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Author: Kirill Shumkin	(author signature)
Tutor: Lin Li, Anatoly Zolotukhin	
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Table of contents

Abstract

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The solutions described in this paper are based on:

- analysis of available information on natural conditions and challenges in the region,
- development and multi-criteria pair analysis of the best development scenarios,
- analysis of available and developing technologies in the global oilfield services market,
- top-level economic assessment,
- calculation of loads for similar conditions of construction of a typical well.

Abstract

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Acronyms and Abbreviations

ARCO - Oil grade ArcticOil

BEP - Break-even point

BOP – The blowout preventer

CAPEX – Capital expenditures

DNV - Det Norske Veritas

DPB - Discounted payback period

SI - International System of Units

FJL - Franz Josef Land archipelago

FPSO - Floating Production, Storage and Offloading unit

GOST - Acronym for Russian governmental standard

HLA– Heisovsky license area

HSE - Health, Safety and Environment

HV - High voltage

HWDP - Heavy weight drill pipe

IEA - International Energy Agency

IEU - Internal-External Upset

IRR - Internal rate of return

IRS - Intervention riser system

LLC - Limited liability company MCDM - Multiple-criteria decision making

MEG - Monoethylene glycol

MET - Mineral Extraction Tax

MODU - Mobile offshore drilling unit

NCS - Norwegian continental shelf

NPV – Net present value

NZA – Novaya Zemlya Archipelago

GBS – Gravity-based structure

LNG - Liquefied natural gas

LRRS - The low riser return system

MCDA - Multiple-criteria decision analysis

PC – Polar class

PDQ – Production, drilling, quarter

PI - Profitability Index

RLWI - Riserless Light Well Intervention

RMR - Riserless Mud Recovery

ROV – Remotely operated vehicle

RSU – Russian State University

SDP – Steel drill pipes

SIL - Subsea Intervention Lubricator

SPE - Society of Petroleum Engineers

SPS – Subsea production system

SSLD - Subsea leak detection system

SURF - Subsea construction, umbilicals, risers and flowlines

TRL – Technology readiness level

WCI – Windchill index

1. Introduction

Due to the maturity of the deposits in West Siberia, hydrocarbon production on traditional Russian fields is naturally decreasing. To maintain existing markets and develop hydrocarbon exports to the Russian Federation, Russia needs to develop its resource potential. Exploration of the Arctic shelf region is still at an early stage. However, based on the available information, we can say that the Arctic shelf is a promising and unique source of hydrocarbons. The Kara and the Barents Sea is considered the most promising.

Currently, 5 oil, 2 oil-gas-condensate, 1 oil and gas field and 5 gas fields have been discovered on the Russian Arctic shelf. Below are some statistics on the Arctic region's reserves by category (Figure 1.1) [3].

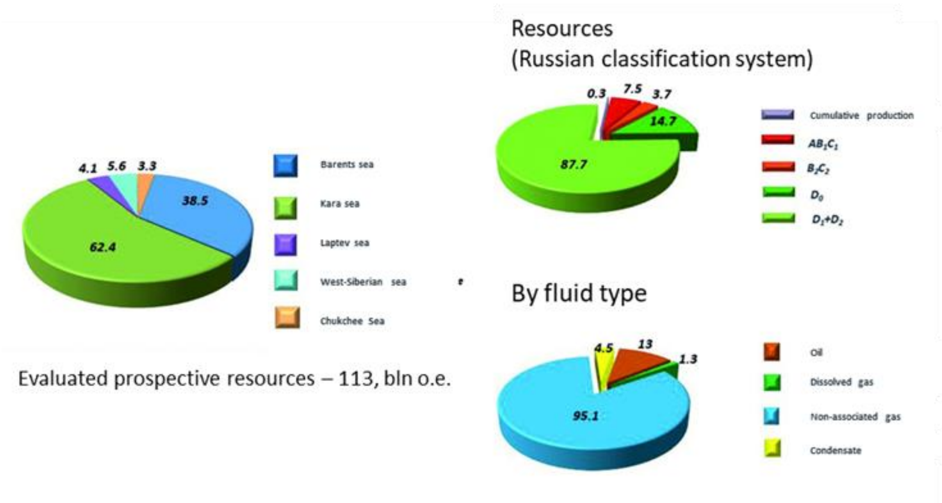

Figure 1.1 Statistics by category of reserves and resources of the Arctic seas of the Russian Federation [3]

1.1. Motivation

In 2019, Gazprom Neft Shelf received a license to explore and produce the Heisovsky license area (HLA) in the Barents Sea. However, developing such a field's resources is a technologically complex task that the industry will face in the next 10-15 years.

Work on the conceptual design and engineering of new Arctic fields is more relevant than ever for the Russian Federation. For further work on studying the prospects of new Arctic deposits, it is necessary to understand the upcoming difficulties and prospects for the development of the discovered deposits as accurately as possible. In addition, exploratory drilling in the Arctic is much more expensive than exploratory drilling on land. The assessment of the prospects for the development of deposits at the stage of seismic studies is the basis for planning and ranking exploration drilling operations.

1.2. Aim and scope

The work aims to study the prospects and propose possible development scenarios to evaluate the project's necessary technologies and capital investments.

The first chapter of this thesis provides detailed information about the Heisovsky license area. The second chapter of the work includes a description of the natural conditions of the region. The third chapter describes and analyses infrastructure and technological challenges. The further chapter presents a list of development scenarios proposed for consideration and an analysis of the current level of development of the necessary technologies. In addition, this section presents the methodology and results of selecting scenarios by multi-criteria pair analysis. Based on the analysis results, optimal scenarios are detailed in logistics, storage, ice management, drilling and downhole operations. Finally, the fifth chapter is devoted to calculating the maximum loads on the hook while drilling a standard well proposed at the conceptual stage. The result is used to confirm the hypothesis that the proposed drilling vessel design meets the project requirements.

1.3. Location, history and exploration program of HLA

HLA deposit is a subsurface shelf located northeast of the Barents Sea between the Novaya Zemlya (NZA) and Franz Josef Land (FJL) archipelagos. Below is a diagram of the location of HLA in the Barents Sea (Figure 1.1).

Figure 1.1 HLA layout

The area of the license area is 83,590km^2. The site is conventionally divided into Southwestern and Northeastern clusters. The decision to divide was made due to the considerable distance between the found promising structures. The distance between the most promising zones of the two clusters is approximately 300 km [1].

According to the consolidated state register of subsurface areas and licenses, for the first time, a license for exploration and production in this territory was issued to Gazprom in autumn 2014. The first and currently only search and exploration activities date back to the end of 2019. At the same time, the subsoil use license was transferred to Gazprom Neft Shelf LLC. In the further quarter of 2019, the first series of 2D offshore exploration works were carried out using the common depth point method. In general, the planned work completion date is a little more than 3 years until the end of December 2023 [2]. In addition, preliminary drilling of exploration wells is planned for 2026 and 2028.

The amount of seismic data collected so far has allowed us to make a resource estimate based on interpretations. The data used in this work was changed to preserve trade secrets, but they adequately reflect the resulting dependencies and relationships. The resource estimate of P50 is 1.54 billion tons of oil and 3 trillion m^3 of natural gas [1].

A total of 11 oil and 12 gas promising structures of different sizes have been discovered so far based on seismic surveys. Further, in the framework of this thesis, it is proposed to consider development scenarios for oil structures with maximum prospective recoverable reserves.

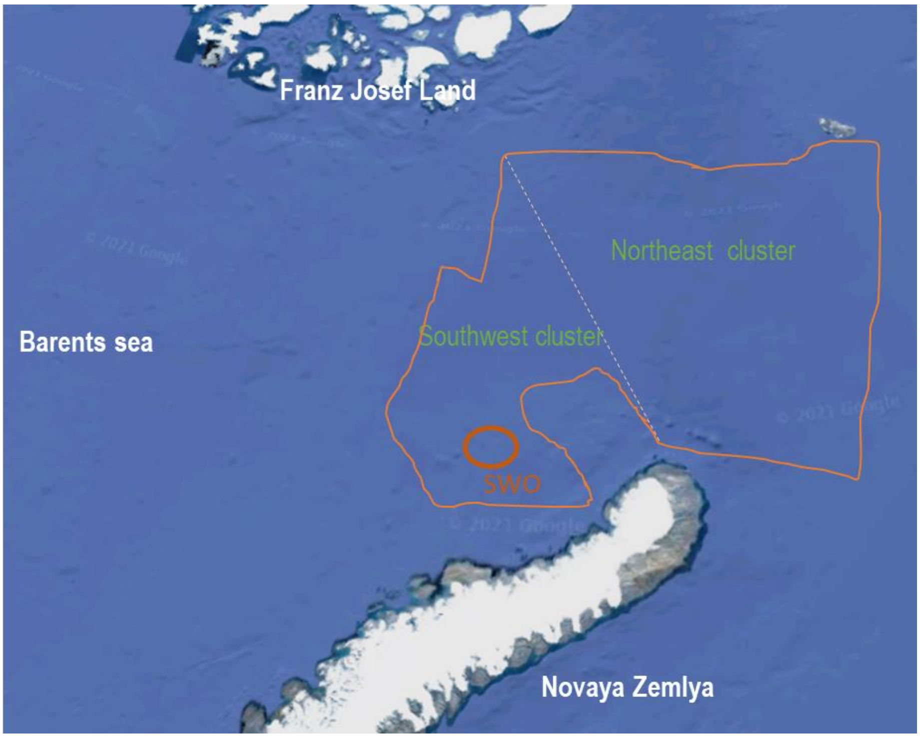

Figure 1.2 Map of the approximate location of a promising SWO structure

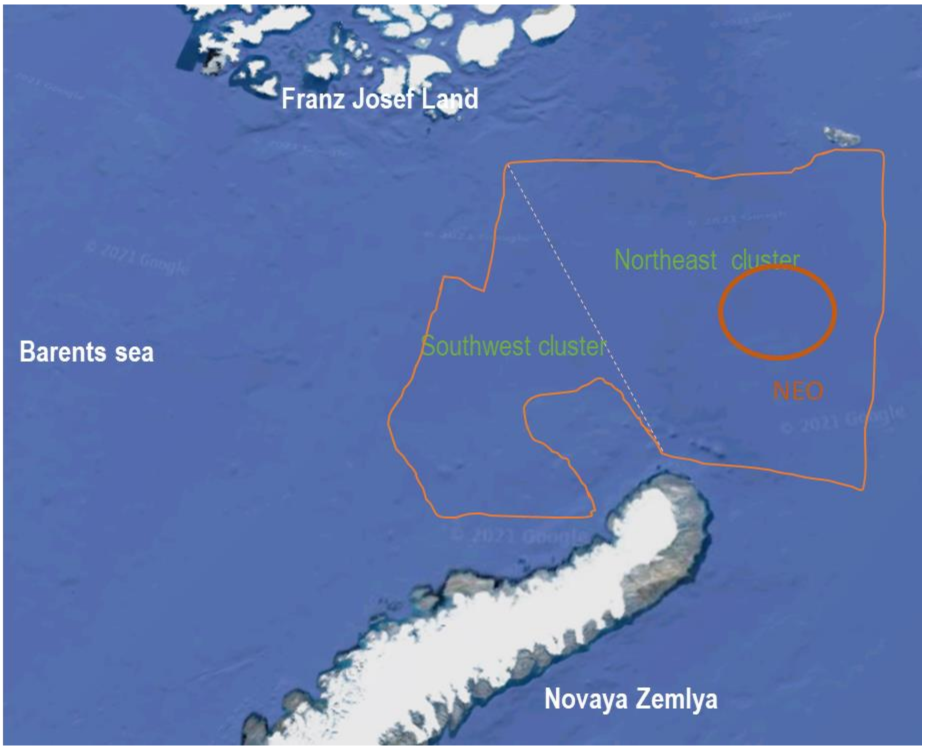

Figure 1.3 Map of the approximate location of prospective NEO structure

1.4.Set of assumptions about the characteristics of hydrocarbon structures

For this paper, the author takes one oil perspective structure in a cluster as the basis. Let's assume that the name of the structure under consideration in the Southwestern cluster is SWO (Figure 1.2). The estimated recoverable reserves for this structure 158 million tons of oil. The structure is located at a sea depth of approximately 150-200 m, 90 km from the coast.

The north-eastern cluster is also proposed to consider one perspective structure with the maximum forecasted reserves. The structure is oil-filled. Let's call it "NEO" (Figure 1.3). Prospective oil reserves for this structure were estimated at 158 million tons of oil. It is located subsea at a depth of approximately 300 m and 160 km from the shore. Let us make assumptions about the characteristics of SWO and NEO structures following Table 1.1.

Table 1.1 Assumptions in the framework of the work characteristics of oil structures HLA

Characteristics	**SWO**	**NEO**
Length, km	50	50
Width, km	40	40
Sea depth, m	175	400

Depth of the structure, m	2750	2750
Reservoir pressure, MPa	40.8	40.8
Reservoir gas factor, m^3/m^3	180	180
Distance from the NZA coast, km	90	160
Recoverable reserves P90/P10, million tons / billion m^3	34 / 170	34 / 170

2. Natural and geological conditions of the region

2.1. Geography and hydrocarbon resources of the Barents Sea

The Barents Sea borders the northern part of the Russian Federation. The sea is enclosed between three archipelagos – Novaya Zemlya in the southeast, Franz Josef Land in the north, and Svalbard in the northwest (Figure 2.1). According to various sources, the sea area ranges from 1405 to 1438.4 thousand km^2 [5]. The Barents Sea covers one of the most extended continental shelves in the world. Sea bathymetry is characterised by coasts and depressions/channels extending into the Arctic Ocean in the north and the Norwegian Sea in the west. The depth of water in open sea trenches varies from 300 to 500 m, while the depth in the shelf zone mainly ranges from 50 to 300 m [3]. According to various sources, the average sea depth ranges from 186 to 229 meters [5].

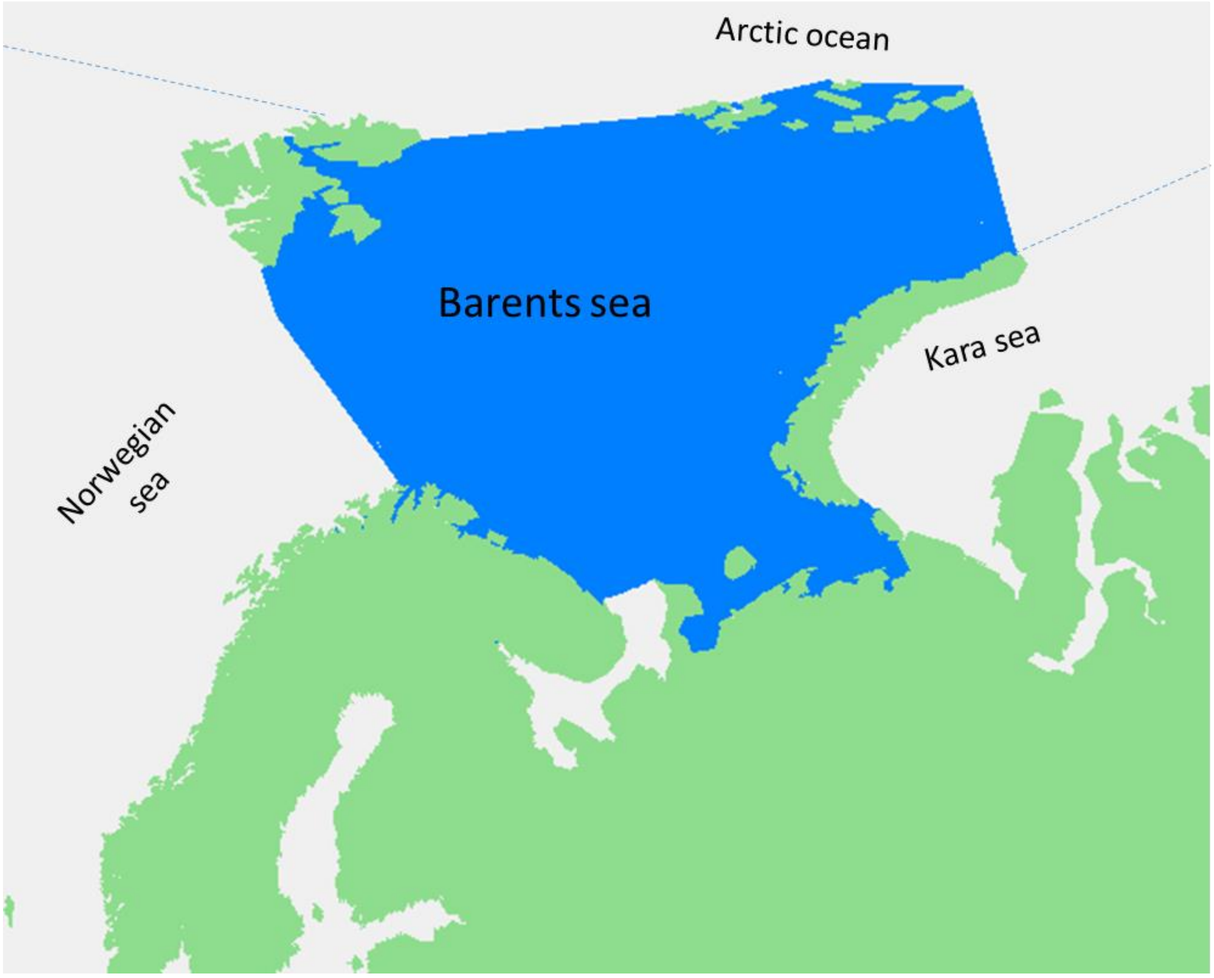

Figure 2.1 Location of the Barents Sea and its borders

Oil. As of 2019, the volume of drilled recoverable reserves in the Barents Sea is 119.4 million tons. Accumulated production in the region at the beginning of 2019 amounted to 9.128 million tons. The estimated recoverable reserves, not confirmed by drilling, are 318.9 million tons. The amount of prepared recoverable resources is 842.4 million tons. In addition, the state's balance sheet includes prospective and projected resources in the amount of 2973.3 million tons of oil [3].

Condensate. As of 2019, the volume of drilled recoverable reserves is 57.4 million tons. The estimated recoverable reserves that are not confirmed by drilling are 5 million tons. The volume of prospective and projected resources is estimated at 697.9 million tons [3].

Free gas. As of 2019, the volume of drilled recoverable reserves is 4,191.8 billion m^3. The estimated reserves not confirmed by drilling were 590.9 billion m^3. The volume of recoverable resources prepared for exploration drilling is estimated at 1,177. 3 billion $m3^3$. The projected volume of prospective resources was 27.147 billion m^3 [3].

In 2012 ARCO (short for ArcticOil) oil production started for the first time in the part of the Barents Sea called the Pechora Sea. The estimated recoverable reserves of the Prirazlomnoye field are 79 million tons of oil. In April of 2020, the project's accumulated production amounted to 13 million tons of oil [6].

Later in the current chapter, publicly available sources were used to describe natural and climatic conditions. Unfortunately, many sources date back to the end of the last century. For this paper, I consider this information to be sufficient. However, in this regard, I would like to express the hope that at the time of a more detailed study of the project for developing the HLA, industry workers and researchers will have more up-to-date information at their disposal. Fortunately, serious work is already underway in the Russian Federation to increase the number of natural and climatic studies of the country's Arctic regions.

2.2. Climatic conditions

Since the Barents Sea is located beyond the Arctic Circle, it is characterised by relatively low Sun heights and the phenomena of polar day and polar night. Such features are the reason for significant intra-annual changes in solar activity in the region. The midday sun height in December is less than 0° (below the horizon). Over the entire sea area, this indicator increases in June to 33° by 80° N and to 45° by 68° N. The polar night lasts from 30 days on the southern border and up to 120 days on the northern border of the sea. The duration of the polar day increases from 50 to 140 days, respectively [5].

2.2.1. Temperature regime of the region

The climate in the region is characterised by a relatively mild climate, relatively high average annual temperatures and a large amount of precipitation. This climate results from the proximity of the Barents Sea to the warm waters of the Norwegian Sea. However, the cold waters of the neighbouring Arctic basin make a significant contribution as they move north and east [7]. The following values characterise the average annual temperature:

- Medvezhy Island: -1,6°C (the island is closest to the midpoint of the Barents Sea);
- Barentsburg: -5,2°C (the city on the territory of the arch. Svalbard);
- Tikhaya Bay -10.5°5°C (arch. Franz Josef Land);

Average temperatures of the coldest months of coastal areas in the south sea range around -10°, -15°With. The northern regions of the sea are characterised by an average annual temperature of about -20°, -22° [7].

The average number of days per year with a stable air temperature below 0°C ranges from 120 days in the southwest to 300 days per year in the northeast of the Barents Sea (Figure 6). Average seasonal temperatures in winter range from --20°C in the north to 0°C in the south. In spring, this indicator ranges from -4°C to 5°C, in winter from 0°C to 9°C and in autumn from -6°C to 4°C, respectively (Figure 2.1).

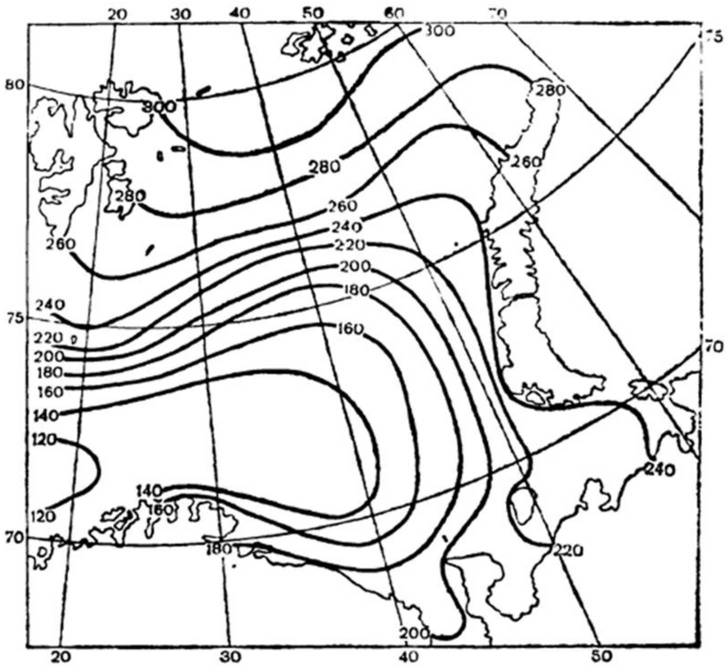

Figure 2.2 Number of days in a year with a stable air temperature below 0°[7]

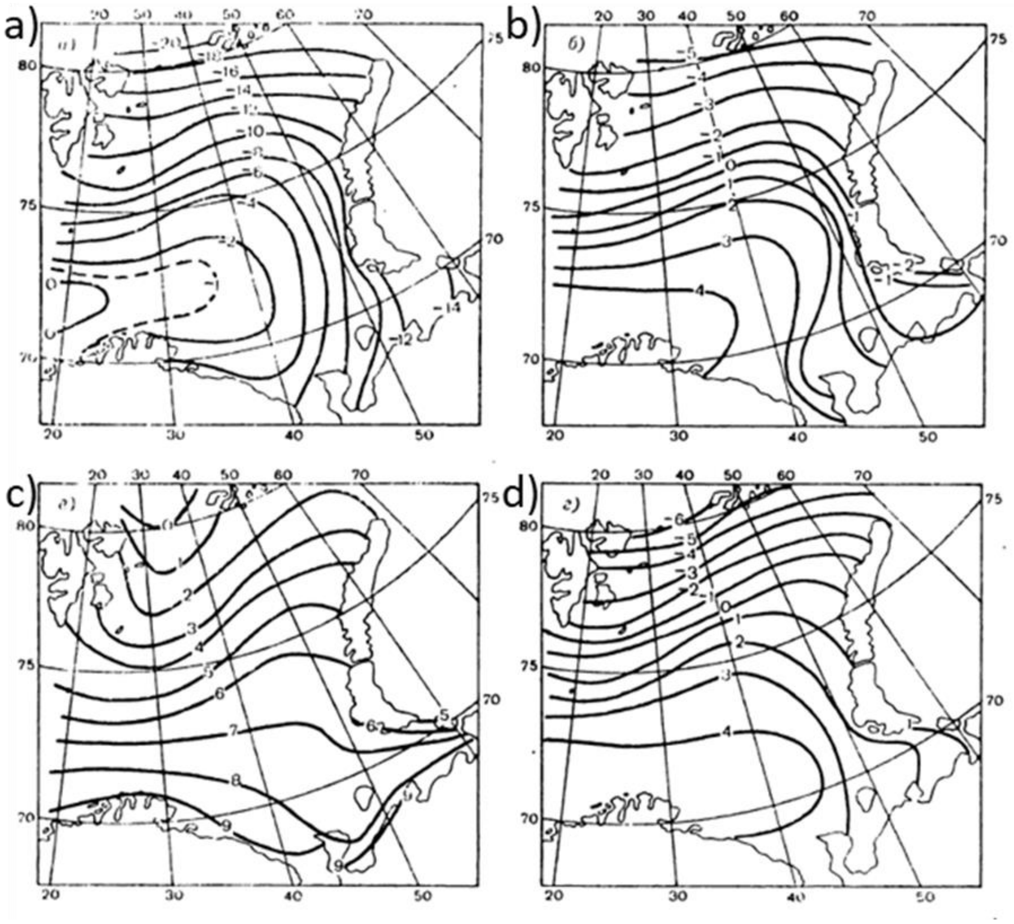

Figure 2.1 Distribution of seasonal average air temperatures in the Barents Sea
a-winter, b-spring, c-summer, d-autumn [7]

As for the area where the HLA is located, the average annual air temperature ranges from 8.4°C to 14.6°C. The distribution of monthly average temperatures reaches a maximum in July-August, and in February-March, temperatures are minimal (Figure 2.2).

The region is characterised by high cloud cover throughout the year (mostly 8-9 points). However, although the atmosphere does not receive a significant part of solar energy, the region has a warmer climate than other Arctic seas. This feature suggests that the main climate-forming factor in the region is not the sun but the circulation of the atmosphere and the system of warm and cold currents and the degree of ice covering the water surface [7]. The average annual sea temperature in the surface layer varies from northeast to southwest from -1°C to 7.5°C in summer and from -1.8 to 4.5 in winter (Figure 2.3).

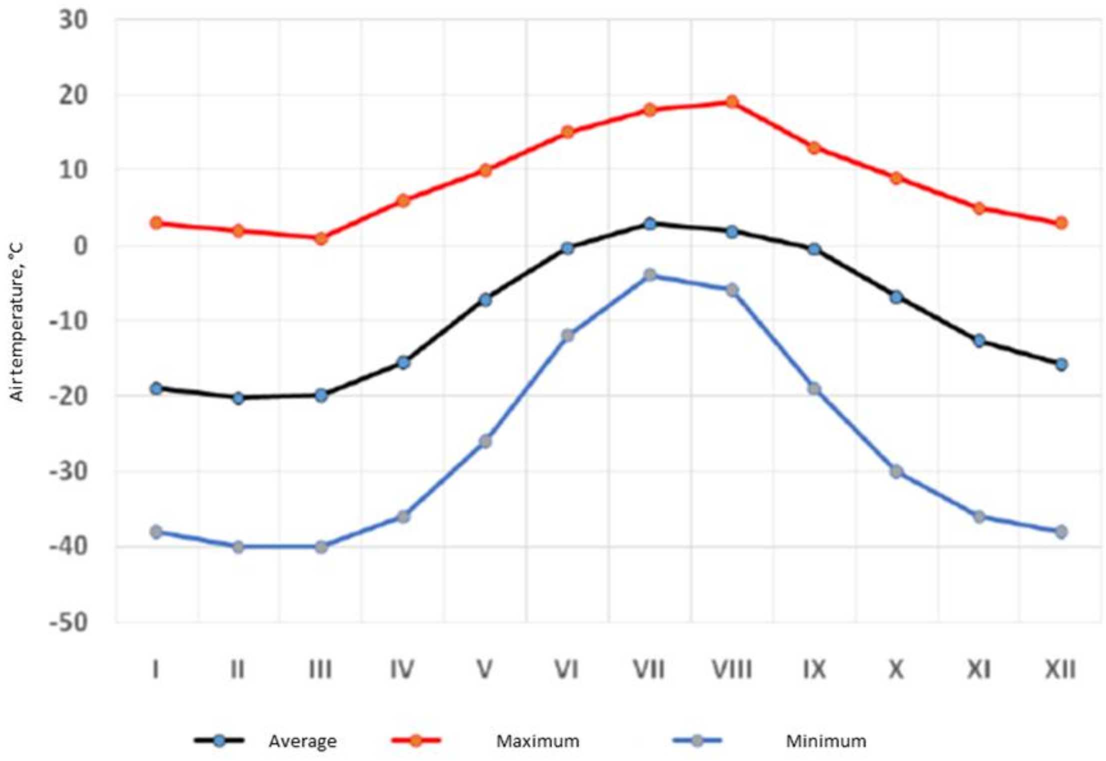

Figure 2.2 Annual courses of the monthly average, maximum and minimum temperatures [1]

According to the source [7], the area of ice formation in the region is -1.8°C. The same temperature is the lowest possible for water. In the southwestern part of the sea, the surface water temperature in winter does not fall below 3°C and does not exceed 6°C. In summer, it ranges from 7°C to 13°C. As can be seen from the maps presented above, the average annual water temperature in the HLA area ranges from 0.5°C to 2°C. In winter, the corresponding values range from -1.8°C to -0.5°C.

As for the depth profiles of water temperature, according to a study from the source [6], the following average distributions of sea-depth temperatures at 5 points occur (Figure 2.4). For this paper, let us consider the profiles in square 3 since, geographically, it is located closest to the HLA (Figure 2.5). According to the temperature profiles, the temperature at a 150 meters depth in summer is -0.5°C and -0.1°C in winter and summer. This temperature can be used when designing temperature requirements for near-bottom equipment used to develop the SWO structure. The structure NEO, at 300 m depth - the temperature at the bottom of the sea is constant - 0.6°C [7].

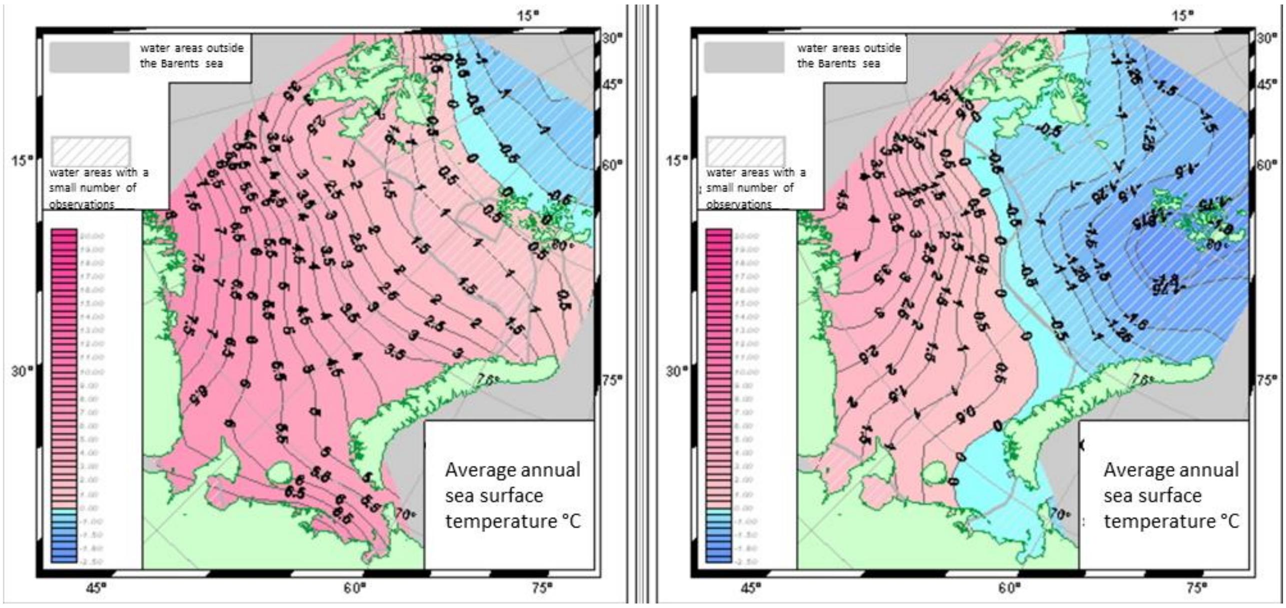

Figure 2.3 Map of isotherms of average annual sea surface temperatures [7]

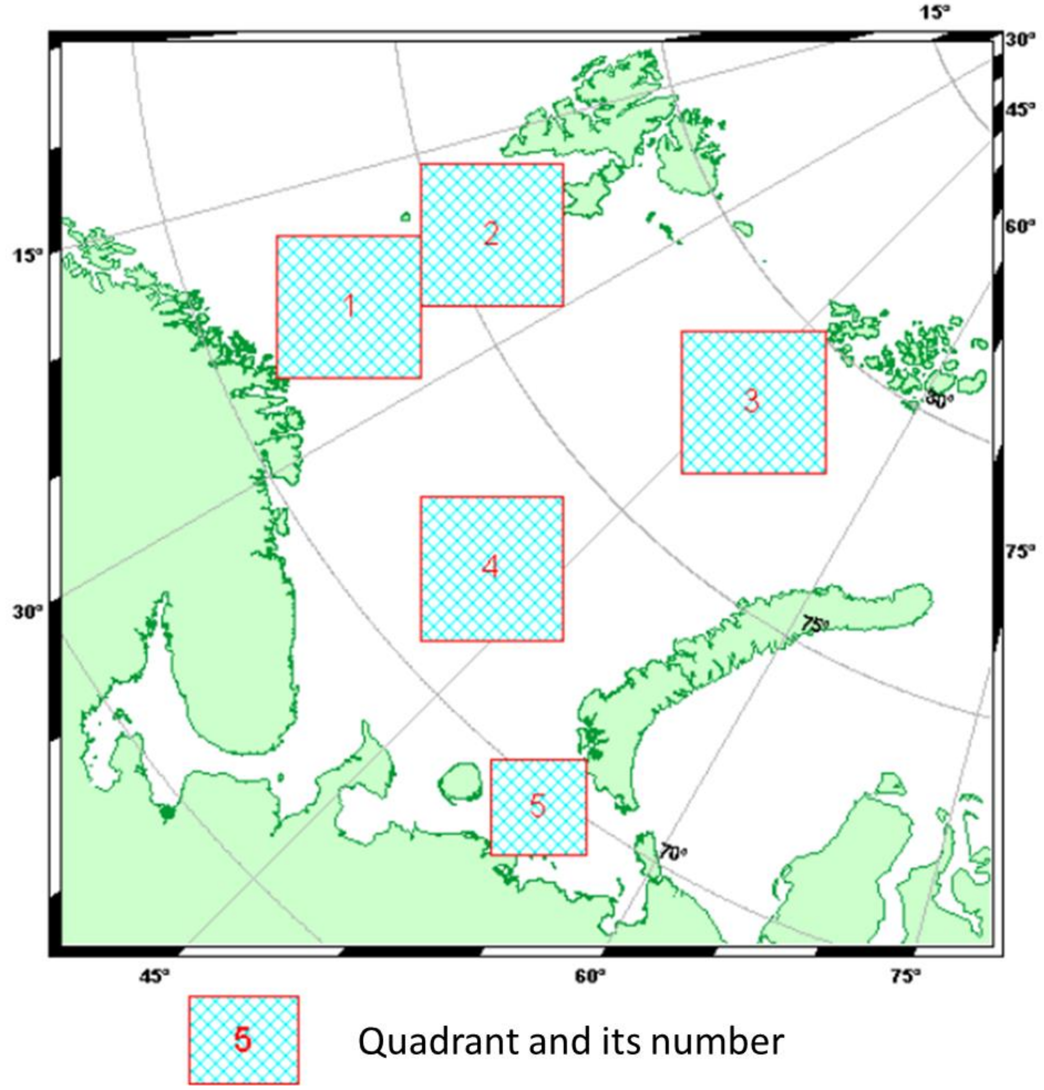

Figure 2.4 Points of observation sites for vertical temperature profiles [7]

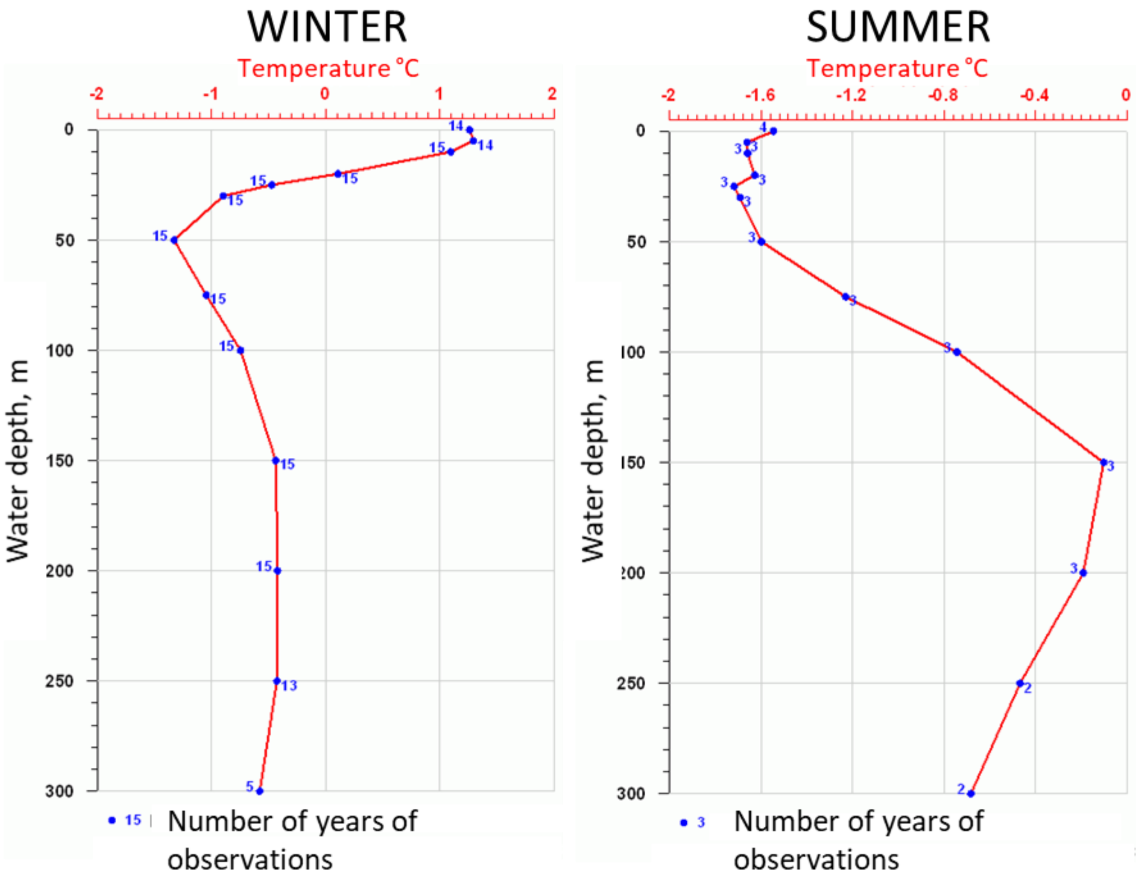

Figure 2.5 Water temperature profiles in square 3 in winter and summer [7]

In addition, according to the source [7], the average long-term salinity of water in the HLA region ranges from 33% at the water surface and up to 34.88% at a depth of 300 m.

2.2.2. Currents

As mentioned earlier, water temperature for the Barents Sea is the most critical factor in shaping the region's climate. Arctic water currents passing through the Barents Sea have a predominant effect on water warming (Figure 2.6).

Separately, it should be noted that according to the results of studies in 2016, the flow velocity of the surface layer in the HLA area does not exceed 10-15 cm/s [1]. Scheme of quasi-constant flows based on simulation results in the HLA area for 2016 (Figure 2.7).

Figure 2.6 The main directions of currents in the Barents Sea
1. Eastern branch The North Cape current. 2. Spitsbergen current; 3. West Spitsbergen current; 4. Murman current [8]

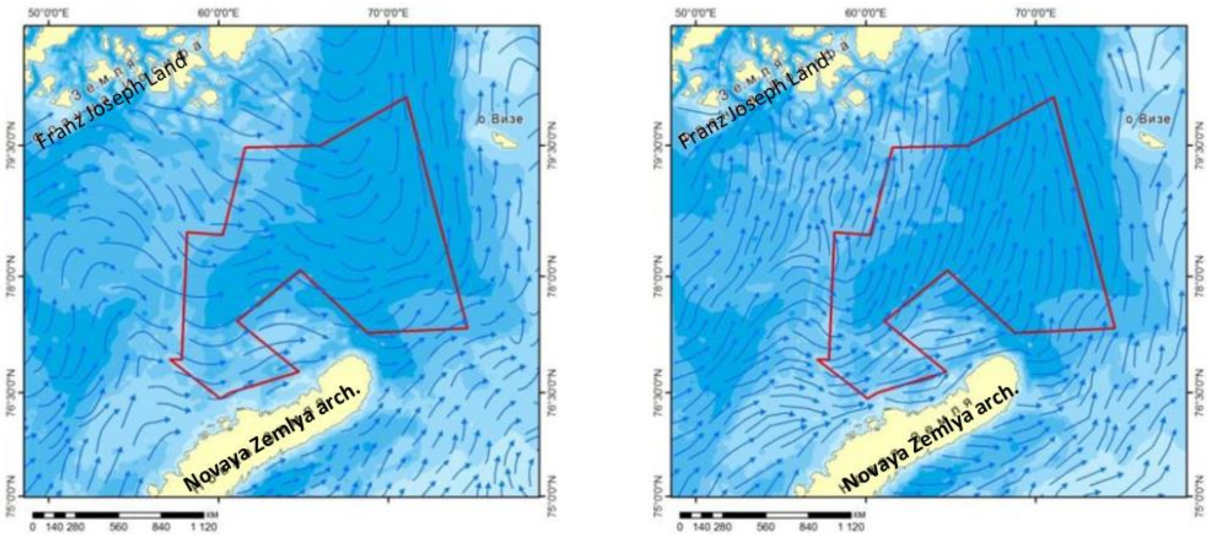

Figure 2.7 Diagram of the direction of quasi-constant currents in the summer (left) and winter (right) periods according to model calculations [1]

2.2.3. Wind and wave conditions

According to existing open data, the wind situation in the region is mainly represented by winds with an average speed of 6 to 10 m/s. In the area of HLA, windsы from the NE and SE directions prevail with an average speed of 10 m/s (Figure 2.8). Table 2.1 presents data on average wind speeds in the Franz Josef Land archipelago by direction.

Table 2.1 Average wind speeds in directions (west FJL arch.) 1952-1983 [5]

Month	**Wind direction**							
	N	**NE**	**E**	**SE**	**S**	**SW**	**W**	**NW**
January	5,6	6,2	6,1	6,7	8,2	6,6	5,7	5,4
May	5.7	4.8	4.5	5.6	6.4	5.3	5.3	5.5
July	4.7	4.3	4.8	6.4	6.8	5.7	5.6	5.0
October	6.0	6.1	5.4	6.6	7.4	6.3	5.7	5.6

It is worth noting that most of the existing studies in the world poorly describe the area of the Barents Sea in which the HLA is located. For this reason, in this work, let us rely on studies of the wind situation that are geographically close to the island.

The wave situation in the Barents Sea is the most active in the Arctic water area. Due to warm currents in the southwestern part of the sea, a large part of the waters is not covered by ice year-round. In winter, storms with wave heights of up to 10-11 m occur in the open sea (the average extreme wave is 10.7 m over a 100-years period). The highest waves are formed in the southeast with easterly and northeasterly winds [10].

Unlike the central and western parts, the northern and eastern part of the sea is covered with ice for 6-10 months, during which time the ice situation is a phenomenon that attracts the attention of engineers.

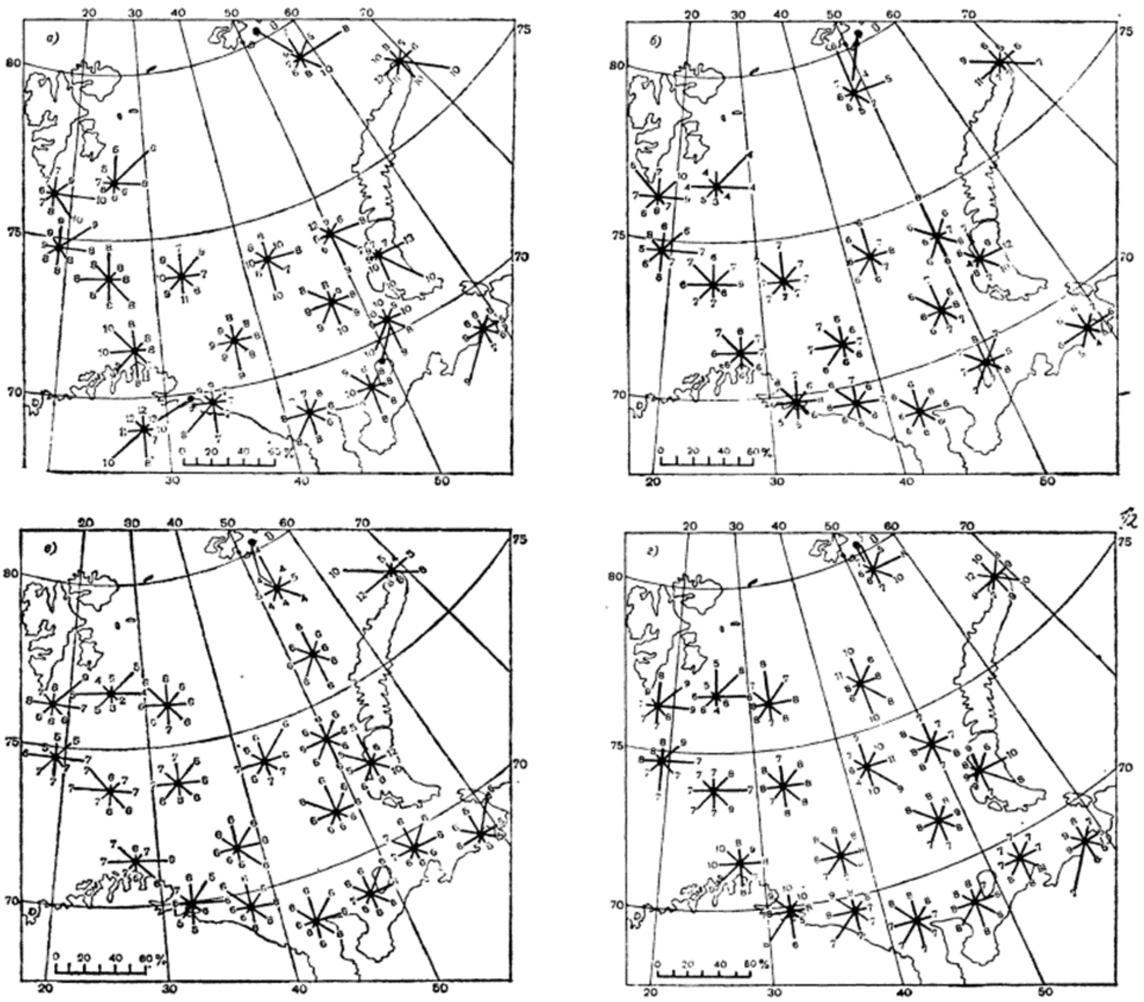

Figure 2.8 Prevailing wind directions, repeatability, and speed. January, May, July, and October, respectively [5]

2.2.4. Ice conditions and iceberg movement

The ice situation in the Barents Sea is quite diverse and varies greatly when moving from southwest to northeast and from south to north. As mentioned earlier, the south-eastern and north-eastern parts of the sea are covered with ice for most of the year. Ice formation usually occurs from east to west. This process usually starts in the 2nd half of October. On average, the ice cover melts from April to July, although it should be noted that in some years, the above-described periods may shift by 2-3 months [8].

The Barents Sea is dominated by ice formed there, but there are years when old ice from the Arctic Ocean arrives in the north-western part of the sea. Also, heavy ice from the Kara Sea often enters the north-eastern part of the Barents Sea. The average long-term position of the ice edges by month is shown in Figure 2.9 [5].

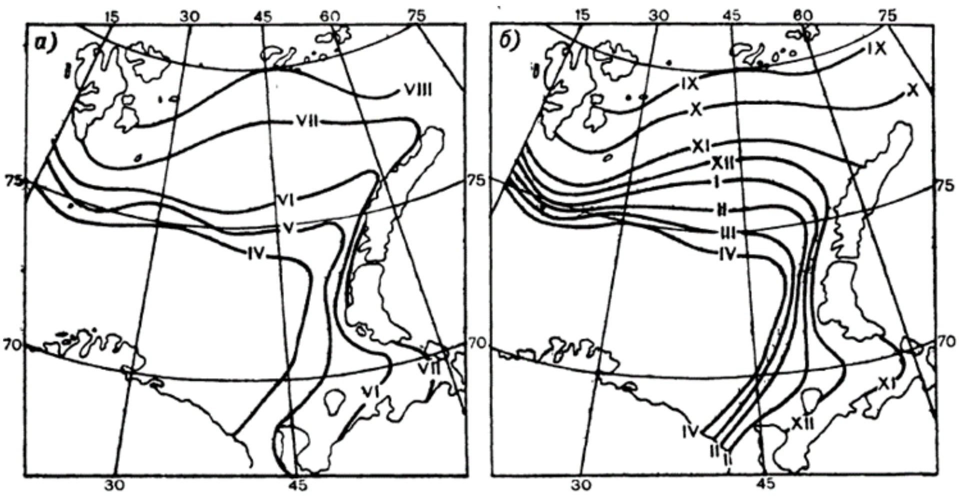

Figure 2.9 Average long-term deposition of ice edges. a – from April to August, b-from September to April [5]

In the open sea, the formed ice has high cohesion. The exception is often the southern and southwestern coasts of the arch. Franz Josef Land, arch. Novaya Zemlya and Kolguev and Vaygach Islands. Along these coasts, wide stellar sagebrush is formed. The state and parameters of such formations are determined by the spin wind [5].

In addition, the ice is constantly exposed to hummocks. The height of hummocks can be up to 5 m. In the coastal zone, there is an intensive stampede formation [5]. Below is information about the ice situation in the HLA area from the source (Table 2.2).

Table 2.2 Characteristics of the ice situation in the area of the Heisovsky license area [1]

Characteristic		**South-west**	**North-East**
Average ice season		134 days	267 days
Type of ice		One-year-old	One-year-old
Icebergs		There are	There are
Ice thickness	*of the media.*	70-120 cm	70-150 cm
	Max	120-150 cm	200+ cm
Hummocks / ridges		1-2 points	2-3 points
Ice drift	*Summer/Winter*	0.16 / 0.25 knots	0.18 / 0.26 knots
	Max.	1 knot (March)	1.4 knots (with heavy ice)

According to a study conducted from 2002 to 2014 [9], the average duration of the open water season in the areas of the southwestern cluster is 272 days. The open water season of the northeast cluster is even shorter – only 141 days a year. The study authors also note the severe variability of the region's ice situation and recommend continuous data collection on seasonal fluctuations in the ice cover.

Existing studies on the movement of icebergs in the HLA region unambiguously confirm their presence [5,9, 11]. It is noted that the average mass of icebergs found in this region is 3.6 million tons. The iceberg's maximum draft is estimated at 82 meters. In addition, these sources contain information about the possibility of encountering icebergs frozen into ice fields [1]. According to the source [11], in 2009, by order of the Shtokman Development AG consortium, a study of the drift of ice fields and icebergs was conducted by installing radio beacons. 25 beacons were installed on the ice fields, 15 on icebergs. Monitoring of the movement of ice fields was carried out in June, icebergs – from the end of May to October. The scope of the study also includes the territories of HLA(Figure 2.3).

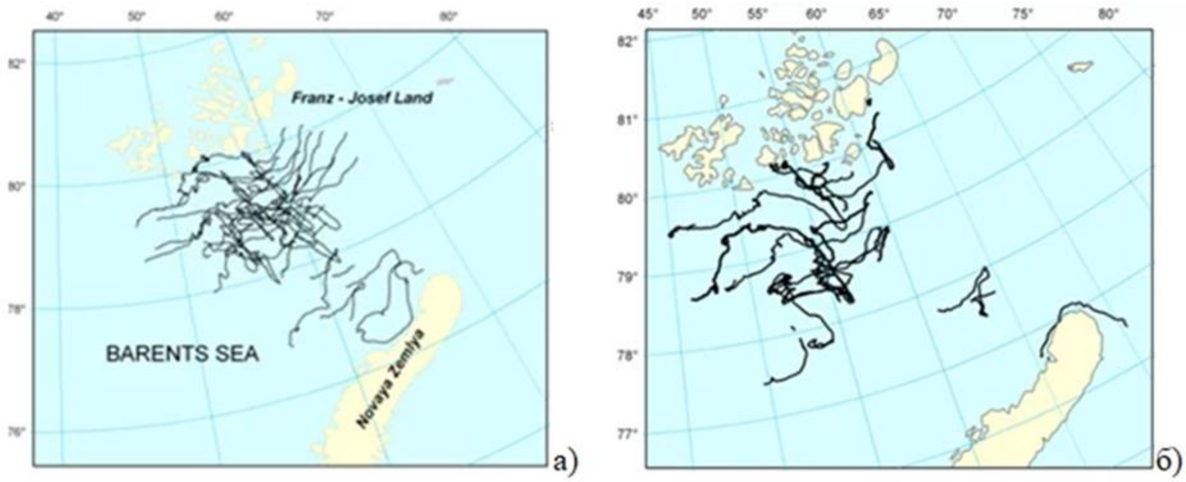

Figure 2.3 Drift trajectories of icefields (a) and icebergs (b) in the HLA area, as observed in 2009 [11]

2.3. Bottom relief and soil properties

The Barents Sea has relatively shallow depths because the topography of its bottom is part of the continental shelf. In other words, it is a continuation of the mainland. The sea depth is 300-400 m. The bottom relief is characterised by a strong dissection (Figure 2.4). The depth differences for tens of kilometres are 50-100 m. There is a central plateau in the sea, some hills, depressions up to 386 meters deep, and troughs with depths from 400 to 600 m. At depths of up to 200 m, there are a large number of slight irregularities. In different places, the composition of the bottom soil differs for some reasons. Mainly the bottom is covered with sandy silt and sand. In places with low mobility of water masses, there are areas of the bottom consisting of silty deposits. Areas of the bottom exposed to strong currents are mainly represented by boulders and rocks [7].

As for the depths in the HLA areas, the sea depth of the southwestern cluster is moderate and ranges from 100 to 300 m, while the northeastern cluster has extremely large depths today - from 200 to 500 m.

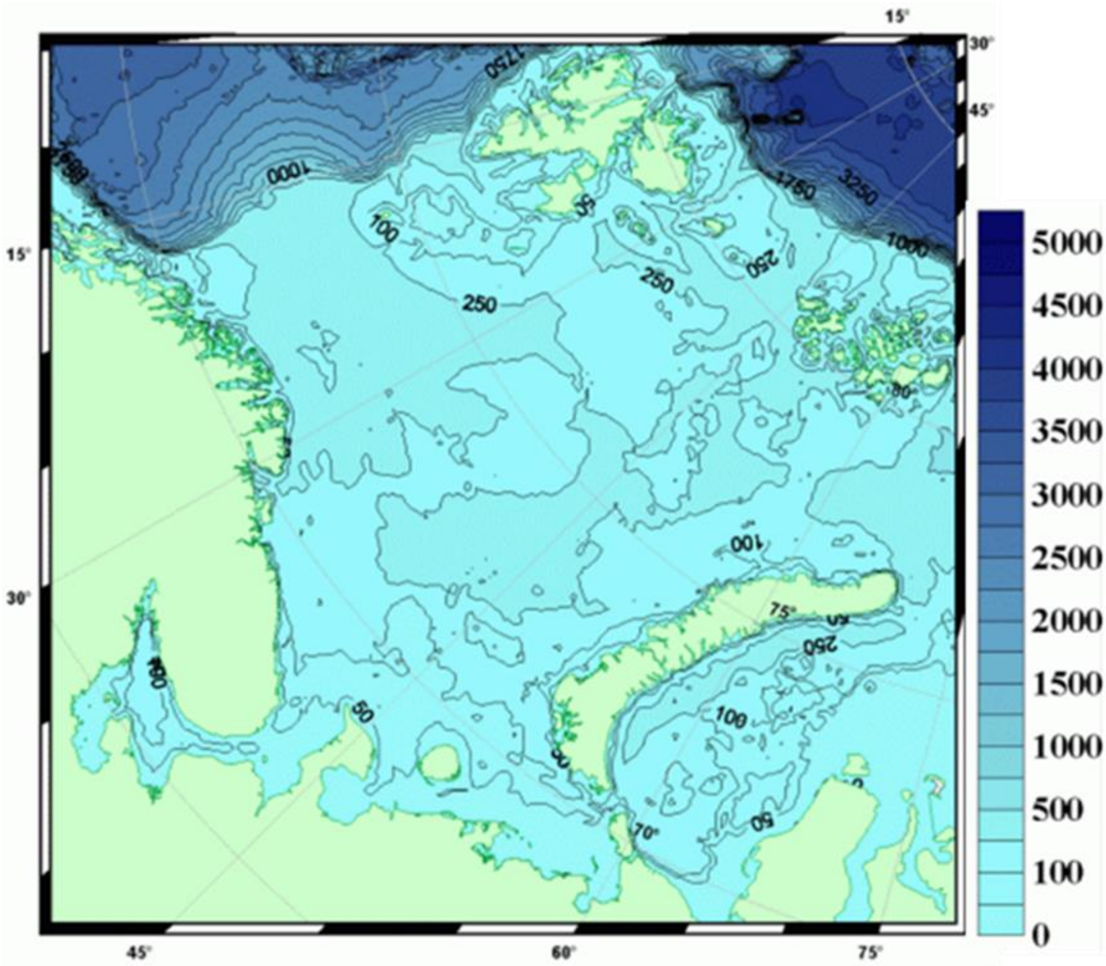

Figure 2.4 Bottom relief map of the Barents Sea [8]

No soil surveys or exploratory drilling has been conducted in the HLA area to date. However, for this paper, we assume the soil properties in the HLA area similar to the available information. The soil data obtained are based on the experience of operations in the southern part of the Barents Sea [1]. The data described above is presented in Table 2.3.

Table 2.3 Engineering and geological data on the properties of the shelf bottom soil in the Barents Sea [1]

Horizon	**Description**	**Humidity level**	**Fluidity**	**Density**	**Clutch cf.**	**Internal friction angle**
m		%		g/cm3	kPa	deg

0-5	Silt and clay soil of fluid-fluid plastic consistency	30-90		1.5	25	5
5-10	Normally compacted loam with inclusion of coarse-grained material	40	<0.5	2.1	200	25
10-30	Sandy-clay soil is normally consolidated, less often over-compacted	20-35	<0,75	1,9	150	10
30-60	Sand and sandy loam with gravelly inclusions	20-40		1,9	60	20
60-100	Re-compacted clays with inclusions of gravel and pebbles	10-30	<0,25	1,9	300	5

3. Key challenges of the development in the Arctic and HLA

3.1. Challenges of the development of offshore fields

The development of birth sites in the Arctic regions is always associated with a large number of challenges. Offshore deposits in the Arctic stand apart in this sense. Let us consider the main factors that complicate the development of birth sites on the Arctic shelf.

Hydrocarbon deposits on the Arctic continental shelf are currently located in tens, hundreds, or even thousands of kilometres from the existing infrastructure. The lack of ready-made facilities for the treatment, processing and transportation of hydrocarbons in the Arctic creates conditions in which operating companies are forced to bear enormous capital expenditures. The same results are achieved by the lack of logistics infrastructure, including warehouses, airfields, heliports, and roads for ground transport. The scale of spending on all the necessary infrastructure can stop projects to develop even very promising structures from a geological point of view.

The impact of this factor varies greatly from field to field. The development of remote offshore fields implies high costs for the rental and operation of supply vessels, ice management vessels, and emergency rescue fleets. In addition, the cost of offshore operations accompanying the stage of construction of production facilities is directly dependent on the remoteness of the field from the shore. Designing offshore operations for transportation and installing unique offshore structures also requires a large amount of material and intangible resources from the field operator. At the operational stage, remoteness from the shore means increased operating costs for safe logistics of inventory and personnel to the production site.

Operating at low temperatures is associated with complications for both equipment and personnel. The production processes of oil and gas drilling and production involve fluid circulation through in-field pipelines. Negative ambient temperatures can cause fluids in pipelines and equipment to freeze, and in the worst case, this leads to ruptures. Depending on the temperature of water, air and wind, it is often necessary to place all equipment in closed rooms with a favourable temperature or to provide heating for elements subject to freezing. Following generally accepted standards, all outdoor work on structures in the Arctic climate should be identified and minimised. Work in areas with a wind-cold index (WCI) above 1000 W / m^2. should be restricted; in such areas, measures are taken to reduce the cold wind cooling index (Figure 3.1). For clarity of the established supercooling effect, below is the classification of wind and cold indices:

Table 3.1 Perceived hypothermia [1]

WCI [W/m^2]	Description of how a person
700	Cold, but comfortable when working physically in warm clothes
930	Cold, uncomfortable when working physically in warm clothes
1000	The standard maximum permissible lower value for allowing workplaces without shelter
1100	It's very cold. Discomfort in cloudy weather
1400	Extremely cold. Discomfort also in sunny weather
1600	unprotected areas of the body freeze
3000	Unbearably cold

WIND CHILL TEMPERATURE INDEX
Frostbite Times are for Exposed Facial Skin

Air Temperature (°C)

Wind Speed (km/h)	5	0	-5	-10	-15	-20	-25	-30	-35	-40	-45	-50
5	4	-2	-7	-13	-19	-24	-30	-36	-41	-47	-53	-58
10	3	-3	-9	-15	-21	-27	-33	-39	-45	-51	-57	-63
15	2	-4	-11	-17	-23	-29	-35	-41	-48	-54	-60	-66
20	1	-5	-12	-18	-24	-30	-37	-43	-49	-56	-62	-68
25	1	-6	-12	-19	-25	-32	-38	-44	-51	-57	-64	-70
30	0	-6	-13	-20	-26	-33	-39	-46	-52	-59	-65	-72
35	0	-7	-14	-20	-27	-33	-40	-47	-53	-60	-66	-73
40	-1	-7	-14	-21	-27	-34	-41	-48	-54	-61	-68	-74
45	-1	-8	-15	-21	-28	-35	-42	-48	-55	-62	-69	-75
50	-1	-8	-15	-22	-29	-35	-42	-49	-56	-63	-69	-76
55	-2	-8	-15	-22	-29	-36	-43	-50	-57	-63	-70	-77
60	-2	-9	-16	-23	-30	-36	-43	-50	-57	-64	-71	-78
65	-2	-9	-16	-23	-30	-37	-44	-51	-58	-65	-72	-79
70	-2	-9	-16	-23	-30	-37	-44	-51	-58	-65	-72	-80
75	-3	-10	-17	-24	-31	-38	-45	-52	-59	-66	-73	-80
80	-3	-10	-17	-24	-31	-38	-45	-52	-60	-67	-74	-81

FROSTBITE GUIDE

- Increasing risk of frostbite for most people in 10 to 30 minutes of exposure
- High risk for most people in 5 to 10 minutes of exposure
- High risk for most people in 2 to 5 minutes of exposure
- High risk for most people in 2 minutes of exposure or less

Figure 3.1 Cold wind cooling index

3.1.1. Depths, currents

Large depths create difficulties both at the exploration and drilling stages and at the operational stage. Therefore, it would be best to start with the challenges that a drilling company faces at a deep-water facility:

Vertical deviation of the riser. The use of MODUs floating drilling rigs at such water depths is possible but quite complex due to the limitations of the maximum allowable angle of deviation riser from the centre of the well: at distances of 2.5% - 6% from the water depth (Figure 3.2). If the proper deflection angle is exceeded, there is a possibility of destroying the riser or depressurisation of the binding.

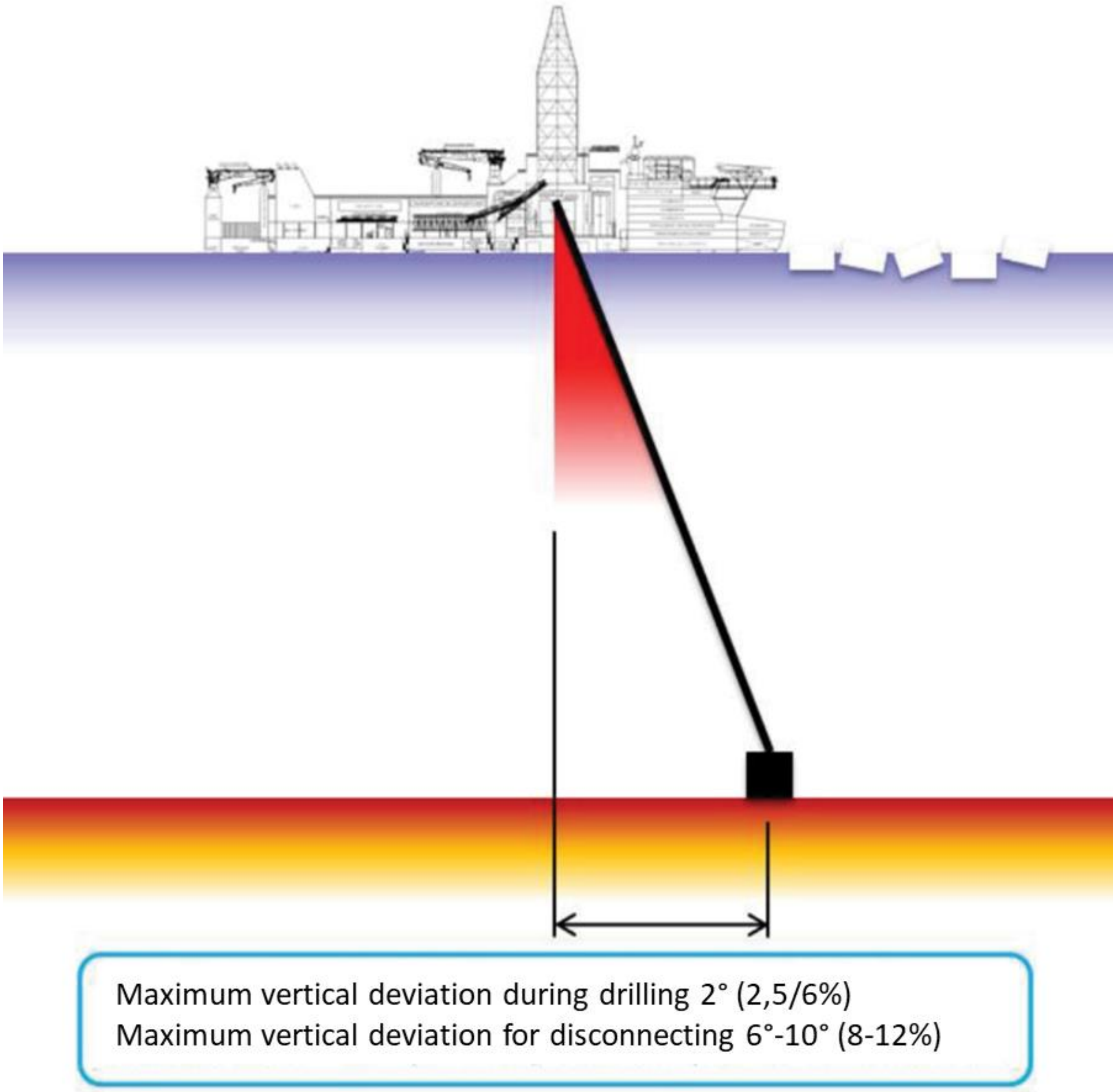

Figure 3.2 Maximum riser deflection values for deepwater drilling [16]

Increased fatigue loads due to vortex vibrations. When drilling wells in deepwater areas, eddy loads can play a significant role. The riser's weariness due to the vibration loads caused by the vortex can be the reason for its accelerated wear and destruction.

The construction of any platform for operation at depths of more than 100 m is a unique challenge for the production complex of any country. This mainly concerns the construction and towing of gravity-based platforms to the production site.

3.1.2. Ice and iceberg conditions

The possibility of a collision with ice can increase the risks associated with already complex offshore projects. Ice can damage equipment and make seemingly trivial tasks impossible if proper precautions are not taken. In addition, the presence of ice creates serious problems and risks for station maintenance operations. While ice management is an essential component of these operations, adding ice management to the existing system does not guarantee the project's success.

Ice management solutions should be used based on an assessment of equipment, operations, and the environment in which it should operate. Preventive identification of problems and risks associated with working in ice should form the basis for designing work in the Arctic. The right ice management solutions minimise operational risks and maximise safety and equipment uptime.

Iceberg movement poses a danger to both offshore platforms and vessels under operation. Ice subsea is dangerous for ships. Sharp hidden ice can easily punch a hole in the bottom of a ship. A hazardous part of the North Atlantic has become Iceberg Alley because of the many icebergs that make their way there.

Today, there are various methods of monitoring the movement of icebergs to prevent collisions. Aerial photography, installation of radio beacons on the surface of icebergs and satellite monitoring are actively used. The first two methods have a relatively limited coverage area (it is limited in the first case by the number of installed beacons, and in the second case by the range and frequency of flight of aircraft used for shooting).

The most promising method for monitoring the movement of icebergs is a satellite radar survey. However, it should be noted that for more accurate forecasting, this method should be used in conjunction with aerial photography and radio beacons. In addition, Russian researchers have already developed techniques that allow simulating a synergistic effect from satellite radar and optical images [12]. The quality of such model forecasting can be seen when comparing forecast models, and actual data on iceberg drift with installed radio beacons (Figure 3.3).

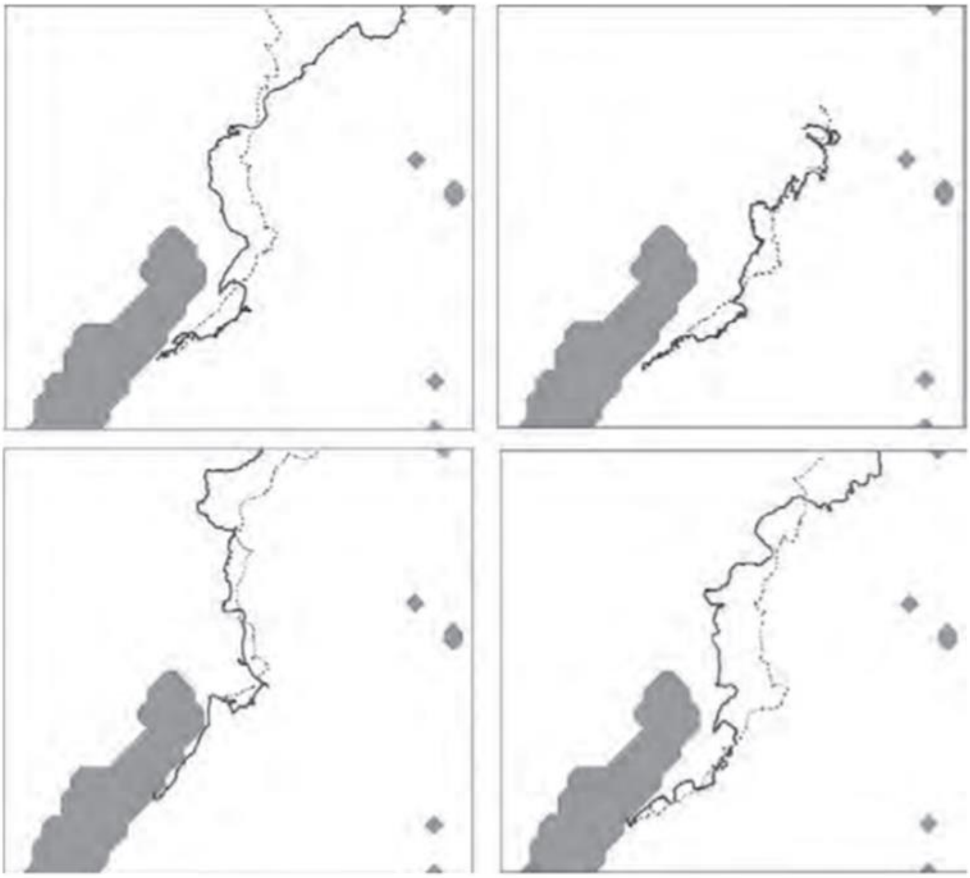

Figure 3.3 Comparison of iceberg trajectories observed (solid line) from the data of four radio beacons and calculated from the model (dashed line) [12]

Previously, the possibilities for such forecasting in the Russian Federation were very limited due to the unavailability of data to the general user, the high cost of images, and the low resolution of radar images. A hydrometeorological satellite was launched this year Arktika-M, which has its primary goal to cover the northern territories of the Russian Federation and the Arctic with an overview. The device's scanners are capable of shooting in 10 spectral ranges [13]. This is the first of two planned vehicles needed for round-the-clock monitoring of the Arctic surface.

Further, it is necessary to increase the amount of weather and ice tracking satellites and develop the infrastructure and the necessary personnel necessary to create a reliable ship warning system in the Arctic. This is one of the main factors for the reliability and stability of the entire Arctic fleet and infrastructure in the future.

3.1.3. Environmental Impact Management

The nature of the Arctic is still relatively "virgin". The Arctic is very rich in such resources as hydrocarbon deposits and fish stocks. However, the Arctic environment is threatened by human activity and climate change. The production and transportation of hydrocarbons must not disrupt this unique and highly susceptible environment.

When developing oil and gas fields in the Arctic, special attention should be paid to harmful emissions into the environment. Sources of emissions to the atmosphere can be gas flaring or burning of hydrocarbons. It is necessary to eliminate/minimise gas flaring or direct gas emissions to the environment. However, burning hydrocarbons is necessary for local electricity generation, so it is acceptable, provided that modern exhaust gas treatment systems are used.

Waste can occur during transportation, drilling, installation, normal production mode, downhole operations, and well plugging and abandonment operations. It is necessary to avoid/minimise the discharge of harmful liquids into the sea.

The risk of accidental releases to the atmosphere or sea should be minimised. Early warning and protection systems and barrier systems should be installed. Emergency preparedness measures should be implemented and appropriate equipment installed.

Typical sources of harmful liquids:

- Drilling mud containing a variety of chemical additives
- Liquid petroleum products
- Water contaminated with oil or chemicals
- Hydraulic fluid
- Chemical agents

After drilling, the drilling mud must be collected and disposed of in the designated area. In addition, it is necessary to provide for filtration of fine particles or drilling without casing with a return. Further, drilling fluids, drilling mud and sludge must be collected and cleaned or disposed of in an environmentally friendly manner.

Water-based hydraulic fluids must be used. The production management system must have closed-loop hydraulic systems; all electrical equipment can only be used after being certified and tested in operation. The chemicals used must be safe for the environment. Hazardous chemicals (if available) must be collected and cleaned, or disposed of in an environmentally friendly manner.

The separation system must remove oil from the water to levels acceptable for discharge into the sea. Otherwise, contaminated water/reservoir water must be prepared and pumped back into the appropriate reservoir.

Process monitoring of the entire system from the bottom of the well to the receiving process unit is essential for process management and optimisation and early warning of failures and transmitting input data to protective systems.

Process monitoring is provided by various sensors, such as pressure sensors, temperature sensors, level sensors, vibration sensors, corrosion sensors, flow meters, scraper detectors, position sensors, load cells, etc. These sensors provide input data for protection systems. Safety-related process monitoring tools include fire detectors, video cameras, and leak detectors. The subsea system detects leaks in hydrocarbon systems (gas and/or liquid) and potential releases to the sea.

Norwegian regulators recommend installing a fixed subsea leak detection system (SSLD) as part of the overall environmental strategy for subsea projects, and [17] is the basis for their practical application.

Leaks can occur through flanges, joints, caps, valves, piping, manifolds, industrial pipes, and risers. It is crucial to detect leaks in the system as early as possible. A visual method, sensors, or a combination of these methods can be used to detect leaks.

For visual leak detection, you can use a subsea video camera, which gives you a good idea of the location and size of the leak. This can be a video recording or several photos taken over an hour. Problems may arise due to marine fouling, lack of visibility, and constant monitoring by the operator. If a leak is detected instrumentally, the operator may receive an alarm from the instruments. There may be problems detecting the location and size of the leak and stopping due to false positives [17].

- Leak detectors or leak detectors that can be used subsea:
- Acoustic: acoustic leak detectors (ALD), passive acoustic and active acoustic, multi-point and single-point
- Electrical: capacitive, solid-state
- Methane leak detectors, from diffusion to alarm membranes
- Optical: non-dispersive infrared, fibre-optic, fluorescent (for detecting a fluorescent medium)
- Bio-data sensors
- Volume-balance method (for large leaks)

The design of the leak detection system should be integrated into the overall design of the subsea development system. Therefore, a leak detection system should be included as an essential design requirement for the SPS, rather than a late-stage design supplement. The subsea leak detection system can be classified according to the probability and size of the leak (Figure 3.4).

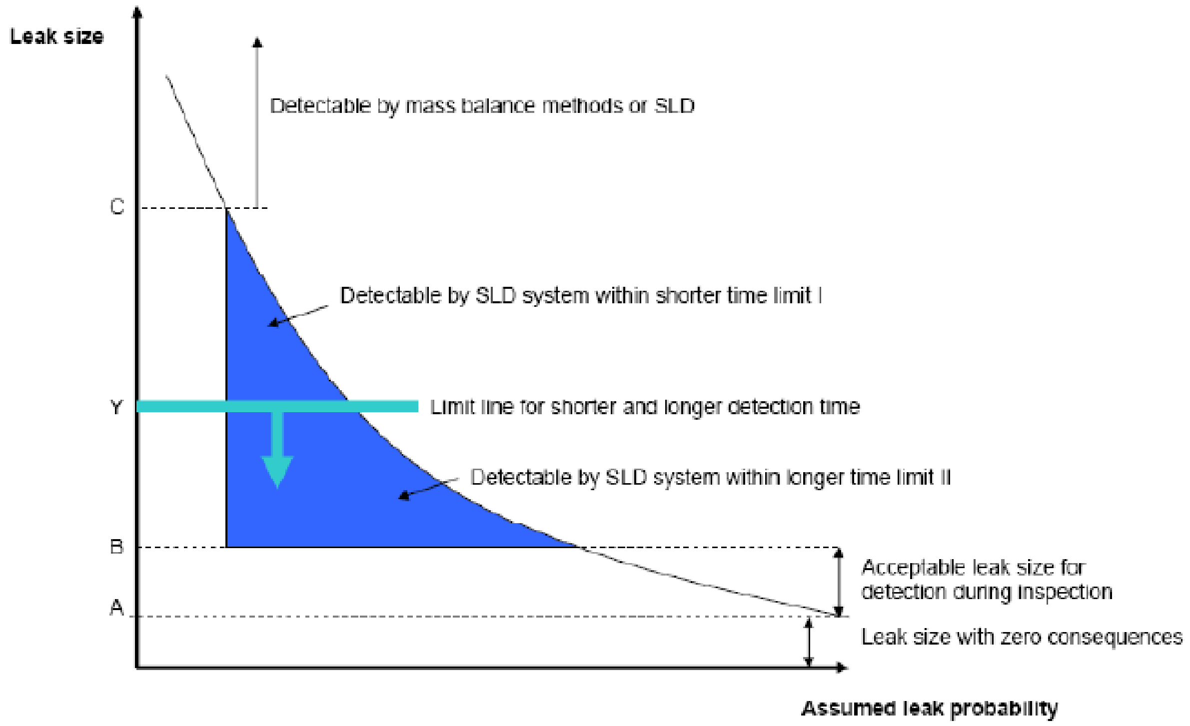

Figure 3.4 Classification of a leak detection system by probability and size [17]

3.2. Overview of challenges and assessment of technological availability of HLA

The main factors that complicate exploration and the future development of oil and gas fields on HLA territory in the Barents and Kara Seas are the unfavourable climatic conditions of the region and constantly drifting continuous ice fields up to two meters thick. Icebergs weigh up to 3.6 million tons, with an impact speed of 0.8 m/s [1], extending over a thousand square kilometres, with icebergs included, the subsea part of which goes to a depth of up to 85 m.

On the territory of HLA, sea ice cover is either present in large quantities or completely absent. In other words, the ice cover reaches 70 % or more, or almost absent.

Conditions in the North-Eastern cluster and the South-Western cluster are significantly different: the South-Western cluster is characterised, on average, twice a longer open water season, including the period of ice cover formation, about 272 days (224 + 48) compared to the North-Eastern cluster, where it is about 141 days (99+ 42). The available data on seasonal fluctuations are limited. From 2002 to 2014 is characterised by significant seasonal variability relative to the average indicators [1].

3.2.1. Technological availability

At the moment, the key challenge for HLA is its technological accessibility. A very important task in assessing the current prospects of a particular field is to assess its technological availability. The solution of this problem using an integrated approach is strategically important for forecasting production in the Russian Arctic. It is essential to strategically and comprehensively assess prospects and opportunities in the implementation of Arctic projects today. Implementing projects in such difficult conditions implies the need to predict the use of capacities already under construction. An important aspect is forecasting the need for capacities and technologies for the medium-term (from 1 year to 5 years) and long-term (5-15 years) prospects. High-quality integrated forecasting and search for synergy between Arctic projects can save significant amounts for operating companies and the Russian Federation in the future. Such forecasting requires an approach to a comprehensive assessment of the technological accessibility of the Arctic shelf territories. Most of the approaches to such an assessment are based on analytical, expert or reference classification based on one or more indicators that characterise the external conditions in a particular field.

In [14], the Gubkin Russian State University of Oil and Gas graduate student K. N. Pivovarov and Professor A. B. Zolotukhin present a comprehensive assessment of technological accessibility based on a mathematical approach using fuzzy logic methods. Since the amount of uncertainty is currently high, and the amount of data on the natural and hydrogeological conditions of the Arctic is very limited, the use of fuzzy mathematics seems very appropriate for assessing the indicator of technical availability. The availability assessment was performed for a different number of parameters used (Figure 3.5). In general, an increase in the number of criteria can be assumed to reduce the "attractiveness" of territories, but it may reflect the situation more adequately.

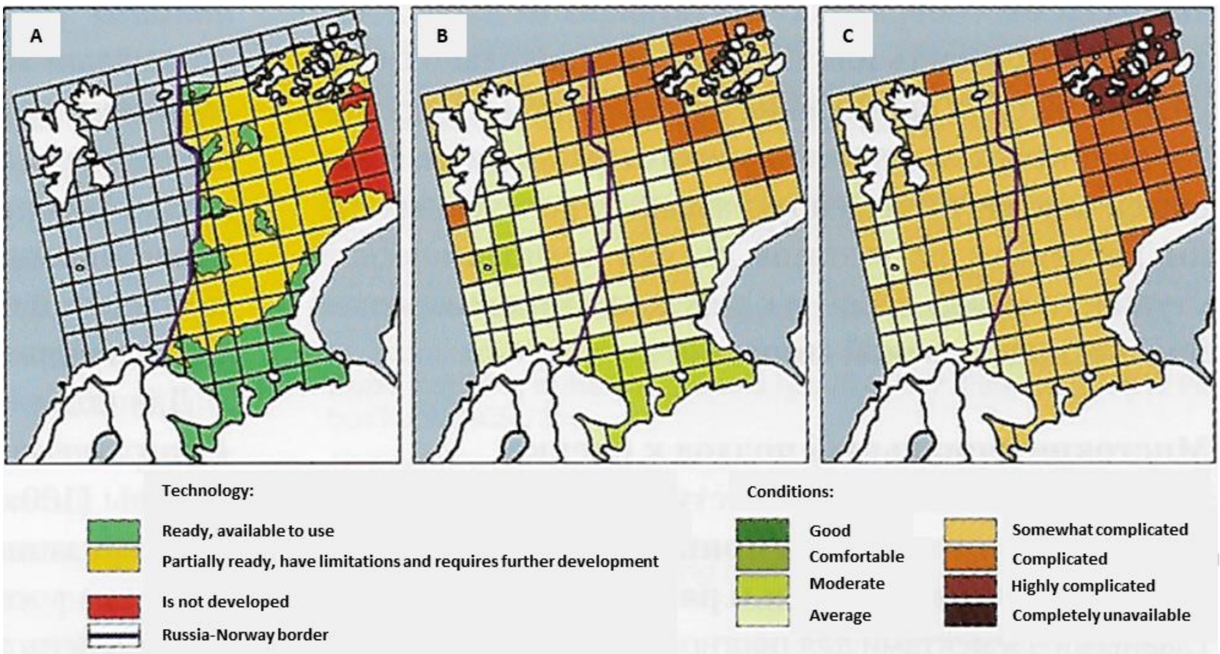

Figure 3.5 Maps of the Barents Sea Accessibility assessment [11]

A-technological accessibility by the method of E. A. Zhukovskaya and O. Ya. Sochnev, B - estimation by the method of fuzzy clustering by the depth and climatic conditions, C - estimation by the method of fuzzy clustering by 10 parameters

The complete assessment results with ten parameters are shown on the map under the letter "C" (Figure 3.5).

Conditions in the HLA area were rated "severe" in this assessment, which generally reflects the current technological capabilities of the industry, taking into account the conditions described earlier in the paper. Interestingly, the assessment by the method of E. A. Zhukovskaya and O. Ya. Sochnev indicates a complete lack of the necessary technologies for the development of such a field. Further in the paper, the author will try to discuss such an unambiguous position in assessing the technological readiness of technologies necessary to implement the scenarios proposed in the paper.

The gradual deterioration of conditions as we move to the northeast immediately suggests the possible usefulness of using such estimates in the medium - and long-term planning of field development on the shelf of the Russian Arctic. The authors [11] compare the forecast of development horizons according to their methodology and according to the INTSOK method (Figure 3.6). In general, the authors' assessment looks less optimistic and probably reflects the situation more fully because of considering many criteria. In any case, both methods show that the development of the territory of HLA is feasible no earlier than on the horizon of 15 years from the current moment.

However, this assessment should not be misleading. To make HLA possible to develop in the next 15 years, it is necessary to plan and carry out a lot of R&D and certification the necessary technologies. It is already necessary to determine priority scenarios for developing these territories to start targeted actions to launch or adapt technologies. This is the first necessity for future use in oil and gas projects in the north-eastern part of the Barents Sea. Since the Russian Federation is currently one of the leading countries in developing the Arctic territories, it is necessary to take the initiative in technological development matters to maintain a leading position.

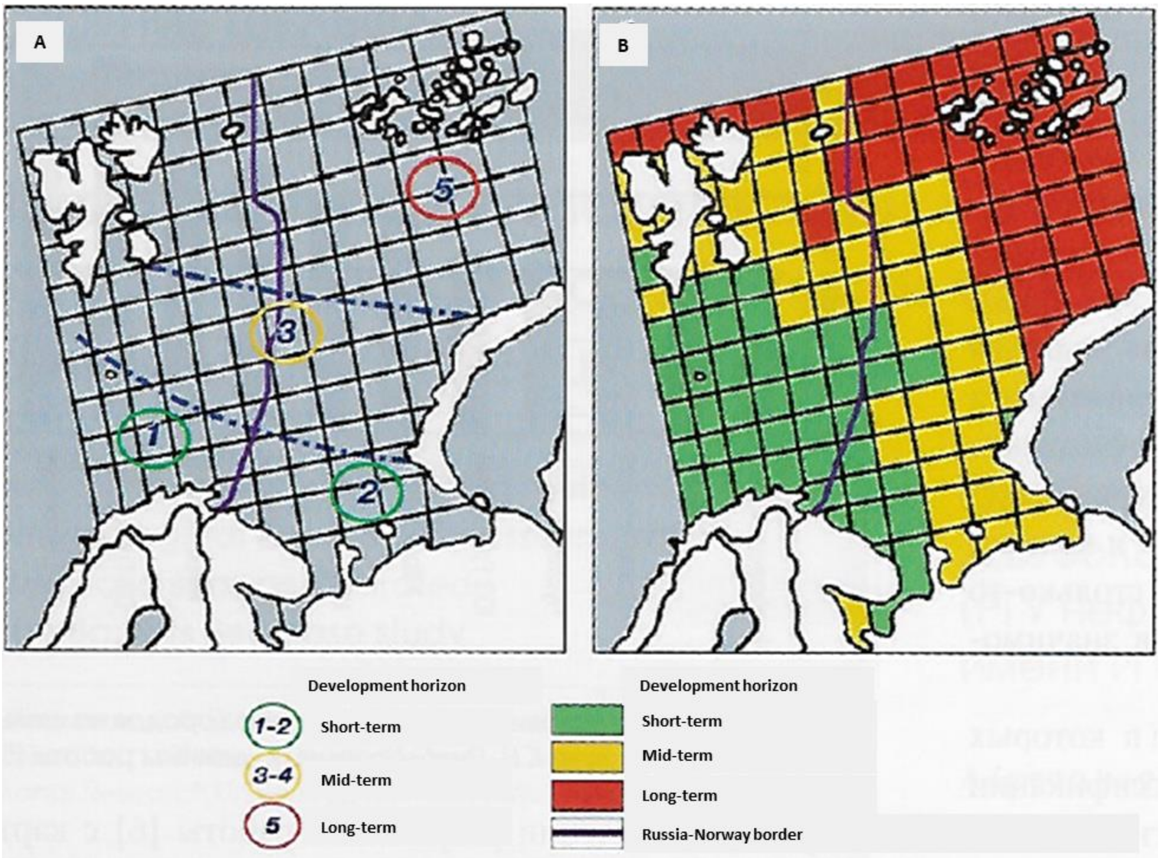

Figure 3.6 Forecast of the time horizon for field development in the Barents Sea [11]

A - according to the INTSOK method, B - the principle of fuzzy ranking by 10 parameters

4. Development scenarios and technology selection

The purpose of this section is to determine the lists of technological solutions for the oil scenario and identify the optimal scenario for the development of promising structures described earlier in the current conditions of the hydrocarbon market and technological development of the industry. In this context, a scenario is understood as a complex of various interconnected existing development facilities necessary to develop a potential field.

In order to select the optimal scenario, it is proposed to divide the selection of scenarios into two stages. The optimality of scenarios planning at the first stage is proposed to be determined by three criteria: technological feasibility, technological readiness, ability to maintain the required reliability, environmental risks. According to the first stage results, at the second stage, it is proposed to consider in detail a limited set of priority scenarios in terms of organising a logistics system, drilling, Flow assurance, and managing ice conditions and conducting downhole operations. Then, it is proposed to conduct scenarios economic assessment and select optimal ones to develop oil structures.

4.1. Description, initial assessment and ranking of development scenarios

To describe the development scenarios in the framework of this work, we have access to two of the most significant oil structures of HLA – SWO and NEO (Figure 1.2, Figure 1.3). The assumed structure assumptions were described earlier in the first and second sections and Table 1.1. Several previously omitted assumptions will be described in development scenarios.

At the first stage, for the development of deposits under the described conditions, it is proposed to start considering the following basic scenarios:

1. Subsea development using technological facilities off the coast of the Novaya Zemlya archipelago;
2. Partially subsea development using an onshore platform for final treatment and shipment of oil off the coast of NZA;
3. Subsea development using detachable floating production platforms/installations;
4. Stationary platform resistant to the effects of ice formations and icebergs on the gravitational foundation, with or without the possibility of connecting subsea wells.

These four basic scenarios were selected for development as best suited to the natural, climatic and hydrometeorological conditions of the HLA.

To describe the scenarios of oil field development in this work, we consider two of the most significant structures of HLA – SWO, NEO (Figure 4.1).

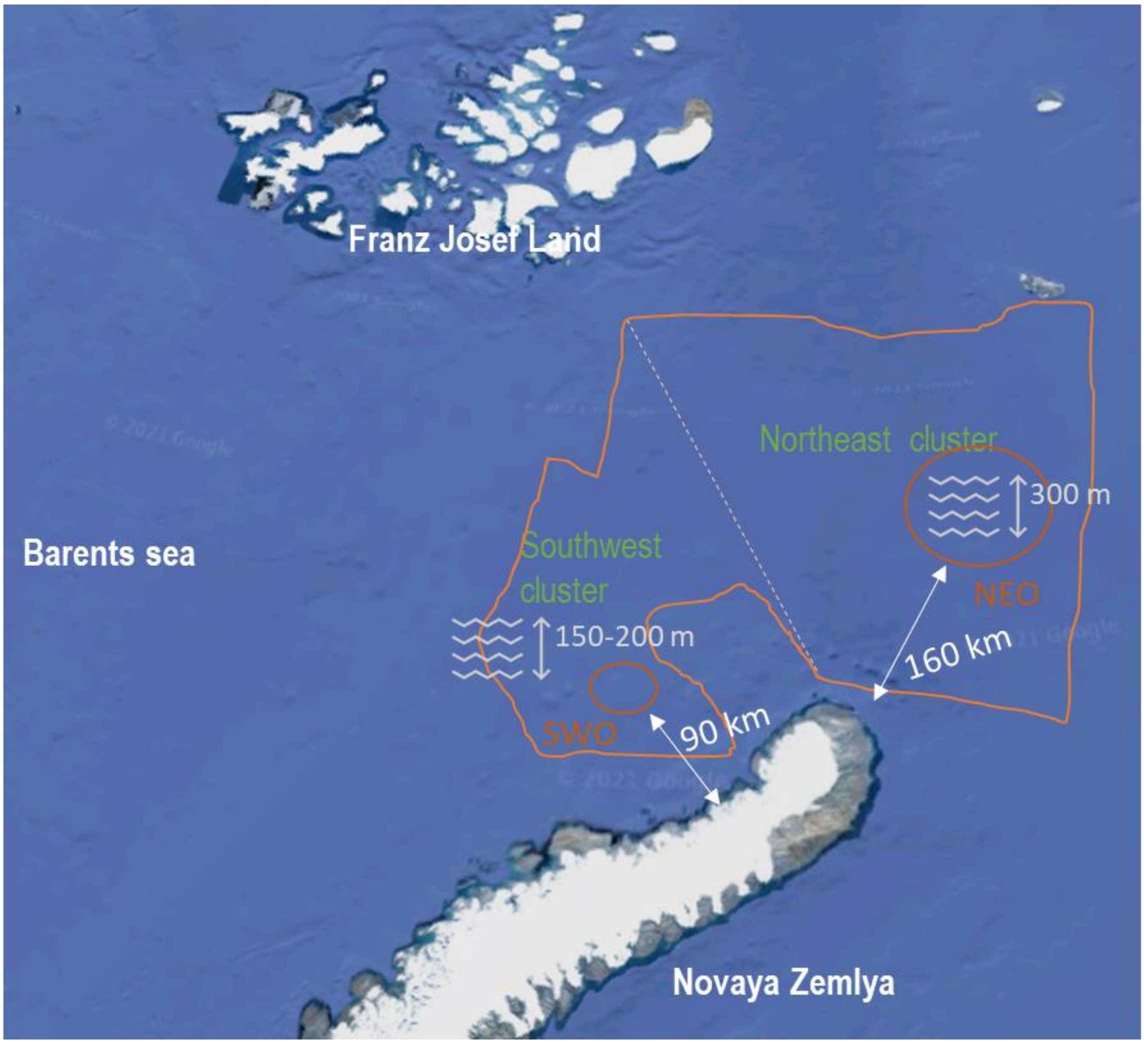

Figure 4.1 Depth and distance from the shore of SWO and NEO structures

4.1.1. Scenario 1

Partially subsea development using an onshore platform for final treatment, storage, and oil offloading (Figure 4.1). See Table 4.1. for a list of the proposed main facilities and their components.

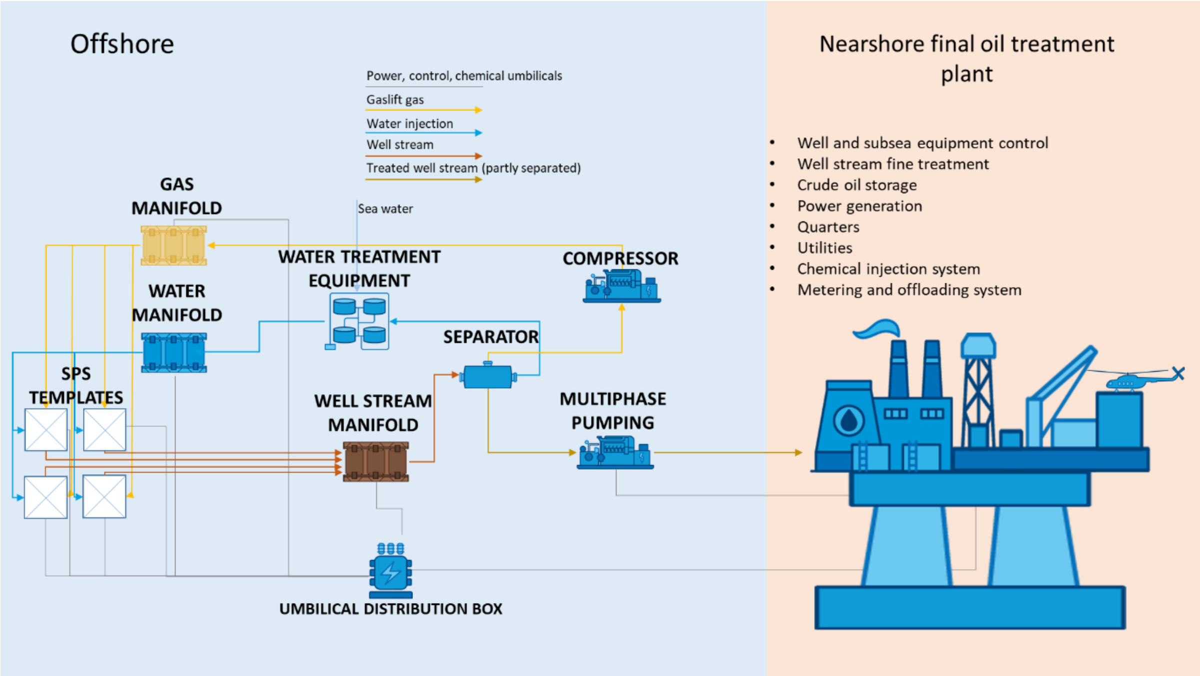

Figure 4.1 Simplified scheme of a partially subsea development scenario c using a coastal platform for final treatment, storage and offloading of oil

This development scenario is intended for subsea wells drilled using the MODUs. Arrangement using a subsea production system (SPS), including templates of wells, manifolds, multiphase flowmeter and SURF. The separation of the recovered fluid, the water injection mixed with the prepared seawater and the treatment and compression of the gas for the gas lift takes place in specialised subsea installations. Partially dewatered and de-gassed reservoir fluid is pumped using a multiphase pump through a two-line multiphase pipeline to the concrete support part of the nearshore PDQ oil treatment plant. PDQ of gravity type with upper buildings with a residential block and auxiliary engineering systems with the possibility of storing and offload crude oil. The power supply of subsea installations should be carried out from the PDQ. Subsea installations and wells should be controlled using umbilicals, which also supply chemicals for subsea installations. Crude oil is offloaded to shuttle tankers using two filling stations.

Table 4.1 List of the main elements for scenario 1

n/a number	**Equipment**	**Element of equipment**
1	Subsea production system	Wellhead housing
		Christmas tree fittings
		Manifolds
		Template
		Connection system
		ROV Launch Cameras
		Control module
2	Subsea separator	Separator
3	Reservoir water treatment plant	Reservoir water treatment plant
		Reservoir water treatment plant
4	Seawater treatment plant	Seawater treatment plant
5	Water injection unit	Water injection unit
6	Gas treatment plant	Gas treatment plant
7	Gas compression unit, gas lift and gas injection into the reservoir	Manifold for gas lift and injection of gas into the reservoir
		Pipelines for gas lift and injection of gas into the reservoir
		Compressor
8	Subsea Multiphase Pump	Pump
		Manifold
9	Double pipelines	Double pipelines
10	Coastal oil refinery on a gravity platform of a caisson type for partially prepared reservoir fluid	Residential block
		Auxiliary systems
		Electricity generation
		Separation
		Chemical supply
		Product measurement and shipment
11	Control and supply hoses, including power cable	Control and supply hoses
		Hose cable junction Box
		Power cable
12	Power supply HV	Subsea transformer
		Subsea switchgear
		Subsea variable frequency drive
13	Flow assurance	Electric heating of the field pipeline

It is proposed to place the coastal gravity platform on the north-eastern coast of NZA**{** XE "NZA" **}** in Inostrantsev Bay. There are two main reasons for this. The first is the availability of places with sea depths less than 100 m, which is an economically important factor in constructing a gravity-based platform. In addition, according to observations [1], this area of the coast has the most predictable and simple ice situation. The data indicate mostly thin annual ice for most of the year (Figure 4.6). This fact reduces the cost of setting up the platform and simplify the ice management of the platform's operations.

This development scenario based on a stationary ice-resistant platform on a caisson-type GBS is a concept confirmed in practice by the development project in difficult ice conditions of the Prirazlomnoye field (the Prirazlomnaya platform).

4.1.2. Scenario 2

Partially subsea development using a nearshore platform for a complete cycle of oil treatment, storage and offloading (Figure 4.2). See Table 4.2. for a list of the proposed main facilities and their components.

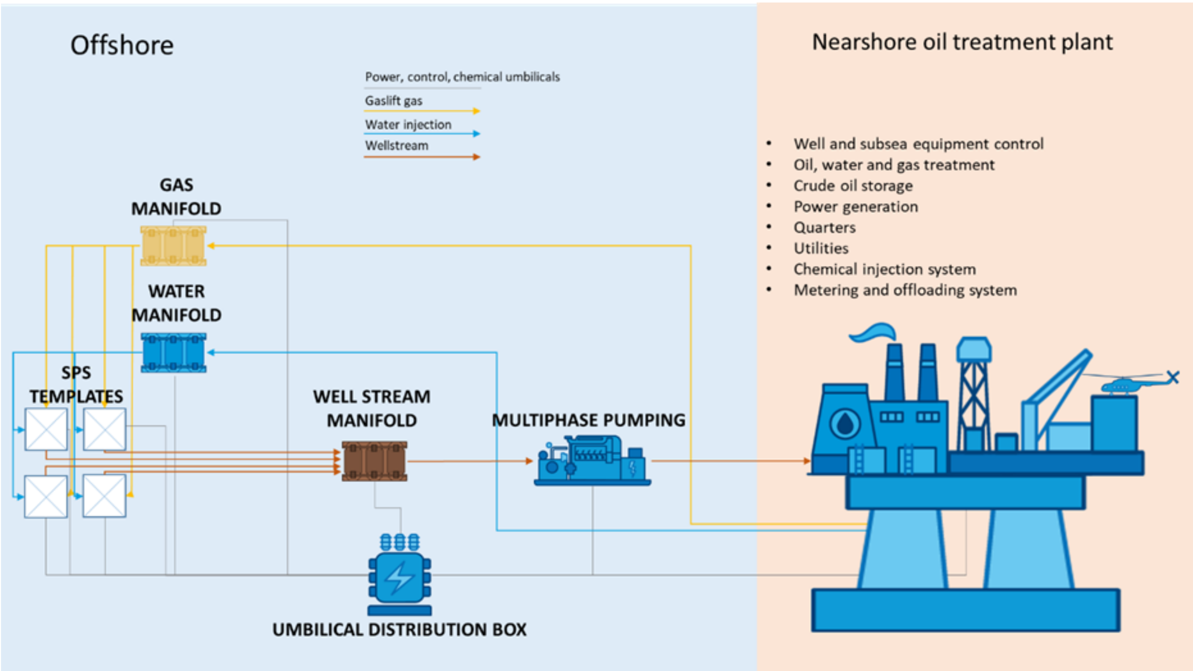

Figure 4.2 Simplified scheme of a partially subsea development scenario using a nearshore platform for a complete cycle of oil treatment, storage, and offloading

This development scenario is intended for subsea wells drilled using the MODUs. Arrangement using subsea production system (SPS), including templates of wells, manifolds, multiphase flow meter, subsea systems, the umbilical, risers and flowlines (SURF). Multi-phase subsea station, pumping crude oil to the direction of formation fluid in a two-line multiphase pipeline on a concrete part of the coastal platform. The platform can store oil in the caisson and has stations for crude oil offloading. The subsea multiphase pump must be power supplied from a platform with a residential unit and auxiliary engineering systems. Control of subsea installations and wells should be carried out through umbilicals, supplying chemicals for the SPS. Crude oil is offloading to shuttle tankers using two filling stations.

It is proposed to place the coastal gravity platform on the north-eastern coast of NZA**{** XE "NZA" **}** in Inostrantseva Bay. There are two main reasons for this. The first is the availability of places with sea depths less than 100 m, which is an economically important factor in constructing a gravity platform. In addition, according to observations [1], this area of the coast has the most predictable and simple ice situation. The data indicate mostly thin annual ice for most of the year (Figure 4.6). This fact reduces the cost of setting up the platform and simplify the ice management of the platform's operations.

The subsea multiphase pump must be supplied with electricity from a coastal technological platform with a residential unit and auxiliary engineering systems. Control of subsea installations and wells should be carried out using hose cables, supplying chemicals for the subsea complex. Crude oil is offloaded to shuttle tankers using two filling stations.

Table 4.2 List of the main elements for scenario 2

n/a number	**Equipment**	**Element of equipment**
1	Subsea production system	Wellhead housing
		Christmas tree fittings
		Manifolds
		Template
		Connection and connection system
		ROV Launch Cameras
		Control module
2	Twin pipelines to the coastal gravity platform	Twin pipelines to the gravity platform
		Pumps
3	Water injection pipelines to the SPS	Water injection pipelines
		Water injection manifold
		Water pipelines from gravity platform to manifold
4	Gas lift and injection pipelines to the SPS	Manifold for gas lift and injection of gas into the reservoir
		Pipelines for gas lift and injection of gas into the reservoir
		Gas lift and injection pipelines from gravity platform to manifold
5	Subsea Multiphase Pump	Pump
		Manifold
6	Chemical control and supply hose, including power cable	Chemical control and supply hose
		Hose Cable Junction Box

		Power cable
7	Coastal LNG plant on a gravity platform of a caisson type	Oil storage
		Residential block
		Auxiliary systems
		Electricity generation
		Separation
		Gas treatment and compression
		Reservoir water injection plant
		Seawater treatment and injection
		Chemical supply
		Product measurement and shipment
8	Power supply HV	Subsea transformer
		Subsea switchgear
		Subsea variable frequency drive
9	Flow assurance	Electric heating of the field pipeline

The proposed Subsea production system in this scenario is a concept that has been tested in practice on the Norwegian Continental Shelf (NCS) and the whole world. Subsea installations reduce the number of pipelines and the need for drying gas for its transportation through subsea pipelines.

The platform with a caisson-type GBS for a complete cycle of oil treatment, storage and shipment is a concept that has already been applied in the Arctic conditions on the Prirazlomnaya platform.

Since each of the promising structures of the Southern and Southern rivers is about 2000 km, several drilling sites are needed for the development of these reservoirs.

Using single wells in the daisy chain configurations production and injection wells will require moving mooring MODUs for each well. This operation is time-consuming and time-consuming in the presence of ice cover.

Therefore, it would be logical to use these templates with at least 4-6 slots where the number of slots equal to the maximum number of wells that can be drilled in one year, i.e. from 16 to 24 template for oil wells for scenario 2, which minimises the need to move the mooring mostly open water seasons or season with the best ice conditions in the year.

4.1.3. Scenario 3

Subsea scenario using a ship / cylindrical type floating installation for a complete cycle of oil treatment, storage and offloading (Figure 4.3). See Table 4.3. for a list of the proposed main facilities and their components.

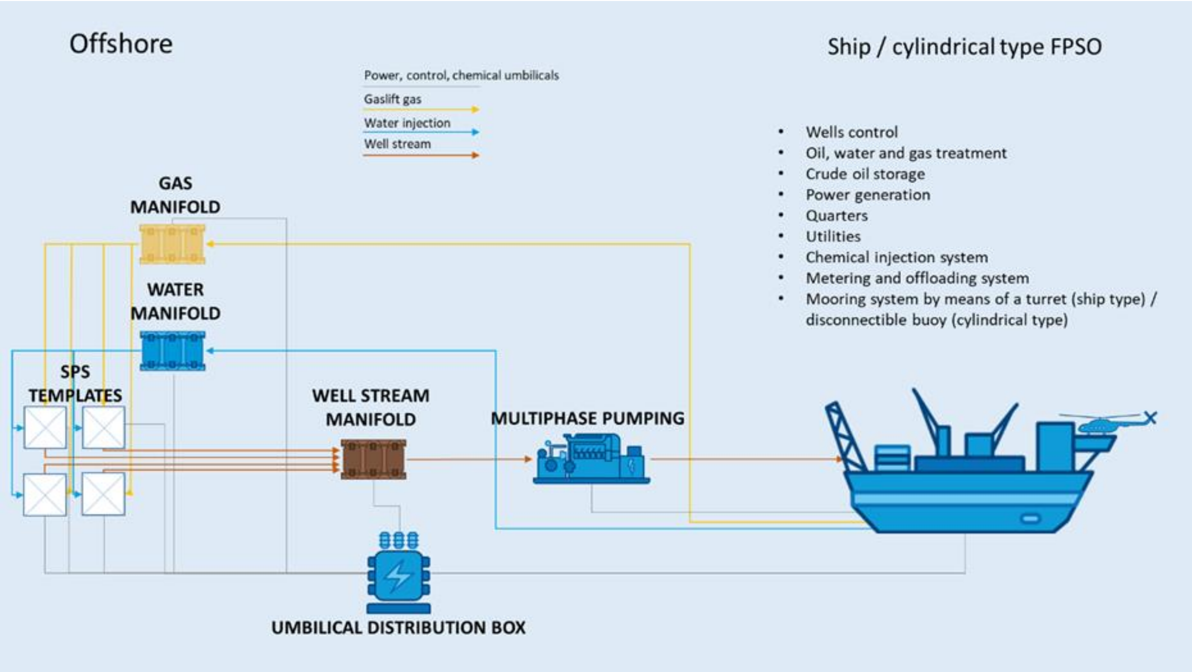

Figure 4.3 Simplified scheme of a partially subsea development scenario using a floating vessel for treatment, storage, and offloading

Subsea wells drilled using the MODUs. Production carried out using a gas lift, while the flow of well products is pumped and fed via flexible risers to a detachable FPSO vessel moored using a turret. Well fluid stream is fed to the FPSO for separation, stabilisation, storage and further offloading crude oil to shuttle tankers.

Gas is used as fuel for generating electricity and heat, and its excess is fed to drying, compression and used for gas lift production and injection into the reservoir. The estimated gas factor is 172m^3/m^3. After pretreatment, the formation water is mixed with the prepared seawater at the FPSO and pumped into the formation. Additional research is needed to determine the compatibility of reservoir and seawater. If there is a possibility of precipitation during heating, an inhibitor should be selected during treatment that excludes precipitation of any kind. It is proposed to provide electricity, supply chemicals, and control functions of the subsea complex and wells using a hose cable.

Table 4.3 List of the main elements for scenario 3

n/a number	**Equipment**	**Element of equipment**
1	Subsea production system	Wellhead housing
		Christmas tree fittings
		Manifolds
		Template
		Connection and connection system

		ROV Launch Cameras
		Control module
2	Subsea hose lines, risers and field pipelines (SURF)	Hose cable
		Riser
		Commercial pipeline
		Power cable
3	Subsea Multiphase Pump	Pumps
		Manifest
4	Floating plant FPSO	Product Measurement and shipment
		Residential Unit
		Auxiliary systems
		Separation
		Compression
		Electricity generation
		Chemical supply
		Detachable turret
		Hull
		Mooring lines
		Reservoir and seawater injection
5	Flow assurance	MEG or electric heating

An ice-class floating FPSO installation with a detachable turret mooring is a proven concept. Two similar installations (vessels) are currently operating in marine areas with ice conditions and the threat of icebergs. These are FPSO "Terra Nova" and "White Rose", installed inы the Jeanne d'Arc Basin on the east coast of Canada. This area is characterised by the seasonal presence of floating ice of various thicknesses from 0.5 to 1.5 m. The FPSO project "Terra Nova" and "White Rose" allows these floating plants anchored within the 100-day storm with waves of up to 90 feet (~27.5 m), operated in the waters of temperate ice cover with the coverage ratio to 5/10, to withstand icebergs weighing 100 tons, and to be disconnected, if necessary. To avoid a collision with a heavy pack of ice and icebergs potential [18]. It is important to note that the traffic situation on HLA differs from the Jeanne d'Arc section. HLA conditions require creating a unique vessel capable of operating in the ice and weather conditions described above.

4.1.4. Scenario 4

Partially subsea construction using an offshore ice and iceberg resistant stationary gravity platform for well drilling, production, collection, treatment, storage and offloading of oil (Figure 4.4). See Table 4.4. for a list of the proposed main facilities and their components

A formation developed using a platform and subsea wells. Well products from subsea wells are mixed with well-product flow from the platform and fed for stabilisation and storage.

It is proposed to offload stabilised oil from two delivery stations on the PDQ Technology Platform. Gas is used as fuel to generate heat and electricity on the platform.

Excess gas is compressed, drained, used for gas lift, and pumped back into the reservoir. Formation water and seawater are prepared, mixed, and pumped back into the formation. Energy supply and injection of chemicals, control functions of subsea wells, as well as SPS facilities are carried out from the platform using a hose cable.

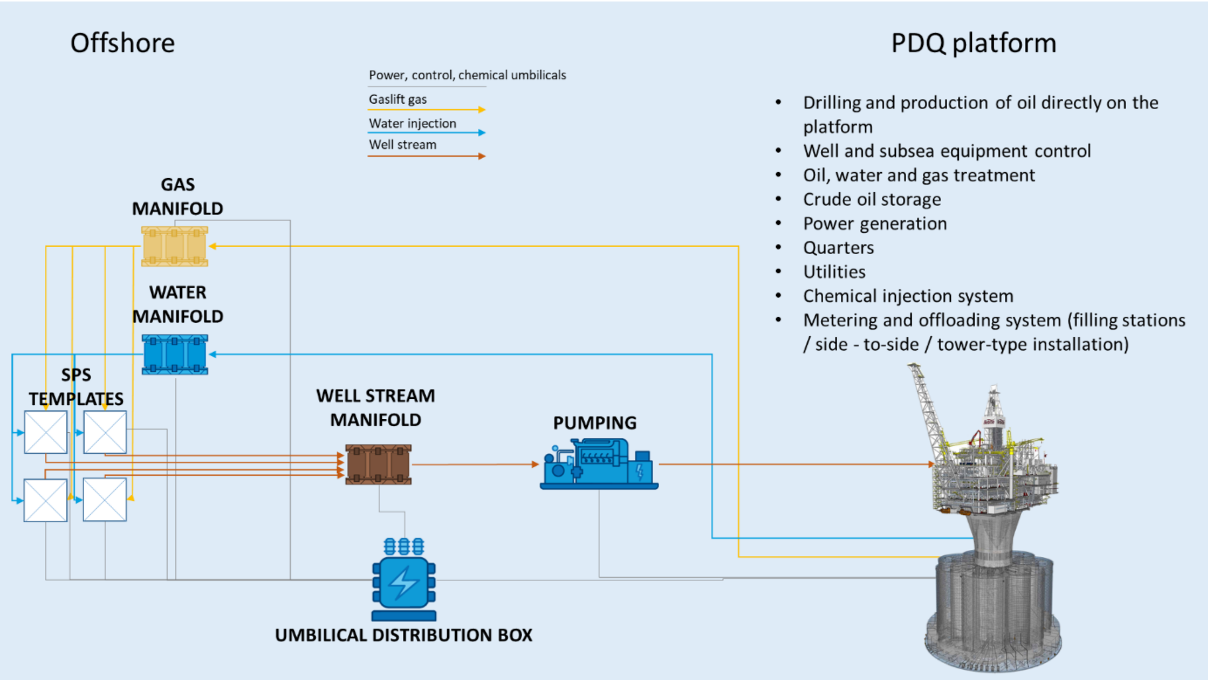

Figure 4.4 Simplified flow diagram of a partially subsea construction scenario using an offshore ice and iceberg resistant stationary gravity platform

Table 4.4 List of the main elements for scenario 4

n/a number	Equipment	Element of equipment
1	Subsea production system	Wellhead housing
		Christmas tree fittings
		Manifolds
		Template
		Connection and connection system
		ROV Launch Cameras
		Control module
		Manifold for gas lift and gas injection into the reservoir
2	PDQ platform on GBS	Residential block
		Auxiliary systems
		Electricity generation
		Drilling
		Separation

		Compression
		Measurement of products and shipment
		Reservoir and seawater injection
		Oil storage facility
		Wells
3	Multiphase pump	Multiphase pipeline
		Pump
4	Water injection line to SPS	Water injection unit
5	Gas lift line to SPS	Gas Lift
		Gas lift manifold
6	Hose cables for SPS control/chemical supply/power supply	Power Cable
		Management and delivery of chemicals
7	Subsea hose lines, risers and field pipelines	Hose cable
		Riser
		Hose cable junction box 8
8	Flow assurance	MEG or electric heating

Proven in operation in the development of offshore fields and tested the concept of development at a water depth of 93 m in ice conditions and non-dangerous icebergs. A similar development project has been implemented on the east coast of Canada. The HEBRON platform is installed at a depth of 93 m in the Jeanne d'Arc basin, where the platform design implements the concept of protection from the effects of sea ice and icebergs. The platform's base can withstand the impact of an iceberg weighing one million tons without damage and contact with an iceberg weighing six million tons with the risk of non-critical damage. The platform has 52 drilling slots for wells. The storage capacity of crude oil in GBS is 1.2 million barrels. The working weight of the upper structure is 65,000 tons [23]. The platform can be equipped with j-shaped pipes for connecting SPS for the operation of satellite wells.

4.1.5. Assessing the technological readiness of scenarios

In order to adequately assess the degree of readiness of technologies for use in a natural field, a universal scale is necessary. In world practice, the TRL (Technology readiness level) scale is widely used. Translated into Russian, the approach is called TRL (Level of Technology Development). The approach is an assessment of a technology using a universal scale that reflects its level of maturity. The original scale was developed and used by NASA at the end of the last century. It consisted of 7 levels. Currently, the methodology has changed and consists of a scale of 9 levels (Figure 4.5). For this paper, it is proposed to use a methodology consisting of 8 levels (Table 4.5). In the author's opinion, level 9 is not relevant for the conceptual design of the object since it rather concerns the level of replication of the results of a technological project at an already launched production facility. In the current subsection, the author tried to evaluate the TRL of technological solutions necessary for implementing scenarios based on information from open sources and expert assessments of his consultants.

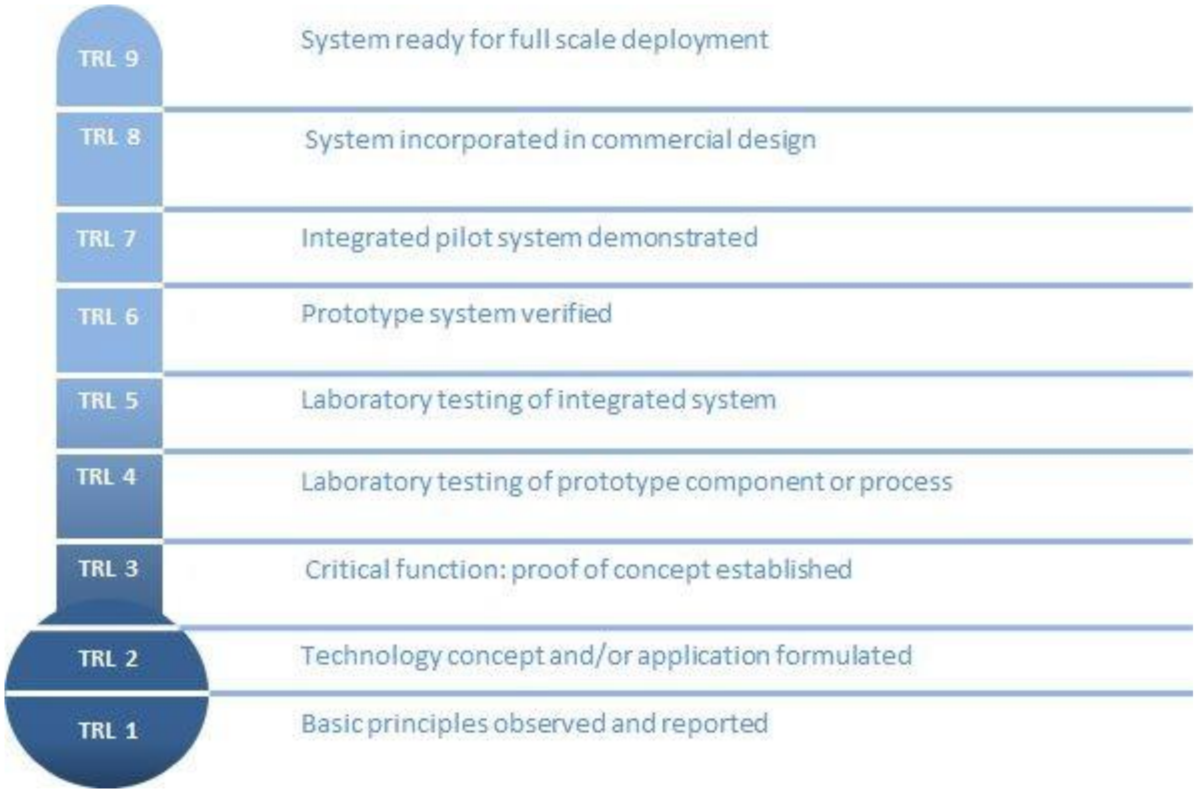

Figure 4.5 Decoding the levels of technology development (TRL)[11]

Table 4.5 Detailed description of the TRL methodology for eight levels [1]

TRL	**Description**	**Example**
TRL-1. The fundamental principles of the technology are observable and described	This is the lowest level of readiness. Scientific research begins to transform into R & D. Examples: research articles, contacts with universities and innovative companies	Let's look at the example of creating an innovative tomograph. TRL1: found articles about a new development-a detector based on an innovative element. A division of the company that is theoretically interested in improving the properties of the tomograph was found

TRL-2. A technological concept and/or possible applications are formulated	The inventive activity begins. Since the fundamental principles are identified, the study of possible practical applications can be initiated. These applications are speculative (as yet unreliable). There is no evidence or detailed analysis to support the assumptions. But the assumptions (and effect) satisfy the business. Examples are limited to analytical data	A literature review is conducted. The published data prove that the physics of the process is possible and the detector is technically feasible. Based on the published materials, you can roughly assess the technical advantages of the future tomograph. The business unit is satisfied with the potential characteristics of the technology. The device concept is defined
TRL-3. There are analytical and/or experimental confirmations on the most important capabilities of the technology	An active R & D phase has been initiated: analytical studies and laboratory studies* aimed at physical confirmation of analytical predictions for individual elements of technology	Analytical calculations show that the size of the detector in the existing concept cannot meet the needs of the business. Three additional concepts have been created. Numerical simulations of the process show that only 2 concepts are viable. Modelling 2 concepts proves the viability of solutions. Calculating economic efficiency requires abandoning one of the concepts. A laboratory study of the detector cell (a component of the detector) was performed.

TRL-4. The main components are tested in the laboratory	Basic technology components are integrated to confirm that they can work together. TRL has approximate reliability of the system compared to the final result	Prototypes of the element from cells and the substrate are created. Tested separately. Open points for optimisation are identified. The optimised design was tested with better results than the previous one. The detector housing has been developed. The cell element and the substrate are integrated into the housing. Laboratory tests were carried out, where the detector is located in a state close to Gentry's state. Experiments were conducted
TRL-5. The main components passed bench tests	The basic technological components are integrated into the system so that the system functions as a final version for most indicators. Examples include tests of high accuracy under simulating conditions and/or in the range of real simulated parameters	Redesigned gentry (not to scale). The compliance of the structural properties of the tomograph with the inherent properties was evaluated(extrapolated estimate)
TRL-6. The prototype was tested under conditions close to real conditions	Industrial models and prototypes are tested in real-world conditions. A major step in technology readiness	The detectors are integrated into the new gentry. The prototype was tested under conditions close to real conditions. The radiation energy corresponds to real conditions. Open questions on the production of components

		(detector, substrate, gentry) have been resolved. During the final version of the production, structural deficiencies identified during testing were taken into account
TRL-7. The prototype was tested under operational conditions	The prototype fully reflects the planned system. The final prototype confirmed its performance in the field	Full-scale prototype tested, optimal conditions, patient layout
TRL-8. Successful operation of a full-size system (in limited conditions)	The technology has confirmed its performance in the final form and under the expected conditions. End of system technology development	Operation of the final full-scale construction in a business unit with realistic conditions

It is worth noting that the assessment of technological readiness was based on information [1] and the author's knowledge of the current experience of the global industry in the use and development of certain technologies. Level of technological readiness 5 means the presence of a developed and tested technology of the arrangement element ready for its intended use or detailed design.

The various equipment and components of the development facilities proposed in the HLA development scenarios for installation on the sea floor have the same operating conditions as similar subsea equipment installed in ice-free areas worldwide [oo. The seawater temperature is usually about 4 °C. Therefore, this assumption is used to assess the level of technological readiness.

Weather conditions, Jasovska license area during the drilling season are expected to be very severe, which can make the operation of the equipment and components mounted on the upper structures of the platforms or barges, impractical or impossible, adversely affect the ability to conduct maintenance and repair (PER), and besides that have a negative impact on the issues of health and environment during the operation of offshore installations. Therefore, the associated problems were taken into account when evaluating TRL levels for the equipment of upper buildings.

TRL assessment of a partially subsea development scenario using an onshore platform for final oil treatment, storage and shipment (Table 4.6). The scenario is characterised by a significant distance from the gravity platform to the subsea infrastructure.

Table 4.6

TRL evaluation of scenario 1

Technology	**Technology element**	**Current TRL**
Subsea production system	Wellhead housing	7
	Christmas tree fittings	7
	Manifolds	7
	Template	7
	Connection and connection system	7
	ROV Launch Cameras	7
	Control Module	
Subsea separator	Separator	7
Reservoir water treatment plant	Reservoir water treatment plant	4
Seawater treatment plant	Seawater treatment plant	4
Water injection unit	Water injection unit	7
Gas treatment plant	Gas treatment plant	7
Gas compression unit, gas lift and gas injection into the reservoir	Gas lift and gas injection manifold	7
	Pipelines for gas lift and injection of gas into the reservoir	7
	Low-flow high-pressure compressor	3
Subsea Multiphase Pump	Subsea pumps	4
	Subsea manifold	4
Double pipelines	Double pipelines	7
Coastal oil final treatment unit on a gravity platform of a caisson type	Residential block	7
	Auxiliary systems	7
	Electricity generation	7
	Separation	7
	Chemical supply	7
	Product measurement and shipment	7
Control/chemical supply/power supply	Hose cable	7
	Hose cable junction box 7	7
	Power cable	7
Power supply HV	Subsea transformer	4
	Subsea Switchgear (RU)	4
	Subsea variable frequency drive	3
Flow assurance (preventing possible complications)	Electric heating	3

The technological challenges of scenario 1 are primarily related to the completion and certification of subsea seawater and gas treatment facilities for gas lift. In addition, subsea installations and high-voltage power supplies for pumping fluid over distances of more than 50 km are also not yet ready for full-scale use, and they need to be finalised and certified for use on the project [1].

Pumping a multiphase flow through a pipeline to the coastal gravity platform is associated with challenges in Flow assurance. Ensuring the stability of the flow of pipelines of this length should mean its isolation and heating. According to the source [1], there are developments in electric heating systems for pipelines for distances, but it requires their completion and certification.

TRL assessment of a partially subsea development scenario using a coastal platform for a full cycle of oil treatment, storage and shipment (Table 4.7). Like the previous one, the scenario, like the previous one, differs significantly from the SPS to the oil treatment facilities in the coastal platform.

Table 4.7

TRL evaluation of scenario 2

Technology	**Technology elements**	**Current TRL**
Subsea production system	Wellhead housing	7
	Christmas tree fittings	7
	Manifolds	7
	Template	7
	Connection and connection system	7
	ROV Launch Cameras	7
	Control Module	
Twin pipelines to the coastal gravity platform	Twin pipelines to the gravity platform	7
	Pumping station	7
Water injection pipelines to the SPS	Water injection pipelines	7
	Water injection manifold	7
	Water supply pipeline from gravity platform to manifold	7
Gas lift and gas injection pipelines to the SPS	Gas lift and gas injection manifold	7
	Pipelines for gas lift and injection of gas into the reservoir	7
	Gas lift and gas injection pipelines from gravity platform to manifold	7
Subsea Multiphase Pump	Subsea pumps	4
	Subsea manifold	4
Control/chemical supply/power supply	Hose cable	7
	Hose cable junction box 7	7

	Power cable	7
Full-cycle offshore oil treatment plant on a caisson-type gravity platform	Oil storage	7
	Residential block	7
	Auxiliary systems	7
	Electricity generation	7
	Separation	7
	Gas treatment and compression	7
	Reservoir water injection	7
	Seawater treatment and injection	7
	Chemical supply	7
	Product measurement and shipment	7
Power supply HV	Subsea transformer	4
	Subsea Switchgear (RU)	4
	Subsea variable frequency drive	3
Flow assurance (preventing possible complications)	Electric heating	3

The main gaps in the technological readiness of this scenario are in the equipment for electric heating of multiphase pipelines, multiphase pumping units and their power sources.

TRL assessment of a partially subsea development scenario using a ship-type / cylindrical floating installation for a full cycle of oil treatment, storage and shipment (Table 4.8). The scenario differs by a small distance from the floating installation to the subsea facilities.

Table 4.8

TRL assessment of scenario 3

Technology	**Technology element**	**Current TRL**
Subsea production system	Wellhead housing	7
	Christmas tree fittings	7
	Manifolds	7
	Template	7
	Connection and connection system	7
	ROV Launch Cameras	7
	Control module	
Subsea hose cables, risers and fishing pipelines (SURF)	Riser	7
	Field pipeline	7
Gas Lift	Pipelines	7
	Manifold	7
Water injection unit	Water injection pipelines	7
	Water injection manifold	7
Control/chemical supply/power supply	Hose	7
	Hose cable junction box 7	7
	Power cable	7
Subsea multiphase pump	Subsea pumps	7
	Subsea manifold	7
Floating plant FPSO	Product measurement and shipment	7

	Residential unit	7
	Auxiliary systems	7
	Separation	7
	Compression	7
	Electricity	7
	Chemical supply	7
	Building	4
	Detachable turret	4
	Mooring lines	4
	Reservoir and seawater injection	7
Flow assurance (preventing possible complications)	MEG or electric heating	7

The main technological gap in this scenario is the lack of analogue vessels capable of operating in the ice conditions of HLA. First of all, it requires a reinforced hull that can withstand ice loads, a detachable turret system, and a mooring system that allows the ship to maintain its position under the impact of ice loads. According to information from the source [1], one of the foreign oil companies has such a project of FPSO, which can be operated in the southwest cluster of the HLA. However, additional testing and certification of the design of this system are required.

Assessment of the TRL of partially subsea construction using an offshore ice and iceberg resistant stationary gravity platform for well drilling, production, collection, treatment, storage and offloading of oil (Table 4.9). The scenario differs by a small distance from the PDQ platform to the subsea facilities. The assessment was carried out for the conditions of the SWO structure because of restrictions on the depth for platforms on the gravity foundation. According to various estimates, gravity platforms resistant to the effects of ice cover and icebergs cannot be installed at depths of more than 250 m [1].

Table 4.9

TRL assessment of scenario 4

Technology	**Technology element**	**Current TRL**
Subsea production system	Wellhead housing	7
	Christmas tree fittings	7
	Manifolds	7
	Template	7
	Connection and connection system	7
	ROV Launch Cameras	7
	Control Module	

	Gas lift and gas injection manifold	7
PDQ platform on GBS (Depth 150m)	Residential block	7
	Auxiliary systems	7
	Electricity generation	7
	Drilling	7
	Separation	7
	Compression	7
	Product measurement and shipment	7
	Reservoir and seawater injection	7
	Oil storage facility	7
	Wells	7
Multiphase pump	Multiphase pipeline	7
	Subsea pumps	7
Water injection line to SPS	Water injection into the reservoir	7
Gas lift line to SPS	Gas injection into the reservoir	7
SPS control and chemical	Hose cable supply	7
Flow assurance (preventing possible complications)	MEG system or electric heating	7

Even though there are no direct analogues of gravity platforms operating at a depth of 150 m and implying ice and iceberg stability, calculations [1] have confirmed the technical feasibility of manufacturing and towing such a platform to the SWO structure. First of all, the benchmark is the Hibernia and Hebron platforms. Although these platforms are designed for a lower depth, the claimed ice and iceberg stability properties fully meet the requirements of the Southwestern cluster of HLA deposits [19,23].

In general, estimates of the time required for technology certification in all scenarios are 10-15 years. This time interval corresponds to the forecast of technological availability of the HLA water area, carried out in [14].

4.1.6. Multi-criteria pair-wise analysis

Multi-criteria decision-making (MCDM) or multi-criteria decision analysis (MCDA) is a division of research that explicitly evaluates multiple conflicting criteria when making decisions. For selection, it is logical to distinguish four main, often conflicting criteria among the scenarios of HLA development (Table 4.10). It is important to note that the author deliberately uses only qualitative indicators since the level of uncertainty at this stage of the study cannot allow for any relevant deterministic assessment.

Table 4.10 Criteria for multi-criteria analysis and selection of scenarios at stage 1

Evaluation criteria	**Actual weight**
Technological readiness	0.1
Reliability	0.3
HSE risks	0,4
Technical feasibility	0.3

It is necessary to detail the above criteria from the author's point of view when conducting the assessment. Technological feasibility refers to the physical ability to apply the technical solutions described in the scenario while maintaining their functionality and efficiency. Technological readiness is defined as a complex level of technological development according to the scenario. The rating for this criterion is based on the analysis performed in4.1.5. The reliability criterion includes assessing the possibilities for timely maintenance of the proposed technical solutions, considering the current geopolitical conditions and environmental features. First of all, they contribute to the assessment of this indicator:

- the relative technological complexity of the scenario -the basic assumption is that the simplicity of the system is the key to its reliability
- share of local Russian manufacturers and service companies that can supply and maintain the required technological solutions
- the complexity of maintenance operations for technical solutions, primarily taking into account the ice situation in the HLA region

The assessment of occupational health, safety, and environmental management risks was based primarily on a top-level assessment of the consequences of possible risk events.

The assessment was carried out in pairs, with a direct comparison of four scenarios according to 4 criteria. The grading scale provides the researcher with a choice of seven grading options. Each of the evaluation options corresponds to a pre-determined number of points (Table 4.11

Table 4.11 The rating scale for multi-criteria analysis

Description	**Number of points**
Much better	than 100
Much better	than 80
Better	than 70
Neutral	50
Weaker	than 30
Significantly weaker	than 10
Much weaker than	0

A multicriteria analysis was performed separately for each of the two HLA clusters. The purpose of the analysis is to determine the optimal scenario for the structures of each cluster by using qualitative comparisons of scenarios based on the selected criteria.

The southwestern cluster is characterized by relatively shorter distances to the NZA coast and relatively lower depths.
Scenarios 2 and 4 (Table 4.12) are the leaders' technical feasibility for the SWO structure.

Table 4.12 Pair-wise scenario analysis for the SWO structure by technological feasibility

Technological feasibility	**Scenario 1**	**Scenario 2**	**Scenario 3**	**Scenario 4**
Scenario 1		70	50	80
Scenario 2	30		30	70
Scenario 3	50	70		70
Scenario 4	10	30	30	
Number of points	90	170	110	220
Weighted number of points	27	51	33	66

Scenarios 3 and 4 are the leaders in terms of technical readiness for the SWO structure (Table 4.13).

Table 4.13 Pair-wise scenario analysis for the SWO structure by technological readiness

Technological readiness	**Scenario 1**	**Scenario 2**	**Scenario 3**	**Scenario 4**
Scenario 1		80	80	70
Scenario 2	30		70	80
Scenario 3	30	30		50
Scenario 4	10	30	50	
Number of points	70	140	200	200
Weighted number of points	7	14	20	20

Scenarios 2 and 4 are the leaders in terms of reliability for this structure (Table 4.14).

Table 4.14 Pair-wise scenario analysis for the reliability structure of the SWO

Reliability	**Scenario 1**	**Scenario 2**	**Scenario 3**	**Scenario 4**
Scenario 1		70	50	80
Scenario 2	30		10	70
Scenario 3	50	80		70
Scenario 4	10	30	30	
Number of points	90	180	90	220
Weighted number of points	27	54	27	66

Scenarios 2 and 4 (Table 4.15) lead in health, safety, and environmental protection risks for the SWO structure.

Table 4.15 Pair-wise scenario analysis for the SWO structure by Health, safety, and environmental management risks

Health, safety and environmental management risks	**Scenario 1**	**Scenario 2**	**Scenario 3**	**Scenario 4**
Scenario 1		70	30	80
Scenario 2	30		30	70
Scenario 3	70	70		100
Scenario 4	10	30	10	
Number of points	110	170	70	250
Weighted number of points	44	68	28	100

Based on the analysis, a histogram was constructed that reflects the results of the unweighted (Figure 4.3) and weighted (Figure 4.2) estimates for the SWO structure. The results show that scenario 4 using the gravity foundation and SPS platform is optimal, considering the above criteria.

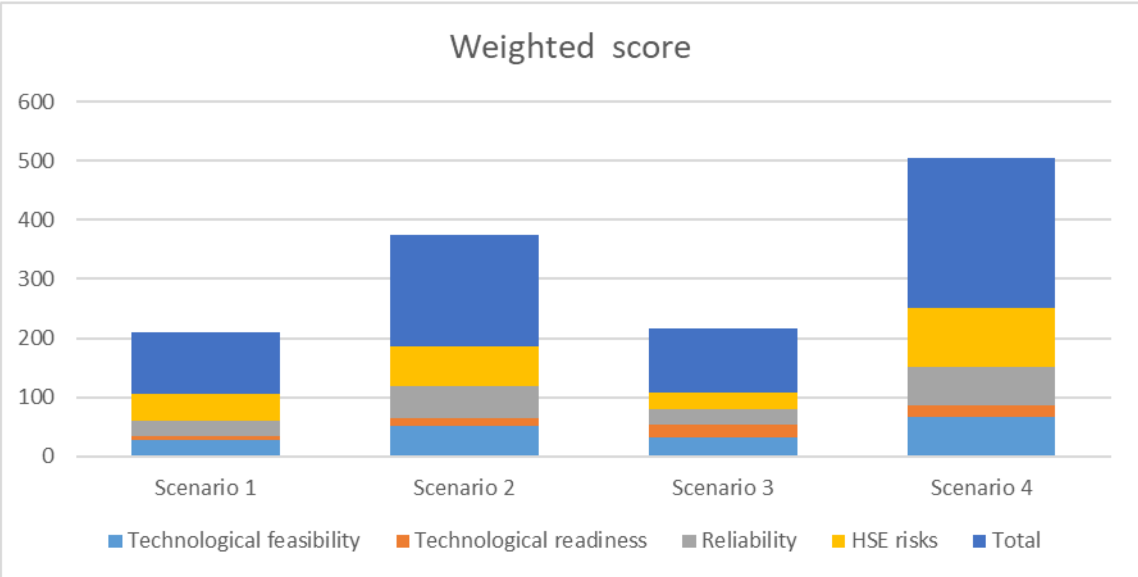

Figure 4.2 Weighted score histogram based on multi-criteria pairwise analysis of scenarios for the SWO structure

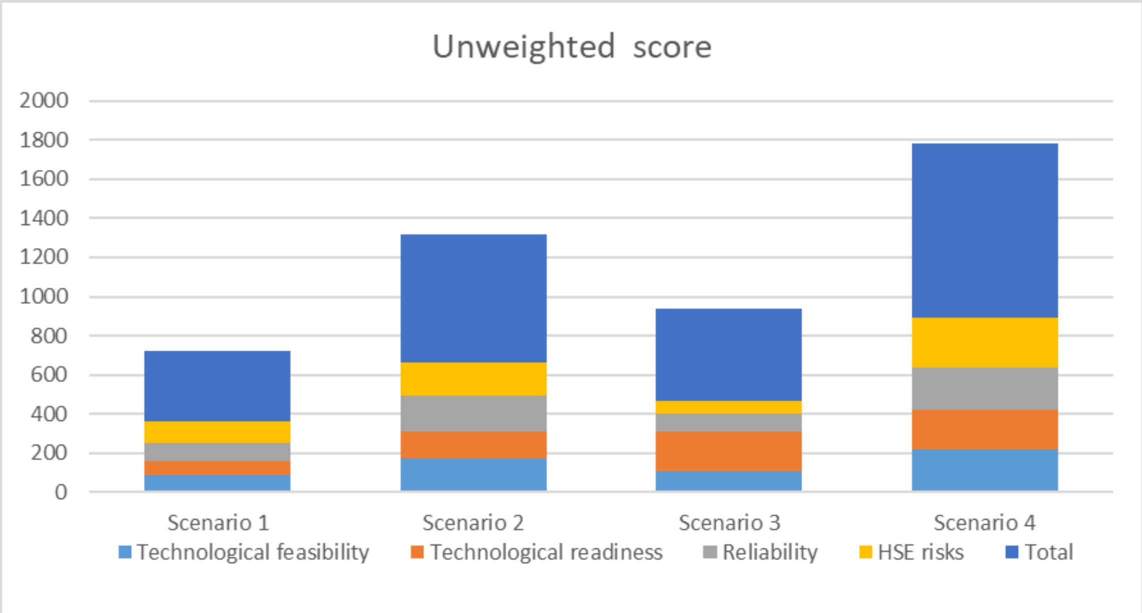

Figure 4.3 Unweighted score histogram based on multi-criteria pair analysis of scenarios for the SWO structure

Next, we will consider a similar analysis for the NEO structure. Again, the main feature is a depth of about 300 m and a distance from the NZA of about 160 km.

According to the criterion of technological feasibility for the NEO lead structure, scenarios 1 and 3 are classified (Table 4.16).

Table 4.16 Pair-wise scenario analysis for the NEO structure by technological feasibility

Technological feasibility	**Scenario 1**	**Scenario 2**	**Scenario 3**	**Scenario 4**
Scenario 1		50	50	0
Scenario 2	30		50	0
Scenario 3	30	30		0
Scenario 4	70	30	100	
Number of points	130	110	200	0
Weighted number of points	39	33	60	0

According to the criterion of technological readiness for the NEO lead structure, scenarios 1 and 3 are classified (Table 4.17).

Table 4.17 Pair-wise scenario analysis for the NEO structure by technological readiness

Technological readiness	**Scenario 1**	**Scenario 2**	**Scenario 3**	**Scenario 4**
Scenario 1		70	80	0
Scenario 2	30		70	0
Scenario 3	30	30		0
Scenario 4	10	30	50	
Number of points	70	130	200	0

Weighted number of points	7	13	20	0

According to the criterion of technological readiness for the NEO lead structure, scenarios 2 and 3 are leading (Table 4.18).

Table 4.18 Pair-wise scenario analysis for the NEO structure by health, safety, and environmental management risks

Health, safety and environmental management risks	**Scenario 1**	**Scenario 2**	**Scenario 3**	**Scenario 4**
Scenario 1		70	30	30
Scenario 2	30		30	30
Scenario 3	70	70		30
Scenario 4	10	30	10	
Number of points	110	170	70	90
Weighted score	44	68	28	36

According to the reliability criterion for the NEO, scenarios 2 and 4 are (Table 4.19).

Table 4.19 Pair-wise scenario analysis for the NEO structure by reliability

Reliability	**Scenario 1**	**Scenario 2**	**Scenario 3**	**Scenario 4**
Scenario 1		70	50	70
Scenario 2	30		10	70
Scenario 3	50	80		70
Scenario 4	10	30	30	
Number of points	90	180	90	210
Weighted number of points	27	54	27	63

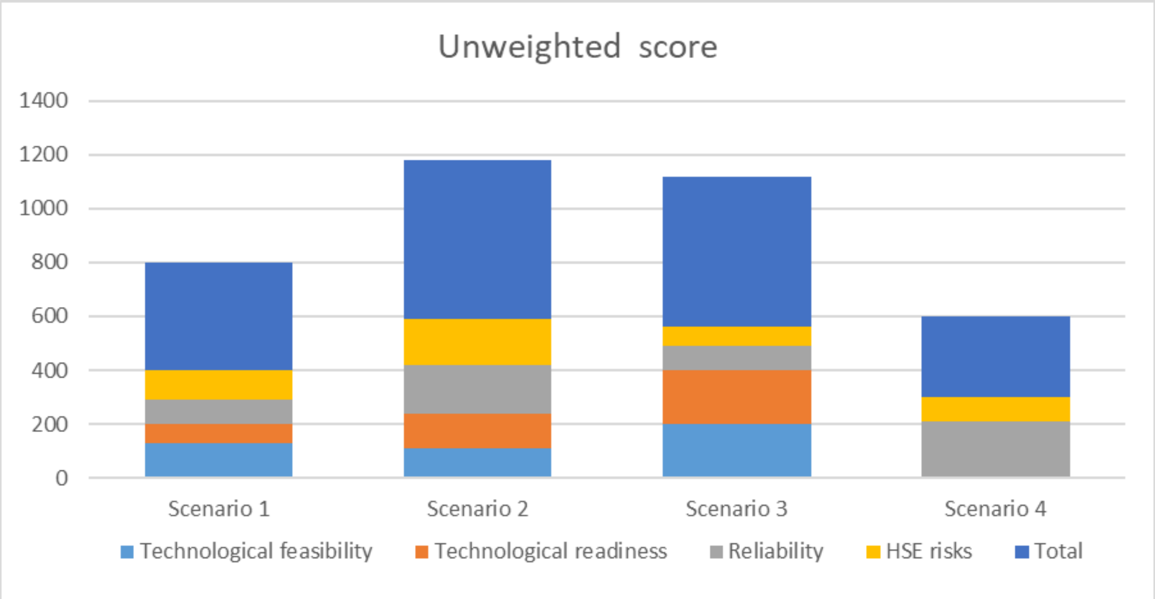

Figure 4.4 Histogram of the unweighted score based on the results of multi-criteria pair analysis of scenarios for the NEO structure

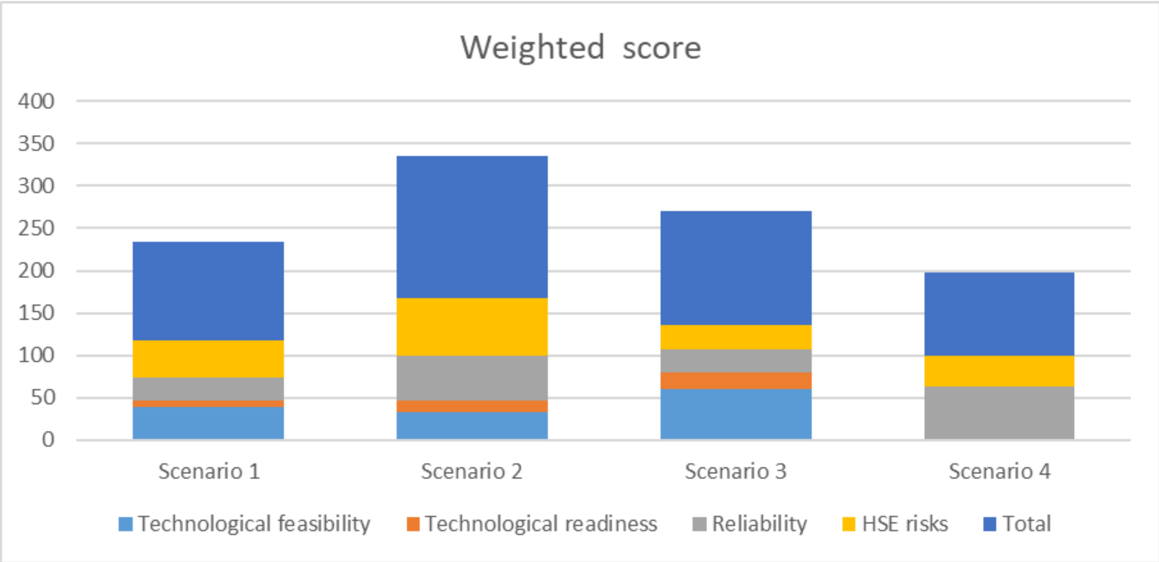

Figure 4.5 Weighted score histogram based on the results of multi-criteria pair analysis of scenarios for the NEO structure

4.1.7. Conclusions on the section and selection of scenarios

Based on the analysis results, it is proposed to choose scenario 4 as optimal for the SWO structure and scenario 2 as optimal for the NEO structure.

Next, you need to solve the problem of describing the issues associated with implementation, namely:

- Organization of logistics and storage systems
- Flow assurance
- Ice situation management both at the drilling stage and at the field operation stage
- Drillingof long-term and production wells
- Downhole operations

Based on the approaches to solving the above problems, estimating the economic indicators for the two scenarios selected at the first stage is proposed.

4.2. Organization of logistics and storage systems

4.2.1. Logistics

The Haiysovsky license area (HLA) is located in a remote area, approximately 1000-1100 km from Murmansk (Figure 4.6):

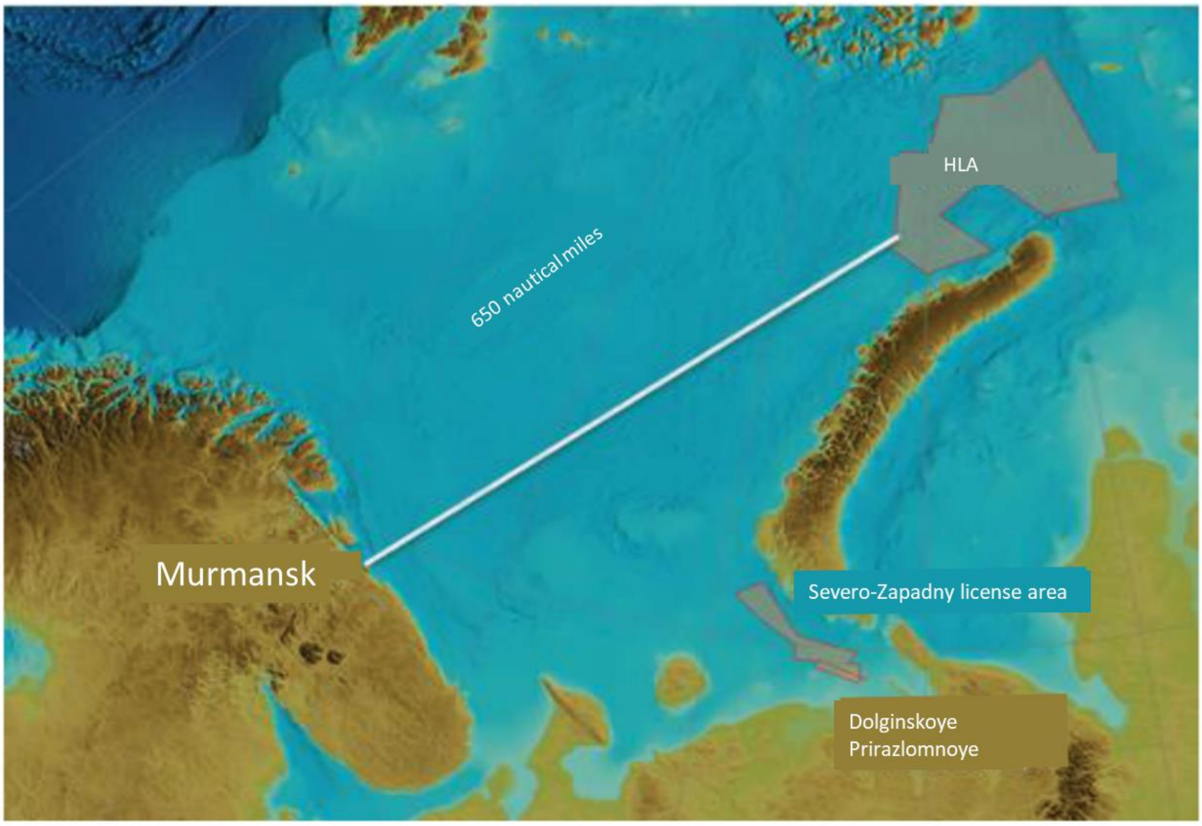

Figure 4.6 Illustration of the approximate distance from the port of Murmansk to the HLA [1]

The purpose of using an intermediate supply base is to reduce the length of routes of ice-class supply vessels serving oil and gas field development facilities in the remote Heisovsky license area, thus increasing the efficiency of supply. Currently, no oil and gas fields are being developed near HLA, and the nearest ice-free port is located in Murmansk, where it is proposed to place the main Supply base for servicing HLA facilities.

Two options should be considered for an intermediate logistics base between the main logistics base in the Murmansk Region and the development facilities at HLA:

- Platform or onshore base in the coastal zone for drilling and auxiliary materials required for drilling and exploitation of deposits in HLA (Figure 4.6)
- A floating storage facility that operates in open water off the coast of the Novaya Zemlya Archipelago or the open sea.

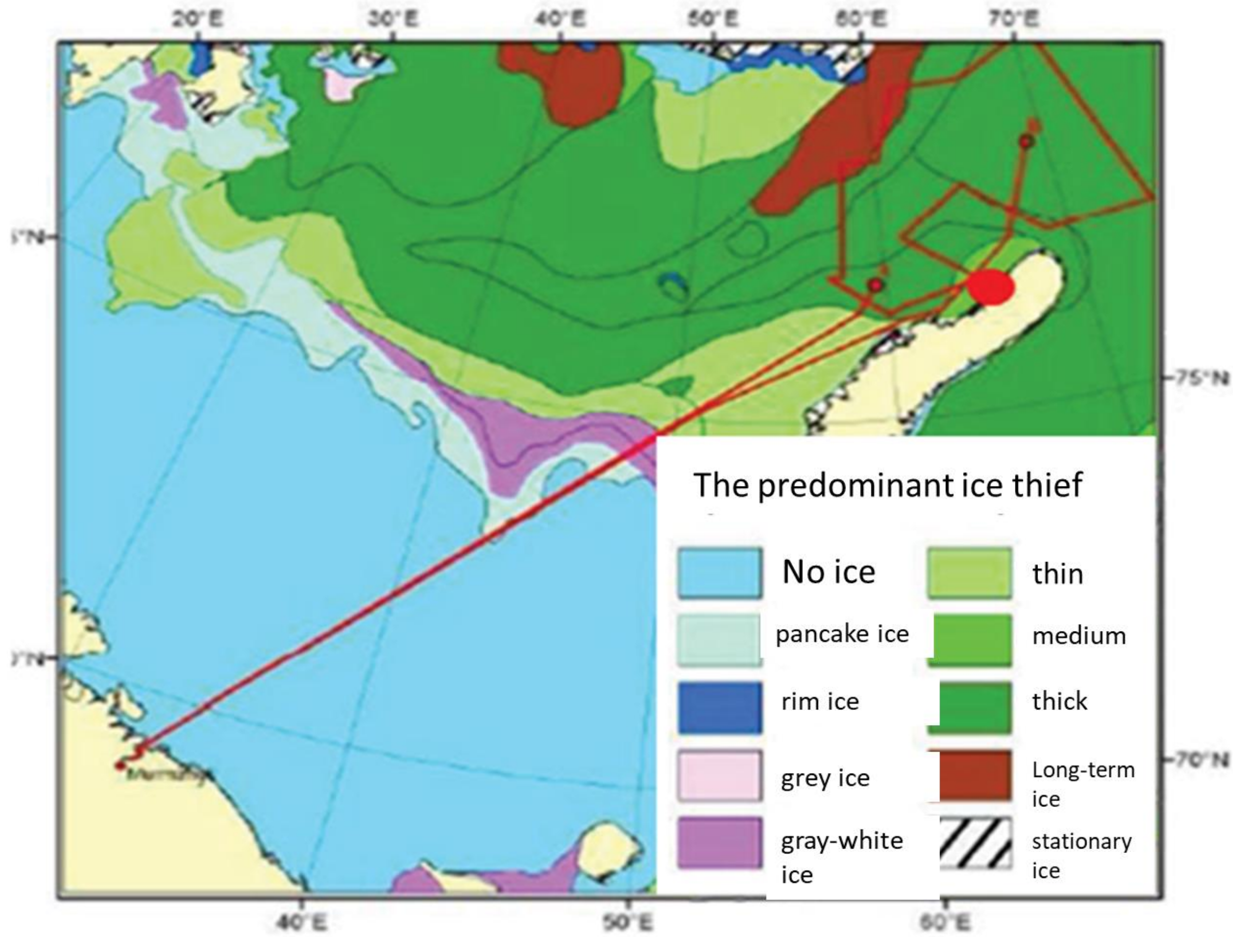

Figure 4.6 Location of the proposed coastal gravity supply/treatment and shipment platform off the coast of NZA [1]

It is proposed to carry out personnel logistics via Sabetta Airport and an intermediate platform installed in the Kara Sea (Figure 4.7).

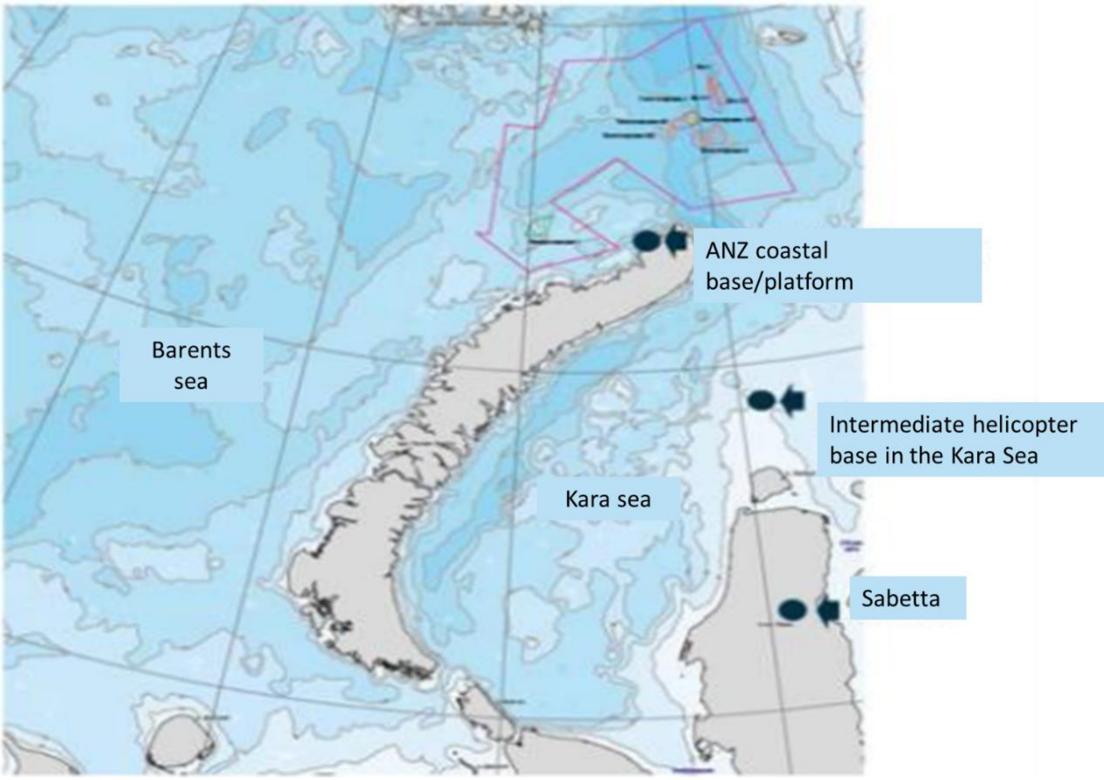

Figure 4.7 Preferred logistics points for personnel transportation [1]

4.3.Flow assurance

Flow stability requirements vary from scenario to scenario; therefore, the basic principles of flow stability must be adapted to different scenarios. The purpose of the basic flow stability principles and related recommended practices is to ensure that the production system can operate in all operational scenarios, as follows:

- in normal operation mode,
- in operation mode with low production volume,
- for scheduled and unscheduled shutdowns and subsequent restarts.

The reservoir information provided for this study is based on two-dimensional seismic maps. No exploration wells have been drilled, so information on the fluid composition is not available and is not included in the study. In this section of the report, it is suggested to assume such classic problems as hydrate formation, paraffin deposition, management of excess gas condensate liquids, and the formation of salt deposits.

This section of the paper suggests the most traditional (generally accepted) basic principles for Flow assurance for each scenario.

4.3.1. Flow assurance of scenario 4 on the SWO structure

In this development scenario, the flow stability needs are related to the SPS and the delivery of reservoir fluid to the PDQ platform. The most common solution for Flow assurance in SPS installations is to isolate the field pipeline to ensure that the fluid flows to the upper structure of the platform at a temperature that exceeds the paraffin deposition temperature for all appropriate options. In most cases, this also ensures that the fluid does not reach the hydrate formation temperature range. A hydrate formation inhibitor (MEG or methanol) is pre-pumped into the field pipeline during a planned shutdown. All elements of the field pipeline from the subsea manifold to the upper structure of the platform must be isolated. Uninsulated parts of the SPS and pumping stations are displaced by methanol or MEG in all shutdown scenarios.

As an alternative to insulated field pipelines, electric-heated field pipelines can be used to ensure flow stability. Using field pipelines with electric heating to ensure flow stability reduces the forced break in production due to pressure relief infield pipelines, restarting the SPS, and reducing gas discharge to the flare during pressure relief.

Gas lift gas is drained at the top of the platform structure; and therefore, gas lift field pipelines do not require any additional solutions to ensure flow stability.

4.3.1. Flow assurance of scenario 2 on the NEO structure

This development scenario includes an SPS with the supply of reservoir fluid to an onshore treatment facility located 160 km from the offshore field. Reservoir fluid is proposed to be pumped through twin pipelines with 160 km to the coastal treatment plant. The distance of well production transportation of 160 km creates significant problems with Flow assurance. There are no analogues of multiphase oil transportation over 160 km. Currently, the longest field pipeline with electric heating, which is in operation, has about 43 km. For pumping multiphase reservoir fluid through a 160 km double pipeline, the only reliable method to ensure flow stability is to heat the pipeline. However, the technology for heating the 160 km pipeline has not yet been developed. However, according to the estimates of [1], it is proposed to consider that a 160 km pipeline with electric heating is a possible/achievable option, subject to certification.

It is recommended to use field pipelines with electric heating and introduce MEG or methanol in all uninsulated parts of the SPS for flow assurance.

Gas for gas lift and injection into the reservoir from the coastal installation are dewatered and supplied to the field for use in an uninsulated pipeline.

4.4. Ice management

Ice management is protecting the construction of development sites, extending the production period, and, in some cases, reducing initial investment in oil exploration and production, which is an important part of solutions for HLA development scenarios. When softening the design criteria for exploration and production platforms in terms of the need to withstand local ice loads, less expensive and, at the same time, fully operational types of platforms can be selected.

The ice situation management system based on observation, monitoring, and measures to reduce and prevent ice impacts makes it possible to implement the approach mentioned above to field development.

4.4.1. Long-distance ice management

The objectives of long-range ice management are for icebreakers to break down floating ice fields to smaller ice floes and collect data on ice properties and up-to-date information about the ice cover. The capacity of an icebreaker used for long-range ice management should be sufficient to operate in conditions of heavy solid ice, including long-term ice fields.

Based on the icebreaker's thickness of 1.5-2 m, an icebreaker of at least Icebreaker 7 class is required to solve this problem Icebreaker 7. According to source [1], the icebreaker's capacity for operation in such conditions should be about 38 MW.

4.4.2. Managing the ice situation over short distances

The objectives of short-range ice management are to provide the necessary conditions for ice conditions near and around drilling vessels, shuttle tankers, floating and stationary platforms operating on HLA. This is achieved by crushing floating ice fields to smaller ice floes before they reach the worksite.

According to the source estimates [1], two Arctic icebreakers can control the ice situation over short distances. A typical icebreaker model can be an icebreaker of at least Icebreaker 7 class with traction power of up to 22 MW and the following dimensions.

In addition to crushing approaching floating ice fields to smaller ice floes, these two icebreakers can be ready and serve as a " haven" in an emergency evacuation of personnel in sea ice conditions, carrying out anchor winding when moving the MODU, and perform auxiliary functions when loading tankers.

In the field development concepts with a caisson-type gravity platform in the coastal zone, one typical task is to remove ice accumulations near these structures. Under dynamic ice cover conditions, drifting ice can accumulate around caisson-type gravity platforms, making it difficult to work around the platform, especially to supply platforms and ship crude oil.

In addition to the three ice management vessels, offshore and coastal operations in the HLA area will require at least one permanent standby vessel and two platform/anchorage supply vessels — all vessels must be of the IA Super Arctic ice class. As necessary, these vessels can participate in ice management. For example, below the iceberg towing vessel Loke Viking is shown (Figure 4.8).

Figure 4.8 Iceberg towing by Loke Viking [20]

For development scenarios with a caisson-type gravity platform in the coastal zone, two backup vessels of constant readiness will be required: one for servicing the needs of the MODU and the second for the coastal platform. Here is an example of an ice-class supply vessel (Figure 4.9). As necessary, these vessels can participate in ice management in the HLA area.

Figure 4.9 Example of an ice-class supply vessel Barge Viking [21]

Managing the ice situation allows exploration and production to be carried out at a lower cost. Each element of the ice management system is well known, but the possibility of moving away from the point, which allows you to secure the platform by disconnecting it from the risers and mooring system, is not yet a well-developed solution for all production strategies. Therefore, it is further recommended to continue research and development of methods for disconnecting platforms that reduce the cost and increase the overall efficiency of disconnecting and reconnecting development facilities.

In addition, the project will require at least two Arc7-class shuttle tankers. An example of such a vessel is a domestic tanker, "Michael Lazarev" (Figure 4.7).

Figure 4.7 Arc 7 class shuttle tanker "Mikhail Lazarev" [27]

4.5. Approach to downhole operations

Hydrocarbon production in the North-Eastern HLA cluster is carried out using subsea wells due to the prevailing water depths. In the Southwestern Cluster, the use of both subsea wells and wells drilled from the platform is considered. Downhole operations provide the ability to safely access a subsea well while monitoring the well to perform a number of different tasks that are not related to drilling.

As a rule, even the simplest repairs and downhole operations in the subsea well are performed using full-size mobile drilling rigs and vessels for downhole operations. Today, the number of subsea wells worldwide is about 5,000, and their number is growing. In addition, the age of subsea wells is also increasing, which leads to the need to increase the number of light downhole operations performed to maintain wells and increase oil recovery.

4.5.1. Types of downhole operations

During the life of the well, a number of planned or unscheduled downhole operations may be required. These activities may include diagnostics, inflow intensification, examination, operations with equipment and repair of mechanical damage.

The following downhole operations can be performed from the ship:

- Elimination of mechanical damage in the well
- Elimination of mechanical damage to Christmas tree fittings
- Providing flow (for example, formation of salt, paraffin deposits, hydrate formation)
- Reservoir monitoring (for example, logging during operation)
- Works in the collector (for example, interval isolation, perforation)
- Well monitoring (for example, geological and technical measures)

When production wells require geological and technical measures to maintain, restore or intensify production, this is classified as a major well repair.

For major operations of wells can be used:

- Logging cable / slickline / braided rope/ electrical cable
- Coiled Tubing
- Pressure drop (pressure well repair)

4.5.2. Riserless operations in the well

The most frequently performed repairs are wire operations on the cable or the logging cable. Wire operations refer to the technology of lowering equipment or measuring devices into a well on a cable to perform downhole operations and evaluate reservoir properties and reserves.

Logging cable - an electrical cable that is lowered into the well for lowering and extracting tools to/from the face.

Slickline is a thin cable used for lowering tools and transmitting data about the state of the wellbore. This wire is used to install and remove downhole equipment such as plugs, gauges, valves and can also be used to adjust valves and couplings in the wellbore and repair tubing. Braided wire rope is usually stronger than IPS wire.

The electric cable is a braided channel with an electric cable for transmitting data from the wellbore and is used both for downhole operations and for reservoir assessment.

Wire operations refer to non-riser operations in the well, so the need for pumping equipment can only be considered for individual operations if required. Wire operations are typically performed using a lubricator for subsea downhole operations (SIL) and vessels for riser-free well operations (RLWI). Riser-free well operations (RLWI) are a cost-effective method for performing many subsea well operations that can be performed without using a riser from the water surface [26]. The technology is based on good maintenance using a cable, where the cable is routed through a system of subsea connectors into the subsea well.

4.5.3. Downhole operations using the riser

When the use of risers is required for major repairs to subsea wells, downhole operations in subsea wells cannot be performed using RLWI vessels. Therefore, as an alternative to full-size mobile drilling rigs, the use of special larger downhole vessels specially equipped to use the IRS system is required.

Downhole operations that require the use of risers:

- Coiled Tubing
- Pressure descent
- Major overhaul

To lower coiled tubing into a subsea well, a riser is required that is lowered from the ship on the water's surface. This process necessitates the use of larger vessels with a larger deck area and improved sea surge compensation characteristics, hence higher daily rates / total costs. Typical major repairs that require the use of a riser are listed below (Figure 4.8).

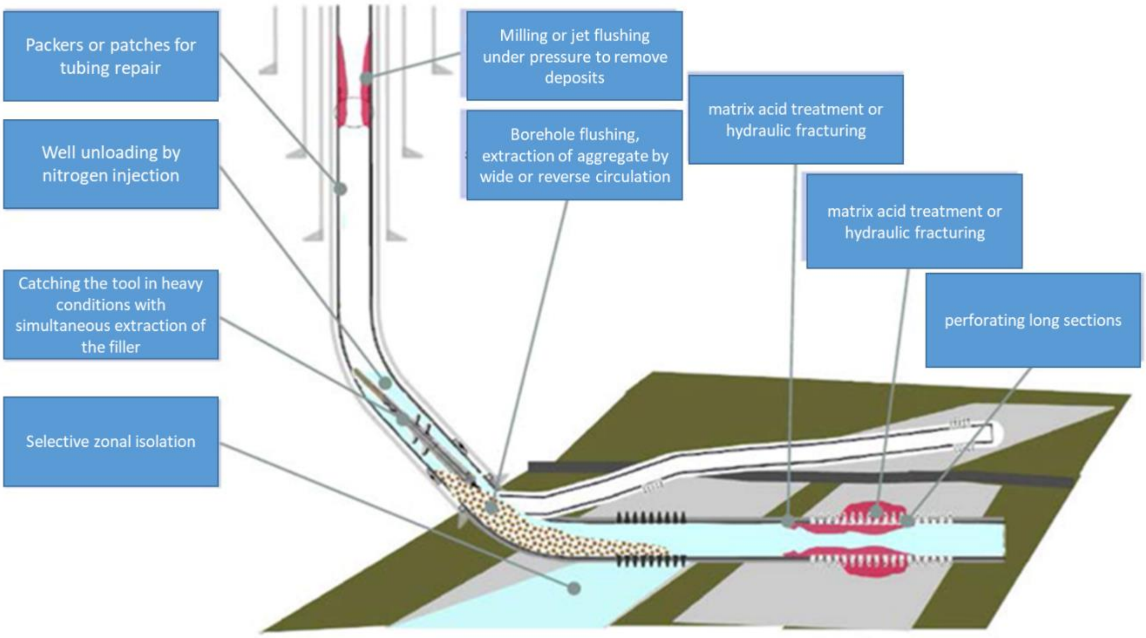

Figure 4.8 Major well overhaul works [1]

When a major overhaul is required, it is usually considered to be carried out using the MODU. Reducing costs is the main incentive for performing downhole repairs using single-hulled vessels rather than performing the same work with full-fledged drilling rigs.

It is recommended to build a special ice-class vessel with a dynamic positioning system for downhole operations, equipped with a riser system, specifically for the HLA, which could also inspect and maintain subsea installations.

4.6.Economic assessment and selection of the currently optimal scenario

In order to better assess the prospects for the development of SWO and NEO structures in the current macroeconomic environment, it is necessary to conduct an integrated economic assessment. As mentioned earlier, the development of the region in which HLA is located is projected to be in an active phase over the next 15 years, according to [14]. It is logical that detailed calculations at this stage do not carry a semantic load due to a large number of uncertainties, both macroeconomic and cost.

4.6.1. Assumptions for scenarios economic assessment

An assumption about the forecast production profile and the rate of decline in production after year 18 was made based on information about analogue structures from the source [1] (Table 4.20) and the estimated production profile (Figure 4.9). Since the tax treatment of Arctic projects differs from project to project, let's assume that the MET, similar to Prirazlomnaya

[28], is 0%, and the export duty is about 11 per ton. At the same time, based on the analysis of the source [29], we assume an income tax of 25%. The volume of capital investments is estimated based on the total cost of the Hebron project at $ 14 billion, taking into account the accumulated ruble inflation since 2013 [30]. Then, this cost is adjusted downwards, taking into account the Russian Federation's policy of localizing the production of technological equipment and, as a result, reducing the cost of purchased equipment and construction.

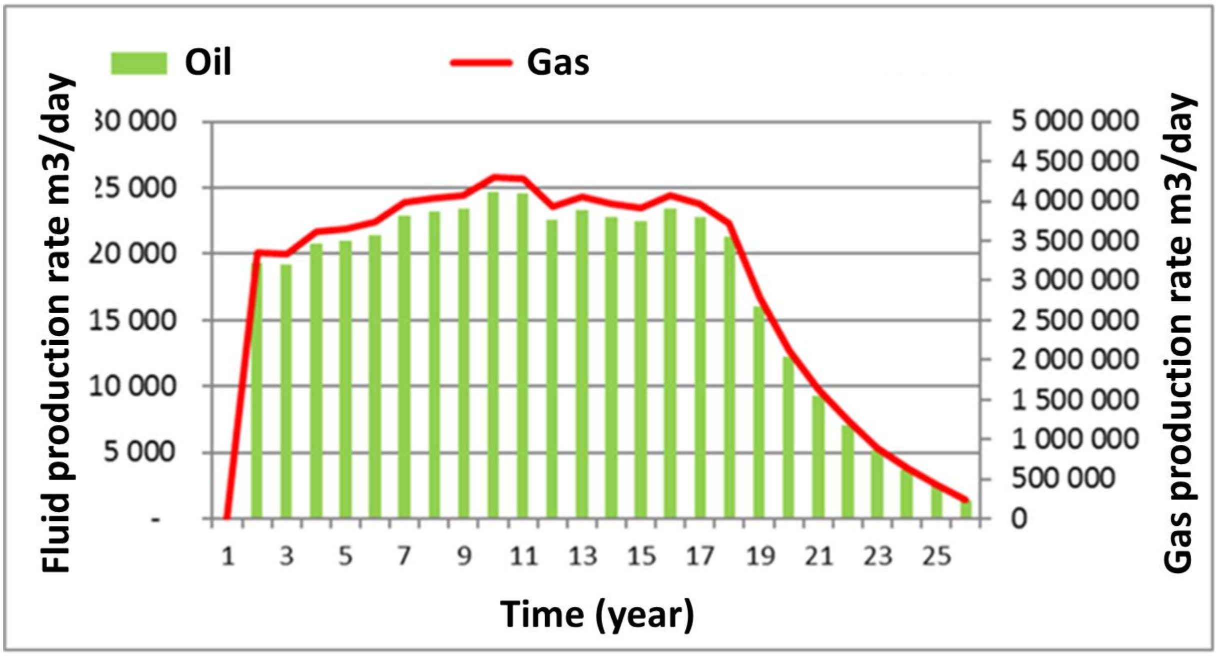

Figure 4.9 Estimation of the estimated production profile by SWO and NEO structures

Table 4.20 Evaluation assumptions for the SWO structure under scenario 4

Indicator	Assumptions	SI
Annual production	7500000	tons / year
The project implementation period	25	years
After 18 years, the volume of production decreases by	15%	per year
Investment volume (CAPEX):	22 000 000 000,0	$
The oil price	70,0	is $ 70.0/bar.
Operating expenses	80	$ 80 / ton
Depreciation rate	20%	of total investment
The credit period	10	years
The term of credit payments	10	years
Amount of borrowed funds	20%	of total investment
Interest rate	10%	
Property tax	0,0%	
Export duty	11	of $11 / ton
MET	0%	

Income tax	25%	
Discount rate	12%	

The content of assumptions for implementing scenario 2 on the NEO structure generally coincides with the assumptions described above, except capital investments and operating expenses (Table 4.21). Capital expenditures are estimated to be higher to consider the costs associated with finalizing the previously discussed technologies to bring them to TRL 5. Estimates of the cost of these works were selected based on information from the source [1]. In addition, operating expenses were increased by 20$ per ton, taking into account the complexity of maintaining SPS systems in the conditions of constant ice cover on the NEO structure. Downhole operations will require the use of specialized ice-class vessels PC4 or PC2.

Table 4.21 Evaluation assumptions for the NEO structure under scenario 2

Indicator	**Assumptions**	**EI**
Annual production	7500000	tons / year
The project implementation period	25	years
After 18 years, the volume of production decreases by	15%	per year
Investment volume (CAPEX):	27 000 000 000,0	$
The oil price	70,0	is $ 70.0/bar.
Operating expenses	100	$ 100 / ton
Depreciation rate	20%	of total investment
The credit period	10	years
The term of credit payments	10	years
Amount of borrowed funds	20%	of total investment
Interest rate	10%	
Property tax	0,0%	
Export duty	11	of $11 / ton
MET	0%	
Income tax	25%	
Discount rate	12%	

4.6.2. Evaluation results

Calculations of economic indicators were carried out using the method from the source [31]. Since the economic assessment methodology of investment projects is generally accepted and understandable, let us not go too deep into its details and proceed immediately to consider its results (Table 4.22, Table 4.23 and Figure 4.10, Figure 4.11).

Based on the evaluation of the SWO development project, it is possible to conclude the attractiveness of such an investment in the first approximation. However, given the volatility of oil prices in the modern world, the break-even threshold is too high relative to oil prices at the moment for unambiguous conclusions. In other respects, the values of IRR, PI, BEP and DPB allow us to look with optimism at the scenario using an offshore gravity platform for developing the SWO structure.

Table 4.22 Results of evaluation of financial indicators of the SWO development project under scenario 4

Estimated indicator	Value
NPV, $	2830346056.31
IRR	15.0%
DPB	9.1
PI	1.128
BEP	62.2

The results of the project evaluation under scenario 2 on the NEO structure are not so optimistic. The project does not show satisfactory values for any of the financial indicators considered. The main reason lies in the current market conditions, significant capital investments and the costs required for finalizing technologies. In addition, given the complexity of the project in terms of technological readiness, the costs taken into account for their development may be too optimistic.

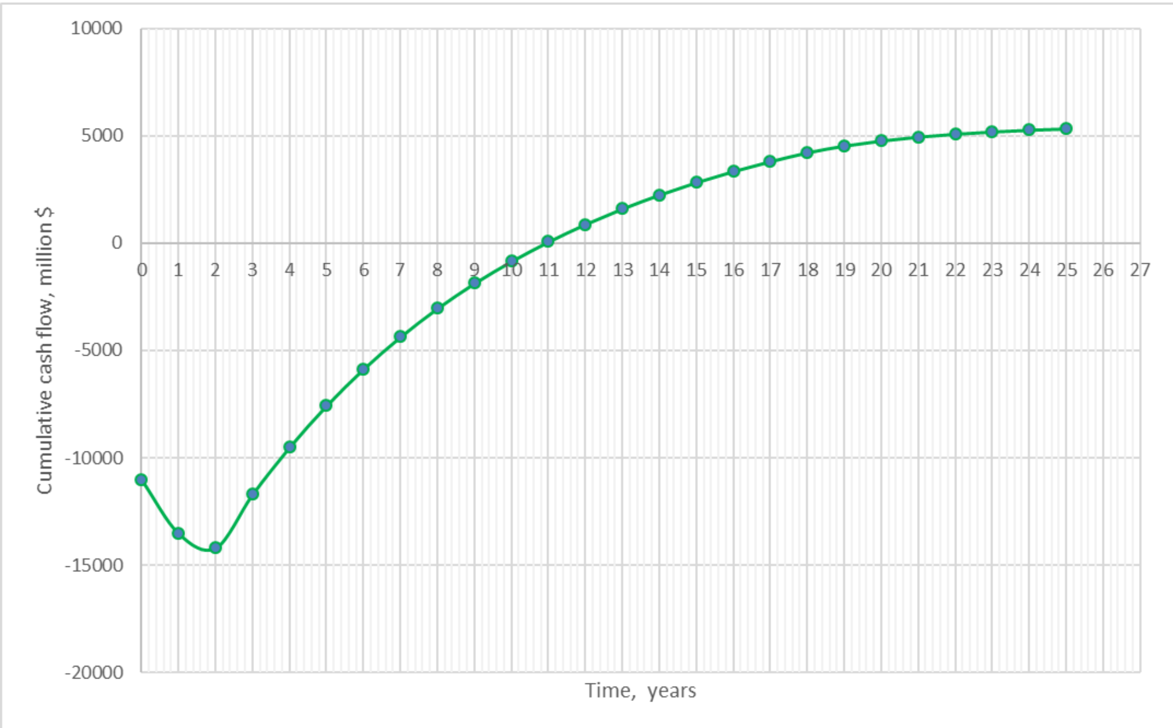

Figure 4.10 Chart of the cumulative cash flow of the SWO development project under scenario 4

Table 4.23 Results of the assessment of the financial indicators of the project for the development of NEO under scenario 2

Estimated indicator	**Value**
NPV, $	-2251178580.55
IRR	10.0%
DPB	23
PI	0.916
BEP	76.2

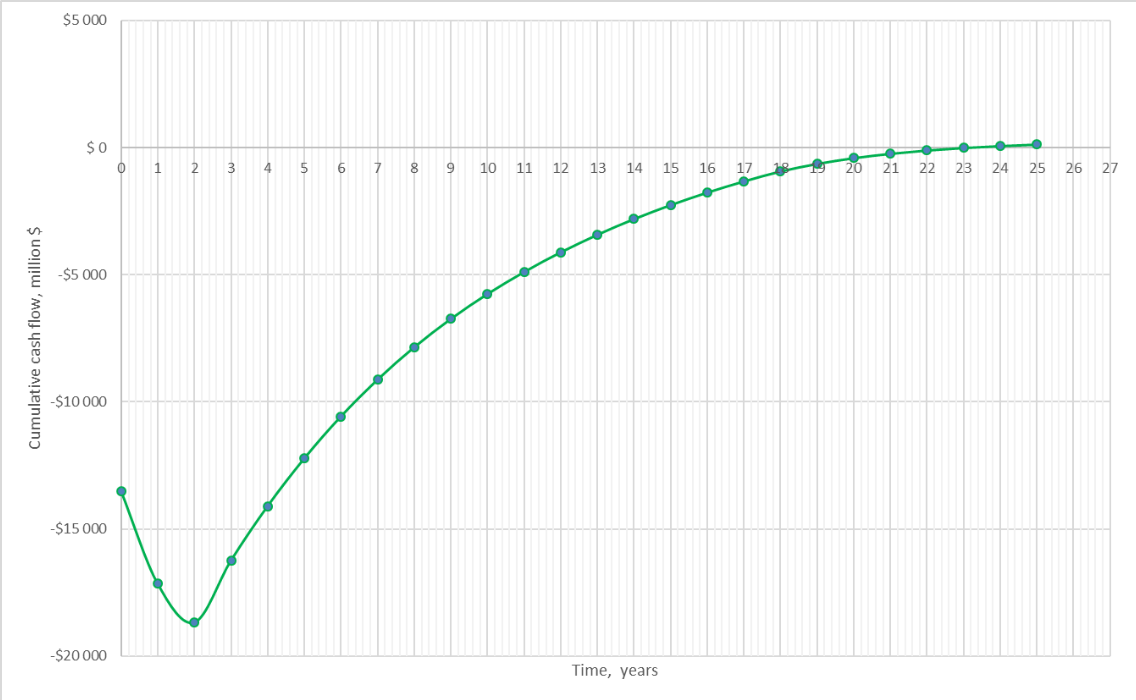

Figure 4.11 Chart of the cumulative cash flow of the NEO development project under scenario 2

Based on the results of an integrated economic assessment, it can be concluded that the project for developing the SWO structure under scenario 4 is most attractive. However, it is worth noting that the results of forecast estimates of projects over such a long horizon are rather conditional. As the practice of the oil market over the past few decades shows, the attractiveness of these projects may sooner or later change both dramatically due to the volatility of oil prices and gradually due to the reduction in the cost of the required technological solutions as they naturally develop.

5. Drilling of exploration and production wells at HLA

5.1.General assumptions and recommendations about drilling at HLA

And the Arctic zone contains huge oil and gas reserves, but the conditions in which they are located are among the most unfavourable in the world. These difficulties raise the cost of exploration and production in the Arctic, as drilling and operating in these areas requires the use of special equipment and procedures. The key factor in the drilling part of field exploration and exploitation is the cost of the finished well or the total cost of drilling and completing production wells. One of the determining factors in the total cost of finished wells in the Arctic is the length of the drilling season and the possibility of performing year-round drilling. Thus, reducing the cost of a finished well by extending the drilling season to year-round is one of the key factors ensuring commercial profitability of exploration and production on the Arctic shelf.

The problems of developing oil and gas fields in the HLA are mainly related to the need to drill a large number of wells in the prevailing unfavourable climatic conditions of the region with a continuously drifting dynamic ice cover and solid ice with the inclusion of icebergs in the winter period. Open water planning is only possible in the Southwestern Cluster, with a season duration of about 200 days. In the North-Eastern cluster, it is necessary to consider permanent ice cover for two of the twelve years for which information is available; the open water season was completely absent. The duration of the open water season in the northeastern cluster varies from 5 to 144 days.

To illustrate the required drilling time and difficulties, the design of a typical production well with a maximum deviation of 30 degrees to a reservoir depth of 2750 m and a horizontal section of 2000 m is shown below (Figure 5.1).

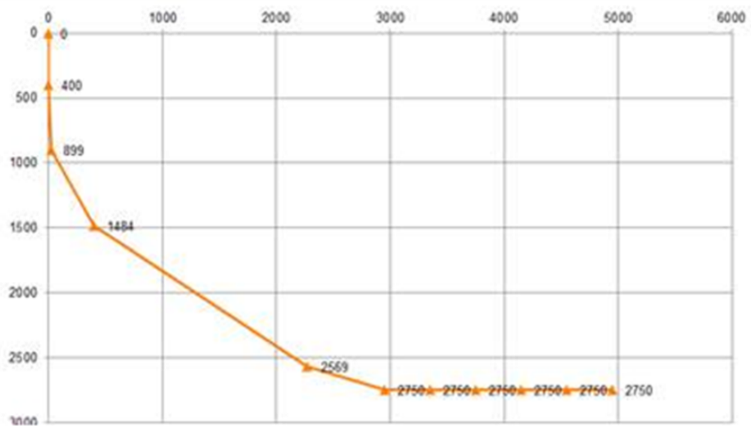

Figure 5.1 Profile of a typical well [1]

The total length of such a typical well is about 5200 m, including a horizontal section of 2000 m. According to statistics, the average drilling speed on the Norwegian Continental Shelf (NCS) is about 80-100 m per day, depending on the MODU used, rock properties, and reservoir conditions. This study proposes to take a drilling speed of 80 m per day, which gives 65 days to drill one well, plus from 7 to 14 days will be needed to complete the work on its completion. It is also worth considering full-length operations, which can significantly reduce the drilling speed with only one drilling machine. Currently, the Prirazlomnaya borehole is drilled from 2 to 3 wells per year [1], but the rate may increase in the long run due to modern drilling rigs and offshore drilling technologies. Thus, let us assume that the maximum number of typical wells that can be drilled by one MODU during the year-round operation of HLA is 4 wells.

For seasonal drilling (open water and intrusion of ice), the average number of wells that can be drilled using existing MODU and support from the management system of the ice during periods of ice cover formation in the South-West of HLA - 3 wells, and in the North-Eastern cluster - 1,5 well (using one MODU). However, there is significant variability in ice conditions in operations from season to the season compared to the average data given in the initial data for HLA, so the indicated number of wells is a fairly optimistic indicator. In addition, it should be noted that there are a large number of uncertainties in the available source data, especially for the North-eastern cluster.

Due to the predominance of unfavorable ice conditions in a region with continuously drifting dynamic ice cover and cohesive ice fields with icebergs included, the design of a floating MODU would require a larger number of mooring lines and increased strengthening of hulls to withstand ice load. In this regard, for economic and practical reasons, MODU designs for drilling in Arctic waters are usually designed with the ability to disconnect quickly. When using one MODU and year-round drilling, the total duration of drilling operations under the most optimistic scenario for the development of HLA oil fields will be more than 15 years. With such a large estimated (projected) number of wells, a year-round drilling mode or the use of several MODUs for drilling wells is considered for development.

5.1.1. Drilling vessel, capable of providing year-round drilling on HLA

Based on the above-described HLA operating conditions, year-round drilling in the North-Eastern cluster will require a polar class PC3 or PC2 MODU, and in the South-Western cluster – PC4 or PC3 with mandatory icebreaker class 8 support or higher to manage the ice situation on the HLA.

Currently, there is no MODU capable of conducting year-round drilling in HLA conditions. Furthermore, according to the study [16], in ice conditions comparable to HLA, the use of semi-submersible and self-lifting units is impractical at depths exceeding 150 meters. However, there are projects of drilling vessels that, according to the study, may be able to provide year-round drilling in HLA conditions.

NanuQ Project (Figure 5.2) is a drilling vessel capable of operating in multi-year ice conditions up to 4 m thick and has an ice-class of PC2. The drilling vessel is equipped with a dynamic positioning system, including two backup systems of the same power. In addition, the vessel can leave the drilling site in the event of approaching hummocks or icebergs thanks to the sixteen-point turret mooring system. Another advantage of this project is the ability of the vessel to carry the number of inventory and supplies sufficient to drill 2 wells in a row.

Figure 5.2 Project of a vessel for year-round drilling in the Arctic NanuQ [16]

5.1.2. Restrictions and recommendations for sinking the upper interval

Following the current Russian legislation (regulatory legal acts), the following restrictions apply to HLA [23]:

- Dumping of waste overboard is prohibited

- Drilling mud must be transported ashore for processing and safe storage or injected into the formation

As an alternative to the traditional method, riser-free drilling can drill the upper well interval on the HLA to avoid the "injection and absorption". Traditional riser drilling for drilling the upper well interval is impractical without installing an anti-blowout preventer (BOP). Water separation columns for drilling were used until 1985, but now this is less often practiced for safety reasons. Drilling of the upper well interval and recirculation of drilling mud to the drilling rig can be performed using a Low water column return system (LRRS) [25] or with a riser-free sludge removal system (RMR) [26].

RMR technology is used for open-face sites (without installing BOP), which allows the circulation of fluid and sludge in a closed system. For example, a subsea pump is used to circulate drilling mud and sludge to the rig for cleaning/recycling instead of distributing it on the seafloor [26].

5.1.3. Drilling in scenario 4 on the SWO structure

According to this concept and arrangement from the platform, it is proposed to assume that the number of drilling slots will be equal to the number of slots on the Hebron platform [23]. Thus, the platform will allow drilling up to 52 production and injection wells (in our case, excluding process wells). According to the estimate [1], the projected number of production and injection wells in the SWO structure is 51 and 26, respectively. In addition to production and water injection wells, several additional wells are needed to re-inject excess gas into the formation and wells for wastewater/drilling mud disposal. Assume that there are 2 slurry wells, 1 gas well, and 2 reserve well slots.

There is no information about the relative location of wells yet, so let's assume that 52 wellsы (including slurry and reserve wells) are located at the same time.) The remaining 30 wells will be drilled from the platform, and the remaining 30 wells will be operated using the SPS and will be connected to the gravity platform.

Some of the subsea wells in this development scenario are natural candidates for advanced drilling. Therefore, they can also be drilled in advance. Therefore, 8 production wells and 4 injection wells are proposed for advanced drilling. When using 2 installations of the polar class PC2 MODU for 2-2. 5 years, or when using 2 installations of the polar class PC4 MODU for 4 years during open water periods (including periods of ice cover formation). Thus, at the start of production, it is possible to launch 8 production wells at once, reducing the waiting time for full capacity utilization and increasing the project's economic efficiency.

Further, it is suggested to drill 2-3 wells per year using a platform drilling rig and 2-6 wells per year using two PC2 polar class MODUs. In addition, it should be taken into account that every year a month will be spent on the maintenance of drilling rigs. Considering the need to manage the platform's capacity utilization and the need for MODUs for work at other sites, it is further proposed to make point-by-point decisions on drilling using PC 2 class2 MODUs based on current conditions. The scenario with preliminary full drilling of the slots available on the platform or drilling the remaining wells during the open water period using a PC 4 class MODU will probably show the best efficiency PC4.

5.1.4. Drilling in scenario 2 on the NEO structure

According to [1], the number of production and injection wells in the NEO structure is 51 and 26, respectively. Thus, a total of 96 wells will need to be drilled. In addition, it is necessary to consider the presence of permanent ice cover since the duration of the open water season in the North-Eastern cluster varies from 5 to 144 days.

It should be clarified that in this scenario, slurry wells are not provided. Instead, the sludge will be stored in slurry containers and sent by supply ships to the mainland for disposal.

If we assume the simultaneous use of two PC2 -class MODUS2 with turret mooring, which drills 2-3 wells per "open water" season (taking into account its extension when using icebreakers), it will take more than 15 years to drill the entire pool of wells.

5.1.5. Load capacity calculation and rig class selection using Landmark software

The permissible hook loads and the load capacity of the rig are of primary importance when choosing a drilling rig. According to the specification from the source [16], the drilling rig class for the "SEA 15,000,000 ICE" modification provides for permissible bit loads of up to 1,500 thousand pounds or 679.5 tons. Therefore, it is necessary to assess the sufficiency of such a load capacity for drilling the proposed standard well.

This section proposes to review the results of the calculation carried out by the author in the Landmark software package during the production internship. For the calculation, we used an offshore well analogous input data to the previously presented standard well for HLA (Figure 5.1, Table 5.1).

Table 5.1 Well depth measurement characteristics based on

True vertical depth, m	2750
Well length, m	5200

The calculation used drill pipes and weighted drill pipes with the following parameters (Table 5.2).

Table 5.2 Characteristics of drill pipes used for calculation

Parameter	SDP 149.2	HWDP 139.7
Pipe outer diameter, mm	149.2	139.7
Wall thickness	9,169	28,575
Running weight, kg / m	40.18	88.81
Strength group	S-135	HW-105
Upset type	IEU	IEU
Connection	XT57	XT57 XT57 connection

The maximum loads on the hook were calculated using the bottom-up finite element method for drilling several sections, lowering casing strings and the production liner of the proposed well (Table 5.3).

Table 5.3 Table of data on sections and calculation results

Operation and section description	Type and density of drilling mud	Well length, m	Vertical depth, m	Maximum lifting weight, tons
Drilling of section 444.5 mm	Oil-based; 1.4 g / cm^3	3380	1850	150.84
Drilling of section 311.2 mm	Oil-based; 1.5 g/ cm^3	5071	2150	138.27
Drilling of section 219.1 mm	Oil-based; 1.05 g/cm^3	5071	2750	178.27
Descent Casing 339.7 mm	Oil-based; 1.4 g/ cm^3	5071	2650	265.78
Descent Casing 244.5,5 244.5 mm	Oil-based; 1.51.5 g/cm^3	5070	270 55	223.70

Production liner descent 168 mm	Oil-based; 1.05 g/cm^3	5200	2750	180.51

When the casing is lowered, the lifting weight is indicated. However, since we are lowering the casing, there is a caveat that the specified weight – is the lifting weight while reciprocating the string.

According to the calculation results, the maximum load is observed when the casing string with a diameter of 339.7 mm is lowered. According to the state standard [32], the maximum load on the hook should not exceed 60% of the maximum permissible load for the drilling rig. Therefore, based on the condition stated above, to obtain the minimum permissible load capacity of the MODU machine, it is necessary to divide the maximum result obtained by 0.6. Thus, the minimum permissible load capacity will be 443 tons.

According to the assessment results, the technical characteristics of the NanuQ vessel of the «SEA 15, 000 ICE» modification meets the minimum permissible requirements for carrying out work on the shelf of the Russian Arctic. However, it is worth noting that the profile of a typical well is currently based only on 2D seismic results. Clarification of geological data may lead to complication of the profile or trajectory of wells. In this case, it is necessary to provide an additional reserve of load capacity when making decisions on launching work on creating such a drilling vessel.

5.2.Resource and production support issues

Resource planning and support surveys are fundamental to the development of complex regions such as the Arctic shelf. It is important not only to assess and plan where the required vessels, installations and equipment can be manufactured but also to ensure their full employment in production during the entire possible service life. In this subsection, it is proposed to consider the current opportunities and difficulties on this topic in HLA development. It is proposed to precisely carry out such detail for the most promising scenario 4 based on the results of the work on the structure SWO.

We should start with exploratory drilling, as it is currently the main driver of further research and work in the field of HLA development. From the point of view of reducing the cost of drilling, it is necessary to prioritise technologies and developments that will allow year-round drilling in conditions of polar ice fields and the presence of the threat of icebergs.

Previously, it was proposed to use the NanuQ series vessel design for use at HLA. Theoretically, it assumes the possibility of year-round drilling in HLA conditions. It is worth noting that at the moment, the capabilities of the vessel built under this project have not been confirmed experimentally; this will still require time and additional costs. However, taking into account the trend of the oil and gas industry in the Russian Federation and discoveries in the Arctic, it is safe to say that the costs incurred for their completion and construction will pay for themselves in full with savings in the absence of restrictions on drilling in seasons with ice conditions. The capabilities of the Zvezda shipbuilding complex can allow the construction of drilling vessels of the NanuQ project with a displacement of up to 110 thousand tons. According to the official website of the complex, its capabilities allow building vessels with a displacement of up to 350 thousand tons [32], and with a favorable macroeconomic situation, such drilling vessels are already provided with work for several decades to come.

6. Conclusions

The north-eastern part of the Barents Sea has significant oil and gas reserves based on 2D seismic data. However, the results of the study show that their cost-effective development currently requireschuge investments and an increase in the technological equipment of the Russian offshore oil industry. At the moment, there are no proven technological solutions for year-round drilling in conditions of long-term ice and for providing power to subsea production complexes with the required power. To solve such problems in the next 10-15 years, the industry needs to create such solutions and invest in the future using all the long-term planning and forecasting tools.

The study of natural and climatic conditions has shown that the mining conditions in the HLA area are currently an almost insurmountable obstacle to its development. The main problems affecting this are the ice situation, depths over 150 meters and remoteness from existing infrastructure. In addition, for stable and safe development, it is necessary to hone methods and approaches to work in conditions where icebergs are likely to appear on future offshore projects in the Arctic that are closer in technological accessibility to the capabilities of the industry today.

An examination of the current technological capabilities of the industry shows that there is only a small range of solutions that can enable reliable and environmentally friendly development of HLA in the future. For the South-Western cluster, this means using a sea ice-resistant production platform on a gravity base, and for the North-Eastern Cluster, partial subsea development using SPS and using an onshore technological platform for a full cycle of oil treatment, storage and shipment.

The possibility of cost-effective year-round drilling in ice conditions is one of the key problems of the North-Eastern part of the Arctic. However, there are already successful conceptual developments and hypotheses that meet the requirements, requiring further development and experimental confirmation.

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