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MASTER'S THESIS

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Abstract

The modern scientific and technological revolution in the development of hydrocarbon resources of the World Ocean has led to a paradigm shift in the development of oil and gas fields. The new paradigm for the development of resources in the Arctic is a new concept of values, technological and technical solutions aimed at maximizing the growth of capitalization and the return on the main assets of oil and gas companies in real-time.

Due to the growing interest in the development of hydrocarbon fields on the West Arctic shelf, the issue of designing ice-resistant hydraulic structures capable of year-round operation in the harsh conditions of the Arctic is of particular importance. Over the past 50 years, a rich material has been accumulated on the natural-climatic characteristics of the Pechora Sea in the areas of proposed production.

The master thesis contains information on the climatic conditions of the Pechora Sea, as well as the hydrology of the region. Three structures of the North-West license area were selected for cluster development: Mezhdusharskaya, Kostinosharskaya and Papaninskaya. Of the four proposed concepts, the most reliable was proposed in terms of technological maturity and minimal risks during operation. The choice of the platform, as well as the subsea production system of the cluster. The calculation of the economic profitability of the project was made.

The purpose of this master's thesis:

Development of an economically and ecologically rational scenario for developing a cluster of hydrocarbon fields (structures) of the Arctic shelf of the Pechora Sea to increase the efficiency of their industrial development.

The objectives of this work are:

1. Description of natural and climatic features within the water area of the Pechora Sea;
2. Description of fields and prospective structures of the Pechora Sea;
3. Allocation of a group of fields (structures) of the Pechora Sea for the cluster concept of their development;
4. Selection of facilities for the selected concept;
5. Assessment of economic profitability for the selected concepts;
6. Choosing the most effective concept.

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List of abbreviations

APG – Associated Petroleum Gas
CAPEX – Capital Expenditures
FPSO – Floating Production, Storage and Offloading
GBS – Gravity Based Structure
IRGBS – Ice-resistant Gravity Based Structure
MPa – Megapascal
NWLB – North-West License Block
OPEX – Operational Expenses
SPS – Subsea Production System
TOE – Tone of Oil Equivalent
WAG – Water-Alternating-Gas

Introduction

The Russian Federation possesses a truly huge reserve of natural resources, some of which are oil and gas. As one of the world's largest oil and gas producing countries, Russia receives significant revenues from the export of hydrocarbons abroad. Since hydrocarbon reserves on land are depleted every year, there is a tendency to develop fields on the shelf. According to the revised results of the quantitative assessment of hydrocarbon resources in 2012, it was found that the reserves of oil, natural gas, dissolved gas and condensate in the amount of more than 120 billion tons of standard fuel are concentrated on the shelves of the seas of Russia. At the same time, approximately 80% are accumulated within the Kara, Okhotsk and Barents (including the Pechora) seas [1]. Thus, in recent years, the Russian oil and gas industry has been actively entering a new stage in the development of Arctic shelf fields.

Almost all fields and promising oil and gas structures of the Russian Federation are remote at a considerable distance from the coastal infrastructure. It is also important to pay attention to the difficult climate of the region, especially concerning ice conditions. In this regard, the development of the Arctic fields requires huge capital expenditures for their construction [2]. Nevertheless, the experience of developing the Prirazlomnoye project has shown a steady demand for Arctic oil of ARCO grade. This oil is a good feedstock for European refineries with a deep refining cycle. In addition, the experience of Prirazlomnaya has made it possible to hone offshore oil logistics in the Arctic region. Therefore, the development of options for cluster arrangement of fields, allowing to reduce capital and operating costs for the development of oil and gas fields on the continental shelf of the Russian Federation, is an urgent task for research in this master's work.

1. Natural and climatic features of the Pechora Sea

1.1. General information and geographic location

The Pechora Sea is a shallow southeastern coastal part of the Barents Sea. The territory of Pechora begins from Kolguev Island in the west. It continues up to Vaigach Island in the east and the southern part of the Novaya Zemlya archipelago in the northeast. In addition, the sea washes the shores of Russia on the territory of the Nenets Autonomous District and the Arkhangelsk Region. The bottom of the Pechora Sea is characterized by a calm relief, which is a gentle plain, smoothly plunging from the south-east to the north-west. Sea depths in the region range from 20 m in the south-east to 150-180 m in the north-west.

The total area of the water area is 81.3 km^2; the volume of water is 4380 km^3 [3]. Figure 1 shows the location of the Pechora Sea on the map.

Previously, this area of the sea was dry land. It was formed as a result of the melting of a large glacier. It can explain the fact that the bottom level gradually decreases with distance from the mainland.

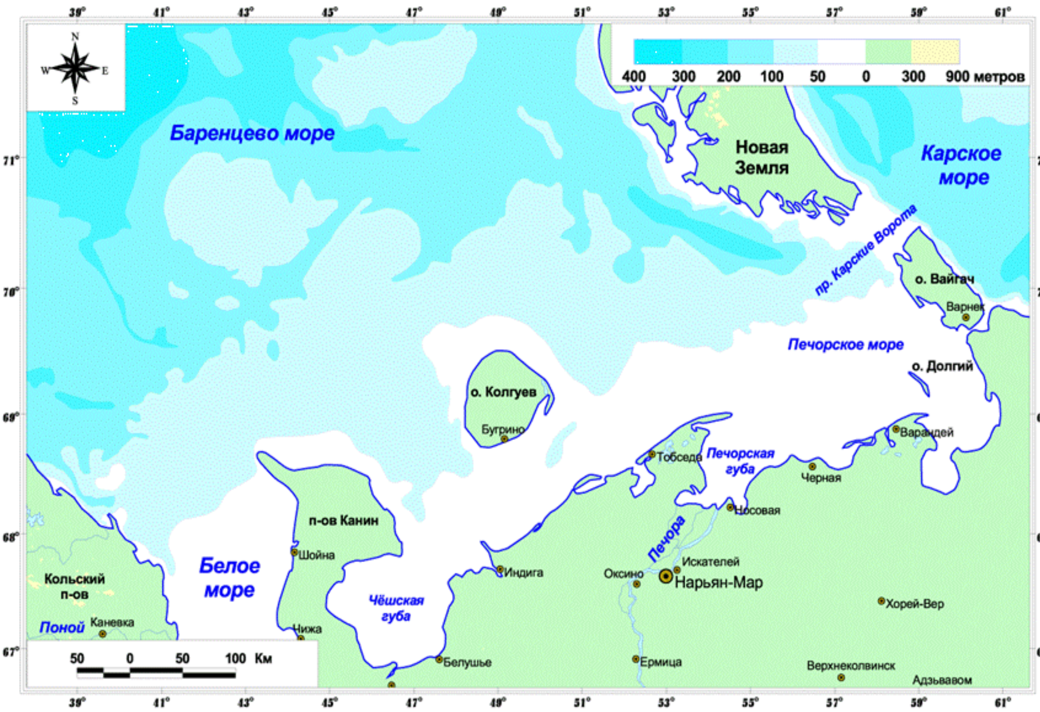

Figure 1. Geographical location of the Barents and Pechora seas

In the vicinity of the Pechora Sea, there are several bays: Ramenka, Pakhancheskaya, Kolokolkova Bolvanskaya, Khaipudyrskaya and Pechora (the largest of them) [4]. On the adjoining land there is moss-lichen and shrub tundra. The tundra inhabitants are reindeer, bear, Arctic fox, wolf, fox, hare, etc. The sea contains valuable commercial fish species [5].

1.2. Hydrological conditions

1.2.1. Currents and tides

The currents in the sea area are determined by the sum of the tidal, wind and density components. The main movement of currents occurs from east to north-west. The maximum speeds of tidal currents on the surface can reach 0.6 m / s, and wind currents with prolonged winds up to 0.3 - 0.4 m / s. Thus, the maximum speed of the total current can reach 1.2 m / s.

It should also be noted that the Pechora current arises in the summer season. It is formed with the help of the freshwater runoff of the river of the same name. Cold current Litke refers to cold, ice from the Kara Sea through the strait located in the south of the Novaya Zemlya archipelago. The invariability of the above flows depends on the influence of several external factors, therefore they are also called quasi-constant (Figure 2) [7].

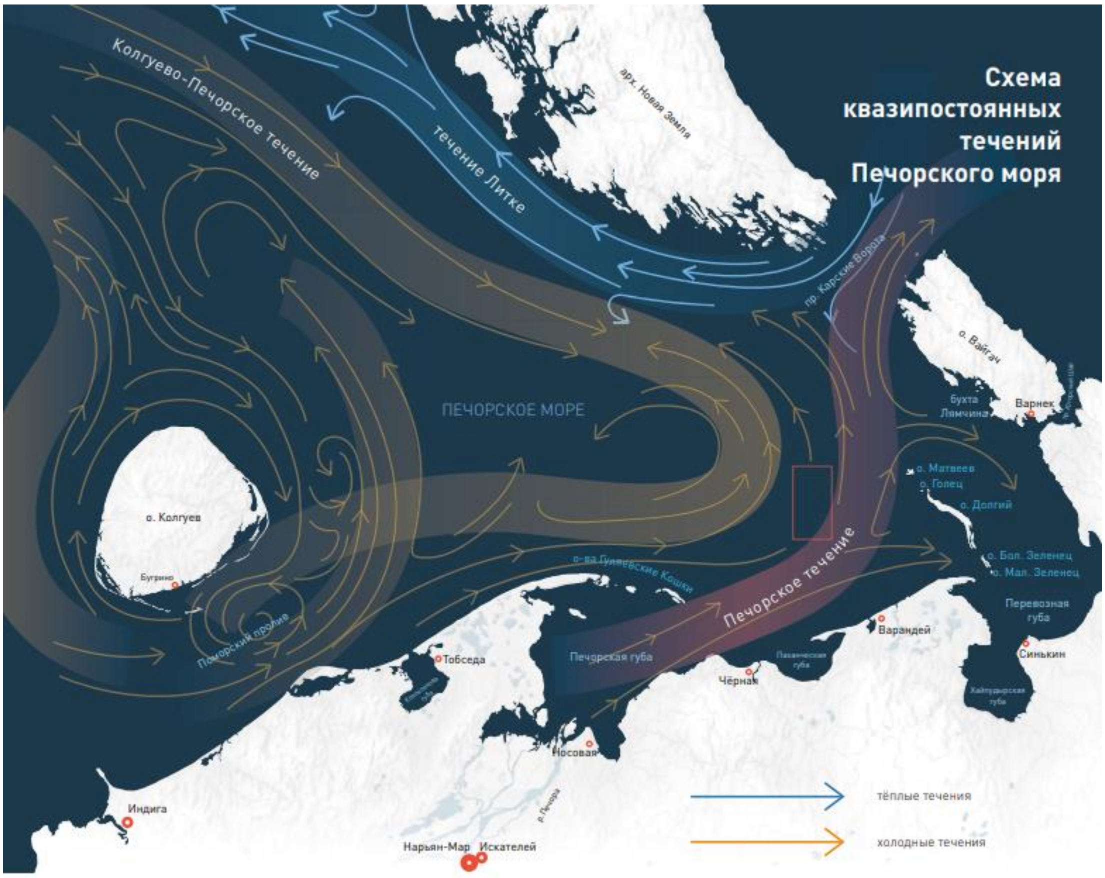

Figure 2. Illustration of the sea currents of the Pechora Sea (blue arrow - warm currents, orange - cold currents) [7]

The maximum possible for astronomical reasons, the magnitude of tides in the area is 0.7-0.75 m. The rise in the level due to surges up to 1.8 m, the largest surge - 1 m. The maximum amplitude of sea level fluctuations can reach 4.2 m [7]

1.2.2. Precipitation

The total amount of precipitation in the sea reaches 550 mm per year. The maximum precipitation indicator is observed from the end of winter to the beginning of spring, and the minimum is in August. Fallout of precipitation in winter in the amount of 13 mm / day or more is observed only 5 days a year from December to April. On some days, the maximum daily rainfall can reach 40-50 mm.

1.2.3. Ice conditions

The ice regime is formed due to the interaction of the Atlantic and Arctic oceans. For this reason, one of the main factors determining the state of the ice cover is the variability of weather conditions in the autumn and winter periods and the heat transfer of water from different parts of the Barents Sea. In addition, wind activity directly affects the mixing of water and the rate of cooling of the surface layer. The timing of ice formation also depends on this [8]. Figure 3 shows the average length of the ice period since the 1982/83 season to the season 2018/19 and for the entire observation period.

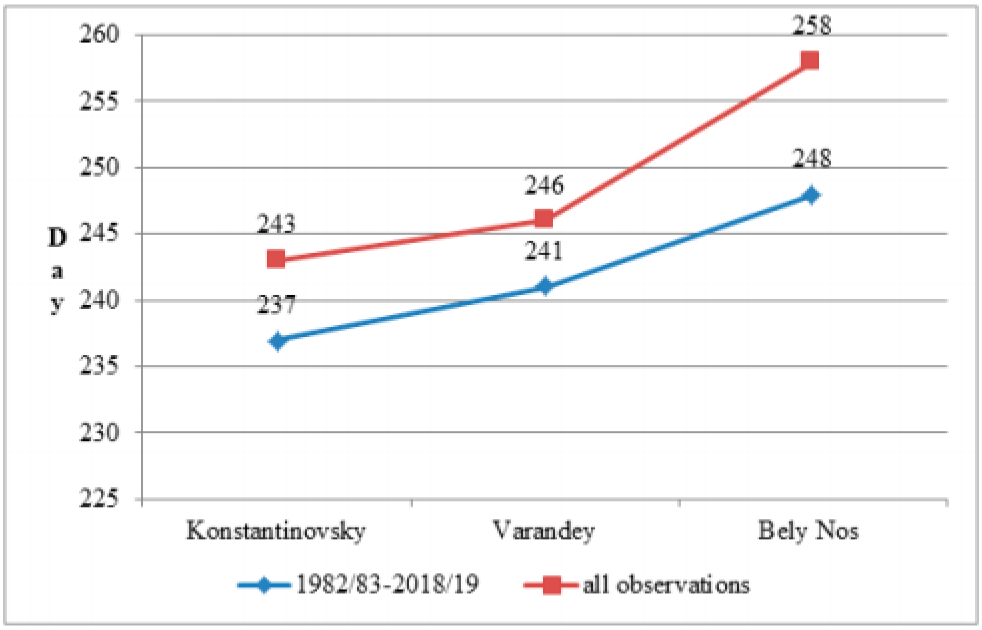

Figure 3. Average duration of the ice period since the 1982/83 season to the season 2018/19 and the entire observation period [8]

The average number of days with ice in the sea area is 240, and the minimum is 160. The maximum duration of the ice period is 258 days. The regular appearance of ice occurs in the first half of November, the early appearance of ice - at the end of October. The maximum late date for the appearance of ice was recorded on January 5. The final clearing of the water area from ice occurs on average on June 25. Late cleansing is observed in the second decade of July. In abnormally warm years, ice is absent already at the end of May, and in abnormally cold years, ice remains until August. In the period from August to October, the Pechora Sea is ice-free. The thickness of ice is on average 50 - 70 cm. During the period of its maximum development, it can reach 120 cm. The average hummocking is 2 - 3 points, the maximum - 5 points on a five-point scale. The overall height of hummocks is 1.0–1.5 m; the maximum is up to 4 m. Areas of water with increased hummocking are located on the edge of the southeastern part of the Pechora Sea and in the area of the Prirazlomnoye field [7]. The probabilities of ice movement by seasons are shown in Figure 4.

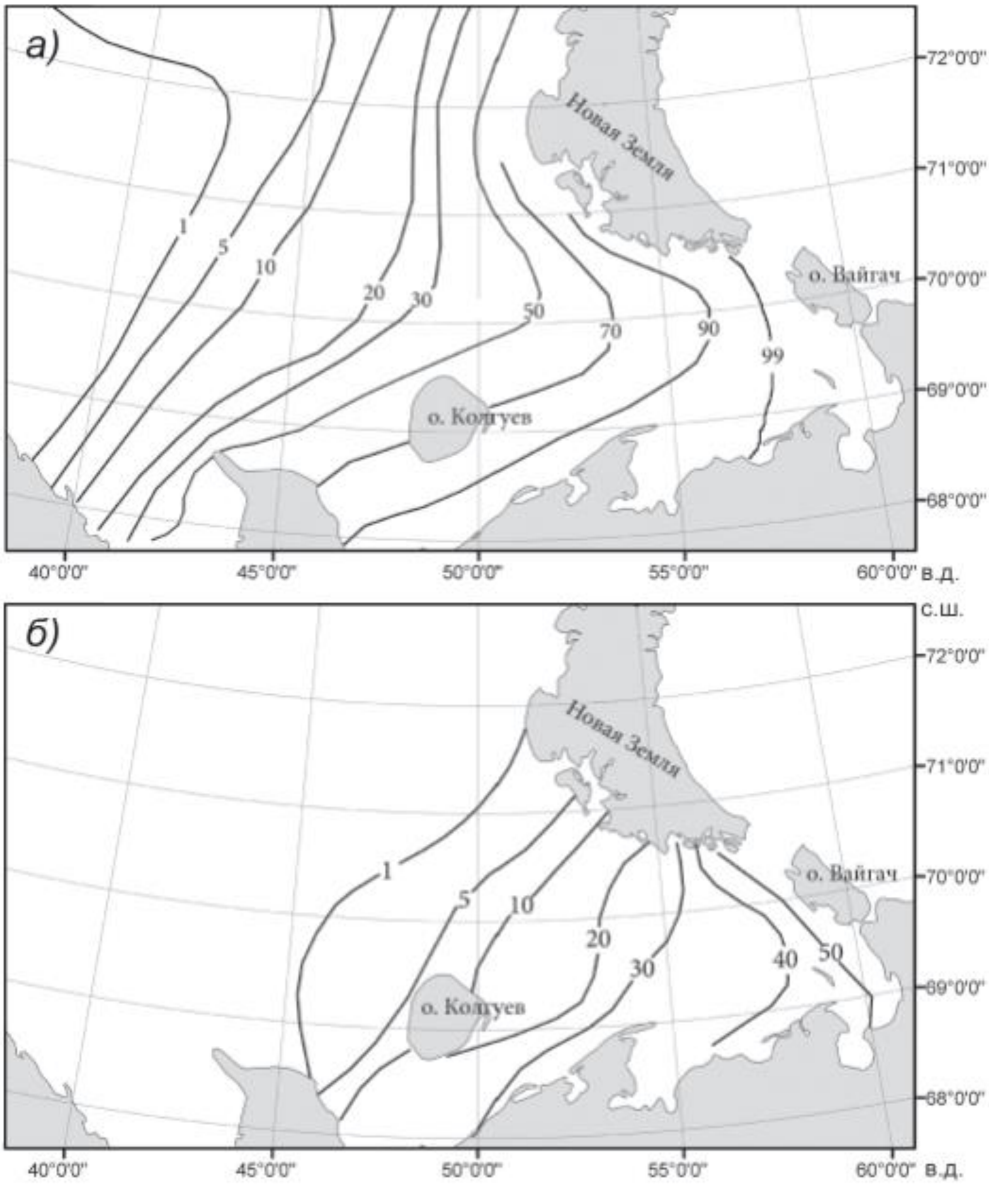

Figure 4. Probabilities of ice propagation of the Pechora Sea in winter (a) and summer (b) for the period from the second half of XX to the present day [8]

Sea vessels begin to ice in October, and icing can continue until May. For October, unhurried icing is characteristic (less than 1.5 tons of ice per hour) with a probability of 10%. For November - slow and fast (from 1.7 to 4.5 tons/hour), the probability of rapid icing is quite small and amounts to 5 %. The latter type of icing (more than 4 tons/hour of ice) has a probability of up to 20% and is dangerous even for large vessels with a displacement of up to 3000 tons.

1.2.4. Water temperature

In summer, the temperature of the near-surface layer of the Pechora water grows everywhere. The isotherms acquire an orientation that is closest to the latitudinal one. The water temperature on the surface reaches a maximum of 8-9 ° C. The 0 ° C isotherm occupies the northernmost position in August at the ice edge. In some years, the maximum summer surface temperature in the Pechora Sea reaches 16 ° C. In winter, the characteristic values of sea water temperature vary in the range from minus 1.8 ° C to 0 ° C, in autumn - from 2 ° C to 4 ° C, in spring - from 0 ° C to plus 4 ° C and in summer - from 5 ° C to 8 ° C. The maximum heating of water is observed in August and some years it can reach 15 ° C, and in the Pechora Bay and other shallow bays - up to 22-23 ° C [7, 8]. The temperatures of the surface and bottom layers are shown in Figure 5 and Figure 6, respectively.

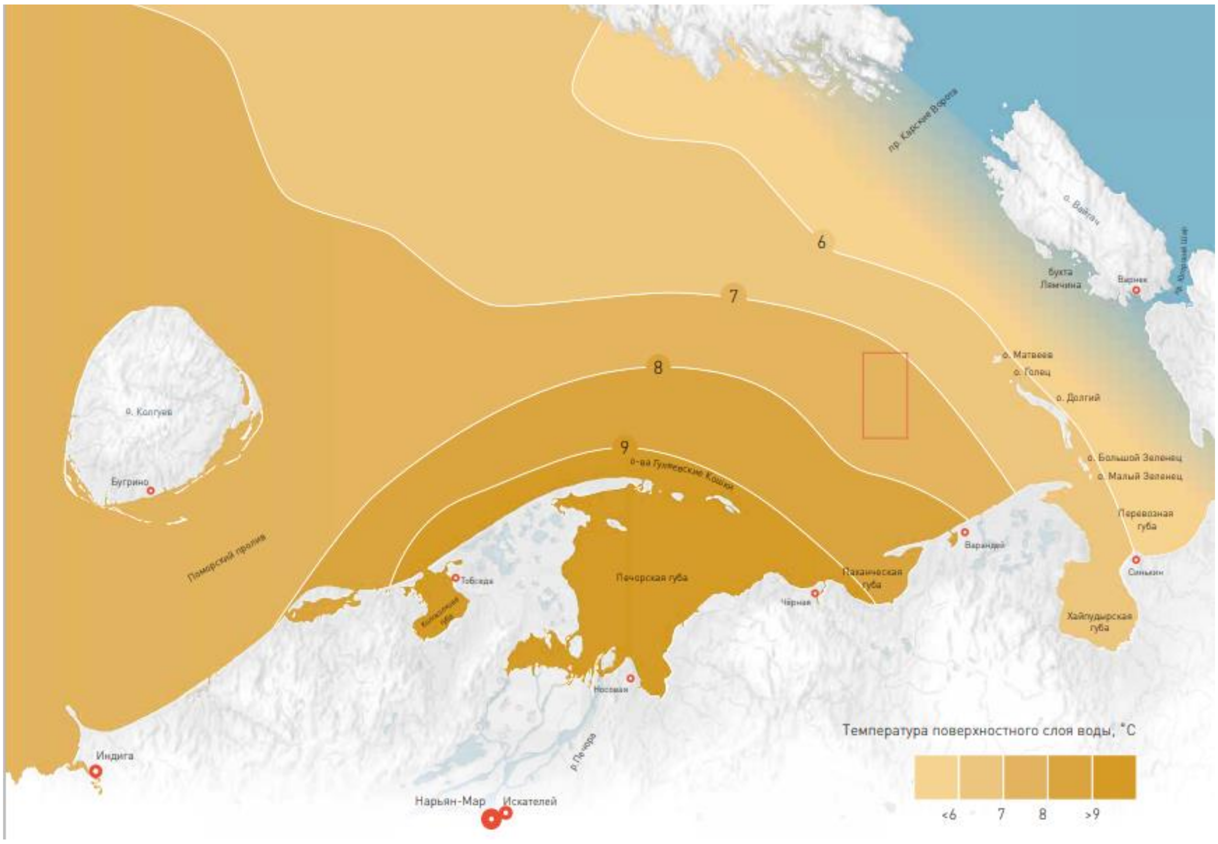

Figure 5. The temperature**s** of the upper layers of the Pechora Sea in summer [7]

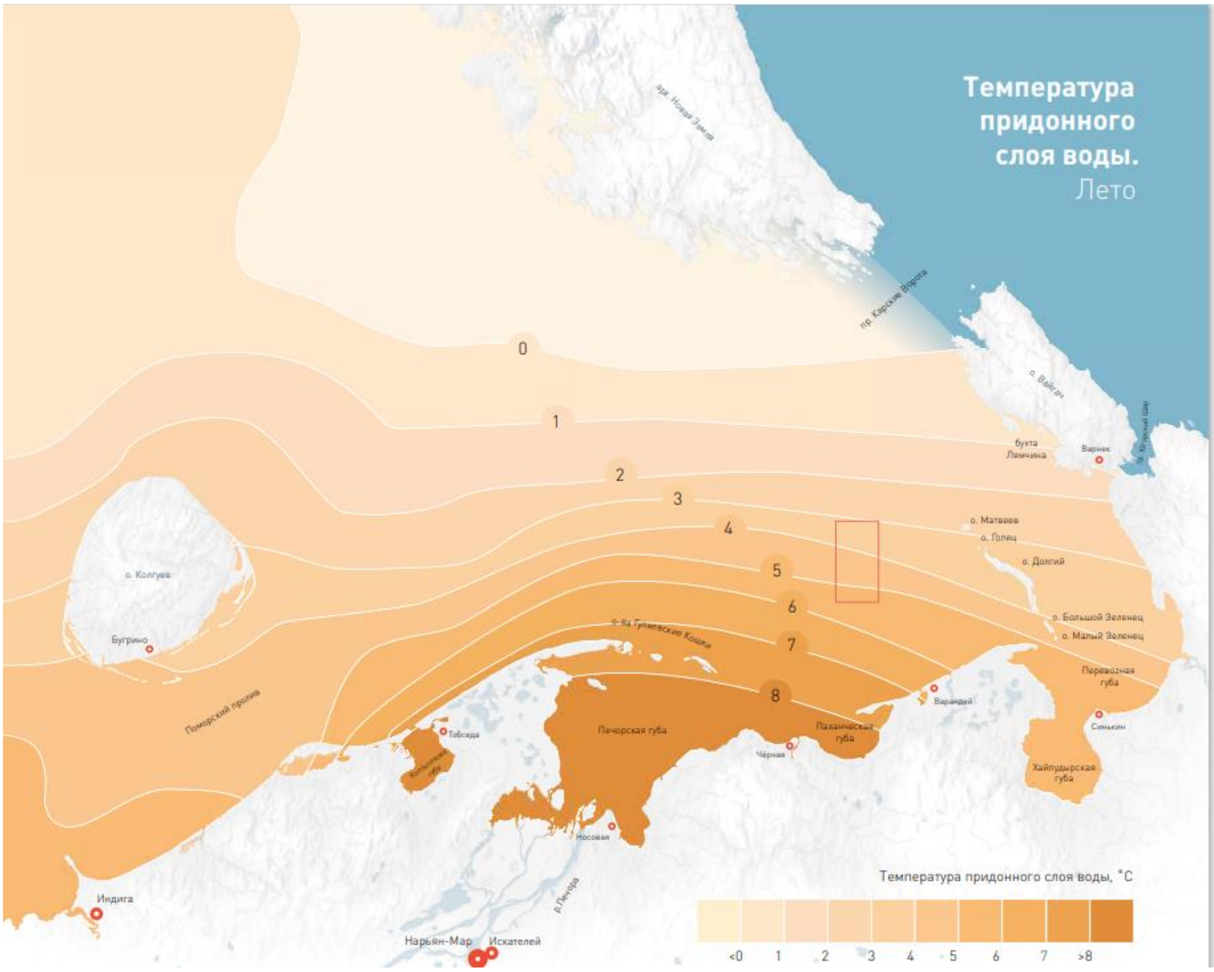

Figure 6. The temperatures of the bottom layer of the Pechora Sea in summer [7]

2. Oil and gas fields of the Pechora Sea and perspective structures

2.1. Resource potential of the Barents-Pechora region

The resource potential for the selected region is shown in Figure 7. (It should be noted that in some literary sources, it is customary to combine the Pechora and the Barents Sea). The selection of provinces in the chart is based on coastal regions north of the Arctic Circle. It includes some subarctic provinces, such as Newfoundland-Labrador off the east coast of Canada and the Sea of Okhotsk in the Russian Far East.

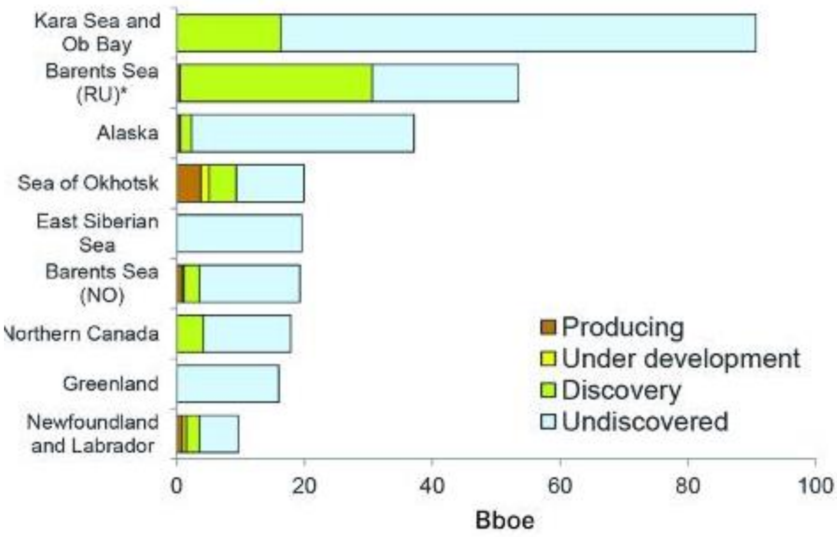

Figure 7. Residual resources of the Arctic shelf provinces by life cycle, measured in billions of barrels (the Barents region also includes the Pechora Sea) [9]

Some of these provinces are believed to contain significant hydrocarbon reserves. However, about 80% of this potential has not yet been discovered. It all depends on successful exploration, which must be proven and justified [9].

To illustrate how Arctic issues affect projects, Figure 8 shows the historical lead times from discovery to the first production for selected projects in the Arctic provinces. On average, these projects took over 21 years to develop. By comparison, the last 40 autonomous projects on the Norwegian Continental Shelf (NCS) have averaged 12 years from discovery to launch.

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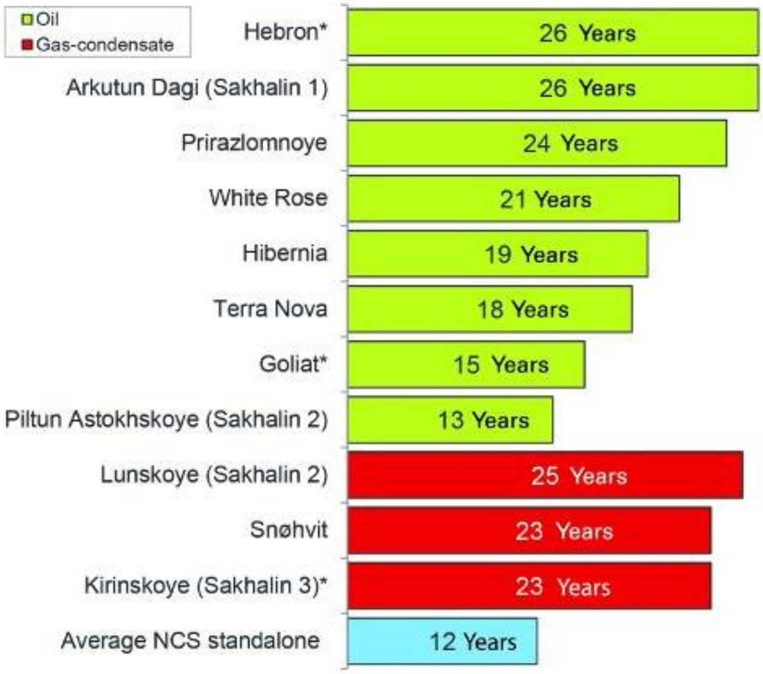

Figure 8. Time from discovery to launch for selected Arctic projects (fields currently being developed with an estimated year of commissioning) [9]

From the course of lectures of Professor Zolotukhin A.B., it follows that the Barents and Pechora seas have reserves of 31 billion TOE [10]. Thus, the region represents one of the most promising areas for the development of shelf resources.

As of the beginning of 2021, 5 fields were discovered in the Russian territory of the Barents Sea:

• 2 gas condensate - Shtokman and Ledovoye

• 3 gas fields - Ludlovskoye, Murmanskoye and Severo-Kildinskoye

Potentially interesting structures are located on the Fersmanovsko-Demidovskoe uplift, the shafts of Vernadsky, Shatsky, Medvezhye and Admiralteysky [10].

In the article published on the Sherpa Konsult company website, it is said that the potential of the Pechora Sea could be up to 2.7 billion TOE. This is enough to extract about 760 million tonnes of oil equivalent between 2014 and 2040. This estimate is rather moderate compared to the data on hydrocarbon resources published by Belonin and Prishchepa in 2006 (4.9 billion TOE) [11].

Six fields have already been discovered in the Pechora Sea, which will be discussed further.

2.2. Prirazlomnoye oil field

The Prirazlomnoye field is located on the shelf of the Pechora Sea, 60 km north of the village of Varandey and 320 km north-east of Naryan-Mar. The field was discovered in 1989. The depth within the field is 19-20 m. Oil reserves are estimated at more than 72 million tons. Maximum production at the peak of exploitation will amount to 5.5 million tons per year. The main object of the field is the Prirazlomnaya offshore ice-resistant oil production platform (IRGBS), installed on the seabed in September 2011. Oil production at the facility began at the end of 2013. The overview map of the Prirazlomnoye field and the Prirazlomnaya IRGBS installation site is shown in Figure 9 [12].

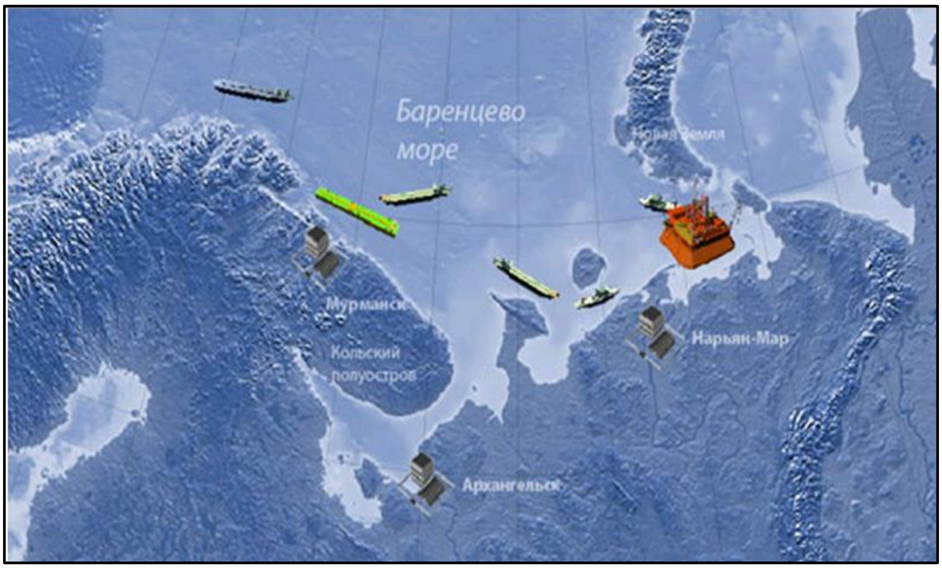

Figure 9. The overview map of the Prirazlomnoye field and the installation site of the Prirazlomnaya IRGBS [12]

2.2.1. Geological and physical characteristics of the field

Three productive deposits are distinguished in the section of the deposit. Deposit I is an operational development target with an effective thickness of 38-64 m.

Deposit II is not considered a reservoir with small oil reserves.

Deposit III has an effective thickness of only 6 m.

According to the group hydrocarbon composition, the oil of Deposit I belongs to the methane-naphthenic type with a weight content (%):

- paraffin 0,14-1,8
- resins 8,70-10,61
- asphaltenes 1,60-3,80
- gas content of oil in the reservoir 40 - 49 м^3/т
- viscosity to depth 2462 m – 3,9 mPa·s

With the accepted oil recovery factor equal to 0.3, recoverable oil reserves in C1 + C2 categories amounted to 72 million tons, incl. in category C1 - 46.0 million tons.

The Central Reserves Committee approved the initial geological reserves of petroleum gas in categories C1 + C2 of the Ministry of Natural Resources of the Russian Federation in 10.4 billion m^3.

When performing predictive calculations of the main indicators of oil production, the operating ratio of production and injection wells was taken equal to 0.895 for all the years of field development under consideration [13]. Physical and chemical properties can be found in Table 1.

Table 1. Physical and chemical properties of oil and associated gas [13]

Indicator	Value
Oil (crude)	
Density, g / sm^3	0,910 – 0,915
Density, API	24,00 – 23,08
Sulfur, wt%	2,31
Mercaptan sulfur, ppm	64 – 114
Paraffin, % of the mass.	1,78
Freezing point, ºC	Minus 48
The beginning of waxing, ºC	22
Asphaltenes (insoluble heptane), wt%	0,85 – 1,61
Asphaltenes (insoluble pentane), wt%	2,90
Dynamic viscosity at 0 ºC, cP	120
Associated gas	
Gas factor, m^3 / m^3	29 – 40
Relative density by air	0,72 – 0,76
Methane, mol%	78 – 80
Hydrogen sulfide, mol%	0,4
Nitrogen, mol%	3,7 – 5,0
Carbon dioxide, mol%	0,75 – 0,77
Density, g / sm^3	0,910 – 0,915

2.2.2. Production facility layout

IRGBS is a gravity-type structure and consists of a support base (caisson) and a platform topside, including a drilling, technological, power complex, a residential module, a helipad and other systems (Figure 10).

To ensure the protection of the topside from ice impacts and wave loads, the caisson has ice and wave deflectors built along the platform's perimeter. The total height of the deflectors is 16.4 m.

The platform topside was manufactured using the structures of the Norwegian Hutton TPL platform.

The main dimensions of the platform:

• overall height - 141 m;

• overall width with the helicopter platform - 144;

• overall length with the platform for the helicopter – 140 [12].

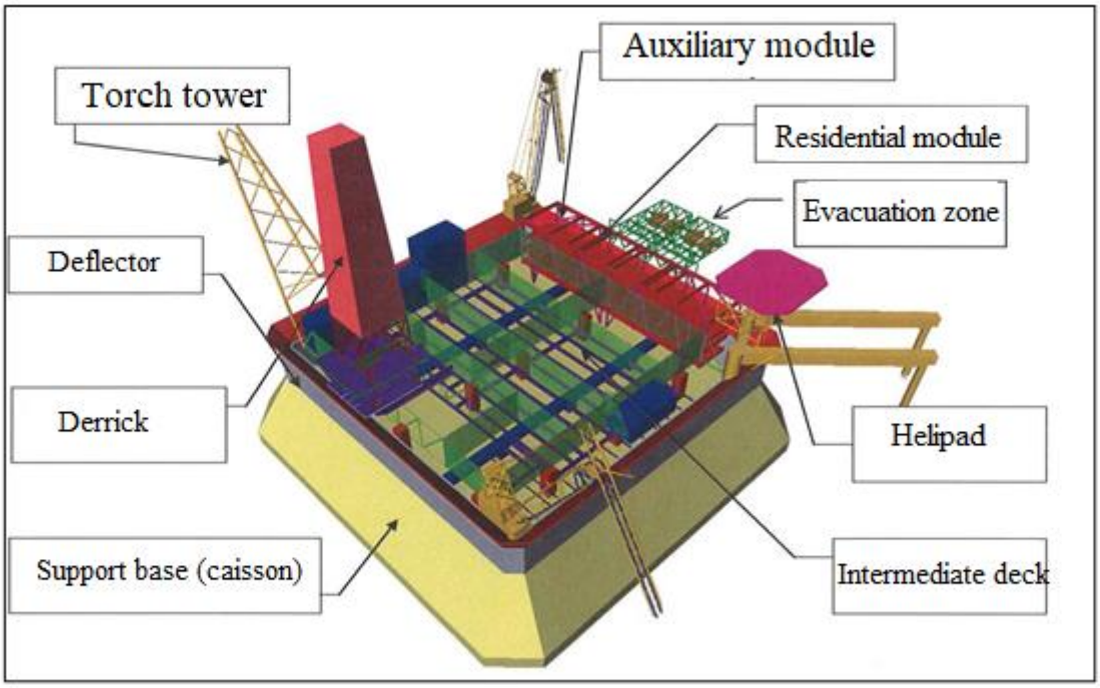

Figure 10. Layout of facilities on the Prirazlomnaya IRGBS [13]

2.2.3. Description of the technological process

Technological processes at the IRGBS provide drilling of wells, collection of formation fluid from wells, refining of oil to a marketable state and transporting it to the caisson storages. Produced water after preparation through injection wells is injected into the formation. Associated gas is used for own needs, emergency gas discharges from safety valves and gas discharges during the repair and maintenance of technological equipment are burned in a flare unit [12].

The schematic diagram of oil flow to the Prirazlomnaya IRGBS is shown in Figure 11.

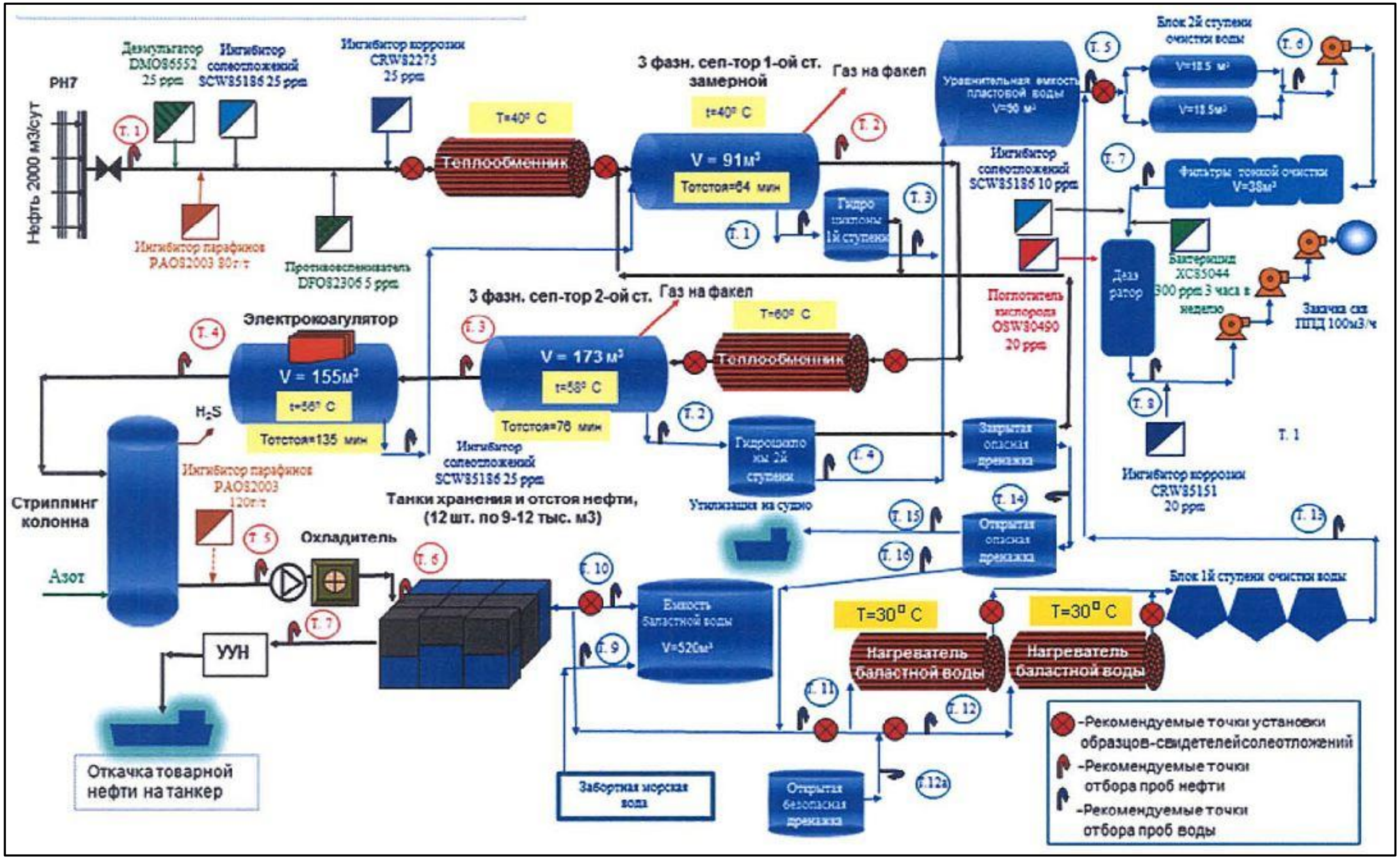

Figure 11. Schematic diagram of oil flow to the Prirazlomnaya IRGBS [14]

One of the options for arranging the cluster is joining the Dolginskoye field to the Prirazlomnaya IRGBS. Technically, such a task is feasible.

Issues to be worked out:

- Compatibility of oils and formation waters;
- Limiting gas factor of the connected fluid;
- Superposition of the peak of production at the Prirazlomnoye field and the start of production of other objects;
- Large peak excess of associated petroleum gas (APG);
- Volley discharge of hydrocarbons into the high-pressure flare during emergency shutdown of the technological complex may require a change in its design and an increase in the height of the flare stack;
- Replacement of the equipment of the drilling complex requires stopping the operation of the field up to 1.5 years;
- Lack of calculation of weight loads on platform decks from newly installed equipment. It is required to recalculate the strength of the platform structures and decks, taking into account the point effect of weight loads.

To solve the tasks at hand, we will need:

• modernization of the IRGBS drilling complex - shutdowns in oil production or later commissioning of wells will be required;

• modernization of the IRGBS power complex - Installing an additional gas turbine generator or replacing them with more powerful units;

• modernization of the technological complex of the IRGBS - shutdowns in oil production will be required for the period of work on the partial replacement of the equipment of the technological complex with a new one;

• The need for APG utilization of the main development facility;

• Modernization of the reservoir pressure maintenance system [14].

As we can see from the above, solving such a complex problem requires a lot of engineering calculations and proof of economic benefits. It should be noted that the issue of using the Prirazlomnaya IRGBS as a production center for groups of fields is not in this master's work.

2.3. Dolginskoye field

That field is located north of Prirazlomnoye, about 80-110 km from Russia's Arctic coast. Arktikmorneftegazrazvedka company discovered the Dolginskoye field in 1999 during geological exploration for oil and gas on the shelf. As of 2020, 4 exploration wells have been drilled in the field. The seabed is characterized by a calm relief - a gentle dip from the south-east to the north-west. Sea depths in the field range from 22-26 m in the southeast to 40-48 m in the north-west.

At the Dolginskoye field, the oil-bearing capacity was established based on data from the drilling of two wells: Severo-Dolginskaya-1 and South-Dolginskaya-1, as well as based on seismic survey conducted in 2006. Based on these data, the oil-bearing capacity of the Lower Permian-Carboniferous deposits was established, and the oil-bearing capacity of the Upper Permian deposits is assumed based on the logging data. At first, it was believed that the Dolginskoye field is an oil field with an insignificant amount of dissolved gas. However, the latest drilling results, in turn, have led to significant changes in the structure of reserves in favor of gas. For example, in well Severo-Dolginskaya-3, from the intervals of 3139-3168 m, 3217-3258 m of the Upper Visean-Lower Permian reservoir, gas inflows with a hydrogen sulfide content up to 22% were obtained.

By the end of 2014, drilling of the Severo-Dolginskaya-3 well was completed. An industrial gas flow was obtained during the testing of formations in the Lower Permian - Carboniferous sediments. For this reason, the estimation of the reserves of the field has been rethought. Oil recovery factors for the Dolginskoye field are taken by analogy with the same-age oil deposits in the carbonate reservoirs of the Prirazlomnoye field [14,15].

The proposed in 2015 model of the geological structure of the Permian-Carboniferous reservoir assumes the distribution of oil deposits only within the southern tectonic block, in the area of well South-Dolginskaya-1. In turn, according to the test results, the deposits of the northern block are considered as gas condensate (without an oil rim) [17].

Thus, it is currently believed that recoverable reserves in the C1 + C2 category for 2017 are about 82.4 million tons of oil, 41 billion m^3 of gas, 11 billion m3 of dissolved gas [16]. A more detailed table with stocks is given below (Table 2).

Table 2. Movement of hydrocarbon reserves at the Dolginskoye field [17]

Reservoir	**Reserves category**	**stocks as of 01.01.2015 (State balance of mineral reserves)**		**Reserves as of 01.01.2017**		**Change in recoverable reserves relative to the State balance of minerals of the Russian Federation**	
		geological	**recoverable**	**geological**	**recoverable**	**thousand tons/mln m^3**	**%**
Oil, million tons							
P2	C1						
	C2	584	175	98	29.6	-145702	-83
	C1	2.9	0.893	4.8	1.4	552	62
	C2	198	59	171	51	-82	-14
		786	235	274	82.4	-153	-65
Dissolved gas, billion m^3							
P2	C1						
	C2			1.9	0.593	1.9	100
P1+C	C1			0.997	0.299	0.997	100
	C2			35.4	10.62	35.4	100
IN TOTAL				38.4	11.512	38.4	100
Free gas (dry), billion m^3							
P1+C	C1			7.5	7.5	7.5	100
	C2			33.7	33.7	33.7	100
IN TOTAL				41.2	41.2	41.2	100

Continuation of Table 2.

Condensate, million tons							
P1+C	C1			1.7	0.85	0.85	100
	C2			7.5	3.8	3.8	100
IN TOTAL				9.1	4.7	4.7	100

2.4. Other fields of the Pechora Sea

2.4.1. Varandey-More field

The history of the discovery of this field dates back to 1995 during exploratory drilling. Varandey-More is located approximately 30 km from the Prirazlomnoye field. In the estimates, the recoverable oil reserves of the field amount to 5.8 million tons [18].

Within the Varandey-More structure, oil was discovered as part of the Lower Permian-middle carbonate complex reservoir due to drilling two prospecting wells. The size of the deposit is 19 × 3 km. In terms of physical and chemical properties, the oil of this field is close to the same-age oil of the Prirazlomnoye field - 903 kg / m^3, sulfur content - 2.02%, resins 14.3%, asphaltenes 5.5%, paraffins 1.44%. [19].

2.4.2. Medynskoye-more field

That oil field was discovered at the end of the last century in the southern part of the Pechora Sea. It is located 40 km from the village of Varandey. The sea depth within the field reaches 22 m.

Arktikmorneftegazrazvedka discovered the field during oil and gas exploration on the shelf. The C1 + C2 recoverable oil reserves in the discovered field amount to 95 million tons. [20,21].

2.4.3. Severo-Gulyaevskoye field

The Severo-Gulyaevskoye field is one of the assets of Rosneft. It was discovered in 1986 by Arktikmorneftegazrazvedka in the course of geological exploration for oil and gas on the shelf. The sea depth within the field ranges from 10 to 30 m. One well was drilled in the field, in the section of which two deposits were identified: oil and gas condensate.

The field belongs to the average hydrocarbon reserves - 13 million tons of oil, gas - 52 billion m^3 (C1 + C2) [22,23].

2.4.4. Pomorskoye field

The field was discovered in the southern part of the Pechora Sea in 1985 by Arktikmorneftegazrazvedka during oil and gas exploration on the shelf. The sea depth within the field is 20-30 m. One well was drilled at the field, in the section of which the presence of gas condensate deposits in the carbonate deposits of the Asselian-Sakmarian stage of the Lower Permian was established.

In terms of hydrocarbon reserves and resources, the Pomorskoye field belongs to the category of medium-sized fields - 21 billion m^3 of gas (in categories C1 + C2) [24].

2.5. North-West license block

The North-West license block (NWLB) is located within the Russian part of the Barents and Pechora Seas in the vicinity of the Novaya Zemlya archipelago. On the nearest sea coast there is a small village of Varandey, 100 km away, and the city of Naryan-Mar, 200 km away, where a seaport is located. The nearest discovered field is Dolginskoye.

The license for the right to use the North-West subsoil block was issued to Gazpromneft-Sakhalin for a period up to 01.10.2044 with the intended purpose and types of work for geological exploration, exploration and production of hydrocarbons. Localized recoverable oil resources within the area are estimated according to the Russian D_{1L} category and amount to 273 million tons. Drilling of prospecting and appraisal wells in this area is planned to begin in 2022-2023. The most promising structures for industrial development are: Mezhdusharskaya, Papaninskaya and Rakhmanovskaya group of structures [14,25]. Detailed information on structures is given in Table 3.

Table 3. Prospective oil and gas fields of the North-West license block [25]

Structure name	Expected total geological oil resources, million tons	Recoverable oil resources, million tons	The amount of associated petroleum gas, billion m^3	Coordinates		Sea depth, m
				Latitude	Longitude	
Mezhdusharskaya	362.5	108.8	15.7	70.6	52	140-180
Kostinosharskaya	50.3	15.1	3.07	70.65	52.2	140-180
Papaninskaya	157.1	44.8	2.1	70.2	53.2	70-80
Rakhmanovskaya	225	67.6	25	69.9	54.7	60
Rakhmanovskaya - 2	66.7	20	10	69.8	55.5	50

At the Mezhdusharskaya and Kostinosharskaya structures, the oil and gas potential of the Upper Permian-Triassic deposits is primarily associated with the Lower Triassic, where the presence of sandy strata with improved reservoir properties is assumed.

In the Papaninskaya area, the oil and gas potential of the Permian-Triassic complex may be primarily associated with regressive Upper Permian sandstones. They have an areal distribution both on the Papaninskaya uplift and in the areas of contoured lithological and lithological-stratigraphic traps and Middle Triassic alluvial sandstones within the Papaninskaya structure [25].

3. Selecting a scenario for developing fields cluster

3.1. Selection of a group of fields for arrangement

Figure 12 shows LBs and fields of PJSC Gazpromneft and NK Rosneft.

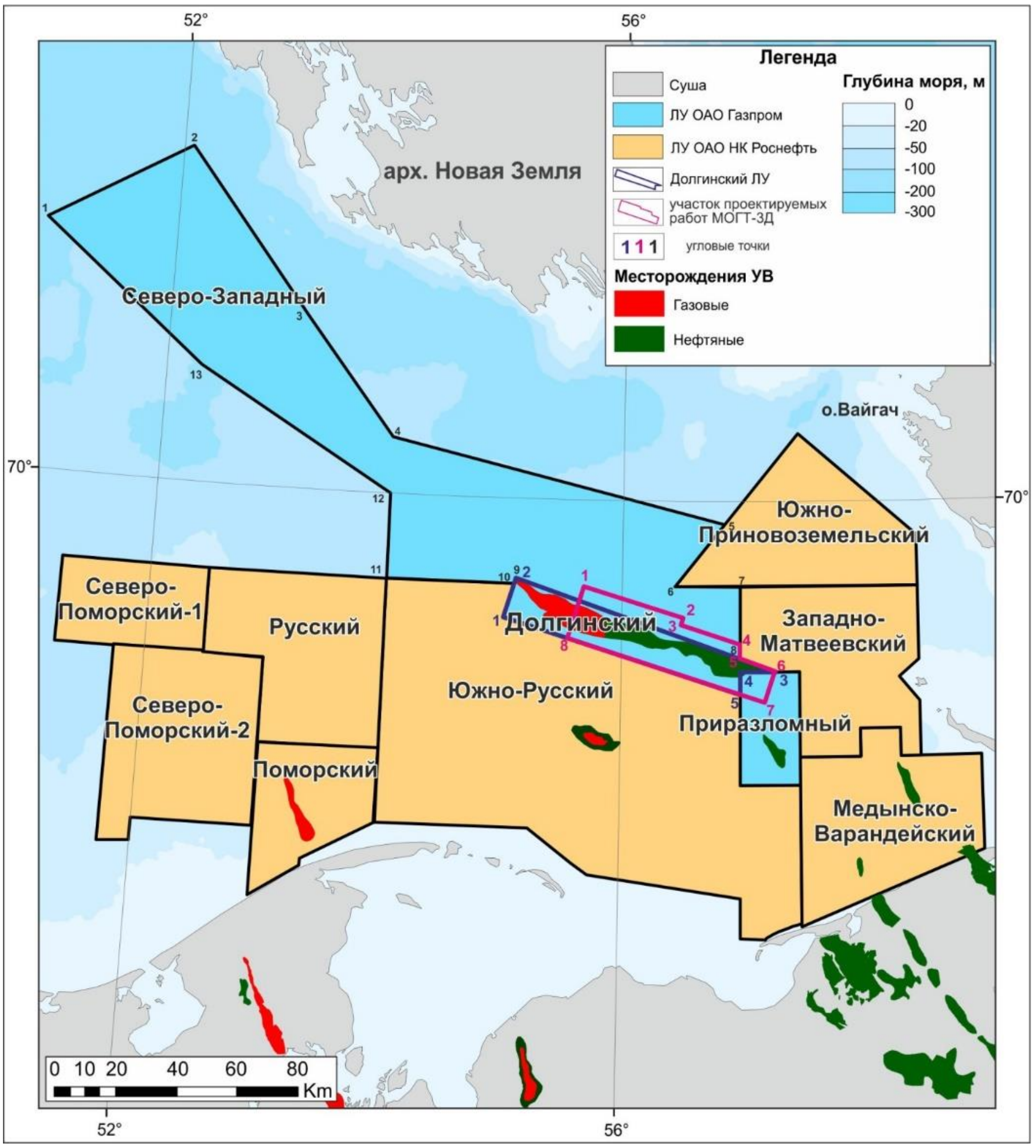

Figure 12. Map of licensed blocks of the Pechora Sea (yellow - NK Rosneft; blue - PJSC Gazpromneft) [14]

Since two companies hold licenses for the right to explore and produce hydrocarbons in the Pechora Sea, it is necessary to consider the zones of influence of these companies in the legal framework of the Russian Federation (for example, the Law "On Subsoil"). The most promising in terms of the availability of oil and gas, as well as the relative proximity of the fields to each other, are the LBs of PJSC Gazpromneft:

1. Prirazlomny license block
2. Dolginsky license block
3. North-West block

The object of research in this work is promising oil fields at the North-West license area, namely: Mezhdusharskaya, Kostinosharskaya and Papaninskaya structures. The selection is based on more resources than in the more southerly LB structures. Another important factor when choosing groups of structures is the relatively close distance from each other. We can verify this with the help of Figure 13.

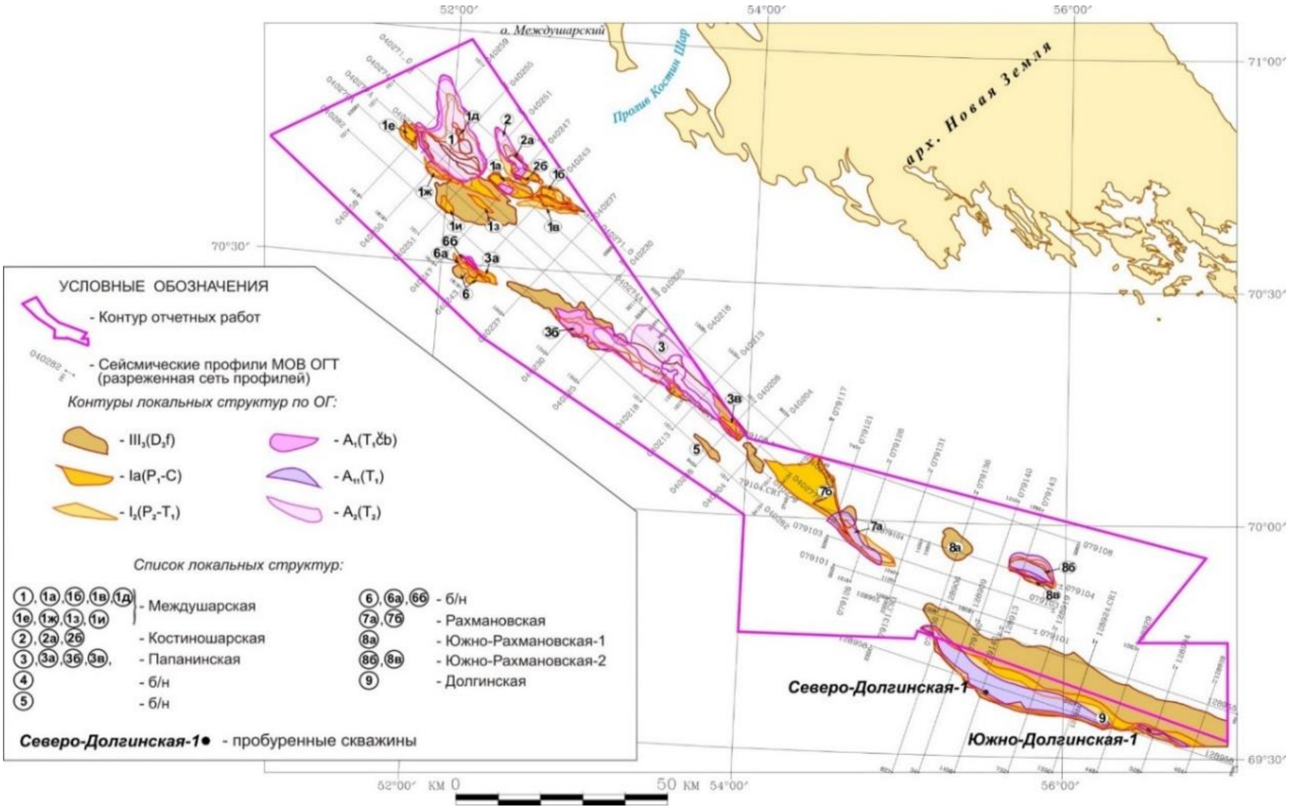

Figure 13. Comparison scheme of local structures within the North-West block [14]

3.2. The main types of offshore technical structures for hydrocarbon production

It is especially important take into consideration the peculiarities of natural climatic, mining and geological, hydrometeorological conditions. It is they who determine the choice of the development method and the corresponding type of marine production.

Modern offshore oil and gas fields are highly mechanized and automated systems for drilling and operating wells, collecting, preparing and transporting oil and gas to the shore by tankers or using pipelines. Table 4 summarizes the main pros and cons of various types of designs.

It is known that there are three main solutions for offshore fields using:

- Stationary structures:

- Gravity platforms;

- Artificial islands.

- Floating structures:

- FPSO vessels;

- TLP platforms;

- Semi-submersible platforms;

- SPAR Platforms.

- Subsea production complexes (tied to hub facilities) [26].

Table 4. Pros and cons of various types of structures [27]

Pros	Cons
1. Artificial islands	
• Year-round production; • Resistance to icebergs; • "Dry" type of wellhead equipment; • Large open area.	– Limited water depth; – Possible lack of building materials; – Marine spraying by waves; – Island icing in the harsh regions of the Arctic; – Service.
2. Offshore gravity-based structure with vertical walls	
• Year-round production; • Drilling with GBS; • Storage capacity; • System of "dry" wellhead equipment; • Large working area; • Low wave loads.	– Restriction on water depth; – Large ice loads can lead to the destruction of the platform; – Decommissioning.
3. Offshore gravity-based structure with inclined walls	
• Year-round production; • Drilling with CDP; • Storage capacity; • System of "dry" wellhead equipment; • Large working area; • Lower ice loads.	– Restriction on water depth; – Large wave loads; – Decommissioning.
4. FPSO vessel	
• Especially effective in remote or deep-water areas; • there is no need to lay main pipelines; • Storage capacity; • Removal from service.	– Dependence on ice management; – Large mooring forces; – Dependence on storms; – Higher likelihood of oil spills compared to GBS platforms.

3.3. The main types of drilling rigs for the Arctic shelf conditions

When drilling in Arctic conditions, the main challenges are the short ice-free period and ice loads on the rig. For these reasons, not every rig is suitable for the Arctic region.

Table 5 describes the main conventional drilling solutions for developing potential NWLB fields and considers their suitability for Arctic conditions.

Table 5. Major offshore drilling rigs and their suitability for Arctic conditions [28]

	A self-elevating or so-called Juck-Up drilling rig is a mobile drilling rig that can reach the drilling point by itself or with the help of tugs. The lifting mechanisms are used mechanical or hydraulic. In world practice, preference is given to mechanical lifting mechanisms. This is due to the simplicity of the design (they are less difficult to operate) and other factors. This type of drilling platform is suitable for working at a water depth of up to 160 m. Jack-up rigs are a very popular solution for offshore drilling. However, they are not suitable for year-round drilling in the Pechora Sea because they can only operate in non-freezing waters for approximately 90-120 days during the ice-free season.
	A rig is also often installed on fixed production platforms and used for drilling operations. The main advantage of this solution is the ability to conduct year-round drilling. The total number of wells that can be drilled from one platform varies depending on the reservoir conditions but is usually limited to 50 wells. Typically, the rig is stationary, but it can be removed and replaced during workovers when all planned wells have been drilled and completed.

Continuation of Table 5.

	A semi-submersible drilling rig is the most popular type of offshore drilling unit, combining the advantages of drilling at great depths. Such installations are floating offshore structures with pontoons and columns, which partially cause the installation to submerge to a given depth when flooded with water. The principle of operation is the same as that of earthed submersible drilling rigs. The exception is that semi-submersible platforms are either moored with heavy anchors weighing more than 10 tons or are held in place using a dynamic positioning system. Semi-submersible drilling rigs are used for drilling at depths from 60 to 2500 m and more, depending on the platform's age, type, and technical characteristics. They are pulled away from the drilling site with the help of tugboats or by themselves.

3.4. Choosing a transport system for Arctic conditions

There are two main alternative delivery systems for offshore fields to the oil and gas markets: pipelines and tankers (Table 6). The assessment of technical parameters made it clear that the most realistic option is a tanker transport system at the initial stage of field development [27].

Pipeline transportation of oil is economically inexpedient for North-West license block, taking into account the actual timing of field development. For tankers, the system is being considered (or already adopted) to develop Arctic oil fields.

The peculiarity of the Pechora shelf is that both existing and planned development projects of oil and gas companies are export-oriented. In general, the development project is focused on the direct export of oil from offshore oil platforms to markets with or without intermediate transhipment [29].

Table 6. Pros and cons of the two main types of transport systems [29]

Pros	Cons
Shipment by oil tankers	
• Lower capital costs (CAPEX); • Easier maintenance.	• Dependence on harsh sea conditions; • Dependence on ice management; • Large OPEX due to ice management; • Prevention of oil spills in ice conditions.
Transportation by offshore pipeline	

Continuation of Table 6.

• Independence from weather conditions; • Fast and easy transportation; • Smaller OPEX.	• Destruction of the pipeline by an iceberg; • Prevention of oil spills in ice conditions; • Complicated service; • Large capital expenditures (CAPEX).

3.5. Cluster development concepts

The main choice in favor of offshore development is based on a large number of factors. That is why it is very important to have flexibility of stages in order to achieve the best result with possible adjustments in the development stages. The following are some of the most significant factors:

•environmental conditions;

• compliance with all environmental and safety requirements;

• feasible technologies with a clear assessment of research and development needs;

• detailed analysis of capital and operating costs, including initial investment, maintenance, etc. [30].

The most feasible solutions require technical and technological ideas that are appropriate for a particular area. For offshore development, the following factors must play a decisive role in choosing the right scenario:

- quantity of reserves (adjusted for oil recovery rate);
- water depth at the site of the field;
- distance from fields to the coast;
- availability of reserves closest to the considered region;
- environmental factors:
  - ➢ presence of ice (icebergs, hummocks, ice windows, etc.)
  - ➢ a seismic factor of the region
  - ➢ waves (maximum wave height, wave period, etc.)
  - ➢ wind loads;
- availability of a sufficient number of technologies;
- means of transportation of hydrocarbons (remoteness from the main sales markets);
- time of emergency response;
- political and economic instability can lead to high investment risks [30,31].

Considering all the above features of the development of offshore hydrocarbons in Russia, the following concepts (Figure 14) are proposed for the development of the Mezhdusharskaya, Kostinosharskaya and Papaninskaya structures.

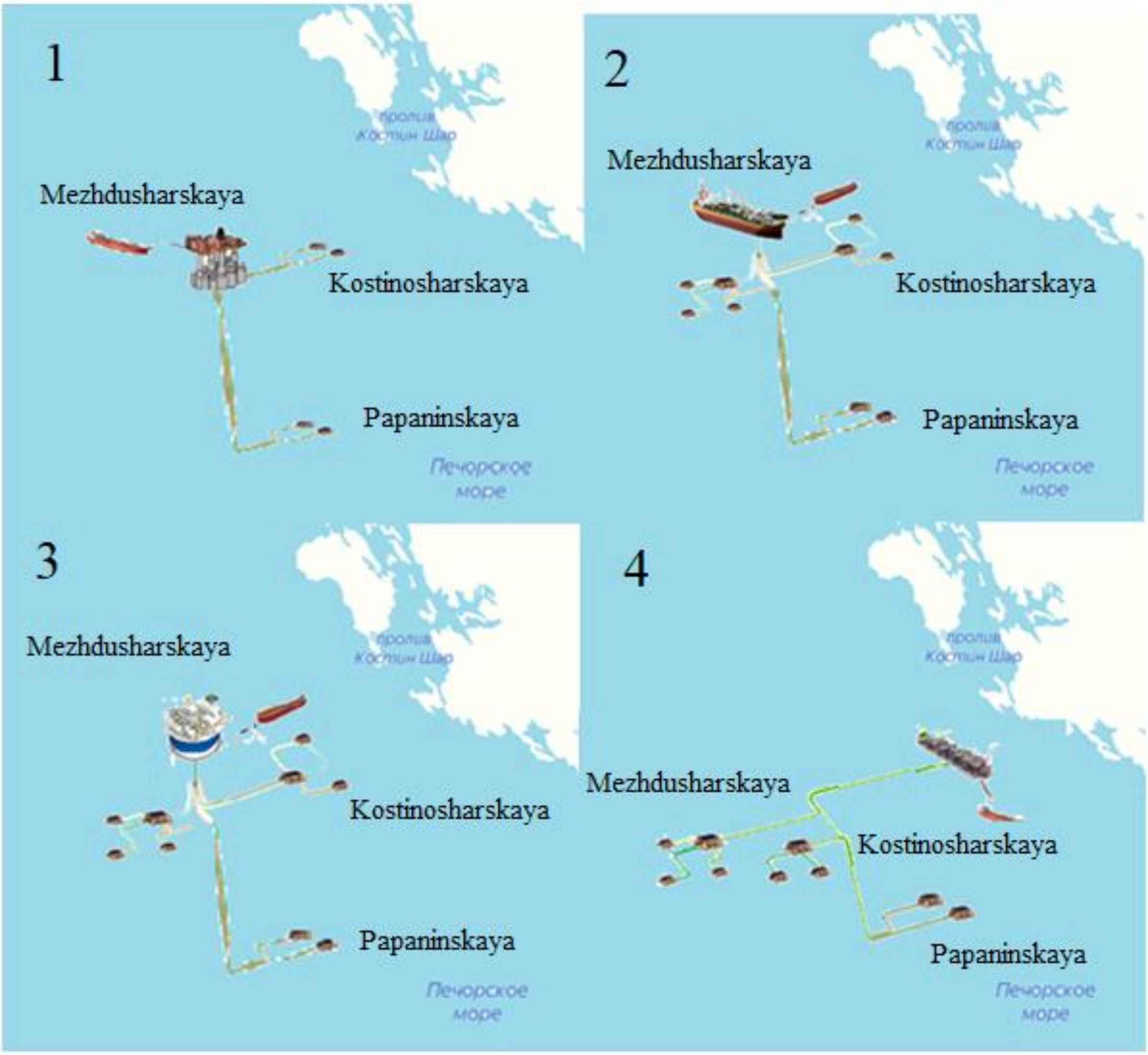

Figure 14. Four possible concepts for the development of the NWLB cluster (the map of the Pechora zone was made using the Google Earth program)

Concept 1. Arrangement using a stationary gravity platform (GBS), resistant to ice and icebergs, can connect subsea production systems (SPSs). Oil transportation is carried out by tankers.

A similar development project was implemented on the east coast of Canada - the Hebron platform with a drilling module installed in the Jeanne d'Arc Basin, which implements the concept of protection from the effects of sea ice and icebergs.

Concept 2. Year-round ice-resistant FPSO. Drilling from a semi-submersible drilling rig. Unloading from the buoy. Oil transportation is carried out by tankers.

Concept 3. Year-round cylindrical ice-resistant FDPSO (with a drilling complex). The cylindrical hull FDPSO reduces ice loads when changing the direction of movement of the ice field. As a result, the frequency of detachments is reduced compared to a detachable FPSO in a ship-type hull with a turret mooring. The concept was investigated for application in the freezing waters off the east coast of Canada and was found to be a feasible solution. The ice conditions at the NWLB differ from the Jeanne d'Arc section.

Concept 4. SPS + Coastal technological facility. Drilling wells from a semi-submersible or Jack-Up drilling rig. Oil treatment will be carried out on an offshore platform with subsequent shipment by tankers.

As for the concepts mentioned above, the first scenario seems to be the most realistic in terms of technological maturity and reliability of development in harsh Arctic conditions.

If we talk about the second and third cases, then the FPSO installation is considered a unique option for the Russian shelf since there was no relevant experience in introducing such a vessel into Russian projects. However, an important obstacle to the implementation of these projects may be the sanctions of foreign states. It is impossible not to mention the price of such installations. For example, the average cost of non-ice resistant vessels is about US $ 700 million [32]. Regarding the arctic conditions of the NWLB, the FPSO should be designed to withstand ice loads on the hull or be immediately disconnected from the wells.

In practice, the fourth option may be the longest since all wells will need to be drilled using mobile rigs, and a short ice-free period (120-130 days at NWLB) will not allow drilling more than 1-2 wells per year. As a result, there will be a need to attract more drilling rigs. In addition, some pipelines to the onshore complex are tentatively estimated to be over 60 km. This will require a significant increase in capital costs and a careful approach to ensuring the reliability of flow. Initially, flow assurance only covered the analysis and assessment of problems caused by particulate matter in pipelines but now covers all the risks associated with maintaining flow [43].

At the moment, no prospecting and exploration drilling has been carried out at the license area, and there is also no information on the physicochemical properties of the oil. For these reasons, it is necessary to assume that the properties of hydrocarbons are similar in their characteristics and can be further trained at the same production facility.

In the future, it will be precisely the concept with the use of a GBS platform at Mezhdusharskaya structure with the alternate connection of the Kostinosharskaya and Papaninskaya oil structures will be considered.

3.6. Selection of technology for enhanced oil recovery

To date, the efficiency of oil recovery by the main development methods is considered unsatisfactory, taking into account the consumption of oil products. The average final oil recovery factor in Russia for various fields is 25-40% (NWLB - 30%). Since the deposits of the selected structures contain a certain amount of associated petroleum gas, it makes sense to inject water and gas into the reservoir alternately.

This method will work best if a gas cap is already in the reservoir or reservoirs with good vertical permeability, ensuring good communication between the injected gas and the oil below it. Gas injected into the gas cap helps slow the drop in reservoir pressure and aids in displacing oil into the wellbore, ultimately increasing oil recovery. According to various studies, the Water-Alternating-Gas (or the so-called WAG-process) injection implementation increases the oil recovery factor by 5-10% to the waterflooding technology [33]. Another important factor during injection is the lack of opportunities for gas export or a ban on gas flaring. According to the Ministry of Energy, the number of fines for excess APG flaring at the end of 2018 reached 405 million rubles. As a result, more than 385 million rubles went to regional budgets. As of 2021, fines are imposed when producers utilize less than 95% of the associated gas. Therefore, the decision to inject gas into the reservoir contributes to the reduction of operating costs and significantly increases the ecological situation in the oil-producing region [34].

Applying the Water-Alternating-Gas method is widely used on the continental shelf of Norway, England and Denmark. This technology was first introduced in the North Sea in 1991 at the

Gullfaks field. The experience of using the water-gas stimulation method with the alternate injection of a water-gas mixture in Norway is shown in Figure 15.

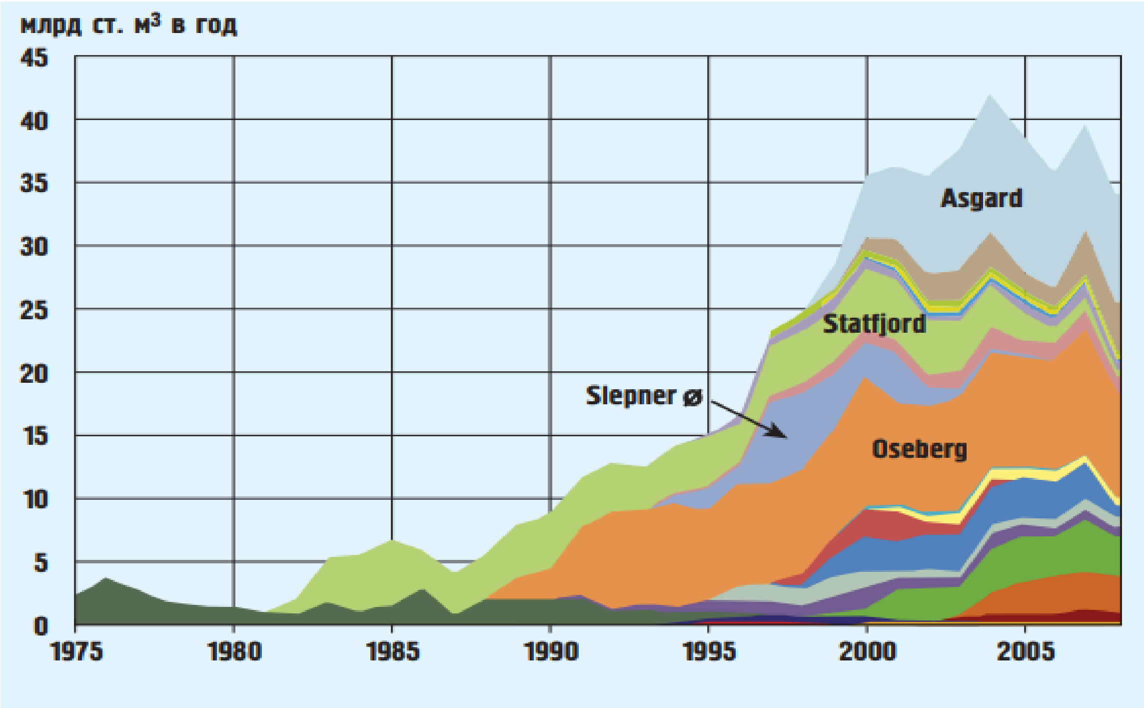

Figure 15. Accumulated data on gas injection on the Norwegian continental shelf [10]

The data obtained as a result of geological exploration at the NWLB indicate that gas injection at the selected objects of the clusters is theoretically possible [14].

3.7. Production profiles

Within the framework of offshore projects for the extraction of resources from oil fields, four main groups of technological stages of development can be distinguished (Figure 16).

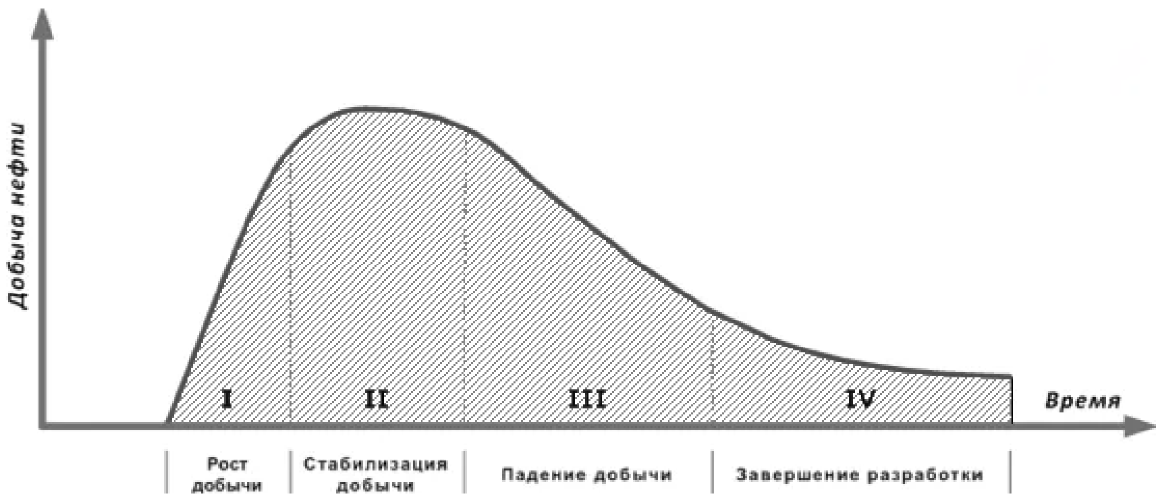

Figure 16. Stages of development of production facilities [26]

Stage I - the beginning of production at the field. At this stage, the drilling of the production facility of the field, the commissioning of production and injection wells takes place. The duration of this stage on the shelf is 4 to 7 years.

Stage II - characterized by maximum oil production and transfer of wells to artificial lift using centrifugal pumps.

Stage III - at this stage, a sharp drop in the current oil production is noticed, water cut increases, and the well stock decreases due to water cut. This stage is the most difficult to develop. The main challenge for engineers is to slow down the decline in oil production. At the third stage, as a rule, methods of enhanced oil recovery are most often applied.

The first three stages define the main development period.

Stage IV - gradually decreasing rates of oil withdrawal. The water cut of products reaches 90-95% and more. The cost of oil production during this period increases to the limits of profitability. This period is the longest.

First, it is necessary to estimate the number of wells for each structure (Table 7). Then, we need to design production profiles on the selected objects of the cluster. The construction of such profiles is necessary for the initial selection of technological solutions to develop potential fields. It should be noted that the obtained oil profiles are only estimates. When constructing them, data from the website of the Norwegian Oil and Gas Directorate and internal data of the company PJSC Gazprom Neft Shelf were studied [14,35]. All subsequent production profiles were built using Microsoft Excel.

Table 7. Number of wells for each of the cluster structures

Mezhdusharskaya structure	Production wells	24
	Injection wells	12
Kostinosharskaya structure	Production wells	4
	Injection wells	2
Papaninskaya structure	Production wells	12
	Injection wells	4

The average gas-liquid mixture flow rate of a production well is 2,100 t/day (similar to the average flow rate of wells in fields with similar geological characteristics of oil reservoirs). The figures below show production profiles for each of the three selected cluster structures: with gravity platform (drilling from platform simultaneously with production) and subsea production system. It should be noted that for SPS, well construction prior to production will be done with a semi-submersible drilling rig.

3.7.1. The production profile at the Mezhdusharskaya structure

Figure 17 presents the oil production profile at the Mezhdusharskaya structure. Since this object contains the largest amount of resources, it is proposed first to introduce this structure into development. The duration of the development of the structure is 25 years.

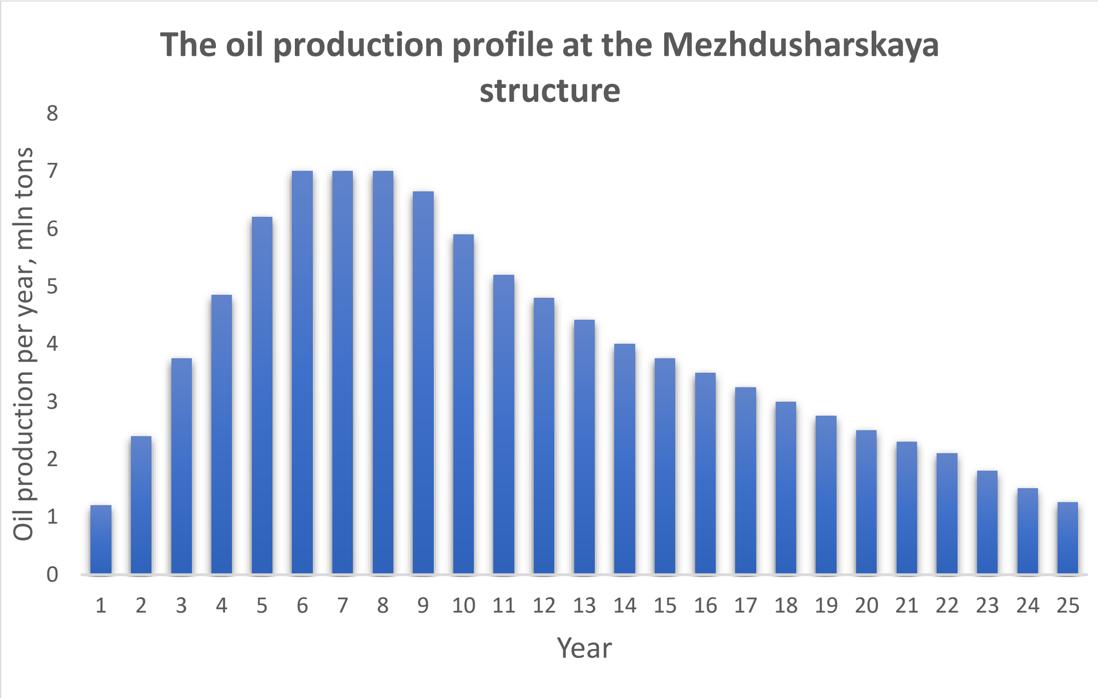

Figure 17. The oil production profile of Mezhdusharskaya structure

3.7.2. The production profile at the Kostinosharskaya structure

After oil production at the Mezhsharskaya structure drops, it is necessary to connect the nearest structure to maintain production capacities. It is supposed to produce oil at the Kostinosharskaya structure with the help of SPS. The oil production profile is shown below (Figure 18). It is planned to develop this object for 10 years.

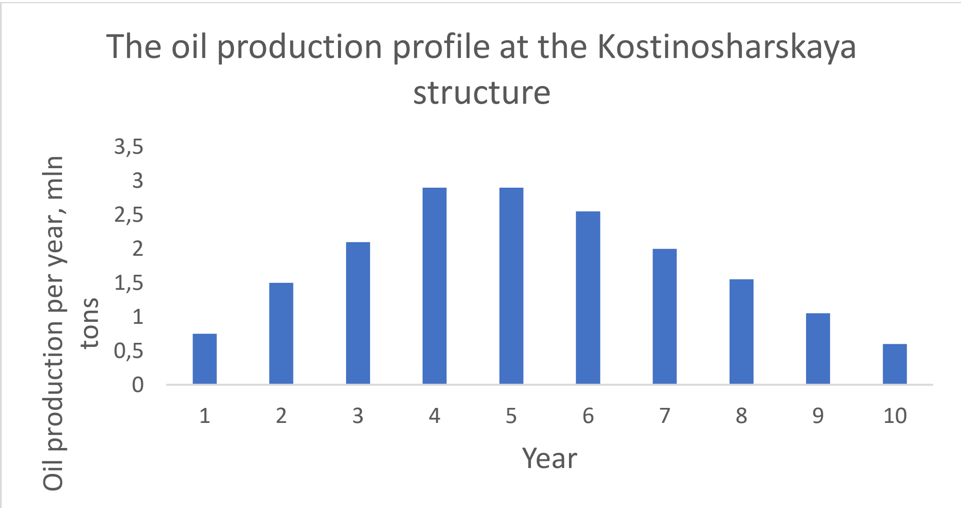

Figure 18. The oil production profile at the Kostinosharskaya structure

3.7.3. The production profile at the Papaninskaya structure

Figure 19 shows the oil production profile at the Papaninskaya structure. The duration of oil production at this structure is 15 years.

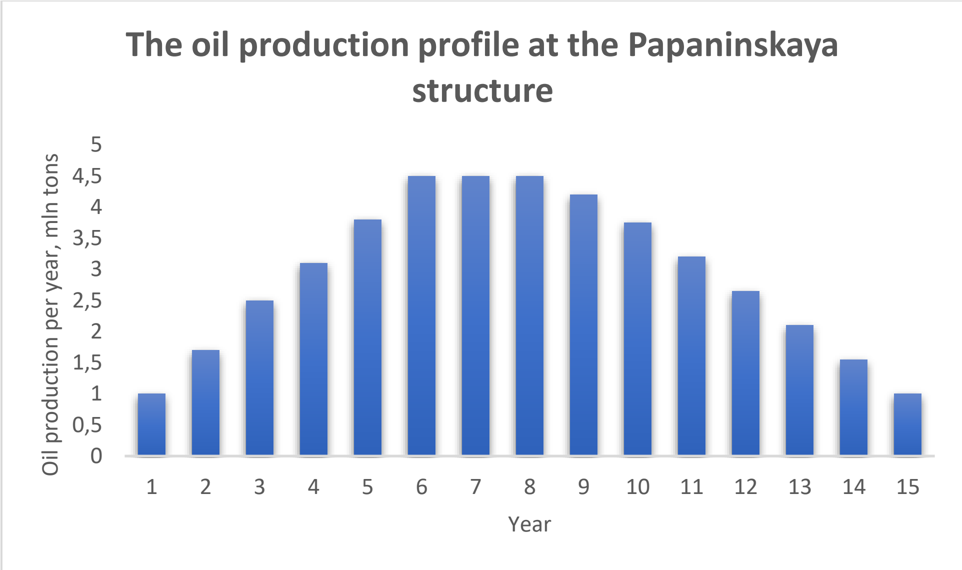

Figure 19. Oil production profile at the Papaninskaya structure

3.8. Chapter Conclusions

A concept has been formed to develop a cluster of three structures of the NWLB - Mezhdusharskaya, Kostinosharskaya and Papaninskaya. The development concept provides for the following solutions:

• Installation of a stationary gravity platform, resistant to the effects of ice and icebergs, at the Mezhsharskaya structure;

• Application of subsea production system for oil and associated gas production at the Kostinosharskaya and Papaninskaya structures;

• Transportation of oil and associated gas to the platform via two-phase pipelines:

- ➢ Approximate length of the pipeline from Kostinosharskaya to Mezhdusharskaya structure - 7 km;
- ➢ The approximate length of the pipeline from the Papaninskaya to the Mezhdusharskaya structure is 40 km.

• Well fluid preparation will be carried out on the platform. Gas separated from oil will be used for own needs, as well as injected into the reservoir to increase oil recovery;

• Delivery of oil to the market by tankers.

For a more uniform production profile and avoidance of excessively high annual production values, it is necessary to bring potential fields into development sequentially. Figure 20 provides information on putting fields into development; Figure 21 shows the total profile of oil production by the traditional method and using Water-Alternating-Gas (WAG) technology:

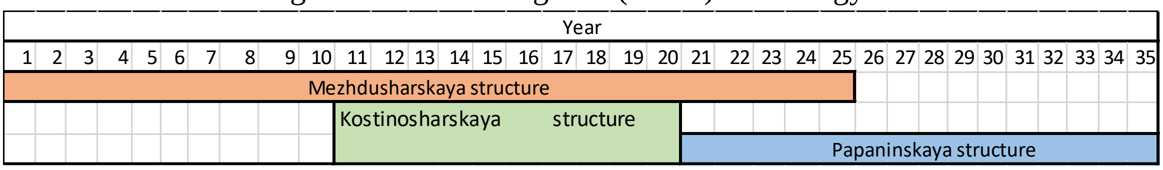

Figure 20. Fields lifetime

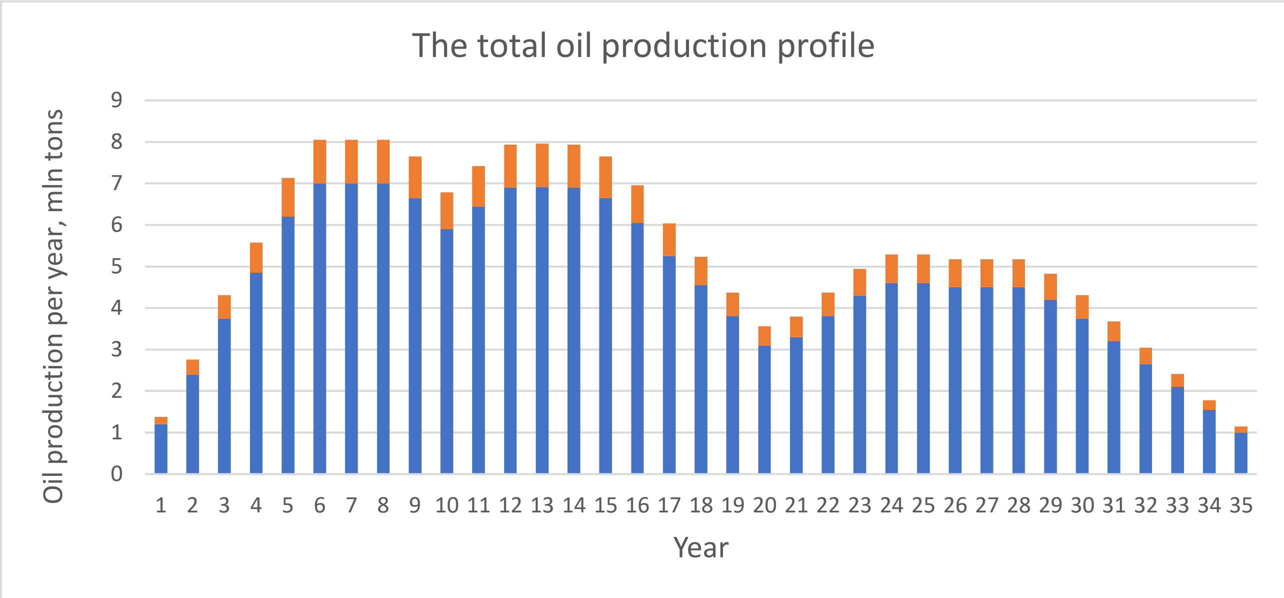

Figure 21. The total oil production profile of the selected structures

4. Selection of equipment for arranging the cluster

4.1. Gravity-based platform

The current design issue of GBS is the depth of water at the field. This is directly related to the capital cost of the potential structure since a lot of building material must be used for manufacturing. All previous projects of the Russian Arctic shelf were designed for shallower depths. It is proposed to place the platform on the site of the Mezhdusharskaya structure. The main reasons for this decision:

• the structure has the largest oil resources;

• a place suitable for further possible connection of other structures.

The existing record for the installation of gravity platforms on the shelf of the Russian Federation was set in the Sea of Okhotsk as part of the Sakhalin-2 project at a water depth of 49 m (LUN-A). Regarding the selected site, it is necessary to consider the estimated water depth of 149-150 meters, measured at the sites of the Mezhdusharskaya structure. In world practice, there are platforms with a higher height. For example, structures at the Draugen (251 m), Gullfaks (217 m) and Troll (303 m) fields are being installed in much deeper areas. Platforms at the Statfjord field (150 m) [36] are an identical example in terms of the depth of installation of the GBS. However, there is no ice within these fields. This fact greatly simplifies the exploitation of the field.

As of 2021, two platforms have been built in the world, the design of which directly took into account the iceberg pile scenario and therefore, they can be called “iceberg resistant”. One such platform, Hibernia, was installed on the northeastern coast of Canada at a depth of 80 m and has a diameter of about 110 m. Production at the field began in 1997. For example, for Khybernia, the design case is a collision with an iceberg weighing 1 million tons (in other words, the bulk of such an iceberg should not even cause structural damage). However, when exposed to an iceberg weighing 5 million tons, the structure may receive non-critical damage with a probable stop of oil production. However, this will not lead to harm to the health of personnel and the environment [37].

The second example of an iceberg-resistant structure is the relatively new Hebron platform, installed 32 km from Hibernia at a depth of 92 m. Production began in 2017 [37].

It should be noted that the NWLB region is characterized by the most "favourable" ice conditions in comparison with the southeastern part of Pechora. The thickness of the ice is on average 50 - 75 cm. During the period of its maximum development, it can reach 120 cm. The average hummocking is 2 - 3 points, the maximum - 5 points on a five-point scale. The overall height of hummocks is 1.0–1.5 m. The maximum height is up to 4 m [8].

For the given water depth characteristics, the platform must meet the following requirements:

- weight of the topside - 65,000 tons;
- GBS height - 180 meters;
- width of the superstructure - 183 meters;
- width of the superstructure - 75 meters (without the helicopter deck);
- height of the superstructure - 113 meters;
- Diameter of the column- 35 m;
- oil storage capacity - 165,000 tons;
- well slots - 50 (including spare slots);
- the number of places to stay - 220.

These values have been determined based on analogue platform ratings and are approximate. The key parameters for comparison are the similarity in water depth and the amount of oil reserves.

Figure 22 and Figure 23 show the technological scheme and the proposed view of the platform.

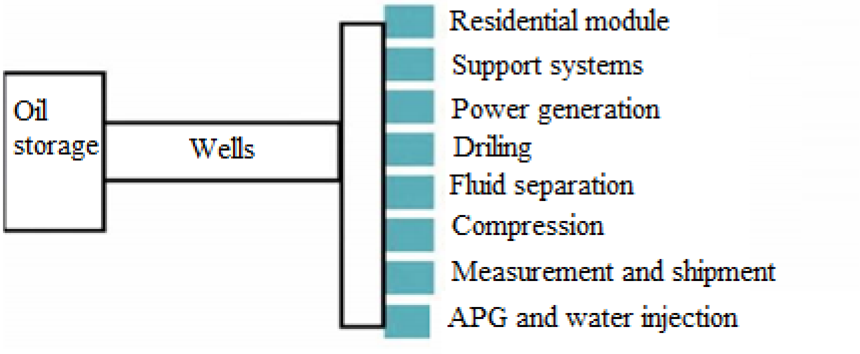

Figure 22. Scheme of technological processes on the platform

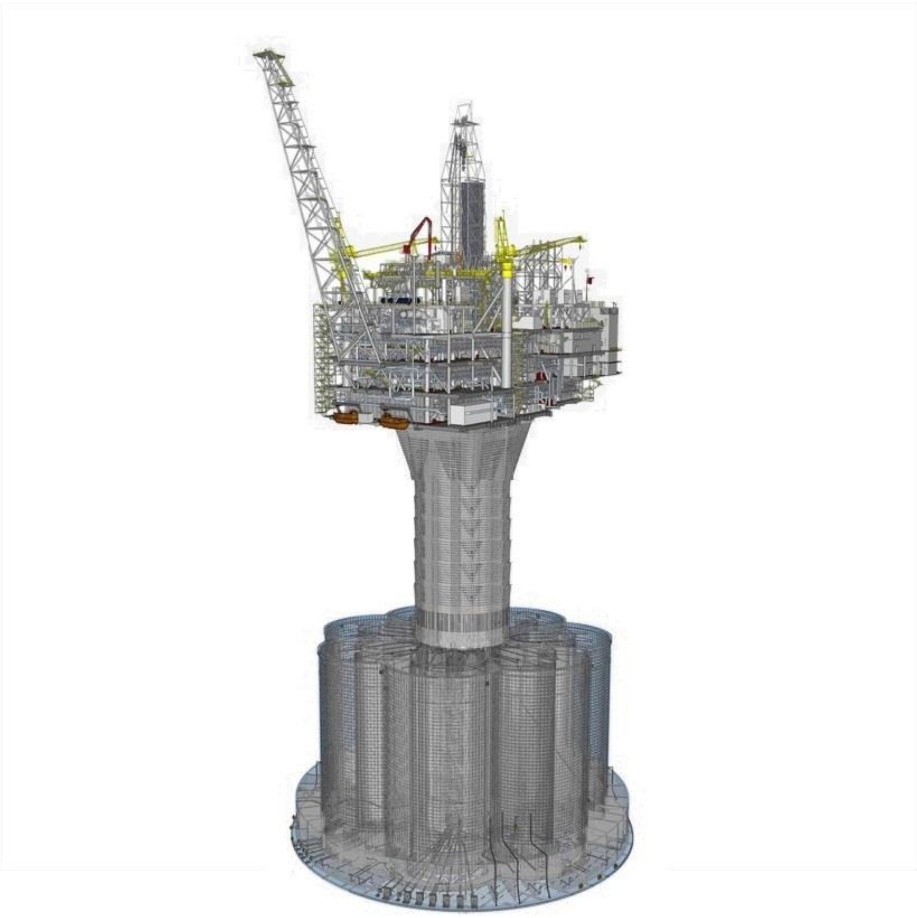

Figure 23. Platform layout [38]

4.1.1. Calculation of ice loads

The Pechora sea are not strong seismically active region. Thus, the most likely dangerous scenario for the development of events will be the level of ice loads exceeding the calculated values. Ice load occurs due to the impact of the ice field on the object and depends on the mass, drift speed and characteristics of the ice, as well as the shape of the object and its size. The consequence of exceeding the ice loads of the maximum values for this project is the platform's shift from the place of its operation. Therefore, improper design of the platform structure can cause an environmental disaster. That is why the issue of forecasting ice loads on offshore ice-resistant stationary platforms is so important.

There are several methods for calculating vertical ice loads on platforms. Below are the standards for calculating ice fields:

- API RP*2N-95
- ISO 19906:2010 (E)
- STO Gazprom 2-3.7-29-2005
- Elforsk 09:55 [39]

API RP*2N-95

The first and one of the most common methods for calculating ice load is the use of the Korzhavin equation [39]:

$$F = m \cdot I \cdot f_c \cdot \sigma_c \cdot D \cdot h \tag{4.1}$$

where:

m – the coefficient of the shape of the structure (for a cylindrical shape, the value is m = 0.9);

I – ice indentation coefficient;

f_c – contact area coefficient;

σ_c – compressive strength of the ice, MPa;

D – the diameter of the platform column, m (D = 35);

h – ice thickness, m (h = 1.2).

It should be noted that the values of the compressive strength of ice (σ_c) differ depending on the climatic zone of the Earth:

2.8 - for the Arctic area

2.4 - for the subarctic area

1.8 - for the moderate area

For the lower base of the platform, according to the CNOOC standard, the value «$I \cdot f_c$» should be obtained from the equation:

$$I \cdot f_c = \frac{3.57 \cdot h^{0.1}}{D^{0.5}} \tag{4.2}$$

where:

D – the diameter of the platform column;

h – ice thickness (h = 1.2).

Calculating the equation, the value $I \cdot fc$ = 0.614 is obtained

Then the total load can be calculated according to the Korzhavin equation. The resulting value is 65 MN.

ISO 19906:2010 (E)

Ice load from ice fields can be obtained from the equation in ISO 19906: 2010 (E) [39]:

$$F = \sigma \cdot d \cdot h \tag{4.3}$$

where:

σ_c – ice pressure, MPa;

$$\sigma = R \cdot \left(\frac{h}{h_1}\right)^n \cdot \left(\frac{d}{h}\right)^m \tag{4.4}$$

where:

h_1 - thickness taken as 1 m;

m – empirical coefficient, taken equal to (-0.16);

n - empirical coefficient equal to (-0.3);

d - diameter of a column;

R - standard value of ice strength for uniaxial compression, MPa (2.8 MPa for the Pechora Sea).

Calculation of ice pressure (σ) according to (4.3) gives a value of 1.5 MPa. Then Calculation of the total force (9) gives the value of F equal to 64.9.

STO Gazprom 2-3.7-29-2005

$$F = m \cdot k \cdot R \cdot d \cdot h \tag{4.5}$$

where:

m – the coefficient of the shape of the structure (for cylindrical structures it is taken as 0.85);

k – coefficient taking into account the tightness of the contact of the ice formation with the structure and the effect of ice constraint upon destruction (taken as 0.95);

R – standard value of ice strength for uniaxial compression, MPa (2.8 MPa for the Pechora Sea);

d - diameter of a column;

h - ice thickness.

The total load can be calculated according to (4.5). Therefore, the F value is 94.9 MN.

Elforsk rapport 09:55

Ice load calculation based on Elforsk report 09:55 [39] can be obtained using the following equation (if the ratio between ice thickness and column diameter is less than 1):

$$F = 0{,}45 \cdot d \cdot h \cdot R \cdot \sqrt{1 + 5 \cdot \frac{h}{d}} \tag{4.6}$$

where;

h - ice thickness, m (1.2 m);

d - column diameter, m (130 m);

R - standard value of ice strength for uniaxial compression, MPa (2.8 MPa for the Pechora Sea.

According to (4.6), the obtained value is 57.2 MN.

Figure 24 shows a comparison of ice loads calculated using the standards listed above:

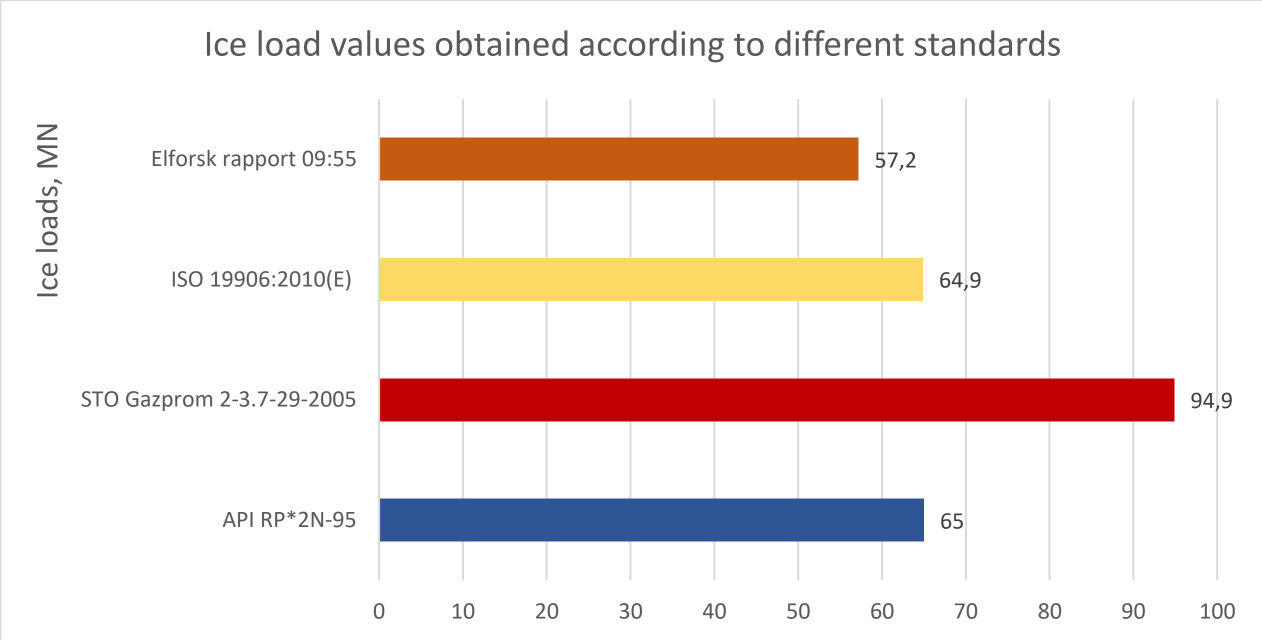

Figure 24. Values of ice loads obtained according to different standards

According to the data obtained, the greatest load was obtained during calculating the STO Gazprom 2-3.7-29-2005 standard - 94.9 MN. The smallest value was obtained when calculating by the Elforsk method - 52.2 MN. The values of the maximum permissible platform loads are shown in Table 8.

Table 8. Maximum loads on the GBS platforms for the Arctic seas [36]

Load	Concrete		Concrete	
	Fy, MN	Mx, MN·m	Fx, MN	My, MN·m
Ice *	324	21.004	310.8	19813.8
Waves (irregular, 0.1% of exceedance)	630	12.932	481.8	10131.3
Wind	0.722	43.36	0.681	40.9
Current	50	1.2	38.7	748
Ice* +wind+cirrent	344.3	22.14	330.1	21602.7
Wave+wind+current	649.3	14.255	521.2	10.92
* Load from adhered ice				

As can be seen from the Table 8, the maximum permissible values of ice loads are much higher than those obtained in calculations.

4.2. Subsea production systems

The use of subsea technology to extract hydrocarbons from deep-sea waters around the world continues to grow rapidly. Such systems are usually wells located on the seabed. For oil production, SPS can be linked to an existing production platform or onshore equipment. An oil well is drilled with a mobile drilling rig, and the produced oil or natural gas is transported by pipeline and then lifted to the processing plant. For the first time such technology of underwater pumping of hydrocarbons was applied in the Gulf of Mexico in the 70s of the last century. In the world today there are already more than 130 fields using SPS [40].

In Russia, production using SPS technology has been carried out only at the Kirinskoye field as part of the Sakhalin-3 project. This field is not located in the Arctic Circle, but its operating conditions are very close to the conditions for hydrocarbon production in the Pechora and Barents Seas. According to experts, mass production of SPSs in Russia will begin in the mid-20s. The largest oil and gas companies – Rosneft, Gazprom Neft, Lukoil and Novatek assess the demand for equipment for subsea production complexes until 2035 as essential [41, 42].

4.2.1. Main elements of subsea production systems

The main elements are:

- Christmas tree;
- Manifold;
- Template.

The heart of a typical subsea production system is the subsea Christmas tree. It performs the same tasks as valves in onshore fields, but its design is very different. This is due to the significant loads on equipment caused by currents, waves and hydrostatic pressure. It is possible to remotely control the Christmas tree using remotely operated crewless underwater vehicles (ROV). Figure 25 shows an image of the Christmas tree.

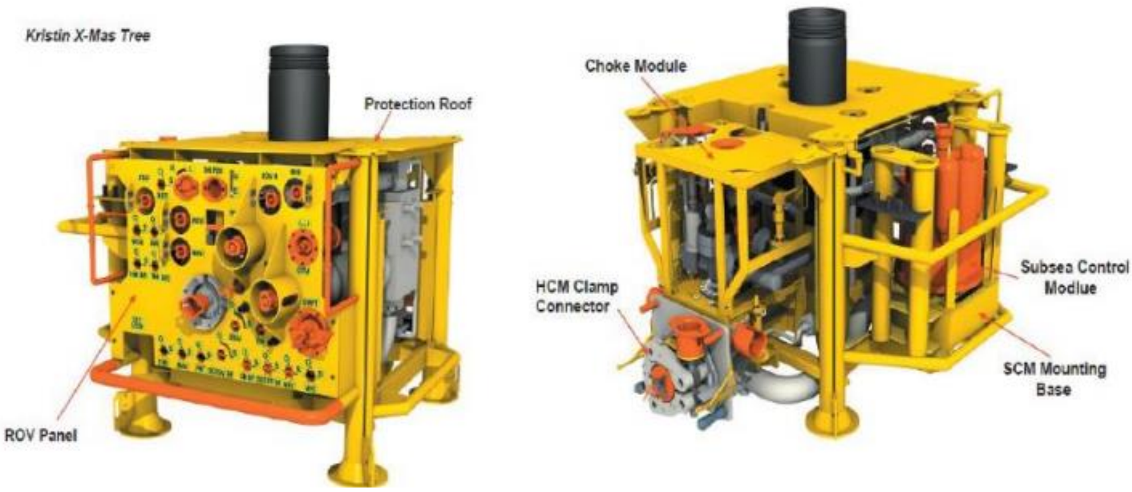

Figure 25. Image of the Christmas tree for SPS [43]

The following are the functions of the subsea Christmas tree system:

- Providing a protective barrier between the sea and hydrocarbon deposits;

- Providing injection of chemicals into a well or flowline;
- Supply of electrical signals to downhole sensors;
- Adjustment of fluid flow through the choke.
- Safe shutdown of produced or injected fluid;
- Control of hydrocarbon production.

A manifold is a special device, the main function of which is to collect oil and gas from several production wells, as well as to inject an agent to maintain reservoir pressure. All produced products are delivered to the onshore processing facility or to the platform via subsea pipeline through the manifold. The size of the manifold is determined based on the data on the number of wells and their drainage system.

The template is required to protect the manifold and X-mas tree from falling objects, as well as from environmental influences.

Since the manifold is inserted into the template and can represent a single structure, the concepts of template and manifold are considered a single whole. Together, they still perform the functions of collecting and distributing products, as well as protecting against environmental impacts on the Christmas tree (Figure 26) [43].

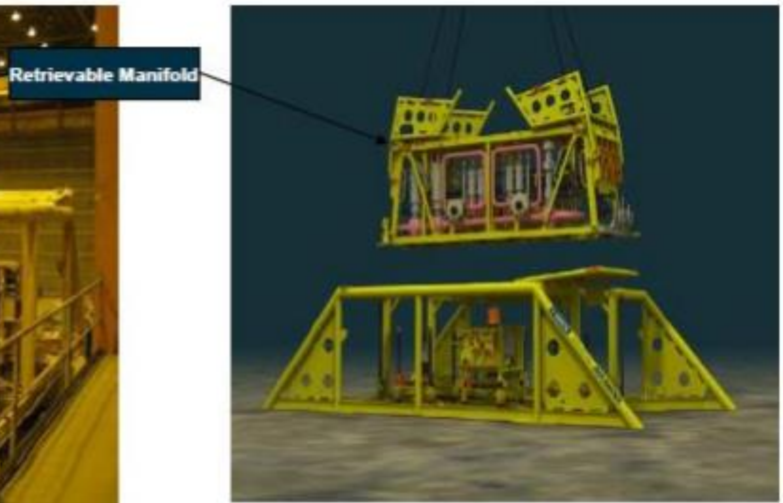

Figure 26. Manifold and template [43]

4.2.2. Choosing SPS for arranging a cluster

As mentioned earlier in the previous chapter, the Kostinosharskaya and Papaninskaya structures are supposed to be developed using SPS. The depth of the sea at the sites varies from 70 to 150 m. Among the two existing development systems, such as the well cluster system and the system using a template, the second option is considered. This is due to several features of the development of such a project. First, cluster systems are believed to take longer to install [44]. In this case, a system with a template collects several well slots inside one structure (standard blocks can include from 4 to 12 well slots [45]). For the ITS system, it should be noted that in harsh climatic conditions, the installation time of such systems is reduced by combining several wells into a system of one design.

For the development of the Kostinosharskaya structure, it is proposed to use SPS of the following configuration:

- One 6-slot template for 2 injection and 4 production wells.

At the Papaninskaya structure, it is proposed to establish:

- four 4-slot templates for 12 production and 4 injection wells.

4.3. Infield pipelines

4.3.1. Selection of pipelines installation technology

The installation of subsea pipelines is very different from the installation of onshore pipelines. Overhead pipes are delivered to the site by overland transport (e.g. trailers). Then they are welded, forming a pipeline, gradually lowered into the trench and covered with bedrock. In traditional subsea pipelines, pipes are transported to a stacker vessel, which is used as a welder to weld the pipes into a single string. In contrast to onshore pipelines, lowering the pipeline to the seabed is more difficult because the bending stress generated in the pipeline is much greater and if not installed correctly, the pipeline can bend. The lay vessel moves forward as more pipes are welded until all the necessary pipes are welded. Open water subsea pipelines are subject to the dynamic effects of vessel movement due to wind, waves and currents. All of these factors add more risks than land installations [46].

Based on the depth of the sea, it is proposed to carry out the S-method of laying the offshore pipeline at NWLB (from 70 to 150 m) (Figure 27). This method is the most common and is usually used for pipes up to 60 inches in diameter. A significant advantage is also the operating speed of pipe-laying, which ranges from 3 to 7 km/day. This is especially important in view of the relatively short ice-free window in this region.

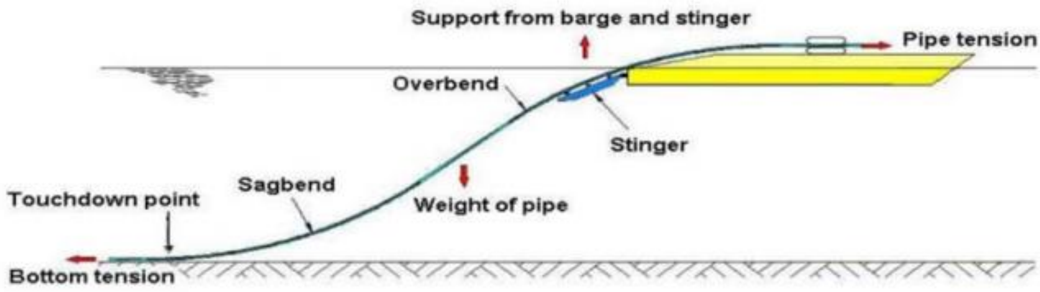

Figure 27. S-Lay Pipe Configuration [46]

The installation technology is as follows: the pipe on the ship is in a horizontal position. Then with the help of a special guide structure - a stinger, bending under its weight, it sinks to the bottom, forming a convex bend. Then, before meeting the seabed, the pipe bends in the opposite direction, forming a concave curve. The pipe must be under constant tension to prevent damage due to excessive bending during installation [47].

4.3.2. Pipeline design

Oil pipelines under internal and external pressure were considered. Calculations were performed according to the selected scheme for the development of NWLB structures (see Chapter 3.5). The diameters shown in Table 9 and other baseline data from Table 10 to 11 were used. In a specific case, the pipeline was considered from the template at the Kostinoshar structure to the base platform at the Mezhsharskaya oil structure. Due to the lack of prospecting and exploration drilling at these structures, information on the reservoir fluid properties was taken from the nearest field, Dolginskoye. The distance between the Dolginskoye field and the Papaninsky structure is about 100 km.

Table 9. Properties of pipes from the American Petroleum Institute (API 5L) [47]

Pipeline diameter	10”	12”	14”
Outer pipe diameter	273.1 мм	323.9 мм	355.6 мм
Standard wall thickness	9.3 - 11.1 мм 12.7 мм 14.3 мм 15.9 мм 18.9 мм	9.5 мм 10.3 мм 11.1 мм 12.7 мм 14.3 мм 15.9 мм 18.3 мм	9.5 мм 10.3 мм 11.1 мм 12.7 мм 14.3 мм 15.9 мм 18.3 мм

Table 10. Properties of steel X65 [47]

Parameter	**Value**
SMYS	448 MPa
Thermal expansion coefficient of steel	1.17E-5˚C
Poisson's ratio for steel	0.3
Young's modulus of steel	210 GPa

Table 11. Initial data for calculations [17]

Pipe data	**Value**
Nominal pipe diameter, Do	273.1 mm
Nominal wall thickness, tw	9.3 mm
Internal roughness, k	0.05mm
Pipeline length, L	7 km
Flow line pressure	150 bar
Constant operating temperature	60 ˚C
Minimum intake pressure at the top of the riser on the platform	50 bar
Installation site temperature	5 ˚C

Working data	**Value**
Flow rate, Q	14562 m^3/day
Fluid density, p	865 kg/m^3
Dynamic viscosity, μ	$2.3 \cdot 10^{-6}$ Pa · s

To begin with, we need to select the required diameter that meets the required conditions for the receipt of the process. Nominal 10" diameter and initial assumed wall thickness have been verified. If the pressure drop in the pipeline section is more than 100 bar, it will be necessary to change the nominal diameter later.

1. The Reynolds number can be obtained in the following way:

$$Re = \frac{v \cdot D_i \cdot p}{\mu} = \frac{4 \cdot N \cdot p}{\pi \cdot D_i \cdot \mu} = \frac{4 \cdot 4 \cdot 2427 \cdot 865}{3.14 \cdot 86400 \cdot 0.2545 \cdot 2.3 \cdot 10^{-6}} = 2.12 \cdot 10^{8}$$

where: Q = N · $Q = N \cdot q_{1w}$– Volumetric flow rate, m^3 / s;

N – number of wells, q_{1w}– oil production from one well, m3 / day.

Re > 2300 (turbulent flow).

2. Relative roughness:

$$r = \frac{\varepsilon}{D_i} = \frac{0.05}{254.5} = 1.962 \cdot 10^{-4}$$

Using the Moody diagram (Figure 28), the Darcy-Weisbach friction coefficient can be found:

f = 0.0135

3. The actual pressure drop has two parts - frictional head loss + static head:

$$\Delta p = \frac{f \cdot p \cdot L \cdot v^2}{2 \cdot D_i} + p \cdot g \cdot h = \frac{0.0135 \cdot 865 \cdot 7000 \cdot 8.45^2}{2 \cdot 0.2545} + 865 \cdot 9.81 \cdot 150 = 9.14 \text{ MPa}$$

4. The calculations have verified the actual pressure drop to meet the requirements for the allowable pressure drop:

$Pi - \Delta p = P_{min}$ = 15 – 9.14 = 5.86 (> 5 MPa)

where: P_i – Wellhead pressure, MPa;

P_{min} – Minimum intake pressure at the top of the riser on the platform, MPa.

MOODY DIAGRAM

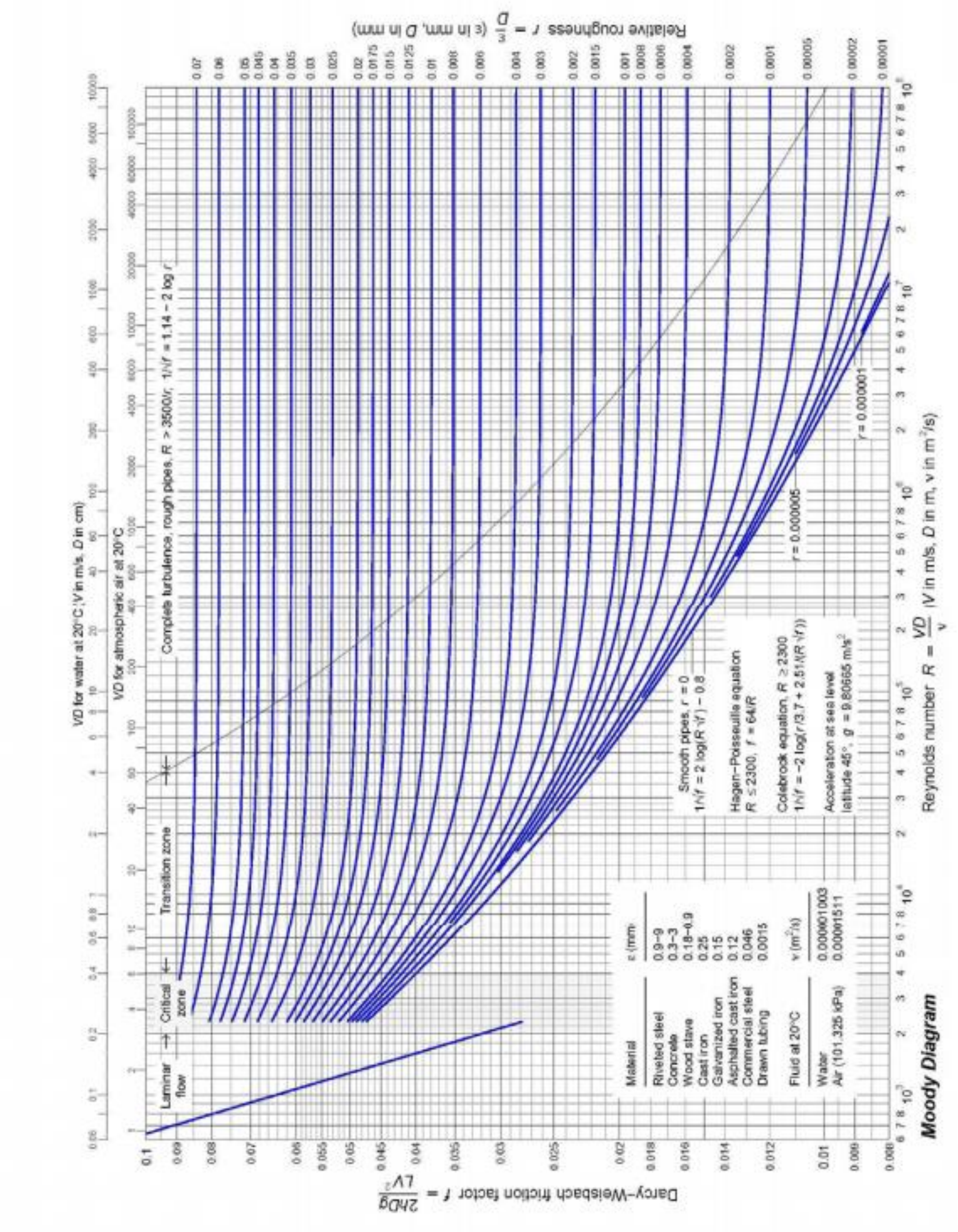

Figure 28. Moody diagram [47]

To check and optimize the pipeline's wall thickness, a design factor of 0.72 should be used.

1. The hoop stress can be found by the formula:

$$S_h = \frac{p_{iD_i} - p_O D_O}{2 \cdot t} = \frac{15 \cdot 0.2545 - 1025 \cdot 9.81 \cdot 150 \cdot 0.2731}{2 \cdot 9.3} = 183.09\ MPa$$

2. For the selected pipe X65 SMYS = 448 MPa.

$$SMYS \cdot Design\ factor = 448 \cdot 0.72 = 322\ MPa$$

322 MPa < 183.09 MPa (ok)

It is also necessary to calculate the combined stresses (von Mises criterion). The value of the calculated coefficient is taken equal to 0.8.

$$\sigma_{eq} = \sqrt{(\sigma_l^2 + \sigma_h^2) - \sigma_h \cdot \sigma_l}$$

1. Moment of inertia could be calculated via the formula:

$$J = \frac{\pi}{64} \cdot (D^4 - (D - 2 \cdot T)^4) = \frac{3.14}{64} \cdot (0.2731^4 - (0.2731 - 2 \cdot 0.0093)^4) = 6.6 \cdot 10^{-5}$$

2. Bending stress:

$$\sigma_{bending} = \frac{D}{2} \cdot \frac{M}{J} = \frac{0.2731}{2} \cdot \frac{50 \cdot 10^3}{6.6 \cdot 10^{-5}} = 103.14\ MN$$

3. Longitudinal stress:

$$\sigma_l = \sigma_{axial} \pm \sigma_{bending} = \frac{4 \cdot F_{axial}}{\pi \cdot D^2} = \frac{4 \cdot 100 \cdot 10^3}{0.2731^2} + 103.14 = 108.51\ MN$$

4. Hoop stress:

$$\sigma_h = \frac{p_{iD_i} - p_O D_O}{2 \cdot t} = \frac{15 \cdot 0.2545 - 1025 \cdot 9.81 \cdot 150 \cdot 0.2731}{2 \cdot 9.3} = 183.09\ MPa$$

5. Von Mises criterion:

$$\sigma_{eq} = \sqrt{(\sigma_l^2 + \sigma_h^2) - \sigma_h \cdot \sigma_l} = \sqrt{(108.51^2 + 183.09^2) - 183.09 \cdot 108.51} = 159.46\ MN$$

6. Now we need to check the obtained values for convergence:

$$SMYS \cdot Design\ factor = 448 \cdot 0.8 = 358.4\ mn$$

$$SMYS \cdot Design\ factor > \sigma_h$$

$$358.4 > 159.46\ MN$$

Conclusion by calculation: The wall thickness of 9.3 mm is sufficient to withstand a pressure drop of 9.14 MPa. Calculations of the hoop and longitudinal stresses, followed by the comparison of the von Mises criterion, showed that such a wall thickness is sufficient to satisfy the condition.

4.4. Offloading and transportation of oil

For offloading oil from the platform, a special device is proposed, the analogs of which are installed at the Prirazlomnaya (CUPON) IRGBS. This loading technology allows oil to be pumped onto tankers in almost any difficult weather conditions. A diagram of the Coupon device is shown in Figure 29.

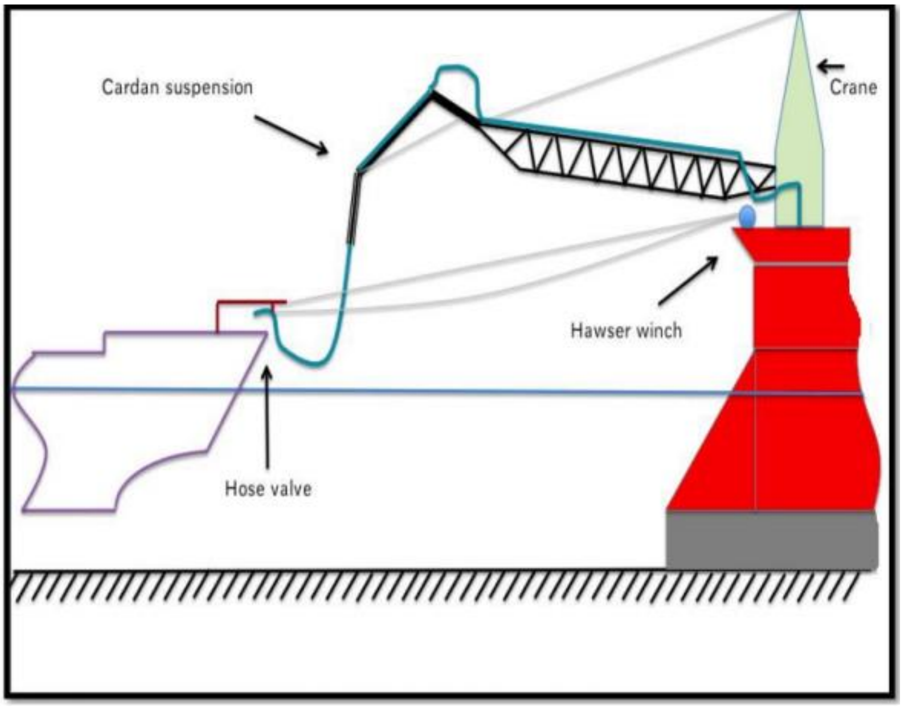

Figure 29. The layout of the CUPON offloading system and its constituent elements [48]

Complexes of direct oil offloading devices provide contactless mooring and oil offloading on special shuttle tankers equipped with a bow loading system and a dynamic positioning system [12].

CUPON provides a throughput of up to 10,000 m3 / h, while the pressure at the inlet to the cargo system of the tanker is not less than 3 bar at the inlet pressure to the CUPON (8.9 ± 0.5) bar [12].

CUPON equipment includes:

- electro-hydraulic crane (maximum working radius 70 m, swing sector during operation ± 90 degrees);
- equipment for oil product pipeline;
- device for flushing the oil product pipeline;
- hose transfer equipment;
- shipping hose 2-section (length of each section 12.2 m);
- control and monitoring system of the complex;
- tanker mooring equipment.

The CUPON control and monitoring system is based on a PLC (programmable logic controller). The system provides control and monitoring of CUPON equipment in all operating modes.

The control is carried out from the crane cabin. In addition, an operator station and a fire and gas alarm system panel are located in the cockpit [14].

Based on the expected annual oil production of the cluster and the distance from the platform to the port of shipment, it is necessary to select a tanker with the following characteristics:

Oil tanker Arc6 (deadweight 140,000 tons);

• Number of tankers - 2;

• Draft 18 m;

• Tanker speed in ice - 7 knots (13 km / h);

• Tanker speed in open water - 30 knots (55 km / h);

• Swimming in seas with ice thickness up to 1.4 m.

The tanker mooring system should provide:

– storage and supply of a mooring line (length 80 m, breaking force 5700 kN), antifriction chain and conductors;
– cable tension control;
– implementation of the emergency release of the mooring line.

An important parameter for shipment is the maximum oil production rate. It was calculated that this value does not exceed 8 million tons/year (25,000 tons/day). Thus, when using the proposed tanker, the shipment must be carried out every five days.

5. Assessment of the economic profitability of the project

This chapter aims to give a rough estimate of the economic viability of the concept for three structures. Summarizing all the previous observations, the development should consider the concept of no gas injection and injection into the reservoir.

A rough estimate of the economic viability is required at the preliminary stages of field development. A typical offshore project can be divided into three main project cost categories:

- exploration costs;
- operating costs;
- development costs.

To analyze the economic profitability of a project, as a rule, three main calculation parameters are used:

- Net Present Value (NPV);
- Internal rate of return (IRR);
- Index of profitability (PI).

5.1. Net present value

Before investing money in the implementation of a project, investors analyze its effectiveness using various indicators. These include net present value (NPV).

NPV is the result of calculations used to determine the present value of the future cash flow. It takes into account the time value of money and can be used to compare similar investment alternatives. NPV is based on a discount rate that can be derived from the cost of capital required to make an investment, and any projects or investments with negative NPV should be avoided. In other words, a dollar earned in the future will not be worth the same as a dollar earned in the present. The discount rate element of the NPV formula allows for this.

An important disadvantage of using NPV analysis is that it makes assumptions about future events that may not be reliable.

NPV is calculated as follows:

$$NPV = -I + \sum_{t=1}^{N} \frac{CFt}{(1+r)^t} \tag{5.1}$$

where:
I – initial investment in the project;
CFt – cash flows;
r – discount rate.
Main conclusions:

- Net Present Value, is used to calculate the current total value of the future cash flow.
- If the NPV of a project or investment is positive, it means that the discounted present value of all future cash flows associated with that project or investment will be positive and therefore attractive.
- To calculate NPV, it is necessary to estimate future cash flows for each period and determine the correct discount rate.

Depending on the value of this indicator, the investor evaluates the attractiveness of the project. If:

- NPV> 1, then the investment project is profitable. In the end, the investor will make a profit;
- NPV = 1, then the project will not bring any profit or loss;
- NPV <1, the project is unprofitable and promises losses to the investor [49].

5.2. Internal rate of return

Internal Rate of Return (IRR) is a mathematical and financial formula used to calculate the discount rate at which a certain cash flow will be equal to zero NPV. In other words, this will be the profitability of the considered investments.

To determine how the IRR is calculated, the following equation is used:

$$IRR = r_1 + \frac{NPV(r_1)}{NPV(r_1) - NPV(r_2)} \cdot (r_2 - r_1) \quad (5.2)$$

Where r – discount rate [49].

5.3. Profitability index

The profitability index (PI) measures the ratio between the present value of future cash flows and the initial investment. This parameter is a useful tool for ranking investment projects and displaying the value created per unit of investment. The profitability index is calculated in the following way:

$$PI = -I + \sum_{t=1}^{N} \frac{NCF}{I} \quad (5.3)$$

Depending on the value obtained, the investor can assess whether the project will be profitable:

- $PI < 1$, the project is rejected;
- $PI > 1$, the project is accepted;
- $PI = 1$, the project is neutral [49].

5.4. Initial data for calculation and results

In general, it can be considered that the project itself consists of two categories of investments: capital costs (CAPEX) and operating costs (OPEX). Due to the fact that offshore projects in Russia are in difficult environmental conditions and political circumstances such as sanctions, the government is applying tax incentives to develop such fields.

Regarding the development of the selected structures of the North-West license block, one of the main uncertainties during this project is the amount of hydrocarbon resources. Below, two scenarios will be compared: with gas injection and without WAG injection. Therefore, the following costs should be considered, presented in Table 12.

Table 12. Initial data for economic calculation

Indicator	The quantity	unit of measurement
Maximum annual production	7.5 - 8 mln	t/year
Project implementation period	35	years
Investments (CAPEX):	17 - 18 billion	$
Oil price	70.0	$/bar.

Continuation of Table 12.

Operating expenses	80 - 90	$/ton
Depreciation percentage	20	% of total investment
Credit period	10	years
Loan payments term	10	years
The amount of borrowed funds	20	% of total investment
Interest rate	10	%
Export duty	11	$/ton
Income tax	25	%
Discount rate	12	%
Production well cost	18 mln	$
Injection well cost	16.2 mln	$
Platform cost	12 billion	$
Price for 1 km of pipeline	1.5 mln	$
SPS init price	100 mln	$
Production well cost (SPS)	12 mln	$
Injection well cost (SPS)	10.5 mln	$
The cost of renting a semi-submersible drilling rig	120 thousand	$ / day

Table 13 shows the results of economic calculations for both scenarios:

Table 13. Results of economic calculations for the first and second (WAG) scenarios

Indicator	Production by traditional methods	Applying the WAG
Investment volume (CAPEX):	18,2 billion $	19 billion $
Operating expenses	80 $	90 $
Net present value	2 846 mln $	$4 052 mln $
Internal rate of return	14.6 %	15.4 %
Payback period	15 years	13 years

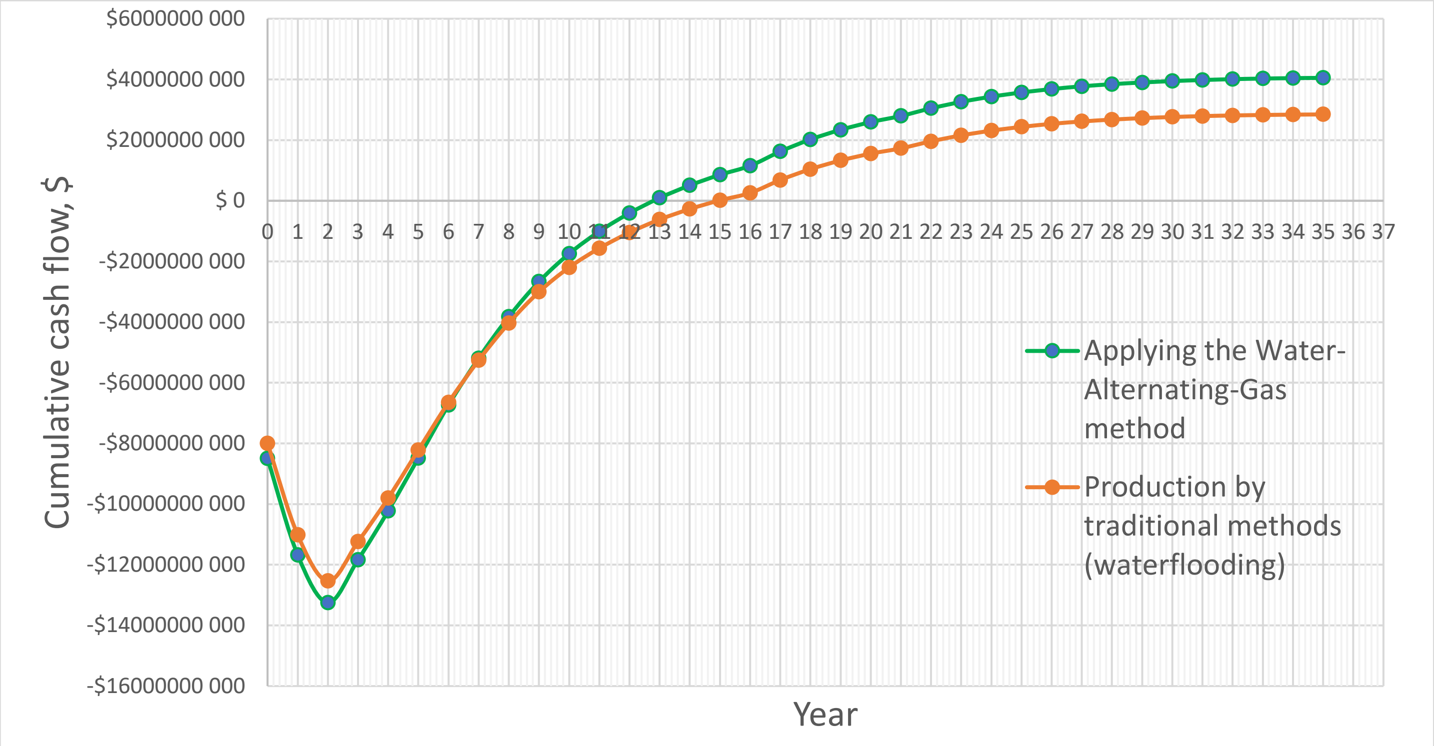

Figure 30. Comparison of indicators of Net present value for two scenarios (with the use of the water-gas impact method and without)

The figure shows that the concept using water-alternating-gas injection is the most profitable from an economic point of view, even despite the large capital costs. That occurs due to an additional increase in oil production. The growth rate is estimated at 25 million tons.

Conclusion

The shelf of the Pechora Sea has significant prospects in terms of the extraction of hydrocarbon resources. An integrated approach using the common infrastructure of the shelf fields and their successive commissioning leads to the project's economic efficiency. The North-West license area studied in the framework of the master's thesis has an approved commercial value. Therefore, prospects for its development in the coming years can be assessed as very high.

For a detailed understanding of this region, climatic conditions, hydrological conditions of the sea, and characteristics of the seabed were taken into account. The main difficulties that could potentially affect the development of the NWLB territory were outlined. When developing the concept, the experience of operating the Prirazlomnoye oil field was taken into account.

Based on the master thesis results, the concept of the development of a cluster of three structures of the NWLB was selected and preliminarily substantiated: Mezhdusharskaya, Kostinosharskaya and Papaninskaya. The total recoverable resources are estimated at more than 150 million tons.

The chosen concept includes the following solutions:

• Installation of a stationary gravity platform (GBS), resistant to the effects of ice and icebergs, at the Mezhdusharskaya structure;

• Application of subsea production complexes (SPS) for oil and associated gas production at the Kostinosharskaya and Papaninskaya structures;

• Transportation of oil and associated gas to the platform via two-phase pipelines:

- ➢ Approximate length of the pipeline from Kostinosharskaya to Mezhdusharskaya structure - 7 km;
- ➢ The approximate length of the pipeline from the Papaninskaya to the Mezhdusharskaya structure is 40 km.

• Well fluid preparation will be carried out on the platform. The gas separated from oil will be used for own needs, as well as injected into the reservoir to increase oil recovery;

• Delivery of oil to the market is carried out by tankers.

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