PERIÓDICO TCHÊ QUÍMICA
ARTIGO ORIGINAL

JUSTIFICATIVA PARA A SELEÇÃO DE UM SISTEMA ÓTIMO DE DESENVOLVIMENTO DE CAMPO DE ÓLEO NA PARTE ORIENTAL DO MAR DE PECHORA E SEU CÁLCULO

RATIONALE FOR SELECTION OF AN OIL FIELD OPTIMAL DEVELOPMENT SYSTEM IN THE EASTERN PART OF THE PECHORA SEA AND ITS CALCULATION

ОБОСНОВАНИЕ ВЫБОРА И РАСЧЕТ ОПТИМАЛЬНОЙ СИСТЕМЫ РАЗРАБОТКИ НЕФТЯНОГО МЕСТОРОЖДЕНИЯ ВОСТОЧНОЙ ЧАСТИ ПЕЧОРСКОГО МОРЯ

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RESUMO

A justificativa para a seleção e o cálculo do sistema ideal para o desenvolvimento do campo de petróleo do Mar de Pechora é uma tarefa técnico-científica extremamente difícil. Condições climáticas severas da região do Ártico, cobertura de gelo, limites de formação de poços, taxas lentas de perfuração para campos de petróleo *offshore* e afastamento das bases de suprimentos multiplicam o custo dos projetos e criam dificuldades significativas no projeto de engenharia do sistema de desenvolvimento de campo. Para resolver esses problemas, é preciso usar tecnologias altamente eficientes para o desenvolvimento de campos de petróleo *offshore*, o que garantirá a produção intensiva de petróleo, obtendo assim receitas significativas para pagar as despesas. O objetivo deste trabalho é fornecer a base para a seleção e calcular o sistema ótimo de desenvolvimento para um campo de petróleo na parte oriental do mar de Pechora. A solução das tarefas foi realizada com base nas características identificadas no desenvolvimento de campos de petróleo *offshore* do Ártico, na análise de dados geológicos e físicos no campo de petróleo, em um conjunto de trabalhos teóricos, analíticos e em modelagem matemática. A modelagem matemática foi realizada usando métodos padrão e adaptados para o cálculo de sistemas de desenvolvimento de campos de petróleo. Com base nos dados recebidos, concluiu-se que o sistema linear de poços horizontais é ideal para o desenvolvimento do campo. A vazão crítica e inicial dos poços horizontais e os indicadores tecnológicos básicos foram calculados em função do tempo. A estimativa do fluxo de caixa descontado e do índice de lucro descontado demonstrou que o projeto de investimento pode ser iniciado. Como o campo de petróleo está agora sob exploração suplementar, os dados obtidos na pesquisa podem ser aplicados para projetar o sistema de desenvolvimento de campos de petróleo assim que sua exploração industrial for aprovada.

Palavras-chave: *Zona de prateleira do Ártico, o mar de Pechora, sistema de desenvolvimento.*

ABSTRACT

Rationale for selection and calculation of the optimal system for the development of the Pechora Sea oil field is an extremely difficult scientific-technical task. Severe climate conditions of the Arctic region, ice cover, well stock formation limits, slow rates of drilling for offshore oil fields, and remoteness from supply bases multiply the cost of projects and create significant difficulties in engineering design the field development system. To solve these problems, one needs to use highly efficient technologies for offshore oil fields development, which will ensure intensive oil production, thus obtaining significant revenues to pay off the expenses. The purpose of this work is to provide the basis for selection as well as calculate the optimum development system for an oil field in the eastern part of the Pechora Sea. The solution of the tasks was carried out on the basis of the features identified in the development of Arctic offshore oil fields, the analysis of geological and physical data on the oil field, a set of theoretical, analytical works, and mathematical modeling. Mathematical modeling was performed using standard and adapted methods for calculating oil field development systems. Based on the data received, it was concluded that it is the linear system of horizontal wells, which is optimal for the field development. Horizontal wells critical and initial flow rate and basic technical indicators have been calculated versus time. The estimation of the discounted cash flow and the discounted profit index has demonstrated that the investment project can be

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initiated. Since the oil field is now under supplementary exploration, the data obtained in the research can be applied for designing the oil field development system as soon as its industrial exploitation is approved.

Keywords: A*rctic shelf zone, the Pechora Sea, development system.*

АННОТАЦИЯ

Обоснование выбора и расчет оптимальной системы разработки нефтяного месторождения Печорского моря является исключительно сложной научно-технической задачей. Суровый арктический климат, тяжелые ледовые условия, ограничения по формированию фонда скважин, невысокие темпы разбуривания месторождений и значительная удаленность от баз обеспечения многократно увеличивают стоимость проектов и создают значительные трудности при проектировании системы разработки месторождения. Для решения этих проблем необходимо применение высокоэффективных технологий разработки нефтяных месторождений, которые обеспечат интенсивную добычу нефти для достижения больших объемов выручки с целью окупаемости понесенных затрат. Цель данной работы – обосновать выбор и рассчитать оптимальную систему разработки нефтяного месторождения восточной части Печорского моря. Решение поставленных задач осуществлялось на основе выявленных в работе особенностей освоения арктических шельфовых нефтяных месторождений, анализа геолого-физических данных о нефтяном месторождении, комплекса теоретических, аналитических работ и математического моделирования, выполненного с использованием стандартных и адаптированных методов расчета систем разработки нефтяных месторождений. На основе полученных данных был сделан вывод, что оптимальной для разработки месторождения является линейная система горизонтальных скважин. Проведены расчеты начального дебита горизонтальных скважин, критического дебита, дан прогноз изменения давления на контуре питания и основных технологических показателей разработки. Оценка накопленного дисконтированного денежного потока и дисконтированного индекса доходности показала, что инвестиционный проект может быть принят к реализации. В связи с тем, что месторождение в настоящее время находится в доразведке, полученные в статье сведения могут быть использованы при проектировании системы разработки нефтяного месторождения после принятия решения о начале его промышленного освоения.

Ключевые слова: *Арктический шельф, Печорское море, система разработки.*

1. INTRODUCTION:

In recent years, the Arctic region is entering a new stage of its development connected with the exploitation of its offshore natural resources. The development of the Arctic shelf zone oil fields is the strategic target for Russia. In the long term they are to replenish the depleting onshore resources (Vasil'cov and Vasil'cova, 2018).

The Pechora Sea is one of the richest in hydrocarbons areas of the Arctic shelf zone. Three average-sized and large oil fields have been discovered in its eastern part apart from the Prirazlomnoye field which is being developed at present. However, the development of the Arctic shelf zone oil fields requires the solution of a number of particular problems (Prokhorova *et al*., 2016; Shatalova *et al*., 2014). The latter include severe climate conditions of the Arctic region, hard ice conditions, well stock formation limits, slow rates of drilling for oil fields and remoteness from providing stations. All of these multiply the cost of projects and create obstacles for their implementation. To solve these problems one needs to use highly efficient technologies for the field development which are to ensure intensive oil recovery thus obtaining significant revenues to pay off the expenses (Carayannis *et al*., 2019; Vasil'cov and Vasil'cova, 2018; Yemelyanov *et al*., 2018, 2019).

The main target of this work was to provide the basis for selection as well as calculate the optimum development system capable of intensive oil production with minimal expenses on its construction for an oil field in the eastern part of the Pechora Sea.

2. LITERATURE REVIEW:

2.1 Geological and physical characteristics of the field

The oil field under examination is located in the eastern part of the Pechora Sea, to the south of the Novaya Zemlya archipelago, 80 km north of the mainland (Figure 1). The seabed in the area of the oil field is a low-lying coastal plain sloping gently to the north-west. The sea floor sediments are represented by fine dust sand underlied by loam and clays. Sea depths in the area vary between 25 and 45 metres. The region is seismically stable (Dzyublo, 2009; Yefremkin *et* *al*., 2009; Zhuravlyov *et al*. 2014). The coldest month of the year is January with average temperature of -8 degrees C°, the warmest is July with +7 degrees C°. Average annual temperature is -2 degrees C°. The strongest winds in the area are observed in November to February with the average monthly velocity being 8 metres per second. Maximum wind speed is up to 28 m/s gusting up to 40 m/ s. Ice cover season lasts from November to June. Ice thickness averages between 0,5 and 0,7 metres, reaching the thickest point of up to 1,2 metres. Prevailing height of hummocks is 1,0 – 1,5 metres (4 metres maximum) (Myuller *et al*., 2003; Terziyev *et al*. 1991).

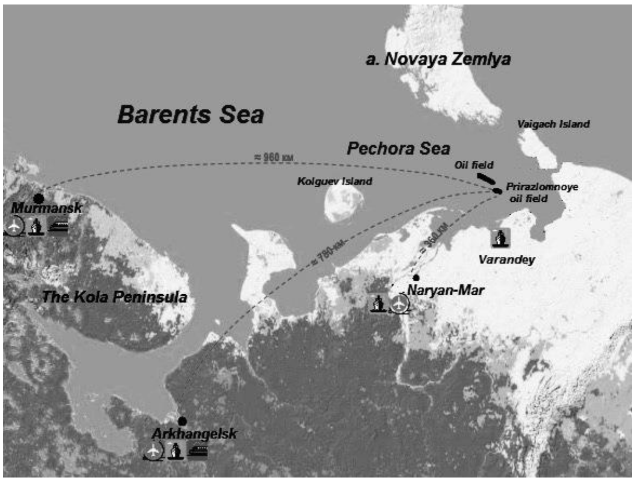


Figure 1. *Overview map of the area*

The oil field is associated with a massive oil reservoir located in Carboniferous sediments (Figure 2). Its structure is a long and narrow anticlinal fold. The size of the reservoir is estimated 45 km long, 2, 0 – 2,5 km wide and 160 m high. Water-oil contact (hereinafter – WOC) is established on the floor of the marginal oil-saturated layer at the point of minus 3285 metres (Dzyublo, 2009; Zhukov *et al*., 2009).

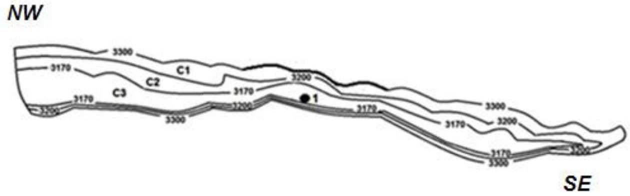


Figure 2. *Oil field diagram (Zhukov et al., 2009).* ***Legend*****.** ● 1 Prospective borehole; —3200 — roof isolines of productive horizons; C1, C2, C3 are target oil-bearing layers represented by carbonate rocks in C1 –C3 horizons.

Productive reservoir bed is associated with the sediments of Serpukhov and Bashkir floors of the Lower Carboniferous period. The reservoir is mainly made up of grained, silt-grained limestones and stretches throughout the field (Abstract on the feasibility study (draft), 2020). The reservoir is of fractured and porous type. Additional characteristics of the reservoir are given in table 1. The overlying seals are represented by the Kungurian sediments of the Lower Perm period (Zhukov *et al*., 2009). An exploration well was drilled within the oil field. During the_exploratory drilling while layers was testing the oil flow rate was received 168 m^3 a day, gas -29264m^3 a day , gas factor 174m^3/m^3. The recovered oil is light, sulfurous, paraffinic and low in tar. Its density is 0,842 gr/cm^3. The geophysical research of the Middle and Upper Carboniferous sediments suggests that they contain industrial oil reserves which have not been confirmed so far by drilling and testing of the layers (Dzyublo, 2009; Tanygin *et al*. 2014; Zhuravlyov *et al*. 2014).

Since the field under examination is located in the area with hard ice conditions, the only possible method of its development is to install gravity-based structure (hereinafter – GBS) (Wang *et al*., 1994).

2.2 The basis for the field development system selection

Developing the Arctic offshore fields has a number of features. To begin with, the projects are highly capital – intensive. Launching such projects is preceded by costly and time-consuming engineering, research and construction activities in the severe climate and hard ice conditions (Matskevitch, 2007). For instance, the engineering of the Prirazlomnoye oil and gas field, also located in the Pechora Sea, was estimated to be 3 billion dollars by its developers PAO "Gazpromneft" (public joint stock company) (Forbes, 2013**)**. Of which 1,5 are the costs of GBS and 1,5 are drilling expenditures. Therefore, it is essential to apply highly efficient technologies for the field development which are to ensure intensive oil recovery thus obtaining significant revenues to pay off the expenses (Gazprom neft, 2020). Alongside this, development systems are traditionally required to provide high degree of oil extraction (Alkhimov *et al*. 2008; Hermawan *et al*., 2019; Seyyedattar *et al*. 2019; Lin *et al*., 2019; Rahman, 2017).

The development systems engineering is complicated by the limits of well stock formation, which depends on the GBS capabilities. High cost of drilling also influences the number of wells (Shandrygin and Dubrovsky, 2015). The price of a single Arctic shelf well construction is more than 50 million dollars. Companies involved in the extraction of hydrocarbons in the Arctic shelf zone, have to develop and implement new technologies constantly in order to reduce the number of wells and hence diminish the drilling expenses and improve the economics of the projects (Osisanya, 1997).

Field development systems are constructed on the basis of inclined directional wells with long horizontal section (hereinafter – horizontal wells) (Ozkan and Raghavan, 1990). As practice shows, such systems only are capable of providing profitable oil extraction on the Arctic shelf zone due to the fast rates of development (Lacy *et al*., 1992; Joshi and Ding, 1996; Thakur, 1999).

The Prirazlomnoye field, where all the production and injection wells have long horizontal section, may serve as an example to this. A 6474 metre long well with horizontal deflection from the vertical axis of 4989 metres was drilled on the field in 2018. Maximum horizontal deflection length wells is planned 6300 metres. Also, highly technological multi-hole “fishbone” well is being drilled on the field. Figure 3 shows the distribution of horizontal wells on the Prirazlomnoye field, 6m variant (Figure 3).

From the analysis of the pattern of wells distribution it can be concluded that it was developed taking into account the size of the oil field, besides, the position of production and injection wells is influenced by the profitability of drilling. The tasks are solved, such as: maximum resource involvement, obtaining high coverage rate and oil recovery factor and introducing water into the reservoir using injection wells for compensation of extracted oil (Alkhimov *et al*. 2008; Lin *et al*., 2019; Alekseev *et al*. 2017).

Finding wellheads of all wells within the limited area of GBS influences the direction of well drilling. That is, if an oil-bearing structure is represented by a long narrow anticlinal fold such fields on land are generally developed by systems of cross-sectional horizontal wells. For instance, the Mikhailovskoye oil field which is located in Bashkiria (Figure 4) (Berdin, 2001). However, offshore fields are commonly developed by systems of wells with long horizontal sections, drilled lengthwise the oil-bearing structure (Figure 3). Drilling transverse wells from GBS is also possible but has some disadvantages. Wells like that will be 10-15% longer which will increase the cost of drilling and thus harm the economics of the project. The trajectory of wells will be very complicated; hence the management and control of wells will be hard to perform which can result in accidents and even loss (Giannesini, 1988).

The selection of the development system is complicated by low projected rates of drilling on the field. The experience of the Prirazlomnoye field exploitation demonstrates that no more than 4 wells on average can be drilled annually on one GBS in the Arctic shelf zone. This could be explained by difficulties in organising logistics operations aimed at delivery of equipment and stuff for drilling to GBS, especially in winter months (Alkhimov *et al*. 2008; Oganov, 2005).

Assuming that the field is associated with a long narrow anticlinal fold and specific features of the Arctic shelf oil fields exploitation it is evident that the development of the oil field under examination must be conducted using linear system of horizontal wells comprising one row of production wells, placed centrally and lengthwise the oil-bearing structure and two rows of injection wells placed along the oil-bearing boundary from its southern and northern sides. The proportion of production and injection wells is 1:1 (Kuznetsova *et al*., 2017).

Since the deflection of wells from the vertical axis reaches 6300 m on the Prirazlomnoye field, the length of the field section for development could be up to 12 km (Figure 5).

3. MATERIALS AND METHODS:

Calculating optimum length of horizontal sections. Since the main criterion of the Arctic shelf zone drilling is its economic profitability, the length of horizontal sections of wells should be calculated on the basis of accumulated discounted cash flow estimation (hereinafter – *NPV*). Thus the optimum length of the horizontal sections will be the one at which *NPV* is the largest (Osisaniya, 1997; Mukhametshina *et al*., 2005).

3.1 Calculus of cash flow

Oil production (in million tonnes per year) is determined at the flow rate of the well corresponding to the length of the horizontal section of the well; cash flow is calculated by multiplying the amount of recovered oil by oil cost per one ton in dollars.

$$NPV = \sum CF_i \alpha - CE \qquad (1)$$

where CF_i – cash flow in i – year (in dollars); α – discount factor; CE – capital expenditures in dollars.

$$\alpha = \frac{1}{(1+E)^{t-1}} \qquad (2)$$

where E – discount rate, %; t – sequence number of the year of project implementation.

The total cost of a well construction was attributed to capital expenditures, taking into account the complication factor when drilling a horizontal section.

After obtaining data, a graph is drawn, showing the correlation between NPV and the length of a horizontal section. The length value of the horizontal section of a well at the inflection point will be optimal (Dosunmu *et al*. 2015; Tadeu *et al*., 2019; iannesini 1988; Rahman and Bobkova, 2016).

3.2 Calculating horizontal wells initial flow rate

Horizontal wells initial flow rate (hereinafter – initial rate) has been calculated using Joshi's method (Joshi, 1991; Ahmed 2010).

Initial rate is computed by

$$Q_{oh} = \frac{0{,}00708 h k_h \Delta P}{\mu_0 B_0 \left[\ln(Z) + \left(\frac{B^2 h}{L}\right) \ln\left(\frac{h}{2r_w}\right)\right]} \qquad (3)$$

where B – the factor characterizing the bed anisotropy; L – the length of a horizontal section, ft; μ_0 – oil viscosity, cP; B_0 – oil formation volume factor, bbl/STB; h – effective stratum thickness, ft; r_w – wellbore radius, ft; ΔP – pressure drop from the drainage boundary to wellbore, psi; k_h – horizontal permeability, md; k_v –vertical permeability, md.

Bed anisotropy factor is determined by

$$B = \sqrt{\frac{k_h}{k_v}}, \qquad (4)$$

Z – parameter is found by the formula:

$$Z = \frac{a + \sqrt{a^2 - \left(L/_2\right)^2}}{\left(L/_2\right)} \qquad (5)$$

where a – half the major axis of the drainage ellipse.

$$a = \left(L/_2\right)\sqrt{0{,}5 + \sqrt{0{,}25 + \left(2r_{eh}/_L\right)^4}} \qquad (6)$$

where r_{eh} – horizontal well drainage radius, ft.

3.3 Calculating horizontal wells critical flow rate

The value of the production rate at which water cone is stationery and water breakthrough are not available is called critical. To calculate the horizontal wells critical flow rate (hereinafter – critical rate) Chaperon's method has been used (Chaperon 1986; Ahmed 2010).

The critical rate is determined by the formula:

$$Q_{oc} = 0{,}0783 \cdot 10^{-4} \left(\frac{Lq_c^*}{r_{eh}}\right)(\rho_w - \rho_0) \frac{k_h[h-(h-D_b)]^2}{\mu_0 B_0}, \qquad (7)$$

$$Q_{oc} = 0{,}0783 \cdot 10^{-4} \left(\frac{Lq_c^*}{r_{eh}}\right)(\rho_w - \rho_0) \frac{k_h[h-(h-D_b)]^2}{\mu_0 B_0}, \qquad (8)$$

where L – the length of a horizontal section, ft; q_c* – dimensionless function; r_{eh}– horizontal well drainage radius, m; ρ_0 – oil density, lb/ft^3; ρ_w = water density, lb/ft^3; μ_0 – oil viscosity, cP; B_0 – oil formation volume factor, bbl/STB; k_h – horizontal permeability, md; h – effective stratum thickness, ft; D_b – distance between the WOC and the horizontal well, ft.

Dimensionless function is found by Joshi's formula (Joshi, 1991; Ahmed 2010):

$$q_c^* = 3{,}9624955 + 0{,}0616438 \cdot \alpha'' - 0{,}000504 \cdot (\alpha'')^2 \quad (8)$$

α'' parameter is found by the formula:

$$\alpha'' = \left(\frac{r_{eh}}{h}\right)\sqrt{\frac{k_v}{k_h}} \quad (9)$$

α'' values lie within the framework: $1 \le \alpha'' < 70$ and $2r_{eh}$ < 4L.

3.4 Calculating horizontal well breakthrough time

To estimate the horizontal well breakthrough time Papatzacos' method has been applied (Papatzacos *et al*, 1991; Høyland *et al*., 1989; Ozkan 1990). The time to water breakthrough as expressed in days is calculated by the formula:

$$t_{BT} = \frac{22758{,}528 h m \mu_0 t_{DBT}}{k_v(\rho_w - \rho_0)} \quad (10)$$

where ρ_0 – oil density, lb/ft^3; ρ_w – water density, lb/ft^3; h – effective stratum thickness , ft; μ_0 – oil viscosity, cP; m – porosity, fraction, %; t_{DBT} – dimensionless breakthrough time; k_v – vertical permeability, md.

The dimensionless breakthrough time t_{DBT} is determined by the formula:

$$t_{DBT} = 1 - (3q_D - 1)\ln\left(\frac{3q_D}{3q_D - 1}\right) \quad (11)$$

The dimensionless rate (q_D) is determined by the formula:

$$q_D = \frac{20333{,}66\mu_0 B_0 Q_0}{Lh(\rho_w - \rho_0)\sqrt{k_v k_h}} \quad (12)$$

where μ_0 – oil viscosity, cP; B_0 – oil formation volume factor, bbl/STB; Q_0 – oil flow rate, STB/day; L – the length of a horizontal section, ft; h – effective stratum thickness, ft; ρ_0 – oil density, lb/ft^3; ρ_w – water density, lb/ft^3; k_h – horizontal permeability, md; k_v–vertical permeability, md.

3.5 Forecast of pressure variations at the well drainage boundary

In order to estimate pressure variations at the well drainage boundary during the oil field development Y. Zheltov's method has been used, taking into account the fact that in the time of drilling t* which is 3 years, the volumes of water coming from the edge water zone and liquid withdrawal from the formation are variables in time (Zheltov 1998; Laperdin, 2013).

The calculations have been done for:

- the period of increasing liquid yield – $0 \le t \le t^*$;
- the period of constant liquid yield – $t^* \le t \le t^{**}$;
- the period of first water injections into the edge water zone; while the current liquid withdrawal is partially compensated by water injections into the bed and its inflow from the edge water zone – $t^{**} \le t \le t^{***}$;
- the period in which oil is forced out only by water injection into the edge water zone – $t \ge t^{***}$.

It has been assumed that the area of the field under consideration has an ellipsoidal shape. In order to define the external boundary radius, we have represented the field as a circle whose radius has been calculated basing on the ellipse perimeter. A circle area is larger than that of an ellipse; consequently, the former was diminished to be equal to the latter. Thus we got the external boundary radius equal to the circle radius reduced to the area of the original ellipse (*R*, m) (Gimatudinov *et al.*, 1983).

Boundary pressure with $0 \le t \le t^*$ is determined by the formula:

$$p_{con}(\tau) = p_0 - \frac{\mu_w \alpha_0 R^2}{2\pi khX} J(\tau) \quad (13)$$

where R – external boundary radius, m; p_0.– formation pressure, psi; μ_w – water viscosity, cP; α_0 – annual extraction from newly introduced wells, m^3/year^2; X – piezoconductivity quotient, ft^2/sec; k – fracture formation permeability, md; h – effective stratum thickness, m.

Thus, the reduced time τ is determined by the formula:

$$\tau = \frac{Xt}{R^2} \quad (14)$$

where t – years.

The value of the integral $J(\tau)$ is calculated by the formula:

$$J(\tau) = 0{,}5\tau - 0{,}178[1 - (1-\tau)^{-2{,}81}] + 0{,}487[(1+\tau)\lg(1+\tau) - \tau] \quad (15)$$

The boundary pressure with t^*≤t≤t^(**) is determined by the formula:

$$p_{con}(\tau) = p_0 - \frac{\mu_w \alpha_0 R^2}{2\pi khX}[J(\tau) - J(\tau - \tau^*)] \quad (16)$$

The boundary pressure with t^(**)≤t≤t^(***) is determined by the formula:

$$p_{con}(\tau) = p_0 - \frac{\mu_w \alpha_0 R^2}{2\pi khX}[J(\tau) - J(\tau - \tau^*)] - \frac{\mu_w \alpha_0' R^2}{2\pi khX} J(\tau - \tau^{**}) \quad (17)$$

where α_0' – conversion factor.

The boundary pressure with $t \ge t^{***}$ is determined by the formula:

$$p_{con}(\tau) = p_0 - \frac{\mu_w \alpha_0 R^2}{2\pi khX}[J(\tau) - J(\tau - \tau^*)] - \frac{\mu_w \alpha_0' R^2}{2\pi khX}[J(\tau - \tau^{**}) - J(\tau - \tau^{***})] \quad (18)$$

3.6 The main indicators of the field development

The calculation of technological indicators of the field development was made using TatNIPIneft (Tatar Scientific Research and Design Institution) methodology (hereinafter – method) for the model of a layer-by-layer and zonally heterogeneous in its reservoir properties bed

(Laperdin, 2013). Apart from layer-by-layer heterogeneity the oil field development indicators are influenced by the difference between oil and water viscosity, as well as incomplete water- oil displacement. The effect of these factors is determined by a complex value – calculated layer-by-layer heterogeneity. While calculating horizontal wells are replaced by vertical ones considering the production rate of horizontal and vertical wells (Borisov *et al*., 1964).

3.7 Calculation of development indicators

The density of well pattern is determined by the formula:

$$S_c = \frac{S}{n_0} \quad (19)$$

where S – oil-bearing area, m^2; n_0 – total number of wells in the field.

The ratio of production and injection wells at which the maximum amplitude production rate is achieved can be calculated by the formula:

$$\bar{m} = \frac{\alpha + 1}{\alpha}\sqrt{\mu_*} \quad (20)$$

where α – the indicator taking into account differences between average recovery factor of extraction and injection wells (depends on zonal heterogeneity); μ_* – the quotient accounting mobility of the displacing agent (water) and oil in bed conditions.

$$\alpha = \frac{1}{U_3^2}\left[0{,}3 - \frac{0{,}02}{U_z^2}\right] \quad (21)$$

where U_3^2 – zonal heterogeneity.

$$\mu_* = \frac{\mu_0}{\mu_w}[1 - 1{,}5(1 - K_2)] \quad (22)$$

where μ_0 – oil viscosity, cP; μ_w – water viscosity, cP; K_2 – water-oil displacement factor.

The maximum rate of recoverable oil reserves withdrawal is reached when the initial ratio of production and injection wells is $m = 1{,}2 \cdot \bar{m}$.

The relative well injectivity factor (v) of the wells selected for injection purposes is determined by the formula:

$$v = \frac{\alpha + 1}{\alpha + 1 - \frac{m}{m+1}} \quad (23)$$

The relative wells productivity function (φ) is determined by the formula:

$$\varphi = \frac{1}{\frac{1}{v\mu_*} + \frac{1}{1 + m - v}} \cdot \frac{1}{m+1} \quad (24)$$

The amplitude production rate of the whole oil reservoir under examination is determined by the formula:

$$q_0 = 365 K_{av} n_0 \Delta p \varphi \quad (25)$$

where K_{av} – average productivity quotient, tonnes/day·Pa; Δp – pressure differential between production and injection bottom-holes, Pa.

3.8 Calculation of oil reserves exploitation characteristics

Mobile oil reserves (Qm) are determined by the formula:

$$Q_m = Q_b K_1 K_2 \quad (26)$$

where Q_b – balance oil reserves (in million tonnes); K_1 - well pattern factor showing the share of oil bed volume under this well distribution; K_2 – water-oil displacement factor.

$$K_1 = 1 - a \cdot S \quad (27)$$

where a – constant quotient (a=0,2); S – one well area, km^2.

The estimated layer-by-layer heterogeneity of the bed is determined by the factor (U_p^2), which is calculated by the formula:

$$U_p^2 = U_1^2 + (U_1^2 + 1)\frac{(U_3^2 + 1)}{\left(\frac{U_3^2}{4} + 1\right)} \cdot \frac{2{,}2}{m+1} \quad (28)$$

where U_1^2 – layer-by-layer heterogeneity.

The marginal share of water in liquid rate of production well is calculated by the formula:

$$A = \frac{A_2}{(1 - A_2)\mu_{0z} + A_2} \quad (29)$$

where A_2 – marginal mass share of water, %, μ_{0z} – a factor which takes into account distinctions between a displacing agent and reservoir oil in mobility in μ_* times and density in ρ_* times.

$$\rho_* = \frac{\rho_w}{\rho_0} \quad (30)$$

where ρ_0 – oil density, lb/ft^3; ρ_w – water density, lb/ft^3.

$$\mu_{0z} = 0{,}5(1 + \mu_*)\rho_* \quad (31)$$

Mobile oil exploitation factor (K_3) under the given layer-by-layer bed heterogeneity (U_p^2) and marginal share of the agent (A) is:

$$K_3 = K_{n3} + (K_{к3} - K_{n3})A \quad (32)$$

$$K_{n3} = \frac{1}{1{,}2 + 4{,}2U_p^2} \quad (33)$$

$$K_{к3} = \frac{1}{0{,}95 + 0{,}25U_p^2} \quad (34)$$

Estimated total liquid withdrawal in fractions of mobile oil reserves (F) is determined from the ratio:

$$F = K_{n3} + (K_{к3} - K_{n3}) \ln \frac{1}{1 - A} \quad (35)$$

Initial recovered liquid (Q_{F0}) and oil (Q_0) reserves are determined by the formulas:

$$Q_{F0} = Q_m F \quad (36)$$

$$Q_0 = Q_m K_3 \quad (37)$$

Mass recovered liquid reserves (Q_{F02}) under surface conditions will be:

$$Q_{F02} = Q_0 + (Q_{F0} - Q_0) \cdot \mu_{0z} \quad (38)$$

Average mass fraction of water in total liquid recovery is determined by the formula:

$$A_{av} = 1 - \frac{Q_0}{Q_{F02}} \quad (39)$$

Oil recovery factor is determined by the formula:

$$K_{ro} = \frac{Q_0}{Q_b} = K_1 K_2 K_3 \quad (40)$$

3.9 Estimating oil and water production rates dynamics

In order to estimate oil production within the task under consideration the process of the field development has been divided into the following stages:

- Stage 1 – the stage of field commissioning (lasts 3 years). New production wells are started (3 wells a year). The development is conducted in the depletion mode and reservoir pressure does not go below the saturation pressure, with elastic regime prevailing;
- Stage 2 – the stage of extraction with constant production rate (lasts 3 years). A system of reservoir pressure support, which consists of 9 injection wells, is formed;
- Stage 3 – the stage lasts until the maximum water cut. Under the Arctic shelf condition it averages 95%;

The current oil production rate is determined by the formula:

$$q_t = \frac{\frac{q_0}{Q_0}}{1 + 0{,}5 \frac{q_0}{Q_0}} \left[Q_0 \frac{n_{t0}}{n_0} - (q_1 + q_2 + \cdots + q_{t-1}) \right] \quad (41)$$

The estimated current liquid rate under reservoir conditions is determined by the formula:

$$q_{tF} = \frac{\frac{q_0}{Q_{F0}}}{1 + 0{,}5 \frac{q_0}{Q_{F0}}} \left[Q_{F0} \frac{n_{t0}}{n_0} - \left(q_{F1} + q_{F2} + \cdots + q_{F(t-1)} \right) \right] \quad (42)$$

The mass current liquid rate under surface conditions is determined by the formula:

$$q_{tF_2} = q_t + (q_{tF} - q_t)\mu_{0z} \quad (43)$$

On the third stage the calculations are made with $\frac{n_{t0}}{n_0} = 1$ (n_{t0} – the number of operating wells in *t* – year) (Laperdin, 2013).

The fourth stage of the field development could also be distinguished. The rate of oil withdrawal amounts 1-2% from the initially extracted reserves, while the water cut exceeds 95%. Oil production rate at this stage is determined by the formula:

$$T_d = \frac{q_t}{Q} \quad (44)$$

where Q – accumulated oil production in million tone; *t* – year.

3.10 Simplified calculating economic efficiency of the project implementation

Economic efficiency of the project is estimated by calculating the accumulated discounted cash flow and discounted profitability index.

Discounted cash flow PV is calculated by the formula:

$$PV = P \cdot \alpha \quad (45)$$

where P – profit in million dollars; α – discount factor.

The profit is determined by the formula:

$$P = В - \gamma - CE \quad (46)$$

where CE – capital expenditures in dollars; B – product sales revenue in dollars; γ – conditionally-variable cost of oil production in million dollars.

Revenue on product sales is determined by the formula:

$$B = Q \cdot C \quad (47)$$

where Q – annual oil production in million tonnes; C – the price of oil sale in dollars per 1 tonne.

Conditionally-variable cost of oil production is determined by the formula:

$$\gamma = Q \cdot C' \ (48)$$

where C' – the cost of oil production in dollars per 1 tonne.

The accumulated discounted cash flow is determined by the formula:

$$NPV = \sum PV \quad (49)$$

Discounted profitability index is determined by the formula:

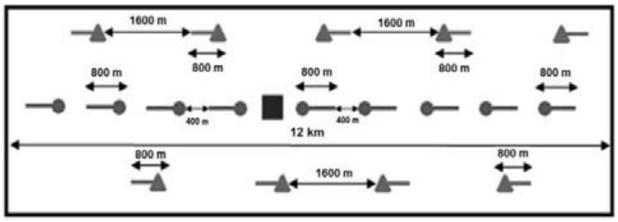
$$DPI = 1 + \frac{NPV}{(\sum CE) \cdot \alpha} \quad (50)$$

4. RESULTS AND DISCUSSION:

Source data for calculations are provided in table 2.

1. Calculation of optimal length of horizontal sections is based on the discounted cash flow rate estimation using the formulas 1 and 2. In order to make calculations, the cost of 1 meter well drilling has been agreed as 6178 dollars without taking into account the complication factor when drilling a horizontal section. The total cost of a well construction, 50,4 million dollars, has been included in capital expenditures taking into account the complication factor, when drilling a horizontal section. Basing on the obtained data, a graph has been drawn (Figure 6) according to which the optimal horizontal section of wells on the oil field is 800 meters long.

Basing on the calculated length of horizontal section, we can represent the schematically linear system of the field development (Figure 7).



Legend:
– Horizontal injection well
– Horizontal production well
– GBS

Figure 7. *The system of the field development diagram*

2. The initial rate was determined according to the Joshi's method by the formulas 3-6.

$$Q_o = 486{,}5 \ \mathrm{m}^3 \text{ per day.}$$

3. The critical rate was determined according to the Chaperon's method by the formulas 7-9.

$$Q_{oc} = 3{,}42 \ \mathrm{m}^3 \text{ per day}$$

The low value of the critical rate is caused by the relatively fast water breakthrough to horizontal wells. The obtained value was not used in further calculations being much smaller than initial rate. The initial rate was used instead.

4. The horizontal well breakthrough time as expressed in days was calculated according to the Papaptzacos' method by the formulas 10-12.

$$t_{BT} = 122 \text{ days}$$

5. The pressure at the well drainage boundary in the course of the field development was determined using Y. Zheltov's method taking into account the fact that in the period of oil field development (t^* = 3 years) the volumes of water coming from the edge water zone and liquid withdrawal from the formation are variables in time.

Well drainage boundary radius *R* = 2547,5 m. Evaluation of pressure variations at the well drainage boundary has been made by the formulas 13-18 and are shown in table 3. While calculating horizontal wells were replaced by vertical ones with 1 horizontal well being equal to 3 vertical wells. This replacement was made due to the correlation between the calculated horizontal well initial flow rate (486,5 m^3 per day) and prospective vertical well flow rate (168 m^3 per day).

Field development indicators were calculated by the formulas 19-25 and are represented in table 4.

Oil reserves exploitation parameters were determined by the formulas 26-40 and are represented in table 5.

The dynamics of basic technological indicators was determined by the formulas 41-44 and is represented in table 6.

The oil recovery factor value for the whole period of the field development is represented in figure 8.

The field development schedule is presented in figure 9.

Oil recovery rate after 25 years of development T_d=0,0087 →0,87%. Consequently, after 25 years of exploitation the field passed to the fourth stage with the rate of oil withdrawal being lower than 1% and product water cut of 84,63%.

Economic efficiency of the field development has been determined according to the formulas 45-50. Capital expenditures are presented in table 7.

In the first year of exploitation the capital expenditures will be 2111,2 million dollars. These costs comprise the price of GBS, ice-class tankers, supply vessels and 3 wells (50,4 million dollars each).

Three wells are planned to be drilled annually between the second and the sixth years, with capital expenditures being 151,4 million dollars. Subsequently capital expenditures are 0.

1. The cost of oil production is accepted to be 219,9 dollars per 1 tonne.
2. The cost of oil sale is accepted to be 806,3 dollars per 1 tonne.
3. Annual operational expenditures on the project implementation have been accepted to be 100 million dollars.
4. The project funding is provided by the company's own resources.
5. The project is expected to be launched in 2031.

Estimated economic outcome of the field development is provided in table 8. The given calculations incorporate the whole period of the field development (39 years). The accumulated discounted cash flow graph on the annual basis is given in figure 10.

It should also be mentioned that no project involving hydrocarbon recovery on the Arctic shelf can be implemented in the Russian Federation under the current tax system. Tax incentives are required for all such projects. Consequently, the current assessment was carried out without considering tax contribution.

At present there are no generally accepted principles and approaches to design and implement systems of Arctic shelf oil field development with specified features (Khaibullina, 2016). This has become the issue of concern while writing the given research paper.

5. CONCLUSIONS:

The present research paper studied the oil field situated in the eastern part of the Pechora Sea on the Russian Arctic shelf zone. Basing on the obtained geological and physical data about the oil reservoir structure and revealed specific features of the Arctic offshore oil field development, the optimum system of the field exploitation has been selected and analysed. The following conclusions have been drawn:

1. The oil field is associated with a massive oil reservoir located in Carboniferous sediments. Its structure is a long and narrow anticlinal fold. The size of the reservoir is estimated 45 km long, 2,0 – 2,5 km wide and 160 m high. The oil of the oil field is light with the density of 0,842 gr/sm^3, sulfurous, paraffinic and low in tar. One prospective borehole has been drilled on the locality. The field is undergoing additional exploration.
2. The field is located in the area under hard ice conditions with ice thickness reaching 1,2 m in its upmost period. As a result, the only feasible way of the field development is to install the gravity-based structure.
3. Production and injection wells stock formation is limited by the potential of the gravity-based structure, which is the only possible one for oil recovery on the given field, and the high cost of drilling (50,4 million dollars a well).
4. The field development system needs to be engineered using inclined directional wells, since such a system solely is capable of providing profitable oil production on the

Arctic shelf zone due to the fast rate of the field exploitation. By doing so we involve the maximum of resources in the process of development, acquire high coverage rate, oil recovery factor and necessary withdrawal compensation by introducing water into the reservoir through injection wells.

5. The rate of drilling is not expected to be fast. No more than four wells can be drilled on the field per 1 year. This can be explained by difficulties in organising logistics operations to deliver equipment and other stuff necessary for drilling to GBS, especially in winter.
6. Since oil-bearing structure is represented by long and narrow anticlinal fold, the field development is made feasible by using the linear system of horizontal wells, drilled lengthwise the oil-bearing structure.
7. Due to the identified geological and physical features of the oil-bearing structure as well as the specificity of the field development and engineering, the linear system of horizontal wells will be the most favorable one for its exploitation. This system consists of one row of production wells, placed centrally and lengthwise the oil-bearing structure and two rows of injection wells placed along the oil-bearing boundary from its southern and northern sides; production and injection wells ratio is 1:1.
8. The optimal length of the horizontal section of wells is 800 m, calculated on the accumulated discounted cash flow assessment. With this taken into account, the designed linear development system consists of 9 production and 9 injection horizontal wells. The approximate length of the field section under development could be up to 12 km.
9. The horizontal wells initial flow rate, calculated using Joshi's method is 486,5 m^3 per day.
10. The horizontal wells critical flow rate, calculated using Chaperon's method is 3,42 m^3 per day. The low value of the critical rate is caused by the relatively fast water breakthrough to horizontal wells.
11. The horizontal wells breakthrough time as expressed in days and calculated by using Papatzacos' method is 122 days.
12. The boundary pressure for the whole period of the field development (39 years) goes down from 36 MPa to 13,26 MPa.
13. By the 39th year of the field development, the following output will have been achieved: the ultimate mass share of water - 95%, oil recovery factor - 0,549 (54,9%), accumulated oil recovery - 11,875 million tonnes, accumulated liquid recovery – 31,219 million tonnes.
14. By the end of the extraction from the field, the accumulated discounted cash flow will have become 257,56 million dollars, profitability index – 1,09. Consequently, the investment project can be accepted for implementation. The project payback period will be slightly over 10 years.
15. The field development is feasible with oil price being a minimum of 110 dollars per barrel.
16. The field development is unfeasible without tax benefits to the project being provided.

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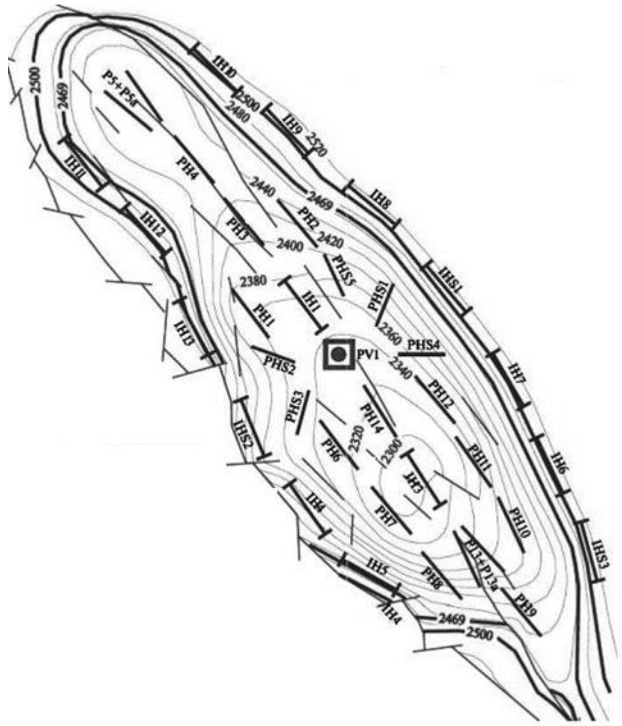


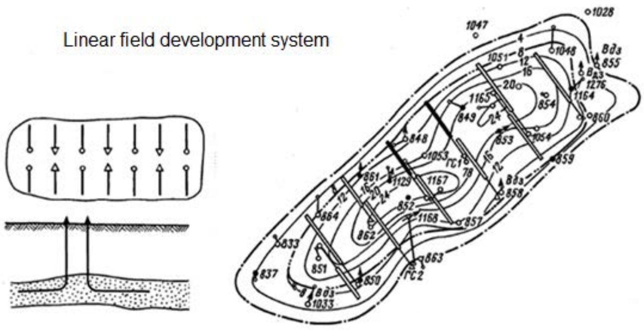
Legend:

2520	– Isolines of productive horizon cover
2500	– Water-oil contact
	– Tectonic disturbances
	– GBS

Wells:

PHS1; PH1	– Horizontal production
P5+P5a	– Double – hole horizontal
IH2; IHS1	– Horizontal injection

Figure 3. *Distribution pattern of horizontal sections of wells on the Prirazlomnoye field. Variant 6 m (Alkhimov et al. 2008)*



Legend:

– Vertical production wells

– Horizontal production wells

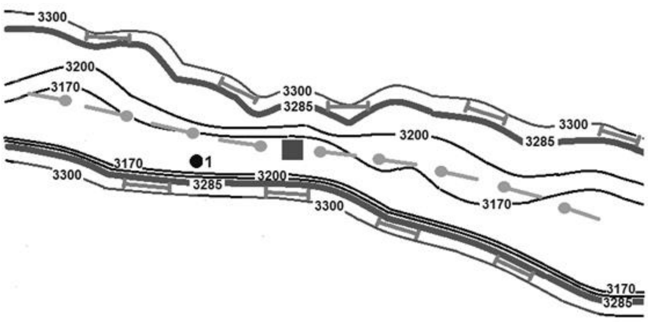
– Horizontal injection wells

– Wells transferred to the upper horizon

– Piezometric transferred wells

– Wells transferred to intaking

Figure 4. *The system of the Mikhailovskoye oil field development (Berdin, 2001)*



Legend:

– Horizontal production wel

– Horizontal injection well

– GBS

3285 – Oil-water contact line

3200 – Isolines of productive horizon cover

1 – Prospective borehole

Figure 5. *Linear field development system*

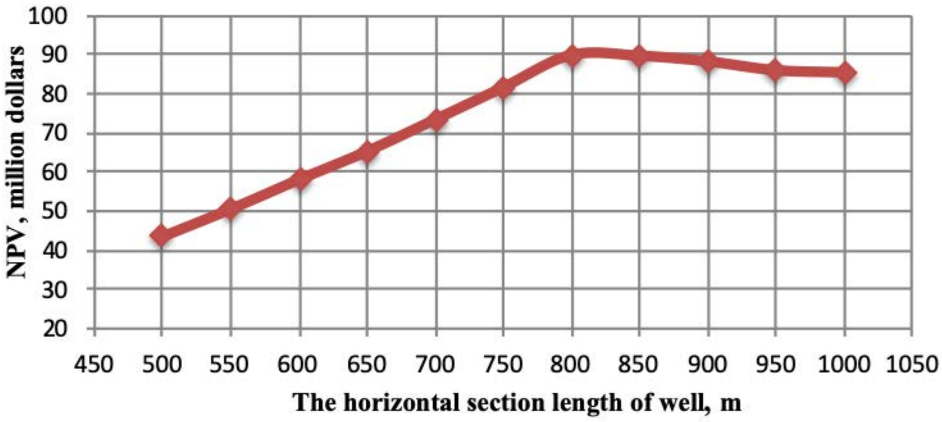


Figure 6. *The graph shows the NPV dependency on the horizontal section length of well*

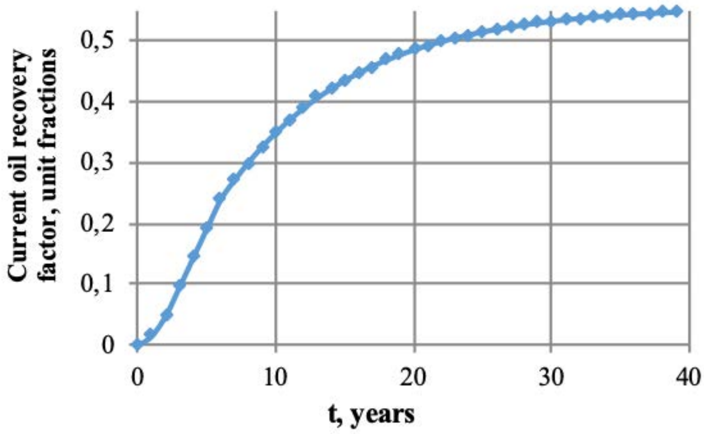
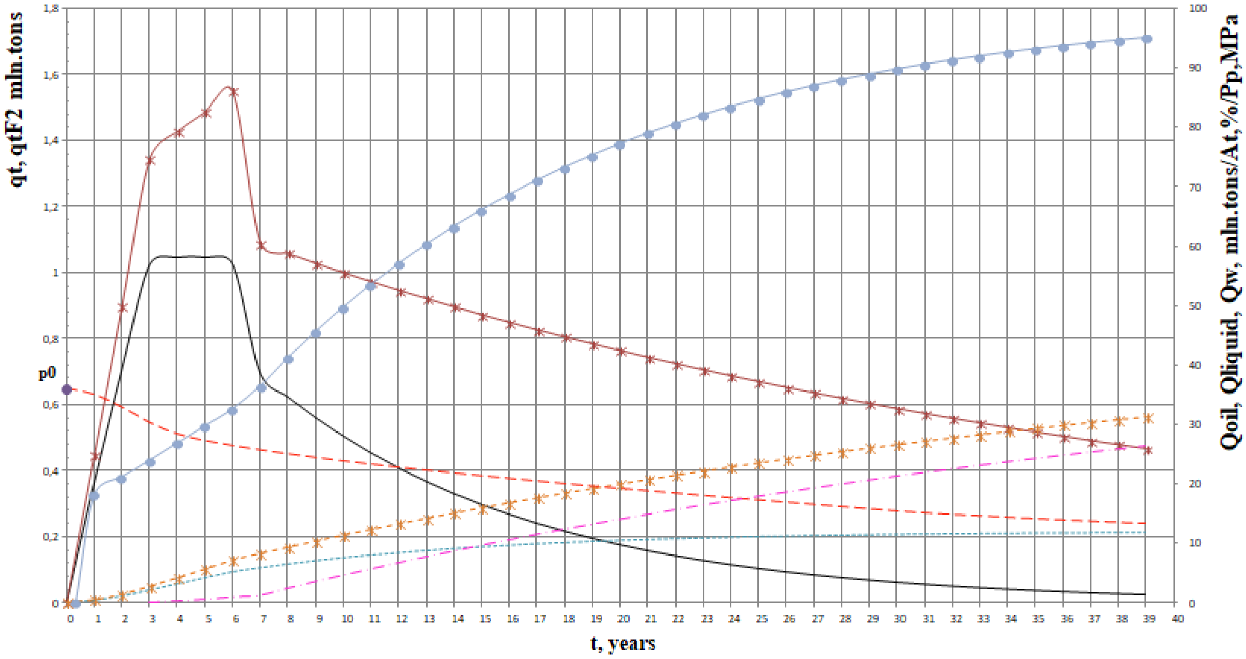


Figure 8. *Oil recovery factor for the whole period of the field development*



Legend:

– q_t, annual oil production, mln tones

– Q_{oil}, cumulative oil production, mln tonnes

– A_t, water cut, %

– Q_w, accumulated volume of injected water, mln.tonnes

– q_{tF2}, annual liquid production, mln tons

– Q_{liquid}, cumulative liquid production, mln tonnes

– P_p, pattern pressure, MPa

Figure 9. *Field development schedule*

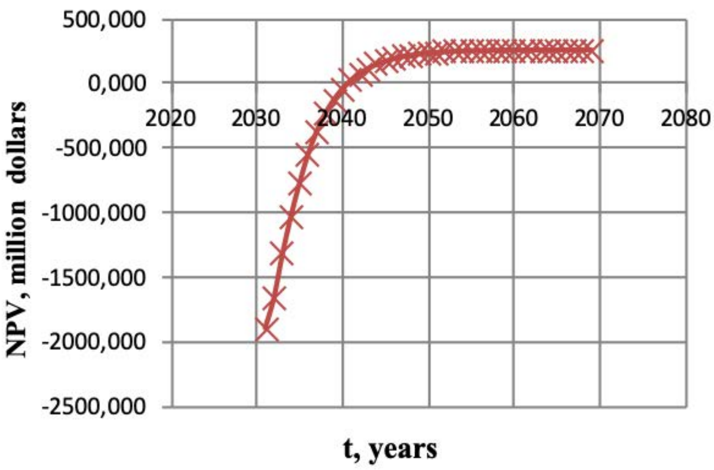


Figure 10. *Annual breakdown of accumulated discounted cash flow*

Table 1. *Geologic characteristics of the reservoir bed in the field*

Formation age	Effective oil-saturated thickness of permeable alternations, m	Reservoir temperature, C°	Saturation pressure, MPa	Formation pressure, MPa	Base oil volume factor	Gas content, m^3/ tonne	Oil density on surface gr/cm^3	Dynamic oil viscosity, MPa·c	Porosity, fraction, %	Permeability factor, sq.mic.	Oil saturation factor, unit fractions (OSF)
C_1	18,8	84	14,9	36	1,32	125	0,842	0,62	8%	$5 \cdot 10^{-3}$	0,8

Table 2. *Source data for calculations*

Parameter	Value in Russian units of measure	Value in British units of measure
Water viscosity, μ_w	1 mPa·s	1 cP
Oil viscosity, μ_0	0,62 mPa·s	0,62 cP
Production well radius, r_w	0,09685 m	0,318 ft
Effective stratum thickness, h	18,8 m	61,68 ft
Porosity, fraction, m	8%	8%
Formation water density, ρ_w	1100 kg/m^3	68,67 lb/ft^3
Oil density, ρ_0	842 kg/m^3	52,56 lb/ft^3
Pressure drawdown, ΔP	5,86 MPa	849,92 psi
Oil formation volume factor, B_0	1,32	1,32 bbl/STB
Horizontal permeability, k_h	$1{,}21 \cdot 10^{-15}$ m^2	1,21 md
Vertical permeability, k_v	$4{,}62 \cdot 10^{-15}$ m^2	4,62 md
Fracture formation permeability, k	$5 \cdot 10^{-15}$ m^2	5 md
Distance to water-oil contact (WOC), D_b	15,24 m	50 ft
Horizontal well drainage radius, r_{eh}	408,4 m	1339,8 ft
Initial water saturation, S_{ws}	0,2	0,2
Residual oil saturation, S_{os}	0,3	0,3
Annual extraction from newly introduced wells, α_0	$0{,}533 \cdot 10^6$ m^3/$year^2$	$0{,}533 \cdot 10^6$ m^3/$year^2$
Piezoconductivity quotient, X	0,09 m^2/s	0,0084 ft^2/sec
Oil-bearing area, S	20388936 m^2	219464680,6 ft^2
Reservoir volume, V	488049000 m^3	17235252464 ft^3
Total number of wells, n_0	18 horizontal	18 horizontal
Water-oil displacement factor, K_2	0,81	0,81
Zonal heterogeneity, U_3^2	0,39	0,39
Layer-by-layer heterogeneity, U_1^2	0,1	0,1
Average productivity quotient, K_{av}	$4{,}1 \cdot 10^{-5}$ t/day·Pa	$4{,}1 \cdot 10^{-5}$ t/day·Pa
Marginal mass share of water, A_2	95%	95%
Saturation pressure, P_s	14,9 MPa	2161,06 psi
Formation pressure, p_0	36 MPa	5221,35 psi
Geological oil reserves of the developed field sector, Q_g	23,61 million tonnes	23,61 million tonnes

Table 3. *Forecast of pressure variations at the well drainage boundary (boundary pressure)*

t, sec, $\cdot10^6$	τ	J(τ)	$\tau-\tau^{*}$	J($\tau-\tau^{*}$)	$\tau-\tau^{**}$	J ($\tau-\tau^{**}$)	$\tau-\tau^{***}$	J ($\tau-\tau^{***}$)	P_p, MPa
31,54	0,437	0,146	-	-	-	-	-	-	34,946
63,08	0,875	0,438	-	-	-	-	-	-	32,837
94,62	1,312	0,800	-	-	-	-	-	-	30,220
126,16	1,750	1,210	0,437	0,146	-	-	-	-	28,314
157,7	2,187	1,656	0,875	0,438	-	-	-	-	27,194
189,24	2,624	2,134	1,312	0,800	-	-	-	-	26,360
220,78	3,062	2,638	1,750	1,210	0,437	0,146	-	-	25,637
252,32	3,499	3,165	2,187	1,656	0,875	0,438	-	-	24,970
283,86	3,937	3,714	2,624	2,134	1,312	0,800	-	-	24,354
315,4	4,374	4,281	3,062	2,638	1,750	1,210	-	-	23,778
346,94	4,811	4,866	3,499	3,165	2,187	1,656	-	-	23,235
378,48	5,249	5,467	3,937	3,714	2,624	2,134	-	-	22,719
410,02	5,686	6,084	4,374	4,281	3,062	2,638	-	-	22,224
441,56	6,124	6,714	4,811	4,866	3,499	3,165	-	-	21,748
473,1	6,561	7,357	5,249	5,467	3,937	3,714	-	-	21,288
504,64	6,998	8,013	5,686	6,084	4,374	4,281	-	-	20,841
536,18	7,436	8,680	6,124	6,714	4,811	4,866	-	-	20,406
567,72	7,873	9,358	6,561	7,357	5,249	5,467	-	-	19,981
599,26	8,311	10,047	6,998	8,013	5,686	6,084	-	-	19,565
630,8	8,748	10,746	7,436	8,680	6,124	6,714	-	-	19,157
662,34	9,185	11,454	7,873	9,358	6,561	7,357	-	-	18,757
693,88	9,623	12,172	8,311	10,047	6,998	8,013	-	-	18,362
725,42	10,060	12,898	8,748	10,746	7,436	8,680	-	-	17,973
756,96	10,498	13,633	9,185	11,454	7,873	9,358	-	-	17,590
788,5	10,935	14,376	9,623	12,172	8,311	10,047	-	-	17,210
820,04	11,372	15,126	10,060	12,898	8,748	10,746	-	-	16,835
851,58	11,810	15,885	10,498	13,633	9,185	11,454	-	-	16,464
883,12	12,247	16,650	10,935	14,376	9,623	12,172	-	-	16,096
914,66	12,685	17,423	11,372	15,126	10,060	12,898	-	-	15,731
946,2	13,122	18,202	11,810	15,885	10,498	13,633	-	-	15,369
977,74	13,559	18,988	12,247	16,650	10,935	14,376	0,437	0,146	15,052
1009,28	13,997	19,780	12,685	17,423	11,372	15,126	0,875	0,438	14,778
1040,82	14,434	20,579	13,122	18,202	11,810	15,885	1,312	0,800	14,526
1072,36	14,871	21,384	13,559	18,988	12,247	16,650	1,750	1,210	14,290
1103,9	15,309	22,194	13,997	19,780	12,685	17,423	2,187	1,656	14,066
1135,44	15,746	23,010	14,434	20,579	13,122	18,202	2,624	2,134	13,853
1166,98	16,184	23,832	14,871	21,384	13,559	18,988	3,062	2,638	13,648
1198,52	16,621	24,659	15,309	22,194	13,997	19,780	3,499	3,165	13,452
1230,06	17,058	25,492	15,746	23,010	14,434	20,579	3,937	3,714	13,263

Table 4. *Basic field development indicators*

S_c, km^2 per 1 well	$\bar{m}$	m	α	μ_*	v	φ	q_0, million tonnes per year
0,48	3,68	4,42	0,22	0,44	3,014	0,16	1,28

Table 5. *Oil reserves exploitation parameters*

K_1	Q_m, million t.	K_{ro}	U_p^2	μ_{oz}	A	K_{n3}	K_{k3}	K_3	F	Q_0, million t.	Q_{F0}, million t.	Q_{F02}, million t.	ρ_*	A_{av}
0,904	18,53	0,604	0,87	0,94	0,95	0,205	0,856	0,82	3,44	15,29	63,84	61,06	1,306	0,75

Table 6. The dynamics of basic technological indicators

Years, t	Production, million tonnes		Accumulated production, million tonnes		Water injection, million tonnes		Encroach-ment, A_t, %	Current oil recovery factor, unit fractions
	Oil, q_t	Liquid, q_{tF_2}	Oil $\sum Q_{oil}$	Liquid $\sum Q_{liquid}$	Annual q_w	Accumulated $\sum Q_w$		
1	0,367	0,449	0,367	0,449	-	-	18,15	0,017
2	0,708	0,897	1,075	1,346	-	-	21,12	0,050
3	1,024	1,346	2,099	2,691	-	-	23,92	0,097
4	1,024	1,399	3,122	4,090	0,251	0,251	26,82	0,145
5	1,024	1,457	4,146	5,547	0,255	0,506	29,71	0,194
6	1,024	1,519	5,170	7,066	0,410	0,916	32,59	0,241
7	0,696	1,090	5,866	8,156	1,199	1,199	36,17	0,273
8	0,626	1,060	6,491	9,215	1,166	2,365	40,95	0,302
9	0,563	1,030	7,054	10,246	1,133	3,498	45,39	0,327
10	0,506	1,002	7,560	11,248	1,102	4,601	49,50	0,351
11	0,455	0,975	8,015	12,223	1,072	5,673	53,31	0,372
12	0,409	0,948	8,425	13,171	1,043	6,716	56,84	0,390
13	0,368	0,923	8,793	14,094	1,015	7,731	60,11	0,407
14	0,331	0,898	9,124	14,992	0,988	8,720	63,13	0,422
15	0,298	0,874	9,422	15,867	0,962	9,681	65,93	0,436
16	0,268	0,851	9,690	16,718	0,936	10,617	68,53	0,448
17	0,241	0,829	9,931	17,546	0,911	11,529	70,93	0,460
18	0,217	0,807	10,147	18,353	0,887	12,416	73,15	0,469
19	0,195	0,786	10,342	19,139	0,864	13,280	75,20	0,478
20	0,175	0,765	10,517	19,904	0,842	14,122	77,09	0,486
21	0,158	0,745	10,675	20,649	0,820	14,942	78,85	0,494
22	0,142	0,726	10,817	21,375	0,798	15,740	80,47	0,500
23	0,127	0,707	10,944	22,082	0,778	16,518	81,97	0,506
24	0,115	0,689	11,059	22,770	0,758	17,275	83,35	0,511
25	0,103	0,671	11,162	23,441	0,738	18,013	84,63	0,516
26	0,093	0,654	11,255	24,095	0,719	18,732	85,81	0,520
27	0,083	0,637	11,338	24,732	0,701	19,433	86,90	0,524
28	0,075	0,621	11,413	25,352	0,683	20,115	87,91	0,528
29	0,067	0,605	11,481	25,957	0,665	20,781	88,84	0,531
30	0,061	0,589	11,541	26,546	0,648	21,429	89,70	0,533
31	0,055	0,574	11,596	27,120	0,632	22,060	90,50	0,536
32	0,049	0,560	11,645	27,680	0,616	22,676	91,23	0,538
33	0,044	0,545	11,689	28,225	0,600	23,276	91,91	0,540
34	0,040	0,531	11,729	28,757	0,585	23,860	92,53	0,542
35	0,036	0,518	11,765	29,275	0,570	24,430	93,11	0,544
36	0,032	0,505	11,797	29,780	0,555	24,985	93,64	0,545
37	0,029	0,492	11,826	30,272	0,541	25,527	94,13	0,547
38	0,026	0,480	11,852	30,751	0,528	26,054	94,58	0,548
39	0,023	0,467	11,875	31,219	0,514	26,568	95	0,549

Table 7. Capital expenditures on the field development

The basic means name	Cost in millions dollars
Gravity based structure (GBS)	1500
Drilling of 18 wells	907,2
Ice-class tankers for oil transportation (2 units)	210
Ice-class supply vessels (2 units)	100
Transit station (tanker)	150
Total capital expenditures	2867,2

Table 8. *Estimated economic outcome of the field development*

Year	Q, million tonnes	B, million dollars	γ, million dollars	P, million dollars	α	PV, million dollars	NPV, million dollars
2031	0,367	296,011	80,730	-1895,919	1,000	-1895,919	-1895,919
2032	0,708	570,575	155,611	263,763	0,870	229,360	-1666,560
2033	1,024	825,483	225,132	449,151	0,756	339,623	-1326,937
2034	1,024	825,483	225,132	449,151	0,658	295,324	-1031,613
2035	1,024	825,483	225,132	449,151	0,572	256,804	-774,809
2036	1,024	825,483	225,132	449,151	0,497	223,307	-551,502
2037	0,696	560,968	152,991	407,977	0,432	176,380	-375,122
2038	0,626	504,517	137,596	366,922	0,376	137,939	-237,183
2039	0,563	453,748	123,749	329,998	0,327	107,877	-129,306
2040	0,506	408,087	111,296	296,790	0,284	84,366	-44,939
2041	0,455	367,021	100,097	266,924	0,247	65,980	21,040
2042	0,409	330,087	90,024	240,063	0,215	51,600	72,640
2043	0,368	296,870	80,965	215,906	0,187	40,354	112,995
2044	0,331	266,996	72,817	194,179	0,163	31,560	144,554
2045	0,298	240,128	65,490	174,639	0,141	24,681	169,235
2046	0,268	215,964	58,899	157,065	0,123	19,302	188,538
2047	0,241	194,231	52,972	141,259	0,107	15,096	203,634
2048	0,217	174,686	47,642	127,044	0,093	11,806	215,439
2049	0,195	157,107	42,847	114,260	0,081	9,233	224,672
2050	0,175	141,297	38,536	102,762	0,070	7,221	231,893
2051	0,158	127,078	34,658	92,421	0,061	5,647	237,539
2052	0,142	114,291	31,170	83,120	0,053	4,416	241,956
2053	0,127	102,789	28,033	74,756	0,046	3,454	245,409
2054	0,115	92,446	25,212	67,233	0,040	2,701	248,111
2055	0,103	83,143	22,675	60,467	0,035	2,112	250,223
2056	0,093	74,776	20,393	54,383	0,030	1,652	251,875
2057	0,083	67,251	18,341	48,910	0,026	1,292	253,167
2058	0,075	60,484	16,496	43,988	0,023	1,010	254,177
2059	0,067	54,397	14,836	39,562	0,020	0,790	254,968
2060	0,061	48,923	13,343	35,581	0,017	0,618	255,585
2061	0,055	44,000	12,000	32,000	0,015	0,483	256,069
2062	0,049	39,572	10,792	28,780	0,013	0,378	256,447
2063	0,044	35,590	9,706	25,884	0,011	0,296	256,742
2064	0,040	32,009	8,730	23,279	0,010	0,231	256,974
2065	0,036	28,788	7,851	20,936	0,009	0,181	257,154
2066	0,032	25,891	7,061	18,830	0,008	0,141	257,296
2067	0,029	23,285	6,351	16,935	0,007	0,111	257,406
2068	0,026	20,942	5,711	15,231	0,006	0,086	257,493
2069	0,023	18,835	5,137	13,698	0,005	0,068	257,560

Basing on the obtained data:
NPV =257,56 million dollars.
$DPI = 1{,}09$.
Cost recovery period is expected to be slightly over 10 years.
The accumulated discounted cash flow graph on the annual basis is given in figure 10.