of various kinds of turbulent formations, ascending and descending flows of water and frontal zones formed as a result of mixing of river waters and sea waters of Atlantic and Arctic origin. With a relatively poor diversity, the productivity of the Pechora Sea is quite high, and its commercial biological resources have significant fishery potential in comparison with other Arctic seas.

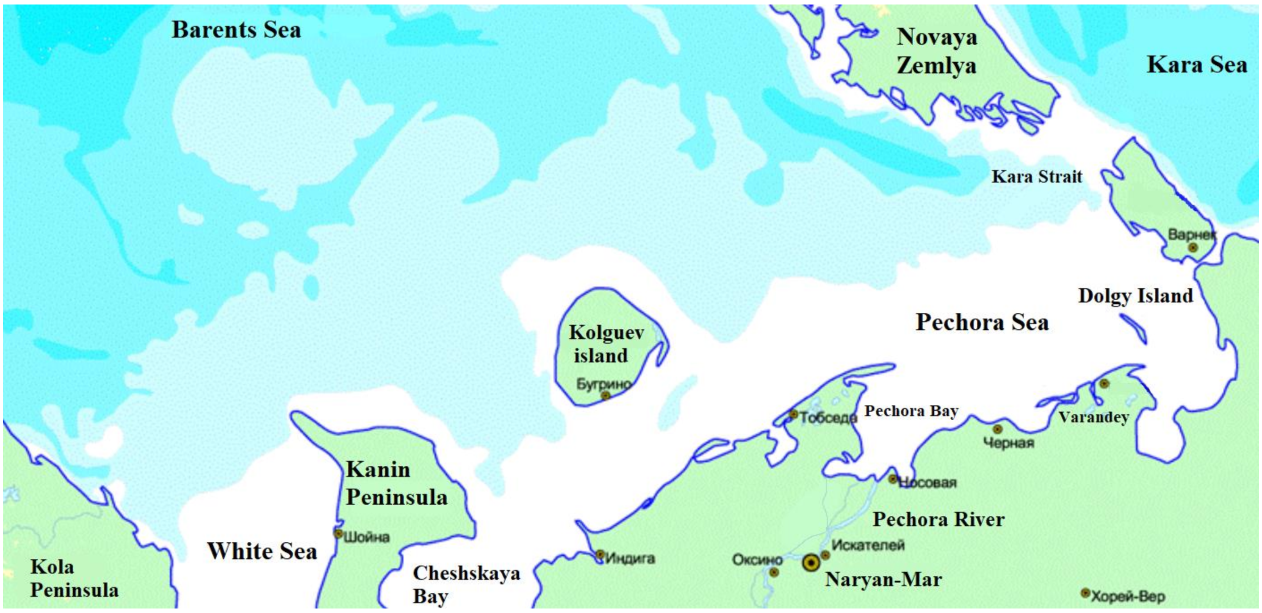


Figure 2.1 - Pechora Sea on the map

The natural and climatic conditions of the Pechora Sea, like the entire Barents Sea, are largely determined not only by its high-latitude position, but also by the warming influence of the North Atlantic and air masses coming from temperate latitudes. Their interaction initiates a large variability of meteorological parameters throughout the year.

Maximum / minimum air temperatures:

The thermal regime significantly depends on the season and circulation processes over the sea - in winter the air temperature over the sea is higher than over land. The maximum air temperatures in the summer months can reach values of plus 30–32 ℃; minimum - minus 42–43 ℃.

Air humidity:

Air humidity has relatively weak spatial and temporal variability. Seasonal fluctuations are weakly expressed, and monthly average values range from 83–89%. In the cold period, precipitation in the form of snow predominates, in the warm period - in the form of rain, in October - mixed precipitation.

Maximum wind speed:

The highest wind speed is in November-December, the lowest in August. The maximum speed along the coast can reach values of 35–40 m/s, and in gusts and more than 40 m/s, especially in the winter months.

Temperature:

In July-August the temperature of the surface water layer rises everywhere, the isotherms acquire an orientation close to latitudinal. The water temperature on the surface reaches a maximum of 8-9 ℃. In some years, the maximum summer surface temperature in the Pechora Sea reaches 15 ℃. In winter, the characteristic values of sea water temperature vary in the range from minus 1.8 ℃ to 0 ℃, in spring - from 0 ℃ to plus 4 ℃, in summer - from 5 ℃ to 8 ℃ and in autumn - from 2 ℃ to 4 ℃. The maximum water warming is noted in August and in some years, it can reach 15 ℃, and in the Pechora Bay and other shallow bays - up to 22-23 ℃. During the monitoring period at the "Prirazlomnoye" license area, the temperature of the surface water layer in the summer period varied from 6 ℃ to 8 ℃ on average. [2]

Salinity:

The distribution of salinity in the Pechora Sea is determined by the influx of Atlantic waters, the system of currents, the bottom topography, the processes of formation and melting of ice, river runoff and mixing of waters. As a result, the waters of the Pechora Sea are more freshened than the waters of the Barents Sea, the salinity of which is close to oceanic.

In winter, the salinity of the sea is quite high - 32.5-33.0 ‰, since at this time intensive ice formation occurs, the highest salinity values are observed in April - up to 34 ‰. In summer, in the Pechora Sea, salinity decreases to values less than 32 ‰, in the south of the sea - to 20-25 ‰. Such a decrease in the salinity of the Pechora Sea can be explained for its northern part both by a general summer decrease in salinity and by a significant influx of highly desalinated waters of the Kara Sea with the Litke current, and for the southern part - by the flood runoff of the river Pechora. In the bottom layer in most of the sea area, the salinity of the water is about 35 ‰. In shallow southeastern regions, water salinity drops to 28-33 ‰ or less.

In autumn, with the onset of ice formation and due to a decrease in continental runoff, the salinity of the water increases and reaches winter values by the end of the season.

Current:

The entire spectrum of sea water movements is represented in the system of currents in the Pechora Sea (Figure 2): quasi-stationary circulation, synoptic-scale currents, and tidal currents. Quasi-stationary currents are represented by the Kaninsky, Kolguevo-Pechorsky, Pechora currents and the Litke current flowing from the Kara Sea and spreading along the western coast of Novaya Zemlya. Their speed is low and usually does not exceed 20 cm/s. The tides are semi - diurnal or irregular diurnal and create a complex picture of currents.

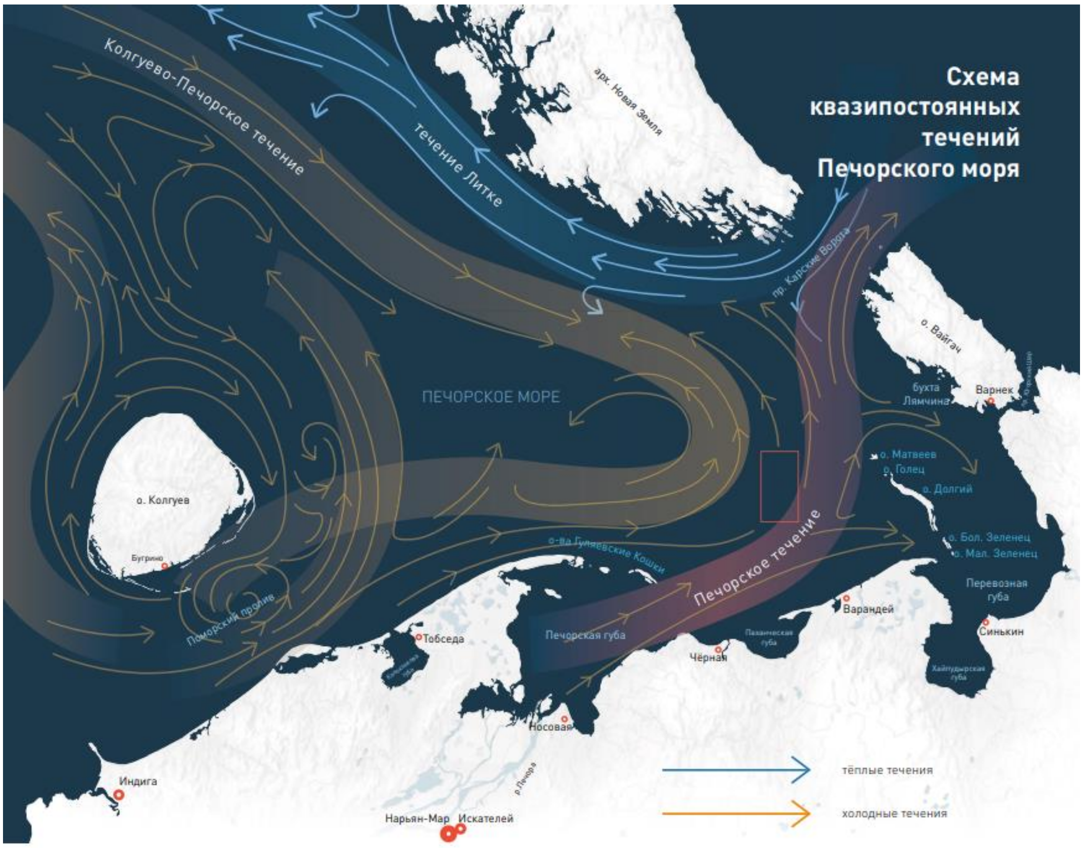


Figure 2.2 - Scheme of quasi-permanent currents of the Pechora Sea

- warm currents
- cold currents

Wave conditions:

The shape of the coastline has a significant effect on the wave regime. The area is completely protected from the north, east and south, the water depth is relatively shallow. The highest waves have a northwest direction, and the intensity of the waves decreases from west to east. The stormy season usually begins in October and at depths of 20-30 m in October-November can cause waves up to 12 m high. As a rule, waves with an average height of 2-3 m prevail. The presence of sea ice completely determines the wave regime in the winter and spring months. In summer, a calm surface prevails, and very rarely wave heights exceed 3-4 m.

The table shows the values of the parameters of the calculated wave of different repeatability and security.

Table 2.1 - Parameters of the calculated wave in the Pechora Sea

Depth, m	H_s, m	$H_{1\%}$, m	λ_m, m	λ_p, m	τ_m, s	τ_p, s
R_p = 5 years						
10	4,3	6,9	7,9	9,5	75	94
15	5,1	7,3	8,1	9,7	87	111
20	5,2	7,6	8,2	9,8	94	123
25	5,3	7,8	8,3	10,0	100	133
50	5,7	8,4	8,6	10,3	114	159
R_p = 50 years						
10	6,1	8,4	8,7	10,4	84	105
15	6,4	9,1	8,9	10,7	98	124
20	6,5	9,4	9,0	10,8	108	138
25	6,7	9,7	9,1	10,9	116	150
50	7,1	10,5	9,4	11,2	135	185

Where:

H_s – the height of a significant wave in the calculated storm;

$H_{1\%}$ – the wave height of 1% is provided;

τ_m – the mean wave period;

τ_p – the peak wave period;

λ_m – the wavelength corresponding to τ_m;

λ_p – the wavelength corresponding to τ_p;

Ice conditions:

Ice is one of the most important factors determining the safety of construction and operation of offshore structures.

The main factors determining the ice regime of the Pechora Sea are:

- geographical position;
- the nature of atmospheric processes in the autumn-winter period;
- morphometric conditions of the coastal zone;
- ice exchange with the surrounding seas;
- river runoff.

The ice regime is formed under the influence of the Atlantic and Arctic Oceans, therefore, one of the main factors determining the state of the ice cover is the variability of weather conditions in the autumn, winter and spring periods, as well as the heat transfer of water from different parts of the Barents Sea.

Ice formation begins at the end of September, in October the amount of ice begins to increase rapidly, because:

• the removal of ice from the Arctic basin is increasing;

• extensive coastal zone, shallow water;

• runoff of cooled fresh waters from the mainland, bringing cold waters of the Kara Sea.

Ice covers the sea in winter and melts in summer. The ice cover of the Pechora Sea consists of first-year ice of various thicknesses: thin (30-70 cm) and thick (120-200 cm) ice. The thin ice dominates in the Pechora Sea during December-April. Thick ice appears in March in the northern part of the sea and spreads along the coastline. Only in late June - early July, thick one-year ice recedes to the east due to the melting and weakening of the ice supply of the Novaya Zemlya ice massif. The sea ice cover varies considerably from season to season. Fast ice begins to form in the northeastern part of the sea and, apparently, along the coast of Novaya Zemlya gradually spread to the southern and western regions of the sea. The greatest ridging of the ice cover of the Pechora Sea is observed at the end of the winter season. The maximum ridging is observed in April, reaching 4–5 points.

The height of ridging on first-year ice varies from 144 to 185 cm. In exceptional cases it can reach 6–8 m, and even 12–13 m. Zones of increased ridging are in the extreme southeastern part of the Pechora Sea and in the area of the deposit itself. During the winter season, ridging of the ice cover in the southeast increases. With the development of processes of melting and destruction of ice, the area of ridging ice begins to decrease.

Information on ice conditions in the sea is provided by the position of the boundaries of ice propagation, from which it follows that during the ice period the zone of drifting ice in the sea extends from north to south and from west to east. The ice concentration at the edge decreases due to the thawing of thinner ice. The maximum ice coverage (the ratio of the area occupied by ice of any concentration to the total sea area in %) falls on April-May, and the minimum - in September. The duration of the formation of the ice cover is 7 months - from October to April, the period of destruction is 5 months - from May to September.

Varandey Oil Export Terminal (VOET) began operating in 2008. The main task is the year-round oil transfer produced in the Timan-Pechora oil and gas province. The design capacity of the terminal is 12 million tons per year. Located in the Arctic Circle, in the village of Varandey in the Pechora Sea. This is a unique facility equipped with a stationary offshore ice-resistant offloading berth.

The uniqueness of the Varandey terminal is primarily due to natural conditions - the Barents Sea is covered with ice on average 247 days a year, while the ice thickness reaches 125-180 cm. The shallow coastal zone does not allow building a shipping terminal on the coast. Therefore, to load large-capacity tankers with a deadweight of up to 70 thousand tons, a fixed offshore ice-resistant off-loading terminal (FOIROT) was built at a distance of 22 km from the coast. See map on the figure.

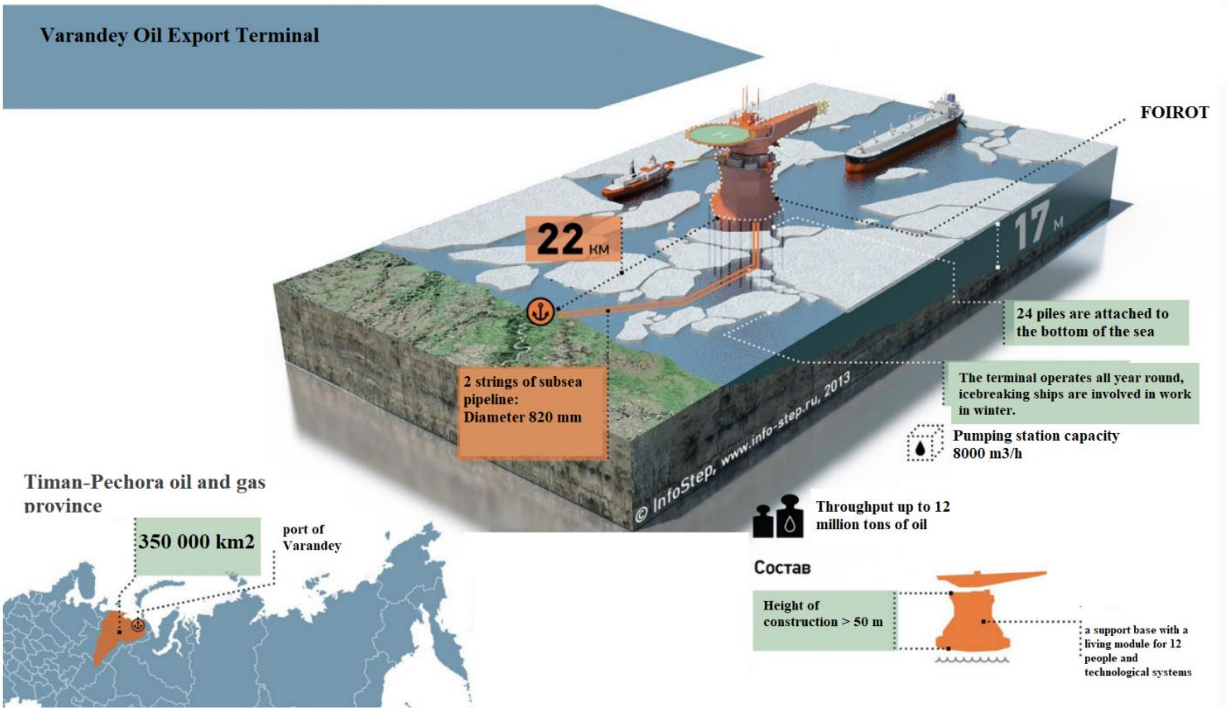


Figure 2.3 - Varandey Oil Export Terminal

FOIROT is a structure with a height of more than 50 meters with a total weight of over 11 thousand tons. It consists of two parts - a support base with a living module for 12 people and technological systems. Oil is loaded into the bow of the tanker from the mooring- cargo-handling equipment using a flexible hose. The Varandey terminal is listed in the Guinness Book of Records as the northernmost year-round operating oil terminal in the world.

FOIROT works on the principle of zero discharge: all industrial and household waste is collected in special containers and taken to the shore for subsequent disposal. In addition to the berth, the Varandey terminal complex includes an offshore tank farm (OTF) and two streams of an underwater oil pipeline with a diameter of 820 mm and a length of 22 km. The total capacity of the onshore tank farm is 325 thousand m^3. The terminal is built on permafrost. All tanks are double walled to avoid oil spills.

In 2011, the Prirazlomnaya offshore ice-resistant fixed platform (OIFP) was installed in the same area. As a result of earlier surveys, it was established that this area is characterized by difficult hydrometeorological and ice conditions due to its high dynamism and a certain physical and geographical position. The study of ice dynamics is especially important in the area of the Prirazlomnaya OIFP. Here the combined action of surge and drift currents leads to an increase in ice concentration and ridging in the area of the platform installation.

Hummocked ice blocks the approaches of transport vessels (tankers) for loading; In some periods, ice accumulations form on the approaches to the platform (right at the wall), up to the formation of stamukhas (at a depth of 20 m). The study of the ice regime of the water area, the dynamics of the waters, as well as the possibility of forecasting the situation is a prerequisite for the creation of ice management to ensure the smooth operation of the fleet serving the platform and the functioning of the platform itself. The octagonal shape of the Varandey FOIROT and its location facilitates the solution of operational issues related to ice conditions. For this object, the main problem is the erosion of the bottom in the area of the construction.

The first appearance of ice in the Varandey region occurs mainly on October 24-27. The earliest ice appearance was noted on October 3, 1986 (for the entire observation period), and at the latest - on November 20, 1944. Sustainable ice formation begins on average on October 29-30. The greatest ice thickness during the winter reaches in April (on average 105-115 cm). The maximum ice thickness observed in the Varandey area is 158 cm.

Ice breakdown begins in the first half of May with the appearance of thawed patches. The average date of the first break-in was May 31, earlier cleansing was May 24, 1943 after a mild winter, and later clearing on July 31, 1946 after a harsh winter. The duration of the ice period in the port water area from the first appearance of ice to the final clearance is on average 246 days, varying from 208 days (1942/1943) to 288 days (1977/1978) [7].

Over the past 36 years, the dates of ice formation in the Varandey area have shifted by 2-4 days to the side of later dates, compared with the long-term average data. The time of fast ice destruction shifted by 5 days towards earlier dates, and the period of complete clearing of the water area of the port of that ice - by 6 days towards earlier dates. The average duration of the ice season was 241 days, 5 days less than the average long-term duration.

In freezing seas, keels of hummocky formations are the main threat to pipelines laid along the seabed. They can create both dynamic and static loads on subsea pipelines and cause damage. Dynamic loads arise during the drift of hummocked ice fields when the keels of hummocks act on the pipeline, the absorbing of which is commensurate with the depth of the sea. Static loads occur as a result of the formation of stamukhas directly above the pipeline.

To calculate ice loads on a structure, information is needed on the morphometric characteristics of the ice cover, the physical and mechanical properties of ice, and the presence of icebergs and calvings in the water area. The development and arrangement of fields located on the coast of the Arctic seas is associated with the problem of exporting oil products. Since the cheapest is the export of oil products by using remote sea terminals, it is obvious that it is necessary to build pipelines from fields, for example, Varandeyskoye, to onshore tank farms and then offshore to the shipping terminal.

The largest number of stamukhas is formed in the Pechora Bay. Stamukhas of the maximum size are formed outside the stable fast ice zone, at drift boundaries - linear, strongly shaken boundaries of the ice massif section with different velocities. The formation of such stamukhas is caused by situations of tangential drift along the coasts. For example, on the Sakhalin shelf, they are found at depths of up to 25 meters, reaching a mass of hundreds of thousands of tons. These stamukhas are the "cores" for the formation of stamukhas of the main type.

In the Pechora Sea, huge stamukhas with sizes from 400 to 1000 meters are formed at depths of 10-15 meters in the area of the Pakhtusov shoal. Their height can reach 8-10 meters. The keels of such stamukhas are buried in the ground up to 2.5 meters.

In general, in the Pechora Sea, within the Varandey-Medynsky coast, the following pattern is observed: with distance from the coast and increasing depths, the sizes of stamukhas occurring increase, while their number (frequency of encounters) decreases.

One of the most dangerous natural phenomena during the construction and operation of oil and gas production facilities is ice gouging, that is, trenches on the ground formed as a result of the movement of the bases of stamukhas and keels of huge hummocks along the sea bottom under the influence of currents.

One of the main ways of using data on ice trenches is to determine the minimum laying depth of the pipeline, at which it is protected from damage by the keels of stamukhas and large hummocks.

2.2. Prirazlomnoye field

The main interest is the Prirazlomnoye field, the only oil field being developed both on the continental shelf of the Pechora Sea, and in general in the waters of all Arctic seas of the Russian Federation.

Oil production at the field began in December 2013, its first shipping to consumers were completed in April 2014. The design peak oil production per year is estimated at 5.0 million TOE. The maximum daily production level is 20,748 cubic meters. Based on the volume of recoverable oil reserves of the Prirazlomnoye field, its planned life is estimated at 36 years

For oil production at the Prirazlomnoye field, horizontal wells have been drilled so far. The total number of wells is planned to be increased to 32 by 2023, including nineteen producing, twelve injection and one absorption wells. The length of the wells ranges from 4,132 to 8,100 m. At the same time, of the total number of wells, eleven will be drilled at outside slope with a depth of more than 6,000 m along the borehole (horizontal sections up to 1,000 m, kick-off up to 4,000 m).

The new grade of oil produced at the Prirazlomnoye field was named Arctic Oil (abbreviated as ARCO). ARCO oil has a number of features in comparison with the usual oil exported by Russia - it is relatively heavier, with a high density (about 910 kg per cubic meter), the paraffin content is low, and the sulfur content is increased. Oil of this grade is delivered to the countries of northwestern Europe, where it undergoes deep processing for the production of specialized products for the chemical, pharmaceutical and space industries, as well as for the production of tires.

PJSC Gazprom Neft developed and in 2016 launched a new scheme for delivering ARCO oil to European consumers. In the Kola Bay (Murmansk region) there is an offshore floating oil storage "Umba" with a cargo capacity of about 300,000 tons with the possibility of mooring from both sides. The storage tanker consists of seventeen oil storage tanks and is additionally equipped with a complex for its transshipment, due to which it provides separate storage of various types of oil (in addition to ARCO, the oil storage is used for transshipment of NovyPort oil produced at the Novoportovskoye field). The use of a floating oil storage facility located in the ice-free Kola Bay made it possible to reduce the duration of circular voyages of special ice-class tankers, as well as to attract a fleet of standard tankers for further sending oil to consumers. The maximum design cargo turnover of the transshipment complex is estimated at up to 15 million tons annually.

Drilling, production, storage, preparation and shipment of oil from the Prirazlomnoye field to ships is carried out within 24 hours (construction of wells and oil production - also regardless of weather conditions) using a specially built offshore ice-resistant stationary platform (OIFP) Prirazlomnaya. This is the only stationary platform in the world used for field development in ice conditions (ice remains in the station area for up to 7 months a year, the height of hummocks reaches two meters). The OIFP is located 60 km from the coastline (Varandey settlement), the depth at its location reaches 19.2 meters. When designing it, the peculiarities of conducting economic activities in the Arctic conditions (natural and climatic, ecological, ice) and compliance with stringent safety requirements were considered. "Prirazlomnaya" independently provides itself with electric and thermal energy, is designed for a year-round stay on it for up to 200 people. Shallow depths made it possible to install the platform (weight about 0.5 million tons, size - 126 by 126 m) directly on the seabed, reinforcing it with a protective safety gravel-rock berm (volume more than 45,000 cubic meters, weight about 0.12 million tons).

Initially, it was planned to build a completely new platform, and in 1995 the first sections of the Pechora project platform were laid at the Severnoye Machine-Building Enterprise. But in 1996, the project documentation was replaced, and the construction of the Prirazlomnaya platform began, which almost immediately stopped due to lack of funding. In 2002, in order to reduce the cost of the platform, it was decided to cut its upper part (drilling, living quarters and technical modules) from a decommissioned foreign drilling platform, for which the Hatton platform, built in 1984, was purchased from the Norwegian company Monitor TLP Ltd. In 2003, after being transported to the Murmansk region, the platform was divided into two parts, and its upper part - Hatton TLP - was delivered to “Sevmash”. During 2004-2005, the lower part of the Prirazlomnaya platform was constructed, and in 2006 both parts were docked, and the completion of the platform afloat began, which continued until 2010. In 2011, the platform was transported to the 35th Ship-Repair yard (Murmansk region), where its completion and a set of commissioning works were completed. By the end of this year, Prirazlomnaya was deployed at the field and fortified. The OIFP was put in commission in 2013.

2.3. General information about the drilled well

№ PH3 is a production well for the Lower Permian deposits. The purpose of construction of a production well is the production of hydrocarbons. The well is directional with a horizontal ending. The target depth of the well is 4964.0 m (2492.0 m vertically) from the rotor table.

The design duration of the drilling and cementing process is 56.2 days. (excluding preparatory work and well testing in the production string).

Drilling of well № PH3 of the Prirazlomnoye field was started on 25.07.2020 at 12:45 and ended on 11.01.2020 at 04:00. The well depth was 4670.0 m, the production string (liner) was run in the range of 3254.0 - 4664.0 m.

Table 2.2 - Basic design data for the well

№	Nomination	Meaning
1	**2**	**3**
1	Area (deposit)	Prirazlomnaya (Prirazlomnoye)
2	Numbers of wells being constructed under this project	PH3, PH8, PHS1, PHS4, PHS5
3	Location (land, sea)	Sea
4	Sea depth at the drilling point, m	19,5
5	Distance from the rotor table to the sea surface, m	42,3
6	Purpose of drilling and purpose of wells	Development drilling, production wells
7	Target horizon	Lower Perm
8	Design depth, m	
	- vertical	2492,0
	- length	4964,0
9	Number of test items:	
	- in a column	1
	- open hole	-
10	Type of well (vertical, directional, cluster)	The well is directional with a horizontal ending
11	Profile type	Five-interval
12	Drilling azimuth, deg.	160,0
13	Maximum zenith angle, deg.	83,89
14	The maximum intensity of the change in zenith angle, degrees/10 m	1,0

15	Vertical depth of the productive roof (basic) layer, m	2378,96
16	Deviation from the vertical of the point of entry into the roof of the productive (basic) formation, m	3868
17	Permissible deviation of a given point of entry into the roof of the productive formation from the design position (radius of the tolerance circle), m	50
18	Construction metal consumption, kg/m	126,74
19	Drilling method	Rotary, PDM, slide
20	Drive type	Diesel-electric
21	Mounting type	Movement
22	Rig type	OIRFP "Prirazlomnaya"
23	Derick type	InDrill International LLC, ODE1600 NLC
24	Availability of TSA mechanisms (yes, no)	Yes
25	Test setup type	InDrill International LLC, ODE1600 NLC
26	Maximum weight of the column, t:	
	- casing	256,8 / 209,3
	- drilling string (BHA)	205,8
27	Duration of the well construction cycle, days including:	72,00
	- construction and installation works	*
	- preparatory work for drilling	1,80
	- drilling	33,45
	- cementing	22,74
	- testing, including.:	14,00
	- open hole	-
	- production casing	14,00
28	Commercial rate	2651,00

During the well construction period, the following stages of work were performed:

1. drilling with a bit Ø584.2 mm of a section of the well to a depth of 557.0 m. Well logging complex. Lowering and cementing with a surface casing Ø473.1 mm in the interval 0 - 554.0 m;

2. drilling with a bit Ø444.5 mm of the well section to a depth of 2249.0 m. Lowering and cementing with an intermediate column Ø339.7 mm in the interval 0 - 2246.0 m;
3. drilling with a bit Ø311.1 mm of the well section to a depth of 3354.0 m. Lowering and cementing with a production-intermediate string Ø244.5 mm in the interval 0 - 3351.0 m;
4. drilling with a bit Ø219.1 mm of a section of the well to a depth of 4670.0 m. Well logging complex. Running the production casing well Ø168.3 mm in the interval 3254.0 - 4664.0 m;
5. well completion operations, including activation of casing packers and inflow control devices, running of the upper well completion assembly and wireline operations.

3. Geological structure of the field

Well №PH3 is located on the Prirazlomnaya offshore ice-resistant stationary platform (hereinafter referred to as OIRFP) of the Prirazlomnoye oil field, which is located on the shelf of the Pechora Sea. An overview map of the work area is shown in fig. 3.1.

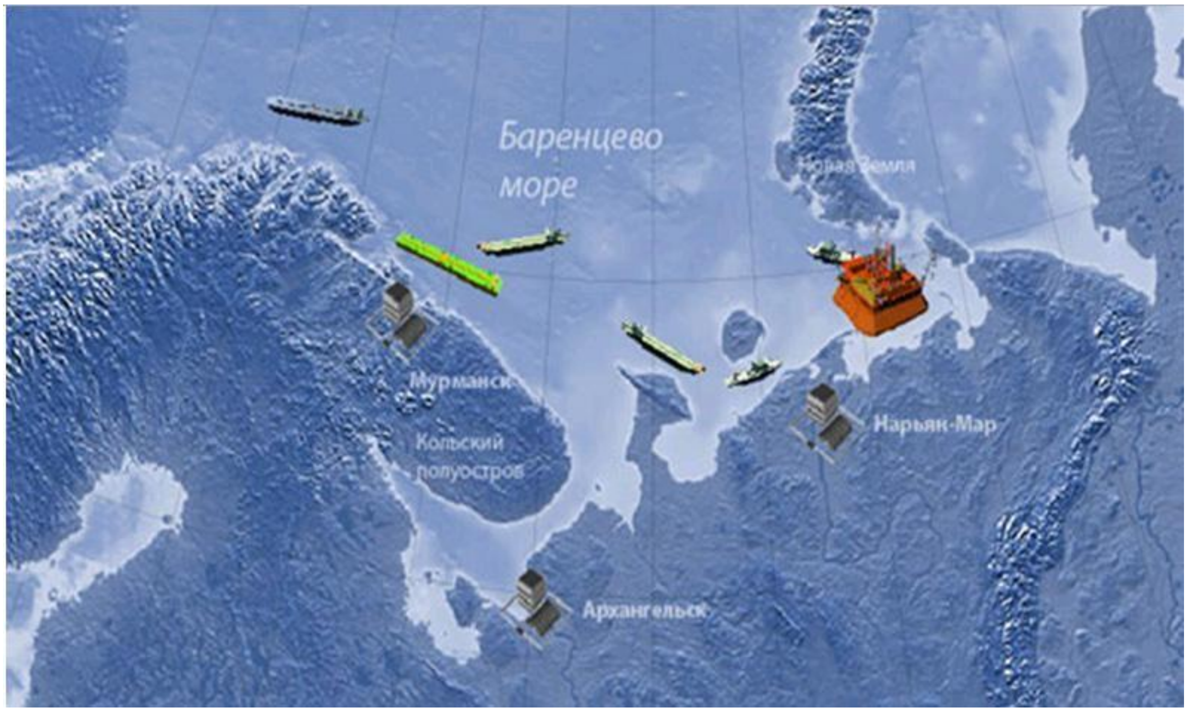


Figure 3.1 - Overview map of the work area

In tectonic terms, the Prirazlomnaya geological structure refers to the offshore continuation of the Sorokin Shaft, located in the Pechora Sea. It is a two-domed northwest-trending anticline fold, the southwestern flank of which is complicated by a tectonic fault of the northwest-trending reverse fault type with an amplitude of 50.0–150.0 m.

The Prirazlomnoye oil field is located in the Pechora Sea, 55.0 km northwest of the coastal village of Varandey, 250.0 km from the Naryan-Mar river port and 980.0 km from the seaport of Murmansk.

The field was discovered by Arktikmorneftegazrazvedka in 1989 with a prospecting well №1 with a depth of 3100.0 m, drilled in the crest of the fold. 5 exploratory wells were drilled, of which 4 opened productive deposits, and one, not reaching the top of the productive stratum, was liquidated for technical reasons.

Three productive horizons are distinguished in the section of the oil deposit: Horizon I is the Lower Permian (Ia, Ib1, Ib2 and Ic), Horizon II is the Lower Permian-Upper Carboniferous, Horizon III is the Middle Carboniferous.

During the construction of a well, almost throughout the entire section, it is possible to partially absorb the drilling fluid, slough, packing, sticking and jamming of the drill string.

In the intervals of occurrence of oil-bearing formations, oil and gas shows are possible in case of violation of the drilling technology.

The well survey was carried out by sampling cuttings every 5.0 m, and in the interval of occurrence of oil-bearing formations - every 2.0 m. Sampling, description and packaging operations were performed by the personnel of the mud logging station.

The design lithological and stratigraphic characteristics of the section are presented in table 3.1.

Table 3.1 - The design lithological and stratigraphic characteristics of the section

Stratigraphy				**CDP**	**Project well №PH3 expected depths**			**Lithology**	**porosity %**	**Perm coef, mD**	**Coef. cavernousness**
System	**group**	**Stage**	**Layer**		**Length, from the rotor, m**	**TVDSS, m**	**Vertical, from the rotor, m**				
Quaternary - Neogene				J2_K	62,27	-19,7	62,3	Clays, loams, gravel, pebbles, quartz			1,5
Cretaceous - K	Lower - K1	Aptian + Albian K1a+al			168	-125	168	Clays, sands, siltstones, calcareous sandstones, pyrite			1,5
		Neocomian			301	-258	301	Clays, sands, siltstones			1,5
Jurassic - J	Upper J3	Volzhsky - J3v			392	-349	392	Clays, sands, siltstones, sapropelic at the base mudstone, pyrite			1,3
		Kimeridge - J3km			511	-461	504	Clays dark gray			1,3
		Oxford - J3o			527	-476	519	Quartz sandstones, interlayers of siltstones and clays			1,3
	Middle J2	Bathan + Callovian -J2bt-J3k		T_g3	563	-508	551	Silty clays, mudstones, interlayers quartz siltstones and fine-grained sandstones, rarely pebbles			1,3

		Aalenian + Bajocian - J2a-b			807	-691	734	Sands, quartz and polymictic sandstones, clay interbeds, carbonaceous, gravel and pebbles of white quartz and siliceous rocks			1,3
Triassic - T	Upper T3	Carnian + Norian - T2n+k			963	-770	813	Silty clay, siltstones, below medium-coarse sandstones granular, pyrite			1,1
	Medium T2	Ladinsky - T2l2			1236	-885	928	Clays with layers mudstones, oligomictic sandstones, siltstones, dark gray mudstones, sandstone with pebbles at the base siliceous rocks.			1,1
			T5	T_g7	1474	-1005	1048				
		Ladinsky - T2l1	F6		1898	-1370	1413	Clay gray plastic, argillite-like in places, rare interlayers of siltstones			1,1
			T6	T_g8	1928	-1400	1443	Siltstones, sandstones polymictic, rare interbeds of mudstones.	18	15	1,1
			F7_1	T_g10	1998	-1469	1512	Mudstones with siltstone interlayers			1,1
			F7_2		2017	-1488	1531				
			T7	T_g11	2056	-1527	1570	The sandstone is polymictic, fine-medium grained	16	10	1,1
			F8	T_g12	2116	-1587	1630	Argillite greenish-gray comminuted			1,1

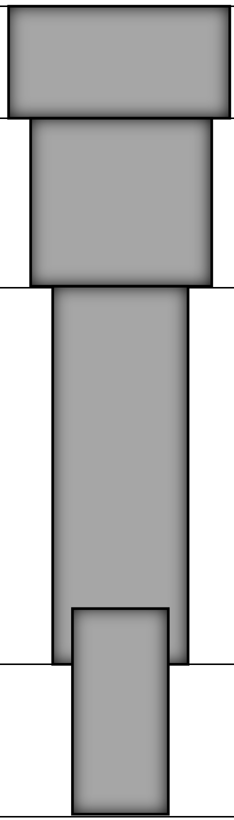
		Anisian T2a	F9		2268	-1739	1782	Clays and mudstones, coal inclusions			1,1
			F9					Clays, mudstones, fine-grained sandstones			1,1
	Lower T1	Oleneksky - T1o2						Clays, mudstones, fine-grained sandstones polymictic, pebbles			1,1
		Oleneksky - T1o1						Silty clays, mudstones, sandstones fine-medium-grained, unevenly oil-saturated, interlayers in the sole conglomerates			1,1

4. Development of the design and well path

1. The lowering of the surface caasing 473.1 mm is provided for the purpose of strengthening the wellhead from erosion in the area of the direction shoe, overlapping unstable Lower Cretaceous and partially Jurassic deposits prone to collapses, screes and losses.
2. Lowering of an intermediate column of 339.7 mm is provided for the purpose of isolating zones that are incompatible according to the drilling conditions.
3. Lowering of the production string 244.5 mm is provided for the purpose of isolating the productive horizons from other rocks and extracting oil from the well.
4. Lowering of the liner 168.3 mm is planned for the purpose of separate exploitation of the reservoirs, as well as to ensure better control over oil production.

4.1. Well design

Table 4.1 - Well design

Column size (mm)	Wellbore diameter (mm)	Well design	Interval (in length), m	Interval of cementing, (in length), m
473,1 x 11,05	584,2		0 – 554	To the well head
339,7 x 10,92	444,5		0 – 2246	To the well head
244,5 x 11,05	311,2		0 – 3351	To the well head
168,3 x 8,94	219,1		3254 – 4664	3254 – 4664

4.2. Well path

Building a profile:

1.Vertical section

Vertical depth

$$H_1 = L_1 = 20\ m.$$

2. Section of angle buildup

The section of the zenith angle set must ensure the patency of the drilling equipment.

Zenith angle at the beginning of the interval $\theta_1 = 0^o$;

Zenith angle at the end of the interval $\theta_1 = 46^o$;

Radius of curvature $R_2 = 1848\ m$;

Vertical depth

$$\mathrm{H}_2 = H_1 + R_2 \cdot (\sin(\theta_2) - \sin(\theta_1)) = 20 + 1848 \cdot (\sin(46) - \sin(0)) = 1208\ m;$$

Departure from the vertical

$$A_2 = R_2 \cdot (\cos(\theta_1) - \cos(\theta_2)) = 1848 \cdot (\cos(0) - \cos(46)) = 432\ m;$$

Measured depth

$$L_2 = L_1 + \pi \cdot R_2 \cdot \frac{\theta_2 - \theta_1}{180^o} = 20 + \pi \cdot 1848 \cdot \frac{46^o - 0^o}{180^o} = 1310\ m.$$

3. Stabilization section

Vertical depth $H_3 = 1500\ m$;

Departure from the vertical

$$A_3 = A_2 + (H_3 - H_2) \cdot \tan(\theta_2) = 432 + (1500 - 1208) \cdot \tan(46^o) = 677\ m;$$

Measured depth

$$L_3 = L_2 + (H_3 - H_2)/\cos(\theta_2) = 1310 + (1500 - 1208)/\cos(46^o) = 1691\ m;$$

4. Section of angle buildup

Zenith angle at the beginning of the interval $\theta_1 = 46^o$;

Zenith angle at the end of the interval $\theta_1 = 87^o$;

Radius of curvature $R_2 = 2640\ m$;

Vertical depth

$$\mathrm{H}_4 = H_3 + R_4 \cdot (\sin(\theta_3) - \sin(\theta_4)) = 1500 + 2640 \cdot (\sin(87) - \sin(46)) = 2442\ m;$$

Departure from the vertical

$$A_4 = A_3 + R_4 \cdot (\cos(\theta_3) - \cos(4)) = 677 + 2640 \cdot (\cos(46) - \cos(87)) = 2608\ m;$$

Measured depth

$$L_4 = L_3 + \pi \cdot R_2 \cdot \frac{\theta_4 - \theta_3}{180^o} = 1691 + \pi \cdot 2640 \cdot \frac{87^o - 46^o}{180^o} = 3908\ m.$$

5. Section of dropdown inclination

Zenith angle at the beginning of the interval $\theta_1 = 87^o$;

Zenith angle at the end of the interval $\theta_1 = 71^o$;

Radius of curvature $R_2 = 1146\ m$;

Vertical depth

$$\mathrm{H}_5 = H_4 + R_5 \cdot (\sin(\theta_4) - \sin(\theta_5)) = 2442 + 1146 \cdot (\sin(87) - \sin(71)) = 2511\ m;$$

Departure from the vertical

$$A_5 = A_4 + R_5 \cdot (\cos(\theta_5) - \cos(\theta_4)) = 2608 + 1146 \cdot (\cos(71) - \cos(87)) = 3449\ m;$$

Measured depth

$$L_4 = L_3 + \pi \cdot R_5 \cdot \frac{\theta_4 - \theta_5}{180^o} = 3908 + \pi \cdot 1146 \cdot \frac{87^o - 71^o}{180^o} = 4670\ m.$$

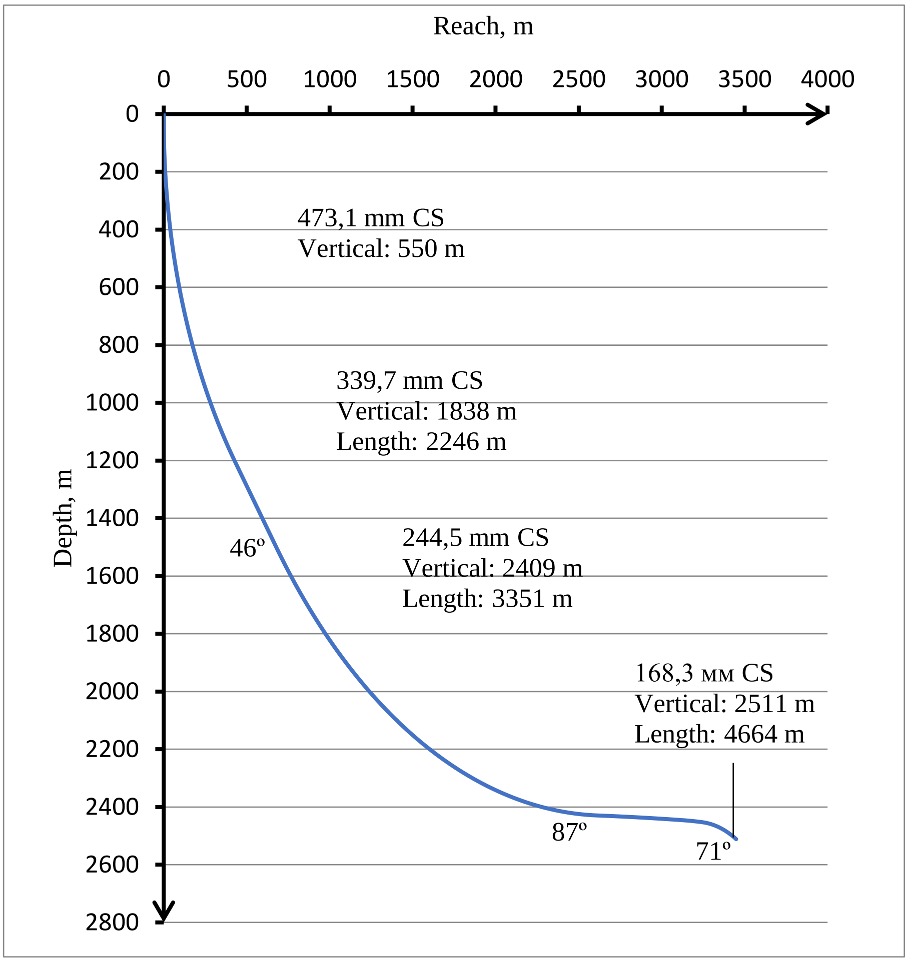


Figure 4.1 - Actual well path

The actual well path is tabulated in Table 4.2.

Table 4.2 - Actual wellbore profile in tabular form

Measured depth,m	**Zenith angle, deg**	**Azimuth, deg**	**Vertical depth, m**	**Intensity, deg/30 m**	**Casing string**
100	0	37,13	100	0,5	
300	6,76	295,93	300	1,5	
554	9,05	290,72	550	1,0	CS 473,1 мм
748	17,95	300,59	739	1,5	
1073	33,16	307,95	1028	2,0	
1397	46,03	306,63	1269	1,7	
1782	46,04	308,61	1489	0,4	
2246	46,04	307,39	1838	0,2	CS 339,7 мм
2630	50,45	311,8	2109	1,5	
3000	61,61	312,71	2301	1,5	
3351	77,92	318,18	2409	1,5	CS 244,5 мм
3802	87,3	323,01	2439	0,5	
4421	85,32	322,84	2470	0,5	
4664	71	319,0	2511	3,0	CS 168,3 мм

5. The choice of the composition and properties of the drilling fluid

Surface casing

The values of the design and actual parameters of drilling fluids for surface drilling are given in Table 5.1. The project documentation provides for drilling of the entire interval using KLA-SHILD water-based drilling fluid. The actual drilling of the interval was carried out by flushing with Primosol HP drilling fluid. The parameters of the applied solution basically correspond to the design data.

Intermediate casing

The values of the design and actual parameters of drilling fluids when drilling for an intermediate string are given in Table 5.2. The design documentation provides for drilling of the entire interval using MEGADRIL drilling mud. The actual drilling of the interval was carried out with a "UNIDRIL" oil-based drilling fluid.

The parameters of the drilling fluid used generally corresponded to the design ones, with the exception of the density, the values of which exceeded the design ones. The inhibitory qualities of the mud and its rheological characteristics did not fully ensure the safety of the wellbore, which required an increase in the density of the drilling mud. But even with an increased density of the drilling fluid in the process of tripping operations of the drilling tool, during the descent of the CS, drag forces and slack off took place.

Production casing

The values of the design and actual parameters of drilling fluids when drilling the interval for running the production intermediate string are given in Table 5.3. The design documentation provides for drilling of the entire interval using MEGADRIL drilling mud. The actual drilling of the interval was carried out using UNIDRIL oil-based drilling fluid.

Liner casing

The values of the design and actual parameters of drilling fluids when drilling under the production string (liner) are given in Table 5.4. The design documentation provides for drilling of the entire interval using MEGADRIL mud. The actual drilling was done using UNIDRIL drilling fluid. The parameters of the applied drilling fluid corresponded to the design ones. The inhibitory qualities of the mud and its rheological characteristics fully ensured the safety of the wellbore.

Table 5.1 - Design and actual parameters of the drilling mud during surface casing drilling

Name (type) of mud	Interval, m		Drilling fluid parameters														
	from (top)	to (bottom)	density, kg/m^3	Nominal viscosity,s	Filtrate return sm^3/30 min	static shear stress, dPa, 1 min.	static shear stress, dPa, 10 nin.	filter cake, mm	solids content, % colloidal parts	solids content, % sand	solids content, % all	pH	electrical stability, V	water phase density, kg/m^3	plastic viscosity,mPa•s	dynamic shear stress, dPa	content KCI, g/l
DESIGN DATA																	
KLA-SHILD	100	678	1120	50-60	<8	48-72	58-120	<2	6	<2	8	8-9	-	-	20	80-120	100
FACTUAL DATA																	
Primosol HP	53	557	1080-1140	76-77	4,3-4,6	15-19	24-25	1,0	-	0,8	4-10	9,5-10,5	-	-	19-23	25-36	-

Table 5.2 - Design and actual parameters of the drilling mud during intermediate casing drilling

Name (type) of mud	Interval, m		Drilling fluid parameters													
						static shear stress, dPa,			solids content, %							
	from (top)	to (bottom)	density, kg/m^3	Nominal viscosity,s	Filtrate return sm^3/30 min	1 min.	10 nin.	filter cake, mm	colloidal parts	sand	all	pH	electrical stability, V	water phase density, kg/m^3	plastic viscosity,mPa•s	dynamic shear stress, dPa
DESIGN DATA																
MEGADRIL	678	2167	1180	-	<5	16-20	18-23	1	<3	<1	6	-	>300	-	20-25	90-110
FACTUAL DATA																
Oil Based Drilling Fluid "UNIDRIL"	557	2249	1400	-	2,0	12-15	22-29	0,3	-	0,1-0,6	21-26	9,0-10,5	612-720	-	37-44	15-24

Table 5.3 - Design and actual parameters of the drilling mud during production casing drilling

Name (type) of mud	**Interval, m**		**Drilling fluid parameters**													
	from (top)	**to (bottom)**	**density, kg/m^3**	**Nominal viscosity,s**	**Filtrate return $sm^3/30$ min**	**static shear stress, dPa, 1 min.**	**static shear stress, dPa, 10 nin.**	**filter cake, mm**	**solids content, %: colloidal parts**	**solids content, %: sand**	**solids content, %: all**	**pH**	**electrical stability, V**	**water phase density, kg/m3**	**plastic viscosity, mPa•s**	**dynamic shear stress, dPa**
DESIGN DATA																
MEGADRIL	2167	3967	1250	-	<5	16-20	18-23	1	<3	<1	6	-	>300	1216	20-25	90-110
FACTUAL DATA																
Oil Based Drilling Fluid "UNIDRIL"	2249	3354	1250	45-70	2,0-2,1	10-11	24-36	0,3	-	0,1-0,2	22-25	9,0-10,5	564-1010	-	36-45	8-19

Table 5.4 - Design and actual parameters of the drilling mud during liner drilling

Name (type) of mud	Interval, m		Drilling fluid parameters													
			density, kg/m³	Nominal viscosity,s	Filtrate return sm³/30 min	static shear stress, dPa,		filter cake, mm	solids content, %			pH	electrical stability, V	water phase density, kg/m³	plastic viscosity, mPa•s	dynamic shear stress, dPa
	from (top)	to (bottom)				1 min.	10 nin.		colloidal parts	sand	all					
DESIGN DATA																
MEGADRIL	3967	4964	1135	-	<5	12-15	15-20	1	<2	<1	6	-	>300	1216	15-20	80-90
FACTUAL DATA																
Oil Based Drilling Fluid "UNIDRIL"	3354	4670	1135	-	2,6-2,8	8-13	15-26	0,5	-	-	6-11	-	620-940		14-17	20-21

6. Improving the technology of drilling the interval of the well

To fulfill the task of the master's thesis, an interval was chosen for drilling a well for a production string with a diameter of 245 mm. The interval starts at a depth of 2249 m and ends at a depth of 3354 m. The total penetration is 1105 m. An increase in technical and economic indicators in this interval due to improved drilling technology will improve the efficiency of well construction at the Prirazlomnoye field.

6.1. Basic technology of drilling (RSS)

A rotary steerable system is a tool that allows the driller to constantly control the bit in the desired direction while rotating the drill string in parallel. This system is located before the bit and is designed to boost or tilt the BHA in the desired direction. This control process is usually planned and supervised by directional drilling engineer to monitor and adjust parameters throughout the drilling process.

Advanced systems are currently being produced by manufacturers such as Baker Hughes, Halliburton, Schlumberger, Rotary Steerable Tools. They differ in design, but their main principle is the use of a telemetry system rotating together with the pipe string, on which external or internal deflecting elements are installed. Internal deflecting elements are electronically controlled, synchronized with the rotation of the drill string and are in constant contact with the borehole walls or the shaft near the bit, which allows continuous control of the borehole trajectory.

In Russia, such systems are of limited use, since their maintenance requires highly qualified personnel and the use of top-drive drilling rigs. It is also worth noting that the use of RSS is expensive for drilling companies. However, drilling of some wells using RSS in the fields of Western Siberia and Sakhalin Island proved the possibility of their application in Russia.*Types of RSS*

RSS can be divided into two main types according to the method of controlling the bit displacement relative to the well axis:

1. "Push the bit" - pushing the entire assembly or most of it relative to the borehole axis, which causes pressure on the side surface of the bit in a certain direction. This type includes the systems "Auto Track" - Baker Hughes Intec, "PowerDrive" - Schlumberger, "ExpressDrill" - Noble Drilling
2. "Point the bit" - bit positioning. It is achieved by mixing the drive shaft relative to the layout, or by changing its curvature, which causes a change in the angle of attack of the bit structure. This type includes "Geo-Pilot" - SperrySun, "SmartSleeve" - Rotary Steerable Tools, "Revolution" - Weatherford.

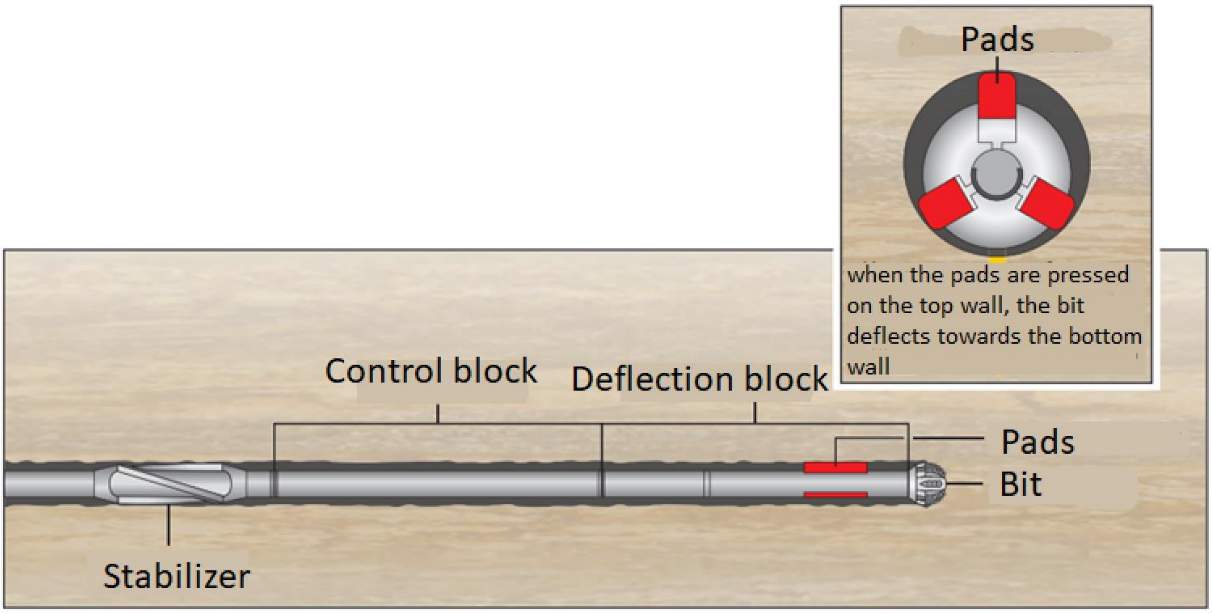


Figure 6.1 – Rotary steerable system Push the bit

Figure 6.2 - Rotary steerable system Push the bit

Manufacturers usually produce several sizes of their products.

RSS of the first type are most widely used due to their relatively simple design and reliability. In RSS "Push the bit" the mixing of the layout and the curvature of the barrel is achieved by extending the pads from the body.

Comparison of RSS and PDM applications:

When drilling with the traditional directional drilling method using a screw downhole motor, when switching from oriented drilling to drilling with a rotation of the string, an increase in the heterogeneity of the wellbore is observed. When using the RSS, the drill string is continuously rotated, which contributes to a significant reduction in the local intensity of the curvature of the wellbore - a higher quality of cleaning and preparation of the wellbore for running the casing string is achieved, as well as reducing the risk of drags and mechanical sticking.

The main, but not the only, advantage of using a RSS in comparison with a PDM in drilling is the quality of the resulting wellbore, in the absence of the need for directional drilling, in which the drill string does not rotate.

Figure 6.3 - Wellbore Quality Comparison: above – PDM, bottom – RSS

In addition, the following features should be noted, such as:

1. reduction of well construction time and cost;
2. trajectory optimization;
3. better control of load and torque on the bit. You can create optimal parameters for the bit used;
4. constant rotation of the BHA and drill string significantly reduces the risk of sticking, especially when drilling through a permeable formation;
5. nominal bore diameter. The hole diameter does not increase, as it happens when drilling in rotary mode with a PDM;
6. lower pressure drop compared to PDM;
7. possibility of application at high temperatures and pressures;
8. RSS design allows drilling the wellbore both downwards and upwards;
9. high reservoir recovery due to ERD drilling.

Also, of course, there are disadvantages:

1. high requirements for drilling mud cleaning, low content of solids and loss control materials;
2. the complexity of servicing at the rig, the need to involve the contractor's personnel;

3. introduction of additional sensors into the drilling system;
4. restrictions on drilling fluid flow and mud pumps;
5. the use of expensive bits specially designed and manufactured for such systems.

PDC drill bits increase the efficiency of rotary steerable systems (RSS) and reduce the risk of deviation from the intended trajectory, so we will use them in the layout for drilling the interval under the production string. Below we will consider in more detail what PDC bits are.

Non-supported bits include bits that consist of a monolithic body and do not have moving parts. The following types of unsupported bits are currently used:

1. diamond bits of the abrasive-cutting type with weapons made of monocrystalline natural or synthetic diamonds (single-layer) and multilayer impregnated diamond chisels of the abrasive type
2. unsupported bits of the cutting-chipping type with polycrystalline diamond-carbide cutters — Fig. 6.4.

Figure 6.4 – PDC bit

Diamond, incl. impregnated, bits have a matrix body made of hard alloy (tungsten carbide). PDC bits can have both steel and matrix casings. The shapes of the body profiles of unsupported bits can be of various configurations: flat or conical, with a cone of various lengths, incl. with a cone concave inside the bit.

Some designs of bits armed with natural diamonds are additionally equipped with heat-resistant inserts containing polycrystalline diamonds, which increase their wear resistance.

Diamond bits with a single-layer structure made of natural diamonds are used for drilling low-abrasive medium-hard and hard rocks. Impregnated diamond bits are used to destroy abrasive hard and strong rocks. Diamond bits with weapons made of natural or synthetic diamonds destroy the rock at the bottom of the well, mainly by abrasion (microcutting).

PDC bits are mainly used in drilling in non-abrasive soft, medium and medium hard formations. The body of the PDC bit consists of blades, along the contour of which round diamond-tungsten carbide cutters are reinforced. The number of blades determines the type of PDC bit designed for rocks of different hardness categories: the harder the rock, the more blades the PDC bit has.

For bits with polycrystalline diamond cutters PDC, the cutting mode of rock destruction is provided both at low and at high speeds. The most suitable for these bits is the medium speed mode - from 200 to 450 rpm. PDC bits provide high ROP, typically on par with or better than tricone bits in similar formations.

Due to the lack of rotating parts, all types of dry drill bits have a long mechanical drilling time. The full resource of a supportless bit before it reaches the limit state, determined by an unacceptable decrease in the efficiency and safety of the drilling process, can be about 300 hours.

The choice of diamond bits with natural or synthetic diamonds, including impregnated ones, is carried out provided that the initial depth the expected drilling interval is more than 2000 m, and the length of the interval is at least 250 m. PDC bits are selected regardless of the expected drilling depth. Due to these limitations, diamond bits of abrasive-cutting and abrasive types are used in small volumes, while PDC bits with polycrystalline diamond-carbide cutters have become widespread in well drilling in recent years.

6.2. New technology of drilling (RSS+PDM)

Downhole motors have their own characteristic features:

- the working body made in the form of a screw pair, consisting of a stator and a rotor, has working chambers that periodically communicate with the inlet or outlet, while the liquid under pressure periodically fills each chamber or is displaced from it;
- hydraulic forces arise in the working body as a result of the action of a pressure drop and almost do not depend on the speed of the fluid in the chambers;
- the movable part of the PDM - the rotor, performs a complex rotational movement, eccentric to the axis of the engine.

Design diagram of a positive displacement motor

The screw downhole motor consists of three main components:

power section, a transmission unit and a bearing section.

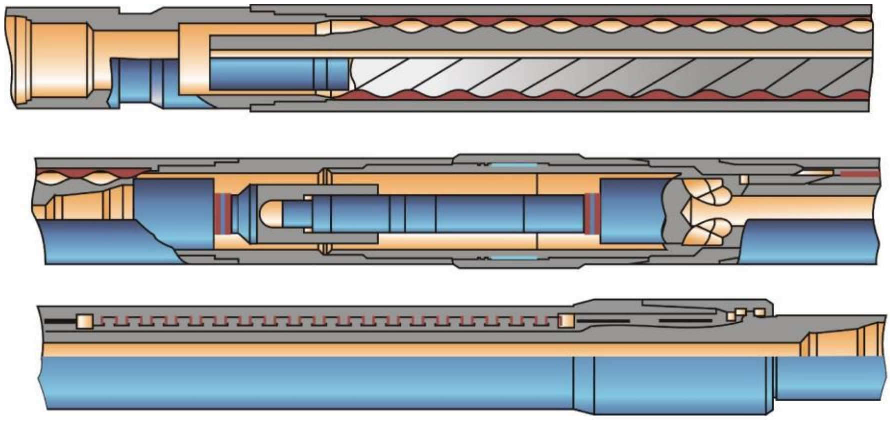


Figure 6.5 - Positive displacement motor

The power section, which is the working body of the PDM, consists of a stator and a rotor. The stator, called the outer element, is a fixed body part of the power section. It has a steel tubular body and an elastic lining made of rubber with an internal helical surface.

The rotor, called the inner element, is the rotating part of the screw pair. It is a steel screw with a wear-resistant working surface. In general, power section of the PDM is a helical pair of internal cycloidal gearing, consisting of a gear stator and a gear rotor, and the rotor has external lobes, one fewer than the stator. This condition is essential for the operation of the PDM.

The bearing section of the motor is placed in a separate section - the shaft. A multistage axial bearing is installed in the shaft section, through which the load on the bit is transmitted. In the shafts of the PDM, mainly ball tracks are used, but rubber-metal sleeve bearing can also be used. The MTBF of the axle bearings is on average 200-250 h. The use of modern axle bearings with elements made of PDC material significantly increases the service life of the PDM shafts.

During the operation of the PDM, the screw pair generates a torque that is transmitted to the rotor of the engine. Due to the peculiarity of the screw pair, the rotor performs an eccentric rotational movement around the stator axis. To transform the eccentric rotation of the rotor into concentric rotation of the shaft, the lower end of which is connected to the bit, a special gear mechanism is used - flex shaft, in the form of a swivel joint. In PDMs designed to change the angle of inclination of the well, the body part of the flex shaft is used to install the bent sub.

In addition to the main units, special valve devices are used as part of the design of the PDM, without which the operation of PDM in the well is practically impossible. The excess flow valve is installed above the PDM housing. In the open position, the excess flow valve connects the inner cavity of the drill string with the annular space of the well, and in the closed position, with the power section of the PDM. The excess flow valve is designed for filling and emptying the drill string with drilling fluid during tripping operations. When the engine is running, the drilling fluid from the well enters the excess flow valve and fills the drill string, bypassing the internal PDM mechanisms. This protects the power section of the engine from unnecessary rotation of the rotor and sludging. When lifting, the use of the valve eliminates uncontrolled spillage of drilling fluid at the drill site. The back valve, which is also installed above the PDM body, serves as a safety assembly in case of unreliable operation of the excess flow valve and to prevent gas-oil-water shows through the drill pipes.

When the PDM is operating with simultaneous rotation of the drilling string, the bit rotation speed can be determined by the formula:

$$n = (n_{idle} + n_d)\left[1 - \left(\frac{M}{M_T}\right)^{\alpha}\right], \quad (6.1)$$

Where

n - rate of rotation;

n_{idle} – idler frequency

n_d - rate of rotation of drill string with help of rotor or top drive;

M_T - braking torque (from catalog);

M – torsion torque

α - exponent characterizing the nonlinearity of the dependence n(M)

The operation of a screw downhole motor in the mode of constant rotation of the drill string is a complex production process. Recently, this technology has been widely used for drilling deviated and horizontal wells with constant control of curvature parameters using MWD downhole telemetry systems. It allows to ensure high-quality drilling of all sections of a directional well with bringing the bottomhole to the design depth without lifting the PDM and the bit to the surface - fig. 5.3.

In this case, a short screw motor is used with a curved sub having a small angle of misalignment of the axes. In the process of drilling a vertical or oblique-rectilinear interval of stabilization of the zenith angle, the drilling assembly slowly rotates with the help of a rotor or top drive. If it is necessary to change the angle of inclination of the well, the rotation of the assembly is stopped, the downhole motor is set in the desired azimuthal direction, and drilling continues with a non-rotating drill string until the required value of the zenith angle is reached. This mode of drilling is called "sliding".

If the next is a directional or vertical interval, then the drill string is again driven into rotation. The whole process is carried out under the control of the operator using a downhole telesystem. The “sliding” technology allows not only high-quality drilling of an inclined well, but also a significant increase in the technical and economic indicators of drilling by reducing the time of tripping operations.

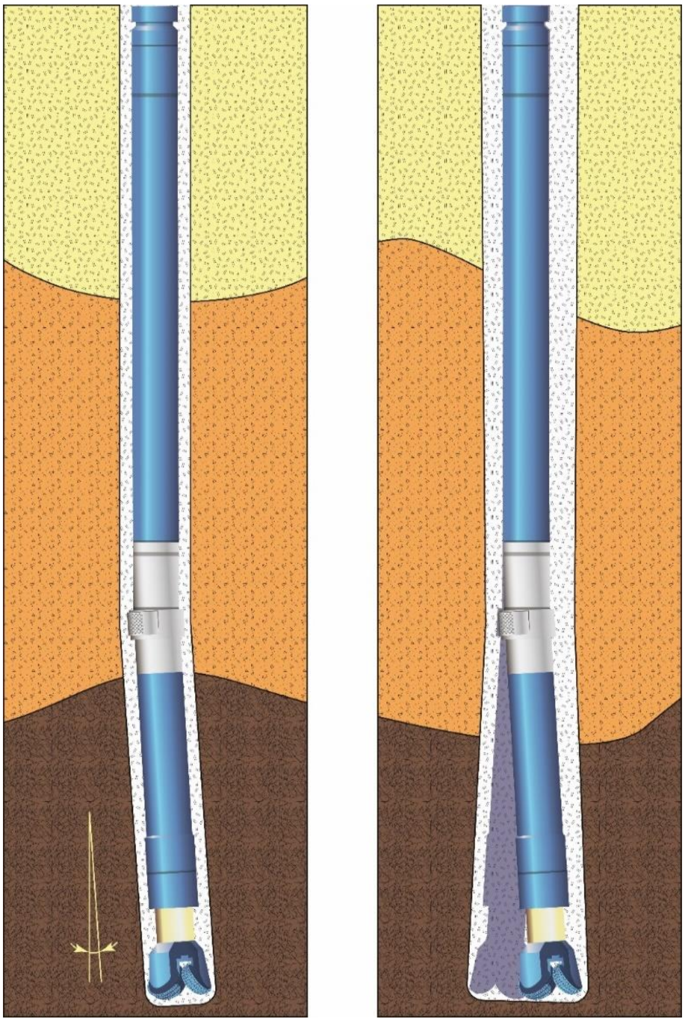


Figure 6.6 - Drilling technology "sliding" of the drilling tool

The rotation of the drill string during the operation of the PDM in an inclined well has a number of technological advantages:

- the friction forces of the drill string in the wellbore are reduced;
- increases the mechanical speed of penetration;
- better cleaning of the wellbore from cuttings is provided.

However, as a result of rotation, the loads on the design of the PDM also increase. This can be critical when high skew angles are installed on the PDM, especially in areas of excessive wellbore curvature. Intensive rotation of the drill string under adverse conditions can lead to rapid wear of the rotor and stator, excessive load and wear of the radial spindle bearings, heating of the PDM body due to friction against the borehole wall, increased fatigue of the engine components due to alternating load. The catalogs of PDM manufacturers contain special tables with the technical characteristics of the downhole motor and the limiting values of the curvature build-up intensity, calculated based on the angle of misalignment, the diameter of the wellbore and installed stabilizers.

6.3. Comparative technical and economic analysis

Table 6.1 – Input Data

№№	Activities	Designations	Unit of measurement	Value
1	Depth of drilling	L	m	3354
2	Depth of occurrence of the sole of a weak formation	L_f	m	3000
3	Hydraulic fracturing pressure	P_f	MPa	40
4	The depth of the cap of the fluid-containing formation	L_c	m	2379
5	Reservoir fluid	-	-	oil
6	Formation pressure	P_r	MPa	27,8
7	Drilling mud properties:			
8	- density	ρ	$\frac{kg}{m^3}$	1250
9	- plastic viscosity	η	$Pa * s$	0,025
10	- dynamic shear stress	τ_0	Pa	12
11	Drilling pump	-	-	UNBT-950A
12	Dimensions of the ground binding:	-		
13	conditional size of the standpipe	-	mm	168
14	diameter of the bore channel of the drill hose	-	mm	76
15	diameter of the bore channel of the swivel	-	mm	90
16	diameter of the bore channel of the kelly	-	mm	100
17	The minimum velocity of the liquid in the annular space, ensuring the removal of cuttings	V_c	$\frac{m}{s}$	0,6

18	Minimum outer diameter of pipes in BHA	d_{out}	m	0,149
19	Drilling interval	ΔL	m	2249-3354
20	Average time of one tripping operation	t_t	h	12
21	Cost of an hour of drilling rig work	R	$\frac{doll}{h}$	985
22	**Data from Well №1**			
23	Drive type	-	-	Rotor (RSS)
24	HDM type	-	-	-
25	The cost of an hour of work RSS	R_{RSS}	$\frac{doll}{h}$	704
21	Mud flow-rate	Q_0	$\frac{m^3}{s}$	0,0466
22	Thrust load	G	kN	80
23	Rotor speed (top drive)	n	$\frac{\text{rev}}{\text{min}}$	180
24	Bit size	-	mm	311,2
25	Bit cost	C_b	doll	19 718
26	Footage per run	h_d	m	1105
27	Time of drilling	t	h	90
28	**Data from Well №2**			
29	Drive type	-	-	Rotor + HDM
30	HDM type	-	-	PDM GT-240-3/4
31	The cost of an hour of work PDM	R_{PDM}	$\frac{doll}{h}$	140
32	Mud flow-rate	Q_0	$\frac{m^3}{s}$	0,0466
33	Thrust load	G	kN	80
35	Rotor speed (top drive)	n	$\frac{\text{rev}}{\text{min}}$	100

36	Bit size	-	mm	311,2
37	Bit cost	C_b	doll	19 718

Check calculation of density and flow rate of drilling mud

Let us establish the compliance of the density of the drilling fluid used in well №1 and №2 with the requirements of the drilling safety rules according to the formula (6.1):

$$\rho = \frac{KP_r}{gL_c}; \tag{6.1}$$

where K – contingency factor.

$$\rho = \frac{KP_{пл}}{gL_k} = \frac{1{,}05 \cdot 27{,}8 \cdot 10^6}{9{,}81 \cdot 2379} = 1249 \approx 1250\ \frac{kg}{m^3},$$

The found density is almost equal to the actual density used in wells №1 and №2. Let us determine the flow rate of liquid Q_1, required for high-quality cleaning of the bottom hole and the bit from cuttings, according to the formula (6.2):

$$Q_1 = \alpha \frac{\pi}{4} D_c^2\ ; \tag{6.2}$$

where Q_1 - drilling mud flow rate, ensuring bottom hole and bit cleaning, $\frac{m^3}{s}$

α - discharge code, $\frac{m}{s}$.

For the method of drilling using hydraulic drilling $\alpha = (0{,}50\ldots0{,}70)\,\frac{m}{s}$.

$$Q_1 = 0{,}7 \cdot 0{,}785 \cdot 0{,}3112^2 = 0{,}046\,\frac{m^3}{s}.$$

Considering the minimum fluid flow velocity specified in the task in the annular space, which ensures the removal of cuttings $V_c = 0{,}6\ \frac{m}{s}$, we find the required flow rate of drilling mud Q_2 according to the formula (6.3):

$$Q_2 = \frac{\pi}{4}(D_c^2 - d_н^2) \cdot V_c\ ; \tag{6.3}$$

where Q_2 - drilling mud flow rate, ensuring bottom hole and bit cleaning, $\frac{m^3}{s}$

D_w – well diameter, m; To simplify calculations, the borehole diameter is assumed to be equal to the bit diameter along the entire length of the borehole;

d_{out} - Minimum outer diameter of pipes in BHA, m

V_c - The minimum velocity of the liquid in the annular space, ensuring the removal of cuttings, m/s

$$Q_2 = 0{,}785 \cdot (0{,}3112^2 - 0{,}149^2) \cdot 0{,}6 = 0{,}04\ \frac{\text{m}^3}{\text{s}}.$$

Because $Q_1 > Q_2$, then according to the condition $Q_0 \geq max(Q_1; Q_2)$ for further analysis, the values will be $Q_0 = 0{,}046 \frac{\text{м}^3}{\text{c}}$. However, the value of Q_0 must be checked for the possibility of ensuring stable operation of the hydraulic downhole motor. In our case, such a hydraulic motor is a positive displacement motor GT-240. For this PDM, the recommended by the manufacturer is the value of the fluid flow rate – 0,036-0,072 $\frac{\text{m}^3}{\text{s}}$. Then we assume that $Q_0 = 0{,}046 \frac{\text{m}^3}{\text{s}}$.

Selection of the number of operating pumps and the diameter of the cylindrical bushings

Since the suction of the fluid by mud pumps is carried out with a backpressure, we take the filling factor of the pumps $m_p = 1{,}0$. To create an equal or slightly larger feed compared to the found flow rate $Q_0 = 0{,}046 \frac{\text{m}^3}{\text{s}}$ we will use two UNB−600A pumps with 140 mm diameter liner and flow rate Q_p= 0,0233 $\frac{\text{m}^3}{\text{s}}$.

Then by the formula (6.4.):

$$Q = m_p N_p Q_p; \tag{6.4}$$

$$Q = 1{,}0 \cdot 2 \cdot 0{,}0233 = 0{,}0466 \frac{\text{m}^3}{\text{s}};$$

Received flow rate $0{,}0466\ \frac{\text{m}^3}{\text{s}}$ will ensure high-quality flushing of the well, cleaning of the downhole and bit from cuttings and stable operation of the PDM. Thus, in further calculations, we take the flow rate of drilling mud Q=$0{,}0466 \frac{\text{m}^3}{\text{s}}$. The maximum outlet pressure of the UNBT-950A pump when using liner with a diameter of 140 mm is 32 MPa.

Determination of the energy parameters of the PDM

For further calculations, it is necessary to recalculate the energy characteristic of the PDM GT-240-3/4 according to the formulas (6.5) - (6.7) for the actually used values of the flow rate and density of the drilling mud:

- moment at the max power mode

$$M_{max} = M_{table} \frac{\rho Q}{\rho_{table} Q_{table}} \tag{6.5}$$

For GT-240-3/4

$$M_{max} = 13205 \cdot \frac{1250 \cdot 0{,}0466}{1000 \cdot 0{,}050} = 15\ 384\ \ \mathrm{N} * m;$$

where $M_{table}, \rho_{table}, Q_{table}$ can be found in Table 4.

-idler frequency

$$n_{idle} = n_{table} \frac{Q}{Q_{table}} \tag{6.6}$$

For GT-240-3/4

$$n_{idle} = 278 \cdot \frac{0{,}0466}{0{,}050} = 259\ \ \frac{\mathrm{rev}}{min};$$

-pressure difference at the max power mode:

$$P_{max} = P_{table} \frac{\rho Q}{\rho_{table} Q_{table}} \tag{6.7}$$

For GT-240-3/4

$$P_{max} = 8 \cdot \frac{1250 \cdot 0{,}0466}{1000 \cdot 0{,}050} = 9{,}3\ \ \mathrm{MPa}$$

where M – moment at the max power mode

ρ – density of drilling mud

Q – drilling mud flow rate

n_{idle} – idler frequency

P – pressure difference at the max power mode

The calculation results are summarized in Table 6.2:

Table 6.2 - Energy parameters of the positive displacement motor GT-240-3/4

Parametrs	**Notation**	**GT-240-3/4**
Flow rate, $\frac{m^3}{s}$	Q	0,0466
Density of drilling mud, $\frac{kg}{m^3}$	ρ	1250
The moment at the max power mode, N·m	M_{max}	15 384
Idler frequency, rpm	n_{idle}	233
Pressure difference at the max power mode, MPa	P_{max}	9,3
Pressure difference at idle mode, MPa	P_i	3

Determination of the drilling mode parameters

To determine the actual parameters of the bit during drilling, it is necessary to determine the operating parameters of the PDM during its joint operation with a specific bit. Using formulas (6.8) - (6.10), we calculate the specific torque on the bit, torsion torque and rate of rotation of the PDM when operating in well №1 and №2. When determining m, the rate of rotation in formula (6.8) will be taken equal to 0.9 rotational speed at idle mode –233 $\frac{\text{rev}}{min}$.

When calculating n, the exponent in formula (6.11) will be taken as $\alpha = 3$ as for the new PDM. Also, using the formula (6.10), we determine the pressure difference on PDM during operating mode.

Specific torque on the bit:

$$m = \alpha_{\text{d}} \left(\frac{28}{n} + 0{,}14 \right) D_{\text{b}}^2 \qquad (6.8)$$

- GT-240-3/4

$$m = 3{,}2 \cdot \left(\frac{28}{233} + 0{,}14 \right) \cdot 0{,}3112^2 = 0{,}08 \text{ m};$$

Torsion torque:

$$M = mG \tag{6.9}$$

- GT-240-3/4

$$M = 0{,}08 \cdot 80000 = 6450 \text{ N*m};$$

Pressure difference:

The pressure difference in the operating mode of the PDM can be calculated using the formula:

$$P = P_i + M\frac{P_{max}}{M_{max}} \tag{6.10}$$

- GT-240-3/4

$$P = 3 + 6450\frac{9{,}3}{15\ 384} = \ 6{,}9 \text{ MPa}$$

Rate of rotation:

$$n = (n_{idle} + n_d)\left[1 - \left(\frac{M}{M_{max}}\right)^{\alpha}\right] \tag{6.11}$$

- GT-240-3/4

$$n = (n_{idle} + n_d)\left[1 - \left(\frac{M}{M_{max}}\right)^{\alpha}\right] = (233 + 100)\left[1 - \left(\frac{6450}{15\ 384}\right)^{3}\right] \approx 308\frac{rev}{min}$$

Determination of average drilling performance

Using formulas (6.12) - (6.14), let us determine for each interval the average headway per drill bit, average time of drilling per drill bit, and the average ROP. Then, using formulas (6.15) and (6.17), we determine drilling speed per run and the cost per meter.

Well №1 – Rotor (RSS)

In this part I will calculate average drilling performance in well №1.

Average headway per drill bit:

$$h = \frac{H}{N} \tag{6.12}$$

$$h = \frac{1105}{1} = 1105 \text{ м.}$$

Average time of drilling per drill bit:

$$t_d = \frac{T_d}{N} \tag{6.13}$$

$$t_d = \frac{90}{1} = 90 \text{ h.}$$

ROP

$$ROP = \frac{H}{T_d} \tag{6.14}$$

$$ROP = \frac{1105}{90} = 12{,}3\ \frac{m}{h}.$$

Drilling speed per run:

$$V_s = \frac{\mathrm{H}}{T_d + T_t} \tag{6.15}$$

$$V_s = \frac{1105}{90 + 12} = 10{,}8\ \frac{m}{h}.$$

The numerical value of the adaptation coefficient:

$$K = \frac{ROP}{n^{\alpha} G^{\beta}} \tag{6.16}$$

$$K = \frac{12{,}3}{180^{0{,}8} \cdot 80^{1{,}0}} = 0{,}0024$$

Cost of a bit - 19 718 dollar.

$$B = 19\ 718\,\frac{90}{300} = 5915 \text{ dollar.}$$

Cost per meter:

$$\mathrm{C}_m = \frac{B + R(T_d + T_{rih}) + R_{RSS} T_d}{H} \tag{6.17}$$

$$\mathrm{C}_m = \frac{5\ 915 + 985 \cdot (90 + 12) + 704 \cdot 90}{1105} = 154\ \frac{doll}{m}.$$

Well №2 – RSS + PDM GT-240-3/4

In this part we will consider well №2, where RSS and PDM were used at the same time.

Average headway per drill bit:

$$h = \frac{H}{N}$$

$$h = \frac{1105}{1} = 1105 \text{ m}$$

ROP

$$ROP = K \cdot n^{\alpha} G^{\beta}$$

$$ROP = K \cdot n^{\alpha} G^{\beta} = 0{,}0024 \cdot 308^{0{,}8} \cdot 80^{1{,}0} = 18{,}8\ \frac{m}{h}.$$

Average time of drilling per drill bit:

$$t_d = \frac{T_d}{N}$$

$$T_d = \frac{H}{ROP} = \frac{1105}{19} = 58 \text{ h}$$

$$t_d = \frac{T_d}{N} = \frac{58}{1} = 58 \text{ h}$$

Drilling speed per run:

$$V_s = \frac{\text{H}}{T_d + T_{\text{сп}}};$$

$$V_s = \frac{1105}{58 + 12} = 15{,}8\ \frac{m}{h}.$$

Cost of a bit - 19 718 dollar.

$$B = 19\ 718 \frac{58}{300} = 3\ 812\ dollar.$$

Cost per meter:

$$\text{C}_m = \frac{B + R(T_d + T_{rih}) + R_{pdm} T_d + R_{RSS} T_d}{H} \qquad (6.18)$$

$$C_{м} = \frac{3\ 812 + 985 \cdot (58 + 12) + 140 \cdot 58 + 704 \cdot 58}{1105} = 110\ \frac{doll}{m}.$$

The results are summarized in Table 6.3.

Table 6.3 - Average drilling criteria

Criteria	**Basic technology of drilling**	**Improved technology of drilling**
Drilling method	Rotor (RSS)	Rotor + HDM
Type of HDM	-	PDM GT-240-3/4 + RSS
Type of bit	311,2 PDC	311,2 PDC
IADC	S323	S323
Flow rate, $\frac{m^3}{h}$	0,0466	0,0466
Density of drilling mud, $\frac{kg}{m^3}$	1250	1250
Thrust load, kN	80	80
Rate of rotating, $\frac{rev}{min}$	180	308
Pressure difference in the operating mode of the PDM, MPa	-	6,9
Number of bits	1	1
Total interval, m	1105	1105
Total time of drilling, h	90	58
ROP, $\frac{m}{h}$	12,3	18,8
Average headway per drill bit, m	1105	1105
Time of drilling per drill bit, h	90	58
Cost of 1 bit, $	19 718	19 718
The cost of all bits worked out in the drilling interval, $	5915	3812
Time of run-in-hole, h	12	12
Drilling speed per run, $\frac{m}{h}$	10,8	15,8
Cost per meter, $	154	110

It can be easily calculated that the economic effect of the combined use of RSS and PDM amounted to 48,5 thousand dollars. It also saved 32 hours of production time.

7. Drill string design

Calculation of the BHA layout

Select the diameter of the first stage of the drill collar located above the bit, according to the formula:

$$D_{dc(1)} = (0{,}65\ldots0{,}85)D_b; \qquad (7.1)$$

where $D_{dc(1)}$ - diameter of the bottom near-bit part of the BHA;

D_b – diameter of the bit

$$D_{dc(1)} = (0{,}65\ldots0{,}85) \cdot 0{,}3112 = 0{,}20\ldots0{,}26;$$

Accept $D_{УБТ(1)} = 0{,}229\ m$

Diameter of drill string will be $d_s = 0{,}140$ m.

Let's take the diameter of the pipes of the near-bit set equal to the diameter of the rest of the drill pipes $d_{nb} = d_s = 0{,}140$ m.

Let us determine the ratio of the diameters of drill pipes and drill collars:

$$\frac{d_{nb}}{D_{dc(1)}} = \frac{0{,}140}{0{,}229} = 0{,}61 < 0{,}75$$

Therefore, we provide for the installation of the second stage of the drill collar with a diameter:

$$D_{dc(2)} = 0{,}178 \text{ m.}$$

As

$$\frac{D_{dc(2)}}{D_{dc(1)}} = \frac{0{,}178}{0{,}229} = 0{,}78 > 0{,}75 \text{ и } \frac{d_{nb}}{D_{dc(2)}} = \frac{0{,}140}{0{,}178} = 0{,}78 > 0{,}75$$

then the outer diameters of the drill collar are correctly selected.

We find the type of DC: DC-229 and DC-178 made of steel "L".

Let's take the coefficient in the formula:

$$L_{dc(1)} = \lambda_1 L_{dc}, \qquad (7.2)$$

where L_{dc} – overall length of collar, m;

$\lambda_1 -$ dimensionless empirical coefficient.

λ_1 = 0,7.

$$L_{dc} = \frac{1{,}15 \cdot G}{g \cdot \left(1 - \frac{\rho}{\rho_{dc}}\right) \cdot \left[\lambda_1 q_{dc(1)} + \frac{1}{n-1}(1-\lambda_1) \cdot q_{dc(2)}\right] \cdot cos\,\alpha}, \tag{7.3}$$

where $q_{УБТ(1)}$ - weight of 1 meter DC of the first stage, kg/m;

ρ_{dc} – collar material density, kg/m^3, for steel – 7850 kg/m^3;

n – number of stages of DC in the BHA;

α - angle of deviation of the DC from the vertical;

Let us determine the length of the two-stage drill collar to create the axial load G = 80 kN previously calculated for the bit 311.2 mm:

$$L_{dc} = \frac{1{,}15 \ \cdot \ 80 \cdot 10^3}{9{,}81\left(1 - \frac{1250}{7850}\right)\left[0{,}7 \cdot 273{,}4 + \frac{1}{2-1} \cdot (1-0{,}7) \cdot (156)\right] \cdot 0{,}8} = 58\,m.$$

Length of the first stage of the DC:

$$L_{dc(1)} = 0{,}7 \cdot 58 = 40{,}9 \text{ m};$$

$$L_{dc(2)} = 62 - 43{,}4 = 17{,}6\,m.$$

We finally accept $L_{dc(1)} = 50$ m, that is, 2 stands of 25 meters each,

$L_{dc(2)}$ = 25 m, that is 1 stand of 25 meter.

Then the total length of the BHA:

BHA: $L_{BHA} = 50 + 25 = 75\,m.$

The total weight of the DC in the liquid is found by the formula:

$$Q_{BHA} = g\left(q_{dc(1)} \cdot L_{dc(1)} + q_{dc(2)} \cdot L_{dc(2)}\right) \cdot \left(1 - \frac{\rho}{\rho_{dc}}\right) \tag{7.4}$$

$$Q_{BHA} = 9{,}81 \cdot (273{,}4 \cdot 50 + 156 \cdot 25) \cdot \left(1 - \frac{1250}{7850}\right) = 145\,kN.$$

Calculation of the drill pipe column for static strength

The length of the near-bit set is taken equal to 300 m. In order to increase the fatigue strength of the drilling tool, we will compose the near-bit set from pipes with stabilizing bands of the TBV-140x8 L type, yield strength σ_T = 637 MPa

The weight of near-bit set in liquid is calculated by the formula:

$$Q_{nb} = g l_{nb} q_{nb}\left(1 - \frac{\rho}{\rho_{nb}}\right); \tag{7.5}$$

$$Q_{nb} = 9{,}81 \cdot 300 \cdot 30{,}9 \cdot \left(1 - \frac{1250}{7850}\right) = 76{,}5\ kN.$$

The value of the possible pressure drop in the bit is estimated at 4 Mpa.

The tensile stress in the upper section of the near-bit set is determined by the formula:

$$\sigma_p = \frac{k(Q_{BHA} + Q_{nb}) + P_b\ \cdot\ F_{K(nb)}}{F_{TP(nb)}}; \tag{7.6}$$

Where k =1,1 - coefficient taking into account the influence of friction forces, inertia forces, forces of resistance to the movement of the mud;

$F_{K(nb)}$ - cross-sectional area of the near-bit pipe channel, m²;

$F_{TP(HK)}$ - cross-sectional area of the pipe body near-bit set, m²;

$$\sigma_p = \frac{1{,}1 \cdot (138000 + 72800) + 4 \cdot 10^6 \cdot 120{,}1 \cdot 10^{-4}}{33{,}1 \cdot 10^{-4}} = 88\ MPa.$$

Further, according to the table, we select pipes for completing the 1st section of the column: TBVK-140x9L

Accept $К_d$ = 1,35

The permissible tensile load for them is found by the formula:

$$QT(1) = \frac{\vartheta \cdot QP(1)}{1.04 \cdot К_d} \tag{7.7}$$

where $QP(1)$ - maximum tensile load for pipes of the 1st section, N

$$QT(1) = \frac{1 \cdot 2150 \cdot 10^3}{1{,}04 \cdot 1{,}35} = 1531\ \text{kN}.$$

The permissible length of the 1st section of drill pipes is calculated by the formula:

$$l_1 = \frac{QT(1) - k(Q_{BHA} + Q_{nb}) - P_b\ \cdot\ F_{K(1)}}{k \cdot g \cdot q1 \cdot (1 - \frac{\rho}{\rho steel})},$$

$$l_1 = \frac{1531 \cdot 10^3 - 1{,}1(138000 + 72800) - 4 \cdot 10^6 \cdot 120{,}1 \cdot 10^{-4}}{1{,}1 \cdot 9{,}81 \cdot 30{,}1 \cdot (1 - \frac{1250}{7850})} = 4422\ m,$$

what exceeds the required length of drill pipes, which can be determined by the formula:

$$l_1 = L - L_{BHA} - l_{nb};$$

$$l_1 = 3354 - 75 - 300 = 2979\ m.$$

The weight of the 1st pipe section in the liquid is calculated by the formula:

$$Q_1 = g \cdot l1 \cdot q1 \cdot (1 - \frac{\rho}{\rho steel});$$

$$Q_1 = 9{,}81 \cdot 2979 \cdot 30{,}9 \cdot (1 - \frac{1250}{7850}) = 759{,}2 \text{ kN}.$$

The calculation results are summarized in table 7.1:

Table 7.1 - Drill string calculation results

Indicators	**Number of sections**			
	DC	DC	NB	DS
Type of string	DC2-229	DC2-178	TBV-140	TBV-140
Outer diameter of pipes, mm	229	178	140	140
Internal diameter of pipes, mm	90	80	124	124
Pipe material strength group	L	L	L	L
Interval, m	0-50	50-75	75-375	375-3354
Section length, m	50	25	300	2979
Increasing weight of the column in liquid, kN	107	145	221,5	980,7

8. Hydraulic calculation of the circulation system

We will perform a second check of the supply of drilling mud.

Let us determine the critical density of the drilling fluid, at which hydraulic fracturing of the weakest of the layers that make up the drilled section can occur, according to the formula:

$$\rho_{cr} \leq \frac{P_f - \sum(\Delta P_{an}) - (1-\phi)\,\rho_c g L_b}{\phi g L_b}, \tag{8.1}$$

where P_f - formation hydraulic fracturing (absorption) pressure, Pa;

$\sum(\Delta P_{an})$ - pressure loss during the movement of the flushing fluid in the annulus space on the way from the bottom of the formation under consideration to the wellhead, Pa;

L_b - depth of the base of the formation under consideration from the wellhead, m;

ρ_c - the density of the cuttings, which can be taken equal to 2600 kg/m^3;

ϕ - liquid content in the cuttings-liquid flow of the drilling fluid in the annulus of the well.

To do this, you must first calculate the parameters ϕ and $\sum(\Delta P_{an})$.

The value of ϕ is calculated by the formula using the mechanical penetration rate of the most efficient bit type found above 311.2:

$$ROP{=}18{,}8\,\frac{m}{h}{=}5{,}2\cdot 10^{-3}\,\frac{m}{s}$$

$$\phi = \frac{Q}{\frac{\pi}{4}ROPD_C^2+Q},$$

$$\phi = \frac{Q}{\frac{\pi}{4}ROPD_C^2 + Q} = \frac{0{,}0466}{0{,}785\cdot 5{,}2\cdot 10^{-3}\cdot 0{,}3112^2 + 0{,}0466} \approx 1{,}0.$$

Those the rock cuttings content in the flow is negligible.

To determine the value of $\sum(\Delta P_{an})$ we will find linear and local pressure losses in the annulus up to the depth of the weak formation bottom. Let us calculate the critical value of the Reynolds number of the flushing liquid Re_{cr}, at which the transition from laminar to turbulent occurs according to formula 7.2 for the flow in the annular channel:

$$Re_{cr} = 2100 + 7{,}3\cdot\left(\frac{\rho d_h^2 \tau_0}{\eta^2}\right)^{0{,}58}, \tag{8.2}$$

where η - plastic (dynamic) viscosity of the flushing fluid, Pa·s;

τ_0 - dynamic shear stress, Pa;

d_h - hydraulic channel diameter, m

- DC – 229

$$Re_{cr} = 2100 + 7{,}3 \cdot \left(\frac{1250 \cdot (0{,}3112 - 0{,}229)^2 \cdot 12}{0{,}025^2}\right)^{0{,}58} = 9\ 775;$$

- DC – 178

$$Re_{cr} = 2100 + 7{,}3 \cdot \left(\frac{1250 \cdot (0{,}3112 - 0{,}178)^2 \cdot 12}{0{,}025^2}\right)^{0{,}58} = 15\ 536;$$

- TBVK – 140

$$Re_{cr} = 2100 + 7{,}3 \cdot \left(\frac{1250 \cdot (0{,}3112 - 0{,}140)^2 \cdot 12}{0{,}025^2}\right)^{0{,}58} = 20\ 077.$$

Let us determine the real Reynolds numbers for the fluid flow in the annular space by the formula:

$$Re_{an} = \frac{4\rho Q}{\pi(D_w + d)\eta} \tag{8.3}$$

- DC – 229

$$Re_{an} = \frac{4\rho Q}{\pi(D_C + d_H)\eta} = \frac{4 \cdot 1250 \cdot 0{,}0466}{3{,}14 \cdot (0{,}3112 + 0{,}229) \cdot 0{,}025} = 5\ 491;$$

- DC – 178

$$Re_{an} = \frac{4\rho Q}{\pi(D_C + d_H)\eta} = \frac{4 \cdot 1250 \cdot 0{,}0466}{3{,}14 \cdot (0{,}3112 + 0{,}178) \cdot 0{,}025} = 6\ 064;$$

- TBVK – 140

$$Re_{an} = \frac{4\rho Q}{\pi(D_C + d_H)\eta} = \frac{4 \cdot 1250 \cdot 0{,}0466}{3{,}14 \cdot (0{,}3112 + 0{,}140) \cdot 0{,}025} = 6\ 575.$$

Since the obtained values of $Re_{an} < Re_{cr}$ in all sections of the annulus, the movement of fluid everywhere in the annular channel occurs in laminar mode.

Calculate the value of Saint-Venant numbers using the formula:

$$Se_{an} = \frac{\pi \cdot \tau_0 (D_w - d)}{\eta V_{an}} \tag{8.4}$$

- DC – 229

$$Se_{an} = \frac{\pi \cdot \tau_0 \cdot (D_w - d)^2 \cdot (D_w + d)}{4 \cdot \eta \cdot Q} = \frac{\pi \cdot 12 \cdot (0{,}3112 - 0{,}229)^2 \cdot (0{,}3112 + 0{,}229)}{4 \cdot 0{,}025 \cdot 0{,}0466} = 29{,}5;$$

- DC – 178

$$Se_{an} = \frac{\pi \cdot \tau_0 \cdot (D_w - d)^2 \cdot (D_w + d)}{4 \cdot \eta \cdot Q} = \frac{\pi \cdot 12 \cdot (0{,}3112 - 0{,}178)^2 \cdot (0{,}3112 + 0{,}178)}{4 \cdot 0{,}025 \cdot 0{,}0466} = 70{,}2;$$

- TBVK – 140

$$Se_{an} = \frac{\pi \cdot \tau_0 \cdot (D_w - d)^2 \cdot (D_w + d)}{4 \cdot \eta \cdot Q} = \frac{\pi \cdot 12 \cdot (0{,}3112 - 0{,}140)^2 \cdot (0{,}3112 + 0{,}140)}{4 \cdot 0{,}025 \cdot 0{,}0466} = 107.$$

We find the values of the coefficient β_{an} according to the formulas:

$$\beta_{an} = 1 - \frac{4}{Se}\left(\sqrt{1{,}2 + 0{,}5Se} - 1\right) \qquad (8.5)$$

- DC – 229

$$\beta_{an} = 1 - \frac{4}{29{,}5} \cdot \left(\sqrt{1{,}2 + 0{,}5 \cdot 29{,}5} - 1\right) = 0{,}594;$$

- DC – 178

$$\beta_{an} = 1 - \frac{4}{70{,}2} \cdot \left(\sqrt{1{,}2 + 0{,}5 \cdot 70{,}2} - 1\right) = 0{,}714;$$

- TBVK – 140

$$\beta_{an} = 1 - \frac{4}{107} \cdot \left(\sqrt{1{,}2 + 0{,}5 \cdot 107} - 1\right) = 0{,}761.$$

Calculate the pressure loss along the length of the annular space behind the drill pipes and drill collars to the depth of the weak formation:

$$\Delta P_{an} = \frac{4\tau_0 l}{\beta_{an}(D_w - d)} \qquad (8.6)$$

- DC – 229

$$\Delta P_{an} = \frac{4 \cdot 12 \cdot 50}{0{,}594 \cdot (0{,}3112 - 0{,}229)} = 0{,}05 \text{ MPa};$$

- DC – 178

$$\Delta P_{an} = \frac{4 \cdot 12 \cdot 25}{0{,}714 \cdot (0{,}3112 - 0{,}178)} = 0{,}01 \text{ MPa};$$

- TBVK – 140

$$\Delta P_{an} = \frac{4 \cdot 12 \cdot (3354 - 50 - 25)}{0{,}761 \cdot (0{,}3112 - 0{,}140)} = 1{,}21 \text{ MPa}.$$

Local losses from locks «ЗШК» - 178 of the annular space in the area TBVK - 140 to the depth of a weak reservoir are calculated by the formula:

$$\Delta P_l = \frac{l}{l_s}\left(\frac{D_w^2 - d^2}{D_w^2 - d_l^2} - 1\right)^2 \rho V_{an}^2 \qquad (8.7)$$

where l_s - average pipe length in a given section of the drill string, m;

V_{an} - average fluid flow velocity in the annulus, m/s.

$$V_{an} = \frac{4 \cdot Q}{\pi \cdot (D_w^2 - d^2)} \qquad (8.8)$$

$$V_{an} = \frac{4 \cdot 0{,}0466}{3{,}14 \cdot (0{,}3112^2 - 0{,}140^2)} = 0{,}78\ \frac{m}{s};$$

Accept l_s = 12 m.

$$\Delta P_l = \frac{3354-50-25}{12} \cdot \left(\frac{0{,}3112^2-0{,}140^2}{0{,}3112^2-0{,}178^2} - 1\right)^2 \cdot 1250 \cdot 0{,}78^2 = 0{,}007 \text{ MPa.}$$

Summing up the obtained values of ΔP_{an} and ΔP_l, we obtain the value $\sum(\Delta P_{an})$ required to calculate the critical density ρ_{cr}:

$\sum(\Delta P_{an})$=$0{,}05 + 0{,}01 + 1{,}21 = 1{,}27$ MPa.

We define ρ_{cr} by the formula:

$$\rho_{cr} = \frac{P_f - \sum(\Delta P_{an})}{\phi g L_b} = \frac{40 \cdot 10^6 - 1{,}398 \cdot 10^6}{1{,}0 \cdot 9{,}81 \cdot 2379} = 1654\frac{kg}{m^3} \tag{8.9}$$

Since the obtained value ρ_{cr} = 1654 kg/m^3 is greater than the accepted value ρ_{mud} = 1250 kg/m^3, the condition for preventing hydraulic fracturing is met.

Next, we calculate the pressure loss inside the drill string. To do this, we determine the critical Reynolds number by the formula (7.2):

- DC – 229

$$Re_{cr} = 2100 + 7{,}3 \cdot \left(\frac{1250 \cdot 0{,}090^2 \cdot 12}{0{,}025^2}\right)^{0{,}58} = 10\ 626\ ;$$

- DC – 178

$$Re_{cr} = 2100 + 7{,}3 \cdot \left(\frac{1250 \cdot 0{,}08^2 \cdot 12}{0{,}025^2}\right)^{0{,}58} = 9\ 538\ ;$$

- TBVK – 140

$$Re_{cr} = 2100 + 7{,}3 \cdot \left(\frac{1250 \cdot 0{,}124^2 \cdot 12}{0{,}025^2}\right)^{0{,}58} = 14\ 466.$$

The real Reynolds numbers are determined by the formula:

$$Re_s = \frac{4\rho Q}{\pi d \eta} \tag{8.10}$$

- DC – 229

$$Re_s = \frac{4 \cdot 1250 \cdot 0{,}0466}{\pi \cdot 0{,}09 \cdot 0{,}025} = 32\ 963;$$

- DC – 178

$$Re_s = \frac{4 \cdot 1250 \cdot 0{,}0466}{\pi \cdot 0{,}080 \cdot 0{,}025} = 37\ 083;$$

- TBVK – 140

$$Re_s = \frac{4 \cdot 1250 \cdot 0{,}0466}{\pi \cdot 0{,}124 \cdot 0{,}025} = 23\ 925;$$

In the drill string, real numbers are everywhere $Re_s > Re_{cr}$, therefore, in all sections there is a turbulent flow regime of the drilling fluid and therefore the pressures inside the string are determined by the Darcy-Weisbach formula:

$$\Delta P_s = \lambda_T \frac{8\rho Q^2}{\pi^2 d^5} l \tag{8.11}$$

We preliminarily calculate the values of the coefficients of hydraulic resistance λ_T according to the formula:

$$\lambda_s = 0{,}1 \cdot \left(\frac{1{,}46K}{d} + \frac{100}{Re_s}\right)^{0{,}25} \tag{8.12}$$

- DC – 229

$\lambda_s = 0{,}1 \cdot \left(\frac{1{,}46 \cdot 3 \cdot 10^{-3}}{0{,}09} + \frac{100}{32\ 963}\right)^{0{,}25} = 0{,}048;$

- DC – 178

$\lambda_s = 0{,}1 \cdot \left(\frac{1{,}46 \cdot 3 \cdot 10^{-3}}{0{,}08} + \frac{100}{37\ 083}\right)^{0{,}25} = 0{,}049;$

- TBVK – 140

$\lambda_s = 0{,}1 \cdot \left(\frac{1{,}46 \cdot 3 \cdot 10^{-3}}{0{,}124} + \frac{100}{23\ 925}\right)^{0{,}25} = 0{,}045.$

Next, we calculate the pressure loss of the in-line space according to the formula (8.11):

- DC – 229

$\Delta P_s = \lambda_s \frac{8\rho Q^2}{\pi^2 d^5} l = 0{,}048 \cdot \frac{8 \cdot 1250 \cdot 0{,}0466^2 \cdot 50}{\pi^2 \cdot 0{,}090^5} = 0{,}9$ MPa;

- DC – 178

$\Delta P_s = \lambda_s \frac{8\rho Q^2}{\pi^2 d^5} l = 0{,}049 \cdot \frac{8 \cdot 1250 \cdot 0{,}0466^2 \cdot 25}{\pi^2 \cdot 0{,}080^5} = 0{,}8$ MPa;

- TBVK – 140

$\Delta P_s = \lambda_s \frac{8\rho Q^2}{\pi^2 d^5} l = 0{,}045 \cdot \frac{8 \cdot 1250 \cdot 0{,}0466^2 \cdot 3279}{\pi^2 \cdot 0{,}124^5} = 11{,}1$ MPa.

Then the total friction loss along the entire length inside the drill string pipes will be:

$\sum \Delta P_s = 0{,}9 + 0{,}8 + 11{,}1 = 12{,}8$ MPa.

Local losses from locks «ЗШК» - 178 inside the drill string are determined by the formula:

$$\Delta P_l = \frac{l}{l_s}\left[\left(\frac{d_n}{d_l}\right)^2 - 1\right]^2 \frac{16\rho Q^2}{\pi^2 d^4} \tag{8.13}$$

- TBVK – 140

$$\varDelta P_l = \frac{3354-50-25}{12} \cdot \left[\left(\frac{0{,}122}{0{,}101}\right)^2 - 1\right]^2 \cdot 1250 \cdot \frac{16 \cdot 0{,}0466^2}{\pi^2 \cdot 0{,}124^4} = 1{,}1 \text{ MPa};$$

Calculate the pressure loss in the ground piping using the formula:

$$\varDelta P_0 = (\alpha_s + \alpha_h + \alpha_{sw} + \alpha_k)\rho Q^2, \tag{8.14}$$

where $\alpha_s, \alpha_h, \alpha_{sw}, \alpha_k$ - coefficients of hydraulic resistance of various piping elements (standpipe, drilling hose, swivel, kelly):

$$\varDelta P_0 = (0{,}4 + 1{,}2 + 0{,}44) \cdot 10^5 \cdot 1250 \cdot 0{,}0466^2 = 0{,}55 \text{ MPa}.$$

Next, we calculate the sum of pressure losses in the entire circulation system, with the exception of the pressure drop in the bit, using the formula:

$$(\varDelta P - P_b) = \sum(\varDelta P_s) + \sum(\varDelta P_{an}) + \varDelta P_l + \varDelta P_l + \varDelta P_0,$$

$$(\varDelta P - P_b) = (12{,}8 + 1{,}27 + 1{,}1 + 0{,}007 + 0{,}55) \cdot 10^6 = 15{,}7\ MPa.$$

Calculate the pressure reserve $\varDelta P_p$ to determine the allowable pressure drop in the bit using formula 7.15 at b=0.8:

$$\varDelta P_p = bP_d - (\varDelta P - P_Д), \tag{8.15}$$

where P_d - limiting discharge pressure at the outlet of the drilling pump, MPa;

b = (0,75…0,80) - coefficient taking into account the required pressure margin during the operation of mud pumps.

$$\Delta P_p = bP_d - (\varDelta P - P_b) = 0{,}8 \cdot 32 \cdot 10^6 - 15{,}7 \cdot 10^6 = 9{,}9 \text{ MPa}$$

Such a pressure margin is quite suitable for the implementation of a pressure drop of 311.2 in the bit nozzles P_b = 4 MPa.

Using formulas (7.16) and (7.17), we determine the total area of the drilling holes of the bit nozzles:

$$V_b = \mu\sqrt{\frac{2P_b}{\rho}}, \tag{8.16}$$

$$\varPhi = \frac{kQ}{V_b}, \tag{8.17}$$

where μ - flow coefficient

Φ – the total area of holes in jet nozzles of the bit, m².

$$\varPhi = \frac{Q}{\mu}\sqrt{\frac{\rho}{2\varDelta P_b}} = \frac{0{,}0466}{0{,}95}\cdot\sqrt{\frac{1250}{2\cdot 4\cdot 10^6}} = 6{,}13\cdot 10^{-4}\ \text{m}^2$$

We choose the number of flush nozzles for the bit 311.2 in the formula (7.18), n=6.

Then the diameter of one nozzle will be:

$$d = \sqrt{\frac{4\varPhi}{\pi\cdot n}} = \sqrt{\frac{4\cdot 6{,}13\cdot 10^{-4}}{3{,}14\cdot 6}} = 0{,}0114\, m\ =\ 11{,}4\ \text{mm} = 12\ \text{mm} \tag{8.18}$$

Thus, to create a pressure drop in the 311.2 bit equal to 4 MPa, it is necessary to install six jet nozzles with a diameter of 12 mm each.

In conclusion, we determine the actual maximum discharge pressure at the outlet of two drilling pumps UNBT-950A:

$$P_{max} = \Delta P + P_b = (15{,}7 + 4)\cdot 10^6 = 19{,}7\ \text{MPa},$$

which is less than the maximum allowable value (32 MPa) for cylindrical bushings of the selected diameter (140 mm).

When the PDM is present in the BHA, the only parameter that will change is the actual maximum discharge pressure at the outlet of the mud pumps. Since the difference in the PDM is 6.9 MPa, then:

Calculate the pressure reserve ΔP_p to determine the allowable pressure drop in the bit using formula (7.15) at b=0.8:

$$\Delta P_p = bP_d - (\varDelta P - P_b) = 0{,}8\cdot 32\cdot 10^6 - 22{,}6\cdot 10^6 = 3\ \text{MPa}.$$

Such a pressure reserve is quite suitable for the implementation of a pressure drop of 311.2 in the bit nozzles P_b = 3 MPa.

$$\varPhi = \frac{Q}{\mu}\sqrt{\frac{\rho}{2\varDelta P_{Д}}} = \frac{0{,}0466}{0{,}95}\cdot\sqrt{\frac{1250}{2\cdot 3\cdot 10^6}} = 7{,}1\cdot 10^{-4}\ m^2$$

We choose the number of flush nozzles for the bit 311.2 in the formula, n=6.

Then the diameter of one nozzle will be:

$$d = \sqrt{\frac{4\varPhi}{\pi\cdot n}} = \sqrt{\frac{4\cdot 7{,}1\cdot 10^{-4}}{3{,}14\cdot 6}} = 0{,}0123 = 12{,}3 = 13\ mm$$

Thus, to create a pressure drop in the 311.2 bit equal to 3 MPa, it is necessary to install six jet nozzles with a diameter of 13 mm each.

In conclusion, we determine the actual maximum discharge pressure at the outlet of two drilling pumps UNBT-950A:

$$P_{max} = \Delta P + P_b = (22{,}6 + 3) \cdot 10^6 = 25{,}6 \text{ MPa},$$

which is less than the maximum allowable value (32 MPa) for cylindrical bushings of the selected diameter (140 mm).

9. Well completions

Completion of a well includes the following main types of work: opening of the productive horizon, structural design of the wellbore in the interval of the productive horizon and its isolation from adjacent intervals with aquifers and permeable formations, creation of a hydrodynamic connection between the productive horizon and the well, exploration of productive formations, development of productive formations with commercial reserves.

Consider the functions of the bottom hole:

• to have a high level of reservoir-well hydrodynamic coupling in the exploited bottom hole intervals;

• for a long time to maintain the stability of the bottom-hole formation, to prevent the collapse of the walls of the well;

• regulate the process of "sand" removal;

• provide reliable isolation of the operated intervals of the wellbore;

The performance of the functions of the bottom hole is also associated with equipping it with the necessary technical means adapted to various options and modes of operation, so as not to provoke deformation of the collector and watering of the product, and to reduce the time between repairs.

Thus, the downhole functions are implemented in two interrelated directions:

• ensuring a high level of reservoir-well hydrodynamic communication;

• equipment with downhole equipment that ensures long-term performance and productivity in real mining and geological conditions.

Also consider the main types of bottom hole construction:

1. Open Hole Completion

Advantages:

• No perforation costs;

• The layer has been opened to its full thickness;

• Minimal deterioration of the reservoir filtration and capacitance properties;

• Can be easily deepened.

Disadvantages:

• The formation must have the appropriate properties;

• It is difficult to prevent gas and water breakout;

• It is difficult to perform selective impact on the formation;

• Frequent cleaning of the bottom of the well from cuttings may be required.

2. Completion without liner cementing

Advantages:

Same as open hole completion. This design also provides partial wellbore containment to help prevent sanding.

Disadvantages:

• Higher construction cost;

• Difficult to perform selective stimulation;

• Difficult to prevent gas and water breakthrough;

• With severe collapse of rocks, the productivity of the well is reduced.

3. Perforated bottom casing

Advantages:

• Allows for separate operation of reservoirs;

• Allows you to perform selective stimulation of the formation;

• Provides better control over water, oil and gas production;

• Causes minimal cavitation in the reservoir.

Disadvantages:

• Requires perforating;

• Need to know the perforation interval;

• Requires cleaning of the perforation interval, as perforations are hydraulic inflow resistances and can become clogged;

• Requires good quality of cementing.

The determining factors in choosing the type and composition of the bottomhole construction elements and its parameters are: the uniformity of the productive formation, its permeability, the resistance of the near wellbore area rocks to the impact of well fluids during the completion process and the movement of formation fluids to the bottomhole during operation, as well as the presence or absence of closely spaced in relation to a reservoir of interlayers with high or low pressure, water-oil contact or gas cap.

If the negative impact of penetration by drilling, cementing and perforation on the level of hydrodynamic perfection of the reservoir-well system is insignificant or near wellbore area treatments (fracturing, acid, etc.) are planned, which significantly increase the performance of the well. In loose reservoirs, bottomholes are equipped with filtering devices to retain sand, or in perforation channels after hydraulic fracturing, a gravel pack is created from a proppant of a certain granulometric composition. Perforated wells are widely used in vertical and inclined shafts (more than 90% of the stock). The design of the closed face is universal and can be used in almost any situation. The level of hydrodynamic perfection of the well is determined by the bottom hole design.

Consider bottomhole designs in horizontal wells:

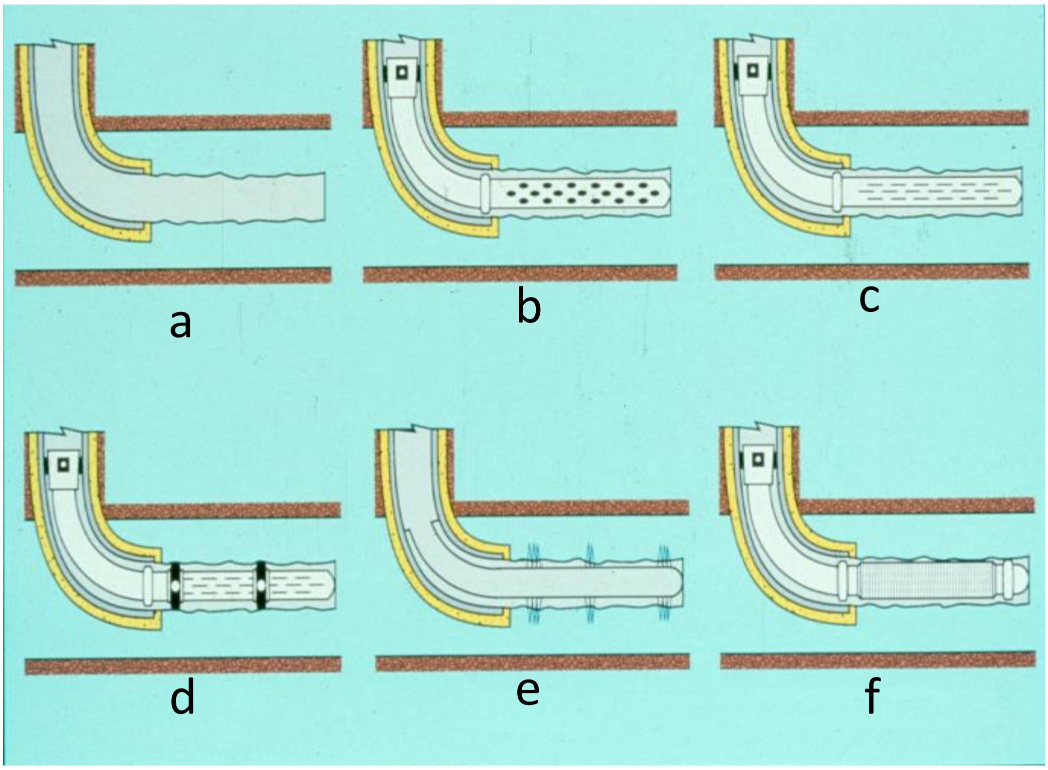


Figure 9.1 - Types of horizontal well bottom design

a - openhole; b - liner with filter; c - liner with slotted filter; d - liner with casing packers; e - cased borehole; f - gravel filter with liner

To improve the well completion technology at the Prirazlomnoye field, we will use the Manara well completion system from Schlumberger. Below is detailed information about this system.

This system can be used:

- In wells that require the use of modular and scalable systems - in single-lateral and multilateral wells;
- In wells with increased area of contact with the reservoir (ERC wells);
- In extended reach wells (ERD wells);
- In wells prepared for running ESP.

Advantages:

- Maximization of production volumes;
- Proactive development management, increase in oil recovery factor;
- Overall reduction in the cost of well ownership.

Features:

- Constant measurements of the parameters of each interval using built-in sensors developed as a result of large-scale research and practical experience;

  - Flow rate measurement with a Venturi flow meter - Water level sensor for early detection of water breakout

  - Pressure and temperature measurements allow you to create a continuous inflow profile for each interval

  - The position sensor of the inflow regulator provides flow rate control
- A two-way high-speed telemetry system provides constant and simultaneous access to diagnostic parameters, it is also used to transmit electricity to power downhole equipment;
- The high-speed adjustable electric valve-inflow regulator serves for accurate and prompt regulation of the inflow from each interval, saves time and ensures rapid implementation of measures to optimize production with a minimum number of production stops and downtime.
- The sealed electrical connector of the Intelite control line ensures the reliability of the electrical cable connection
- The use of an inductive coupling increases the reliability of power supply and communication;

  - Characterized by structural strength, the coupling is part of the casing, it is able to withstand all the same loads during drilling as the casing;

  - Quick installation in multi-barrel wells;

- No impact on drilling operations.

- Separation of intervals by means of swelling packers with one port for the Manara cable. The Manara integrated intelligent completion system is designed for continuous monitoring of single-barrel and multi-barrel wells. The measurement of flow rates, water content, pressure and temperature provides operational control of the inflow from the side shafts to optimize the production regime and the rate of selection.

Unique advantages of the system:

1. Maximum increase in production volumes
   - High-precision measurements of pressure, temperature, flow rate and water content
   - Precise regulation of the inflow from each interval
   - Automatic visualization of technological parameters of each interval, the trunk and the well as a whole
   - Monitoring and diagnostics of mining modes in real time
2. Proactive development management, increase in oil recovery factor
   - Observation and monitoring during the well cleaning process allows you to get the flow from each interval
   - Water and gas breakthrough management with model-based development supervision
   - A more complete study of heterogeneous reservoirs with an improved interference test method with an expanded set of options
   - Alignment of vertical and horizontal injectivity profile
3. Overall reduction in the cost of well ownership
   - Reduction of the well stock and surface infrastructure, increased reservoir penetration ratio
   - No downtime or production restrictions during research or diagnostics
   - Efficient interdisciplinary collaboration, decision support through the use of user-friendly products

Accuracy as the basis for decision making:

- High-precision measurements of pressure, temperature, water cut, production rates, determination of fluids in sidetracks provide comprehensive management of reservoir development;
  - Operational production data serves for early detection and estimation of water inflow
  - Production monitoring with self-diagnostics and alarms provide proactive management of reservoir drainage

- Hydrodynamic studies in every interval during production to monitor and refine production and reservoir models in real time with minimal production delay
- Integration with SCADA and iField systems for data transfer from the well to the workplace

Now let's look at the design of the system.

The Manara Well Completion System is a fully electronically controlled, integrated system that operates with multiple measuring stations connected to a single control line via the field-proven Wellnet telemetry system. Each station has 2 pressure and temperature sensors, a Venturi flow meter and a water cut sensor. The electrically driven inflow regulator provides stepless position control. The installation of sensors above the inflow regulator allows to conduct hydrodynamic studies while simultaneously producing from other intervals. This will allow to collect a large amount of data on the behavior of the reservoir with minimal impact on the production process itself. Ground modules and modules for real-time data collection have a special design that takes into account the need to monitor the operation of the system and optimize client interfaces. Several more Answer Products are in development, which include user-supported well design and optimization software.

Using this system at another field, it was possible to increase production by 25% compared to the initial production.

10. Conclusion

In this work the basic information about the field, the geological structure of the field, the design and profile of the well were considered. The calculation of the parameters of the drilling mode and performance of the bits was carried out, as well as the calculation of the drill string and the hydraulic program for flushing the well, and the well completion systems were considered.

The main aim of this work was to improve the technology of drilling the interval for the production string, as well as to improve the completion system. As a result of the performed calculations, it was found that the drilling technology can be improved due to the use of the RSS together with the PDM.

Summing up the work done, I want to note that:

- The economic effect from the improvement of drilling technology amounted to 48,5 thousand dollars;
- 32 hours of production time was saved;
- There is an opportunity to increase the flow rate by 25%.

I would like to note that it is necessary to constantly improve both drilling technology and completion technology. This is how we can achieve a reduction in the cost of work, and therefore earn more money.

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Appendix A

Table A.1 – Description of formulas

Equation number	Equation	Description
6.8	$m = \alpha_{\text{d}}\left(\frac{28}{n} + 0{,}14\right)D_{\text{b}}^2$	m – specific torque on the bit, m; α_d - dimensionless coefficient depending on the bit type; D_b – diameter of drilling bit, m; n – idle rate of rotation. $\frac{rev}{min}$;
6.11	$n = (n_{idle} + n_d)\left[1 - \left(\frac{M}{M_{max}}\right)^{\alpha}\right]$	n – rate of rotation of drilling bit, $\frac{rev}{min}$; n_{idle} – idle rate of rotation of motor, $\frac{rev}{min}$; n_d – rate of rotation of drilling string, $\frac{rev}{min}$; α – a coefficient characterizing the; volumetric losses of the drilling fluid in the power section; M – torsion torque, N*m; M_{max}– moment at the max power mode, N*m;
6.10	$P = P_i + M\frac{P_{max}}{M_{max}}$	P – pressure difference in the operating mode of the PDM, MPa; P_i – pressure difference at idle mode, MPa; M – torsion torque in the operating mode, N*m; P_{max} – pressure difference at the max. power mode, MPa; M_{max}– The moment at the max. power mode, N*m;
6.12	$h = \frac{H}{N}$	h – average headway per drill bit, m; H – total interval of drilling, m; N – number of bits;
6.13	$t_d = \frac{T_d}{N}$	t_d – average time of drilling per drill bit, h; T_d - total time of drilling, h; N - number of bits;
6.15	$V_s = \frac{\text{H}}{T_d + T_t}$	V_s – drilling speed per run H – total interval of drilling, m; T_d - total time of drilling, h; T_t - time of run-in-hole, h;

6.16	$$K = \frac{ROP}{n^{\alpha}G^{\beta}}$$	K – adaptation coefficient α, β – empirical coefficients determined based on the results of the actual operation of all bits of the same standard size in the considered interval. n – rate of rotation of drilling bit, $\frac{rev}{min}$; G – thrust load, kN;
6.17	$$C_m = \frac{B+R(T_d+T_{rih})+R_{RSS}T_d}{H}$$	C_m – cost per meter, $\frac{doll}{m}$; B – cost of drilling bit, doll; R – the cost of an hour of operation of the drilling rig, $\frac{doll}{h}$; T_d - total time of drilling, h; T_t - time of run-in-hole, h; R_{RSS} - rental price of RSS, $\frac{doll}{h}$; H – total interval of drilling, m;
6.18	$$C_m = \frac{B + R(T_d + T_{rih}) + R_{pdm}T_d + R_{RSS}T_d}{H}$$ We are using equation 3.3.7. in well №2, so that is why we need to consider rental price of RSS and PDM simultaneously.	C_m – cost per meter, $\frac{doll}{m}$; B – cost of drilling bit, doll; R – the cost of an hour of operation of the drilling rig, $\frac{doll}{h}$; T_d - total time of drilling, h; T_t - time of run-in-hole, h; R_{RSS} - rental price of RSS, $\frac{doll}{h}$; R_{pdm} - rental price of PDM, $\frac{doll}{h}$; H – total interval of drilling, m;