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Abstract

When a company undertakes to develop an oilfield, certain activities represent the foundation of the development, ranging from information about the metocean conditions at the site to marketing.

The concept phase itself includes screening of concepts, selection of concept and concept development. Use of engineering data and calculations that represents a feasibility study of offshore oil and gas field is essentially the screening of concepts.

The selection of concept consists of finding a solution that would meet world technical, environmental and safety demands. Despite the fact that Sakhalin Island shelf contains enormous hydrocarbon reserves, it is also a very environmentally sensitive region. High environmental risks and extreme weather conditions entail high capital expenditures, which put significant burden of responsibility on the project team during the development concept stage. This is of great importance during the early stages of concept selection.

Selecting the optimum Sakhalin Shelf development concept is the aim of my thesis. Significance in the concept selection chain affects selection of various parameters affecting the optimum development concept and subsequent prioritization.

Special attention is paid to challenges and peculiarities that can be faced at the Sakhalin Region and could affect the concept of field development. My paper analysis addresses concept screening and engineering solutions. The main driving factors of concept selection are touched upon. The development concept and the criteria of its selection are paid special attention to in the thesis. The criteria selection process in this case is based on scientific literature, as well as articles and publications, containing useful material about offshore field developments in Arctic and Sub-Arctic. Development and design industry standards, those of Russian Federation and other countries, were also touched upon.

All analysis results are presented in the form of methodological research, applicable to the entire Sakhalin region. A phased model for Sakhalin development concepts is created. Key parameters are discussed for the screening stage. Comparison of criteria for concept selection is also included.

The final model – step by step approach to concept phase execution, is concluded to be applicable to Sakhalin oil and gas development projects.

Conclusions drawn upon provide recommendation for the concept selection, applicable to the Sakhalin Shelf.

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The adventure I set off on two years ago was anything but easy, and at times it seemed like I faced impossible situations. However, I deeply believe that one can only prove his worthiness by constantly challenging himself, be it professionally or personally. You have to proof to yourself first and only then to others. All this would have been impossible without support from my professors and mentors whom I have a lot of respect for. My first mentor, back in Russia, was Vladimir Balitsky who encouraged me and supported in all my endeavors, guided me though all the years of studying and always gave timely and much needed advice.

I would like to express special gratitude to professor Anatoly Zolotukhin. I can’t stress enough his enormous input into this program as a person who started and developed it from 2010, which enabled us to see a whole new world, submerge into the unknown as well as develop necessary skills and change our views of the world. I wish you luck in all your beginnings, and many, many years of success to you and your family. I will never forget everything you have done for me by letting me have the chance to participate and finish this program.

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Introduction

Background

As it is well known the basis of field development concept - is the basis for the project as a whole. The first and important step in order to ensure cost-effective and trouble-proof operation in the offshore oil and gas field is so principle of the "right" choice of the development concept.

Implementation of the project concept phase offshore oil and gas fields is composed of three consecutive phases: concept screening, conceptual engineering and concept selection [1]

Concept screening phase is responsible for the identification of possible concepts of field development.

The purpose of the conceptual engineering stage is the confirmation of technical possibility of development concepts under consideration.

The objective of concept selection phase is to compare the technical implementation of the concept and to select best possible option of offshore field development that meets all current standards in terms of economy, technology and safety.

The theme of my master's work is the Development concepts for Sakhalin's offshore field development; in this regard special attention will be given to the very process of selection of the concept, that is, the final stage of the marine phase of the project concept. In this regard, the designation of my work is the decision-making process for the optimal choice of concept development in the conditions of the Sea of Okhotsk, Sakhalin region.

Problem formulation

In order to achieve cost-effective and environmentally friendly development of the Sakhalin shelf projects, as I have already described above, it is necessary to identify and to select the acceptable development concept, which will meet the parameters of the field in conjunction with the natural and climatic characteristics of the region's location. Otherwise, it may cause problems related to the environmental, social and financial aspects of the field development. The very same terminology "development concept" refers to systems of exploration / development drilling, production, refining and transportation of hydrocarbons from the field. It should also be noted that the development of projects on the Sakhalin shelf is the subarctic zone and impose the same restrictions as the Arctic conditions. [2]

History knows many cases when, due to selection of the incorrect concept development, even in the later stages of the development extremely high prices had to be paid. In some cases, due to adoption of incorrect solutions we may suffer the object of production itself. A demonstrative example can be notorious platform YME [3] of former Canadian company TALISMAN ENERGY INC. which was later acquired by the Spanish company Repsol. “As I interpret it, this means that the Yme platform must be secured immediately to weather the coming autumn storms,” professor Gudmestad Ove Tobias, told the publication. Even Shell [4] will be engaged with a similar challenge with the decommissioning of Brent Delta platform.

Chart shows (Figure 1) the relationship between the costs Ease of change and Cost incurred. From which it follows that the lowest cost can be achieved when making changes in the early (pre-engineering) stage. However, when making different kinds of changes in the later stages entails considerable costs than seems appropriate. This demonstrates the importance of acceptance of a decision, as well as its precision, accepted at the commencing plays a pivotal role in the decision-making process.

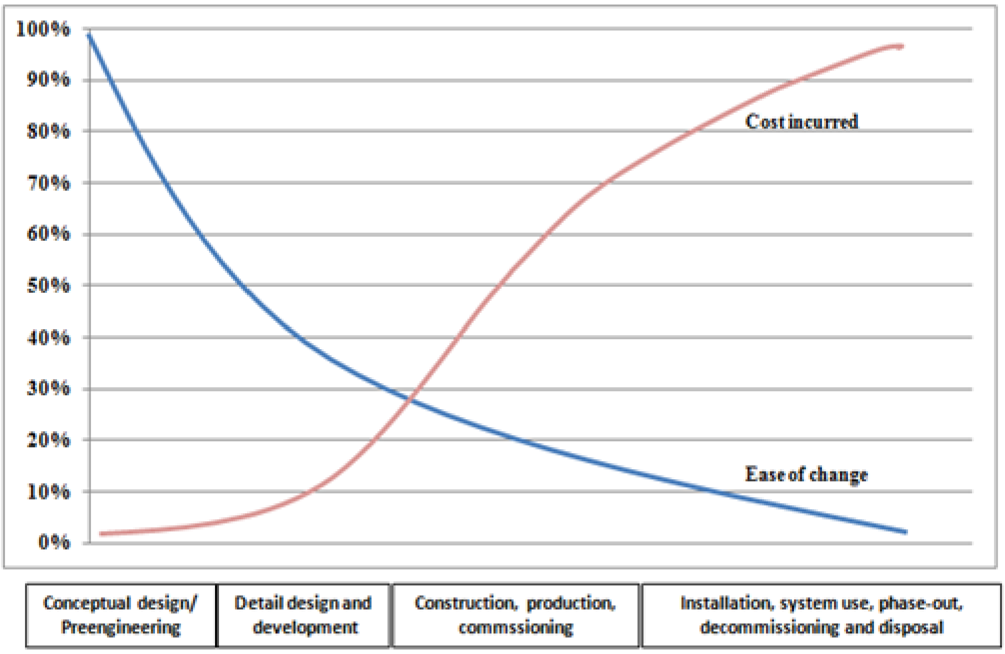


Figure 1. Dependence between changing of development concept and its cost during the project life.

In this regard a rational question of adopting the "right" choice of concept arises (concept selection) with the condition of particular vulnerability of the Sakhalin region becoming the most important. This is caused primarily by the existence various kinds of risk, diversity of flora and fauna, as well as the presence of the seismic activity in the region. Therefore, such projects require special attention due to the huge investment associated with the development of the sub-Arctic region, and imposed additional responsibility for decision-making in the early stages of the project.

So what is the principal difference between the concept selection and concept development? In this case it is necessary to consider given concepts.

Developing concepts phase of the offshore fields consists of three stages [1]

- Concept screening
- Conceptual engineering
- Concept selection)

The first two processes are a logical chain of the design characteristics of the reservoir up to a certain sales markets. The main task consists of the fact that they determine the technical feasibility and the possibility of concept development with the strict compliance of the engineering-geological conditions of the deposit, such as reservoir characteristics, water depth winds conditions, and the presence of ice. The number of feasible concepts under certain conditions is affected by the accuracy and the optimal selection in this case.

Concept selection is an optimum balance between technological, economic and safety aspects of the implemented concept, as is the process of mapping all technically feasible concepts to the above aspects. The concept selection process should be based on a number of criteria that can distinguish between the feasible concepts. Therefore, there is always a list of important parameters since these criteria may vary from case to case

In this case there is no comprehensive document that would contribute to the concept of choice, while the number of normative literature, trying to determine these criteria is sufficiently large.

Purpose and scope

The purpose of this master's thesis analyzes, identifying all possible concepts applicable to the optimal development of the Sakhalin shelf. In addition, this work includes the whole range of tasks associated with ice conditions, civil engineering, petroleum engineering, geotechnical.

It will also be necessary to analyze all the possible criteria that may affect the selection process for the concept. Not taking into account these criteria in the selection process concept may lead to irreversible consequences. Identification and determination of possible concepts applicable to the Sakhalin shelf is made based on a variety of textbooks and research articles. There will also be described only suitable for the region options for exploration / drilling, transportation and processing hydrocarbon raw materials.

In the thesis the experience of foreign and Russian companies will be described:

- Investigation of physical and mechanical properties of ice in the Okhotsk Sea;
- Ongoing projects and infrastructure;
- A detailed analysis of the environmental conditions of the Okhotsk Sea;
- Risks and challenges associated with the development of offshore fields in the Sea of Okhotsk;
- Building Technologies of various types of offshore structures applied to the Okhotsk Sea conditions;
- Classification of the systems applicable to the exploration / development drilling and production scenarios, transportation and processing of hydrocarbons;
- Possible solutions to the deep-water sector of the Sakhalin shelf in the Okhotsk Sea.

Final conclusions taking into account the advantages and disadvantages of each of the possible concepts considering comprehensive approach to the choice of the development of the Sakhalin offshore fields will also be described in the final chapters of this work.

Thesis organization

The Master Thesis is composed in the following way:

Chapter 1 (Offshore project development process) provides an elaborated study of the planning phase of offshore project's. The chapter includes a description of the whole chain of a project's development process and concept phase highlights; consisting of concept screening, concept engineering and concept selection stages.

Chapter 2 (Environmental conditions on Sakhalin Island) This chapter focuses on all the physical and environmental phenomena taking place on the island of Sakhalin with a detailed description of all geological, metocean, hydrological tectonic and ice conditions in the area of the proposed field development.

Chapter 3 (Challenges on Sakhalin Island) provides a study of the main challenges in the Sea of Okhotsk of the Sakhalin Island, including environmental conditions, geotechnical conditions, underdeveloped infrastructure and main risks. Based on the data of the Sakhalin-III project of Kirinskoye field analysis and calculation is made to access the possibility of ice gouging of subsea pipeline in the areas of its outlet to the shore. Also remedy measures of a pipeline against this kind of phenomenon are described, and brief summary is written.

Chapter 4 (Ongoing developments of offshore Sakhalin fields). This chapter describes in detail all of the current projects and infrastructure, which take place throughout the territory of the Sakhalin Region with the implementation of foreign and domestic experience as part of consortium cooperation in the development, transportation and storage of hydrocarbons, extracted from the deposits in the Sea of Okhotsk

Chapter 5 (Concepts structures for Sakhalin Island offshore developments) The purpose of this chapter is to identify all the possible concepts applicable to the subarctic zone of Sakhalin shelf. Chapter includes the examination of possible areas of application of marine ice-resistant structures, identifies and describes in detail the main factors influencing the selection of construction type, detailed fixed production platforms operating in shallow and deepwater ranges. The main features in the selection of concrete gravity base structures are identified.

Chapter 6 (Subsea concepts for deep water Sakhalin development). The final chapter provides a detailed analysis of possible options for field development on the Sakhalin shelf with only subsea production systems, the advantages and disadvantages of each of the concepts described in detail. Technical description of schemes carried out on the basis of the project DEPTH Norwegian company Aker Solutions whose main objective was to reduce the operating costs, the search for new of economically feasible solutions and technologies for the production of natural gas at the fields located at a considerable distance from the shore.

Chapter 7 (Risk analysis during subsea development). This chapter describes the execution of risk analysis related to the concept of field development using subsea production systems by means of the Bow-tie analysis.

Chapter 8 (Summary and recommendations). Finally, the acquired findings are summarized and suggestions for further research wrap up this thesis.

1. Offshore project development process

Investment projects are divided into two periods: project planning and project execution. Decision to start project execution is a result of the planning period, and start-up of the completed facility is the result of an execution period. The two main periods are divided into several phases, where each has a defined purpose and defined result. [1]

To maintain control, the project process and to ensure a structured decision process, a number of decision gates (DGs) and approval points (AP) are determined. [1]

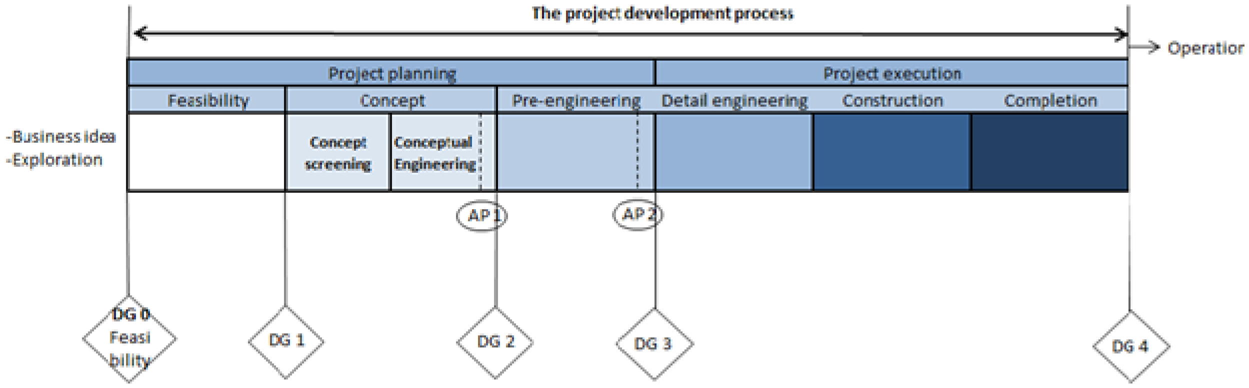


Figure 2. The project development model for investment projects with phases and decision gates [1]

The planning period

The planning period covers the feasibility, concept and pre-engineering phases.

The main appointment of planning period is scrutinizing of vast majority of concepts, and definition of a selected concept, to designate whether a commercial scope can be developed to satisfy requirements for profitability for profitability, HSE and technical feasibility within defined limits of uncertainty. [1]

The feasibility phase

The main purpose of the feasibility phase is to establish and document whether a business opportunity discovered or a hydrocarbon find is technically feasible to develop and has an economic potential in accordance with the corporate business plan to justify further development. The feasibility phase leads to decision gate DG 1, «Decision to start concept development»

Approbation statement of the decision to start concept development (DG1) is an authorization by Consortium to continue developing the project through the concept phase towards decision to start provisional project sanction (DG2) in accordance with the approved project plans and budgets.

Decision gate 1 may be passed when the business concept has been developed to a level where it is likely that it is profitable, technically feasible and in accordance with the corporate business plan. [1]

The concept phase

The purpose of the concept phase is to provide a firm definition of a decision of the design (resource and product) basis and to identify all relevant and feasible technical and commercial concepts. Then to evaluate and define the selected alternative (preferably one) and confirm that profitability and feasibility of the business opportunity will be in accordance with the corporate requirements and business plans. The concept development phase comprises of two sub phases: concept screening and conceptual engineering. The result of the concept phase is selection of the concept for further developing up to decision gate «Provisional project sanction». [1]

Concept selection - Approval point 1

The approval point «Concept selection», AP1, marks that one concept (or where necessary, a limited number of concepts) has been chosen for further detailing towards DG2 «Provisional project sanction».

Concept selection, AP1, shall be the result of a screening process including all relevant and feasible alternative concepts identified for a further development of business opportunity.

The selection of the base concept shall be supported by documentation describing the concept screening process, focusing on:

1. Design basis
2. Concept alternatives and variants
3. Screening parameters and weighting
4. Description of and justification for both the selected concept and the rejected option
5. Technology qualification program. [1]

Provisional project sanction - Decision gate 2

Approval of the provisional project sanction is an authorization by company and the partners to continue developing the project through the pre-engineering phase towards DG3 - «Project sanction» in accordance with the approved project plans and budgets.

The approval includes a decision to develop the necessary applications to the authorities.

The provisional project sanction – DG2 documentation shall include an evaluation of the availability of qualified personnel resources and of the capacity in the relevant supplier industry. [1]

Pre-engineering phase

The goal of the pre-engineering phase is to further develop and document the business opportunity based on the selected concept to such a level that a final project sanction can be made, application to authorities can be sent and contracts can be entered into. The pre-engineering phase leads to approval point 2 (AP2), «Application to the authorities», and to decision gate 3 (DG3) «Project sanction». [1]

Application to the authorities - Approval point 2

The project shall compile and prepare for submittal of the necessary application for approval of the facility development in accordance with the relevant laws and regulations. [1]

Project sanction – decision gate 3

The DG3 approval is an authorization by company and the partners to continue developing the project through the execution period in accordance with the approved project plans and budgets. [1]

Execution phase

The execution phase covers the detail engineering, construction and completion phases. The purpose of the execution phase is through a detailed design of the chosen concept and quality facility construction and installation come to the successful hydrocarbon production. [1]

Summary

The elaborate study of the Offshore Field Concept Development process shows that there are three stages relevant to this Master Thesis – Concept screening, Conceptual Engineering and Concept selection. All of them are parts of the concept phase of the project planning and the result of them is a defined field development concept for further design and construction of the field development system.

2 Environmental conditions of the Sakhalin region

The name Sakhalin translates as “Rocks of Black Mountain” from one of the indigenous languages. Sakhalin island is one of the largest and very significant island for Russia. Being located on the far east of Eurasian continent it is washed by Okhotsk Sea and Japan Sea. Sakhalin Island separated from mainland with narrow straight which is named Tatar straight where the narrower place has a width about 7.3 km. [22] It comprises on one hand unique and fragile nature and on the other hand tremendous amounts of hydrocarbons. For Russia it is not only economically attractive island but also is some sort of outpost to the Pacific Ocean.

2.1 Geographical disposition

Sakhalin Island - the largest island of the Far East of the Russian Federation (76,400 km^2). It is washed by the Sea of Okhotsk and the Sea of Japan. The island stretches over 948 km from north to south. The maximum width of the island - 160 km. Minimum width - about 30 km.

The whole offshore of Sakhalin Island is considered to be a high category water object, as offshore waters are a place of mass feeding and spawning grounds of valuable fish species and marine mammals in Okhotsk Sea, also about 20 millions of birds stop at the shores of Sakhalin Island in the winter, during migration. [24]

2.2 Climatic conditions

Climate conditions and air temperature

Climatic conditions of Sakhalin Island and its offshore are affected by the Okhotsk Sea currents system and coastal orography. Warm Kuroshio Current passes in the southwest of the island, and in the north and east - the cold waters of the Sea of Okhotsk.

The area belongs to the North-Sakhalin lowland climate zone, characterized by the cold continental air in the winter and the air masses from the Okhotsk Sea in the summer.

General climate on the Sakhalin Island is determined by its contiguity to the Siberian continental array.

The duration of the period with negative air temperatures is constituted up to 185 days.

Winters are long and harsh, with frequent storm winds and blizzards. Throughout this period, blizzards are observed 6-14 days in a month with blizzards, the duration of which can reach several days. The months with the most blizzards - December and January, due to the strong winds during this period. In some years, snowstorms in October and May are observed.

Summer periods are chill and gloomy, with lots of rains and dense fogs.

Springs and autumns are short, cold and cloudy. Impact factors of the cooling effect more than a warming and the resulting heat transfer on the surface is negative.

Average statistical long-term data observations in the area according to [25]

- The average temperature of the warmest month, +19,4 °C;
- Absolute maximum temperature +37 °C;
- The average temperature of the coldest month -10,3 °C
- Absolute minimum temperature is -48 °C.
- The duration of the period with average daily temperature below 0 °C – 186 days.

Table 1 and 2 gives summarized climatic features for warm and cold periods of the year for the hydro meteorological station «Nogliki»

Table 1. Climatic parameters of the warm period of the year for hydrometeorological station "Nogliki"

Parameter	SNiP 23-01-99
Atmospheric pressure, gPa	1010
Air temperature, ° C with a frequency of 0,95	17
Air temperature, ° C with a frequency of 0.98	21,4
Average maximum temperature of the warmest month, ° C	19,4
Absolute maximum temperature, ° C	37
The average daily amplitude of air temperature of the warmest month, ° C	9,2
The average monthly relative humidity of the warmest month, %	85
Average monthly relative humidity in the 15 hours of the warmest month, %	72
The amount of precipitation in April - October, mm	481
The daily maximum precipitation, mm	87
Prevailing wind direction in June - August	SW
The minimum average wind speeds at compass point July, m / s	-

Table 2. Climatic parameters of the cold period of the year for hydrometeorological station «Nogliki»

Parameter		SNiP23-01-99
The temperature of the coldest days, °C, with frequency	0,98	-36
	0,92	-35
The temperature of the coldest five-day week, ° C, with frequency	0,98	-33
	0,92	-32
Air temperature, °C, with frequency 0,94		-25
Absolute minimum air temperature, ° C		-48
The average daily amplitude of air temperature of the coldest month, °C		-10,3

<table>
<tr><td rowspan="6">Duration, per day, and the average air temperature, ° C, the period from the average daily air temperature</td><td rowspan="2">≤ 0 °C</td><td>duration</td><td>187</td></tr>
<tr><td>average temperature</td><td>-11,7</td></tr>
<tr><td rowspan="2">≤ 8 °C</td><td>duration</td><td>260</td></tr>
<tr><td>average temperature</td><td>-7,2</td></tr>
<tr><td rowspan="2">≤ 10 °C</td><td>duration</td><td>281</td></tr>
<tr><td>average temperature</td><td>-6</td></tr>
<tr><td colspan="3">The average monthly relative humidity of the coldest month, %</td><td>76</td></tr>
<tr><td colspan="3">Average monthly relative humidity in the 15 hours of the coldest month, %</td><td>69</td></tr>
<tr><td colspan="3">The amount of precipitation in November - March, mm</td><td>149</td></tr>
<tr><td colspan="3">Prevailing wind direction in December - February</td><td>NW</td></tr>
<tr><td colspan="3">The maximum of the average wind speed rhumbs January, m/s</td><td>-</td></tr>
<tr><td colspan="3">Average wind speed, m/s, during the period from the average daily temperature ≤ 8 ° C</td><td>4,2</td></tr>
</table>

Precipitation

Precipitation over Okhotsk Sea, primarily associated with the monsoon circulation.

20-30% of the annual norm of precipitation occurs in the cold period, while 50-60% for the warm, the rest of them are spring and autumn periods. The average annual precipitation is 700 - 800 mm. According to the [26], from November to April is dominated by precipitation in the form of snow, from June to September - in the form of rain. Thunderstorms are infrequent in the Sakhalin and as a rule occur in the summer. The average duration of precipitation in summer is 6-8 hours, maximum 54 hours, the duration of the autumn precipitation increases, reaching, respectively, 8-10 and 60 hours. [27].

Characteristics of precipitation according to the hydrometeorological station «Nogliki» is presented in Table 3. Average number of days with snow cover during the winter according to observational data on hydrometeorological station «Nogliki» is 186 days.

Table 3. The average amount of precipitation (mm) by month and year according to the hydrometeorological station «Nogliki»

The period of observation	I	II	III	IV	V	VI	VII	VIII	IX	X	XI	XII	Year
1930-1980	21	21	28	40	57	50	66	86	107	74	44	35	629
1930-1960	28	14	13	40	41	50	64	81	94	58	58	36	577

Soil freezing temperatures and snow covering

Soils become frozen at a relatively shallow depth in the north and in the central part of the island up to 140-160 cm, and the south - up to 40-70 cm, which is caused by a large blanket of snow and high groundwater levels. In the north of Sakhalin there are some areas of permafrost. Characteristics of freezing soil according to the hydrometeorological station «Nogliki» are given in the Table 4.

Table 4. Average and extreme values of surface temperature according to the hydrometeorological station «Nogliki» (sand-clay soil)

The temperature of the soil surface	I	I	II	IV	V	VI	VII	VIII	IX	X	XI	XII	year
Average	22	19	13	3	5	2	17	8	2	2	9	18	2
Average maximum	14	9	1	5	4	5	9	0	2	1	2	12	8
The absolute maximum	6	5	2	2	8	7	0	0	0	8	4	4	0
Average minimum	29	28	22	11	2	3	8	10	5	3	15	25	9
The absolute minimum	52	46	43	32	13	4	2	0	7	20	38	46	52

Snow cover on the coast of Kirinskoe gas field usually appears in the late of October, and disappears in the middle of May. The average number of days with snow cover are 170 to 186.

Features of snow cover according to the hydrometeorological station «Nogliki» are presented in Table 5 and Table 6.

Table 5. The dates of appearance and disappearance of the snow cover according to the hydrometeorological station «Nogliki»

Date of appearance of snow cover			Date of disappears of snow cover		
Average	**The earliest**	**The latest**	**Average**	**The earliest**	**The latest**
29.X	4.X	13.XI	12.V	6.IV	1.VI

Table 6. Snowcover depth (cm) according to the hydrometeorological station «Nogliki»

Month																								Maximum snow cover depth in the winter		
X			XI			XII			I			II			III			IV			V					
1	2	3	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3	avr	max	min
The average decadal snow cover depth at a constant rail (open space)																										
*	*	*	1	2	3	7	9	12	13	16	17	18	20	21	21	22	22	21	14	8	3	1		26	62	8

Humidity and thaw

The east coast of the island is characterized by a high relative humidity, particularly in the summer (84-86%) Table 7 [28].

Table 7. Average relative humidity over the year and by month (%) at the hydrometeorological station «Nogliki» near Kirinskoe field.

Station	Month												Year
	I	II	III	IV	V	VI	VII	VIII	IX	X	XI	XII	
Nogliki	75,8	74,6	75,5	77,8	79,4	80,0	86,7	87,3	81,5	77,0	73,9	77,1	78,3

The lowest values of relative humidity on the eastern coast of Sakhalin Island related to the winter and make up 75-78% in the North, 65-80% - in the South. The number of days with relative humidity is less than 30%, approximately 12 days per year, and with a moisture content of no less than 80% was observed in the average of 100-120 days yearly. The annual average number of days with high moisture (relative humidity of 90% or more) are 77 to 128 days. Almost everywhere, in some years a thaw is observed in which the air temperature rises to +4 ...+6 ° C.

Cloudiness

Gloomy weather dominates throughout the year over the north of Sakhalin (cloudiness 8-10 points), the average number of cloudy days about 139-156 per year. From May to November, the number of overcast days are 12-18 per month, from December to April - 7-13 days. Table 8 [26]

Table 8. Average number of overcast days on total and lower tiers cloudiness at the hydrometeorological station «Nogliki» near Kirinskoe field.

Station	Overcast.	Month												Year
		I	II	III	IV	V	VI	VII	VIII	IX	X	XI	XII	
Nogliki	T	7,5	7,3	9,5	11,6	14,6	12,5	17,3	13,9	9,3	8,5	6,4	8,2	127
	L	2,4	1,5	2,9	6,1	8,0	6,6	8,8	7,8	2,9	2,9	1,8	3,2	55
Note: T - total cloudiness; L - cloudiness of the lower tier.														

In the summer months above the area of the shelf the overcast weather recurrence is about 64%, in the autumn - about 50%. In the summer the lower edge of the cloudiness below 500 meters is more than 55%, in other cases with less than 200 meters approximately 40%. In autumn cloudiness dominates above the sea with a base height of 0.6-1.0 km, cloudiness repeatability with heights below 200 meters decreases to 21-25%.

Fogs

Fog over Okhotsk Sea can be observed throughout the year, the number of foggy days per year: the average – 66 days, the most – 98 days. The most favorable conditions for their formation and development are during the warmer months from April to September, in this case the average number of foggy days in a month make up 10-20 days. Repeatability of fogs over the sea in July is 25-30%. Features and average duration fogs are presented in Tables 9 - 10 and [29]. Average duration of one case of fog at sea is about 20 hours, maximum - more than 100 hours. With light fog the visibility is more than 500 m, with mild fog from 200 to 500 meters, heavy about 50-200 meters, and very heavy less than 50 meters, respectively.

Table 9. Characteristics fogs according to the hydrometeorological station «Nogliki»

I	II	III	IV	V	VI	VII	VIII	IX	X	XI	XII	YEAR	The period of observation
The average number of days with fog, days													**1936-80**
0,2	0,3	2	4	9	14	14	11	7	3	0,9	0,3	66	
The maximum number of days with fog, days													**1936-80**
2	4	10	12	17	22	24	22	15	11	8	3	98	
Average duration of fogs, hour													**1936-80**
0,8	1	9	28	60	107	103	73	19	10	3	1	25	

Table 10. Average duration of the fogs per day with fogs (hour) according to the hydrometeorological station «Nogliki» from 1966 to 1980 years.

X-III	IV-XI	Year
4,2	6,7	6,5

Visibility

Visibility on the northern and north-eastern coast of Sakhalin Island attains values less than 3.8 km approximately 40-50% of the summer period and 20-30% of winter time and is defined by the fog's regime, precipitation and depends on cloudiness.

The total value of visibility during the summer period of time is less than 1.9 km and recorded during almost 30-40% of the time, however during the autumn period of time it is less than 10%.

Winds

The main movement of air masses is associated with the monsoon circulation in the atmosphere over the northern part of Sakhalin Island, as over the adjacent offshore areas of

Okhotsk Sea.

In winter, over the water area of Kirinskoe field and the adjacent lands the winds are dominated by the western and north-western areas, their total repeatability about 54-74%. In the summer times, south, south-east movement of air masses is expressed less clearly, however, the total repeatability of these wind directions exceeds more than 40%, and winds that blow from southeast and eastern part are present more profoundly in the vicinity of Nogliki district Table 11.

Table 11. Repeatability (%) of wind's directions in January and July at the hydrometeorological station «Nogliki» near Kirinskoe field

Station	Direction of the wind								Calm
	N	NE	E	SE	S	SW	W	NW	
January									
«Nogliki»	12,37	1,61	1,92	1,01	4,17	22,40	39,94	13,80	2,77
July									
«Nogliki»	8,61	5,19	20,59	21,53	10,86	9,25	14,13	2,08	7,76

The average wind speeds at the hydrometeorological station research area is about 4-5 m/s. The maximum of average monthly wind speeds about 4.5 m/s which is observed in December-January, and minimum about 3.5 m/s – which is observed in July and August. Table 12.

Table 12. Average monthly and annual wind speeds in m/s at the hydrometeorological station «Nogliki» near Kirinskoe field

Station	Months												Year
	I	II	III	IV	V	VI	VII	VIII	IX	X	XI	XII	
Nogliki	4,5	4,4	4,4	4,3	4,2	3,8	3,5	3,5	3,9	4,3	4,4	4,5	4,1

The maximum wind speeds at the hydrometeorological station «Nogliki» is 31 m/s (see Table 13). The absolute maximum speed mostly observed during the winter months. In the summer time maximum of wind speeds is less than 20 m/s. [28].

According to observation data on the floating drilling rig, features of wind conditions of northeastern shelf of Sakhalin for the navigation period from July to November is shown in Figure 3 [27].

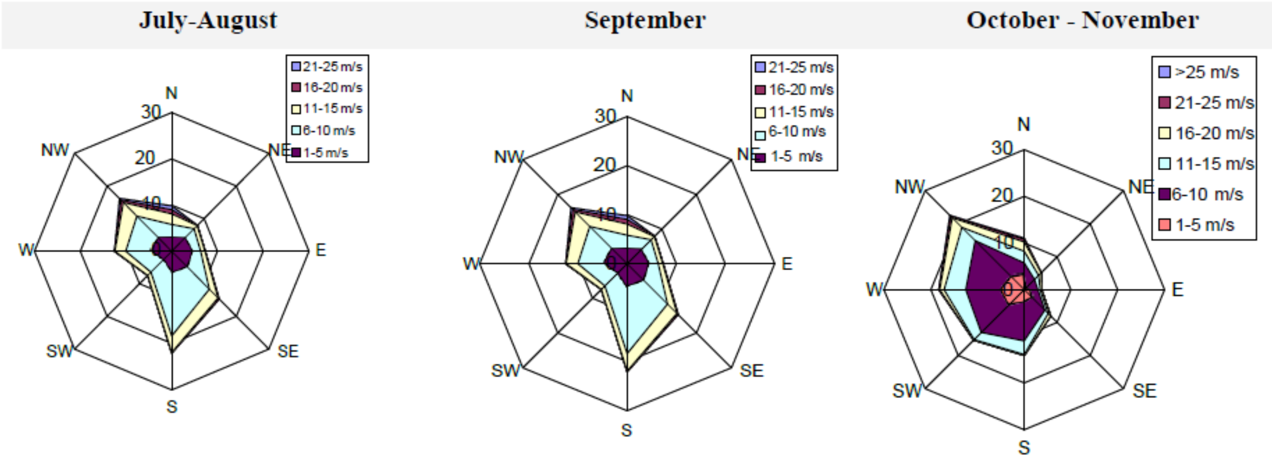


Figure 3. Features of wind conditions of northeastern shelf of Sakhalin for the navigation period from July to November. [27]

In summer times, average monthly wind speeds over the northeast shelf of Sakhalin is 6.5 m/s, the maximum speed - 20 m/s was recorded in 1992 year. In September average monthly wind speeds rise up to 7.4 m/s, the maximum wind speed is 24 m / s what was observed in 1981 year.

In October and November average monthly wind speeds reach 8.7 m/s, the maximum wind speed about 43 m/s was recorded in 1988 year.

Characteristic of winds frequency with different strength over the water area of the northeastern part of Sakhalin shelf was obtained from observational data of vessels between 1977- 1990 years (Table 13).

Table 13. Repeatability of winds (%) above the water area according to the shipboard observations

Months	Speed graduations, m/s				
	1-4	5-9	10-14	15-19	≥20
June	30,5	60,0	8,4	1,1	0,0
July	30,2	48,0	20,4	1,2	0,2
August	34,8	48,9	14,8	1,3	0,2
September	31,6	43,7	20,3	4,1	0,3
October	20,6	37,2	29,6	8,7	3,8
November	9,0	36,3	38,0	11,8	4,9

Estimated maximum wind speeds for the hydrometeorological station «Nogliki» (average-out of 10 minutes) obtained from annual maxima of wind, is shown in Table 14.

Table 14. Estimated maxima of wind speeds of rare repeatability (m/s) at the hydrometeorological station «Nogliki»

Station	Repeatability once in the number of years					
	2	**5**	**10**	**20**	**50**	**100**
Nogliki	12	21	24	28	33	37

Estimated wind speeds of rare recurrence over the sea presents according to the results of calculations performed by Far-Eastern Marine Engineering Geological Expedition are shown below in Table 15 [30]

Table 15. Estimated wind speeds of rare repeatability (m/s) for the navigation season over the water area.

Averaging time	Repeatability in a specified number of years					
	1	**5**	**10**	**25**	**50**	**100**
10 minutes	24	29	32	35	39	42
2 minutes	28	34	37	40	45	48
3 minutes	31	38	42	46	51	55

2.3 Hydrological conditions

Water temperature and water salinity

The maximum temperature of the superficial seawater layer within +18 °C on the surface, the maximum temperature at the depth of 30 meters is +8 °C. The minimum temperature of the superficial seawaters layer in this region is minus 1,6-1,8 °C which is indicated between January to March. Average temperature of seawater on the surface on the navigation period is about +6 °C. Freezing temperature of seawater -1,9 ° C, its salinity about 30-35 mg/l. During the winter months, the water surface is covered with ice, and temperature across the water column ranges from -1.7 to -1,9 °C. Ice cover with the thickness of 1.5 meters moves at speed of 1-2 knots, but under extreme conditions it can move at a speed of 4 knots.

One of the main characteristic of the water thermal structure of Okhotsk Sea is a cold intermediate layer (CIL), which remains after the autumn-winter convection of superficial waters. Depth of the CIL's core closer to Sakhalin Island is 40-50 m. It can be observed that the minimum water temperature at the depth of 50 meters in July and constituted -0.5°C, maximum observed in October and it is 3-4 °C.

The main feature of the vertical distribution of salinity is ubiquitous and at all seasons of the year (except for ice formation) increase of salinity goes along with the depth increase. Variability of salinity during the year associated with the ice cover, correlation of precipitation and evaporation as well as river runoff. Maximum salinity of a superficial waters is observed from December through March, differences in time are related with different periods of the emergence and the greatest development the ice cover.

Minimum salinity is observed from June to August. Minimum values of salinity at the surface reaches about 28 ‰ while maximum is 32,2 ‰. The greatest variability of salinity can be seen at the surface, however it decreases sharply to the depth and make up about 0.5‰ at 50 meters. [29].

Sea level

Seasonal variations in the area have a significant amount and are distinguished by high values in the autumn-winter period from October to January and the lowest in spring and summer from March to August.

A transitional period is observed February and September, which is characterized by rapid changes in the medium level. Maximum differences in the annual monthly average height is about 15 cm. At the same time, in various years, there are significant deviations from the multiyear average values so the difference between the absolute maximum and minimum from the series of monthly average height reaches half a meter.

Seasonal variations in the area can be characterized on the basis of monthly average height calculated from the long-term observations at the shore station in Nabil Gulf.

Calculated statistical characteristics of average long-term, maximum and minimum values from the series of average monthly are shown in Figure 4.

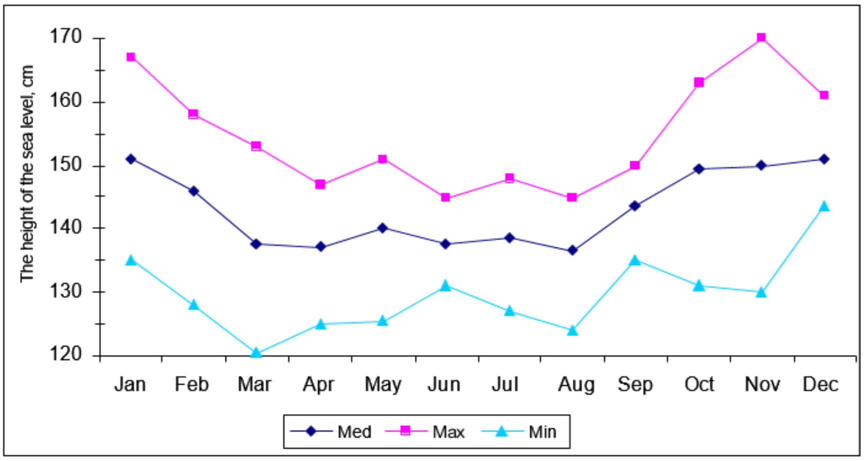


Figure 4. Annual distribution of average monthly heights above the sea level in Nabil Bay [29]

Changes in the sea level within the year (seasonal movement) are relatively minor, minimum is usually recorded in April (May), maximum in December.

Table 16 - represents the deviations of average monthly values against average annual

for Poronaisk village obtained during the period of 28 years of observations. [29]

Table 16. Deviation (expressed in cm) average monthly sea levels from average annual value in Poronaisk settlement between the dates from 1950 to 1956, 1959-1961, 1965-1998.

Month	I	II	III	IV	V	VI	VII	VIII	IX	X	XI	XII	Amplitude, cm
Deviation, cm	1,6	- 2,4	- 6,5	- 7,5	- 2,1	- 1,7	- 0,1	1,1	1,3	4,5	4,4	7,4	14,9

Currents

Along the north-eastern coast of Sakhalin Island runs the East Sakhalin cold current. Maximum of the current speed reaches 12-15 cm/s. The maximum speed of aggregated flows is observed in the coastal belt.

Common regional features of the currents complex on northeast Sakhalin offshore are preserved in winter. It is a longshore direction of combined currents with predominance of southern rhumb points.

In addition, the effect of fast-ice is imposed, which entails an increment in the maximum flow rate. The calculated flow rate possible under the ice once in a hundred years, in times of possible ice Lying is more than 200 cm/s. Calculated flow rates under the ice is possible once in a hundred years, in a periods of plausible ice dumping which is constituted more than 200cm/sec.

With the increase in depth of the sea waters average flow rate at the surface can reach more than 50 cm/s, and in the bottom layer about 30 cm/s.

The highest total flow rate observed with the action of currents in the prevailing directions, is the southern rhumba points (influence of East-Sakhalin current)

A characteristic feature of non-periodic currents is their direct dependence of the wind direction and strength of the wind. Average values of non-periodic currents for the depths of 15-30 meters are: 5-10 cm/sec at the surface and less than 5 cm/sec s on the horizon 1 meter above the seabed. During the storms the speed of residual flows in the surface layer can be up to 30 cm/s. Maximum speed of non-periodic currents near the shore may be up to 2 to 2.5 times higher than in the open sea. In the area of coast influence, at any winds, the long shore component is dominating.

Tides play the dominant role in the shaping of the system of currents in the northeastern Sakhalin offshore. The velocity of tidal current is sufficiently high and can reach in the surface layer about 110 to 120 cm/sec. With increasing depth of tidal current, the speed is decreased.

Average speeds in non-periodic currents in the surface layer can reach from 20 to 30 cm/sec, maximum values of non-periodic currents beneath in the surface layer can reach from 46 to 75 cm/sec in autumn due to the winds strengthening during the cyclone passage.

Maximum registered speeds of total flow in the region can vary within 190 cm/sec at the surface and up to 60-80 cm/s at the bottom and it belongs to southern currents.

Okhotsk Sea is a tidal sea, where it can be seen tidal currents in the coastal area, which are characterized by high variability over space and time. The main feature of tidal currents in the region is their daily frequency.

Maximum speed of tidal currents is most likely in May or June and in December-January and can reach more than 200 cm/s (bottom level). Total tidal flow is directed to the south along the coast, ebb - to the north.

In contrast to the coastal area, in the open sea tidal currents don't have any pronounced features of reversible character.

Maximum velocities of the overall currents observed in the coastal belt. At the entrance to the Gulf of Nabil speeds observed are up to 260 cm/s. [29]

Tsunami

An open border the Sea of Okhotsk goes along Kuril Islands in the vicinity of one of the main area of origin of a tsunami in the Pacific Ocean Kuril-Kamchatka Trench. Kuril Islands are one of the most seismically active regions in the world, and the Gulf of Patience is potentially exposed to tsunami waves passing through the Kuril Straits. However, the huge amount of energy of tsunami waves, which are generated in the ocean, is absorbed by the Pacific littoral areas of Kuril Islands. Tsunamis passing the Sea of Okhotsk, substantially attenuated by the time when they reach the north-eastern coast of Sakhalin Island.

The probability of occurrence of significant tsunami-genic shallow-focus earthquakes here is unlikely. During observations at the hydrometeorological station «Komrvo», the vast majority of Pacific tsunami, even commonly known for its destructive force, had a height about 0.2-0.4 m. Only one of them, the catastrophic Chilean tsunami that occurred in May 22, 1960 had a height of about 0.7 meters.

According to the materials of sea level observations from the period between 1961 to 1987 years at the hydrometeorological station «Katangli» and the results of research in the district Katangli - Nyyskiy Bay conducted at the Institute of Marine Geology and Surveying registered extreme heights of the sea level, caused by the tsunami. These data are shown in Table 17.

Table 17. Extreme height of sea level (cm), caused by tsunami.

Constituting part level	Recurrence interval, year			
	25	50	100	200
The height of tsunami	72	96	122	146

In order to estimate the recurrence intervals approximation of lognormal distribution of the tsunami heights by the recurrence intervals was used as a method. Figure 5 shows a graph of the repeatability of events, where solid curve shows the lognormal distribution.

Evaluation of the repeatability for a number of selected periods is as follows:

- 10 years - 47 cm
- 50 years - 120 cm
- 100 years - 160 cm
- 500 years - 270 cm

The solid line shows the lognormal approximation of the distribution of the wave heights for recurrence intervals.

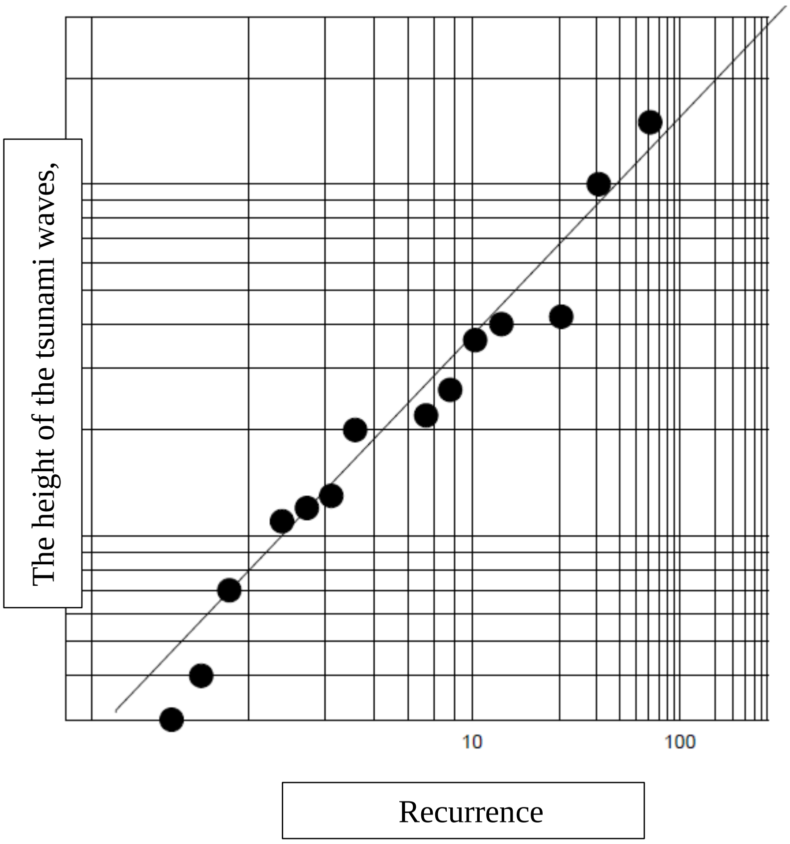


Figure 5. Repeatability of the tsunami on the eastern coast of Sakhalin [29].

2.4 Tectonic processes

Sakhalin Island is located in the southern part of the North-Sakhalin trough. Trough occupies most of the territory of Northern Sakhalin, Sakhalin waters of Sakhalin's Gulf and the western part of Okhotsk Sea (North-Eastern Sakhalin offshore). Trough is filled with sediment thickness of 5 to 12 km, and stretches in a northwesterly direction at 500 km and a width of 80 - 100 km. Base lies at a depth of 1.5 to 5 km along the interior raisings synclinorium.

The current structure of the trough was formed as a result of several stages of orogeny, two of which, Kamchatka (Late Cretaceous-Paleogene) and Sakhalin (Pliocene quarter) had high-amplitude elevations accompanied by the same name of the periods of orogenesis. The other two phases - Kuril (early Miocene) and Aleut (Middle Miocene) are characterized by low-amplitude elevations, but are not accompanied by well-defined periods of orogenesis.

Structural-stratigraphic complexes of the North Sakhalin trough differ from one to another in style and level of dislocation.

2.5 Ice conditions

Ice formation and ice exaration

The only type of ice in Okhotsk Sea is first-year ice. Multi-year ice is absent. Maximum thickness of rafted ice is up to 2÷2.5 meters. The earliest commencing date of the ice season in the water area of the northeastern shelf of Sakhalin Island begins approximately from November 21st, almost simultaneously all along the coastline, moving from north to south.

For the deposit area characterized by drifting ice, the cohesion of which reaches 7-10 points, with ice thickness of 130 cm, and the drift velocity about 1.6 m/s covering the waters since the beginning of winter to spring or even early summer. There are also ice-hummocks. The height of the ice-hummock's sails reaches 2.8 meters, the maximum depth of the keel about 12.4 meters.

The process of melting from the ice goes from South to North. Difference in medium terms of the final melting from the ice between Cape Elizabeth and Komrvo village are 6 days, in the early stages and about 15-18 days in the later stages. In the open sea ice appears in the 1-2 decade later and disappears on a much lagging long term.

In January, first-year ice appears in an array of drifting ice, shifted under the action of winds and currents into the area of northeastern shelf from the northwestern part of Okhotsk Sea.

In March-April ice edge reaches its maximum eastern position. Since the middle of April spring ice cover destruction process begin to predominate.

In May, intensive melting and crushing of ice is observed. The ice edge moves toward the shore. In June, comes the final cleavage of ice field in the broken forms and new-ice disappears in the ice massif with only first-year ice left behind.

As a rule, the destruction of the ice cover along the northern coast of the island does not occur until the end of June. The latest end date of the melting ice in the northeastern shelf of Sakhalin Island is July 9th.

The average duration of ice season is 160 - 210 days.

Ice conditions are characterized not only by the presence of pack ice and ice hummocks, but also grounded hummocks as known as stamukhas. Consequently, there is a danger of damaging offshore pipelines due to ice gouging seabed that poses a threat on the sites with a water depth of less than 25-30m. Mainly coastal sites of shore sea-gate require particular attention.

However, trenches of ice gouging and other impact traces of floating ice on the surface of the seabed at the area were not found.

According to observations in the area of the hydrometeorological station "Odoptu" and "Komrvo" total speed of ice drift is very large and often exceeded 1 ÷ 1.5 m/s.

The maximum rate speed of the tidal ice drift on the northeastern shelf of Sakhalin Island, obtained by precomputation in harmonic constant, may reach a value of 1.3-1.4 m/s.

In the area of Chayvo field stamukhas mainly observed at the depths of 5 to 16 m. With the depth the quantity of stamukhas reduces significantly. At the depths of 16 to 26 m stamukha is not observed annually and their impact probability to the pipeline is very low.

The average gouge depth of stamukhas into the ground on the northern shelf Sakhalin Island according to environmental test researches is 0.5 meters, the maximum registered gouging depth of stamukha into the bottom is 2.13 meters. [32]

Ice accretion

Offshore structures may be exposed to ice build-up from October to December, potential period of icing is about six months. Ice build-up of vessels and hydro-technical engineering structures in the project area, as well as at the nearby areas of the Sea of Okhotsk, is observed during the winter season from October to May, and individual cases of possible icing in October, in June and in September. The highest intensity of ice accretion noted in January, but in contemplated region it may vary from 5 to 10%.

The main hydrometeorological parameters that influence to the ice accretion onto installations and vessels are air and water temperature, wind speed and direction, swelling (wave height and direction of it) as well as the intensity of changes in the weather's characteristics. Long-term observation analysis has shown, that the icing most commonly occurs when the air temperature is -4 °C to -16 ° C in 78% of cases, and at a temperature of -3 °C and a wind speed of 6 m/sec in 93.2% of cases. In the north-eastern part of the shelf ice accretion is most likely under the action of the winds from the north, northwest and northeast. During the southern winds ice accretion in the area was not observed.

Marine and mixed ice accretion occurs when the air temperature is below -1,8°C (the freezing temperature of sea water).

The mass of water falling on the vessel, depends on the frequency of vessel – vase, height of the vessel board, its size, the ship's course towards the front of the wave's propagation. Vessels face see water at a wind speed of 8-10 m/s and above.

As a result, marine and mixed icing grows on the main deck, as well as deck's machinery, superstructure and other ship's structure.

The thickness of the accrued ice is 20-30 cm, in certain cases, may reach 1 m. The following types of vessel's icing have been established:

Slow icing. The average rate of ice accretion in ice thickness mn ≤ 1 cm/h, and the mass Ma ≤ 2 t/h, occurs at 0> Ta ≥ -3 °C, Va>0 m/s and when Ta <-3 °C, Va ≤ 10 m/s.

Fast icing. The average rate of ice accretion in ice thickness 1 <mn ≤ 3 cm/h, and the mass of 2<Ma≤ 6 t/h, occurs at Ta <-3 ° C, 10 <Va ≤ 15 m / s and at -3> Ta ≥ -8 ° C, Va> 15 m / s.

Very fast icing. The average rate of ice accretion in ice thickness mn>3 cm/h and the mass Ma>6 t/h, Ta occurs at <-8 °C, Va> 15 m/s. [33]

3 Challenges of the Sakhalin region

However tough and harsh climate may seem to be in the area of our study, for many inhabitants of the island it is primarily a shelter and natural habitat. Not to mention the fact that some of the local native tribes inhabited the island for several thousand years in spite of the harshness of the climate. Any infringement of the balance between man and nature can lead to catastrophic consequences, throwing to the brink of survival many species of unique flora and fauna of the island. Therefore, the primary task facing the government in the region and the country as a whole is to protect nature of any consequences and support this intact corner of nature in the world.

In this regard the most important aspect is the high efficiency and the quality of all activities, in order to avoid water pollution. Since the overwhelming majority of the ecosystem is directly dependent on this resource vital to keep everything in its previous form. Environmental pollution can be caused by the oil spill in the region, which in turn will create a thin layer of liquid hydrocarbons that can then spread to the vast distance, devastating all life in their path. Cold temperatures in combination with an emulsion of hydrocarbons within the range of the crystal lattice makes it incapable of dissolving, thereby decay will be lasting for decades. Moreover, technological operations caused by development of hydrocarbons such as noise and vibration caused throughout the whole work will create a detrimental impact on the entire ecosystem in the area. Whales, dolphins and other marine mammals are able to perceive this kind of signal, while the man is unable to detect it unaided eye. An inconvenience will contribute to a radical change in migration routes of marine mammals, which may lead to the extinction of entire groups of animals.

Returning to the issue of indigenous people who inhabit this island for thousands of years it should be noted that their entrenched life and traditions will also essentially undergo changes, and therefore adapt to change. Their main and essential source of feeding will be significantly shrunk, thus it would cause extinction and mass migration of people. Influence of big city life to their mentality incomparable and frequently these people will finish their days in certain cases suicidal outcome. Whether these individual types of tribes are capable of opposing to transnational corporations is a rhetorical question. I consider that the government on the legislative and executive level should protect the lives of the tribes. Both the companies and the government will have to be investigated in before the first stages of development of natural resources in the region, for maximum ensuring with minimal impact to the local ecosystem, indigenous people and their inner culture. Proceeding from this, compromise can be achieved only through negotiations with local residents and impact assessment on the nature of the region's ecosystem, even if they are not very well versed in the mechanics of sophisticated equipment, they are very well familiar with region which they have inhabited for thousands of years.

To gain an understanding of the conditions in which operation will be carried out for the development resources necessary to identify the main issues that will be discussed in detail. Among them, we would like to note the following:

• Sea Ice Cover
• Polar lows
• Frost climate
• Atmospheric icing and ice spray
• Fogs
• Market remoteness
• Lack of infrastructure
• Escaping and evacuation

In order to find solutions to these problems, consider the basic characteristics of the Kirinskoe gas field.

The Kirinskoe field has two bays - the Lunskoe and Nabil (Butakova). The coast between the bays is sandy, well-formed beach, resulting from the erosion of low cliffs by storm waves. Spacious Lunskoe Bay represents a shallow lagoon separated from the Sea of Okhotsk by two relatively narrow sand spits (sandbars). Entrance to Lunsky Bay is possible in the high water only for ships with a draft of 0.8 m. Furthermore, during the severe storms the passage can be completely mudded with sand. Nabil Bay is separated from the Sea of Okhotsk with the wide sandbar of Aslanbekova. Inside of the spit (sandbar), completely closed from swelling (waving), two-meter depth stretches are at the distance of 45-50 meters from the shore. There are berths with the range of the depths of 5-7 meters. Gate to Nabil Bay through the Strait of Aslanbekov is available for vessels with a draft of up to 3.0-3.5 m. In the northern part of the bay along the sandbar stretches a lineup of islands.

The eastern coast of Sakhalin Island has been studied relatively poorly. The water area of the sea off the coast of the district has a sloping low-angle character with a smooth bottom with a gradual growth in the depth of the distance from the coast. Two meter isobaths passes about 300 meters from the coast, a five-meter isobaths - at 500-550 m, 10 meters isobaths passes at the distance of 1100 - 2000 meters from the shore and 20 meters isobaths - 4000 - 6500m. The average water depth of the sea area of gas-field depth constitutes approximately

90 up to 160 meters [25].

In general, the above mentioned depths of the sea and soil conditions provide favorable conditions for deepwater work in the sector of the sea. Thereby the installation of subsea production systems in the production of hydrocarbons will help to avoid the consequences of such natural phenomena as hummocks, sea ice, wave and wind loads, influence of cold temperatures and icing. The most dangerous problem of what was described above is the presence of first-year ice in the seawaters of the shelf zone. Ice can cause severe impact loads that can damage the vessels and ships involved in operations with drilling and / or transport logistics (maintenance) operations.

For little less than six months the vast area of Okhotsk Sea is not covered with ice nevertheless from November to May it is covered with drift ice about 130 cm in thickness. This can cause great difficulties for maritime operations, as additional environmental considerations must be taken during design stage. Consequently, the presence of ice with its properties and features, as well as the presence of pack-ice or hammocks certain operations are currently recommended to be conducted approximately from June to mid-October.

In conjunction with the problems of ice and prolonged low temperatures in the described field, I would like to mention the factor of the hydrates buildup in pipes both during production and transporting products from the field into the workshop of primary processing and separation.

On one hand the pipe leak can lead to severe environmental consequences, but on the other - maintaining the desired temperature will increase the cost of the production process whether MEG injection or heating of the pipe, which will undoubtedly affect the OPEX.

In continuation of transport issue and touching on the further development of the project "Sakhalin-III" the following should be noted: “South Kirinskoe” field contains huge reserves of oil, and therefore oil transportation for example by means of tanker raises a question about the use of ice-breakers, but in our case we will not consider the issue in more detail because the distance to shore about 30 km, and in our region, type of ice is a first-year ice.

However, not only the ice and ice ridges are the primary challenges that must be taken into account to mitigate the consequences at occurrence of risks during operations. These features will be presented in more detail below. What is the main difference between them from the first two that has been described and that has not obtained sufficient attention, even if it occurs periodically from year to year?

Despite the fact that many have not heard of such a phenomenon as polar lows, polar low not only the phenomenon of the North East Atlantic and the Scandinavian Peninsula.

Erik A. Rasmussen claimed “While the early studies of polar lows were concerned with systems over the northeast Atlantic and the Barents and Norwegian Seas, meteorologists soon noted that similar vortices were to be found in other parts of the world, including the North Pacific, the Sea of Japan and the Labrador Sea. Mesoscale lows in these areas varied in intensity, but they were clearly very similar to the polar lows that had been observed over the northeast Atlantic and in the Scandinavian region. In most of these areas there is a large difference between the sea surface temperature and near-surface air temperature, pointing to the importance of air–sea interactions in the development and maintenance of the vortices.” [34].

Polar lows are defined as low - pressure systems that are normally generated when cold air breaks out over the warmer sea. Energy to drive the system is provided by heat and moisture transferred from the sea and by energy transformation within the atmosphere [35]. Wind speeds typically increase to storm force in a very short time (1/2 – 2 hours) reaching wind speeds of up to 35 m/s at a height of 10 m averaged over 10 minutes, with changing wind directions [35], [36].

All this is accompanied by heavy snowfall and poor visibility. And usually high waves accompanied by strong winds, creating the risk when driving and the operation of the sea thereby stopping all processes and activities. Polar lows can cause capsizing of vessels. Also, in addition I would like to note the impact of winds that predominate over the water area and the island. Despite the fact that the average annual speed of 4,1m/s, the maximum wind speed has always accounted for the winter period where the maximum wind speed can make up 24 m/s. There was also a maximum speed recorded in 1988 and it constituted hefty 43 m/s. This is a fairly substantial value that should not be neglected during the planning and conducting of maritime operations, construction and maintenance.

In addition to the extreme weather conditions we should include high waves, low temperature. Near the station «Nogliki» the average temperature of the coldest month is -10,3 ° C, while absolute minimum temperature was constituted -48 °C, wherein duration of the period with average daily temperature below 0 °C about 186 days. [26]. Therefore, it should be noted that temperatures near or below 0 °C issued a threat and can affect the conducting of any operation in many cases such as:

- Reduced mobility of personnel and increased risk of human error
- Malfunction of mechanical equipment
- Increased weight with high center of gravity on vessel deck and superstructure (could lead to capsizing)

- Atmospheric and sea spray icing (discussed further below)
- Need for winterization leading to increased need for ventilation and increased risk during gas leaks
- Blockage of escape equipment, escape routes and process equipment
- Escape routes build up ice and become slippery

Design and selection of appropriate materials for insulation must be included in the risk assessment in order to reduce risk of freezing machines and equipment. As it is known when freezing water expands it can cause rupture of pipes and valves. But as sea spray or atmospheric precipitations such as rain or fog may lead to icing on ships and structures which are located in Okhotsk Sea.

Atmospheric icing may be divided into 3 types

1) When the cooling vessel in the fog at temperatures from 0 ° C to -10 ° C;

2) Rain at temperatures from 0°C to -10 °C,

3) Snow at temperatures of about 0°C to + 3°C.

This form of icing is limited, and it is easily removed by heating or by applying a special solution for key types of equipment.

different accretion zones on a vessel and the two pictures that follow show the possible extent of such icing.

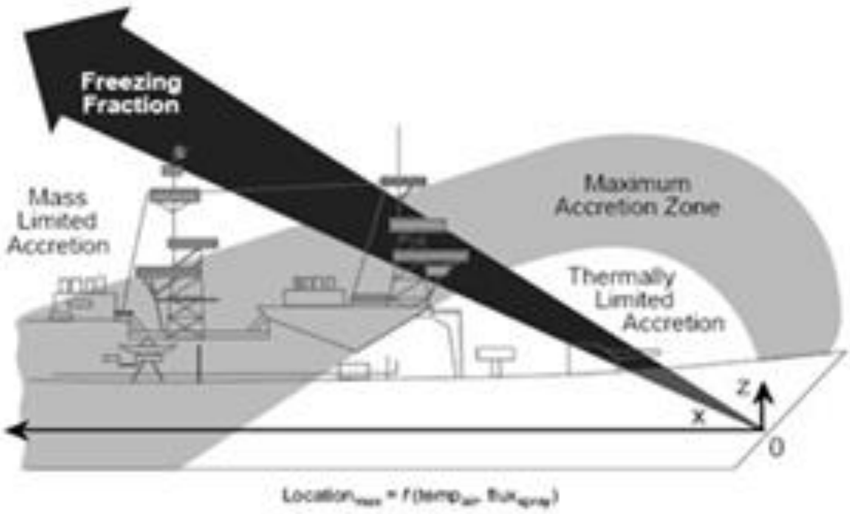


Figure 6. Ice accretion zones in the result of sea spray on a vessel [37]

Sea spray entail more problems as it can lead to the overturning vessel. Frequently it depends on the ambient temperature and the sea, the height of the waves, wind speed, and the shape and speed of the vessel.

When the temperature falls below the freezing point of sea water (-2 °C) and sea spray and droplets hits the deck it starts progressing rapidly in size and the weight of the vessel is greatly increased. Worth noting that a layer of about 40 cm can weigh about 1,000 tons.

One of the challenges that should be attributed to our problems is fogging. It's quite an acute problem as mentioned earlier that fog is not only premise for the appearance of icing, but also the fact that the fog is a problem #1 for the navigation itself.

1. Fog is one of the main elements that affect flying conditions in the Arctic. Moist air streaming over cold land creates fog. It is most common in the areas along the shore line. [38].

2. Ice fog occurs generally around -45°C or colder but may also appear in higher temperatures as -30°C [38].

3. Cold air hovers over warmer water not being able to sustain water content in it is called sea smoke. [38].

4. Arctic haze may reduce horizontal visibility but generally has no effect on vertical visibility [38]. It can cause weather delays and affect the operations.

In addition to the uncontrollable aspects related to the natural atmospheric and climatic parameters, it is worth to take into consideration other very serious problems. One such example could be a question of distance. This subject should be considered also in the light of the full or partial lack of infrastructure. However, in the case "Sakhalin-III" project it is worth noting that only through joint efforts as an example of cooperation of the project "Sakhalin-3" project and Sakhalin Energy was able to drastically reduce CAPEX. It represents joint venture construction of a pipeline to transport condensate from the fields. The importance of infrastructure availability and remoteness from major markets becomes very, very urgent issue in the light of the rapid fall in hydrocarbon prices. For the island of Sakhalin as well as for project as a whole an important and essential market for the products are the countries of the Pacific Rim. This raises several questions, whether to develop the field by single 100% stake company, or to establish a consortium consisting of companies that nowadays have been involved in projects to develop offshore fields on Sakhalin Island, and the second important question the advantages of Floating Liquefied Natural Gas (FLNG) in comparison with pipeline system.

Moving on to the discussion of the economic aspects it should be noted that due to the sharp drop in world prices for hydrocarbons and sanctions imposed by Western countries the key production equipment as well as all available materials must be sourced within the Russian Federation. It is worth mentioning as an example the construction of the lower mounting base semi-submersible drilling rig Polyarnaya Zvezda (Polar Star), for Shtokman and Sakhalin-III projects made at the Vyborg Shipyard Vyborg while larger part the work - the drilling rig - was built in South Korea, at the Samsung Heavy Industries factory. Moreover, I believe that the engineering designing and support must be procured in Russian Federation. Thus we are solving several tasks, the first of which supporting domestic products manufacturer, and the second reduces the risk of dependence on supplies from one country or another. However, on the other hand we should still consider cooperation with world leading companies producing oil and gas equipment such as Schlumberger, Aker Solutions, and creation of joint venture in Russia for the purpose of supplying consumable materials and spare parts production facilities, as well as designing of new objects.

It is also necessary to plan thoroughly in order to organize all phases of construction and at the same time rigorously follow the schedule to project time-line as this is necessary for the economy of the whole project. With regard to the development of such a large deposit as Sakhalin-III, you first need to find a major customer or group of customers for this kind of project before initiating the development of the field, to assess all collateral risks beginning from the risks related to the environmental protection and finishing with the economic and geopolitical risks. The Asia-Pacific region have a presence of focused major players-vendors of hydrocarbons such as Australia, Malaysia, etc.

Continuing with the subject of the distances I would like to emphasize specifically another important aspect. This is from my point of view is the most important aspect that needs to be carefully designed and evaluated before all the works begin is a procedure for the evacuation of all personnel working on all types of vessels and installations at sea. The development of fields in southern latitudes in this issue is less problematic due to availability of well-developed coastal infrastructure for search and rescue personnel. However, in the northern latitudes in the conditions of ice infested waters carrying out such operations increases in a geometrical progression. Nowadays the maximum cruising range of a helicopter is about 300 km. A good example is Shtokman project located in the Russian sector of the Barents Sea, 610 km north-east of Murmansk, where the nearest land (about 300 km) is the west coast of Novaya Zemlya [39]. Another problem is associated with a descent of rescue floating lifeboat onto water from a platform or a vessel when the structure itself is surrounded by ice and / or drifting ice. It also issues a threat to a life and can be extremely dangerous because the navigation equipment and materials for manufacturing, as well as construction projects for the classes of ships of the northern vessels is significantly different from class of equipment for the southern vessels. The challenge is that currently there is no unified base of standards, rules and regulations for the design of such vessels for the Arctic and sub-Arctic regions. At the same time there is a huge difference in numbers of vessels on the shelf of warm seas, for example the Gulf of Mexico and all the countries of Arctic Council, so in the event of an oil spill nobody will be able to even respond to the consequences because the amount of fleet is very negligible. For example, Deepwater Horizon accident response 1,500 large and small vessels were involved, but if such an accident occurs in the Arctic, how many vessels will there be at our disposal? Rhetorical question...

As a result, the most important aspect of this is the environmental safety and the risks associated with operational safety during procedures. Absolutely all the works must be strictly regulated with the rules of HSE (Health, Safety and Environment). Only in this way we can avoid the catastrophic consequences caused by human activities thereby to preserve our planet for future generations.

4 Ongoing developments of offshore Sakhalin fields

General information about Sakhalin region

Sakhalin Region is unique in its geographical position. It is situated on 59 islands and has a favorable geographical location to the world markets, particularly to the Asia-Pacific markets.

The region has a huge resource potential for energy sources: oil, gas, coal. Recoverable reserves are estimated to be 495 million tons of crude oil and condensate, 1.3 trillion m^3 of natural gas. Major reserves are concentrated in the offshore zone.

In this case the economic potential of the island region continues be disclosed in new oil and gas projects. And even despite the fact that in Russia the growth rate of oil production in 2014 amounted to 0.4% in the Sakhalin region – it has grown up to 4.8%. Natural gas production in Russia as a whole decreased by 4.3%, while in the Sakhalin region, these indicators increased by 2.9%.

The basic document setting forth a development strategy for gas supply to Eastern Siberia and the Far East as well as gasification of these regions is the state-run Development Program for an integrated gas production, transportation and supply system in Eastern Siberia and the Far East, taking into account potential gas exports to China and other Asia-Pacific countries (Eastern Gas Program). It is these circumstances have served as an impetus for the concept of active development of hydrocarbon resources of the Sakhalin shelf, which developed the Russian Government. The whole island's shelf was split into perspective blocks, which has received name "Sakhalin-I", "Sakhalin-II", "Sakhalin-III" - down to "Sakhalin-IX" (Figure 7).

Currently the development of the Far East Okhotsk Sea shelf of Sakhalin Island is carried out in several phases, the first three of which already underway. Implementation of the projects themselves are leading such well-known companies as ExxonMobil, Rosneft projects themselves, Shell, Gazprom. Table 18 provides a brief description about Sakhalin's production facilities

Table 18. Sakhalin's production facilities

№	Project	Lease operator	Location	Water depth	Patterns	Drilling	First oil	Peak production
1	Sakhalin-I "Arkutun Dagi"	Exxon Neftegas Limited	Okhotsk Sea, Sakhalin Island	18 meters	GBS + pipeline	Fixed platform	2015	90 MBOPD 60 MSCFD
2	Sakhalin-I "Chayvo"	Exxon Neftegas Limited	Okhotsk Sea, Sakhalin Island	15 meters	GBS + pipeline	Fixed platform	2008	94 MBOPD
3	Sakhalin-II "MolikPaq (PA-A)"	Sakhalin Energy Investment Company	Okhotsk Sea, Sakhalin Island	32 meters	GBS + pipeline	Fixed platform	1999 tanker 2008 pipeline	90 MBOPD 72 MMSCFD
4	Sakhalin-II "PA-B"	Sakhalin Energy Investment Company	Okhotsk Sea, Sakhalin Island	34,5 meters	GBS + pipeline	Fixed platform	2007	70 MBOPD 100 MMSCFD
5	Sakhalin-II "LUN-A"	Sakhalin Energy Investment Company	Okhotsk Sea, Sakhalin Island	48 meters	GBS + pipeline	Fixed platform	2008	50 MBOPD 1800 MMSCFD
6	Sakhalin-III Kirinskoye	Gazprom	Okhotsk Sea, Sakhalin	90 meters	Subsea production system	Semi-submersible platform	2014	TBD

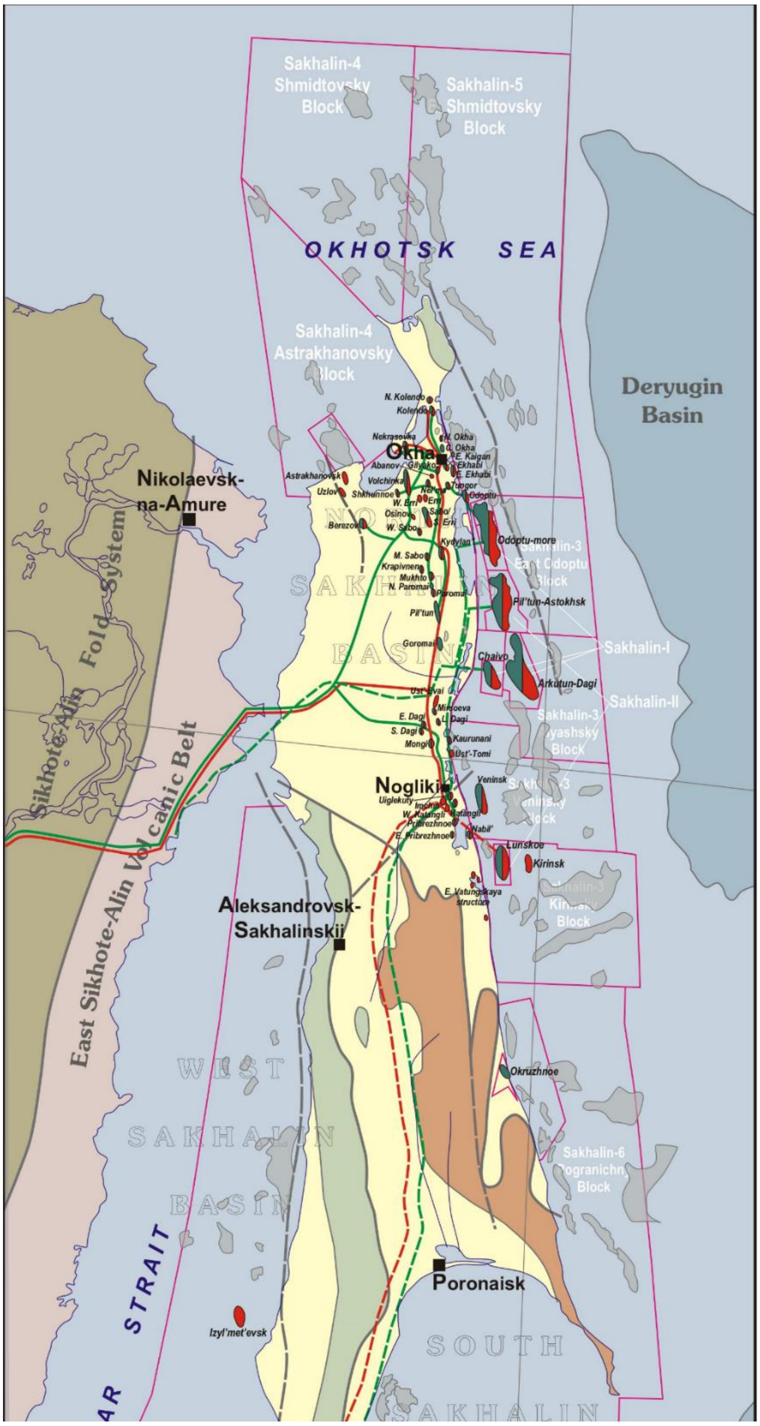


Figure 7. General map (Courtesy of Blackbourn Geoconsulting) [45]

«Sakhalin-I» project. Consortium partners: ExxonMobil, Rosneft, ONGC, SODECO. Operator: Exxon Neftegas Limited.

Sakhalin-I (Russian: Сахалин-I) project (Figure 8), includes three oil and gas fields - Chayvo, Arkutun-Dagi and Odoptu - located off the northeast coast of Sakhalin Island in the Russian Far East. Potential recoverable resources are 307 million tons (2.3 billion barrels) of oil and 485 billion m^3 (17.1 trillion $feet^3$) of natural gas.

Figure 8. Exxon Neftegas company's assets (Picture courtesy of Itochu Corp.) [46]

At *Chayvo* field development of "Sakhalin-I" project using floating platform *«Orlan»* (in Russian «Sea Eagle») (Figure 9). The 20-well concrete structure is being used to develop the southwestern flank of the main Chayvo zone. [47] The «Orlan» Drilling Platform consisted of a refurbished Beaufort Sea exploration gravity based structure (GBS) previously known as the Alaskan Concrete Island Drilling System (CIDS). It was initially built in 1983 for year round drilling in arctic waters. Refurbishing the CIDS presented a cost savings opportunity of more than $100 million USD rather than constructing a new gravity based platform. The chosen execution strategy was to tow the CIDS from Alaska’s North Slope to a Russian shipyard where the existing topsides would be removed and the structure would be strengthened to withstand the heavy ice loads, extreme temperatures and severe seismic and wave conditions found offshore Sakhalin Island. CIDS was stripped to the deck and outfitted with new quarters, drilling and production modules. [48] [49] Installation of the Orlan platform was completed in July 2005 and drilling operations commenced in December 2005. Offshore processing facilities are minimal, with a full well stream sent to shore for further processing at the Chayvo OPF. Drilling operations on the Orlan platform were completed with a total of 21 ERD wells drilled. Most of the Orlan wells are in the 5.5 kilometer range, with the longest well drilled measuring 7.5 kilometers long. [47] Now the Orlan, one of the largest company’s operated platforms, features a fifthgeneration drilling rig with more than 13,000 hp, a 10 MW power plant and living quarters for 120. The total weight of topsides was 12,000 tons, which required internal strengthening of the CIDS steel deck barge. The platform's ~950 MN base shear capacity was more than adequate to resist global ice and wave loads. The 15-meter water depth was near the upper design limit of the CIDS, so special provisions had to be made for wave loading. [48] [49]

Figure 9. The «Orlan» platform (Photo courtesy of ExxonMobil Corp.)

On another oil field bearing the name *Arkutun Dagi* of the project "Sakhalin-I" is located approximately 25 km off the northeast coast of Sakhalin and to the east of the Chayvo field. Peak daily production from the field is expected to reach 90,000 barrels. The platform *«Berkut»* (means Golden Eagle) has been installed, specially built to operate in sub-Arctic conditions (Figure 10). The Berkut structure consists of a four-shaft gravity based structure (GBS) with a topsides operating weight of approximately 50,000 tones. The structure is designed to operate year-round and to withstand extreme winter temperatures, seismic shocks, seas up to 16 m, and sea ice that can be as much as 2 m thick. Water depths at Arkutun-Dagi range from 15-40 m. [50]

Figure 10. The «Berkut» platform (Photo courtesy of ExxonMobil Corp.)

The Odoptu development produces oil and gas from the Odoptu field, located off the northeast coast of Sakhalin Island near Piltun Bay, approximately 100 kilometers north of the Chayvo field. The Yastreb (in Russian Hawk) land-based drilling rig at Chayvo was relocated to Odoptu in 2008, where it is used to drill extended-reach wells to the offshore field. An onshore oil and gas treatment facility is being constructed at the Odoptu site and a flow line transports oil and gas from Odoptu to the existing Chayvo onshore processing facility. [51]

The Yastreb arctic, seismic class land rig (Figure 11), was designed and built by Parker Drilling, is drilling horizontal wells to reach the Odoptu field offshore Sakhalin Island. The rig was sold to Exxon Neftegas Limited and is operated by Parker. [52] The 13,000 hp Yastreb is the world’s largest and most powerful onshore drilling rig designed to drill Extended Reach Drill (ERD) wells that extend almost 3 km down and more than 10km laterally with pinpoint accuracy of offshore targets, making the wells among the longest in the world. The enclosed rig, standing at 22-stories high, is earthquake resistant and is designed for year round operations. Attached to the rig is a 40 by 41 meter fully enclosed pipe barn where stands of drill pipe and casing are made up and racked horizontally as a safety precaution against earthquakes. During the winter months, temperatures routinely dip to -40°C and storms produce gale force winds; the temperature inside the fully enclosed rig and pipe barn is maintained around 21°C. Moving the rig and the utility modules, mud pits and pipe barn from one well head to the next was accomplished by placing the rig on rails and hydraulically sliding everything into position. [49]

Figure 11. The «Yastreb» rig (Photo courtesy of Parker Drilling)

Offshore oil export terminal in De-Kastri.

The De-Kastri terminal provides storage and export facilities that accommodate year-round crude oil export to world markets. Centered on a peninsula on the Russian mainland, the De-Kastri Terminal is even more remote than the Chayvo work sites. The area of the terminal covers nearly 256,000 m^2. The terminal includes two 100,000 m^3 (650,000 barrels) storage tanks, three 3,600 m^3/hr crude loading pumps, three 6MW duel-fuel turbine generators, two duel-fuel crude oil heaters and inlet, custody transfer metering units and a 48-inch subsea loading line. In addition to the terminal facilities, the remoteness of the De-Kastri terminal requires the terminal to be self-sufficient with its own power generation, water supply, waste management and living quarters for the operating staff. [49]

Onshore Processing Facility in Chayvo

Production from the Chayvo and Odoptu fields is transported to the Chayvo Onshore Processing Facility (OPF), which is designed to produce at the rate of approximately 34,000 metric tons (250,000 barrels) of oil and 22.4 million m^3 of gas per day. The OPF produces stabilized crude oil which is shipped to the De-Kastri terminal for export, and natural gas which is either supplied to the Russian Far East or injected back into the Chayvo field to maintain reservoir pressure. [47]

The facility and the supporting infrastructure, which was built using a combination of ‘stick built’ and module fabrication, consists of the following:

• Inlet slug catcher

• Three phase separation

• Gas handling and compression

• Export oil pumps

• Produced water handling and disposal via onshore wells

• Utilities, warehousing, control room and living quarters [49]

Pipeline System

Pipeline system consists of:

• 19.31 km 36” full well stream pipeline from the Orlan platform to the Chayvo OPF.

• 19.31 km 24“ gas reinjection pipeline from Chayvo OPF to the Orlan platform.

• 225 km 24” export oil pipeline from Chavyo OPF to DeKastri Terminal with 19.31 km under the Tartar Strait

• 5.7 km 48” subsea loading line from DeKastri Terminal to the SBM

The 225 km export oil pipeline from the OPF a crossed Sakhalin Island and the Tatar Strait to De-Kastri and nearly 90 streams as well as three fault lines, so high-strength pipe was laid in these areas as a precaution against earthquakes. Pipe lay across the streams were conducted during the winter months to minimize any possible sediment impacts on salmon. The export system consists of eight fully automated isolation valve stations, a fiber optics cable for telecommunications across the project area and a state-of-the-art leak detection system [49], [51]

Tankers

The tankers are able to weathervane around the platform so as to stay in the wake of broken ice and minimize hawser loads. Icebreaker escort is provided for the ice-strengthened tankers during winter transits of the strait.

Tanker trials were performed in 2002 using the tanker the double-hull “*Primorye”* with a dead weight tonnage (DWT) of 105,177 metric tons and two Russian icebreakers to confirm escort requirements and design transit speeds for Tatar Strait ice conditions. [48]

The “Sokol” single point mooring loading tower

The “Sokol” SPM (Single Point Mooring) oil loading platform shown in Figure 12 It is located 5.7 km east of the Klykov Peninsula in the Chikhacheva Bay offshore from DeKastri terminal, represents the world’s largest fixed tower of its kind weighing 3,200 tons and rising 61 meters above sea level. Up to 33,000 tons (250,000 barrels) of the Sakhalin-I “Sokol” crude is exported daily with tankers departing every three-four days on average. It was designed with conical waterline geometry to facilitate bending failure of the ice, which minimizes ice loads and therefore foundation requirements for the piled structure. [47], [48], [49]

Figure 12. The «Sokol» Single Point Mooring (Photo courtesy of ExxonMobil Corp.)

«Sakhalin-II» project. Consortium partners: Gazprom, Shell, Mitsui, Mitsubishi. Operator: Sakhalin Energy Investment Company Limited.

The Sakhalin-II (Russian: Сахалин-II) a sister project to Sakhalin-I. The project includes development of the Piltun-Astokhskoye oil field and the Lunskoye natural gas field offshore in the Okhotsk Sea, and associated infrastructure such as: three offshore drilling and production platforms, offshore pipelines, onshore processing facilities, an oil export terminal, Russia's first liquefied natural gas (LNG) plant, and approximately 800 km onshore Trans-Sakhalin pipeline system (Figure 13).

In implementing these oil and gas fields, three gravity types of platforms are used to drill: «Piltun-Astokhskoye-A» platform (PA-A / Molikpaq) (Figure 15), «Piltun-Astokhskoye-B» platform (Figure 17), and «Lunskoye-A» platform (Figure 18). Obtained after separation, hydrocarbons are transported through the system of offshore and onshore pipelines onto the offloading of oil and gas terminal, respectively, through the oil pumping and gas compressor station.

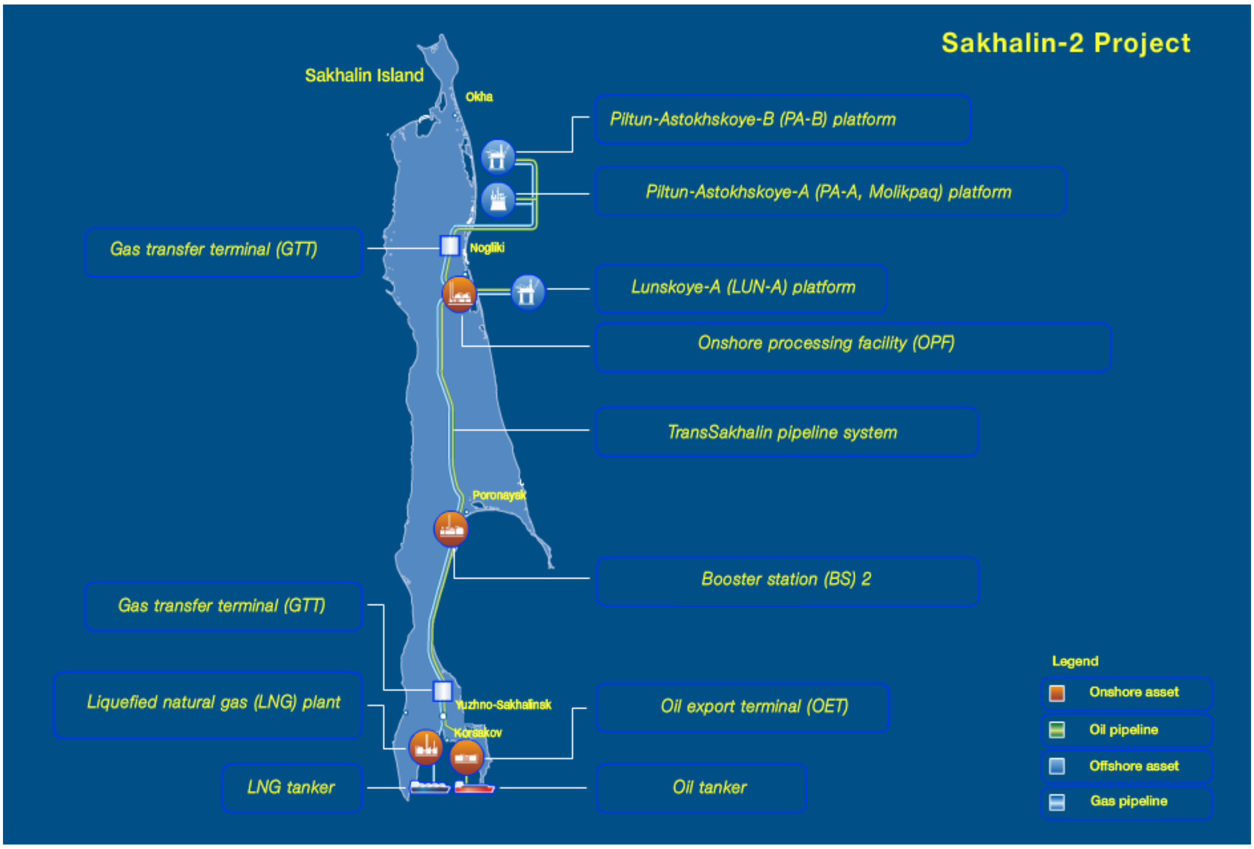


Figure 13. Sakhalin Energy company's assets (Picture courtesy of Sakhalin Energy Investment Company)

Phase 1

The first phase of development on Sakhalin II was launched by the Russian government in July 1996, and project partners approved the plan of development in July 1997. Phase 1 (Figure 14) involved the installation of the Vityaz Production Complex on the Piltun-Astokhskoye oil field. Located in 30 meters of water in the Sea of Okhotsk, 16 kilometers off the eastern coast of Sakhalin Island, Vityaz consists of the refurbished Molikpaq offshore oil production platform, mooring system and Floating Storage Offloading (FSO) unit. [53]

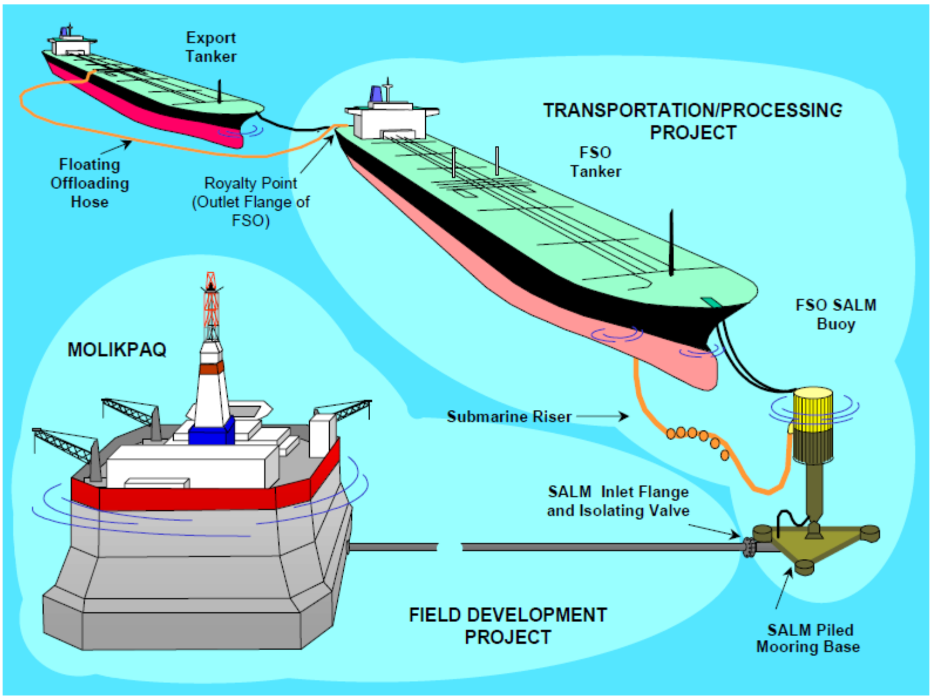


Figure 14. Piltun-Astokhskoye Phase-1 Development (Picture courtesy of Sakhalin Energy Investment Company)

Piltun-Astokhskoye-platform (PA-A / Molikpaq) former The-Vityaz Offshore Production Complex.

The Vityaz Production Complex offshore Sakhalin Island (Russian Far East) centers around the permanent drilling and production unit Molikpaq and serves development of the Piltun-Astokhskoye (PA) Field. This production complex was installed at the Piltun-Astokhskoye Field in 30 meters' water depth, 16 kilometers offshore Sakhalin Island's northeast shore in the Sea of Okhotsk on Sept. 1, 1998.

The Molikpaq was the first in Russia offshore oil production platform. It was constructed in 1983/1984 as a massive, octagonal Mobile Arctic Caisson, offshore drilling unit, with a classification rating of Ice Class 1AA by the American Bureau of Shipping (ABS). The Molikpaq had operated in this capacity in the Beaufort Sea (Canadian Arctic) as a drilling facility only. However, the engineering studies indicated that it could be modified to support additional wells and process facilities and become a full production platform operating safely in the challenging wave, ice, and seismic conditions characteristic of the Sakhalin region.[54] In 1997 it was acquired from Gulf Canada and afterwards in 1998, the Molikpaq was towed from the Beaufort Sea across the Pacific Ocean to the Daewoo Heavy Industries Shipyard at Okpo South Korea where then was upgraded to provide all of the required facilities for this remote development, including accommodations, the ability to drill and produce up to 32 wells, an oil export system and appropriate gas utilization.[55] After that the Molikpaq was placed on an engineered foundation pad formed by dumping of dredged sand into an excavation which removed inferior seabed material. After set-down of the platform, the center core of the Molikpaq was hydraulically filled with dredged sand. The foundation pad soil improvement and core filling was required to provide sufficient stability to the platform under wave, ice, and earthquake loading during its service life of 30 to 40 years. [56]

To accommodate the 30 meters' water depths and harsh wave climate, the Molikpaq had to be deepened. After assessing a number of alternatives, the solution chosen was to design a pontoon-type steel base, ultimately named the "Spacer". The "Spacer" is necessary for the Molikpaq's operation in waters deeper than its initial 15-to 20- meter Beaufort Sea design.

From 1999 till 2008 for the export of the produced oil a 324 mm (12.75") diameter subsea pipeline was installed connecting the Molikpaq to a Single Anchor Leg Mooring buoy (SALM). After that produced oil was delivered by to the shore processing facility by double hull "Okha" floating storage and offloading (FSO) vessel. Oil production occurred only during a six-month period when ice cover was not prohibitive to navigation and SALM operation. The combined Molikpaq, SALM and FSO facilities have recently been named the "Vityaz Complex."[55]

Year-round oil production from the Piltun-Astokhskoye-platform (PA-A / Molikpaq) was launched in December 2008. Oil from the platform streams through the Trans Sakhalin pipeline system to the oil export terminal of the Prigorodnoye production complex.

Platform statistics:

- 120 meters wide.
- About 37,500 tones weight.
- Molikpaq is ballasted down with 278,000 m^3 of sand.
- The living quarters have a capacity for 134 permanents and an additional 30 temporary staff.
- Production capacity: oil – 90 000 b/d; associated gas – 2.0 mln m^3/d.

Figure 15. Piltun-Astokhskoye-A (PA-A/Molikpaq) platform (Photo courtesy of Sakhalin Energy Investment Company)

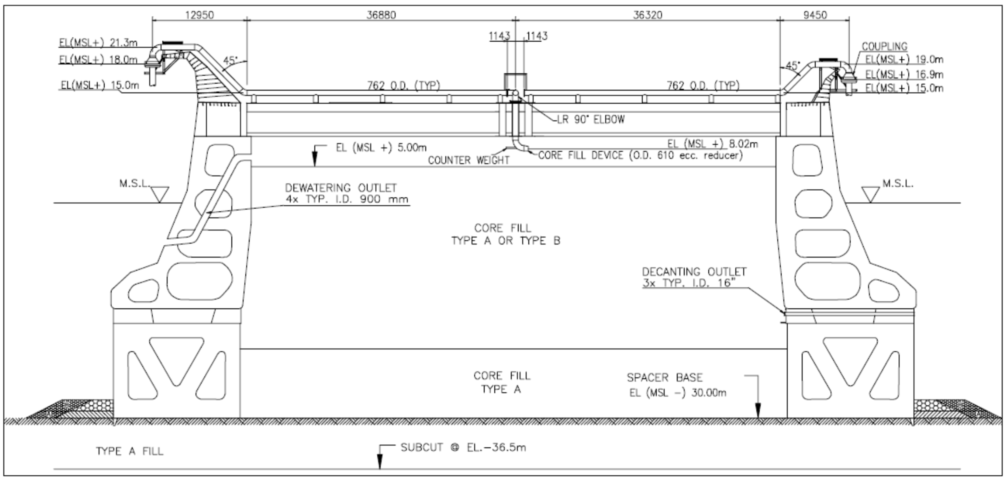


Figure 16. Cross-section over Molikpaq after refurbishments (courtesy of Sakhalin Energy Investment Company)

Phase 2.

Phase 2 of the Sakhalin II project was launched in 2003. It provided for the comprehensive development of the Piltun-Astokhskoye and Lunskoye fields.

Phase 2 included commissioning of the Piltun-Astokhskoye-B (PA-B) platform in the Piltunskaya area of the Piltun-Astokhskoye field and Lunskoye-A (LUN-A) at the Lunskoye field. Extracted gas being routed from both platforms run through the offshore multiphase pipelines to the Onshore Processing Facility (OPF). From there the treated gas is being sent to the liquefied natural gas (LNG) plant in the south of Sakhalin via 800-kilometer onshore Trans-Sakhalin gas pipeline system.

The Structural Platform Solutions for both Lunskoye A (Lun-A) and Piltun-Astokhskoye B (PA-B) platforms for the Sakhalin II development are in principle identical and comprise a four-legged concrete gravity base structure (GBS), supporting an integrated deck, with a proprietary seismic isolation system known as Friction Pendulum Bearings (FPBs), interposed between the topsides and GBS. Four FPBs per platform are utilized that correspond with the four concrete GBS support legs. Table 19 provides some high level data for both Sakhalin II platforms. [57]

Table 19. High Level Platform Data

	Lun-A	**PA-B**
Design Life (years)	30	30
Topsides Dry weight (tons)	21 000	27 500
Topsides Operating weight (tonnes)	27 000	33 500
Approximate Topsides Plan Dimensions (m)	100 x 50	100 x 70
Water Depth (m)	49	30
Approx. % Topsides Structural weight vs. Topsides Dry weight	56	57
Number of longitudinal Primary Trusses and Transverse Primary Trusses	4 and 6	4 and 6
Number of Conductors	27	45
Facilities	Drilling, Production utilities, Living quarters	Drilling, Production utilities, Living quarters
Gas production	1850 MMSCFD	100 MMSCFD
Oil/Condensate production	50000 BPD	70000 BPD
GBS caisson size LxBxD (m)	105x88x13.5	105x88x13.5
Number of GBS columns	4	4

Figure 17. Piltun-Astokhskoye-B (PA-B) platform (Photo courtesy of Sakhalin Energy Investment Company).

Figure 18. Lunskoye-A (Lun-A) platform (Photo courtesy of Sakhalin Energy Investment Company.)

Lunskoye-A platform (Lun-A)

Located in 48 meters of water 15 kilometers off the northeast coast of Sakhalin Island, the Lunskoye-A platform will develop the Lunskoye gas field, producing gas and condensate. The offshore facility houses a directional drilling unit with slots for 27 wells and processing facilities, as well as living quarters. With a daily production capacity of 50 MMm^3/d and 50,000 bpd of condensate, the Lunskoye-A platform will supply the majority of gas to the new LNG facility. The substructure for the facility was installed in July 2005, and the 24,250-ton (22,000-tonne) topsides was installed by Saipem in 2006. [53]

Piltun-Astokhskoye-B platform (PA-B)

The Piltun-Astokhskoye-B (PA-B), the largest platform of the Sakhalin-II project, is a drilling, processing and production platform that has been extracting oil and associated gas from the Piltun reservoir since 2008. The hydrocarbons from the PA-B platform flows through the offshore and onshore pipelines to the LNG plant and oil export terminal at the Prigorodnoye production complex. Platform statistics:

The PA-B platform is designed for year-round operation in harsh climatic conditions and is built to withstand rough seas, ice and high seismic activity. It is located 12 km off the northeastern coast of Sakhalin Island, in a water depth of around 30 m. Four legged concrete gravity base substructure (CGBS) that was engineered and constructed in Vostochniy port by Aker Kværner Technology AS and Quattro Gemini OY. PA-B CGBS was installed in August 2005.

Fully integrated deck construction built separately in South Korea, Samsung Heavy Industries construction yard. The topsides were installed in July 2007 on the pre-installed CGBS by float over technique. With the topsides installed on the base structure, the total height of the PA-B platform is 121 m from the sea floor to the top of the derrick - as large as a 30 storey building.

The platform includes drilling and gas/hydrocarbon liquids/water separation facilities, storage for chemicals. The living quarters have a capacity for 100 permanents and an additional 40 temporary staff.

Production capacity: oil approximately 70,000 b/d; associated gas 2.8 mln m^3/d. [58]

Trans Sakhalin pipeline system

Oil and gas produced under the Sakhalin-II project are transported via the trans Sakhalin pipeline system. These oil and gas pipelines run almost the length of the island and cross 19 seismic faults.

Onshore oil and gas pipelines are running from the landfall near Piltun-Astokhskoye field in the north of Sakhalin Island via the Onshore Processing Facility (OPF), to Prigorodnoye, in the south. The two pipeline systems (one for oil and one for gas) share a single 800 km right of way (RoW).

The distance from the Piltun-Astokhskoye landfall to the OPF is 172 km (pipeline diameters in this part of the route are 20 inch for both the oil and the gas line). The distance from the OPF to the LNG plant and Oil Export Terminal (OET) is 637 km (pipeline diameters in this part of the route are 24 inch and 48 inch for the oil and gas line respectively). Two short multiphase pipelines (30-inch diameter, onshore length 7 km) and a 4-inch Mono-Ethylene Glycol (MEG) pipeline in the same RoW connect the landfall at Lunskoye to the OPF.

The oil and gas pipelines share a single pipeline corridor. The pipelines are each installed in a separate trench (backfilled by a minimum 0.8-1.0 m layer of soil over the pipe). The external surface of the line pipe has an external three-layer polyethylene to protect them against external corrosion. At fault-crossing sites, special pipe-laying techniques are used to ensure their safety in case of seismic activity.

Operation of both main pipelines is controlled by a state-of-the-art pipeline leakage detection system. Six pipeline maintenance depots (PMD) and 104 block valve stations are installed along the pipeline route.

The total length of the pipeline system, including offshore pipelines, is 1,900 km, slightly shorter than the main artery of the Great Wall of China. [58]

Prigorodnoye Production Complex

The Prigorodnoye Production Complex (Figure 19) comprises a Liquefied Natural Gas (LNG) plant and the Oil Export Terminal (OET). The complex is located on the southern shore of Sakhalin island, alongside Aniva Bay, 15 km to the east from Korsakov. Aniva Bay doesn't freeze through winter and is an ideal place for oil and LNG deliveries as part of the Sakhalin-II project.

The area of the complex measures about 4.2 km^2. The Sakhalin-II LNG plant is the first of its kind in Russia The LNG plant has two parallel process trains and general services facilities. Gas treatment and liquefaction are performed on the process trains. LNG is produced using Double Mixed Refrigerant technology developed by Shell.

Shell developed this state-of-the-art technology for the Sakhalin LNG plant, to ensure maximum LNG production during severe Sakhalin winters. The production capacity of the plant is 9.6 million tons of LNG per year. The general services facilities of the Complex include nitrogen and air production units, instrument air systems, water and wastewater treatment plants, flare units and gas turbine generators for producing electricity. After liquefaction, LNG flows into two 100,000 m^3 tanks for storage before shipment. A special loading jetty, which can handle custom-designed LNG carriers with a capacity from 18,000 m^3 to 145,000 m^3, loads the LNG. [59]

The LNG plant includes:

- Two 100,000 m^3 LNG storage tanks
- An LNG jetty
- Two LNG processing trains, each with capacity of 4.8 million tons of LNG per year
- Two refrigerant storage spheres, 1,600 m^3 each (gross capacity) for propane and ethane storage
- A diesel fuel system
- A heat transfers fluid system for the supply of heat to various process consumers
- Five gas turbine driven generators with a total capacity of around 129 MW electrical power
- Utility systems including instrument air and nitrogen plants and diesel fuel systems
- A waste water treatment plant to treat both sewage water and coil-containing water.

The LNG plant has two LNG double-walled, storage tanks with a capacity of 100,000 m^3 each. LNG is exported via an 805 meters jetty in Aniva Bay. The jetty is fitted with four arms – two loading arms, one dual purpose arm and one vapor return arm. The upper deck is designed for a road bed and electric cables. The lower deck is used for the LNG pipeline, communication lines and a footpath. LNG is pumped from the storage tanks into the parallel loading lines which are brought to the LNG jetty. At the jetty head, the pipelines are connected with the jetty's four loading arms. The water depth at the tail of the jetty is 14 meters. The jetty will serve LNG tankers (Figure 20) which have capacities of between 18,000 and 145,000 cubic meters. Loading operations are estimated to take from six to 16 hours, depending on vessel capacity. The jetty will be able to handle loading of around 160 LNG carriers per year. [59]

Figure 19. Prigorodnoye Production Facility of Sakhalin-II project (Photo courtesy of Sakhalin Energy Investment Company Ltd.)

Figure 20. Grand Mereya LNG carrier at LNG jetty, Sakhalin II (Photo courtesy of Sakhalin Energy Investment Company)

Oil export terminal (OET) (Figure 21), including offloading pipeline and *Tanker Loading Unit (TLU)* (Figure 22) for loading oil to the tankers, is located to the east from the LNG plant and has management and supporting systems in common with it. The OET operations are managed in the Control Room, the supporting utilities are located on the territory of the LNG plant.

Oil is transported from the Piltun-Astokhskoye and Lunskoye fields through the transsakhalin pipeline system to the OET. The oil is then mixed with a small amount of condensate recovered from the natural gas stream, and stored in two floating roof storage tanks each with a capacity of 95,000 m^3.

Afterwards, the oil is transferred through the offshore pipeline to the tanker loading unit, which is situated in a water depth of about 30 m, 4.8 km offshore. Oil tankers with a capacity from 40,000 m^3 to 150,000 m3 can be loaded at the TLU. The 73.7 meters-high TLU is about as tall as Taj Mahal.

The LNG carriers and oil tankers are serviced in the first in Russia Prigorodnoye sea port. In May 2008 the port was opened for international connections by the Russian Federation Government decree.

Figure 21. Oil Export Terminal. (Photo courtesy of Sakhalin Energy Investment Company)

Figure 22. Tanker Loading Unit (TLU) (Photo courtesy of Sakhalin Energy Investment Company)

«Sakhalin-III» project. Gazprom is 100% owner. Operator: Gazprom Dobycha Shelf Yuzhno-Sakhalinsk

In April 2011 the Gazprom Board of Directors approved the updated Program for hydrocarbon resources development on the Russian Federation shelf until 2030. The Program implementation will enable Gazprom to annually produce over 200 billion m^3 of gas (without regard to gas from Sakhalin-II) and some 10 million tons of oil on the Russian shelf by 2030. [60]

Within the Sakhalin-III project (Russian: Сахалин-III) Gazprom operates in three blocks: Kirinsky, Ayashsky, and Vostochno-Odoptinsky (Figure 23). The Kirinskiy block comprises the Kirinskoye gas and condensate field together with the Yuzhno-Kirinskoye and Mynginskoye gas and condensate fields discovered by Gazprom. Sakhalin-III resources estimated at around 1.1 trillion m^3 are mostly concentrated within the Kirinsky block.

Figure 23. Gazprom Sakhalin III project company's assets.

Kirinskoye gas and condensate field

In 2009 Gazprom started developing the Kirinskoye field discovered in 1992 and located in the Sea of Okhotsk, 28 kilometers off the coast. Geological exploration was completed in 2011. All reserves are within the C_1 category (explored) and amount to 162.5 billion m^3 of gas and 19.1 million tons of gas condensate. In 2012 Kirinskoye started the construction of production wells with the use of the «Polyarnaya Zvezda» (Polar Star) semi-submersible drilling rig. After reaching full capacity in 2013, the field is projected to annually produce 5.5 billion m^3 of gas. In this case the equipment used for the production of hydrocarbons, is a so-called subsea production system (SPS), which was first implemented in the Okhotsk Sea shelf as part of arrangement of Kirinskoye gas field development phase one. This subsea production system in Kirinskoye field will service seven wells of which in line currently are only two of them, from which gas flows to the manifold, that is the centerpiece of the complex (Figure 24). Produced gas is collected in the manifold, and then transported by offshore pipeline to an onshore processing facility. Transportation is carried out without additional compression under the action of the reservoir pressure. At the onshore processing facility after the preparation for the transportation, gas is directed by 139 km pipeline to the main compressor station of gas transportation system «Sakhalin - Khabarovsk – Vladivostok». The manufacturer of subsea production system is the Norwegian FMC Technologies company. [61]

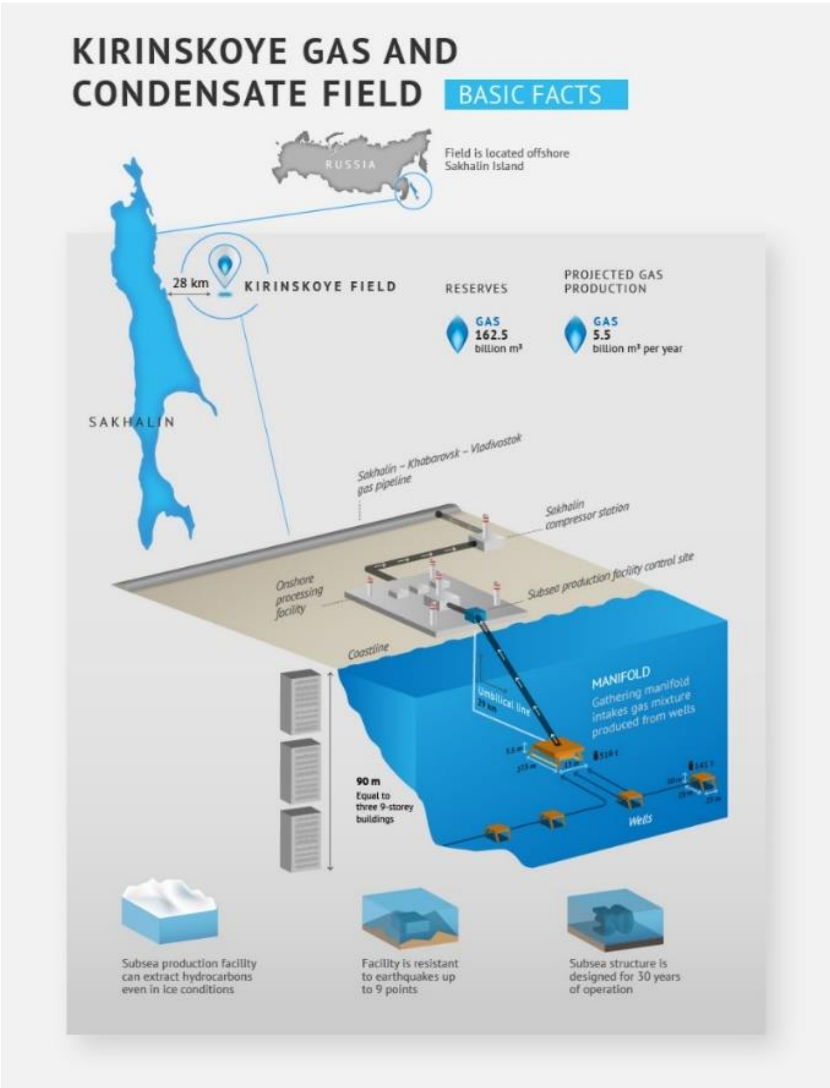


Figure 24. Subsea production system (Picture courtesy of Gazprom) [61]

Yuzhno-Kirinskoye gas and condensate field

In September 2010 Gazprom discovered a large Yuzhno-Kirinskoye field in the Kirinsky block. As of today, its C_1+C_2 reserves (proven and provisionally estimated) amount to 706 billion m^3 of gas and 110.6 million tons of condensate.

In 2013 two exploratory wells were be drilled in the field, one of which – with the use of the Severnoye Siyaniye (Northern Lights) semi-submersible drilling rig. In 2014 another two wells were drilled. In 2015 geological exploration was completed and the field is ready for pre-development.

Gas will be also produced from the field by the means of subsea production facility. Gas extraction is expected to exceed 21 billion m^3 per year. The field is planned to be brought on-stream in 2021. [61]

Mynginskoye gas and condensate field

In autumn 2011 Gazprom discovered another field within the Kirinsky block – Mynginskoye gas and condensate field. Its C_1+C_2 reserves total 19.8 billion m^3 of gas and 2.5 million tons of gas condensate. [61].

«Polyarnaya Zvezda» (Polar Star) and «Severnoye Siyaniye» (Northern Lights) Semi-Submersible Floating Drilling Rigs (SSFDR) MOSS CS-50 Mk II

These SSDRs were manufactured on Gazprom's order by Vyborg Shipyard in 2011.They are self-propelled floating catamaran installations with two pontoons and six stabilizing columns, supporting the top hull and topside structure (Figure 25, 26). The platforms are designed for operation under the Arctic conditions in broken ice up to 70cm with ambient temperature up to -30°C. Both rigs can perform exploration and production drilling as well as testing of oil and gas wells up to 7,500 meters deep, in water depths ranging from 70-500 meters.

Construction of the multi-purpose bare-deck platform Moss CS-50 was a result of the long-term cooperation of Vyborg Shipyard with the Norwegian engineering company Moss Maritime. Platform Moss SC-50 represents the 6th generation of deep water semi-submersible platforms designed by Moss Maritime. The CS-series comprises a range of sizes from the smaller of 25,000 tones displacement to the (so far) largest of 60,000 tones displacement. The CS-series of designs share the common features such as; flexibility, ruggedness and excellent motion characteristics. Field proven in the harshest of environments, the CS designs guarantee a long life with top performance. The CS- series comprise platforms for a variety of requirements and the structural layout of the lower hull allows alternative configurations of the deck arrangement and installations. The CS50 was primarily developed for DP operations in ultra-deep water and harsh environment with requirement for dual activity and high capacity drilling systems. [62]

The multi-purpose bare-deck platform built at Vyborg Shipyard has fully outfitted spaces underneath the bare deck, including tanks for ballast water, diesel oil, special drilling liquids and pump rooms. All systems, electrical equipment and cables are installed and tested by English company Converteam which was subsequently acquired by General Electric (GE). Fabrication of the Topside of the Rig made by the Samsung Heavy Industry.[63]

Technical specifications

Power - 32 MW

Length - 84.48 m

Breadth - 72.72 m

Operational draft - 23.50 m

Draft (transit) - 9.85 m

DWT - 6000 tones

Gross Tonnage: 55700

Speed - 8-10 knots

Endurance - 60 days

Crew - 128 people

Main propulsion plant - 6 diesel engines rated 5420 kW

Design - Moss Maritime CS-50 MkII Rig

Figure 25. «Severnoye Siyaniye» (Northern Lights) semi-submersible drilling rig (Photo courtesy of Gazflot)

Figure 26. «Polyarnaya Zvezda» (Polar Star) semi-submersible drilling rig (Photo courtesy of Gazflot)

Infrastructure: pipelines and loading

The Sakhalin – Khabarovsk – Vladivostok Gas Transmission System (GTS).

The 1,822 km Sakhalin – Khabarovsk – Vladivostok GTS is a key element of the Unified Gas Supply System, commissioned in 2011, in the Russian Far East as an integral part of Eastern Gas Program (Figure 27). The full throughput of the S-K-V pipeline will be able to annually convey 30 billion m^3 by 2020. Natural gas extracted from the subsea wells of the Sakhalin-III project is sent to the onshore processing facility then, via the Sakhalin's main compressor station and a 140 km pipeline, thereby forming the main resource base for the S – K – V GTS (Figure 28). The Sakhalin Compression Station (CS) has two gas compressor units with an aggregate capacity of 32 MW. The GTS pipeline will cover the gas consumption of the Khabarovsk Krai as well as feed a planned Vladivostok-LNG project, producing liquefied natural gas for export to the Asia-Pacific countries, and a proposed Gas Chemical Facility.

The GTS route starts in Sakhalin, crosses the Nevelsky Strait, passes near Komsomolsk-on-Amur and Khabarovsk and finished in the vicinity of Vladivostok. The pipeline runs through 94 km of high seismic activity and 32 tectonic faults zones. The S-K-V pipeline system has a diameter of 1,220 mm (48”) and wall thickness up to 27 mm (Sakhalin–Komsomolsk and Khabarovsk–Vladivostok) with a total length of 1,352 km, and 700 mm (28”) (Komsomolsk– Khabarovsk) length – 472 km, and operates at working pressure of 100 bar (9.8

MPa). The offshore section crossing under the Nevelsky Strait with a distance of 23 km has two twin-lines with the diameter of 1,020 mm (40”) and wall thickness 27mm, each. [64]

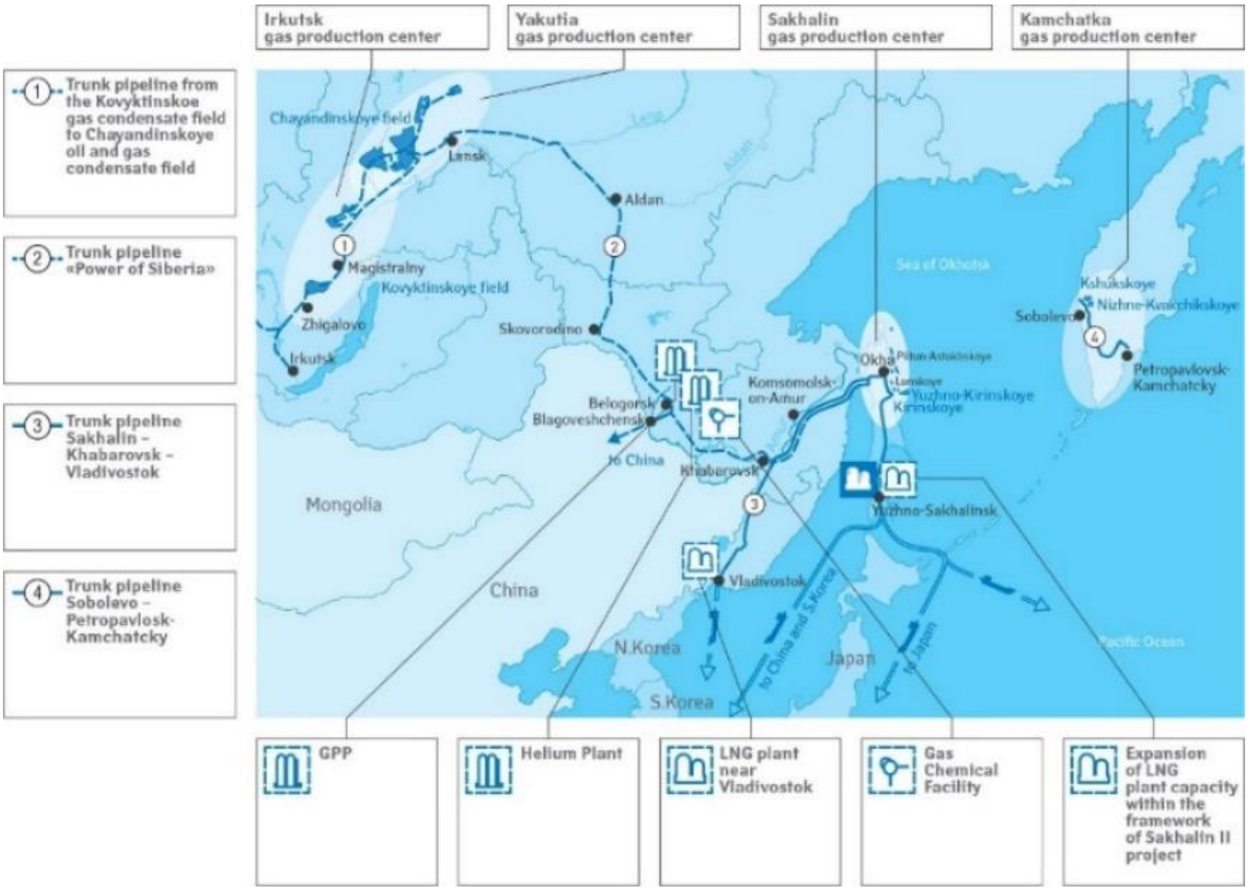


Figure 27. Plan of resources development in the Eastern Siberia and Far East of Russia (Picture courtesy of Gazprom)

Figure 28. The Sakhalin – Khabarovsk – Vladivostok gas transmission system (Courtesy Gazprom)

5 Concepts structures for Sakhalin Island offshore developments

The main principles in developing the deposits of Sakhalin Island taken as a basis of development of oil and gas fields, namely taken into account only the characteristics of the major meteorological factors of this marine area, allowing the principal to select the type of technical equipment and construction for carrying out exploration and subsequently for operating activities. First of all, it is necessary to know the exact data about the water depth, the duration of the ice period, and the depth of the oil and gas reservoir, i.e. the depth of drilling. t should be noted that the basic types of objects for exploration and production offshore fields, which include hydraulic structures depend on the sea depth and ice conditions. Also, a significant role is played the presence of coastal infrastructure for the manufacture of structural elements, as well as for future transportation of hydrocarbons from the shelf.

Currently, remoteness from shore bases, as well as the duration of the ice period, impeding regular logistical support platform, makes it necessary to give them enhanced autonomy. Considering that the winter period in Sakhalin rather inclement, it is necessary to create favorable conditions for the autonomous work of the personnel up to 100 people. All this leads to an increase in the overall dimensions of structures. Also worth to ensure the protection of the environment from pollution.

The collection of these factors, reflecting the specific requirements for the design and methods of construction facilities, stipulated to the creation of new types of fundamentally different from traditional steel-truss structures, or framed structures proved itself in ice-free seas, but are unacceptable for the more severe conditions of the Arctic and Subarctic.

In this case taking into account the geography of the Far Eastern offshore, as well as climatic and economic characteristics of this region can set the following areas of application of mobile, fixed and artificial island construction.

In the waters of freezing seas, where ice free period is sufficient for the drilling of exploratory wells, exploration activities carried out by technical means, suitable for the conditions of the ice-free seas, and in the seas with heavy ice conditions, i.e. with short ice free period, drilling should be carried out all year round with ice-resistant engineering structures (Figure 29).

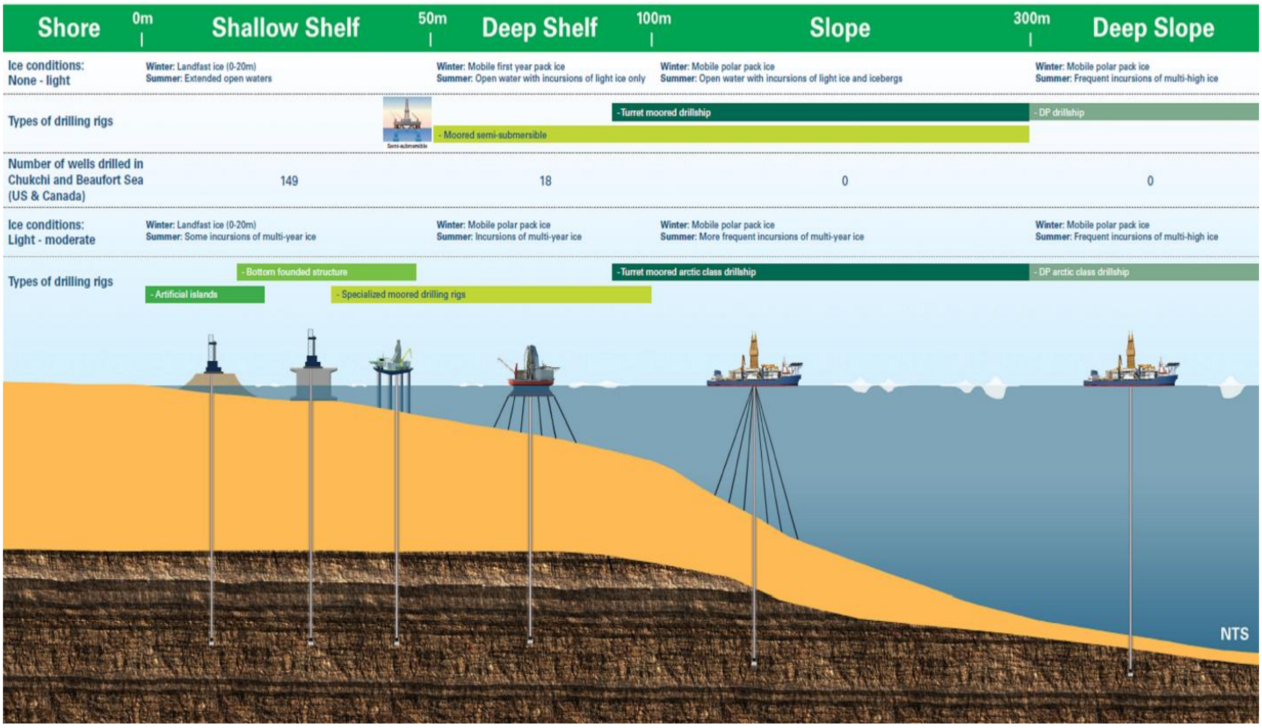


Figure 29. Arctic and Subarctic exploration drilling technology (Picture courtesy of BP)

5.1 Offshore marine structures for exploratory drilling in shallow waters

Artificial offshore islands

Artificial islands date back to the mid-1970s. In the last 40 years, eighteen islands have been constructed for exploration and development of oil and gas off the coast of Alaska.

The majority of the artificial islands were constructed in shallow water depths less than 6 meters. The two most recent artificial islands constructed in the Beaufort Sea were in approximately 2 m of water; Oooguruk Island and Nikaitchuq Island. Five artificial islands, including Northstar Island, have been constructed in deeper waters up to 12 meters. [67]

Artificial offshore islands were constructed by either dredging the local sea bottom and building-up an island (referred to as a sacrificial beach or sandbag-retained island, or by trucking gravel from the shore and depositing it to form an island (referred to as a hauled island). The latter approach was carried out during winter months across ice roads [68]. These islands have typically been located in areas with first-year ice. With increasing depth should apply special mobile submersible rigs/platforms placed on the gravel berm. Under conditions of fast-ice need to use ice constructions.

There are five general categories of offshore structures incorporating granular material ("islands"). Such "islands" include sandbag retained islands, sacrificial beach islands, gravel islands (mainly in the U.S. Beaufort Sea), Caissons, Caisson Retained Islands (CRI) and a water ballasted caisson on a berm. Despite the fact that primarily these structures were constructed to conduct exploratory drilling operations, however in preparation for possible development, production concepts are being devised. Although the majority of these islands were in water depths less than 10 m some hybrid islands have been successfully constructed in depths hefty up to 31 meters. [69]

Sandbag Retained Islands (maximum water depth = 7.0 meters)

A sandbag retained island (Figure 30, 31) is one where a ring dyke of sandbags is placed on the seafloor to hold back the fill. The sandbags not only retain fine grained materials and hence achieve steeper island slopes but also offer protection against wave attack. Fill quality was not a major design issue. The objective was to utilize fill of sufficient quality to support the drilling package. Design considerations included slope failure, edge failure due to ice and potential for decapitation. Borrow sources included clam shelled local seabed materials and soils barged to the site from a remote submarine borrow pit. [69]

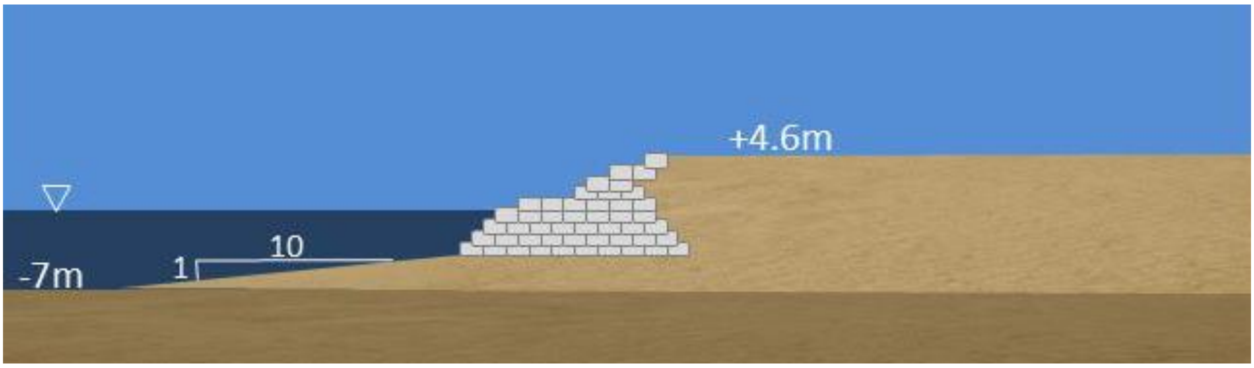


Figure 30. Cross section of Netserk F-40

Figure 31. Endicott Island (Photo courtesy of BP Exploration Alaska)

Sacrificial Beach Islands (maximum water depth = 19.0 meters)

Sacrificial beach islands have flat beach slopes (1:15 to 1:25) (Figure 32) which are intended to attenuate wave energy and provide an erosion buffer, thus protecting the island top from wave attack. This type of island was usually constructed when the island was located near a large borrow source since a large amount of fill is required. The major advantage of a sacrificial beach island is the reduced requirements for slope protection which is both costly and difficult to construct. The construction method is simple. The island fill was dredged and placed hydraulically usually using either a plain suction dredge with a floating pipeline or, when available, Trailing Suction Hopper Dredgers (TSHD's). The very flat side slopes precluded the economical use of this approach at deeper water sites. Volume increases exponentially with water depth. [69]

Figure 32. Cross section of Isserk E-27

Gravel/Rock/Sand Islands (maximum water depth = 14.6 meters)

One advantage of using gravel for island construction (Figure 33) is the reduced fill quantities resulting from steep slopes (1:3 to 1:5). Construction of these islands is possible where abundant gravel is available or distance from the quarry to the site not so far. The gravel might be obtained from onshore sources and either dumped on site by barges during the summer or, more commonly, hauled directly to the island site in winter via an ice road. The exploration islands have been protected by a revetment, normally consisting of large sandbags overlying filter cloth, although other types of armor have been used. One major disadvantage of this island type is that the placement of the slope protection can be very time consuming, especially below water. [69]

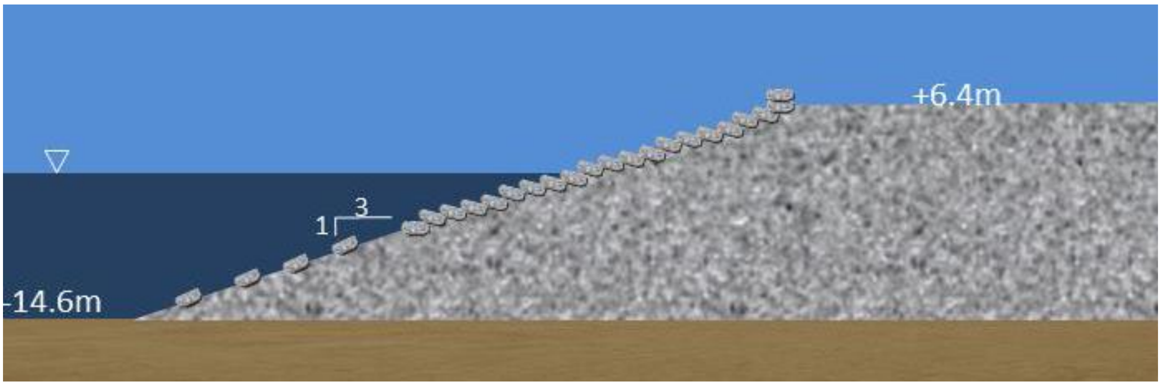


Figure 33. Cross section of Mukluk Island

Caisson and Caisson Retained Islands (maximum water depth = 31 meters)

The Caisson Retained Island (CRI) concept has the most promise for its acreage. It was developed to reduce the volume of fill material by 65% to 90% of that required of a sacrificial beach island, by simplifying construction methods and eliminating the need for elaborate slope protection. The CRI design, shown in Figure 34, consists of eight trapezoidally shaped caissons connected to form an octagonal ring. Each caisson measures 43 m long by 12.2 m high by 13.1 m wide and weighs 1500 tones. The total ring weighs 12,380 tones and the outside diameter measures 117 m. The caissons are held together by two pre-stressing bands of steel wire cable. Each band uses eight 75 rom diameter cables with a breaking strength of 400 tones. The total length of 75 rom diameter cable measures 5 km. Pre-stressing of the cables is achieved by a hydraulic jacking system consisting of thirty-two 800 tones capacity jacks. Design pre-stress equivalent to the restraining force required for stability under active earth pressure was chosen based on results of geotechnical analysis.

The main features of the caisson include: a draft of 2.7 m for shallow water transportation and assembly; the outer face of the caissons is designed with a slope of 60° to the horizontal to minimize ice loading on the structure; it is reusable with a life-expectancy for at least 3 drilling locations; and the system is deployed as a single unit. The complete ring is ballasted down onto a sand berm, levelled to a tolerance of +30 cm. Only water ballast is used to simplify and expedite the de-ballasting and relocation procedures. The central core of the ring is filled with sand to provide the working area and for stability against ice loads. Vertical joints provide articulation during the consolidation period of the island base and the core fill. The caisson ring has a set down depth of -9 m, providing it with a freeboard of 3 m. angled wave deflectors extend an additional 4.5 m above the deck to +7.5 m to protect the island from summer waves and to minimize over topping. At the ice impact zones, high ductility, high tensile normalized steel is used. The CRI is instrumented with structural, geotechnical and ice sensors to monitor the forces acting on the structure. [70]

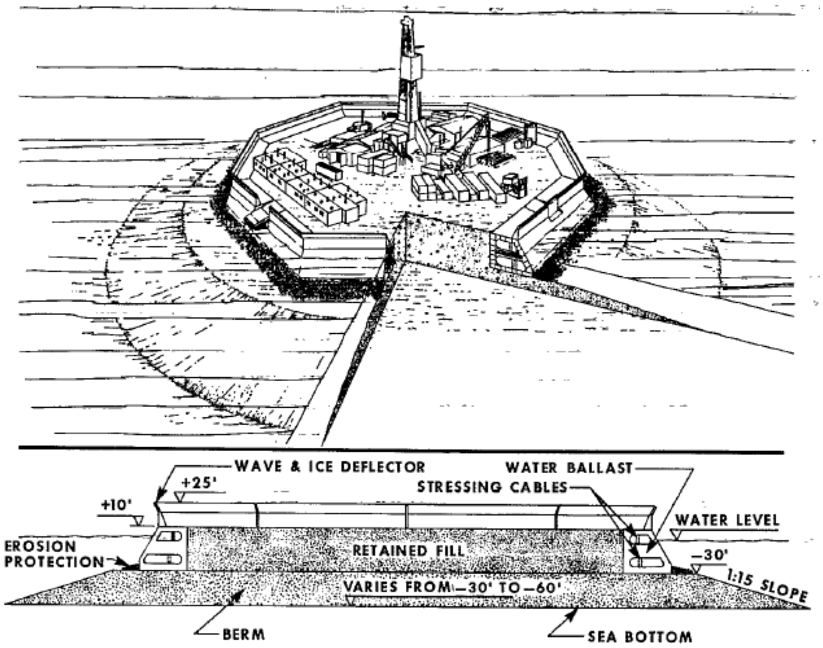


Figure 34. Caisson-Retained Island (CRI)

Concrete Caisson (Tarsuit Caisson)

The bottom founded fixed island concept was selected because the floating systems available at the time did not allow all-season operations in the Beaufort Sea. Tarsiut Island consisted of four watertight, made of lightweight, reinforced concrete caissons that were floated to 100 km northwest of Tuktoyaktuk drilling site and ballasted down with sand to form a square over an underwater berm that was within 6 m below of the water surface. The central core was filled with dredged sand. At its center, this configuration left the island with 8 meters between the waterline and its upper deck (Figure 35, 36). The octagonal island had a working area of 7947 m² and housed all of the drilling rig platform's topside components. The island was designed for 12 m storm waves and ice up to 5.6 m thick. The design ice-loading was 560 MN and design ice-pressure was 4.1 MPa. This concept resulted in considerable cost savings compared to a similar sized "ring" type structure which would require a large amount of reinforcement to create a ring strong enough to transfer the forces around the structural system. [71] The structure was not considered a "mobile" structure due to the difficulty of resetting and connecting the four caissons. It had no issues with wave loads, but wave action undercut the footings of the caissons necessitating remedial action. Wave splash was also a problem, due to its low freeboard and flat sides. Later caisson structures were designed with wave deflection collars. The concrete (Tarsuit) caisson structure was only used for drilling at the Tarsuit N-44 location. [72]

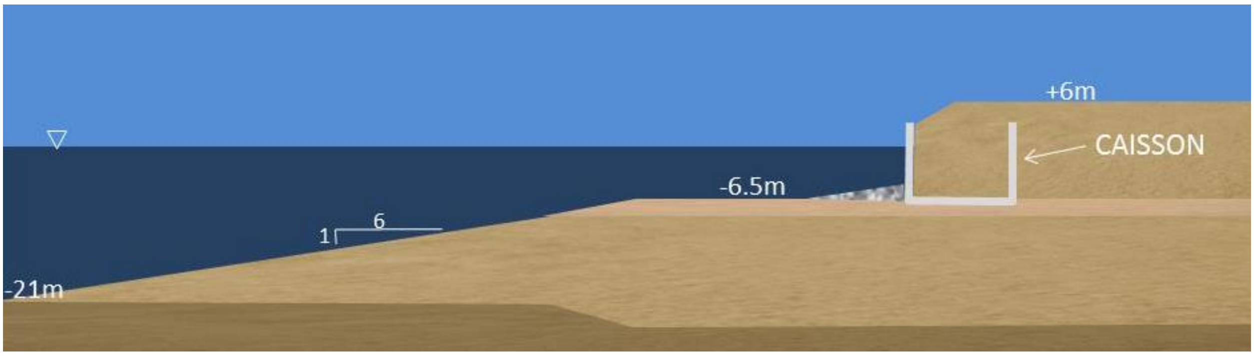


Figure 35. Tarsiut Island

Figure 36. Dome's Tarsuit Caisson Retained Island in the Canadian Beaufort Sea - Under Construction

Single Steel Drilling Caisson (SSDC/SDC)

In 1982 Dome Petroleum developed a new concept for year round drilling from a subsea berm. The system, called the Single Steel Drilling Caisson (SSDC) (Figure 37). It is a complete, self-contained, mobile exploration drilling unit, equipped to drill to 7600 m and capable of carrying all consumables required for continuous drilling through the winter. It was fabricated by modifying the forward half of a·231,150 deadweight tonnage Very Large Crude Carrier (VLCC)" World Saga" oil tanker with a double hull with concrete between the shells. Then it was reinforced to withstand ice, and equipped with drilling equipment as well as eight moon pools that allow multiple appraisal wells to be drilled on the same location. The principal dimensions of the finished system are: 202 m. long, 53 m. wide and 25 m. high, deck area

10220 m^2; lightship weight 80 000 tones When it is fully ballasted onto the subsea berm it has an effective net contact weight of 175,000 tones against which ice rubble forms. The berm is built to within 9.1m. of water surface. In the winters of 1982/83 and 1983/84, it drilled at two different locations in 28 m of water depth in moving pack ice. On 25 September 1983, before the drilling had begun, the unit was impacted by a multi-year ice floe with an estimated diameter of 1.7 km and thickness of 3 to 4 m. While the impact was clearly felt on the rig, no structural damage or movement relative to the seafloor was detected. The drilling of the well began on 28 October 1983 and was completed on 30 January 1984. On 25 June 1984, during the ice break-up, SSDC was impacted again by a large second-year ice floe, estimated to be 24 by 13 km in size and 1.5 to 2 m in thickness. During the winter, a grounded rubble field had again formed around the unit, shielding it from the colliding ice floe. [73]

In 1985/86, a new steel base, the MAT, was designed, built and deployed by Hitachi Zosen Corp. (now it is JFE Holdings Inc.) This removed a limitation of the SSDC that had required construction of a subsurface sand berm for locations deeper than 9m. The SSDC combined with the MAT was capable of operating year round in water depths of 7 to 24m without a berm, in a wide variety of bottom soil conditions. SSDC and MAT have not been separated since (Figure 38). It was renamed the SDC and used in the winter of 2005/06 to drill the Paktoa C-60 well in 13m of water. [68]

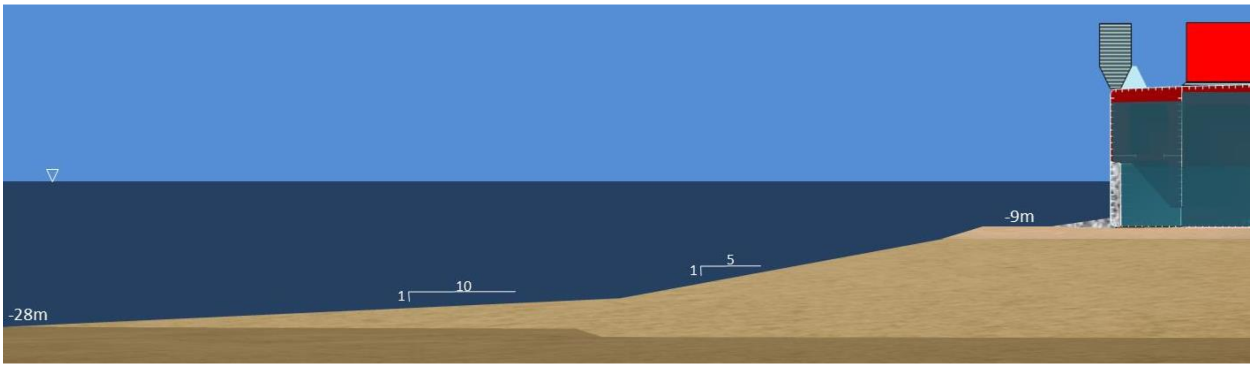


Figure 37. SSDC on the Kogyuk berm in 1983

Figure 38. SDC - formally the SSDC

Mobile Arctic Caisson (MAC)

This concept unit referred to as Mobile Arctic Caisson (MAC) as known as Molikpaq (Figure 39, 40). It is a single piece mobile caisson rig designed and constructed for bottom founded year round drilling operations in Arctic waters from 10 to 40 m. Molikpaq is a mobile Arctic caisson that is designed to withstand the severe ice loading conditions experienced in the Arctic offshore and operate on a year round basis. The structure itself is an octagonal steel annulus containing floatation ballast tanks and having a simply supported steel deck. The caisson has three functions; it serves to retain the sand within the core, to armour the sand core against ice attack and to provide a permanent platform on which the drill, associated equipment and accommodation are housed The overall caisson's outside dimensions of 111 m and 86 m at its base and deck respectively and is 33.5 m in height, including a 4.5 m ice deflector which extends above its deck. Molikpaq is designed to have a set down draft up to 21 m and can operate without being placed on a submerged berm in water depths ranging from 10 to 20 m. In more than 21 m of water, a dredged subsea sand berm is required with its thickness being matched to the water depth and condition of the natural seabed at the deployment location. The deep draft of the caisson reduces the height and cost of the berm on which it sits at these deeper water deployments. Excavation of weak surficial sea floor sediments beneath either the structure or its berm is sometimes necessary, depending upon site conditions, to achieve Molikpaq' s stability requirements

The central core of Molikpaq is filled with sand after the structure is ballasted down onto the sea floor or berm to provide lateral stability against ice forces. This core fill, with typical volumes of 115,000 m^3 of the coarsest sand available, contributes up to 85% of the structure's design horizontal (sliding) resistance. The ice loads on the outer face of the caisson are passed through the structure to the base and sand core, through the sand berm and finally to the foundation. A system of closely spaced ribs supports the skin plate of the caisson, and loads are sequentially passed through an arrangement of frames and bulkheads to main vertical bulkheads spaced on 2.4 m centers. Molikpaq is covered with a low friction coating to reduce ice loads and mitigate ice ad freeze. The structure's hull has been engineered to resist a design horizontal ice loading of 100MN (100,000 tones) with a load factor of 1.5 [74]. Between 11.9 and 24 m above its base, the hull's surface is constructed of EH36, low temperature steel and is capable of safely accepting a combined local and global load maximum of 7 MPa.

Once the core is filled, drilling operations can begin in one of two 3 m. square moonpools which penetrate the operations and box girder decks to provide access to the core area below. The drill rig can be skidded longitudinally and transversely on the operations deck to facilitate movement to the four drilling slots. [75]

The caisson weighs up to 30,000 tones (lightship condition). It is not equipped with winches or any other anchoring system [76]. The caisson is divided into twelve major ballast compartments for lowering Molikpaq during set down and lifting it during removal. A typical deployment sequence for the structure takes several weeks and involves foundation preparation and dredged berm construction, towing the caisson over location and ballasting down onto the prepared surface, and then pumping dredged sand fill into its central core. Freezing of the ballast tank water and sand core is prevented through hull insulation and heat. After completion of operations at a site, a portion of the structure's central core fill is removed, the floatation tanks de-ballasted and Molikpaq lifted off [77]. The caisson was constructed by IHI Corporation in Japan, and modules by Dominion Bridge-Sulzer of Quebec [78]

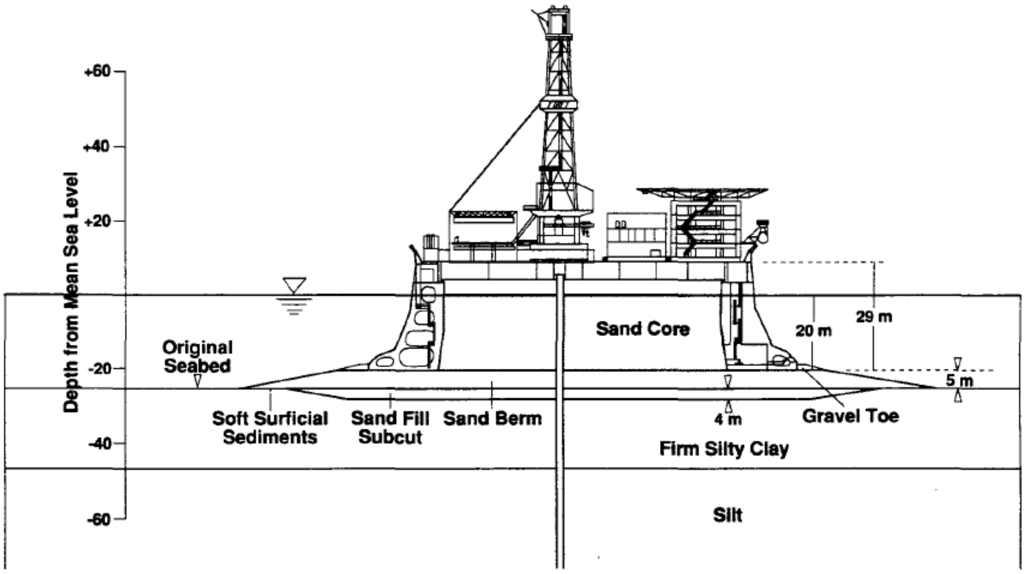


Figure 39. Schematic cross-section of Mobile Arctic Caisson

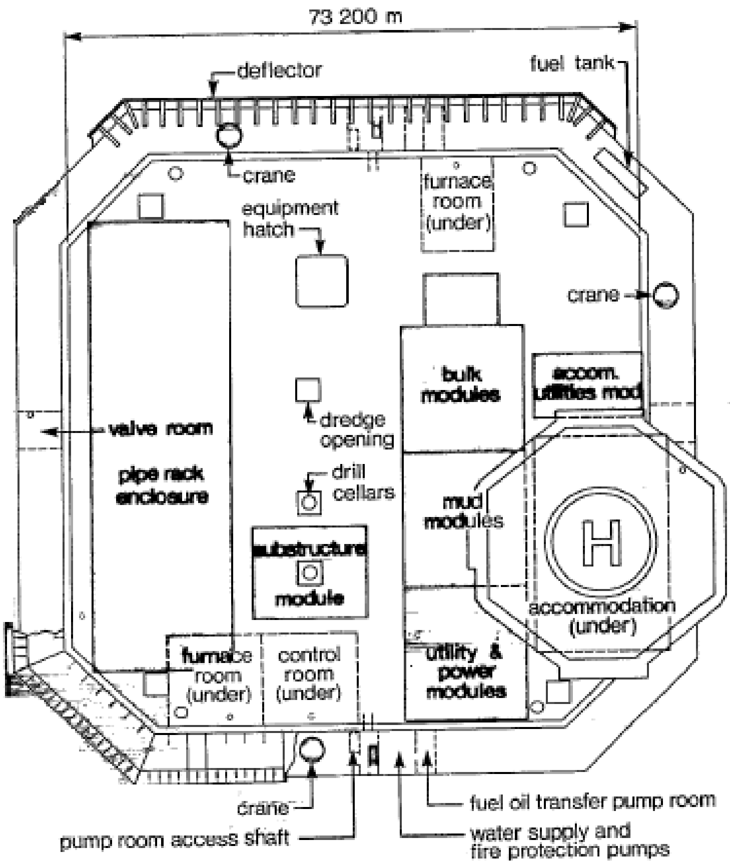


Figure 40. Deck plan

Concrete Island Drilling System (CIDS)

The concept for exploratory drilling named as CIDS was constructed in Japan by Nippon Kokan (NKK) in June 1984. It is composed of four individually constructed and towable modules – the BB44 BRICK (44 designates the height in feet- 13.4 m), two Deck Storage Barges (DSBs) and the Mud Base (MD). The «arcticized» drill rig, the 100-man quarters and the Rubble Generation System are all mounted on the DSBs prior to stacking of the modules. An additional BRICK module, of various heights can be added to the stack to increase the gravity load or increase freeboard.

The central modules of the CIDS are the concrete BRICKS which are positioned at the air/water inter face. The BRICK is designed as an eight sided structure with vertical sides to simplify construction and provide stacking capability. There appears to be little difference in ice loads between a round and square plan shape but by cutting the corners off of a 71.32 m^2 shape, the maximum diagonal distance is significantly reduced to 84.73 m (Figure 41).

The structural design concept is based on a sandwiched panel system using reinforced and pre-stressed, post-tensioned, concrete. This "honeycomb" sandwich design has the definite advantages over steel and other concrete structural framing systems. The loads from ice forces are initially encountered in the 584.2-mm-thick side wall and shear walls by deep beam action. The reactions of the shear walls are transferred to the top and bottom slabs. That portion of the load carried in the 304.8-mm-thick top slab is ultimately carried to the bottom slab through the shear of the "honeycomb" field and other orthogonal walls. The entire load is then transferred from the 381-mm-thick bottom slab to the Mud Base by friction between the units and compression with the Mud Base shear curb.

The top and bottom slabs are post-tensioned to 500 psi in both the longitudinal and transverse directions. The outer wall is post-tensioned to 500 psi in the horizontal direction and 300 psi in the vertical. The shear walls and the interior wall are vertically pre-stressed to suitable levels to enhance their shear friction connection with the top and bottom slabs

The uppermost elements of the system are the two Deck Storage Barges (DSBs). These units are 88.39 m long, 41.45 m wide and 8 m deep and provide the tankage and storage areas for the 12 months of fuel, drilling supplies, the drill rig, and the quarters. Since these elements are always above the ice line they are constructed of relatively lightweight steel in a standard marine barge design. The starboard barge is fitted with the quarters module while the port barge contains the drill rig and most of the drilling equipment. The use of steel hulls for the working areas provides flexibility in arrangement and compartmentation. Because of their exposure to the ambient air temperatures, the barges were constructed entirely of ABS Grade EH3G steel especially modified for the minus 51°C ductility test temperature. The sides of the DSBs are raked all around and project 6 to 9.75 m out from the BRICK unit to insure that ice rubble and ocean spray are deflected away from the deck. The watertight compartmentation of these DSBs are such that the overhanging rake sections are void, but intercommunicative, thus forming a below deck access walkway completely around the structure. Access to and from this enclosed passage is provided directly from the quarters, the rig, and the main deck life boat stations. The internal compartmentation of the two DSBs combined have a total capacity of 227,000 barrels.

The Mud Base element is designed to be submerged at least 3 m below the ice line during drilling operations - thus setting the minimum operational water depth at 10.6 m. The Mud Base is 90 m by 95 m at the baseline and 7.62 m high and it is constructed entirely of ASTM A537, Class II material with a minimum yield strength of 60,000 psi. The top deck of the structure is 80 by 13.4 m with a 37° sloping face around the perimeter. The Mud Base is divided into 24 watertight components to facilitate ballasting. A heavy structural steel "shear curb" 0.6 m high and arranged to be slightly larger than the mating BRICK module, is provided on the deck to transfer the global ice loads from the BRICK to the Mud Base [79], [80]

In 2004 CIDS platform, Glomar Beaufort 1 was renamed the "*Orlan"* and the facilities aboard the platform were completely refurbished for oil drilling and production off the coast of Sakhalin Island, Russia. [80]

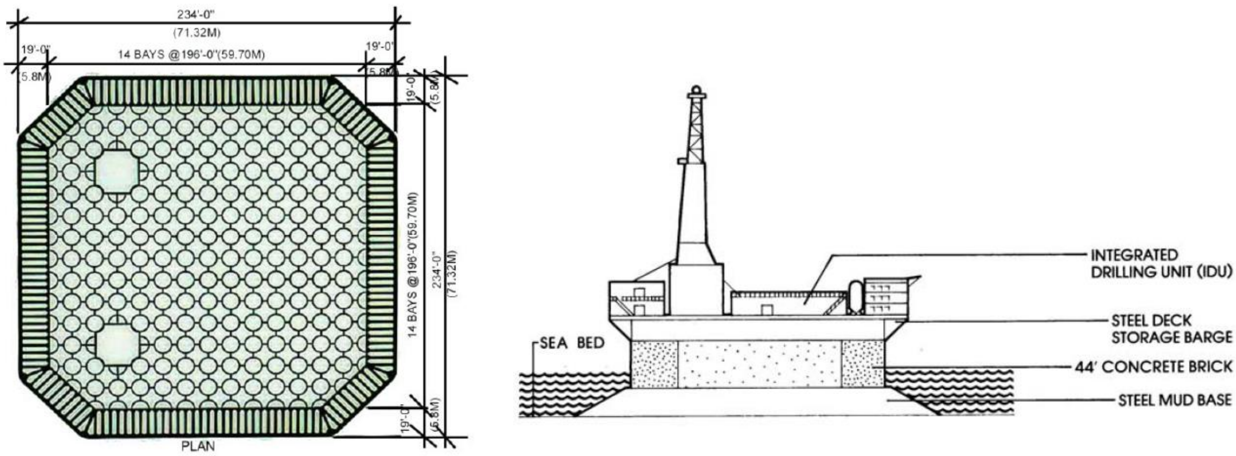


Figure 41. «Glomar Beaufort 1» Concrete Island Drilling System (CIDS)

5.2 Offshore marine structures for drilling and production

5.2.1 Major factors affecting the selection of the type of offshore structure

In order to achieve the maximum efficiency in the offshore development of hydrocarbons it is necessary to correctly justify the selection of the type of offshore structure. Reasonableness of an acceptance of a certain solution in its turn depends on the thoroughness and preciseness of the factors listed below:

Technological factors,

Engineering and geological factors,

Hydrometeorological factors

Industrial factors

Environmental factors

Analysis of these factors make it possible not only to make a right selection of offshore structure, but what is more important to develop a general layout conception a deposit, as well as the region entirely. Therefore, only by detailed consideration at these factors individually we can estimate their effect on the selection of a definite structure (Figure 42). [10]

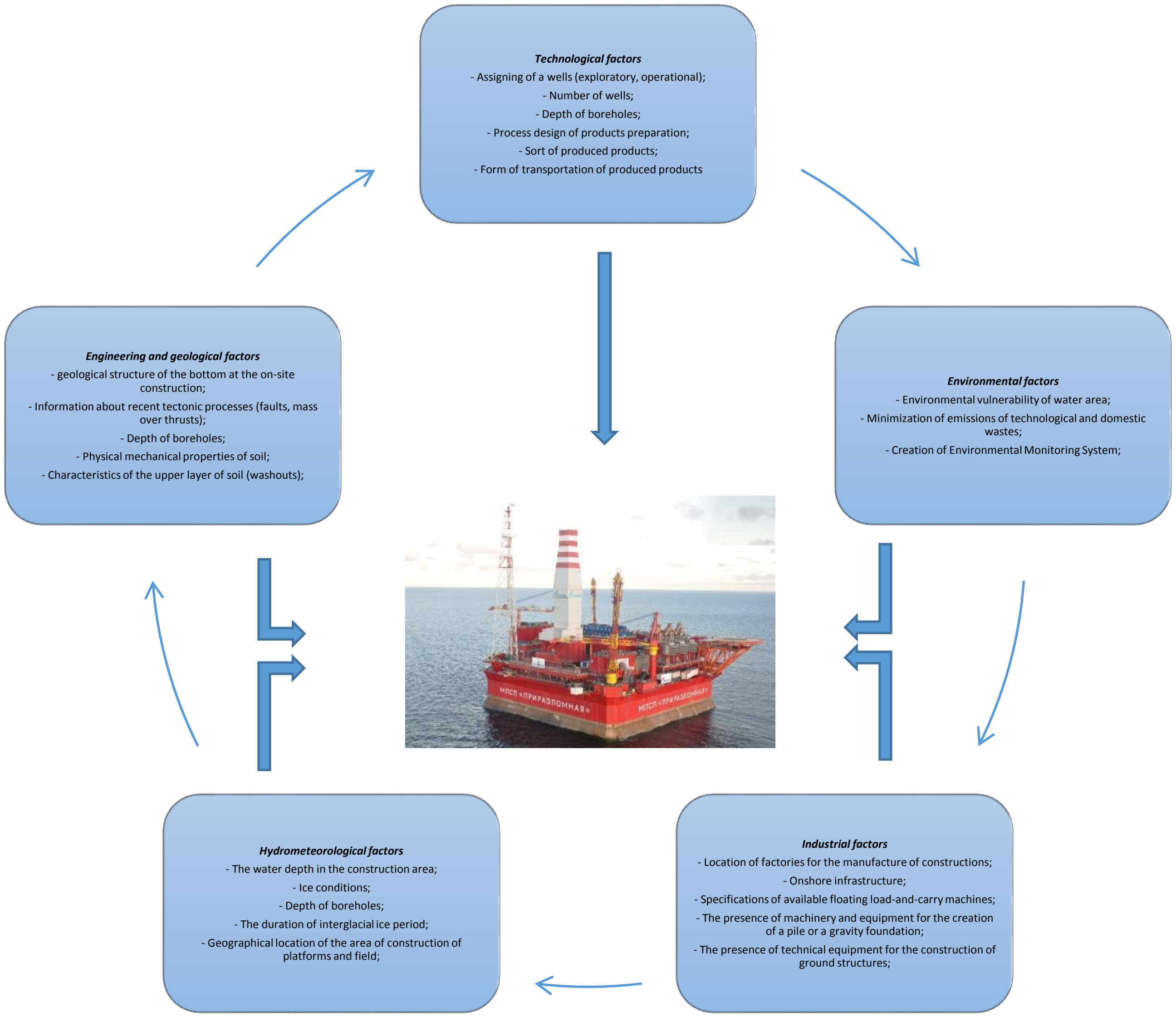


Figure 42. Major factors affecting the selection of the type of offshore structure [10]

Technological factors. [10]

The main technological factor which influencing to the selection of the type of offshore structure - is the purposive appointment of the contemplated drilling of offshore wells:

- Structure drilling (to identify promising areas and their preparation for exploratory drilling)

- Experimental drilling (For the preparation of proven reserves of industrial categories and preparation of development projects)

- Operating hole

An important technological factor is the type of product produced, i.e. oil, gas and condensate, their properties directly determine the process design on the platform, the methods of exploitation (flowing well, artificial lift, etc.), and therefore the composition of the maintenance equipment

It can also be attributed to technological factors the drilling depth, regardless of their purpose, since its size determines the type of drilling equipment, in its turn determines the weight and dimensions of the superstructure of the building. Moreover, this factor affects the ability to conduct exploration drilling in the conditions of freezing seas for one interglacial ice period.

The amount of materials demanded for the uninterrupted maintenance drilling and production facilities, directly connected with the autonomy of platforms.

It also includes technological requirements in selecting the method of transportation of hydrocarbons (oil tanker, pipeline) and its storage.

The requirements for fire safety and labor health protection are also depending on technological factors.

Hydrometeorological factors. [10]

Hydrometeorological factors are crucial in selecting the type of offshore structure. According to him determine the organization and construction period and further exploitation of structure. Initially, it is necessary to have the data about the ice conditions and the sea depth. Based on the ice conditions determine the class of structures (ice-resistant or non-ice-resistant), but on the basis of the depth of water selects the type (GBS, artificial island, subsea production system).

Duration interglacial period is also one of the key factor that affects the autonomy of the structure and the period of drilling exploratory wells (possibility of drilling in one season), and building and construction works. Distance from the shore determines the type of material handling system (water, air, combined)

Hydrometeorological conditions also play an important role at designing of structure. For example, speed of wind determines load from wind pressure, the parameters of sea – seaway loads, flow velocity - strain on him. In addition, it is necessary to take into account the aggregate exposure of these loads.

One of the main factors in selecting the type of ice-resistant structures is the ice regime, characterized by complex parameters (thickness, porosity, salinity, and an area of drifting ice formations, the presence of icebergs or grounded hummocks, their geometrical and weight characteristics).

In order to determine the construction of above-water portion of offshore structure the information about the possibility of its icing is required in order to carry out activities that would protect from such phenomena.

Chemical characteristics of sea water are necessary to assess its corrosiveness, and the choice of structure's materials.

Knowledge of the ambient air heat condition is required for the construction of living accommodations on a platform or an artificial island, as well as selection of an appropriate drilling and production equipment. Moreover, for this type of impact above-water structures should be calculated. In Arctic and Subarctic duration of the negative conditions of air temperature greatly influences the selection of the type of structures for exploratory drilling in shallow water

Information about changes in the water level (wind-surges and tidal phenomena) at the site of dislocation needed to determine the level of the lower deck of the superstructure of the buildings, as well as application points of the resultant forces of ice, wave and other loads at various calculated options.

Information about the seismic activity at the construction area can change the entire concept in selecting the type of offshore structure.

Engineering and geological factors. [10]

Engineering and geological conditions primarily influence the selection of the design of foundation of the structure. Depending on the properties of the soil at the site of construction the design of foundation structure (gravity or pile). Moreover, the quality and quantity of relevant sand and gravel quarries with considerable reserves at the site of construction may depend on the type and choice of structure (artificial island or fixed platform). To initiate the design also marine surveying of the place of proposed construction (plan, profile) needs to be performed.

The main engineering and geological data are:

- The geological design of the offshore structure (information about structure's occurrence and lithological characteristics of ground);

- Information about recent tectonic processes at the construction site;

- Physical - mechanical properties of soils, obtained from the result of field and laboratory research;

The degree of sea water corrosiveness towards the foundation construction material.

Depending on the properties of the upper layer of soil the degree of protection at the base of the foundation of offshore structure from erosion under the combined action of currents and hurricane wave is determined. This is the most important factor in selecting of gravity type construction.

Industrial factors. [10]

Industrial factors can influence the selection of the design type of offshore structure. The presence of factories and other onshore construction bases requires the development of transportation technology construction elements of offshore structures in the buildup. It is this factor affects the creation of temporary and permanent onshore bases to maintain the building of offshore structure and further exploitation of the deposit.

The availability of the appropriate load-and-carry equipment depends on weight and dimension characteristics of the elements of offshore structures, which in its turn determines the load intensity that arise during the manufacture, transportation and structure erection.

When selecting structure's foundation (gravity, shaft, combined) requires information on the pile driving equipment and technical facilities of foundation base under gravity base structure. The data on machinery and equipment for the manufacture of ground is needed for construction of artificial island structures, as well the creation of protective berms around foundation for preventing erosion of the bottom soil.

Method choice of the superstructure of the installation (aggregate, block, integral, etc.) also depends on the availability of appropriate load-and-carry machines and special floating facilities. Industrial facilities must be designed for a minimum volume of construction and erection works in the main sea conditions.

Environmental factors. [10]

In the development of projects related to the offshore field development, particular importance is the recognition of environmental factors requiring overall estimate of environmental impact and possible consequences of various processes associated with the field development, for example, drilling, production, processing, transportation and others.

5.2.2 Development Drilling and Production Platforms

Fixed Platforms are used year round for drilling as well as production activities in Arctic and sub-Arctic environments. GBS, or Gravity Based Structures, are included (by increasing water depth progression). Ice loads and geotechnical conditions define water depth limit, but is estimated to be in the 70-120 m range depending on economic considerations.

For Arctic and sub-Arctic environments GBS is a proven concept. First year ice conditions in Sakhalin I and II platforms in the Sea of Okhotsk are good examples as well as Hibernia (Figure 43), east coast Canada. The platform designed for icebergs. Although different in terms of larger ice loads, GBS built for Chukchi, Beaufort and Okhotsk Seas, use the same technology.

ISO 19906 codifies the established design practice for fixed and floating structures. This standard, consistent with the ISO 19900 series uses a limit states design method for safe and reliable design. Ultimate, Serviceability, Fatigue, and Accidental are included in limit states that need to be evaluated. In order to achieve annual failure probability of 1.0x10-5 for a manned platform with high consequence exposure level Load and resistance factors for the Ultimate and Accidental limit states have been calibrated. Representative loads for Chukchi and Beaufort Seas GBS.

Ice loads determining methods are covered in ISO 19906 and are also the subject of industry design tools and guidance. Well established and supported by field measurement data Methods for determining first year ice actions (loads, and for manmade islands ice pile up and ride up). Methods for determining ice action from interaction with multiyear ice are developed, but lack the same field measurement support as first year ice loads. Competent engineers know sufficient uncertainties to allow for safe and reliable design. Limit stress approaches lie in the base of design methods, while limit force – a known limiting effect – is ignored in design approaches because of insufficient supporting measurements. [81]

Figure 43. Hibernia platform with multi-shaft GBS (Photo courtesy of Hibernia Management and Development Company)

Concept selection drivers

<u>1. Water depth</u>

Water depth is one of the basic parameters that define the selection of platform type. Shallow water depth requires manmade islands, while Gravity Based Structures (GBS) are more viable when water depth (10-15m) provides sufficient float in draft. The GBS practical limit depends upon ice load and geotechnical conditions and could range between 70-120m (however, the Troll A GBS is installed in more than 300m depth in a non-ice environment). Beyond the feasible range of GBS, floating systems and/or subsea are required. The minimum water depth for a floater could range between 80- 100m water depth but they have been used in shallow waters as well. Year round floating systems are not feasible at this point in time with the ice environment in Chukchi, Beaufort and Okhotsk Seas. [81]

<u>2. Platform float in draft</u>

The towing route can be limited by using the float-in draft for a fixed platform (GBS) such as passing Point Barrow and where it can be used, specifically with the topside installed. However, mitigations can be taken to optimize the design to adhere to the available draft. For GBS drilling and production platforms a draft of 20m (or less) is feasible.

A float in draft limitation will have a direct influence to the platform design as additional buoyancy has to be built in to the lower section of the platform structure. This buoyancy requirement has to be less for a steel structure than for a concrete. Also a steel structure will have a shallower draft. [81]

3. Topsides weight

Maximum topside weight related to the GBS buoyancy capabilities and stability is only applicable when installing the topside on the substructure prior to tow into the final platform location. Setting maximum topside weight is not possible as other factors including storage volume and payload come into consideration. [81]

4. Storage volume

The platform design, both topside and substructure will be influenced by the storage volume both with respect to consumables as well as produced oil. The philosophy for whether the platform shall be completely self-supported during the winter season or rely on frequent resupplies is crucial as will the export solution (pipeline versus offloading by tanker).

A “wet” storage system is used for most of the existing GBSs with storage. This way the storage tanks are always full as the oil is floating on top of sea water. When producing oil into the storage tanks the seawater is displaced into sea. This water may contain traces of oil (typically 3-5 ppm) which is an environmental issue. Sliding resistance against ice loads is important factor when determining the platform foundation.

The alternative is a “dry” storage tank system, as ones used in crude carriers, with only oil and a blanket gas on top of the oil in the tanks. A large portion of the tanks is required to be above water line to avoid empty tanks creating buoyancy and reducing the on bottom weight. [81]

5. Export system choice

When designing a fixed (GBS) platform, export through a pipeline versus offloading and export via tankers is an essential element. If tanker offloading is chosen there will be a requirement for a substantial storage volume to allow for some contingency and poor tanker schedule regularity in some seasons. A storage volume of 250,000m^3 is deemed reasonable. [81]

6. Number of wells

To some degree, the spacing of the production wells can have an influence on the substructure design. For a production platform a high number of wells in combination with larger well spacing than used for non-Arctic areas (typical 2.5-3 m) could impact the substructure and neck design. For an exploration platform only a limited number of wells will be drilled from the same location, but this is not considered to have any impact on the GBS design.

J-tubes in the substructure walls and spare risers have to be included in the design which could have some influence on the substructure design, to enable future tie-in of adjacent fields and sub-sea wells. [81]

7. Construction and installation

Platform type define construction and installation drivers and they are key considerations are summarized below for steel or concrete structures.

- Location of yard or graving dock
- Skilled labor force access
- Substructure or combined substructure and topsides tow
- Maximum allowable tow draft and tow route selection
- Availability of marine vessel
- Contingency planning for tow

8. Ice, metocean, geotechnical, and earthquake

All these design drivers are important, and their combination is often a challenge to overcome, especially large ice loads and poor geotechnical properties. In regions with seasonal ice cover the wave loads are often not the dominant design element as the ice load, both local and global, normally is higher. Due to the nature of multiyear ice floes in the area which may have large embedded ice ridges, the global ice load on a platform could be very high.

Ice: Ice loads will be discussed in detail later.

Geotechnical: Soil properties are an important driver for determination of platform configuration as this has a direct impact on the foundation design sliding resistance and thus the size of the platform base area/structure. The foundation design may require skirts or alternatively piles/dowels to achieve sufficient sliding resistance to the large horizontal ice loads.

A top layer varying from relatively weak soil of 25-50kPa to a denser layer of 50-100kPa on top of a strong competent soil of 10-200kPa. The upper layer thickness can have expected to be in the range of 1 to 13m. [81]

Metocean: Due to the short summer open water season the maximum wave height is limited in the area. Severe storms appear during the ice covered period and typical maximum Hs are in the order of 8.8m. This Hs value is not considered severe and should not govern the substructure design as the ice loads will be significantly higher. However, wave loads and their effect should be calculated to confirm this for each project. [81]

Current erosion: As described above the maximum Hs is relatively low for the area and wave erosion still has to be evaluated and mitigation means considered. The most common way to protect the structure from scouring due to erosion induced by waves or current is by dumping gravel/stones on the seabed along the perimeter of the structure. This activity will require mobilization of special vessels and has to be performed within the limited open water season.

The ocean current in the area is modest and not expected to be an issue with respect to erosion.

Earthquake: Seismic acceleration criteria for the Sakhalin area is relatively high and has to be considered as a driver for design. Seismic activity is present in the the seas east of the Sakhalin Island. Some other areas north of Russia are also exposed to significant seismic activity. Seismic isolators are frequently used to reduce the seismic impact on the topside facilities in these areas. [81]

9. Distance to Market and Evacuation Infrastructure

There is no local market for hydrocarbon products in the area as a result they have to be exported to market to Asia either via an offshore offloading facility or through a pipeline.

Due to a lack of infrastructure, the platform design (both topside and substructure) has to be designed to handle an extended emergency situation. This could require improved hospital facilities on board as well as higher heat radiation shielding for the living quarters. Both of these elements will increase the topside weight and could lead to increases in size and weight of the substructure. [81]

10. Non-Technical Considerations

Nontechnical considerations include:

- Marine Sound → drives consideration for insulation and isolation of rotating equipment; and may impact material selection for GBS
- Discharge: liquids, solid, cutting, etc. → drives consideration of process facilities and requirements for injector wells.
- Air emissions → drives topsides process and utilities functional design [81]

Platform types and feasibility to the Sakhalin's offshore field development

Jacket structures

Steel jacket structures are proven concepts for sub-Arctic environments like Cook Inlet and Bohai Bay, China (Figure 44). This structure is not considered feasible for the Sakhalin's offshore field development due to insufficient resistance to withstand global ice loads resulting from interaction with first-year ice. [81]

Figure 44. Bohai Bay Project (Photo courtesy of ConocoPhillips)

<u>Gravity Based Structures</u>

Both steel and concrete GBS are considered the solutions for water depth from 20 m and deeper. The maximum water depth as described earlier is a function of the environmental loads (mainly ice) in combination with the geotechnical properties of the soil. Large areas in Okhotsk Sea, at least those presently being considered for exploration and production, have water depth of less than 50 - 70m and a GBS alternative will be the most likely production platform solution. Arctic and sub-Arctic GBS constructed to date include both monolithic, single shaft, and multi-shaft configurations.

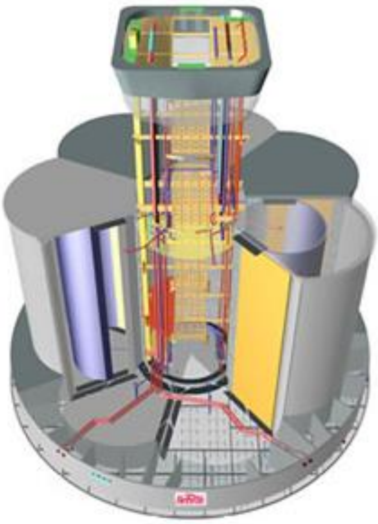
Monolithic examples include the Molikpaq (steel), Orlan (concrete), and Prirazomnaya (steel-concrete hybrid), platforms (Figure 45). The Molikpaq and Orlan platforms now located in the Sea of Okhotsk were originally installed in the US and Canadian Beaufort Seas, respectively.

Single shaft examples include Hibernia and the Hebron platform (Figure 46) under construction. Both are for sub-Arctic conditions, east coast Canada.

Multi-shaft examples include the Sakhalin-II concrete platforms (Lunskoye and Piltun-Astokhskoye-B) and recently completed Berkut concrete platform for Sakhalin-I.

The preferential solution for the Okhotsk Sea will be multi-shaft concept like Lunskoye and Berkut concrete platforms to accommodate first-year ice interaction with the structure.

Figure 45. The Prirazlomnaya offshore ice-resistant oil-producing platform (Photo courtesy of Gazprom-neft)



GBS Key Quantities

• Water depth	93 m (mean sea level)
• Height of GBS	120 m
• Diameter of GBS base	130 m
• Shaft diameter	35 m
• Concrete volume	130,000 m3
• Rebar (density approx. 325 kg/m3)	40,000 t
• Post tensioning steel	3,400 t
• Steel skirts	400 t
• Mechanical outfitting (Piping systems & structural steel)	5,500 t
• Well Slots	52

Figure 46. Hebron platform executions scenario (Picture courtesy of ExxonMobil Canada Properties)

Ice Actions Overview

Sea ice is often not stationary, but moving. An offshore structure (fixed or floating) has to be capable of initiating a failure mechanism in the incoming ice while remaining stable. Forces exerted on the structure by ice interaction should not cause damage to the structure in this process. Design for serviceability criteria should allow for continuous operations on the topside during these interactions, except for action caused by abnormal ice features (such as icebergs in regions where they are not an annual occurrence). Collectively, these ice-structure interactions are termed ‘actions’ in ISO 19906.

Ice actions have both global and local effects. The global effect relates to platform lateral sliding loads and overturning moment. Local pressures have focused impact on plates (outer platform wall) and local stiffening elements, magnified by inhomogeneity of the ice (strong inclusions).

ISO 19906 Clause 8 describes ice action scenarios to be considered, while ISO 19906 Clause A.8 provides guidance on specific methods to calculate ice loads. This includes both vertical sided and sloped sided structures and addresses both first year and multiyear ice features. The basis for the calculation methods in ISO 19906 is a combination of field measurements, analytical models based on field measurements and model tests, and engineering mechanics. [81]

Significant ice structure interaction enhancement activities post-2008 include:

ISO 19906 implementation guidance: Results from the DnV led ICESTRUCT JIP provide help to the non-specialist designer to comply with the normative provisions of ISO 19906, and (ii) to supplement ISO 19906 by addressing selected gaps that have been identified therein. Results provide a common and documented approach to achieve acceptable safety levels for offshore structure designs in cold climate regions, by adhering to the normative provision of the ISO 19906 Standard, and by supplementing it through the provision of practical design recommendations and case studies. Key issues addressed in ICESTRUCT will be incorporated into 19906 as it is being revised.

Ice induced vibration: This industry project carried out by Olaf Olsen developed and verified a numerical tool for simplified analyses of ice induced vibrations for vertically faced fixed offshore structures. This is a design concern for steel and concrete structures and the project results enhance guidance provided in ISO 19906. The project involved leading experts from both industry and academia. [81]

Ice actions: Gravity Based Structures

Ice interaction with vertical GBS will result in multi-modal failure including bending, buckling and compressive or crushing failure. For structures in the >15-20m water depth range ice ridges will be the principal design ice feature. The latter failure generally results in the maximum ice loads. Ice interaction with sloping sided GBS will also result in multi-modal failure, but will predominately produce bending failure. Ice loads from bending failure are lower than those from crushing and therefore loads will be lower on a slope sided GBS than for a vertical sided structure for the same ice feature. Due to better ice clearing, ice will be less likely to ground in front of a sloped sided GBS than a vertical sided GBS.

Reliable calculation of ice loads requires a detailed understanding of the methods in ISO 19906 including the underlying weaknesses and uncertainties for each method. For multiyear ice interaction with sloping sided structures, where field measurements are minimal, prudent design would include physical model testing in an ice basin supported by engineering calculations based on the methods in ISO 19906.

ISO 19906 is based on limit state design and the use of load and resistance factors to achieve a target reliability. Load factors for the Ultimate and Accidental limit states have been calibrated to achieve an annual failure probability of 1.0x10-5 for a manned platform with high consequence exposure level. Code calibration included determination of representative loads for Okhotsk Sea GBS (reference OGP Report 422). OGP 422 shows a 100-year load of 330MN for a vertical sided structure of 100m diameter. [81]

Other ice related design considerations for GBS include:

Ice ride-up**:** To avoid ice loading of the underside of the deck due to ice ride-up on the side of the structure, the air gap between the sea level and the bottom of steel might have to be increased compared to what will be required due to wave run-up. A conical structure will have a higher ice run-up than a cylindrical/vertical structure and the platform deck elevation has to be increased accordingly

Abrasion: of structure outer shell materials due to ice action should be considered in the design of offshore structures for Arctic regions. Concrete abrasion can be an issue in highly dynamic ice environment as several thousand km of ice may pass an offshore structure per year. Measurements and inspections of lighthouses in the Baltic Sea in the 1980s and 1990s showed that some of the structures experienced significant abrasion due to ice action. Inspection of the concrete piers of the Confederation Bridge in Canada indicated a very low abrasion rate (0.3 mm/year). A number of laboratory and field studies were performed to investigate abrasion of different materials due to ice action. These studies found that the rate of material abrasion depends on a number of parameters: material and ice properties, ice pressure, drift rate, surface roughness and ice-material friction coefficient. Use of high strength concrete will decrease abrasion significantly and was used as ice abrasion protection for the Sakhalin I GBS. An additional protection measure could be an application of low-friction coatings. [81]

Ice seafloor gouging**:** Ice gouging at the seafloor will require any pipelines or cables to be trenched and buried for protection. The observed depth of ice gouging indicates that trenches may have to be several meters deep to ensure protection.

Structural icing**:** Mainly a floating platform issue

GBS design

1. Substructure

Concept development work for the Sea of Okhotsk has identified multi-shaft configurations like Lunskoye, Piltun-Astokhskoye-B, and Berkut, as leading contenders. Single shaft concepts may be workable from an ice load standpoint, but will have substantially less storage volume. Ice load calculations for multi-shaft platforms are not challenging particularly with regard to loading from first-year ice.

The multi-shaft concept may have some advantages with respect to float in draft and topside support. The reduced draft may also open up for alternative and possibly local GBS construction sites. [81]

Steel: The extremely low ambient temperature down to -50°C, do introduce additional requirements for the steel qualities to be used. Although equipment has been produced for and operated in the area for decades there is still a lack of international steel standards for suitable commodity “low cost” high strength materials. However, significant work has been and still is being performed to develop new steel qualities suitable for Arctic areas.

Concrete: For concrete the existing “standard” offshore quality (grades B55 or B60) is documented to handle the low temperature. Activities are ongoing to further develop light weight concrete to increase the ductility especially at low temperatures. This quality could be an alternative if the minimum platform draft for is an issue. To overcome ice abrasion effects, concrete GBS shafts can be constructed with a special high strength concrete that was developed for the Sakhalin-I Berkut platform. This concrete was used for the ice exposed area and will reduce ice abrasion over the lifetime of the platform.

Composite: The Prirazomnaya platform is a hybrid solution where steel “form work” is filled with concrete. The concrete has the function of both increasing the capacity of the platform hull to resist larger ice load as well as providing the required on bottom weight for the platform to resist global ice load.

2. Topsides

Topsides functionality would nominally include facilities for oil and gas processing, utilities including power and living quarters, and drilling rig(s). This functionality is similar to any oil and gas installation, regardless of location. Arctic specific requirements are associated with winterization and human factor engineering. Winterization includes heating or insulation of working and machinery spaces, tanks or compartments containing liquids (ballast, firewater, potable water), and possibly process related equipment for flow assurance. Winterization requirements are also important for HVAC air intakes to accommodate snow accumulation.

Heat tracing and insulation are required for piping exposed to the elements, including redundancy. Heat tracing may also be required around safety critical equipment such as evacuation craft and lowering appurtenances. Enclosures for process equipment create added complexity for explosion and fire design.

Human factor engineering is important for equipment exposed to the elements including valves, gauges, and communication devices to ensure functionality by workers having limited movement due to PPE. Human factor engineering is also an important consideration for exposed walkways and ladders. A key implication resulting from the need for winterization is heavier topsides relative to temperate and tropical climates for the same functionality. [81]

3. Tow from construction site, offshore mating of topsides and base

Towing a platform (Figure 47) (substructure only or complete platform) is not considered to be a feasibility issue. A number of complete platforms (GBSs), the majority being multi legged, with topsides installed have been wet towed to final location and installed. The only challenge foreseen for Sakhalin region is the limited ice free season which will require good operational logistics management to enable completion of all operations including any ballasting and scour protection within the available installation period. The wet towing distance from a potential construction site in the Primorsky Krai of Russia to the Okhotsk Sea is relatively short and quite feasible.

Figure 47. Towing of one of the Sakhalin II concrete GBSs from Vosthosny Port to field location outside Sakhalin Island

Offshore (or very often nearshore) mating of topsides and substructure is the preferred method as this will reduce the activities at the final location significantly. However, if there is no deep water area available allowing a mating, an offshore float over at the final location as was performed for the last three Sakhalin platforms is feasible. [81]

4. Construction, transport, installation

Local construction of GBS has so far not been considered practical.

The practice for all concrete GBSs constructed has been to perform this in a purpose built graving dock. Some evaluations have been performed to locate suitable areas where a dry dock was established and one potential area at the Nakhodka Bay in the Primorsky Krai which located about 85 km east of Vladivostok City have been identified.

These considerations have been evaluated to a sufficiently detailed level to enable a final conclusion regarding feasibility.

Local fabrication of large steel structures is not practical. No facilities exist and they cannot reasonably be expected to be developed.

From an execution and construction risk point of view but also taking into account economical consideration, the tow and installation of a complete platform including the installed topside is by far the preferred solution. By this the in-field activities will be significantly reduced compared to a float over of the topside after the substructure has been installed. The short ice free season increases the risk of not being able to float over the topside in the same season as the substructure is installed. The two Sakhalin-II platforms were installed in two seasons (i.e. topsides installed the summer after the GBS base) due to this reason (Figure 48).

One of the main differentiators between a concrete and steel GBS would be that the steel version most likely will require some additional solid ballast to obtain sufficient on bottom weight to be able to resist the ice load. If this can be installed prior to float in to the final location this should not have any impact on the in-field activities. However, if the solid ballast has to be installed after installation this would be another operation that has to be completed in the short open water season. [81]

Figure 48. Construction of the Lun-A concrete GBS at the Wrangel site, Vostochny Port (Photo courtesy of Sakhalin Energy Investment Company)

Successful near shore mating such as for Hibernia (Figure 49) and the North Sea GBS's and offshore float over of topsides as for the three latest Sakhalin platforms have been performed. For both methods a number of the topsides have had a weight of more than 40,000 tones.

During concept studies the possibility to carry a topside weight of close to 100,000 tones has been verified while still keeping the tow-in draft in the range of 20-25m. If an offshore float over installation method is used as for the three latest Sakhalin platforms, the topside weight limitations will be given by the marine equipment used in combination with the geometry of the top of the substructure. [81]

Figure 49. Towing of the Hibernia platform from Bull Arm, Newfoundland, to final location (Photo courtesy of Hibernia Management and Development Company)

5. Decommissioning

The basic requirement when designing a GBS substructure is that it should be possible to remove it when the field life has come to an end. This has been the case for large GBS structures designed and built for the last 30 years in the North Sea (Figure 50). Removal of the platform is in principle a reverse installation process and the same systems used for installation will be in operation. This does require that all the applicable systems like ballast and skirt evacuation/soil drain system have the same design life as the platform. To obtain this will require high quality stainless steel or titanium material to be used for some equipment and piping systems. The large GBSs that so far have been taken out of service were designed and built prior to implementation of the decommissioning requirement and the substructures of these platforms have been left after removal of the topside. Examples are the Frigg Field Center at the border between Norway and UK in the North Sea and the Ekofisk Tank in the Norwegian sector of the North Sea. [81]

Figure 50. Remaining concrete structures at the Frig Field Center, North Sea (photo: Norwegian Petroleum Directorate)

Decommissioning in areas with short open water periods may lead to decommissioning/removal activities to last for more than one season.

6. Other issues

Non-Technical Design considerations include

- Marine sound
- Discharge: liquids, solid, cutting, etc.
- Air emissions

7. Well Systems Topical Paper TP6 – Arctic well integrity and spill prevention methods and technology addresses both surface and subsea wells including drilling, completion, and source control. [81]

8. Resupply The resupply philosophy will influence the platform and substructure design. If long resupply periods are expected the platform has to be self-supplied for a long period which will increase the required storage volume and operating weight. It is important to include this element as a part of the design basis at an early stage in the project to avoid potential changes late in the project. [81]

5.2.3 Stationary platform

Shallow water platform

In cases where it is necessary to ensure the strength and stability of a fixed platform, exposed by force impact, for example, of ice in shallow waters, instead of fixed gravity platforms in the form of a massive monolith, or artificial island platform on the columns are used.

The column means a single vertical supporting pole with cylindrical or other cross-sectional shape, the most typical size is comparable to the height of the column (e.g., column diameter of 2 m and a height of 15 m).

A typical size which is called the greatest cross-section, for example, the diameter (in the case of its cylindrical shape) or diagonal (in the case of a square or rectangle).

Structurally, fixed offshore platforms on the columns have three basic components of

- superstructure (the topside deck);
- supporting columns;
- lower support base, which is the foundation of a platform.

The shallow water platform resting upon the columns into separate foundations

Each columns of the cylindrical cross-section rest on its own foundation. The use of separate foundations under each column allows setting a fixed platform on a light soil, or on an uneven bottom, for example, on the underwater side-hill. In this case, pillars are located at different depths, and the columns respectively have different lengths (or heights) (Figure 51).

The cross-sectional area of columns and their number is determined from the conditions of the strength and stability of each column and platform itself and all the load of the superstructure, wind, waves, currents and ice. [11]

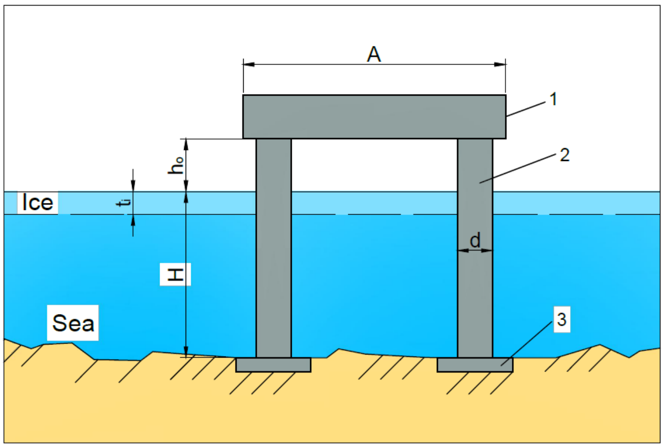


Figure 51. The GBS resting upon the columns into separate foundations

The shallow water platform resting upon a common foundation.

The main difference between this form of the platform is used as a capacity of solid concrete foundation of a structure (or metal container filled with concrete) slabs. Such form requires the alignment of the bottom so that foundation is in a horizontal position (Figure 52). [11]

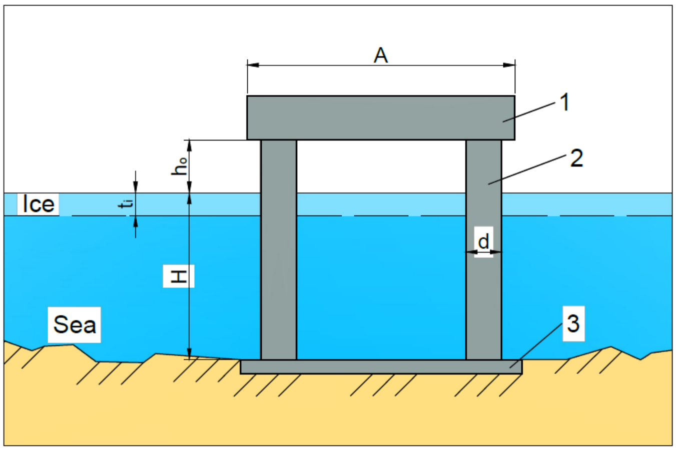


Figure 52. The GBS resting upon a common foundation

The shallow water platform resting upon the columns on pile foundations.

Superstructure of a platform *1* is arranged on the columns *2*, but the columns are based on the piled foundation *3*, held under each column. Piles are driven into the ground at the target depth, either directly through the interior space of the column or the column itself is mounted on a pre-installed foundation. Aligning the bottom floor at the installation site these types of fixed offshore platforms are not required. These circumstances significantly simplify the construction works in comparison with the resettlement option (Figure 53).

Reinforced concrete is broadly used as a material used for the production of columns. Columns are manufactured in the port or special shore base and then delivered by boats to the installation site and installed onto the foundations. Frequently in order to install the columns metal jackets are used which are filled with concrete after their installation on site. This method is very practical for the option of resting upon the columns on piled foundations, since it allows to drive the pile throughout the inner space of a jacket (its diameter can reach few meters). [11]

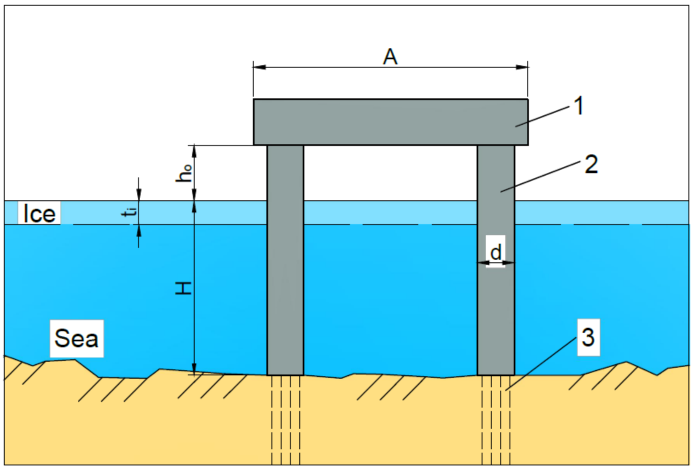


Figure 53. The GBS resting upon the columns on pile foundations

The monopod

Fixed offshore platforms "monopod" represents the construction of tower modification: the central bearing structure ("mono" means single), resting upon the seabed throughout a cone-shape base.

Components of fixed offshore platform are: superstructure *1*, supporting column *2* and a bearing mounting base *3*. This scheme of offshore fixed platform is used as a gravity platform, i.e. held in prearranged position only by its own weight. Used offshore fixed platforms of this type most often when the sea ice is possible on the surface in winter time. Fixed offshore platforms "monopod" is able to withstand strong external impacts (current, wind, waves and ice pressure), because its elements are cylindrical bearing part *2*, cone *3* and foundation base *4* are made from monolith reinforced concrete. Inside of them are arranged various facilities for equipment, materials, water tanks, fuel, etc. The wall thickness *2*, *3*, *4* of the parts is calculated for all externally acting factors. To improve reliability, the cylindrical part may be protected by a metal jacket (Figure 54).

The difference between the fixed offshore platforms "monopod" from pole type platforms, mainly determined by its gravity nature, which allows it not only to maintain in an upright position under its own weight, but also to withstand lateral pressure of ice, currents and wind. [11]

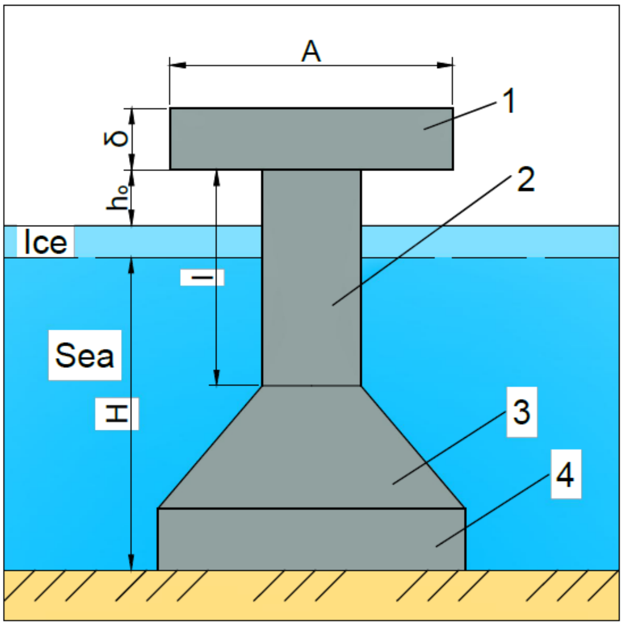


Figure 54. The monopod

5.2.4 Specifics of gravity base structures

The term «gravity» refers to all the platforms that are held at the bottom by its own weight and links of the lower part of the platform with ground base. Areas of application of fixed offshore gravity platforms are mainly stipulated to powerful force impacts towards platform, seeking to move or overturn it. Such power impacts are: seismic load, current, waves, wind, ice and especially ice-drift in the winter time. If the impact of seismic shocks, currents, waves and wind can withstand light type of platforms, the pressure moving an ice in winter periods can withstand a massive platform, located on the ground and held down from shearing action by corresponding fixturing on the sea-bottom.

Gravity base structures by shape and construction peculiarities can be classified as follows:

The massive gravity base structure with vertical walls

Gravitation mass *2* which having upright walls made in the shape a rectangle (vertical section) of concrete or reinforced concrete, installed on the seabed, whose depth is *H*. On the top plane of the mass mounted *1* superstructure. Deck dimensions is determined with stringent conformity to technological and household requirements. On top of it (and inside it) are placed block modules with equipment, energy installations, living quarters, drilling rigs, helipad. Lower deck plane is located at a height *h* from the water surface. In the mass *2* there is a shaft *5* for the passage of the drill pipes and storage tanks for petroleum products and other liquid materials, stockpile of pipes *3*, and other equipment (Figure 55).

The whole solid monolith (it can be called even all-body) can be monolithic or assembled from individual concrete blocks, prefabricated at the coastal base and delivered to the installation site by special barges or other floating facilities. [11]

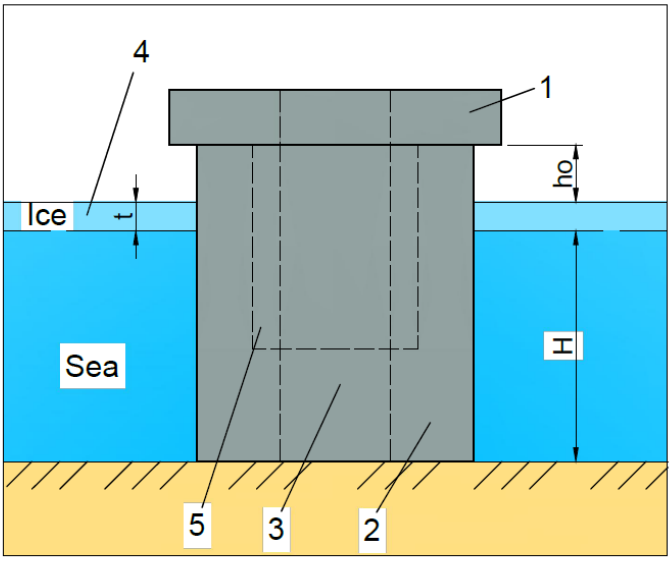


Figure 55. The GBS with vertical walls.

Solid-cast monolith can be manufactured using the so-called «caisson» substantially representing a metal box an enormous size. The solid-cast monolith *2* using the caisson is not necessarily to fill completely with concrete. It is possible to make the inner wall (jacket) *2* with concrete or reinforced concrete, and to fill the inside *4* with cohesion less or coarse-material, such as gravel or stone.

Solid-cast monolith, assembled entirely from blocks is erected directly on site of its permanent location, where technology of manufacturing solid monolith using the caisson comprises two major phases: in the port, on a special fabricating yard where the metal frame of a block body *2* is developed, and then on a floating delivered to the installation site, where flooded, following that block *2* is concreted (using underwater concreting) and finally filled with coarse-material. It is also possible manufacturing block body *2* is completely in the port (manufacturing of caisson, and filling it with concrete), then shipping this block body *2* afloat, dropping it to the bottom and filling the inner space with a coarse-grained and coarse-stone material (Figure 56). [11]

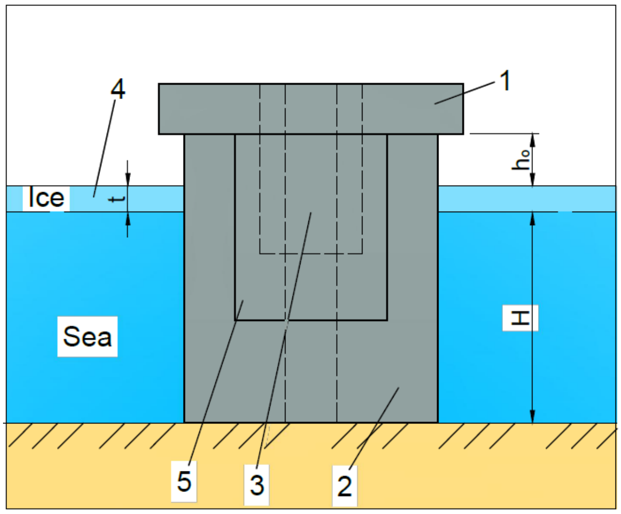


Figure 56. The GBS with vertical walls (with caisson).

The massive gravity base structure with inclined upsides

The shape of structure with vertical walls has along with the advantage, such as minimum volume of material on the consumable its construction also has significant disadvantages. These disadvantages include primarily that the ice thickness t and waves affect to upright walls. In this case, the impact strength will be highest, which requires the increasing of solid-cast monolith volume, to hold the platform from shearing action or capsizing.

To reduce the force impact magnitude to the structure sectional shaped of a truncated pyramid is given. Ice in this case like a waves, when exposed to lateral upsides, will be changing the direction of response forces, climbing up the inclined surfaces.

Lifting range of the upper block ho is dependent on the possible ascent of the water level in the sea and determined as the sum of the tidal water level rise, the wave height (maximum), the amplitude of swell during a surge to the wave slope and navigational altitude margin (Figure 57). [11]

$h_0 = h_1 + h_2 + h_3 + h_4$, where

h_1 = the tidal water level rise;

h_2 = the wave height (maximum);

h_3 = the height of rise of water during a surge on the wave slope;

h_4 = the navigational clearance.

Thus, the cross section of the massive size depends on the depth of the sea at the site of construction, given the size of the missives' upper area and the angle α. These three parameters determine the width of the massive in the base of *B*

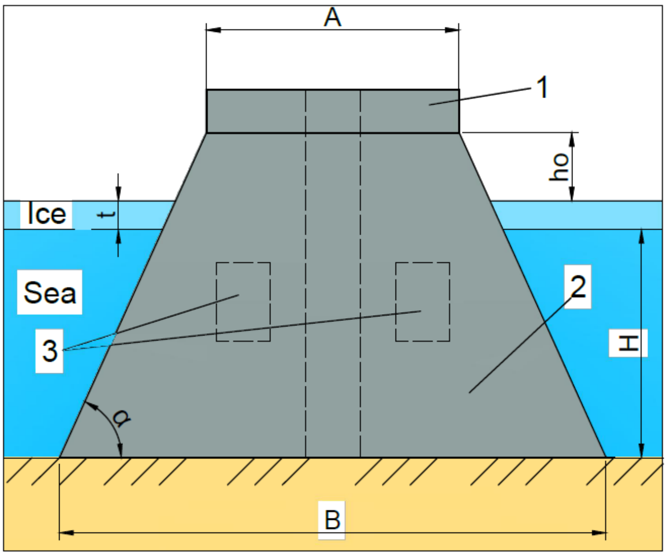


Figure 57. The GBS with inclined upsides.

Massive gravity base structure with polygonal side upsides

Structure with polygonal side superficies consist of two parts: The top which is manufactured from a concrete in the metal jacket (caisson) *2* and lower - of the concrete blocks or tetrahedron form of filled soil (ungraded stone *3*). The lower part is dumped on the height *a* and within it the wave impact is minimal or non-existent. The angle α is formed naturally when stone is dumped. On the surface of 0-0 is set upper part of a massive structure that can withstand the impact of currents, waves and ice.

The upper part *1* is a so-called upper deck superstructure (or main deck), where a drilling rig (or derrick), technical equipment, warehouses, living quarters) housed. Consequently, the outline dimensions *A* should be selected from the conditions of accommodation them on the top structure (Figure 58).

In the concrete body of solid-cast monolith *2* (under water) can be displaced compartments *3* (structure with the smooth side surfaces) for the storage of drill pipes and consumables. For structures with polygonal lateral sides such quarters are containers *4*. In both structures shaft passes from the top to the bottom (*4* and *5* -, respectively) for passing through sold monolith of drill string. [11]

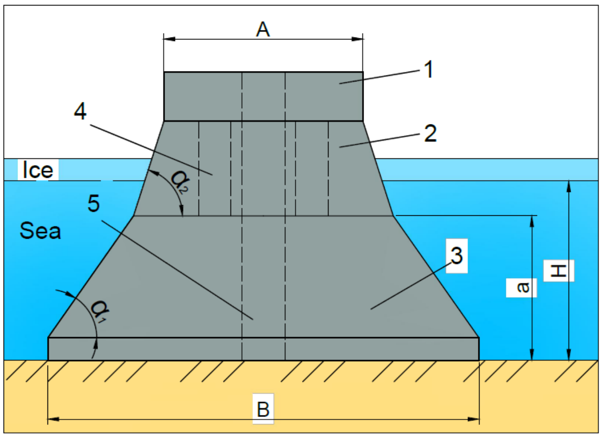


Figure 58. The GBS with polygonal side upsides.

6. Subsea concepts for deep water Sakhalin development

6.1 General information about subsea production systems.

At the present time the application of subsea production systems is to become the most promising direction in the development of deposits in freezing seas. The system is arranged on the construction of offshore wells, where the mouth of hole is situated at the bottom. Here the equipment for gathering facilities and transportation the products from wells, subsea pipelines, power systems, telecommunications and controls are placed.

Subsea production systems can operate in fully autonomous mode (Figure 59), or in combination with a fixed or floating structures, often such complex also called combined, but more on that later.

It is worth noting a number of advantages compared to marine works:

- A more rapid introduction into operation of deposit in the project by commissioning the drilled wells with floating drilling outfit.

- The flexibility of the technology of subsea production because of the possibility of a quick-change of equipment - the transition from free-flow well output regime to the gas lift production (replacement of one equipment unit to another)

- Field development in harsh conditions, even in the presence of ice ridges and grounded hummocks, etc.;

- Field development with a local hydrocarbon reserves.

However, at the same time there are a number of disadvantages:

- Necessity in arctic conditions (especially in shallow waters) to create a special design for the protection of subsea production systems from the impact of ice formations;

- The complexity of ensuring the transportation of extracted product without prior field processing.

In Russia, as I mentioned in the previous chapters of my work already operates one industrial subsea production system by Gazprom company on Kirinskoye field, block "Sakhalin-III. As the basis was taken the experience of Norwegian state-owned Statoil company in the Snøhvit field, manufacturer of the same complex also made Norwegian FMC Technology company. Distinctive aspects of the Norwegian project that distance from the subsea production system to the onshore processing facility is up to 143 km, and the water depth over the complex varies from 250 to 345 meters. At the present time the overall sum of the wells from 3 fields Snøhvit, Albatross has about 20 wells while Askeladd field be under development.

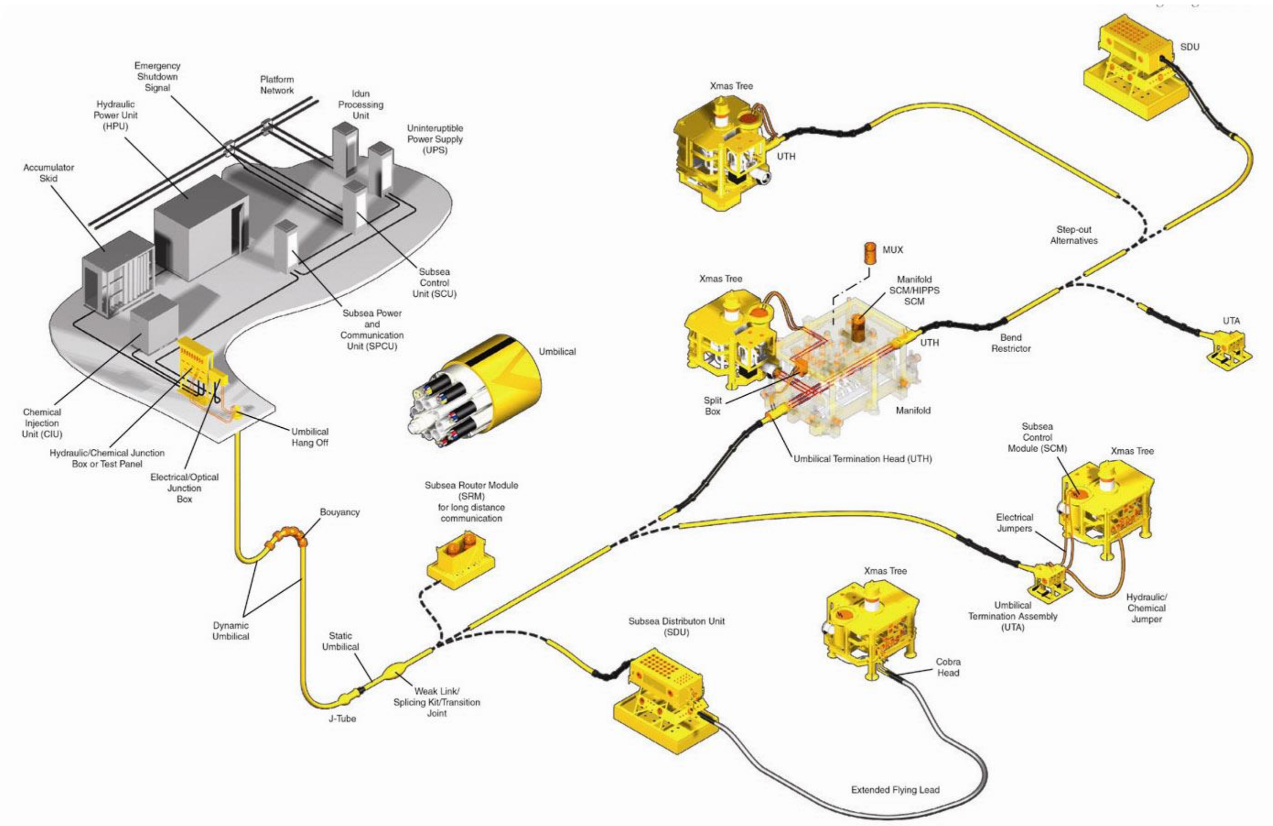


Figure 59. Autonomous subsea production system.

Combined systems

In this case we are talking about the so-called combined fields in which a combination of above-water extraction with subsea wellhead completing on a mouth of hole in the gang of wells complex is used (Figure 60). In this case, the above water part of the system is placed directly on the platform on which are mounted drilling and production wells, as well as the system of remote monitoring for the wellhead equipment. A demonstrative example of such a combination may be an example of fields Troll B and Troll C in the Norwegian sector of the North Sea. About 110 horizontal wells were drilled during the development of the deposit of which 28 wells are so-called multilateral wells. This is truly a jewel of engineering thought from the moment field development project.

Production wells are often drilled with that using the drilling vessel, the dimensions of which allow to allocate a drilling rig, power equipment, materials and accommodation spaces.

These combined constructions are used, depending on weather and ice conditions in the sea area. Drilling wells goes in interglacial ice period, while taking into account the high performance of modern drilling rigs, it is appropriate to assume that even a short interglacial ice period may be sufficient to carry out a significant amount of drilling operations. Upon completion of drilling facilities, production wells are installed on the ice resistant base area which is designed to accommodate all service equipment.

Among the disadvantages we should mentioned:

- Considerable capital investments are required for the development of these types of fields do not allow their use in the development of fields with small reserves.

- In deep water areas of the Arctic seas with severe ice conditions we cannot use this type of field development.

All of the described above types for the development of the Sea of Okhotsk offshore fields, allow to carry out selection of the most cost-effective option or combination of options in development according to the specific geological and technical, metocean and climatic conditions of the area field location.

Above-water production is effective in the Okhotsk Sea conditions at depths of up to 60 meters. With increasing of depth becomes possible the use of subsea production systems, which in its turn implies the creation of the combined methods of field development.

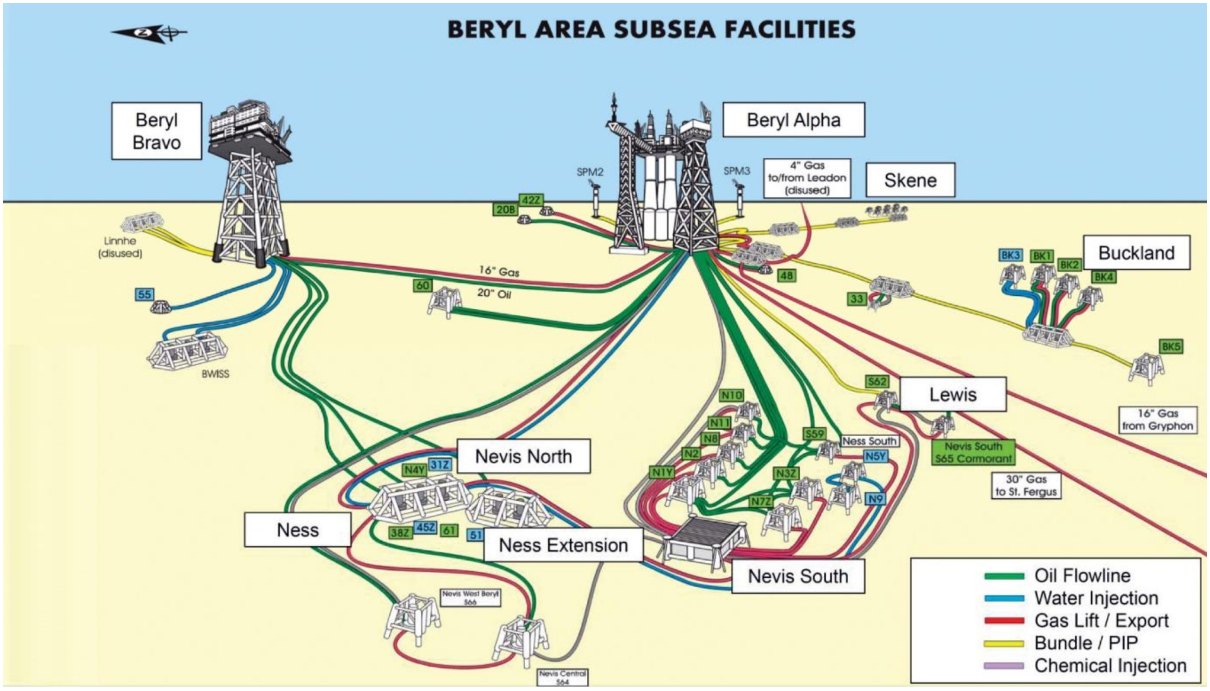


Figure 60. Combined subsea production system.

6.2 Possible concepts of subsea production systems for deep water Sakhalin

Presently, in view of the sharp fall in prices for hydrocarbon and increased competition in the global market, the main task is to use high-tech equipment for production of oil and gas from the shelf.

As has been described in detail in the previous chapters the Sakhalin's shelf is developed using a variety of systems including production directly from the platforms, but also already has an active project of subsea completion using subsea production system on the project «Sakhalin-III» company Gazprom. However, the Sakhalin shelf includes a number of other blocks in which exploration was carried out and identified promising areas, but the production of hydrocarbons is not conducted. In general, these fields have roughly similar parameters to those that are already underway. At the same time in the world there is trend in increasing the number of fields using subsea production technology. And indeed, this technology has a lot of undeniable advantages due to its evolution, such as the ability to produce hydrocarbons in deep and ultra-deep seas, as well as to develop satellite fields with a low resource base. However, the most major challenge lies in the fact that because of great remoteness of a field there are problems connected with the flow assurance and transportation of oil and gas from the field to the shore. The world has developed enough concepts regarding the usage subsea production systems and many of them in essence can be called the state of art, such as Ormen Lange, Snøhvit, and even I would say a super-unique example of natural gas production at a large distance of over 500 km on the example of Malampaya Project in the Philippines.

In our case, we will focus on possibility of using the concept of subsea production system in various forms applicable to the Sakhalin shelf and its natural and geographical features. The Sakhalin Shelf can truly be called unique because it has a number of unique advantages for the possibility of applying this technology. First of all, it is the remoteness of all explored fields, where the distance does not exceed 30 km from the shore, the second important aspect - is the depth (bathymetry) here too, the figures can be said about similar within 100 (160) m at most. And at last the moderate ice conditions such as the presence of first-year ice and ice ridges in the winter period of time which are not exceed more than 7 months, and the absence of multi-year ice and icebergs at all.

The final chapter's purpose of my thesis is the consideration of various concepts using subsea production systems and assessment of the feasibility of using a fully autonomous subsea complexes without injection of MEG for gas production associated with tie-back to shore connections. This study was performed with the use of the applied experience of the Norwegian company Aker Solutions. Solutions. [15]

The pipeline pressure drop and pipeline liquid accumulation are the main challenges for this development strategy and they will increase with longer step-outs. For the base case, the hydrate management philosophy is the same as the mentioned developments, specifically injection of MEG at the wellhead to inhibit hydrate formation.

Due to high pressure drop in the pipeline boosting is required, in the form of gas compression.

Existing «Sakhalin-III» project in the Kirinskoye field is used as basis. At 28 kilometers from the coast at 90 meters depth.

Mainly gas, with some condensate and water is produced. The peak production rate is 15mln m^3/d of gas, and a Flowing Well Head Pressure (FWHP) of 293,9 Bar early life. The field development consists of one separate manifold center, each 10 km away from a subsea production hub, visualized in Figure 61. The subsea production hub gathers the flow from each of the three fields (Kirinskoye, Yuzhno-Kirinskoye, Mynginskoye) and transfers the fluid to shore. A premise of the study is that subsea technology is used for the development of fields, without permanent surface facilities.

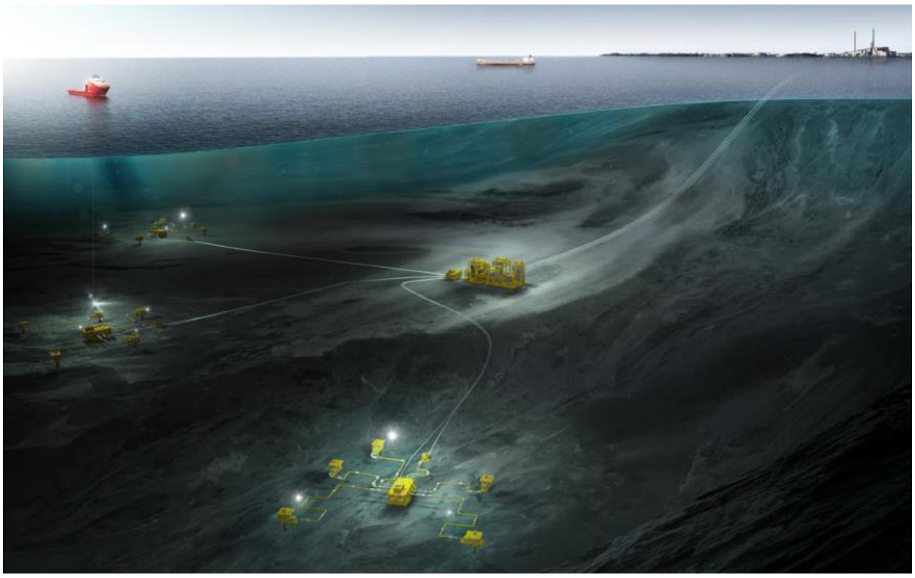


Figure 61. A premise of the study is that the fields are to be developed solely using subsea technology, without the support of any permanent surface facilities.

Major drivers for field development of subsea systems:

- One of the major driver is to maximize production of oil or gas from reservoir to receiving facilities;
- The basic parameters from a flow assurance point of view are temperature, pressure and the fluid properties from the reservoir;
- Major parameters for the selection of subsea production system are reliability, safety, technical feasibility, and total cost;
- Subsea design must meet the requirements such as, simplicity, efficiency, reliability.

The equipment needs to operate for decades with a minimum of down time in harsh conditions, i.e. internal/external pressure, temperature;

- The flow assurance project team must be able to design multiphase systems in order to provide the uninterrupted transportation of reservoir fluids to the onshore processing facility;
- Major challenges associated with are hydrate formation, flow induced vibration, wax accretion, water hammer and erosion.

Identified concept options

Fluids transport options from subsea to shore, the philosophy of hydrate management for the pipelines and subsea water handling are all elements of the subsea field development strategy that will affect each other. The onshore infrastructure options needed will be driven by the complexity of the subsea system.

Transport options

Increasing the distance of subsea tie-backs will effect increased pipeline liquid inventory and pressure drop, making the importance of good flow predictions even greater. The quality of multiphase flow simulators have improved over the past decades and field developments have been realized with long-distance subsea tie-backs to shore, good examples being Ormen Lange and the Snøhvit developments in Norway, with subsea tie-backs over a distance of 120km and 146km respectively. [15]

An important characteristic of gas dominated multiphase flow in pipelines is the minimum flow needed to maintain stable operating conditions. The gas will effectively sweep the liquid forward in the pipeline, with flow rates in the friction dominated pressure drop range. The liquid will start to accumulate in the pipeline, and eventually hydrostatic pressure drop will become dominant, at low flow rates; the pressure drop is gravity dominated and will increase with lower flow rates, shown in Figure 62. Gravity dominated flow is often related to unstable production and slugging conditions, and a minimum flow rate is defined for the pipeline to avoid operating within this range.

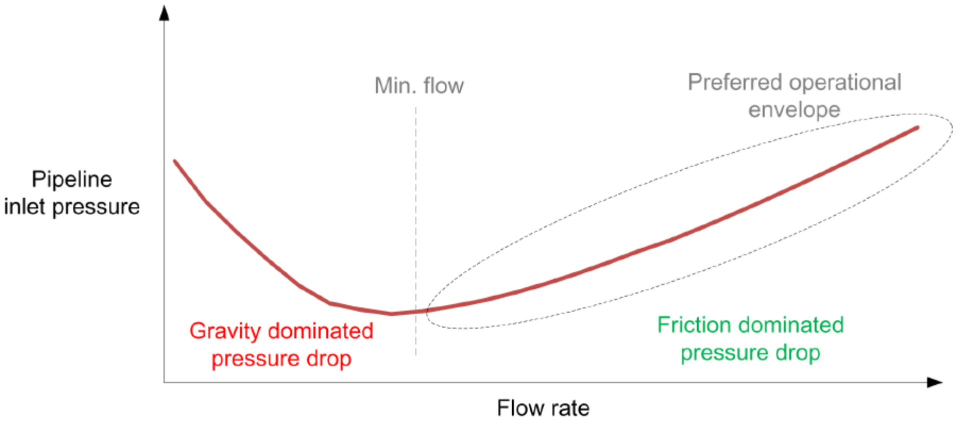


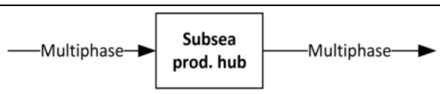
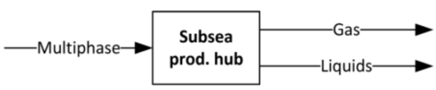
Figure 62. A typical pipeline inlet pressure vs. flow rate curve for a multiphase pipeline. [15]

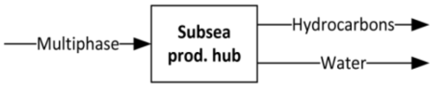
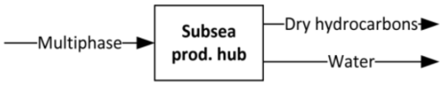
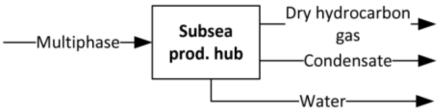
The general challenges of multiphase flow over long distances are summarized below:

- High pressure drop in the pipeline and maximum pipeline size limitations; larger pipelines lower the pressure drop, but also leads to a higher minimum flow rate and limits turndown operation
- Continuous MEG injection for hydrate inhibition, which requires a pipeline for MEG supply and an onshore MEG regeneration facility
- Large volumes of MEG which is stored onshore for turndown operation when liquid accumulates in the pipeline
- Turndown operation, liquid accumulation and subsequent ramp-up that causes massive liquid surges onshore and requires large slug catchers

The alternatives to the base case in the DEPTH study, multiphase transport of the gas to shore, were identified and categorized as transport options and are presented in Table 20. These options are covering all the transport options in which gas can be transported to shore from the subsea production hub; ranging from multiphase flow to single-phase flow. All the options in Table 20 can be combined with subsea boosting when needed. [15]

Table 20. Transport options summary. All the options can be combined with subsea boosting when needed

Concept of subsea development	Simplified overview	Description
Option 1: **Multiphase transport to shore**		The entire untreated well-stream is exported to shore
Option 2: **Subsea gas-liquid separation**		The well-stream is separated into gas and liquid phases which are separately transported to shore. The gas is not sublimated due to solved water and hydrocarbons in the gas

Option 3: **Subsea hydrocarbons water separation**		Gas and liquids are separated before the liquids, consisting of condensate and water, is further separated. The condensate is commingled with the gas and exported to the shore. The hydrocarbons are not dry due to solved water in the gas and water carryover in the condensate.
Option 4a: **Subsea dehydration – commingling of gas and condensate**		Same separation and commingling of hydrocarbons as in option 3, but both the gas and the condensate are dehydrated so that the transportation to shore is without any water content in the pipeline
Option 4b: **Subsea dehydration – separate gas and condensate**		The same separation as in Option 2, but the gas is dehydrated so that no water is present in the gas pipeline.

Currently available subsea separation equipment allows one to separate the phases of free gas from the free liquids and subsequently free oil or condensate from free water. This technology is the basis for *Options 2* and *3*. *Options 4*, includes technology that has never been placed subsea before. These options represent a future vision within the industry of making subsea processing facilities that may replace surface facilities and enable subsea tie-backs over very long distances.

The single main difference between the transport scenarios in Table 20 is the amount of liquid entering the pipeline together with the gas, and thus the liquid holdup and the total liquid inventory of the pipeline. This will affect the absolute magnitude of the multiphase flow challenges listed above, which can help *reduce the cost, or enable, long distance subsea tie-backs.* It should be noted that the hydrate management philosophy chosen also affects the amount of liquid entering the pipeline with the gas. [15]

Subsea condensate handling

The method of which the liquid that is not following the gas is routed to shore or disposed is a separate discussion from the transport scenarios. Several solutions for the liquid are possible for each of the transport scenarios in Table 20 without affecting the gas transport to shore.

The condensate can be handled in the following ways:

- Separated from the water and transported to shore with the gas
- Transported to shore with the water
- Separated from the water and transported to shore in a separate pipeline

For the options with gas-liquid separation, the condensate is at the bubble point at the separator outlet. When transporting the condensate to shore in a separate pipeline or together with the water, it will flash extensively upon depressurization. Two methods of solving this issue are:

1. Transport the condensate at pressures above the subsea separation pressure to avoid flashing

2. Fully stabilize the condensate subsea.

Subsea water handling

In addition to the mentioned alternatives for condensate handling, the water can be handled in the following ways:

- Re-injected into a reservoir
- Treated and discharged to sea
- Transported to shore in a separate pipeline

Hydrate management philosophy

The hydrate management philosophy will have to be considered separately upstream and downstream of the subsea production hub, schematically shown in Figure 63. For example, if the subsea production hub has a water separation and reinjection system, injection of MEG upstream of the subsea production hub is not practical, as all the MEG would be reinjected into the reservoir and lost. [15]

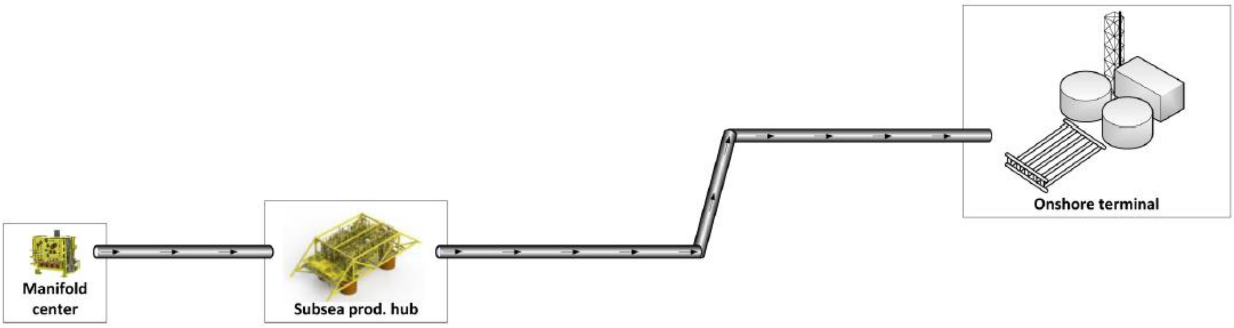


Figure 63. A simplified field development schematic. The three manifold centers are shown as one to illustrate that there are two sections with regard hydrate management philosophy: upstream and downstream of the subsea production hub.

The hydrate management philosophies for the multiphase pipeline, between the manifold center and the subsea production hub, can be:

- MEG injection
- Low Dosage Hydrate Inhibitor (LDHI) injection
- Temperature control (Heating and/or insulation)

The hydrate management philosophies for the pipeline containing the gas, between the subsea production hub and shore, can be:

- MEG injection
- Low Dosage Hydrate Inhibitor (LDHI) injection
- Temperature control (Heating and/or insulation)
- Subsea dehydration

Dehydration is only considered at the subsea production hub, and is thus only a hydrate philosophy for pipelines downstream of the subsea production hub. Insulation of the 30 km pipeline from the hub to shore alone is not considered as a feasible option due to the very large surface area, and the fact that the Joule–Thomson cooling becomes significant when insulation is applied for gas-dominated systems with high pressure drop and low arrival pressure. Heating systems for the 30km pipeline has not been evaluated. Choosing insulation as the hydrate management philosophy for the pipeline between the manifold center and the subsea production hub would require another strategy for shut down situations. [15]

The need for boosting

In order to maintain pressure in the pipeline the subsea gas compression system is required from the first day of production, due to the large pressure drop in the 30km pipeline to shore. The pipeline sizing philosophy in the study was to find the minimum pipeline size with an inlet pressure below the pipeline design pressure, and to use a maximum of two pipelines in parallel. The pipeline design pressure is 350 Bar and requires a High Integrity Pressure Protection System (HIPPS), as the wellhead shut in pressure will be even higher for the first years of production. [15]

To summarize there are two options for installing a subsea compression system:

A subsea compression system can be installed from the first day of production, allowing a smaller pipeline diameter to be selected. This option can produce at a wider range of flow rates, and will have a higher accumulated production over the life of the field.

A larger pipeline diameter can be selected, allowing for production by the reservoir drive mechanism for the first years, before the pipeline minimum flow is reached and a subsea compression system has to be installed to continue producing. This option will produce at a higher flow rate than option 1, but would also have a lower accumulated production over the life of the field. [15]

Option 1 was chosen because it is based on the assumption that this is the cheaper choice, due to the pipeline material cost and installation cost. A smaller pipeline provides some flexibility for pipeline installation method, and results in a wider range of possible pipeline installation vessels that can be used. A complete cost-benefit evaluation between the two options has not been performed in the current phase of the study. The main conclusions are however the same whether option 1 or 2 are chosen: a subsea compression system is needed and it will have to operate with a high suction pressure, ranging from above 100 bars to almost 300 bars depending on pipeline size.

Concept descriptions

The options in Table 20 will affect the challenges of multiphase flow over long distances, such as pressure drop and liquid accumulation. Different permutations of *Options 1*, *2* and *3* will reduce the amount of liquid entering the pipeline with the gas, and reduce the pressure drop and liquid accumulation compared to base case version of *Option 1*. The cost of these improvements will generally be a more complicated subsea process system and a different interface to shore (e.g. number of pipelines). *Option 2* will, as an example, lower the pressure drop in the pipeline to shore but also require the installation of at least one extra pipeline for the liquids, and still require the MEG supply lines, shown in Figure 64. Whether the condensate and water is transported together to shore, or the water is reinjected, does not affect the transport of the gas to shore.

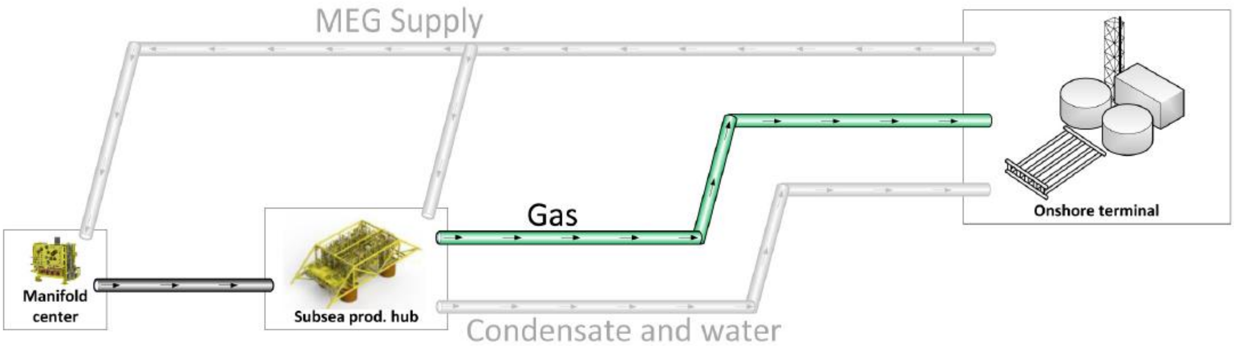


Figure 64. ***Option 2*** **schematic with the MEG supply pipeline and the liquid pipeline shown in grey to illustrate that the hydrate philosophy and the liquid handling shown are one of several options that can be combined with the transport scenario.**

Lowering the pressure drop in the pipeline to shore will increase the reservoir recovery and postpone the minimum flow problems in time, or reduce the requirement for boosting. A cost-benefit evaluation, including the differences in reservoir recovery, is needed to differentiate variations of *Option 1* to *3*.

In *Option 4A*, the gas and condensate will be separated, processed and comingled again at the subsea production hub before being exported to shore as a dry multiphase fluid, without any water or MEG. Figure 65 shows a high-level schematic of *Option 4A*, while Figure 66 shows a block diagram of the process system needed.

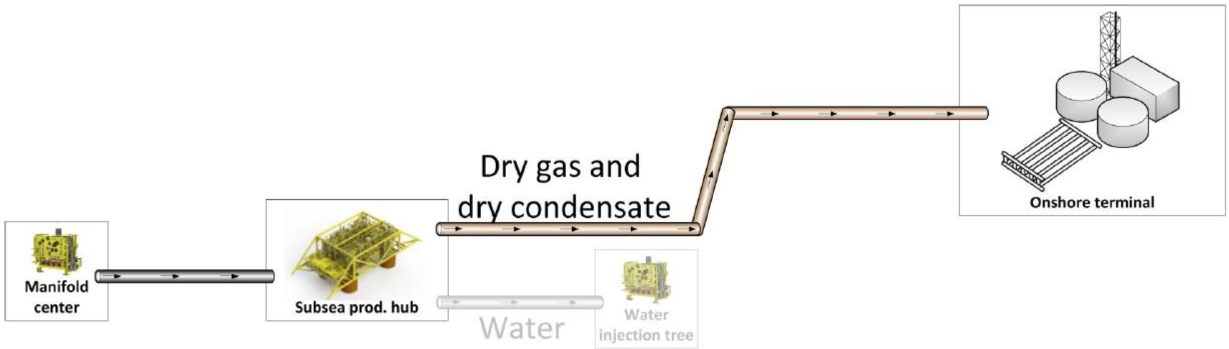


Figure 65. *Option 4A* schematic with the water injection shown in grey to illustrate that the water handling shown is one of several water handling options that can be combined with the transport scenario.

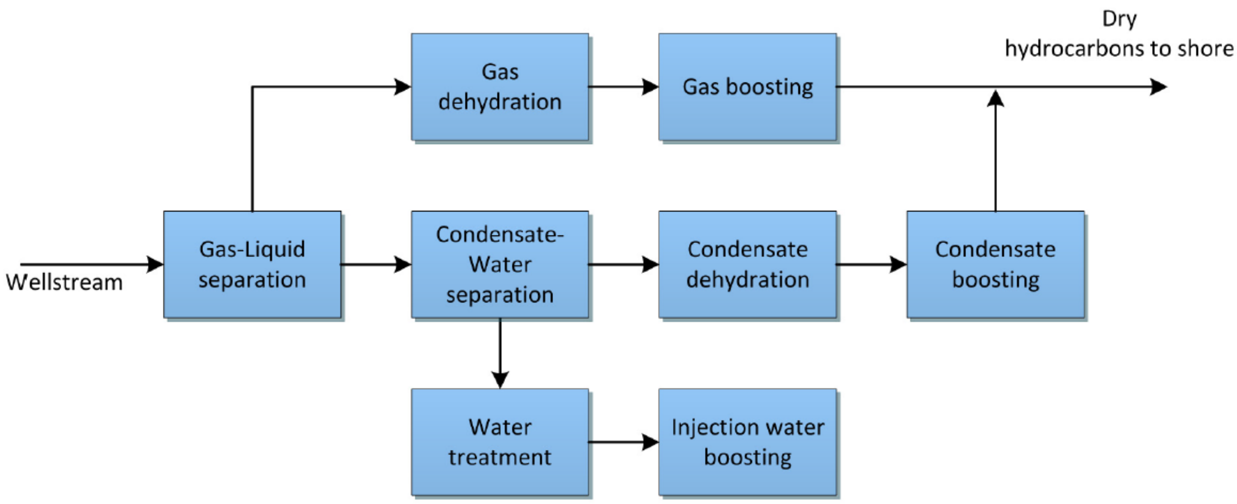


Figure 66. Block diagram of the process system needed for *Option 4A*.

In addition to gas dehydration, the subsea process system required for *Option 4A* will have to include condensate dehydration, i.e. remove the water from the condensate. Condensate dehydration can be done by first separating out the free water, typically by gravity separation with the help of electro-coalescence, before the condensate is dried in a contactor with a dry stripping gas. The stripping gas can potentially be taken from the gas dehydration system and has to be recycled back into the process. [15]

The system performance in *Option 4A* is dependent on the condensate to gas ratio in the produced fluids. If the water is reinjected, the interface to shore will be simpler compared to the base case of *Option 1*, as the MEG supply is no longer needed. Pipeline insulation and heating will be needed for the section between the manifold centers and the subsea production hub when the water is reinjected. The process system needed to reach the ultra-low water content in the condensate, in combination with the gas dehydration system in *Option 4A*, will be highly complex from a subsea point of view. A similar process system and transport scenario was considered for the surface facility for the Shtokman field. [15]

In *Option 4B*, the condensate is separated from the gas at the subsea production hub and will not be comingled before it is exported to shore, which will lead to even less liquid entering the gas pipeline compared to *Option 4A*. The results are lower liquid accumulation and pressure drop at the cost of an extra pipeline. A high-level schematic of *Option 4B* is shown in Figure 67, while a block diagram of the process system needed is shown in Figure 68.

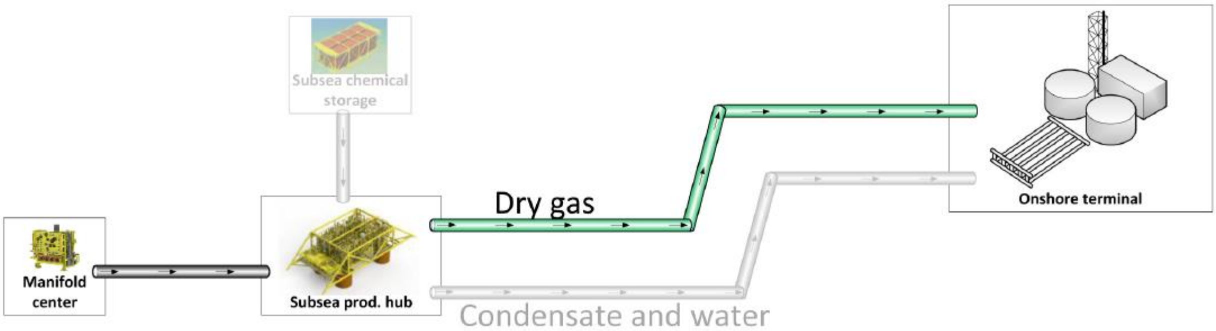


Figure 67. *Option 4B* schematic with the chemical injection and the liquid pipeline shown in grey to illustrate that the hydrate philosophy and the liquid handling shown are one of several options that can be combined with the transport scenario.

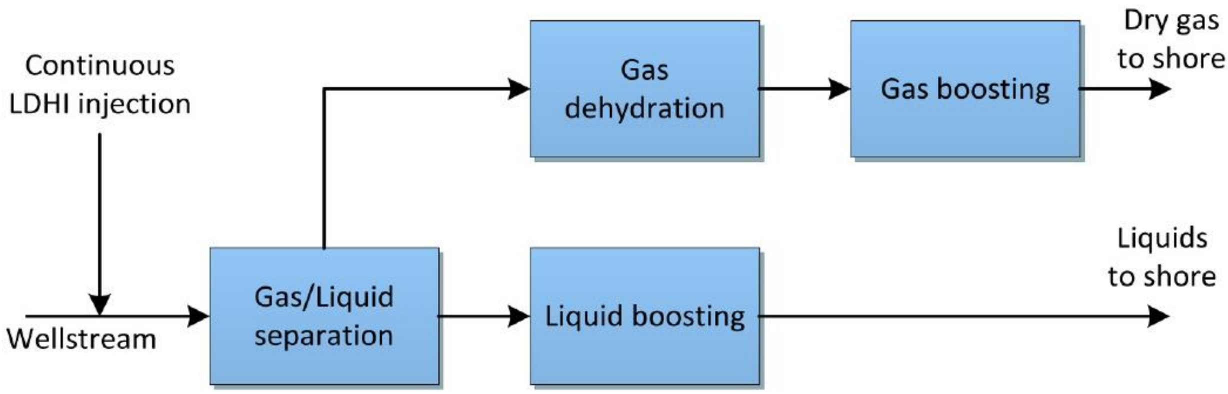


Figure 68. Block diagram needed for *Option 4B*.

In its simplest process configuration, the water and condensate of *Option 4B* is transported together in one pipeline to shore, operating above the bubble point of the condensate. *Option 4B* will have limited benefits compared to Option 2 if the chosen hydrate inhibitor for the liquid line is MEG. The use of an Anti-Agglomerates (AA)- Low Dosage Hydrate Inhibitor (LDHI) would simplify the Option 4B interface to shore, especially if the

AA-LDHI could be stored subsea. Combining the use of AA-LDHI, subsea chemical storage and a liquid pipeline to shore, with a pipeline operating pressure above the bubble point of the liquids, will simplify the *Option 4B* process system compared to *Option 4A*. [15]

Concept selection

General

Two scenarios are suitable: the base case of multiphase transport to shore (*Option 1*) using a subsea compression system from the first day of production, and subsea gas dehydration (*Option 4B*) in combination with a subsea compression system. The driver for installing a subsea compression system from the first day of production is to minimize the pipeline diameter. The driver for choosing subsea gas dehydration is the exclusion of MEG as a hydrate inhibitor and the entire infrastructure needed for MEG regeneration and supply onshore.

Subsea compression systems are operated on the falling reservoir pressure to minimize the subsea compressor work and power. For a gas field in deep waters, the Flowing Well Head Pressure (FWHP) can be very high in early life, e.g. ranging up to 300 Bar, but may still not be high enough for transporting the fluids all the way to shore without compression. The main challenge of operating a subsea process system at these elevated pressures, from a process point of view, is the gas-liquid separation performance.

Subsea gas compression for long step-outs

A compression system similar to the one used in the Åsgard Subsea Compression project was evaluated for the case in the DEPTH study. Technology qualification is unavoidable when the operation envelope is significantly stretched, considering both operating pressure and water depth, and the success of these qualifications is a premise for the feasibility of such a system. A subsea compressor installed in early life would have to operate with a suction pressure of 272 Bar. [15]

Gas liquid separation, and mainly demisting, will be increasingly challenging at high pressures due to the very low liquid surface tension and the smaller density difference between gas and liquid. Subsea compression systems where more off the liquids are allowed through the compressor might be relevant for *Option 1*, and would lead to relaxed separation requirements. For the remain *Option 2*, gas liquid separation is inevitable and a prerequisite for the systems to work (e.g. separate gas pipeline).

Subsea gas dehydration

Gas dehydration systems have never before been installed subsea and are needed in *Option 4A* and Option *4B*. The dehydration system will have to be able to work at high operating pressures to minimize the boosting requirements, and should also operate without the use of solvents.

Little information exists in literature on the use of dehydration technology in a subsea environment, and the information that does exist is mostly on very novel dehydration systems that incorporate hydrate formation and melting as part of the system design (4)(5).

Conventional topside dehydration systems for natural gas are in general divided into the following categories:

- Absorption
- Adsorption
- Low temperature separation
- Membrane separation

Not all of the technologies within these categories are applicable subsea. The systems requiring glycol for dehydration become less attractive for tie-backs, when the driver for doing dehydration is to remove the need for continuous injection of MEG. The interface to shore will have to be considered when assessing the use of a gas dehydration system subsea. Working on the assumption that a subsea glycol regeneration facility is not feasible, the lean glycol will have to come from shore. Conventional absorption systems use glycol as a liquid desiccant, while low temperature separation systems use glycol for hydrate inhibition. The glycol would have to be regenerated onshore, supplied in a pipeline and returned, as the water mixed with glycol is excluded for reinjection subsea. Dehydration technologies for subsea gas fields with long step-out should avoid the use of glycol to minimize the number of pipelines to shore, and by that reduce the cost. [15]

Dehydration systems that are able to dehydrate gas without the use of glycol include:

- Adsorption
- Membrane separation
- Supersonic separation (Low temperature separation without glycol)

Other focus areas

As the tie-back distance increases, the distance dependent costs, such as power cables, umbilicals and pipelines, become larger. An important part of research and development within subsea processing is reducing cost of subsea developments with long tie-backs. The feasibility of power transmission and the cost of umbilicals are also very important parameter of long-distance subsea tie-backs.

Power supply is a major challenge for long-distance subsea tie-backs. Aker Solutions has developed a subsea rotary converter, which makes it possible to transform a specific input frequency/voltage to another output frequency/voltage. This technology enables much longer step-outs without additional requirements for subsea phase compensation, because the flow of reactive power is limited when the frequency is reduced. [15]

Summary

The purpose was to evaluate the feasibility of a fully autonomous subsea gas field development with tie-back to shore. Several options that will reduce the pipeline pressure drop and liquid accumulation, and subsequently reduce the requirements for the onshore support systems needed, have been identified and evaluated.

The base case, multiphase transport to shore, has proven to be feasible using a subsea compression system from the first day of production, but faces challenges with the increased depth and the very high associated operating pressure. Several parameters effect the feasibility including bathymetry, fluid composition and successful technology qualification for the new operating condition.

The study has in addition to the base case identified potential solutions for a fully autonomous subsea gas development with tie-back to shore without the use of MEG for hydrate inhibition; a challenging element for long-distance tie-backs. The focus in this part of the study was on gas dehydration technologies that can operate without the use of any solvents, at high pressure.

6.5 Pipeline route challenges

Subsea pipeline has a nominal diameter of 20"(508 mm). The wall thickness of 26.3 mm (area 2,500 meters from the pipe-joint) and 24.3 mm (0.5 MP - 28), the material - carbon steel DNV SAWL 450 FD. Corrosion allowance - 5.0 mm.

The choice of carbon steel as the material of the underwater pipeline is also stipulated by the presence of internal corrosion allowance.

Calculating corrosion allowance is made, on the basis of an engagement of injection systems corrosion inhibitor and a pH stabilizer.

The pipeline will be a straight line from the manifold to the point of landfall area. It considerably accelerates and simplifies the work of laying the pipeline. However, the last 6-8 kilometers of track near the shore pipeline will be laid as a zigzag to compensate extension pipelines.

Given the degree of risk and the load pipeline is divided into three main sections (Figure 69).

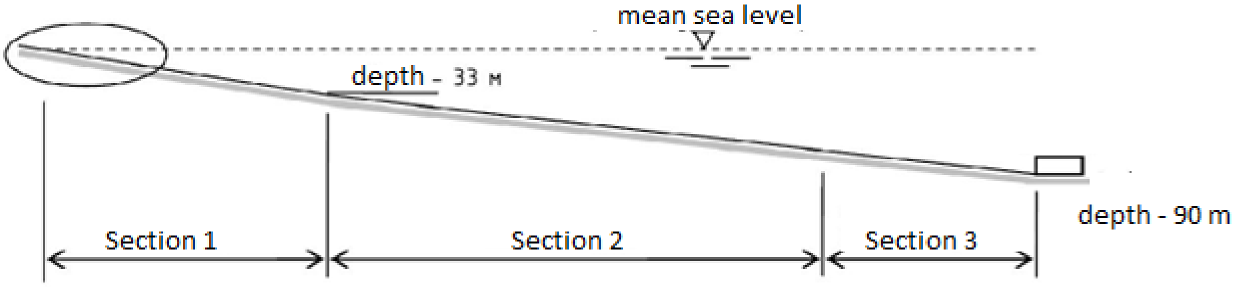


Figure 69. Three main pipeline sections [24]

The section I

Landfall area from the RP (ranging point) 289 to the RP 210. In this section the pipelines are exposed to the pack ice, which penetrates into the bottom to a depth of 3 m. Pipelines and umbilical laying into the trench and covered with ground in the area from the point of landfall area (RP-289) to a depth of 33 m (RP-210) to protect them from the effects of the pack ice. The trench will have a depth of 4 m, and after laying the pipes is covered with soil.

Landfall is performed in the buried trenches. The landfall trench is reinforced along the length of 170 m with tongue and groove pile fence.

In the eastern part of Sakhalin several points of landfall area are already of equipped. Methods of development of landfall area point for Kirinskoe field will be similar.

The trench for the pipeline and umbilical from the point of landfall to KP 8 must be prepared before the beginning of installation. Layout of the trench is done by dredging. Laying pipeline as a rule begins with the tightening of the pipeline from the barge by means of shoreline's winches. After installation of the pipe section in position for connection to shore piping work begins on laying the pipeline in the direction of the manifold.

The section is around 500 - 700 meters from shore is an area of Class 2. Area Class 2 is characterized by possible human activity, so the class of security is increased with medium to high.

The section II

From RP 210 to about RP 70 pipes are laid on the seabed open way. Thermal expansion of the pipe due to changes in temperature / pressure in this area is limited. To avoid possible adverse effects of erosion / out washing and increase the stability of the pipeline on the seabed provides certain measures. One possible option is covering the pipeline with rock material up to the top of the pipe. The nominal distance between the two pipelines is accepted 30 m. The umbilical will be laid at a distance of 30 m from the pipeline (Figure 70).

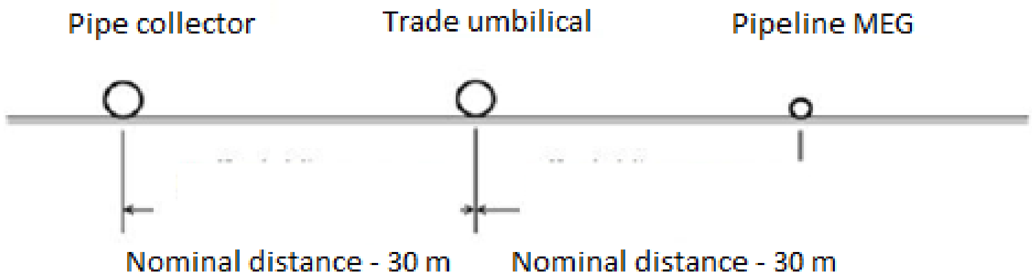


Figure 70. Pipeline location at the sea bottom [22]

The section III

From RP 70 to RP 0 pipe lines experiencing the effects of extension, which special attention must be paid to. To compensate for the extension provided for the installation of intermediate berms of rock (to control the axial displacement and to prevent of buckling). The pipes to the manifold is made through the coil with the same parameters as the pipe lines themselves. The coils need to be protected from trawls and dropping objects in the drilling of the well P1. The structures of reinforced fiber optic or steel will be used to protect the coils. Protecting structure will take into account the possibility of extending the pipeline is under them and the movement of coils. Cleaning pipelines during operation will be carried out with pipeline pigs in the flow of transported product without stopping the process of pumping product. The direction of pig movement through conduit corresponds to the direction of transport of the product. Clean-up operation and diagnostics of pipeline to be carried out periodically.

Ice conditions in the water area of gas-field are characterized not only by the presence of pack ice and ice hummocks, but also grounded hummocks as known as Stamukhas. Consequently, there is a danger of damaging offshore pipelines due to ice gouging seabed that poses a threat on the sites with a water depth of less than 25-30 m. Mainly coastal sites of shore sea-gate require particular attention.

However, trenches of ice gouging and other impact traces of floating ice on the surface of the seabed at the area were not found.

According to observations in the area of the hydro meteorological station "Odoptu" and "Komrvo" total speed of ice drift is very large and often exceeded 1 ÷ 1.5 m/s.

The maximum rate speed of the tidal ice drift on the northeastern shelf of Sakhalin Island, obtained by precomputation in harmonic constant, may reach a value of 1.3-1.4 m/s.

In the area of Chayvo field stamukhas mainly observed at the depths of 5 to 16 m. With the depth the quantity of stamukhas reduces significantly. At the depths of 16 to 26 m stamukhas is not observed annually and their impact probability to the pipeline is very low.

The average gouge depth of stamukhas into the ground on the northern shelf Sakhalin Island according to environmental test researches is 0.5 meters, the maximum registered gouging depth of stamukhas into the bottom is 2.13 meters.

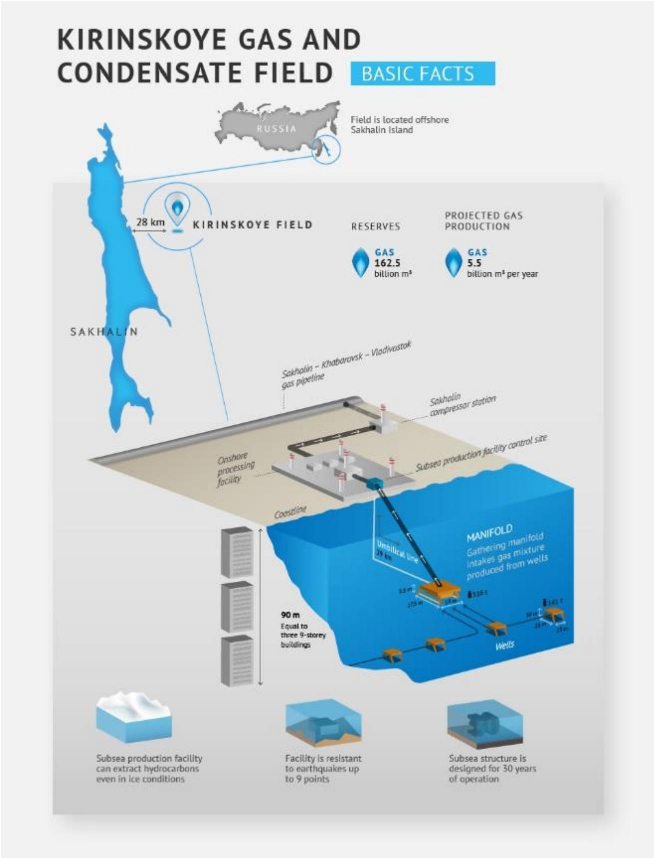


Figure 71. Field infographic [23]

6.5.1 Design philosophy

This design philosophy must contend with at least three sources of uncertainty: [40]

- The maximum expected gouge depth: Based on the past gouging regime (gouge depth distribution and gouging frequency, especially), one must rely on probability analyses to estimate the likely maximum gouge depth at the planned pipeline deployment site during its full operational lifespan (e.g. 20–40 years). This type of analysis is not unusual in civil engineering – textbooks are written on this subject. But changing climate patterns are an added source of uncertainty, since it is uncertain how climate change will affect future gouging regimes.
- Subgouge deformation: Seabed gouging by ice is a relatively complex phenomenon, depending on a number of parameters (keel dimensions and properties, soil response, etc.). Even if the maximum gouge depth can be ascertained, it is difficult to assess the amount of soil displacement below it, a parameter considered when establishing what a safe pipeline burial depth should be.

Pipeline strain: Another source of uncertainty is the amount of strain that the pipeline is likely to see at a given depth below the gouge.

6.5.2 Calculations

The downward transmission of the gouge cutting force causes subgouge. Gouging ice keel is extremely blunt, acting as a cutting device, it applies force that spreads outward and deforms a large volume of soil. Pipeline can be damaged severely by that deformation.

Estimating the extreme maximum gouging depth has been the most conventional approach, coupled with estimation of extent of subgouge deformation and a safety margin require that the pipeline to be trenched below that depth. Extreme gouge depth and subgouge deformation are not fully studied and understood. Erosion allowance must be considered to mitigate any possible seabed erosion or wave and current action. The trench must be extremely deep which brings additional undesirable consequences including environmental impact and the increased difficulty of external monitoring when pipeline begins operation.

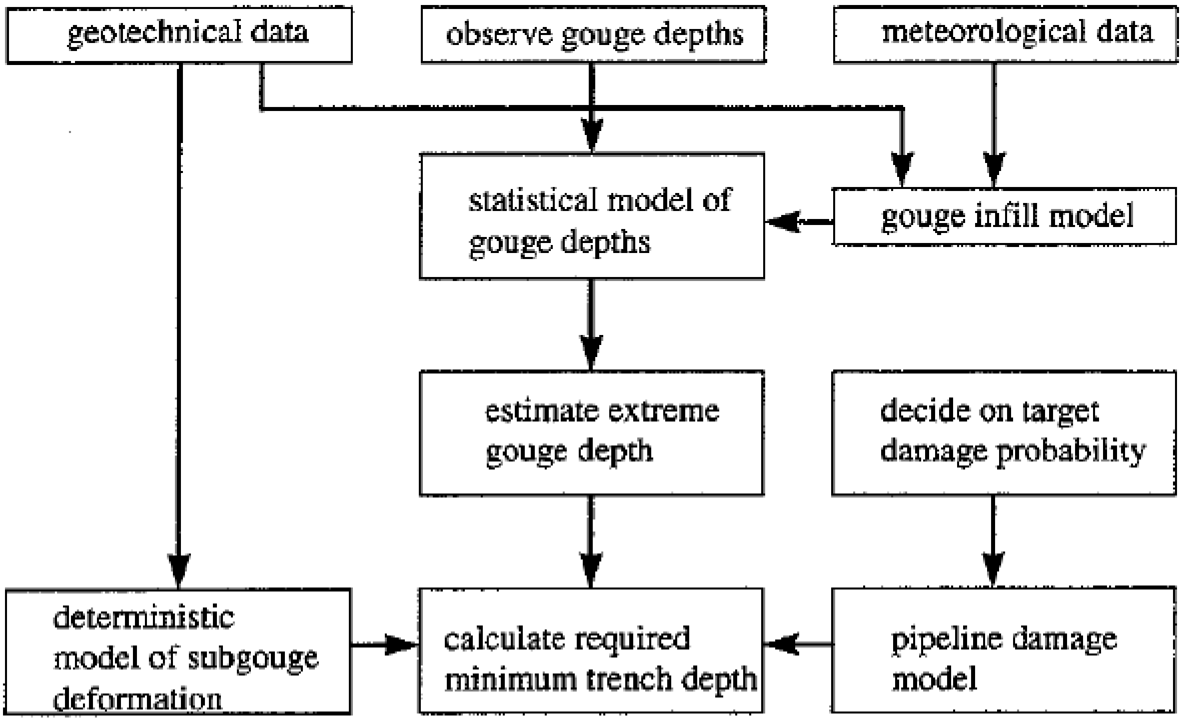


Figure 72. Decision tree based on observations of gouge depth.

A weak layer can help prevent the downward transmission of the force if placed immediately above the pipeline but below the gouging depth. Figure 76 illustrates this idea. The pipeline is laid at the bottom of the trench, and an intentionally weak layer is installed over it. The layer is too weak to transmit downward the shear forces that provide subgouge deformation.

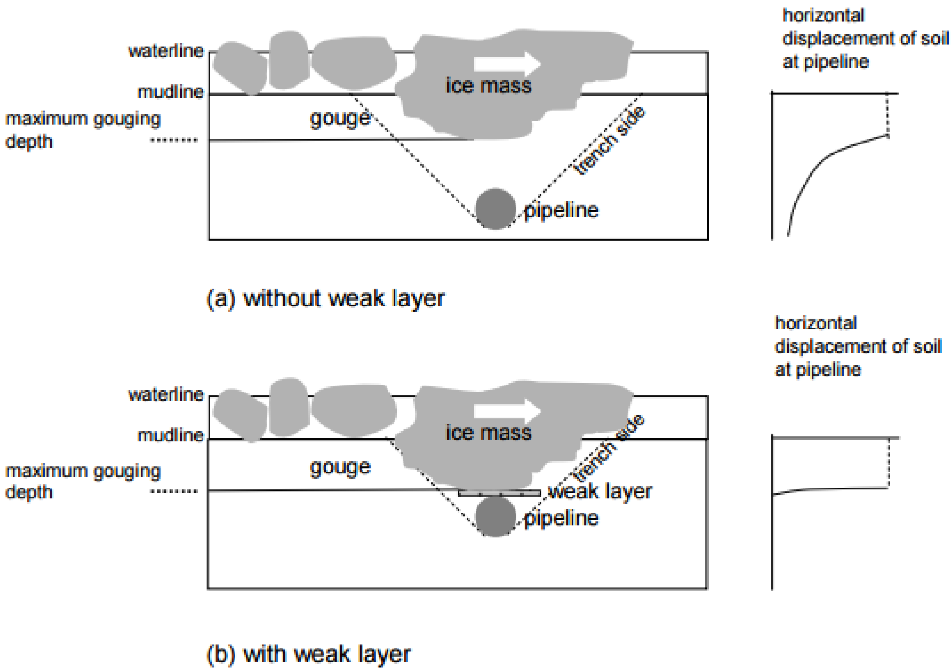


Figure 73 Effect of weak layer protecting the pipeline below [41]

The disadvantage of this scheme is that the weak layer can be severely damaged by the keel passage, and can't prevent damage by yet another keel that crosses at the same place. However, the layer is primarily used to protect against subgouge deformation rather than against direct contact with a keel. The weak layer is placed below the design maximum gouging depth, almost certainly estimated and with some safety margin.

It is complicated to correctly interpret the gouging profile due to many factors, such as the time history of gouging, the soil infill due to repeated gouging, and the normal seabed sediment process due to waves and currents. Nevertheless, the most of gouges have constant cross-section for quite long distance.

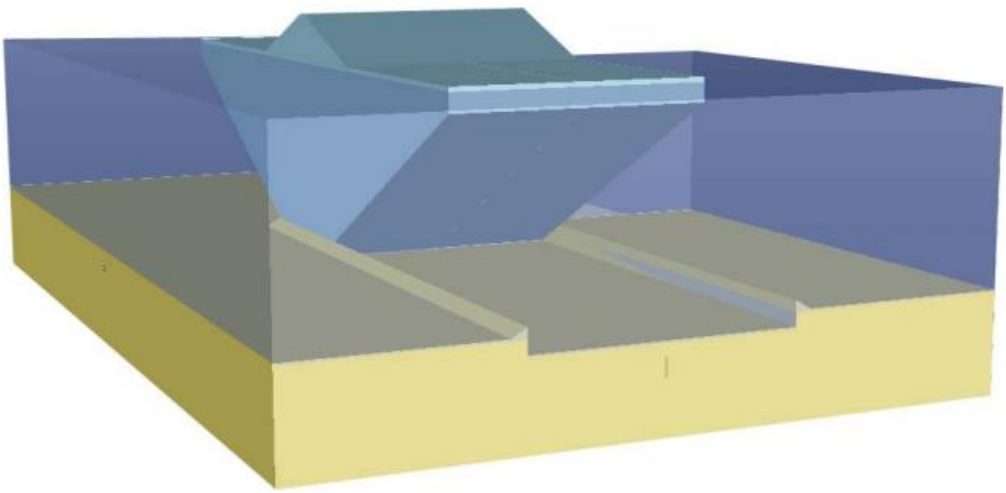


Figure 74. Model of keel-soil-pipeline interaction [42]

The ice ridge scouring the seabed could damage marine pipeline. But except ploughing process itself, intensive deformations occur beneath the gouge, and a pipeline would still be damaged by being dragged with the soil. Hence it becomes clear, that the required depth for pipeline burial should be:

$$D_b = d + b$$

Where d – is the gouge depth and b – cover depth.

Anticipating the certain conditions of the ridge and environment, the gouge depth could vary from place to place. The accuracy of its value determination is high: on the one hand it is cost, on the other – safety of the pipeline system.

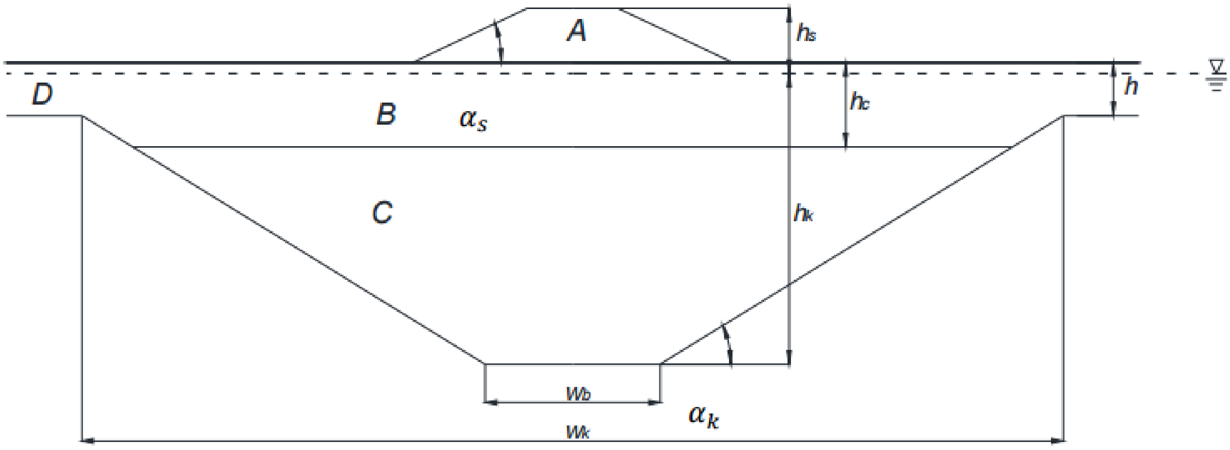


Figure 75. Geometrical parameters for typical first-year ice ridge.

Where *A* – sail; *B* – consolidated layer; *C* – keel; *D* – level ice.

ISO 19906 [17] recommends a typical cross-section of a ridge, shown in figure 10, where h_c – is the thickness of consolidated layer; h_s – sail height; h – level ice thickness; h_k – keel height (from the sea level to its bottom); w_k, w_b – keel width at the sea level and at the bottom, respectively.

Information about the correlations between the mentioned parameters has important implications for the loads the ridge could exert either on the seabed or on the pipeline.

The research of ice gouge estimation has been carried out by Phillips et al. [43], where the maximum gouge depth was estimated at the moment of keel destruction, based on the keel cohesion values. The algorithm for calculating the ice ridges' parameters is shown in Appendix A

In that case Vershinin et al. [44] has established several design models, determining the behavior of ice ridge when contact with soil occurs. These models are as follows:

1) Force model – analysis of static forces equilibrium.

2) Energy model –based on kinetic energy dissipation through the soil friction.

In our paper we will implement the force model of ice gouge estimation. The critical gouge depth is relevant when the following force system exists in equilibrium:

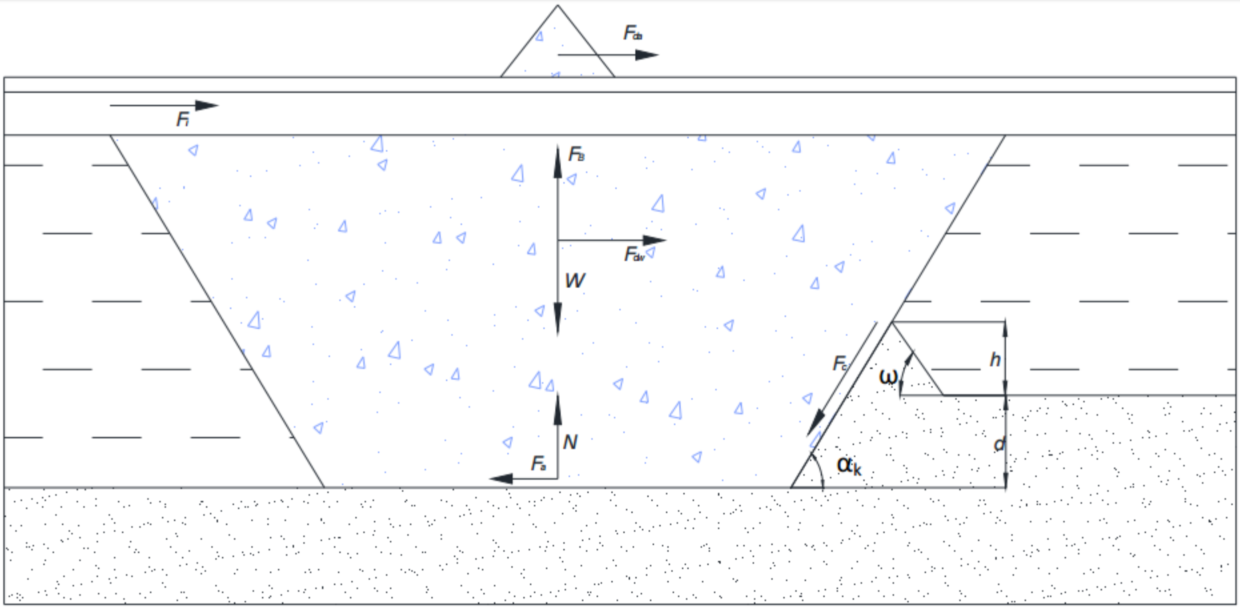


Figure 76. Force system on the ice ridge.

Here

F_{da}, F_{dw} – drag forces from air and water respectively;

F_b – buoyancy force;

W – weight of the ridge;

N – reaction from the seabed;

F_a – friction force on the bottom of the ridge;

F_c – Coulomb's passive friction force, acting in front and on both sides of the ridge;

F_i – driving force from surrounding floe;

ω – angle of the front surcharged soil slope; αk – keel angle;

h' – height of the frontal mound;

d – scour depth.

A set of assumptions has been made in order to fulfill the model integrity:

• Ridge is assumed to be initially motionless such that all forces exert their maximum values. Otherwise drag force from current could act in opposite direction: wind accelerates the ridge and it moves faster than the current. And water resists the ice ridge movement;

• The seabed in the presented model is even and has no inclination. It was neglected in order to simplify the system without considerable error;

• Ice ridge is an absolutely rigid body with negligibly small elasticity, which doesn't consume energy for its structure reorganization;

• Ridge keel bottom has an infinite strength, so it is not being destroyed scouring the seabed;

• Substantial surface ice restricts the ridge upward motion.

The equations of equilibrium in either direction are given by:

Horizontal direction:

$$F_{da} + F_{dw} + F_i - F_a(d) - F_{cx}(d) = 0$$

Vertical direction

$$F_b - W - F_c \cdot \sin\alpha_k + N = 0$$

Each force component of the system is defined below.

Drag force from the wind:

$$F_{da} = \frac{1}{2} \cdot \rho_a \cdot C_{da} \cdot A_{a1} \cdot {u_a}^2 + C_{sa} \cdot \rho_a \cdot A_{a2} \cdot {u_a}^2$$

Drag force from the current:

$$F_{dw} = \frac{1}{2} \cdot \rho_w \cdot C_{dw} \cdot A_w \cdot {u_c}^2$$

Weight:

$$W = \rho_{iw} \cdot B \cdot g \cdot [\frac{\rho_{ia}}{\rho_{iw}} \cdot \left(h_s - \frac{\rho_w - \rho_i}{\rho_w} \cdot h_i\right) \cdot \cot\alpha_s + \frac{\rho_i}{\rho_{iw}} \cdot h \cdot w_k + \frac{1}{2} \cdot (w_k + w_b) \cdot \left(h_k - \frac{\rho_i}{\rho_w} \cdot h\right)]$$

Buoyancy force:

$$F_b = \rho_w \cdot B \cdot g \cdot [\frac{1}{2} \cdot (w_k + w_b) \cdot \left(h_k - \frac{\rho_i}{\rho_w} \cdot h\right) + \frac{\rho_i}{\rho_w} \cdot h \cdot w_k]$$

Ice force:

$$F_i = 0.43 \cdot 4.059 \cdot B^{0.622} \cdot {h_i}^{0.628}$$

Passive friction force:

The equation for horizontal component of Coulomb's force is:

$$F_{cx}(d) = \mu \cdot P_f(d) \cdot \cos\phi_w \cdot \cos\alpha_k + \mu \cdot P_s(d) \cdot \cos\phi_w$$

The equation for vertical component of Coulomb's force is:

$$F_{cy}(d) = \mu \cdot P_f(d) \cdot \cos\phi_w \cdot \sin\alpha_k$$

Active friction force:

This force is a function of soil reaction:

$$F_a(d) = \mu \cdot N(d) = \mu \cdot F_{cy}(d)$$

Replacing all forces with outlined formulas, the quadratic equation with respect to the gouge depth d is derived and easily solved.

$$F_{da} + F_{dw} + F_i - \mu \cdot F_{cy} - F_{cx} = 0$$

As we know the trench of subsea pipelines of Kirinskoye field has a depth of 4 m, and after laying the pipes is covered with soil. This gouge depth is enough to not be damaged by ice ridges.

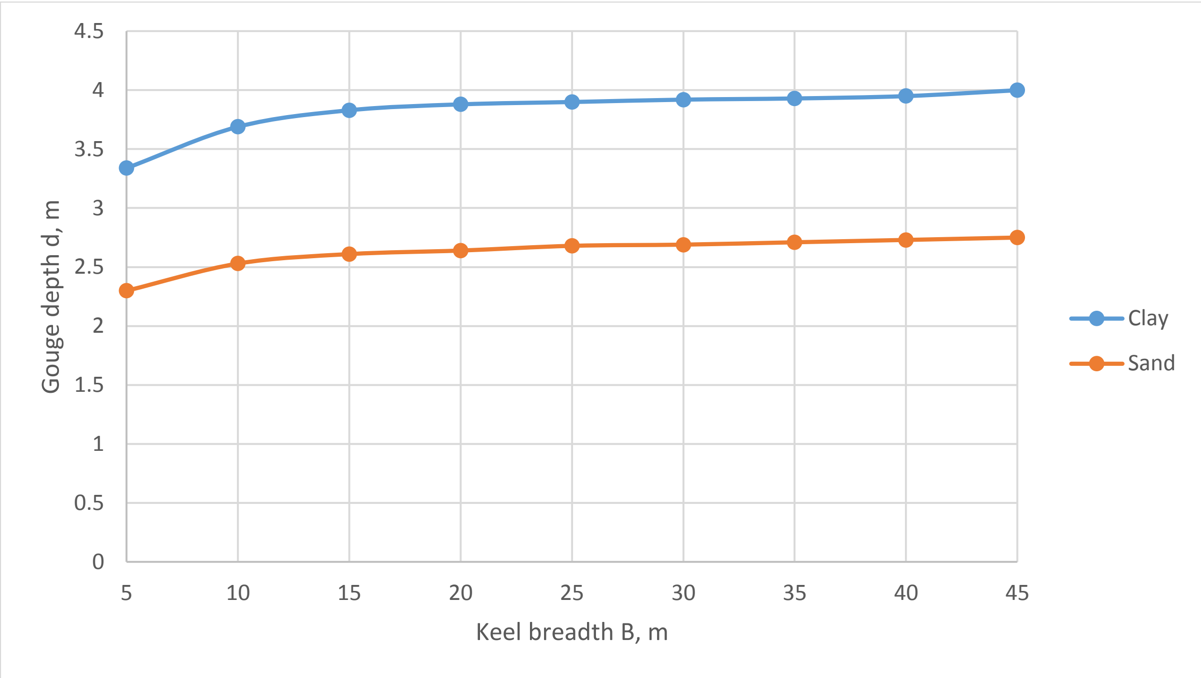


Figure 77. Gouge depth vs keel breadth

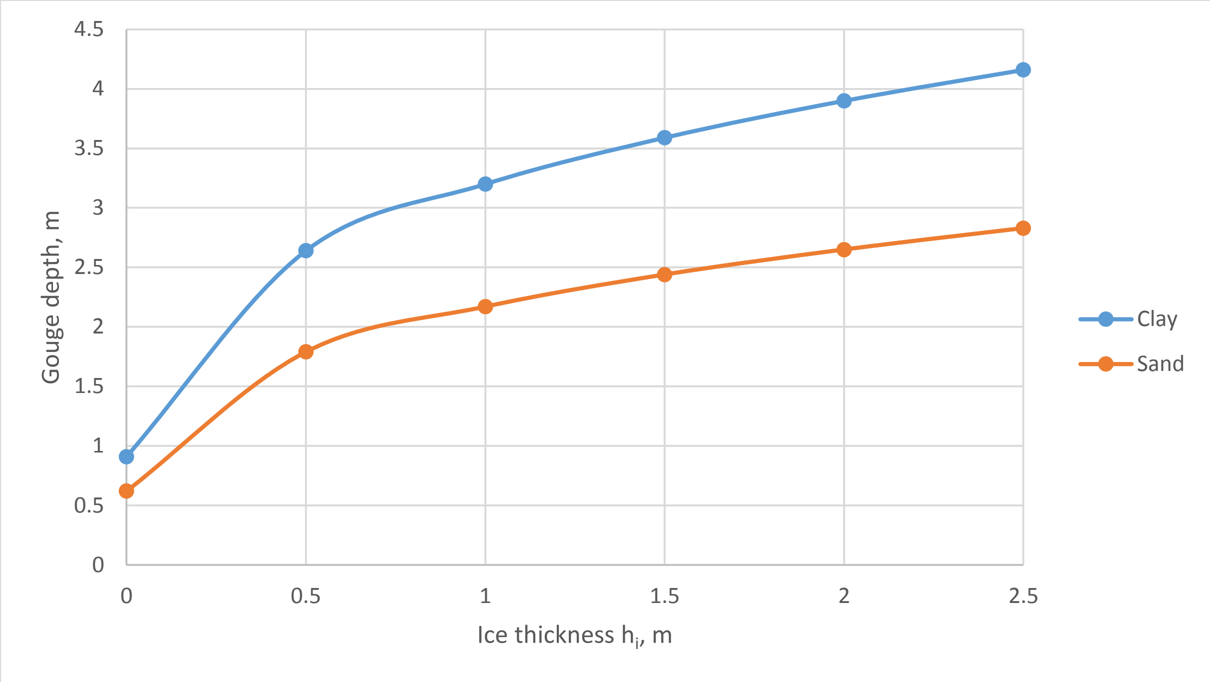


Figure 78. Gouge depth vs ice thickness

6.5.3 Remedial measures

The Arctic conditions dictate both pipeline trenching equipment and the associated project execution plan. The equipment is supposed to operate in any environment and be able to create a trench profile in the specific soil conditions. An option suitable for deep water may not work for near shore areas (e.g., a plough may be effective in thawed soils but completely useless with permafrost near shore).

The trenching capability must allow for additional excavation or trenching. Over excavation may be required in case of seabed permafrost presence. This will in turn require additional reach capability of the trenching equipment. Insufficient reach may result in inability to excavate the trench to the designed pipeline depth (seabed to top of pipe). When operating in temperatures below freezing, ice may form on the support vessel (s), trenching equipment and any equipment inspection used to measure the profile of the trench. Heavy accumulation of ice on the equipment can result in equipment damage. Trench survey operations may also be affected by the cold weather, which can prevent the necessary documentation configuration of the trench and measure the depth of the pipe cover. Icing can also lead to weight gain and / or delay equipment de-icing.

Existing floating trenching equipment, as a rule, is not designed specifically for use in arctic conditions. Floating vessels used in the trenches or in the support trenches during the open water can be subject to intrusions of ice. Equipment that is not designed for such conditions may not be useful for working in this environment and can be damaged. The ice, which is not in direct contact with the floating equipment may still affect the construction, if the ice had come in contact with the mooring ropes. The use of ships in support of the management of the ice trenches should be considered in the planning of construction.

For operation in arctic conditions, significant changes in existing equipment may be required. The vessels will require preparation for winter operation in conditions of freezing and the hulls may require reinforcing to be able to withstand ice loads. If construction cannot be completed in a single season, attention should be paid to the mobilization and demobilization of equipment or preparing the equipment for winter.

Summer trenching

Several trenching techniques could be used during the summer. Some are applicable only to pre-lay i.e., before the pipeline is installed, whereas others are best suited to post-lay installation. These methods include, but are not limited to:

- Conventional excavation;

- Hydraulic dredging;
- Ploughing;
- Jetting; and mechanical trenching.

Protection of the installed pipeline could be provided by pre- or post-lay techniques. However, a pre-lay method or post lay immediately following installation of the pipeline would most likely be required for Arctic conditions (depending on the area) since the pipeline would otherwise rest on the seabed and be potentially exposed to the action of ice keels moving into the area.

Winter trenching

Several trenching techniques could be used during the winter and some are variations on the summer methods presented above. Again, protection of the installed pipeline could be provided by pre- or post-lay techniques. However, a pre-lay method or post-lay immediately following pipeline installation would most likely be required for Arctic conditions since the pipeline would otherwise rest on the seabed and be exposed to the action of ice moving through the area.

Ice based excavations were carried out on a number of pipeline projects using hydraulic excavators working with stable fast ice in the sea. Sea ice artificially concentrated to support trenches and pipe laying activity. Slots are cut on the order of 3m ice using a mechanical trencher. The ice blocks are cut and removed using excavators. The blocks are then moved to front-end loaders and trucks from the field work site to prevent excessive deflection of the floating ice in the work areas.

The trench is then excavated using backhoes. This method allows the construction of a continuous trench, pipe laying and backfilling program. The excavation could start in more than one place simultaneously. Trenching activity is characterized by depth, as it affects the efficiency of an excavator. The length of the boom excavator should be increased in deeper water, which requires a change in the size of the associated bucket. In short hard-excavators with large bucket (3 m^3) will be used in shallow water. In deeper water, the boom and lower the bucket bottom (0.76 m^3) can be used.

The depth of the trench will be checked along excavation process. A smaller version of CSD pump attached to the excavator arm can be used to achieve the desired smoothness of the bottom of the trench is set immediately before the pipeline is laid.

Most of the excavated trench would need to be temporarily stored on ice before backfilling. The material extracted from the floating ice will have to be transported and temporarily stored at the bottom of the fast ice in the designated area. When stored on the floating ice, attention should be paid to the sinking or creep (deviation) of ice. After the section of the pipeline is installed in the trench, backfill with newly unearthed trenches production begins.

Summary

Piping engineer must make a definite decision on the depth of the trench, and to make a decision based on the mass of statistics data. Much of this evidence is more or less uncertain. If the path of the solution is too complex, there is a risk that the multiplication of uncertainty will lead to a final number, which leads unacceptably wide confidence.

- Trenching/burial system required must be capable of performing of the below operations, in order to meet JIP goals;
- Trenching to depths greater than current industry norms (burial depths greater than 3m);
- Trenching in highly variable soil conditions that may include sand, gravel, clay, glacial till and bedrock, including the possible presence of boulders;
- Trenching in water depths beyond the majority of trenching requirements (water depths from 5m up to 300m);
- Operating in harsh marine conditions (for example, the Western North Atlantic).

A "trencher" or "excavation system" is considered not only the active element (s) of the equipment on the sea floor, creating a trench or perform burial, but everything else that is needed for transportation, inspection (pre- and post-), deployment (supply, tracking, monitoring, etc.), operation of backfilling (if required), and retrieval.

Very deep trench is not the only way to protect the Arctic marine pipelines from ice gouging strudel erosion. Optimum scheme requires a combination of several ideas.

In our case the trench of subsea pipelines of Kirinskoye field has a depth of 4 m, and after laying the pipes is covered with soil. Calculations proved that this gouge depth is enough to not be damaged by ice ridges.

7. Risk analysis during subsea development

General

Qualitative risk analysis enables detection and identification of possible types of risks specific to the project. It also identifies and describes the causes and factors affecting the level of this type of risk.

Qualitative risk analysis includes the following aspects:

1. Accept criteria;

2. HAZID (Hazard Identification);

3. Risk Analysis;

4. Risk Reduction;

- Non Acceptable;
- As low as reasonable practical (ALARP);
- Acceptable

Table 21 below shows a matrix (often called as Risk Matrix) built for the risk analysis within development of oil and gas fields.

The Risk Matrix considers *"Probability rating"* divided into 5 categories:

– Probable;

– Remote;

– Extremely remote;

– Improbable;

– Extremely improbable

Where all categories are marked from 1 to 5.

As well, the Risk Matrix considers «*Severity Rating*», which is divided into catastrophic, major, serious, minor and negligible risky situations. They are marked as A, B, C, D, E. Low, Medium, High and Extreme indicators correspond to the Risk Level.

Acceptable risk is highlighted with white color in table 21 below. It is a level of human and/or material damage or loss from an industrial process that is considered to be tolerable by a society or authorities in view of the social, political, and economic cost-benefit analysis [36].

In the thesis the following HAZIDS have been considered as Acceptable Risk: high pressure drop together with decrease in flow rate, hydrate formation, slugging.

Table 21. Risk Matrix

Severity (from Low to High)					
E	M	H	H	E	E
D	M	M	H	H	E
C	L	M	M	H	E
B	L	L	M	M	H
A	L	L	L	M	M
	1	2	3	4	5

Probability (from Low to High)

Security code

L – low

M – medium

H – high

E – extreme

Probability ranking

1 - minor (Very unlikely)

2 - low (Unlikely)

3 - medium (possible)

4 - high (probably)

5 - critical (very likely)

HAZID to identify the risk during subsea production operation

Hazard identification (HAZID) is "the process of identifying hazards, which forms the essential first step of a risk assessment" [83].

Let us make a HAZID list, which possibly can occur during the production operation in subsea equipment:

1 - Internal/external corrosion of pipeline

2 - Burst of pipeline

3 - Fracture in umbilical

4 - Scouring of pipeline/umbilical

5 - Leakage in manifold/X-mas tree

6 - Loss of functionality of umbilical

7 - Failure in control valve

All described HAZIDs have been inserted into the Risk matrix (Table 22).

Table 22. HAZID to identify the risk during production

Severity (from low to high)	1	2	3	4	5
E	**4**	**2**			
D				**1**	
C		**7**			**5**
B		**3**			
A			**6**		

Probability (from low to high)

Bow-tie analysis

To carry out a bow tie analysis, let us identify barriers and ensure that a sufficient number of barriers are in place for issues where the risk is high. Under the term “high risk” let us consider that type of risks, which are within the red color (risk matrix above) area namely “Non Acceptable Risks”.

Figure 79 shows the principle of bow-tie diagram based on determination of potential causes, preventive and mitigative controls and consequences of a major accident.

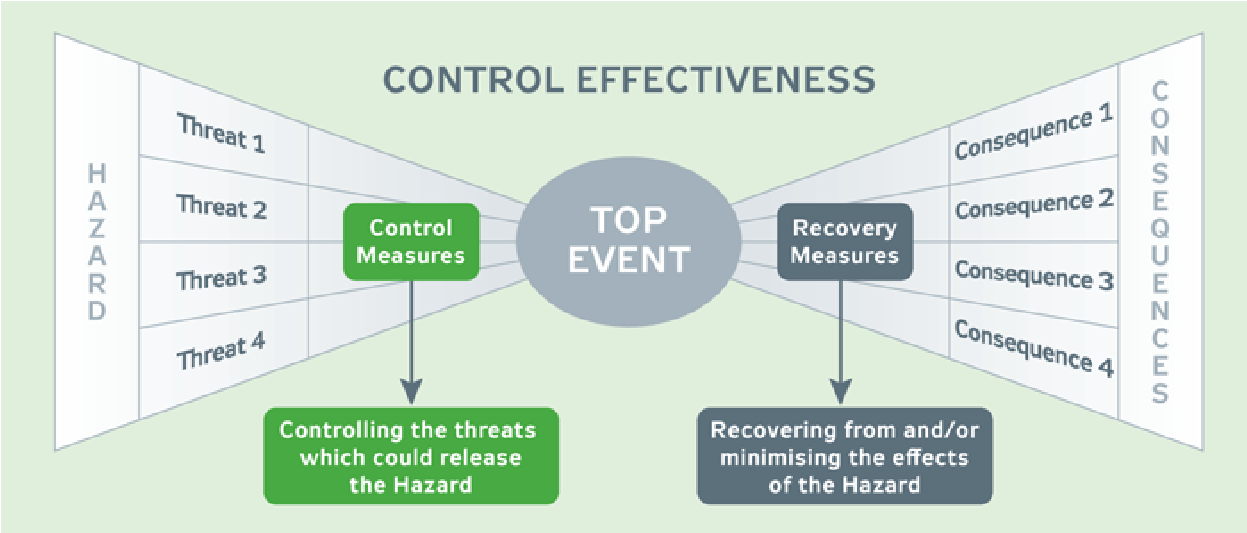


Figure 79. Principle of bow-tie diagram

Diagrams below present threats, consequences and barriers that are necessary to take into account when there is a possibility to encounter given challenges.

In the following bow-tie analysis the risks with the highest probability of occurrence and the most serious consequences are reviewed.

The following “Non Acceptable Risks” has been considered in this study:

5 - Leakage in Manifold/X-mas tree

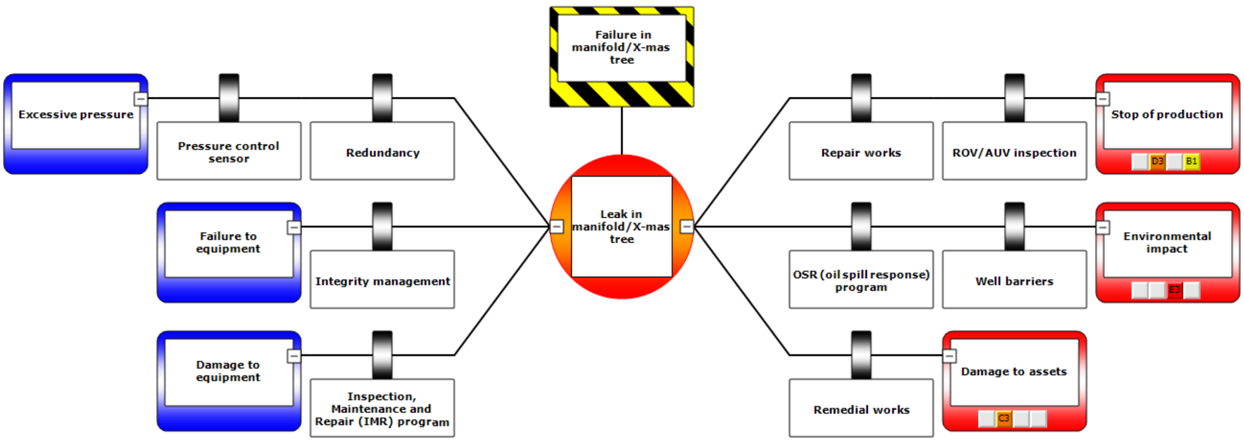


Figure 80. Bow-tie diagram

Summary and recommendations

- This work is the result of the analysis of the discussed possible concepts of effective and safe development of oil and gas resources of the Sakhalin shelf. The work takes into account the specifics of the region, including the freezed, freezing and deep part.

- The analysis, due to its complexity, includes the whole range of problems related to the natural and climatic conditions, characteristics of civil construction, oil and gas engineering as well as engineering geology.

- The thesis is a detailed analysis of each of the stages of conceptual design development of hydrocarbon fields on the Sakhalin shelf. A list of factors determining the concept of everything in the conceptual stage screening (concept screening) is presented, the influence of each factor on the concept of the development is covered

- The choice of development concepts, including exploratory drilling stage, the most applicable to oil and gas fields of Sakhalin shelf is developed.

- For deep-sea sector of the Sakhalin shelf subsea production concept is proposed. This conclusion is a recommendation for the conditions specific to the region of Okhotsk Sea.

- The risk analysis of the concept of field development using subsea production systems is carried out. With the help of security Diagrams (bow-tie analysis) it is shown that of those surveyed potential hazards highest risk (Non-acceptable risk) has Leakage in Manifold / X-mas tree.

- Results Are presented in the form of methodological recommendations on the technical and technological solutions for the development of oil and gas resources, applicable on the Sakhalin shelf as a whole.

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APPENDIX A

Table 23. Environmental data.

Parameter	**Unit**	**Value**
Water density	$\rho_w, \frac{kg}{m3}$	1030
Current speed	$u_c, \frac{m}{s}$	2
Current drag coefficient	C_{dw}	0.9
Air density	$\rho_a, \frac{kg}{m3}$	1.3
Wind speed	$u_w, \frac{m}{s}$	9
Wind drag coefficient	C_{da}	0.9
Wind skin friction coefficient	C_{sa}	0.001

Table 24. Ice data

Parameter	**Unit**	**Value**
Level ice thickness	h_i, m	2
Ridge sail height	h_s, m	6
Consolidated layer thickness	h, m	2.8
Keel angle	a_k, rad	0.523
Sail angle	a_s, rad	0.349
Keel breadth	B, m	25
Ridge block size	T_b, m	0.4
Ice density	$\rho_i, \frac{kg}{m3}$	916
Ice speed	$u_i, \frac{m}{s}$	1.1
Elasticity modulus	E_i, MPa	8000
Poisson ratio	v_i	0.34
Ice rubble internal friction angle	ϕ_i, rad	0.349
Keel rubble cohesion	c_i, kPa	15
Ridge sail porosity	η_s	0.07

Table 25. Soil data

Parameter	Unit	Value (clay)	Value (sand)
Wall friction angle	ϕ_w, rad	0.349	0.443
Internal friction angle	ϕ, rad	0.401	0.523
Friction between ice and soil	μ	0.4	0.5
Soil density	$\rho_s, \frac{kg}{m3}$	1600	1500

The sail angle α_s has an average value of 20°, while the angle of the keel shape α_k is approximated by 26°.

Kharitonov reports [17] that the average sail macro porosity of ridges in the Sea of Okhotsk falls within 6 – 8 %, which is 3-4 times less than keel macro porosity (22 – 24%).

The macro porosity, used in subsequent calculations, should be distinguished from total porosity represented by brine pockets inside ice blocks. Brine inclusions strongly affect the ridge strength and demand additional study.

Under assumption that brine volume is small and all pores are occupied either by water or by air, the density of porous keel part of the ridge therefore will be outlined as:

$$\rho_{iw} = \eta_k \cdot \rho_w + (1 - \eta_k) \cdot \rho_i =$$

The upper sail part, located above the sea level has a density:

$$\rho_{ia} = \eta_s \cdot \rho_a + (1 - \eta_s) \cdot \rho_i =$$

Keel draught

$$h_k = 3.95 \cdot h_s$$

Keel width at water line

$$w_k = 3.91 \cdot h_k$$

Keel width at bottom line

$$w_b = w_k - 2 \cdot h_k \cdot \cot \alpha_k$$

Current projection area

$$A_w = (h_k - \frac{\rho_i}{\rho_w} \cdot h_i) \cdot B$$

Wind projection areas

$$A_{a1} = (h_s - \frac{\rho_w - \rho_i}{\rho_w} \cdot h_i) \cdot B$$

$$A_{a2} = w_k \cdot B$$

Table 26. Ridge features

Parameter	**Unit**	**Value**
Ridge keel macro porosity	η_k	0.23
Average keel density	$\rho_{iw}, \frac{kg}{m^3}$	942.22
Average sail density	$\rho_{ia}, \frac{kg}{m^3}$	851.97
Wind projection area	A_{a1}, m^2	144.5
Wind projection area	A_{a2}, m^2	2316.7
Current projection area	A_w, m^2	548
Keel draught	h_k, m	23.7
Keel width at the sea-level	w_k, m	92.67
Keel width at the bottom	w_b, m	10.45

Force model calculations

Wind drag force

$$F_{dw} = \frac{1}{2} \cdot \rho_a \cdot C_{da} \cdot A_{a1} \cdot {u_a}^2 + C_{sa} \cdot \rho_a \cdot A_{a2} \cdot {u_a}^2$$

Current drag force

$$F_{dc} = \frac{1}{2} \cdot \rho_w \cdot C_{dw} \cdot A_w \cdot {u_c}^2$$

Ridge weight

$$W = \rho_{iw} \cdot B \cdot g \cdot [\frac{\rho_{ia}}{\rho_{iw}} \cdot \left(h_s - \frac{\rho_w - \rho_i}{\rho_w} \cdot h_i\right) \cdot \cot \alpha_s + \frac{\rho_i}{\rho_{iw}} \cdot h \cdot w_k + \frac{1}{2} \cdot (w_k + w_b) \cdot \left(h_k - \frac{\rho_i}{\rho_w} \cdot h\right)]$$

Buoyancy

$$F_b = \rho_w \cdot B \cdot g \cdot [\frac{1}{2} \cdot (w_k + w_b) \cdot \left(h_k - \frac{\rho_i}{\rho_w} \cdot h\right) + \frac{\rho_i}{\rho_w} \cdot h \cdot w_k]$$

Ice force

$$F_i = 0.43 \cdot 4.059 \cdot B^{0.622} \cdot {h_i}^{0.628}$$

Passive friction force

Passive earth pressure coefficient

$$K_p = \frac{\cos \phi^2}{\cos \phi_w \cdot (1 - \sqrt{\frac{\sin(\phi + \phi_w) \cdot \sin \phi}{\cos \phi_w}})^2}$$

Front resistance

$$P_f(d) = \frac{1}{2} \cdot K_p \cdot \rho_s \cdot g \cdot (d + 0.635 \cdot d^2) \cdot B$$

Side resistance

$$P_s(d) = \frac{1}{6} \cdot K_p \cdot \rho_s \cdot g \cdot d^2 \cdot w_b \cdot (w_b + \frac{d \cdot \cot \alpha_k}{2})$$

Horizontal passive friction force

$$F_{cx}(d) = \mu \cdot P_f(d) \cdot \cos \phi_w \cdot \cos \alpha_k + \mu \cdot P_s(d) \cdot \cos \phi_w$$

Vertical passive friction force

$$F_{cy}(d) = \mu \cdot P_f(d) \cdot \cos \phi_w \cdot \sin \alpha_k$$

Active friction force

Seabed reaction

$$N(d) = F_{cy}(d)$$

$$F_a(d) = \mu \cdot N(d)$$

And finally the equation will depend only on d. It will be easily to calculate

$$F_{da} + F_{dw} + F_i - F_a(d) - F_{cx}(d) = 0$$

Table 27. Forces action

Force component	Unit	Value	
		Sand	**Clay**
Drag force due to wind	F_{dw}, N	7090	
Drag force due to current	F_{dc}, N	1016055	
Ridge weight	W, N	$3.22\ 10^{8}$	
Buoyancy	F_b, N	$3.27\ 10^{8}$	
Force due to drifting ice	F_i, N	$19.97\ 10^{6}$	
Passive earth pressure coefficient	K_p	7.83	4.12
Specific horizontal Coulomb friction	F_{cx}, N	$17.95\ 10^{6}$	$18.53\ 10^{6}$
Specific vertical Coulomb friction	F_{cy}, N	$6.1\ 10^{6}$	$6.2\ 10^{6}$

Table 28. Gouge depth

Force component	Unit	Value	
		Sand	**Clay**
Gouge width	B, m	25	25
Gouge depth	d, m	2.64	3.9