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MASTER'S THESIS

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Abstract

Regardless of the current oil and gas industry sufferings, the Arctic region still stands as one of the most perspective areas for the development of hydrocarbon fields. Estimated resources of the Arctic Ocean are ca. 100 BTOE (Zolotukhin, A., & Gavrilov, V., 2011). Taking into account its severe conditions and environmental fragility, it is crucial to find both economically efficient and environmentally safe ways to produce and transport oil and gas from offshore fields.

Therefore, current work is dedicated to evaluate feasible transportation concept for hydrocarbon fields in the Barents and Kara Seas and estimate the possibility of using Novaya Zemlya archipelago as a transportation hub.

Main challenges for oil and gas transportation system in the Kara and Barents Seas are analysed. These include environmental conditions, ice features and iceberg occurrence, ice management strategies, navigation possibilities, variation of production technologies and pipeline design peculiarities.

The thesis also provides climatic, environmental and infrastructural assessment of the Novaya Zemlya archipelago. In addition, advantages of accessing the archipelago are investigated as well as its relative location towards existing and perspective oil and gas fields.

The emphasis of the work is put on pipeline transportation system, evaluating of suitable pipeline routes, ensuring the sustainable flow regime of the produced fluid and design specifications of the subsea pipelines in the Arctic. State-of-the-art landfall construction and on-going Arctic offshore practices are discussed as part of the investigation. Analyses of collected information are to show the best location for future infrastructure and preferable method for constructing the shore approach for the pipeline. Estimation of installation loads and stresses is conducted for the chosen construction method.

Al in all, current work emphasizes whether the suggested pipeline transportation of the hydrocarbons from the Barents and Kara Seas to the Novaya Zemlya Archipelago is a reliable and feasible concept for this Arctic region.

Acknowledgements

I would like to show my great appreciation to my supervisors Professor Ove Tobias Gudmestad from University of Stavanger (UiS) and Professor Anatoly Borisovich Zolotukhin from Russian Gubkin State University of Oil and Gas (National Research Institute) for their guidance, patience and shared knowledge. In addition, I would like to thank all academic staff from UiS, Gubkin University and University Centre in Svalbard, especially professors V. Balitsky, Muk Chen Ong, S. Løset, who put enormous amount of effort and professionalism while teaching and guiding us and were always there to answer any questions.

I would like to thank the University of Stavanger and Russian Gubkin State University of Oil and Gas (National Research Institute) for provided access to scientific literature and databases, which made it possible to expand the knowledge upon the studied topics and increase the quality of conducted work.

I am also very grateful for the opportunity to be enrolled in a joint Master's Degree program, to be able enhance my credentials in the chosen field and adapt knowledge of two great universities.

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List of Abbreviations

BTOE	Billion Tons of Oil Equivalent
BCM	Billion Cubic Meters
CAPEX	Capital Expenditures
CBA	Cost-Benefit Analysis
DPBP	Discounted Payback Period
EDC	Emergency Disconnection
EDL	Emergency Dosconnection Limit
EDZ	Emergency Disconnection Zone
ERD	Extended Reach Drilling
FP	Floating Platform
FPSO	Floating, Production, Storage and Offloading
FPU	Floating Production Unit
GSZ	General Surveillance Zone
GBS	Gravity Based Structure
HDD	Horizontal Directional Drilling
$\mathbf{H_s}$	Significant Wave Height
IAC	Ice Alert Color
IM	Ice And Iceberg Management
IRR	Internal Rate of Return
LNG	Liquefied Natural Gas
MEG	Monoethylene Glycol
MET	Mineral Extraction Tax
MMBOE	Million Barrels of Oil Equivalent
MTPA	Million Tons Per Annum
NPV	Net Present Value
NSR	Nothern Sea Route
OPEX	Operating Expenses
PBP	Payback Period

PDL	Planned Disconnection Limit
PI	Profitbility Index
POD	Probabiltiy of Detection
PV	Present Value
ppg	Pounds Per Gallon
psi	Pounds per Square Inch
SMYS	Specified Minimum Yield Strength
SPS	Subsea Production System
$\mathbf{T_p}$	Peak Period
TAZ	Threat Assessment Zone
UFR	Umbilical, Flowlines and Risers

1. Introduction

1.1 Background

Commercial production of arctic oil began in the 1920s in Canada's Northwest Territories. During the 1960s, extensive hydrocarbon fields were discovered in Russia's Yamalo-Nenets region, the North Slope of the Brooks Range in Alaska, and Canada's Mackenzie Delta. During the last several decades, the Arctic territories of Russia, Alaska, Norway, and Canada have produced billions of cubic meters of oil and gas (http://arctic.ru).

The sedimentary basins of the Russian Arctic shelf are comparable to the world's largest petroleum regions in terms of total oil and gas potential. According to experts' estimates, the Arctic shelf will account for 20% to 30% of Russia's total oil production by 2050. Most recently, the Russian Energy Strategy up to 2035 aims to increase energy production in the Arctic so that by 2035, Arctic offshore resources occupy 5% of national oil extraction and 10% of national gas extraction (Gubaidullin, M.G. et al., 2016).

Despite the fact that there are clear challenges associated with the Arctic oil and gas resources development in Russia (geopolitical issues, lack of technology and appropriate equipment, undeveloped infrastructure, severe climate, presence of ice, high cost, low exploration status, shortage of qualified personnel, environmental issues, logistics, etc.) strategic focus of Russian state oil and gas companies for offshore projects is the development of the continental shelf of the Arctic Seas. Combination of severe weather and ice conditions with shallow waters of most of the Russian seas represents yet another big challenge to the development of the region but the process has already started with the number of projects in Russian Sea of Okhotsk and Pechora Sea with Barents and Kara Seas next to come.

The latest of Russian activities in the Arctic include the following projects.

Prirazlomnoye oil field (operated by Gazprom Neft Shelf) is the first upstream project on the Russian Arctic Shelf with production started in December 2013. It is located in the Pechora Sea. The field is being developed using Gravity Based Platform with the stone berm for protection against ice scouring around the oil-storing caisson (Thomas, M., 2016).

In addition to Russia's northernmost waters, its long-established sub-Arctic producing zone in the Sakhalin area in the Sea of Okhotsk is continuing to gradually increase its output levels.

The Sakhalin-I project includes the development of the oil and gas fields Chayvo, Odoptu and Arkutun-Dagi. The first production began in Chayvo field in 2005 and was subsequently followed by Odoptu field development in 2010. Production is performed with the help of extended reach drilling from the land and gravity based structures located offshore.

The Sakhalin II project covers Lunskoye and Piltun-Astokhskoye oil fields. The production in Piltun-Astokhskoye field started in 1999 via the Molikpaq platform. The Piltun-Astokhskoye B facility and the Lunskoye gas field, both drilled and produced via concrete gravity-base structures, began producing in 2008 (Thomas, M., 2016).

The Sakhalin-III project, operated by Gazprom, is the pioneering subsea development in Russian waters. The distance from offshore is about 28 km and the fluid is transported from the Kirinskoye gas field to the northeast coast of Sakhalin Island via subsea pipelines. Further development includes Yuzhno-Kirinskoye gas-condensate field, discovered in 2010 and located 6 km to the southeast of Kirinskoye in water depths ranging from 110 m to 320 m. Development of this sub-Arctic field is planned for 2018.

To develop the logistics through the Northern Sea Route and transport hydrocarbons from the existing onshore and potential new offshore fields in the Pechora region Varandey Export Terminal was built. It is located in the Pechora Sea 23 km from the shore in a water depth of 17 m. The structure presents a conical shape with twenty-four steel piles around the skirt periphery piling the steel structure to the seabed. The loading arm can swivel around 360° to allow a tanker moored to the terminal to "weather-vane" around the terminal dependent on wind and tide. The structure is currently the most northern operational oil facility in the world. The terminal is owned and operated by "LUKOIL" company. Tankers using the terminal are ice-class, and are supported by dedicated ice breakers (Efimkin, 2015).

The above activities illustrate that Russia, despite the on-going economic sanctions, possesses nearly 60% of the Arctic's estimated hydrocarbon resources and has established itself as one of the region's major players for current and subsequent development (Thomas, M., 2016).

Therefore, to meet the growing energy demand and assure the production and development of the mentioned regions cooperative work and joint development of various fields is the main task for the companies. Meanwhile, Rosneft and Gazprom have already signed a cooperation to create and jointly operate Arctic offshore fields. The agreement was signed by Igor Sechin, Chairman of the Management Board at Rosneft, and Alexei Miller, Chairman of the Management Board at Gazprom, in the presence of Russian Prime Minister Dmitry Medvedev. Under the agreement, the two companies will strengthen cooperation and identify the most efficient methods and solutions to drive exploration of Russian continental shelf by combining their technical and financial capacities. It is agreed to implement a long-term business strategy encompassing industrial, infrastructure and socio-economic development founded in the creation of high-tech production facilities for the study, exploration and production of hydrocarbons, the exploration of offshore fields and the creation of transport and energy infrastructure (www.rosneft.com).

Therefore, to combine the infrastructure for further development and establish cooperation among producers a common transportation system is suggested and being analysed in the current work with a hub on the Novaya Zemlya Archipelago.

1.2 The scope of work

Current Master's thesis provides the assessment of the concept for the transportation system of hydrocarbons in the Russian Arctic offshore fields. Analyses include the following aspects:

- Environmental conditions of the Barents, Pechora and Kara Seas;
- Assessment of the oil and gas resources and reserves in the Barents and Kara Seas;
- Description of the Novaya Zemlya Archipelago;
- Winter navigation possibilities in the Barents Sea;
- Iceberg occurrence probabilities and ice management strategies in the established regions;
- Evaluation of production technologies for the chosen fields;
- Arctic pipeline design features;
- Economic evaluation of the project;

Chapter 1 (Introduction) contains a short historical overview of the Arctic projects' development in Russia, gives the scope of work for the thesis and the analysis of previously conducted research upon the topic.

Chapter 2 (Environmental conditions of the surrounding seas) gives the analysis of the Kara, Barents and Pechora Seas and surroundings of the Novaya Zemlya Archipelago in terms of physical environmental characteristics. The description includes wave and ice conditions, parameters of currents, winds, air temperature, bathymetry, soil properties of the seas and ice features.

Chapter 3 (Oil & Gas reserves and resources of the Barents and Kara Seas) addresses the research upon the hydrocarbon reserves and prospective fields in the considered areas for its comprehension in the suggested concept. In this chapter the specific fields are evaluated to implement them in following transportation system.

Chapter 4 (Novaya Zemlya Archipelago) includes the general environmental conditions of the Archipelago and lists existing and required infrastructure for the future development, processing and offloading of hydrocarbons. In addition nuclear background of the Novaya Zemlya is being considered.

Chapter 5 (Navigation in the ice covered Barents Sea) explains the conditions and possibilities to navigate during the winter seasons in the Barents Sea and how it affects the transportation system in the Arctic.

Chapter 6 (Gas terminal features) evaluates the possibility of locating the terminal and LNG plant in Belushya Bay, estimates the required capacities and number of LNG trains and type of the LNG carriers.

Chapter 7 (Iceberg occurrence) provides the analyses of iceberg origins, probability of icebergs occurrence; suggestions are given upon ice and iceberg management systems and appropriate pipeline routes. A lot of attention is given to prevent iceberg threats for the subsea equipment, therefore, possible risks and measures are provided.

Chapter 8 (Production technologies for the suggested fields) describes the possible technological solutions for the production infrastructure in the harsh Arctic offshore conditions in the Barents and Kara Seas, evaluates the key elements of the subsea production system that can be applied, assesses the most important risks in the production sector.

Chapter 9 (Pipeline design) studies the most relevant pipeline transportation design problems from the explored offshore fields to the Archipelago. Investigation includes pipeline routing, flow assurance and landfall design. Significant part of the chapter is devoted to the landfall design and all the obstacles related to the issue. Existing experiences are provided as well as new technologies, which were not applied in the Arctic yet.

Chapter 10 (Economic evaluation of the project) addresses the evaluation of feasibility of the chosen concept and comparison of different scenarios in economic perspective.

1.3 Existing research on the topic

Arctic region has always been of great interest for petroleum scientific world as it contains very significant volumes of hydrocarbons. Especially when the economical indicators and oil market had been showing very promising numbers, a large amount of research works were conducted on the Arctic oil and gas field development topic. Some of the works related to the current Master's Thesis are listed below.

– Barnes, R. J. (2011, January 1). The Challenges of Russian Arctic Projects. Society of Petroleum Engineers. doi:10.2118/149574-MS.

– Belonin M.D., Prischepa O.M. Oil and gas resources of the North-West region of Russia and prospects for their development, Moscow, 2006.

– Bulakh, M., Gudmestad, O. T., & Zolotukhin, A. B. (2011, January). Potential for oil and gas projects in the new oil and gas province shared between Russia and Norway. SPE Arctic and extreme environments conference and exhibition.

– Gudmestad, O. T., Løset, S., Alhimenko, A. I., Shkhinek, K. N., Tørum, A., & Jensen, A. (2007). Engineering aspects related to Arctic offshore developments. *St. Petersburg, Lan, 255*.

– Zolotukhin A. (2014): Russian Arctic resources. Abstracts and Proceedings of the Geological Society of Norway, No 2/2014, ISBN: 978-82-92-39489-2, Norsk Geologisk Forening www.geologi.no, 2014.

In addition, the following works were written during the last years on the topic of transportation systems in the Arctic:

– Efimov, Y., Zolotukhin, A., Gudmestad, O. T., & Kornishin, K. (2014, February 13). Cluster Development of The Barents and Kara Seas HC Mega Basins From the Novaya Zemlya Archipelago. Offshore Technology Conference. doi:10.4043/24650-MS.

– Gubaidullin M.G., Østbøl N., Zolotukhin A.B., *et al.* (2016). Simulation of Oil Spill in the Western Sector of the Russian Arctic. Northern (Arctic) Federal University, Arkhangelsk, SAFU.

– Lange, F., Van Zandwijk, K., & van der Graaf, J. (2011, January 1). Offshore Pipeline Installation In Arctic Environment. Society of Petroleum Engineers. doi:10.2118/149581-MS.

– Paulin, M., DeGeer, D., Cocker, J., & Flynn, M. (2014, June). Arctic offshore pipeline design and installation challenges. In ASME 2014 33rd International Conference on Ocean, Offshore and Arctic Engineering (pp. V06AT04A006-V06AT04A006). American Society of Mechanical Engineers.

– Shumovsky S.A. (2010). Prospects for development of a new route transportation of hydrocarbons through the creation of oil and gas terminals on Novaya Zemlya archipelago. All-Russian scientific conference «Modern hydrogeology of oil and gas. Fundamental and applied problems», OGRI RAS, Moscow.

– Starodubtcev A. (2016) Cluster development of the Barents and Kara Sea Oil and Gas fields from the Archipelago Novaya Zemlya, Master’s Thesis, Gubkin Russian State University of Oil and Gas, Niversity of Stavanger.

A significant number of annual conferences and exhibitions are held around the world to provide further assessment of the Arctic region, which indicates the relevancy of the subject for the energy industry.

Despite the fact that a lot of data and materials for accurate analyses are provided with the literature written by the Arctic explorers, experienced engineers of offshore structures and petroleum engineers, the current research might still be limited by the amount and accuracy of the information about the remote region of the Russian North, as well as the lack of experience for oil and gas field development in the severe Arctic conditions.

2. Environment

Novaya Zemlya is an archipelago in north-western Russia. It is located in the Arctic Ocean and is surrounded by Kara Sea on the eastern side, Barents Sea from the west and Pechora Sea on the south-western side. The Kara Strait separates the most southerly point of the archipelago from the mainland (Fig. 1).

Fig.1. Location of the Novaya Zemlya (en.wikipedia.org)

The following section gives a general description of the physical environment in the Kara, Pechora and Barents Seas with emphasis on the ice conditions. This data is useful for identifying the suitable location for future infrastructure on the Novaya Zemlya archipelago as well as for prevention of possible ice and climate hazards.

2.1 Wind conditions

Table 1 shows the main characteristics of the wind in the seas, which surround the Novaya Zemlya Archipelago. The data are based on observations from 1940 to 1956, and 1959-1965.

Table 1. Wind characteristics (Loset et al., 1999; Gudmestad et al., 1999; Bilello, M. A., 1973)

	Average wind speed, m/s	Prevailed directions	Extreme values, m/s
Kara Sea	7	SW/SE (winter) N (summer)	40
Barents Sea	8	S (winter), SW(summer)	40
Pechora Sea	8	SW (winter), N/NW (summer)	41

2.2 Air temperatures

The monthly average and extreme minimum air temperatures for the seas are shown in Table 2. In general, summers are short and cold with a cloudy rainy weather. Strong winter cooling and weak summer warming, unstable weather during the cold season characterizes the considered seas.

Table 2. Monthly temperatures (Løset et al., 1999)

Sea	January		February		March		April	
	T_{mean}	T_{min}	T_{mean}	T_{min}	T_{mean}	T_{min}	T_{mean}	T_{min}
Kara	-18,3	-50	-20,1	-50	-20,7	-48	-12,4	-38
Central Barents	-5	-24	-7	-25	-6	-24	-3	-22
Eastern Pechora	-17,5	-48	-18,3	-48	-17	-46	-9,8	-37

2.3 Wave conditions

Frequent and strong winds develop considerable water movements in the Kara Sea. However, the size of waves, besides depending on the wind speed and duration of the wind, also depends on the ice, which is responsible for the length of the wind fetch. In connection with this, the most powerful motion occurs in years with little ice during the late summer - early autumn. Waves with the highest frequency have heights of 1,5-2,5 m. The maximum wave height is 8 m (Bulakh et al., 2012).

Most Storms in the Barents Sea are dominated by SW winds, which have the longest fetch. Swells from the Atlantic Ocean and the Norwegian Sea enter the Barents Sea and fade out towards the east. The average wave height decreases slightly towards the east (Gudmestad et al., 1999).

In the Pechora Sea the wave regime is substantially influenced by the bordering shorelines, the region is fully protected from the north, east and south, and the water depths are relatively small. The highest waves enter from the NW and the intensity falls from west to east. The storm season usually starts in October and causes occasionally extreme waves up to 11,5 m at water depths of 20-30 m in October-November. The presence of sea ice totally controls the wave regime in the winter and spring months. In the summer, the waves very rarely exceed 3-4 m (Gudmestad et al., 1999).

Parameters of the waves in the Kara Sea, Barents Sea and Pechora Sea are shown in Table 3.

Table 3. Wave conditions (Loset et.al., 1999; Bulakh et al., 2012; Gudmestad et al., 1999)

	Average wave height, m	Prevailed direction of the waves	Significant wave height, m
Kara Sea	1,5-2,5	NE	5,7
Barents Sea	2,2	SW	12,5
Pechora Sea	2-3	NW	6,2

2.4 Current conditions

Current characteristics vary significantly for the considered seas. Especially for the Barents Sea, where the water masses of the northwestern part of the Barents Sea consist mainly of the Norwegian Coastal Water, relatively warm Atlantic water and cold Arctic water in the central part of the sea, the water circulation is influenced by the Murmansk, Kanin and Kolguev currents.

A branch of the warm North Atlantic current, called the North Cape Current, nestles in the Barents Sea from the south-west, bathing the coast of Norway and the Kola peninsula. Then, the warm current runs parallel to the south coast at a distance of several hundred kilometers away and "rests" near the Novaya Zemlya archipelago, and then turns to the north-east, washing the west coast of both islands of the archipelago to the 75th degree of northern latitude.

The warm current can not get closer to the southern coast of the Barents Sea because of the number of very distinguished barriers: the Kanin Peninsula, Kolguev Island and shallow areas. As a result, there are unique winter conditions in the Barents Sea – the ice is widely present in the southern and the northern parts of the sea, while there is an ice-free corridor in the central part about 400-500 kilometers wide, running from the coast of Norway to Novaya Zemlya (www.nordport.ru).

Table 4 and the Fig. 1 show the current features and directions for three considered seas.

Table 4. Current parameters (Løset et al., 1999; Gudmestad et al., 1999; Bogolitsin, 2012)

	Average current speed on the sea surface, m/s	Sources of motion	Extreme values, m/s
Kara Sea	0,02-0,05	Topographic steering by the coasts: Novaya Zemlya, Yamal and Ob-Yenisei	1,8-2
Barents Sea	0,05-0,5	Norwegian Coastal Water, relatively warm Atlantic water and cold Arctic water, Murmansk, Kanin and Kolguev currents	0,8
Pechora Sea	0,02-0,05	Kanin, Kolguev and Litke (through the Kara Gates) currents	1

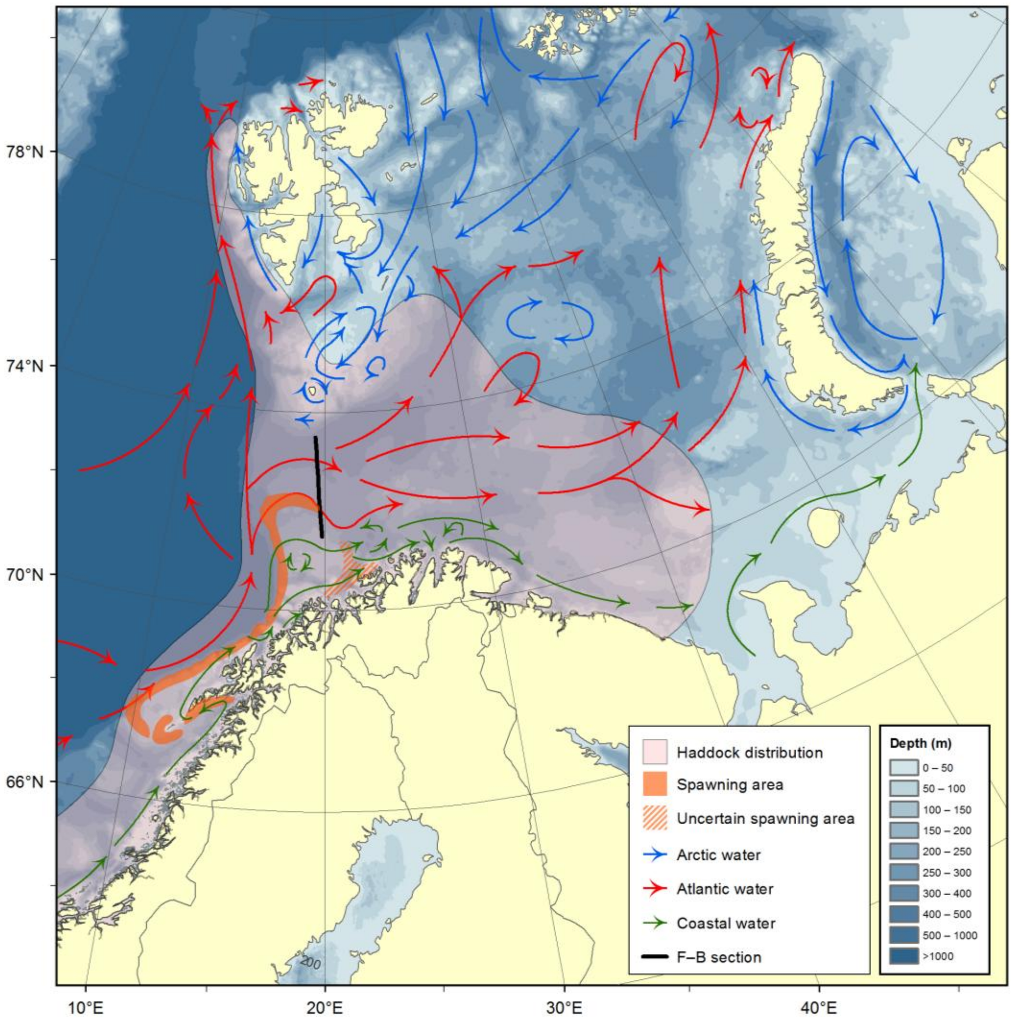

Fig. 2. Water circulation in the Arctic (www.mn.uio.no)

2.5 Bathymetry

The Barents Sea seabed topography is characterized by a strong segmentation. The deepest place of the sea is located in its western part. The bottom is mainly covered with sandy silt.

The Bathymetry of the Kara Sea is rather complex and governs to a large extent the characteristics of the water exchange with adjacent waters and large scale water circulation pattern (Volkov V., et al., 2002).

Bathymetry chart is provided below (see Fig. 3.) for the waters around southern part of the Novaya Zemlya Archipelago.

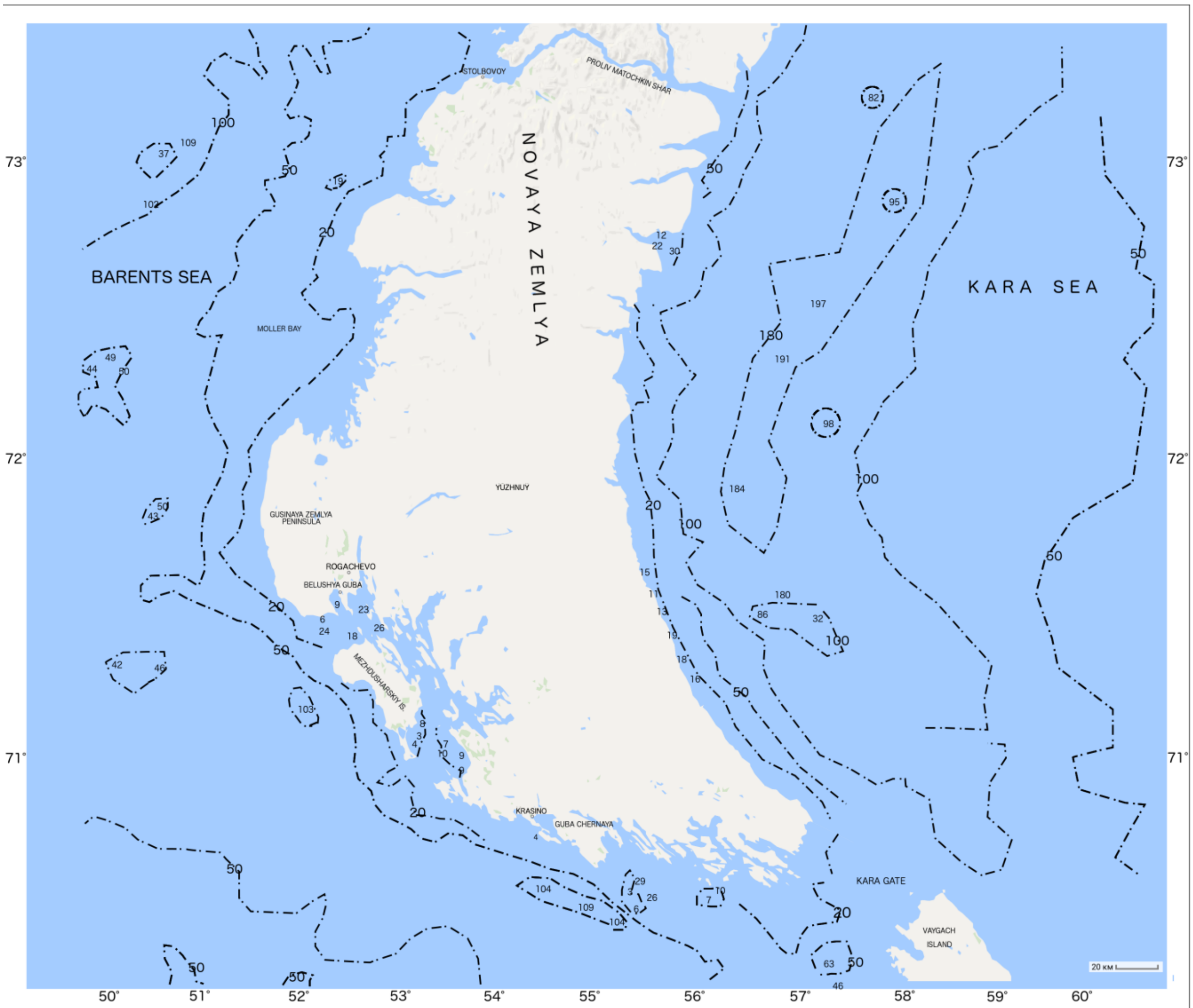

Fig. 3. Bathymetry chart

According to the bathymetry map it looks reasonable to consider the Belushya Bay as the possible location for the port as water depths remain large enough when reaching the shore. Meanwhile, another bathymetry map is provided below to show precisely the depths of the considered bay and location of existing infrastructure (see Fig. 4.).

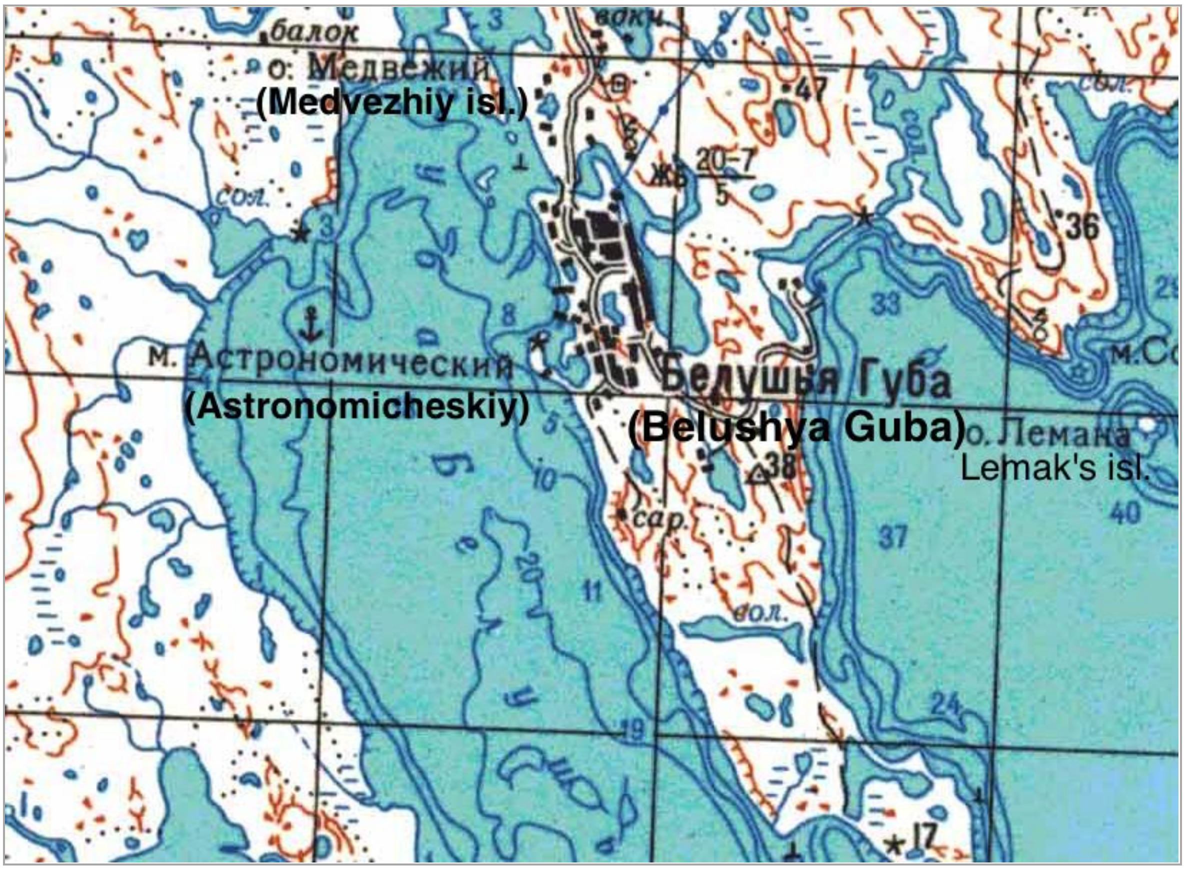

Fig. 4. Bathymetry chart of the Belushya Bay (loadmap.net)

2.6 Soil conditions

Sub-bottom permafrost is wide spread phenomenon of Arctic offshore areas. It has been identified in the Pechora, Kara, Laptev and other Russian Arctic seas. Offshore permafrost can be an important geohazard and constraint for various marine and near-shore constructions. According to general opinion, frozen soils were formed during the last glaciation period when the surface was exposed and subsequently covered by seawater following the marine transgression (Loktev A., et al., 2012).

Although sub-bottom permafrost is predicted in the Arctic offshore, there is limited direct evidence for its existence. Most of this evidence is from the Pechora Sea and the Kara Sea, where frozen soil with or without visual ice has been drilled, sampled, described and tested (see Fig. 5).

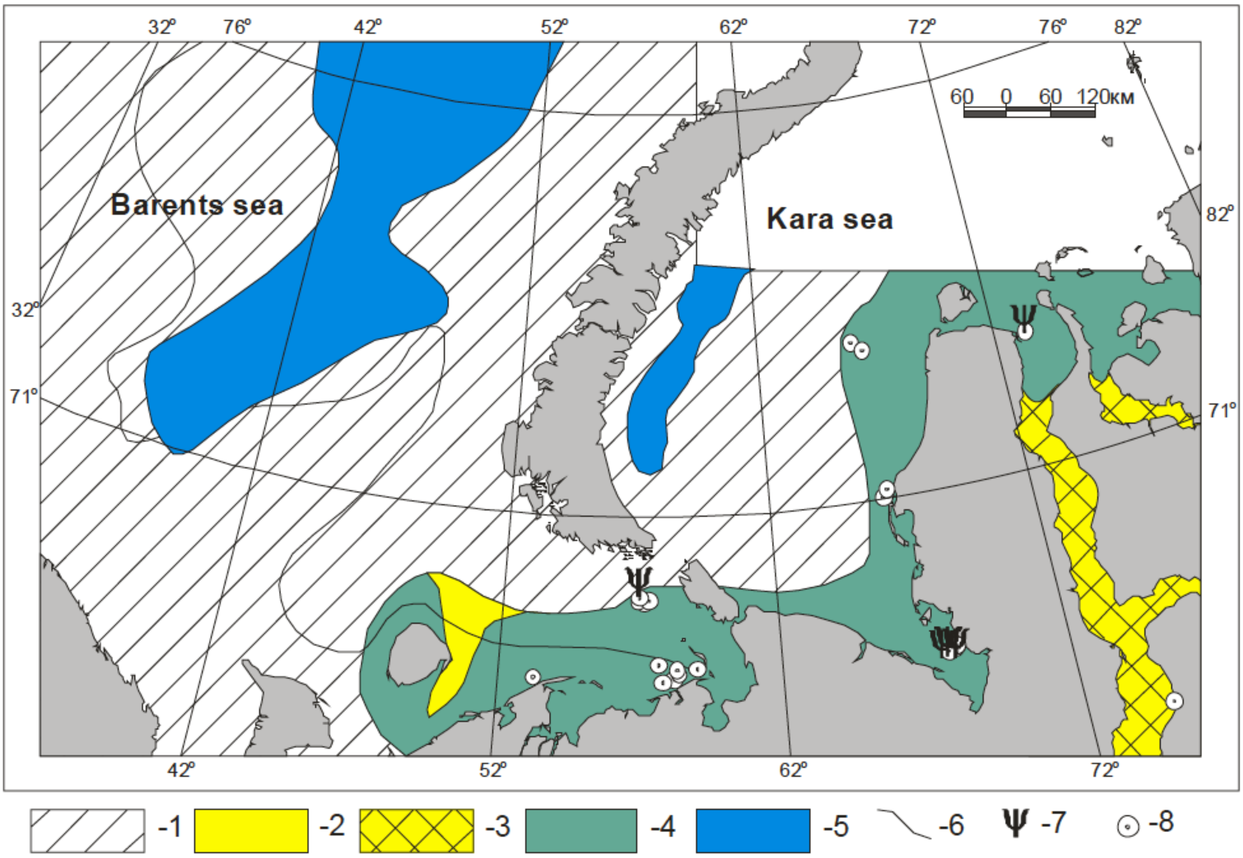

Fig. 5. Sub - bottom permafrost of the western Russian Arctic offshore: 1- not frozen soils; 2 – thawed zone; 3 – Ob river thawed zone; 4 – permafrost; 5 – area of theoretical hydrate stability; 6 – 0°C isotherm; 7 – gas and diapir; 8 – borehole recovered frozen soils (Loktev, et al., 2012)

Frozen soils are spread extensively along Arctic shorelines and found in shallow waters (Fig. 5). Permafrost is recognized in Pechora Sea, including the approaches to the Novaya Zemlya archipelago, but is absent over most of the Barents Sea.

It is also present in the south-western parts of the Kara Sea and may be present further north, but this area has not yet been surveyed. The top of the zone of permafrost typically occurs 20 – 40 m below the seabed and the bottom reaches to ~100 m below the seabed (Loktev A., et al., 2012).

The frozen section is not homogeneous because of varying lithology, initial conditions and current surroundings. The soil section consists of silty-sandy clays to sands, to gravely sands. Clays can include visible ice as ice lenses, whereas sands are mostly ice-cemented and well-bonded. Thermal conditions vary along the shore with thaw zones at the mouths of rivers (e.g. the Ob and Pechora rivers, and paleo Baydara flow).

2.7 Ice conditions

Kara Sea. The sea is very dynamic and ice compression occurs quite often. This compression may hamper ship movement significantly. The formation of fast ice takes approximately 20 days, and extends to a water depth of 20 m. The ice is extremely hummocked near the external border of the fast ice, with some hummocks grounding.

The drift ice generally consists of first-year ice. Sometimes, the occurrence of multi-year ice caused by the south–west current along the eastern coast of the Novaya Zemlya is possible.

An ice concentration of 10/10 exists during the winter and beginning of spring. The drift direction and speed can vary during the short time period depending on the wind direction. A significant factor for navigation is the 'ice river' near the Kara Gate. This ice river consists of relatively small ice pieces. In 1995, a river ice patch of length 200 km and width 15–20 km was observed (Løset et al., 1999).

Pechora Sea. The ice conditions vary significantly from east to west. Four periods of long and four periods of short duration of ice covering have been observed during the last 54 years (115–139 or 160–190 days).

The landfast ice zone is relatively narrow and during extreme years it extends 10–15 km offshore to a water depth of 12–15 m. The landfast ice cover is not stable and fracturing occurs very often during the winter, causing extensive hummocking. Ice in the Pechora Sea is of local origin. Some thick first-year ice that may exceed the maximum local ice thickness of the Pechora Sea by 0.3–0.4 m, may be imported from the Kara Sea. Multi-year ice incursion to this region from the Kara Sea is rare. Sometimes, extremely great ice fields are formed during the calving of the fast ice under the action of shore winds. The ice drift speed is determined by wind, current and tide action (Løset et al., 1999).

Barents Sea. The Northern Barents Sea is a part of the seasonal ice zone in the Arctic. Some years the ice melts or withdraws entirely from these waters during summer. Other years, the ice remains in the northwestern and northeastern parts of the Barents Sea. The Barents Sea ice contained 58% of multi-year ice, 23% of thick ice (>1 m) and 18% of new ice (thickness less than 1 m). However, comprehensive information obtained from a number of surveys during the last decades shows that multi-year ice rather seldom appears in the Western Barents Sea. Thus, the most common type of ice in the Barents Sea is first-year ice (Løset et al., 1999).

The comparison of the ice cover in several seas is shown in Table 5 and Fig. 6.

Table 5. Level ice parameters (Løset et al., 1999; Gudmestad et al., 1999; Vinje, 1991)

	Duration of period with ice-free navigation, days	1st year ice thickness, m	Multiyear ice thickness, m	Predominant ice drift direction	Max ice drift speed, m/s
Kara Sea	0-130	up 2	3-3,5	S to N	0,5
Barents Sea (central)	135-255	up to 1,8	3-5	Towards SW	0,8-1
Pechora Sea (eastern)	115-190	up to 1,45	-	S to N	1,1-1,3

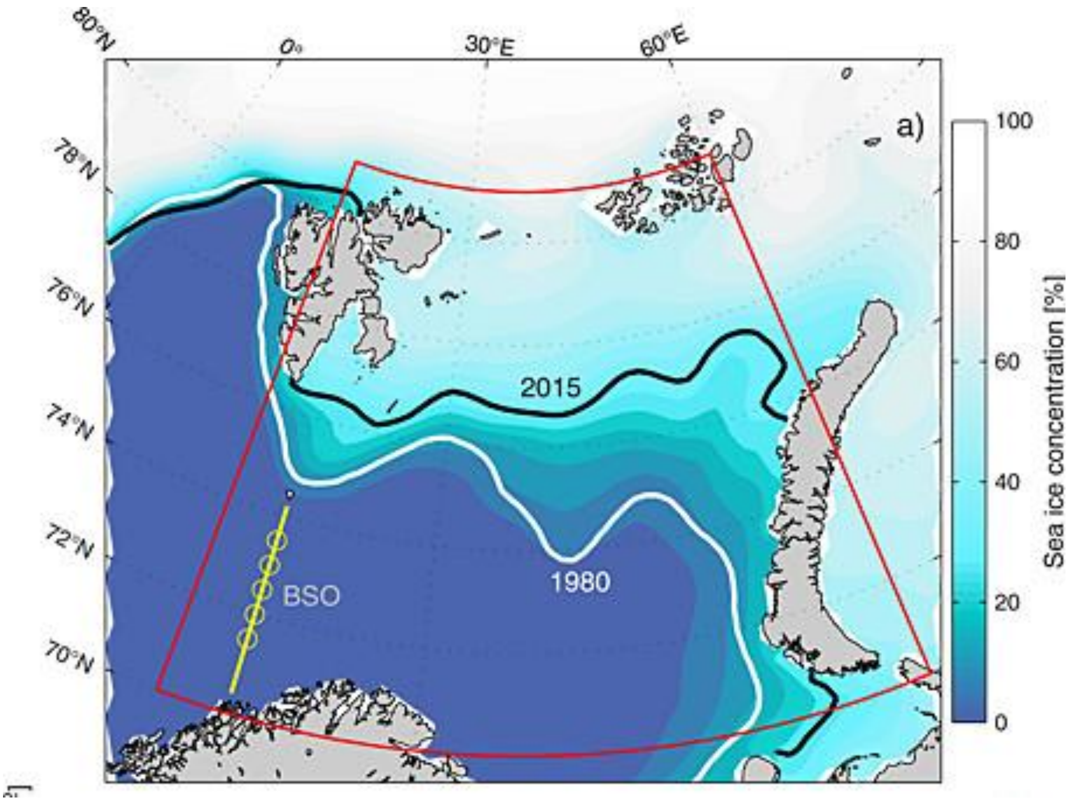

Fig. 6. Mean sea ice concentration between 1980 and 2015; ice edge (15% ice concentration) is indicated for 1980 (white line) and 2015 (black line) (National Snow and Ice Data Center, NSIDC)

2.8 Ice features

The following features can be met in the nearshore zone:

- Level ice;
- Rafted ice;
- Ridges and hummocks;
- Grounded hummocks (stamukhas);
- Icebergs.

Ice ridge is a linear feature formed of ice blocks created by the relative motion between ice sheets. Fig. 7 illustrates the composition of an ice ridge. Ridges generally consist of blocks with thickness 0,3–0,6 m but sometimes parts of fast ice 1,2 m thick can be observed. The block length is usually less than 3 m (Løset et al., 1999). Ice ridges can be observed in April-May in the Barents Sea and during the most time of the year in the Kara Sea.

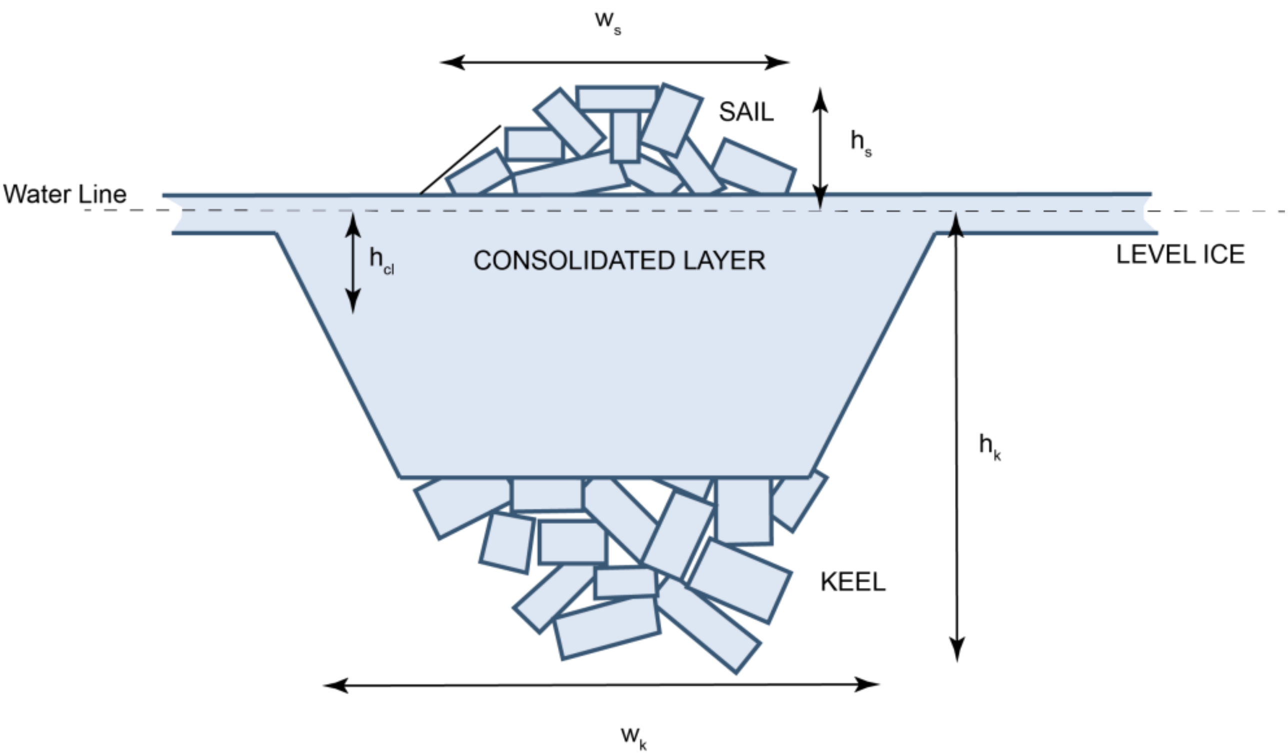

Fig. 7. Ice ridge (Shestov, lecture course, 2016)

Stamukha is a grounded accumulation of sea ice rubble that typically develops along the boundary between fast ice and the drifting pack ice, or becomes incorporated into the fast ice (wikipedia.org). Stamukhas were not observed at water depths exceeding 20 m. Stamukhas consist mostly of ice blocks that are not consolidated. Their porosity is 30-35%. The sail height can reach 7-12 m while the length can be hundreds of meters. The prevailing length is 30-150 m. In the Pechora Sea they are located mainly in the vicinity of the Matveev and Dolgy Islands and along the southern extremity of Novaya Zemlya (Løset et al., 1999). Because stamukhas extend downward into the seabed, they present a risk to subsea pipelines and telecommunications cables that cross the shoreline. Special mitigation measures have to be applied to prevent the damage of the subsea constructions.

Icebergs are occasionally observed in the Kara Sea. In the Pechora Sea, icebergs are not present. However, icebergs either drifting in from the Franz Josef Land archipelago or descending from the glaciers on the east coast of Svalbard regularly invade the Barents Sea. Several multi-sensor ice data acquisition programmes (IDAP) have been launched in the Barents Sea. They have gathered data on icebergs and showed a substantial variation both in number and masses over the 5-year period 1988–1992. The most severe year in this period had a total of 17 icebergs with mass greater than 1 million tons (Løset et al., 1999).

However, no icebergs have been observed south of 72,5° N in the Barents Sea (see Fig. 8). This area is liable to iceberg appearances because of the climate conditions and such effects as Polar Low pressures (Bulakh, M., et al., 2011).

The large glacier along Novaya Zemlya has relatively few kilometres of ocean front. These fronts terminate mostly to shallow waters and cannot produce very large icebergs (Gudmestad et al., 1999). Ice features are presented in Tables 6 and 7.

Table 6. Ice features (Løset et al., 1999; Gudmestad et al., 1999).

	Number of ridges per km	Sail height, m	Possible keel draught, m	Rafted ice thickness, m	Average hummocking, balls
Kara Sea	1-4	2 (average)	18-20	3-3,5	2-3
Barents Sea (central)	1-9	up to 5 m	15	2	3
Pechora Sea(eastern)	-	0,5-2,5	12-18	2,5-3	3-4

Table 7. Iceberg features in the Barents and Kara seas (Rosneft, 2015; Chernetsov et al., 2008)

Parameters	Severnaya Zemlya (Kara Sea)	Novaya Zemlya (Kara Sea)	Barents Sea
Average length, m	301	49	136
Average width, m	133	30	75
Average sail height, m	14	10	11
Average draught, m	29	30	-
Maximum observed height, m	30		35
Maximum possible draught[1], m	210		245
Maximum observed draught[2], m	137		-

[1] There were no direct measurements, the draught is evaluated from sail/draft ratio =1/7

[2] There were no direct measurements, the draught is evaluated from sail/draft ratio =1/7

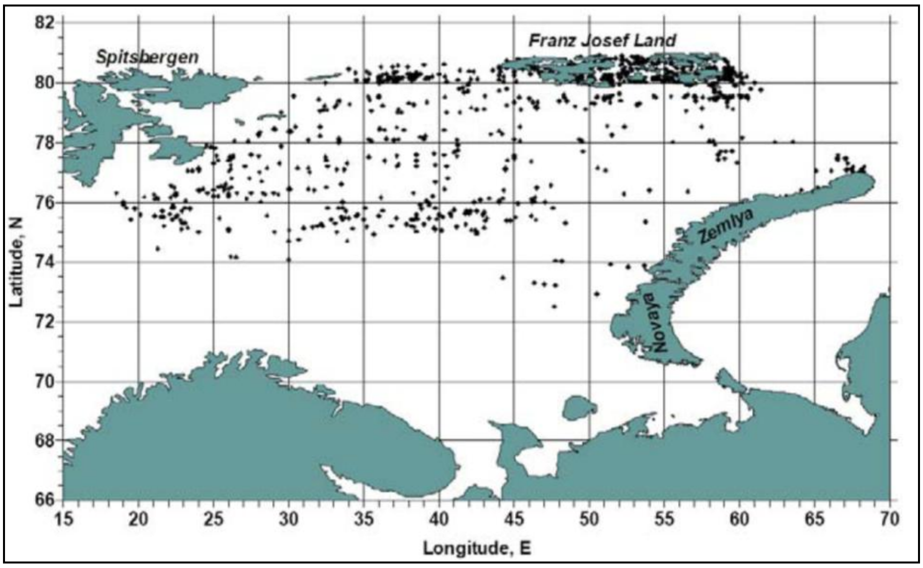

Fig. 8. Location of icebergs in the Barents Sea 1928-2005 (AARI)

Following table summarises the environmental conditions discussed in the section.

Table 8. Metocean conditions in different seas (Løset et al., 1999)

Parameter	Kara Sea	Barents Sea (central)	Pechora Sea
Latitude	70 N	74 N	70 N
Max wind gust (m/s)	40	40	41
Max air temperature, C	-50	-24	-48
Significant wave height, m	5,7	12,5	6,2
Current speed, m/s	1,8-2	0,5	1
Freeze up (average)	Oct-Nov	Dec	Nov
Clearing (average)	July-Aug	May	June
Open water period, days	0-130	135-255	110
Multi-year ice, %	40	-	-
Maximum level ice thickness, m	1,8	1	1,3
Rafted ice thickness, m	3,6	2,0	2,6
1st year ridge thickness, m	18-20	-	12-18

Preliminary conclusion

The most important results are the following:

- The air temperature of the Barents Sea is substantially milder than in the three other seas;

- The Kara Sea is quite sheltered with consequently lowest waves in contrast to the Barents Sea where waves enter from the SW (the Western Barents Sea has the most severe wave climate);
- The average wave height in the Barents Sea decreases slightly towards the east, as well as most parameters except for marine and air temperatures;
- The most extreme currents appear in the Barents Sea, but mostly in the western part and warm currents in central Barents Sea provide moderate ice conditions near the Novaya Zemlya Archipelago;
- Ice in the Kara Sea is mainly of local origin, and represents first-year ice, bergy bits can occur near the Novaya Zemlya, some multi-year ice features 3–4 m thick have been observed in the eastern part of the sea;
- Duration of periods with mean air temperatures below 0 °C in the Kara Sea can reach 250 days;
- Stamukhas in the Kara Sea are located usually at a water depth of 5–15 m;
- The large glacier along Novaya Zemlya has relatively few kilometers of oceanfront, these fonts terminate mostly to shallow waters and cannot produce large icebergs;
- There are possible areas with stable seabed hydrates east of Novaya Zemlya archipelago which should be accounted for drilling and construction activities.

It is possible to identify from which side of the Novaya Zemlya it might be more appropriate to design the facilities for transportation of hydrocarbons in terms of environmental conditions. For instance, the Barents Sea appears to be more suitable for vessel navigation due to relatively low ice period, higher temperatures. It could be possible to design the offloading terminal at that location. According to the bathymetry map the Belushya Bay is a suitable place for the port as water depths values remain large enough when reaching the shore.

At the same time the bathymetry of both Kara Sea and Barents Sea could provide appropriate conditions to lay and safely operate pipelines on the bottom without any threat from the ice ridges due to deep waters. However, icebergs may cause very significant problems in the Kara Sea and the protection of possible subsea structures should be considered precisely.

Further investigation is provided in the following chapters upon the suitable routs and design problems.

3. Oil & Gas reserves and resources of Barents and Kara Seas

According to Ananev V.V. et al (2015) the Arctic shelf accounts for 87% of Russia's total offshore initial petroleum resources mostly concentrated in 4 large petroleum provinces (extensions of the Timan-Pechora and the West Siberian petroleum provinces and offshore Barents-Kara and East Arctic provinces).

The current aim of Russian Government is to increase Arctic oil extraction up to 5% and gas extraction up to 10% of national extraction values. A ten-year moratorium on new Arctic offshore leases was announced in September 2016, but a significant number of leases was issued in advance (see Fig. 9). In addition, there are specific requirements that companies have to meet in order to hold Russia's strategic offshore blocks (Ananev, V.V. et al., 2015):

- 5 years or more of experience in development of offshore blocks in the Russian waters;
- Russian government's share in the authorized capital should be more than 50%.

Therefore, only a few companies can be assigned to operate in the region.

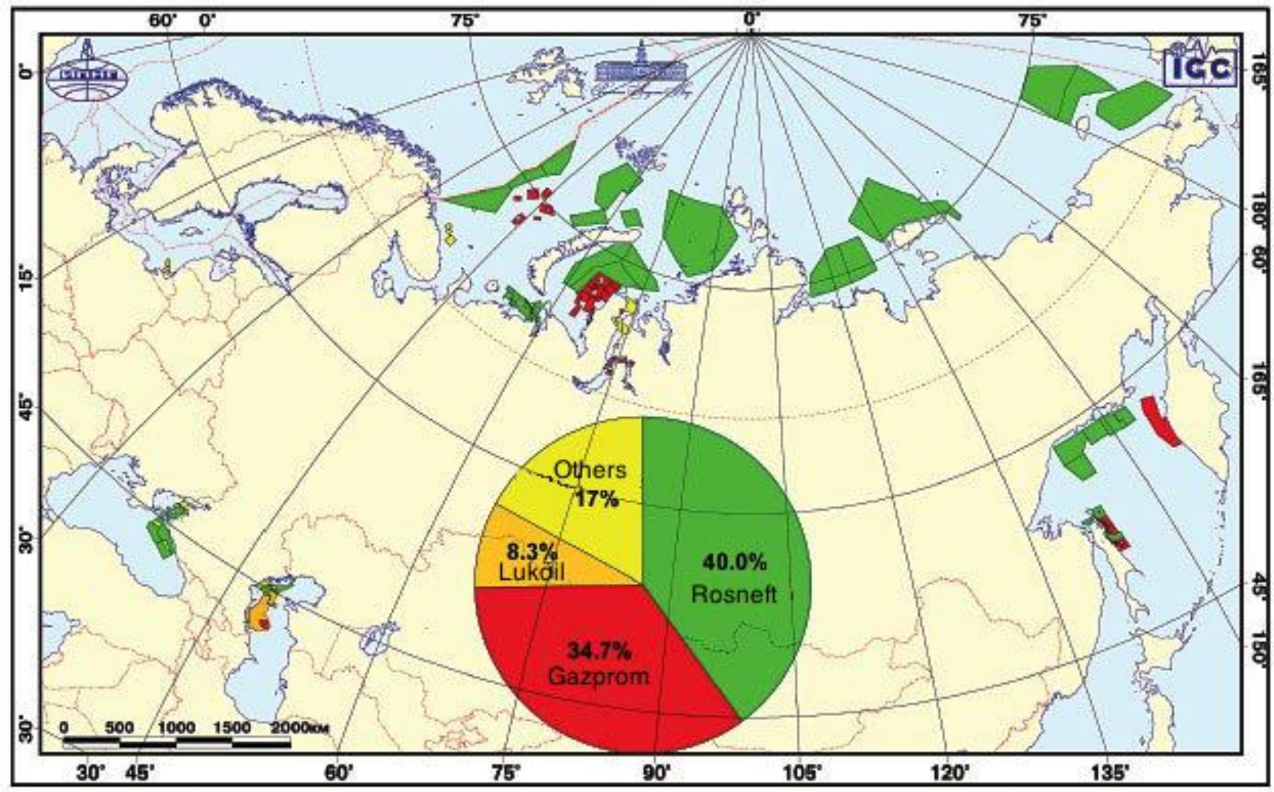

Fig. 9. A map of oil leases in the Russian Arctic. Green = Rosneft, red = Gazprom, orange = Lukoil, yellow = others (https://cryopolitics.com)

Oil state company Rosneft controls more than 40 offshore licenses, among which six are in the Barents Sea, eight in the Pechora Sea, four in the Kara Sea, four in the Laptev Sea and four in the East Siberian Sea (see Fig. 10).

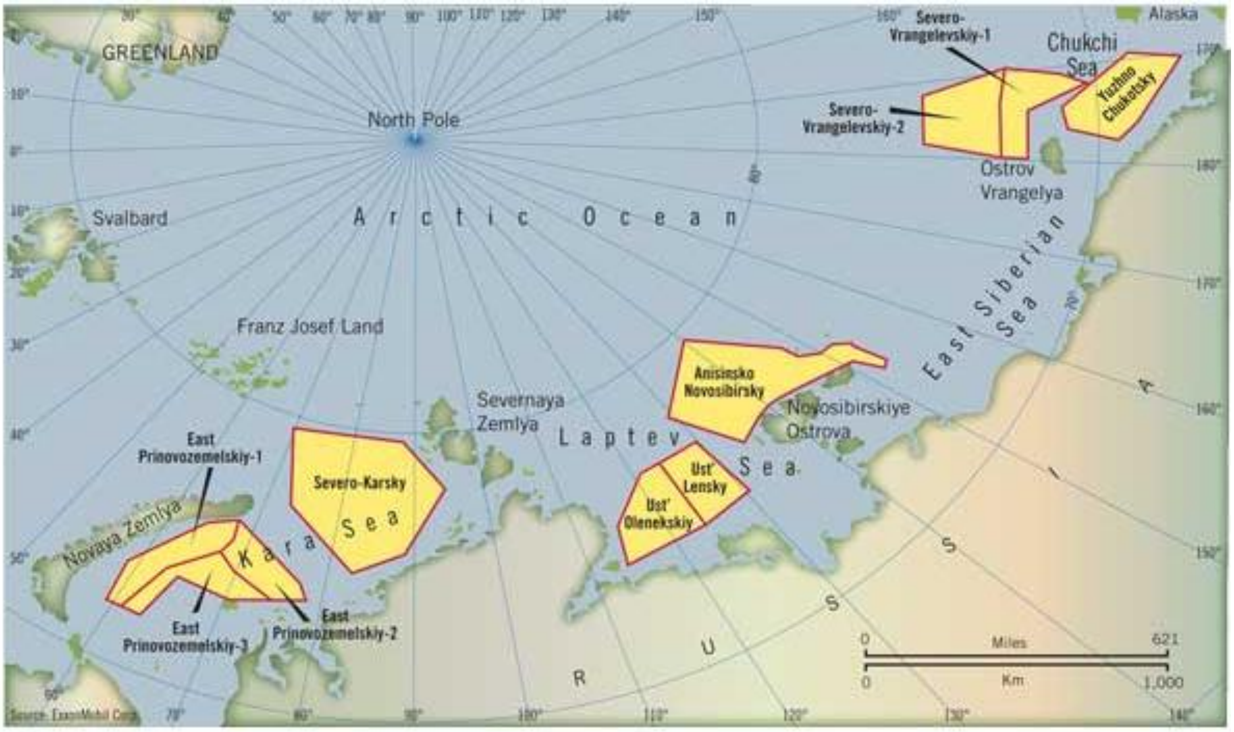

Fig. 10. Rosneft license blocks in the Kara, Laptev, East Siberian and Chukchi Seas (http://energydesk.greenpeace.org)

Another state company that meets government requirements for developing the Arctic offshore is Gazprom. It has been developing the only Russian Arctic offshore project Prirazlomnaya and controls a total of 33 offshore licenses, including seven in the Barents Sea and 20 in the Kara Sea. A total of 6,700 square km of 3D seismic mapping were conducted in 2015 in 2016 of the Barents and Kara Sea license areas (Staalesen, A., 2016).

License blocks in the Barents Sea include:

- Severo-Vrangelskiy (estimated reserves 632,8 mln. tons of oil, 994 bln. m3 of gas);

- Heysovskiy (estimated reserves 140 mln. tons of oil and condensate, 2 trn m3 of gas;

- Severo-zapadniy (estimated reserves 105 mln. tons of oil and condensate, 60 bln. m3 of gas);

- Dolginskoye field (estimated reserves 200 mtoe).

License blocks in the Kara Sea include: Amderminskiy, Nevskiy, Obbruchevskiy, Zapadno-Sharapovskiy, Sharapovskiy, Severno-Harasaveyskiy, Leningradskiy.

Fig. 11 illustrates the main discovered Arctic offshore fields in the Barents and Kara seas.

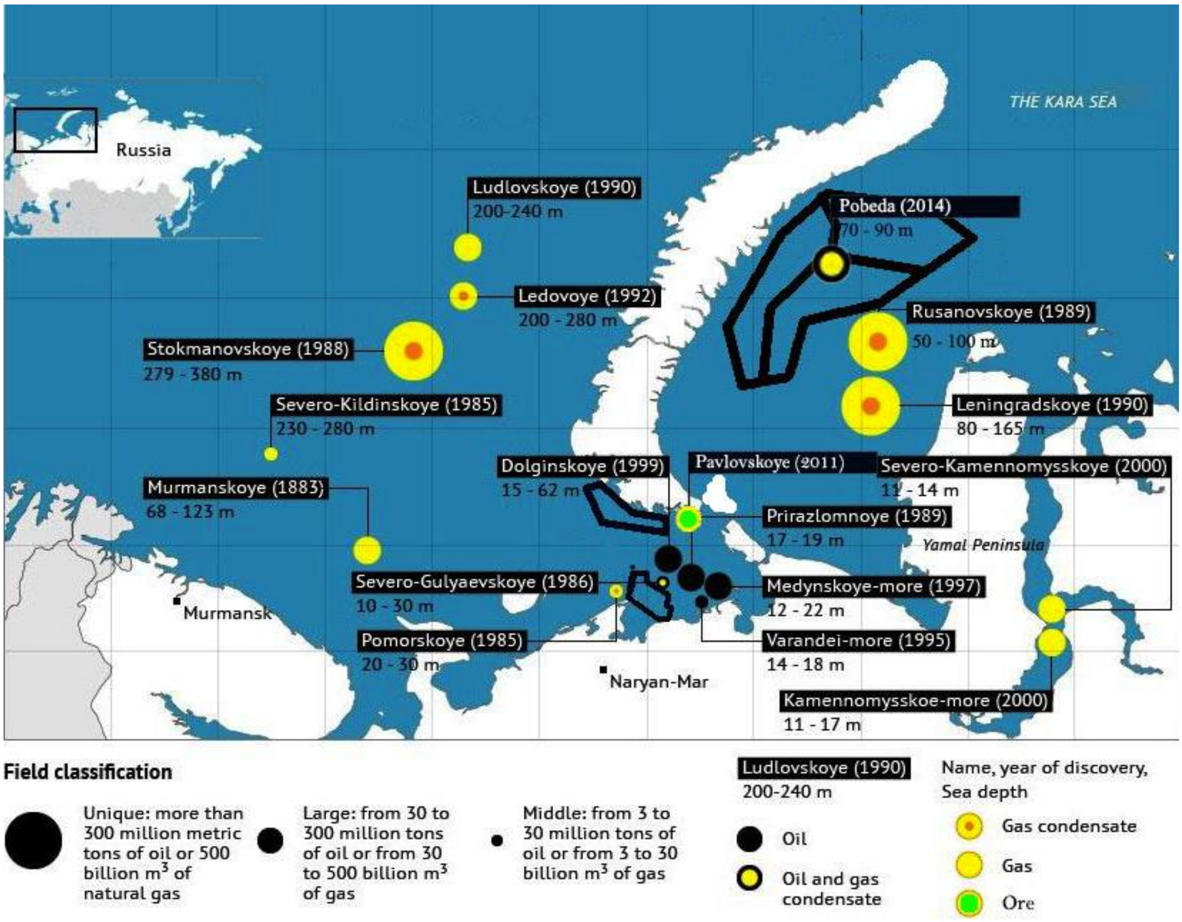

Fig. 11. Russian oil and gas fields in the Arctic (www.sputniknews.com)

All in all, estimated reserves for Kara, Barents and Pechora Sea are ca. 200 000 MMBOE (Lange et al., 2011). Between 1983 and 1992, 10 oil and gas fields were opened in 10 years, including 3 unique fields; the reserves of 3 additional fields exceed 100 billion m^3 (Novikov et al., 2008). To be more specific, two gas-condensate fields – Shtokmanskoye and Ledovoye, and three gas fields – Ludlovskoye, Murmanskoye and North-Kildinskoye have been discovered in the Barents Sea. Potentially interesting structures have been detected in the Fersman-Demidov shoulder, Shatsky and Vernadsky swells, and also in the area of Medvezhy and Admiralteisky swells (Zolotukhin, Gavrilov, 2011). The fact that the discoveries of the majority of fields were produced by the first prospecting well is remarkable and the same time brings more uncertainty. Exploration and calculation of reserves were conducted with a minimum quantity of wells. Overall 22 wells with total length of ca. 64,000 m were drilled for 8 fields including 17 prospecting wells and 5 exploration wells. This predetermined the extremely high economic effect of entire geological survey process, which is composed of the savings of inputs for drilling of several exploration wells. However, small amount of exploration wells also increases the uncertainty of geological reserves.

Further fate of these fields has been formed differently. Only two fields: Shtokman (the biggest on the reserves) and Prirazlomnoye oil field appeared in the distributed fund with their subsequent additional exploration for the preparation for the development.

The remaining fields, explored by 1- 2 wells, until now, count as exploring ones and are in the undistributed resource fund. Eight gas fields from the undistributed fund of Western Arctic shelf have reserves of 2.7 trillion cubic meters. Leningradskoe, Rusanovskoe, Ledovoe, Ludlovskoe, and

Murmanskoe, the largest of these fields, have official status of strategic resources for providing national energy safety, and they are taken into account in the plans of joint stock company “Gazprom” in their 2020 development program.

In 2014, an exploration drilling was conducted in the Kara Sea with successful outcome from the Universitetskaya well in the Vostochno-Prinovozemelsky license block. Discovered “Pobeda” field has the total recoverable resources of 130 million tons of oil and 499,2 billion m^3 of gas.

Nowadays, both economical efficiency and the lack of state-of-the-art technologies put the limitations on Arctic projects and cause the delay of their development.

The start of production for the Shtokman field was postponed till 2025 due to geopolitical uncertainties, market oscillations and technological risks.

Started with Prirazlomnoye field in 2014, production from the Russian part of the Barents Sea is expected to reach 400 million boe by 2040, to which gas contributes with nearly 72% (Gafiatullin et al., 2016).

Therefore, reliable transportation scheme is one of the key features towards bringing the mentioned fields to the level of profitable projects.

Due to allocation of the number of license blocks and discovered hydrocarbon fields along the coastal lines of the Novaya Zemlya Archipelago and far from the continental shelf (see Fig. 11) it is reasonable to consider the archipelago as a possible transportation hub.

It is also unclear whether development of the oil fields discovered in the Pechora Sea (Dolginskoye, Medyn-more, Varandey-more, Kolokomorskoye oil fields, Severo-Gulyaevskoye oil-gas-condensate field and the Pomorskoye gas-condensate field) (see Fig. 12) might be more reasonable with the use of continental infrastructure and infrastructure of Prirazlomnoye field or Novaya Zemlya archipelago. Therefore, mentioned fields might also be added to the transportation concept.

Fig. 12. Discovered fields and prospective structures of the Pechora Sea (http://www.storvik.com)

However, for now it is assumed that Barents and Kara Seas fields are the most relevant and applicable fields for the earlier proposed concept.

Preliminary conclusion

Environmental and prospective field analyses lead to the following conceptual proposal for the transportation system. It is anticipated that development of the Barents Sea will start from the Shtokman field, which later would be accompanied by the satellite fields of Ledovoye and Ludlovskoye. Besides these fields there are several large and prospective structures located in the Kara Sea (Pobeda, Rusanovskoye, Leningradskoye), which are also considered to be part of the concept in the later stages (Fig. 13). Subsequent order would also enable utilization of available infrastructure so as to reduce investment costs as well as to follow the up-to-date demand for the gas in the world energy market.

The level of exploration also influences the choice of the fields; therefore, it is reasonable that with more exploration activities more hydrocarbon structures might be added to the concept.

It is suggested to transport produced hydrocarbons via subsea pipeline system to the Novaya Zemlya (see Fig. 13).

The development of the Barents Sea is certainly more cost-effective if its resource base is combined with resources of the Kara Sea and the Novaya Zemlya archipelago is used as a base and hub for development of the whole region. The "unitization principle" and cooperative work of the main Russian state companies would certainly mitigate economical and environmental risks for the fragile Arctic region.

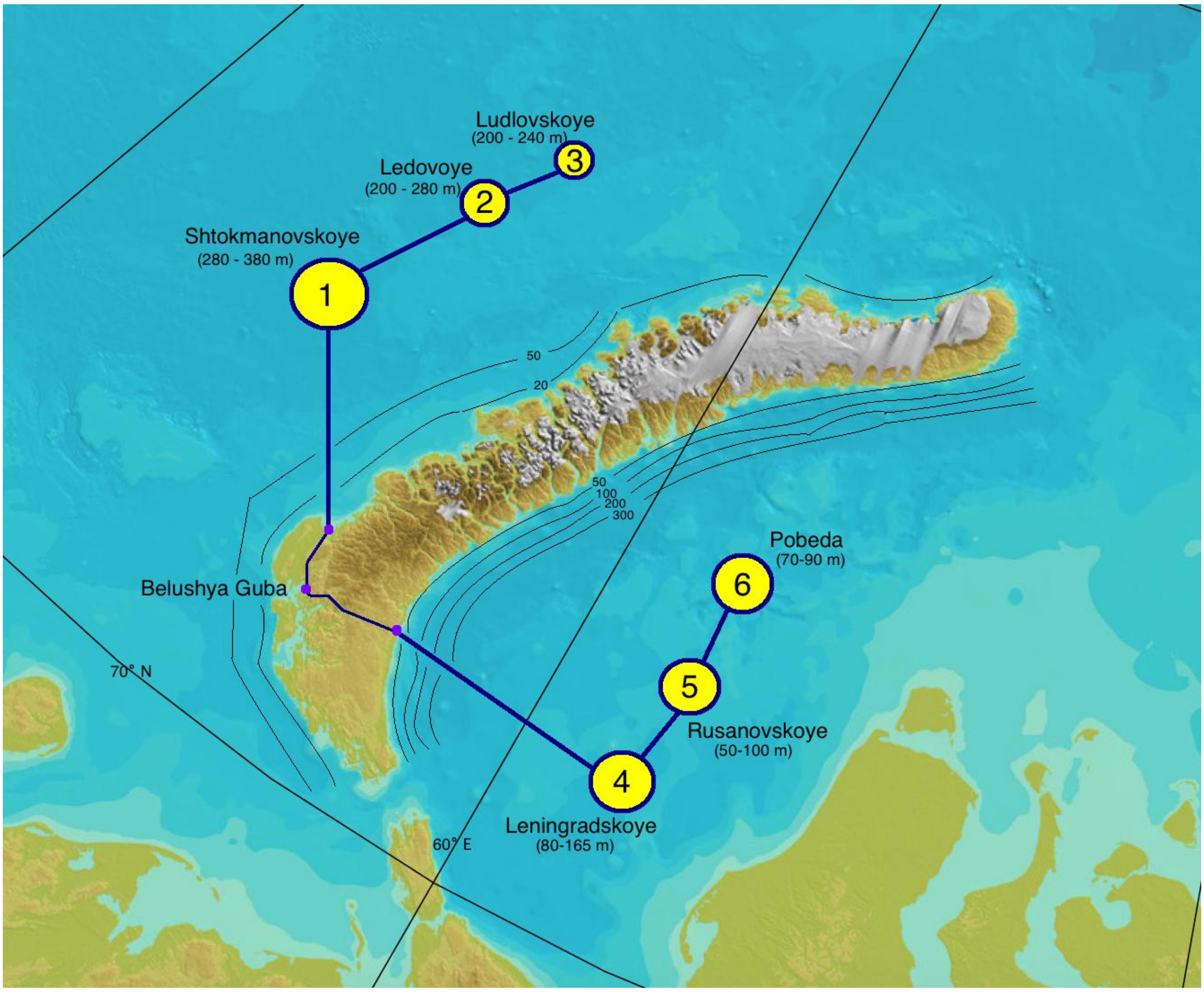

Fig. 13. Transportation concept for the Kara and Barents seas

Table 9 provides characteristics of the chosen fields.

Table 9. Characteristics of the fields (http://neftegaz.ru)

Parameter	Shtokman	Ludlovskoye	Ledovoye	Leningradskoye	Rusanovskoye	Pobeda
Gas reserves, trln. m^3	3,8 (C1)	0,21 (C1+C2)	0,22 (C1+C2)	1,05 (C1+C2)	0,8 (C1+C2)	0,499 (C1+C2)
Condensate, mln. t	53,3 (C1)	-	3,9 (C1+C2)	3,0 (C1+C2)	7,8 (C1+C2)	
Oil, mln. t	-	-	-	-	-	130 (C1+C2)
Sea depth, m	280-380	200-240	200-280	80-165	50-100	70-90
Distance to NZ[3], km	250-300	200	200	250-300	250-300	200
Coordinates	73.1 N, 44.1 E	74.8 N, 46.9 E	74 N, 46.7 E	72.3 N, 65.7 E	73.4 N, 65.6 E	74.0 N, 66.8 E
Operator	Gazprom	Gazprom	Gazprom	Gazprom	Gazprom	Rosneft

[3] -Novaya Zemlya

4. Novaya Zemlya Archipelago

4.1 General environmental conditions

Novaya Zemlya Archipelago has an area of 82,600 km^2. It lays in the Arctic Ocean and separates the Barents and Kara seas. Novaya Zemlya consists of two large islands, Severny (northern) and Yuzhny (southern), plus several smaller islands. The two major islands are separated by a narrow strait, Matochkin Shar, only about 1.6 to 2.4 km wide. The Kara Strait separates the most southerly point, the island of Kusova Zemlya, from Vaygach Island and the mainland.

Novaya Zemlya has a severe climate, with frequent, extremely strong winds ("Bora"), which accompany lower temperatures and cause snow or dust storms.

On Novaya Zemlya, summers are cold and short, starting in June and continuing until September. Temperatures can rise to a maximum of 24 °C in July. The mean relative humidity averages at 80%. Rain is frequent but light. Thunderstorms are rare but may occur during late spring and summer. The surface frost-free period is less than 45 days, from early July to middle August, but night frosts can occur during any of the summer months. During May, June and July the sun does not set and dense fogs can occur. Clear days are rare, ranging from one to four days per month in the summer, to three to nine days per month in the winter. By mid-October both the mean and average maximum daily temperatures are below freezing.

Winter begins in late October and generally continues into April. Temperatures rarely rise above freezing. Months from January through April are the least cloudy one, but even then there are only seven to nine clear days. During November, December, and January the sun does not rise. The average temperatures drop to about -12 °C. The coldest month on the island is March, during which temperatures can drop to -44 °C. Despite of these temperatures, Novaya Zemlya is slightly milder than northern Siberia because of the warming influence of the Murman current. (Matzko J.R., 1993)

The vegetation in those portions of the islands free from ice is predominantly low-lying tundra, with much swamp, though low bushes are found in sheltered valleys. Lemmings, Arctic foxes, seals, walruses, and occasionally polar bears are found on Novaya Zemlya; a rich bird life abounds in summer. The area of the southern island of Novaya Zemlya experiences from eight to ten cyclones per month during the winter, with the main direction of the cyclone trajectories from the west and south-west to north-east (Campbell, 2009).

Table 10 below summarises the climate conditions for Novaya Zemlya.

Table 10. Climate summary, Maluye Karmakuly station, Novaya Zemlya[4] (Matzko J.R., 1993)

Parameter \ Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ann
Temperature, °C													
Mean	-15	-14,5	-15,4	-10,8	-4,5	1,4	6,4	6,3	2,7	-2.7	-9	-13	-5.7
Maximum	1	1	1	6	13	20	24	20	17	10	3	2	24
Minimum	-41	-40	-44	-32	-24	-17	-10	-1	-13	-18	-34	-36	-44
Precipitation, mm													
Mean	26	18	19	18	20	24	30	36	41	35	26	24	317
Maximum						59	82	95	88				
Minimum						2	2	7	8				
Wind, m/s													
Mean speed	10,3	10,4	9,2	8,1	7,2	6,9	6,3	6,9	7,1	7,9	9	10,4	8,3
Prevailing direction,	SE	SE	SE	SE	N	N	N	N	SE	SE	SE	SE	SE
Mean peak gusts	27,1	26,7	25	27	22,3	22,9	22,2	21,4	22,7	20,6	24,9	28,9	32,6

[4] - conditions reported for the station at Malye Karmakuly, about 130 km south of Matochkin Shar on the west coast of Novaya Zemlya The data in this extracted from Lydoph, 1977, and US Department of Commerce, 1990

Novaya Zemlya falls within the zone of continuous permafrost. The thickest permafrost can be found in the higher mountains. At elevations up to 500 meters, permafrost in the Matochkin Shar area may be as much as 100 meters thick in valleys and 400 meters thick on watersheds.

The active layer is only 0.3 to 3 meters thick, depending on the soil type and condition, and the vegetation cover, and thaws in the two to three months of warmer temperature (July-September).

The elevation and topography of the base of the permafrost is not known; the base may be a subdued reflection of the topography of the land surface. The base of the permafrost may extend to depths below sea level in some areas, particularly along the strait. The stable ground temperature (at that horizon in which seasonal temperature fluctuations cease) ranges from -5° to -1° C at 400 to 1,000 meters elevation; at the 100 to 500 m elevations, the stable temperature is from -3° to -50 C

A frost-shattered zone very likely exists at least to the depth of the active layer, and possibly extends to a few tens of meters into the permafrost zone as well. Within the active layer, thermal expansions of the rock and ice expansion contribute to the fracturing and weathering of the bedrock, thereby reducing its strength.

The physical properties data on Novaya Zemlya indicate that, in general, the clastic rocks of the Caledonian complex (Ordovician to middle Devonian) are resistant to weathering and are characterized by a high (bulk) density of 2.55 to 2.60 g/cm^3. Early Carboniferous limestone from the South Island, from 9-17 meters depth, has a grain density of 2.65 g/cm3 (three measurements), bulk density of 2.63 g/cm3, and uniaxial compressive strength of 87 MPa (water saturated). The limestone underwent 50 freeze/thaw cycles with no change in strength. Limestone samples collected from the surface of the South Island have a bulk density of 2.61 to 2.65 g/cm^3, water absorption of 0.39 to 0.20 %, compressive strength (airdried) to 68 - 96 MPa, water saturated to 68-82 MPa (Matzko J.R., 1993).

In Yuzhny Island, about 150 km from Belushya Guba there are rich ore-bearing deposits of various metals: manganese, lead, zinc and silver. Their total reserves are estimated at 3 billion tons (nordport.ru).

There are sand and stone quarries on the archipelago as well as a large undeveloped flat area suitable for construction on the south-eastern part of the Yuzhny Island.

All these create a solid base for the power supply of the mining and petrochemical industries.

4.2 Existing and required infrastructure on the Novaya Zemlya

The main permanent settlement of the Novaya Zemlya Archipelago is Belushya Guba. It is located on the Gusinaya Zemlya peninsula. The urban settlement Belushya Guba is also an administrative center of the Novaya Zemlya District of the Arkhangelsk region. The Rogachevo village, another settlement, is located to the north-east. According to the 2016 the population of the Belushya Guba is 2469 people (approximately 75% of men and 25% of women). The amount of men prevails over women due to the military-technical work specialization. Belushya Guba settlement is the capital of the Central Range of the Russian Federation.

The whole Novaya Zemlya archipelago, including Belushya Guba, is an area of restricted access (formally, as part of border security zone), and a special permit is needed to visit the archipelago.

The existing infrastructure of the settlement includes a port with two cargo and four auxiliary berths, a secondary school for 560 people, a kindergarten for 80 people, 17 dwelling houses, 3 hotels, a shop, a naval hospital for 200 beds, polyclinic, recreation and sports center, Orthodox church (wikipedia.org).

There is a regular airplane connection from Arkhangelsk to Rogachevo Airport, located 9 kilometers north-east of the settlement.

Special attractiveness of the Belushya Bay is that it is located in the warm current influence zone and environmental conditions allow providing a year-round navigation of all types and classes of vessels with minimal costs for an icebreaker escort. The fast ice zone does not exceed 1 km with an ice thickness of up to 1 m in the most severe winters. The bay is well protected from wave disturbances and penetration of drifting ice into its waters. The depth at the entrance of the bay is 30-50 m, and 10-30 m in the bay water area.

In order to be able to meet the requirements for being a transportation hub following infrastructural facilities should be designed and constructed on the archipelago:

- Onshore LNG plant with several trains;
- Seaport for ice class LNG carriers with terminals for loading the LNG tankers;
- Storage tanks for liquefied natural gas;
- Gas condensate processing facilities.

Sea terminals and ports are often the most complex facilities in the arctic region with sophisticated ice conditions and harsh weather. Nevertheless, about 15 seaports were constructed during the last decades along the Russian part of the Northern Sea Route (NSR), including 3 in the Barents Sea (Varandei, Murmansk, Naryan-Mar) and 4 in the Kara Sea (Amderma, Dixon, Dudinka, Igarka). The port of Arkhangelsk was remodeled and to increase its capacity as well. In addition, state-of-the-art Novuy Port in Yamal Peninsula is already in operation as part of Yamal LNG project.

While existing seaports lead to a more flexible and interconnected transportation system in the arctic region, new suggested hub on the Novaya Zemlya Archipelago would bring the NSR to the whole new level of demand. Construction of the oil and gas terminal on the base of existing infrastructure at the Belushya Guba will reduce costs for long-distance transportation of hydrocarbons to the market via pipelines.

4.3 Nuclear pollution and wastes on the Novaya Zemlya

Novaya Zemlya is the site of two Russian underground nuclear test sites: a southern and a northern site.

The northernmost nuclear test site is located about 73° 25' north latitude and 54° 45’ east longitude, along the Matochkin Shar strait on the northern end of the South Island. The southernmost site is located on the southwest coast of the South Island, about 70° 45’ north latitude and 54° east longitude.

The former Soviet Union conducted 132 nuclear tests on the Arctic islands of Novaya Zemlya between September 21, 1955 and October 24, 1990. This includes 87 explosions in the atmosphere (one explosion on the land surface; three explosions on the water surface; and 83 air bursts); three underwater explosions between 1955 and 1962; and 42 underground tests between 1964 and 1990. An underground site on the southern part of the islands was deactivated in 1975. The estimated yield of the largest test at the Matochkin Shar site is 2 Mt. Following map indicates locations of the test sites on the Novaya Zemlya archipelago.

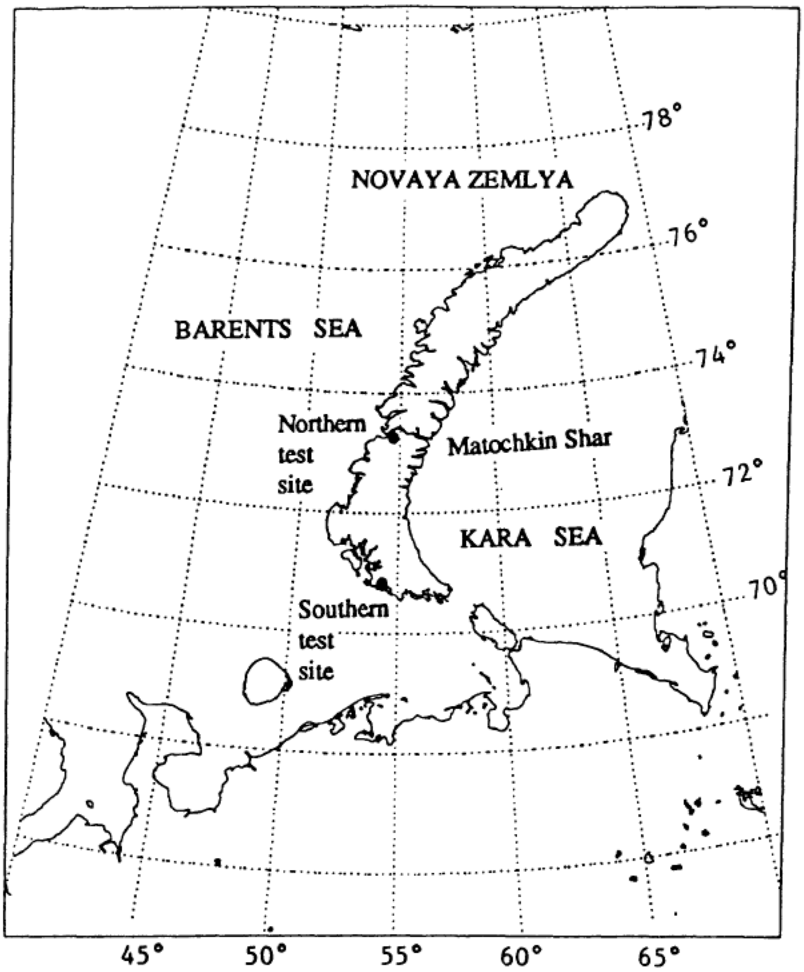

Fig. 14. Locations of the northern (Matochkin Shar) and southern test sites on Novaya Zemlya (Matzko, 1993)

Preliminary conclusion

Collected data is of great importance for designing the infrastructure and placing the facilities on the archipelago. Environmental and soil conditions would influence the materials and technologies for constructing the seaport, LNG plant, process and trunk pipelines and other structures.

Nuclear test sites were found to be mostly on the Matochkin Shar and no tests were carried after 1990 with no evidence for future continuation.

Clear advantages for placing the transportation hub on the Novaya Zemlya archipelago were identified:

- There is an existing settlement with airport and seaport, which would ease the transportation of all materials, equipment and personnel without additional capital investments;

- Belushya Guba proved to have an optimal location and conditions for constructing the terminal in its bay:

- Room to maneuver and good safety in the harbor basin;
- Acceptable weather conditions (wind, visibility, sea swells);
- Calmness (little undertow) and wind load at the quay;
- Safe anchorage in the vicinity of the terminal;
- Potential waiting areas outside the coast for ships waiting for clearance;
- Beneficial geographical position of the archipelago in relation to the Northern Sea Route;
- Favorable environmental conditions compared to the northern Siberia, ice-free zone in the Barents Sea, moderate winters;
- Proximity to hydrocarbon and ore deposits.

5. Navigation in the ice covered Barents Sea

It was mentioned above that Belushya Bay was chosen as the possible place for terminal location. Therefore, it is necessary to discuss navigation conditions for vessels in the Barents Sea, as there will be constant supply of the Archipelago with goods and materials, as well as export of the hydrocarbons to the consumers.

There is a number of main directions for maritime transport through ice-covered vast areas of the Barents Sea (see Fig. 9): Murmansk - Kara Gate strait; Murmansk - Zhelaniya Cape (Novaya Zemlya Archipelago); Murmansk - Franz Josef Land Archipelago. The first two are the main options for the initial part of the Northern Sea Route; the third provides the transportation of goods to the islands of Franz Josef Land Archipelago. The standard length of these routes is 510, 700 and 680 miles respectively. For the further analysis the Murmansk - Zhelaniya Cape direction will be discussed more precisely as it lies along the western coast of the Novaya Zemlya Archipelago.

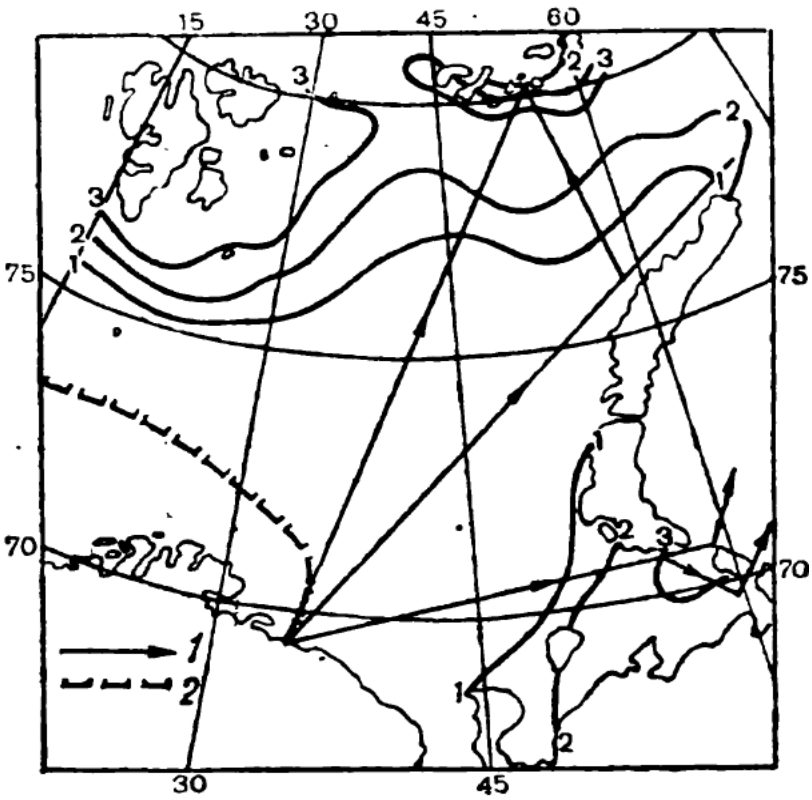

Fig. 15. Navigation routes (1) and maximum ice edge location (2), isoclines – average ice hummocking in April, ball (Barents Sea, 1990)

Summarized data about sailing in ice conditions in the Barents Sea are given in Tables 11 and 12.

Data from November to January is absent due to lack of systematic observations in the dark time of the year. Sailing distance through each type of ice is used as the main indicator of ice conditions. It is differentiated by ice age gradation (for winter and spring) and ice concentration (summer and autumn). To account for intra and inter-annual variability of ice navigation conditions, tables contain mean monthly data divided into easy, medium and hard years.

Table 11. Distance through different types of ice for Murmansk - Zhelanya Cape (Novaya Zemlya) trip for different winter-spring months, miles (Barents Sea, 1990)

Ice type	Navigation difficulty												
	Easy					Medium				Hard			
	Jan	Feb	Mar	Apr	May	Feb	Mar	Apr	May	Feb	Mar	Apr	May
No ice	680	680	560	510	570	420	370	380	410	250	210	220	315
New ice			-	-									
Young	20	20	130		30	170	120	170	180	30	50		10
1st year													
Thin			60	190	100	110	205	170	130	200	210	180	90
Medium										60	50	70	100
Thick										190	225	290	180
2nd year	-												

Table 12. Distance in different ice concentration areas for Murmansk - Zhelaniya Cape (Novaya Zemlya) trip in summer - autumn period, miles (Barents Sea, 1990)

Ice concent	Navigation		
	Easy	Medium	Hard

ration, balls	June	July	Aug	Sep	Oct	June	July	Aug	Sep	Oct	June	July	Aug	Sep	Oct
No ice	630	700	700	700	700	580	700	700	700	700	375	520	680	680	480
1-3			-	-										20	
4-6	70											80	20		
7-8						110					170	40			
9-10											150	60			240

Concentration of the winter ice is always assumed to be 9/10 or 10/10, which refers to the presence of small spots of pure water in fractures. In such conditions navigation capabilities are limited and require means of ice reconnaissance (satellites, radars, aircrafts, helicopters). During this period, the main limiting geometric characteristic is ice thickness or age.

In summer season (from the beginning of the ice destruction till the new ice formation) the defining characteristic of the ice is considered to be ice concentration. When ice is at different stages of destruction, thickness is no longer characterizing navigation possibilities through the ice cover due to loss of strength properties. Table 13 shows ice thickness depending on type of the ice (age).

Table 13. Average ice thickness for different types of ice for different months, cm (Barents Sea, 1990)

Type of the ice	Thickness range, cm	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May
Nilas	5-10	5	5	5	5	5	5	5	5	5
Young ice (grey)	10-15	12	12	12	12	12	12	12	12	12
Young ice (grey-white)	15-30	25	25	25	25	25	25	25	25	25
1st year ice										
Thin	30-70	30	30	40	40	50	50	60	60	60
Medium	70-120	70	70	70	70	70	85	100	110	120
Thick	120-180	120	120	130	135	135	150	160	180	185
2nd year	180-270	180	180	180	200	200	220	220	250	250

Ridging and hummocking (in winter) and ice destruction (in summer) are very important characteristics of the ice cover that significantly affect shipping. Ice is considerably hummocked in the Barents Sea due to highly cyclonic atmosphere and well-defined tidal movements of ice sheets. The highest values of hummocking are typically in the south-eastern part of the sea, the Franz Josef Land area and the North-East Svalbard. Here they make up to 3-4 balls. Most of the ice routes lie through areas with ice ridge concentration of 2-3 balls. Hummocking effects the movement of icebreakers and icebreaking transport vessels at values over 2 balls when the possibility of avoiding ridges is excluded.

Transport operations with winter fast ice in the Barents Sea are possible with medium conditions from February (in the area of Franz Josef Land), and from March (in the Pechora Sea), when the fast ice reaches thickness of 80 - 90 cm (required safety criteria for unloading operations) (Barents Sea, 1990).

Preliminary conclusion

If we compare described ice conditions along the Barents Sea navigation routes with the possibilities of modern icebreakers (atomic icebreaker of Arktika type, icebreaker of Ermak type, icebreaker of Captain Sorokin type) and icebreaking transport vessels and tankers (Dmitry Donskoy type, Norilsk Type, Mikhlail Ulyanov type) we can conclude that there should be no serious difficulties for such ice fleet to navigate in the Barents Sea for the needs of hydrocarbon transportation. More to say, state-of-the-art ice class LNG and Oil tankers are capable to sail through the ice with thickness of up to 2 m. Therefore, the chosen location for the offloading terminal sounds reasonable in terms of ability for winter season navigation, especially towards the west from the Novaya Zemlya. Thereafter, western part of the Northern Sea Route can be applicable for exporting the hydrocarbons to the European market even during the winter period.

6. Onshore gas terminal features.

Construction of the liquefied natural gas plant in the arctic region, especially in such remote area as Novaya Zemlya, is definitely a very sophisticated task both technologically and economically. However, low temperatures of the region actually simplify gas-cooling process making it more convenient.

The decision to commercialize a gas field by either LNG or direct pipeline is related to the distance to the market from the gas reservoir or processing facilities. A suggested rule of thumb states that LNG could be a viable option versus pipeline transport when the following characteristics are present:

1. The gas market is more than 2,000 km from the field.
2. The gas field contains at least 100 Bcm to 150 Bcm of recoverable gas
3. Gas production costs are less than $1/MMBtu, delivered to the liquefaction plant.
4. The gas contains minimal amount of impurities, such as CO_2 or sulfur.
5. A marine port where a liquefaction plant could be built is relatively close to the field.
6. The political situation in the country supports large-scale, long-term investments.
7. The market price in the importing country is sufficiently high to support the entire chain and provide a competitive return to the gas exporting company and host country.
8. A pipeline alternative would require crossing uninvolved third-party countries and the buyer is concerned about security of supply (Fedorova E., 2011).

Considered project meets most of the listed conditions for applying the LNG production technology. Economical evaluation and properties of the reservoir fluid will be the subject of further analyses.

In addition, Belushya Guba proved to have appropriate geotechnical conditions at the site, possibility of pipeline approach, availability of water for cooling and gas treatment and other necessary parameters to construct an LNG plant in its location.

An “LNG chain” illustrated in the Fig. 16 below contains four main components:

1. Exploration and Production;
2. Liquefaction;
3. Shipping;
4. Storage and Regasification.

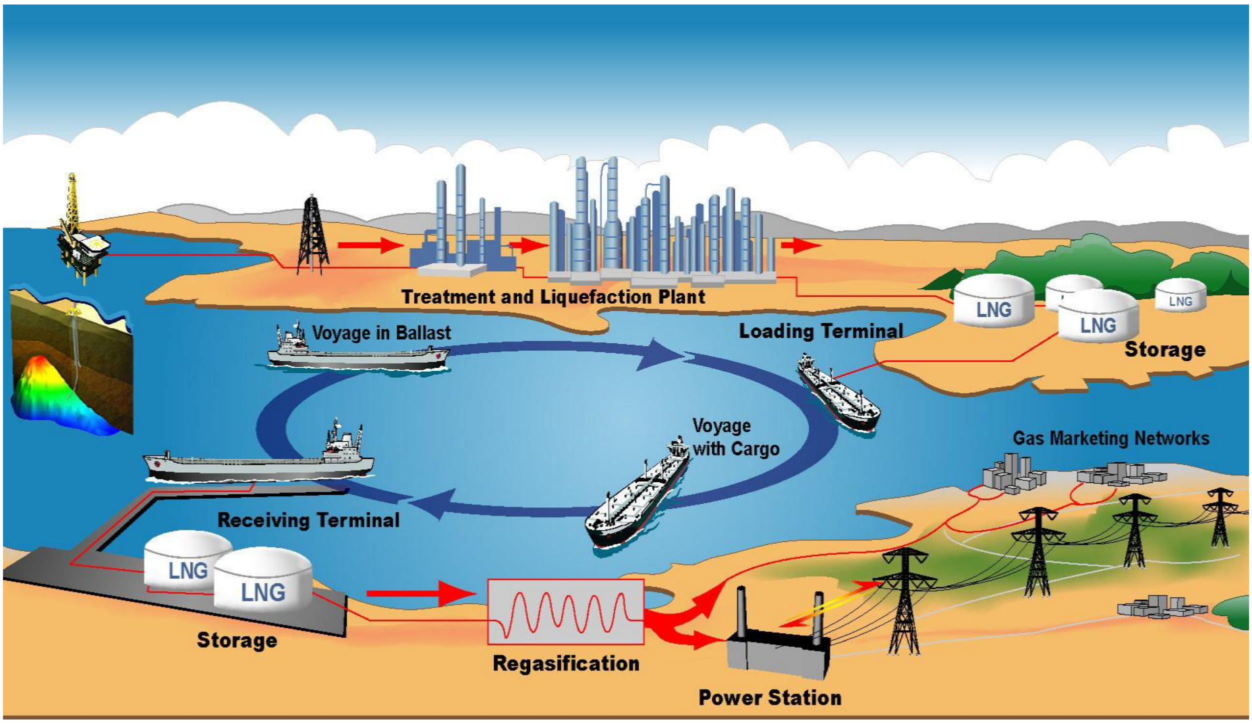

Fig. 16. LNG chain (Fedorova E., lecture course, 2016)

The minimum number of equipment items that would be required for such an LNG project determines the plant configuration. The list of main technological units includes LNG storage tanks, a jetty with loading equipment, relief systems, fire protection and storage tanks for imported refrigerants. Due to dry composition of the Shtokman field, and high methane content, gas from this field is very suitable for liquefying. However, if a multiphase fluid arrives form the field more complex treatment processes would be required before its liquefaction. Depending on feed gas composition, the base plant might be expanded by adding utilities, acid gas treating, fractionation, extensive feed gas treating, and other processes that could be required at various locations (Kotzot, H. et al., 2007). Corresponding scheme for maximum possible treatment units is illustrated in Fig. 17.

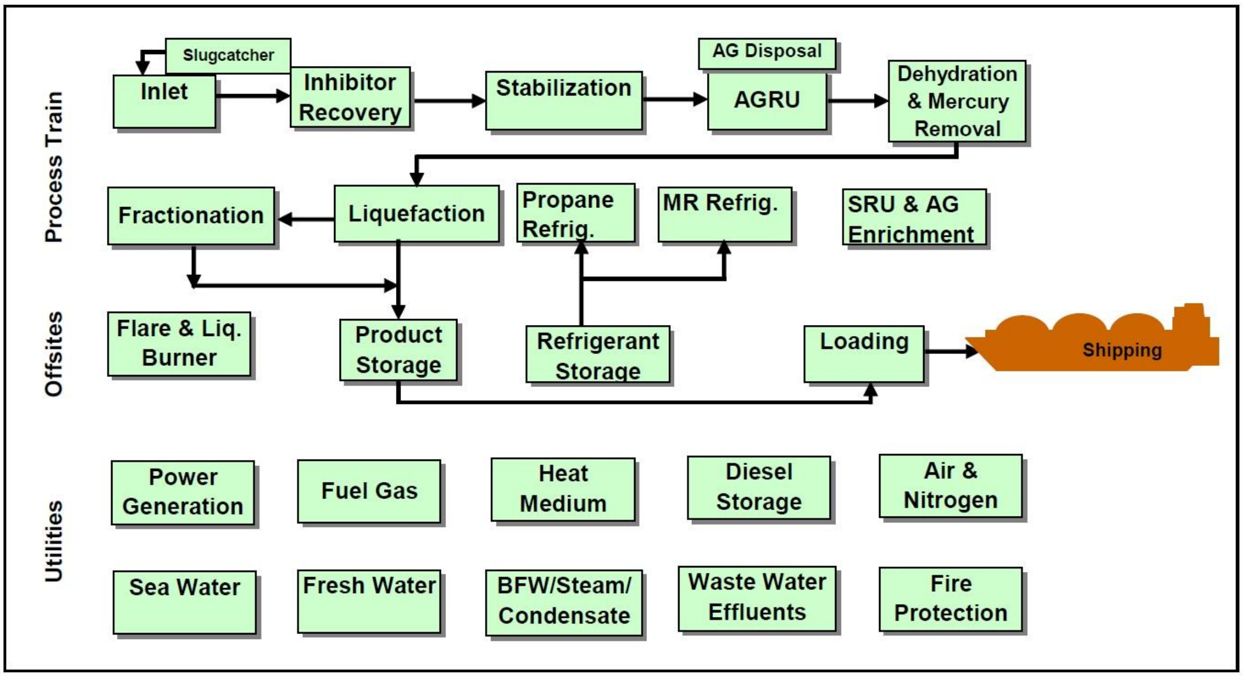

Fig. 17. Maximum units in LNG facility (Kotzot, H. et al., 2007)

Yamal LNG project with Sabetta Seaport can be taken into consideration as a reference for gas terminal and LNG plant in Novaya Zemlya.

The capacity of the plant has to meet the maximum production level of the considered fields. The maximum production of the Shtokman field is assumed as the reference for the capacity of the LNG plant. However, it is reasonable to execute the construction of the terminal in several stages. Following table provides the maximum annual gas production for 3 phases of the Shtokman field and its conversion into tons of liquefied natural gas. However, when liquefying methane, about 10 to 15 percent of the gas gets consumed during the process, mostly to run the plant's turbines, compressors and other machinery (oilprice.com). Therefore, the 4th column of the table accounts for this additional loss.

Table 14. Shtokman field production phases (www.gazprom.ru)

Phase #	Gas production, bcm	LNG equivalent, MTPA	LNG after the losses, MTPA
1	23,7	17,5	14,9
2	47,4	35,1	29,8
3	71,1	52,6	44,7

The world’s largest liquefaction train is capable to produce up to 7,8 MTPA (wikipedia.org). Therefore, for the 1st phase two trains with capacity of about 7,5 MTPA each are required. The same pattern follows for the phases 2 and 3. A significant issue for the Yamal LNG project was an existence of permafrost beneath the ground; therefore, to ensure its stability, the plant is supported by thousands of piles driven into the permafrost. In the current case it is not that relevant because according to the soil conditions on the Novaya Zemlya there is no permafrost accumulations near Belushya Guba.

Another important part of the LNG plant is the storage area.

LNG tanks are often a very critical element due to the large ground surface area they take up, their visual impact, often considered unacceptable by the local population, and finally, because they are a potential source of major technological risks (Fedorova E., 2011).

Following parameters determine the size of the storage tanks:

- Production rates of the supplying gas fields and processing facilities;

- The size and number of the LNG vessels: the corresponding storage volume must always be available;

- The maximum duration of port unavailability or vessel delays, mainly due to adverse weather conditions: this determines the back up stock required;

- The area available for construction, considering the possibility for future expansion of the storage volume for new projects;

- The flexibility of the flow rate through the plant: a parameter that may vary considerably according to changes in the supplied market and in technological regimes of the production site.

LNG tanks are supposed to withstand low temperatures of liquid and atmosphere. Each tank should be composed of a 9% nickel stainless steel interior container and a pre-stressed concrete external container (abarrelfull.wikidot.com).

The infrastructure for an LNG loading terminal for Arctic conditions includes a loading rack with two berths, equipped with ice protection facilities.

LNG tankers.

Maritime transport is an important link of the LNG chain.

Ships that are purposely designed to maintain extremely cold chain under optimal safety conditions transfer natural gas from liquefaction plants to regasification terminals.

Modern LNG carriers are typically 300-345 m long, 40-50 m wide and have a draught of 11-12 m. Therefore Belushya Bay has suitable water depths for loading such vessels. They sail at an average speed of about 19.5 knots, their above water height is 40 m.

Even a fully loaded LNG carrier sits high in the water due to the low density of the LNG it carries. Its relatively light cargo allows it to sail at a faster cruising speed — 19 to 20 knots — than the 13 to 14 knots reached by a conventional oil tanker.

The internal hull on these very special ships is separated from the external hull by water ballast tanks. When filled, the tanks make the LNG carrier heavier and provide the desired stability when it is sailing empty after offloading its cargo at a regasification terminal.

LNG Carriers are categorized according to their cargo containment designs or tank designs.

Tanks are usually classified into one of the following categories: self-supported tanks and membrane tanks.

<u>Self-supported tanks</u> have a single wall made of aluminium and surrounded by an outside foam insulation.

Their design prevents any damages of inner tanks in case of an outside hull crack.

Two proven systems based on this principle are already on the market:

- the Norwegian Moss Rosenberg system with spherical tanks.
- the SPB prismatic tank system developed by Japanese company IHI.

And

- Prismatic Aluminium Double-barrier Tanks (ADBT) is a new system, which has been developed and offered for the market recently.

Membrane tanks are divided according to membrane systems, which include:

- Gas Transport 96,
- Technigas Mark III and
- CS-1 (Fedorova E., 2011).

A “standard” class for LNG cargo capacity includes 125,000 - 170,000 m^3 of storage volume. However, there are carriers with capacities over 250,000 m^3.

In order to be able to operate in the Arctic LNG carriers are supposed to have a certain ice class.

The Russian Maritime Register of Shipping (RMRS) has a set of ice class rules for vessels navigating in freezing non-Arctic and Arctic seas. Currently the ice classes are divided to non-Arctic, Arctic and icebreaker classes. Brief description of these categories is presented in Table 15.

Table 15. Ice class ship classification (http://www.rs-class.org/)

Ice1 to Ice3	non-Arctic ships
Arc4 to Arc9	Arctic ships
Icebreaker6 to Icebreaker9	Icebreakers

Therefore, to identify an appropriate type of vessel following parameters should be considered: time of the year, ice conditions, operating tactics, and icebreaker escort possibility (Wikipedia.org; Russian Maritime Register of Shipping, 2017).

Taking into consideration existing classification for ice class vessels, technologies and practices, environmental conditions in the Belushya Bay, ice features and possible navigation obstacles, Arc7 ice class LNG carrier is proposed with a capacity of 170 000 cubic meters.

Following Table 16 provides characteristics of the suggested vessel.

Table 16. Arc7 Arctic LNG carrier parameters (sovcomflot.ru, novatek.ru)

Length:	299 metres
Width:	50 metres
Freshwater draft:	12 metres
Capacity and type of propulsion system:	3x15 megawatts, diesel-electric ship with three rudder propellers
Volume capacity	172,600 m3 of LNG
Deadweight	85000 tons
Open water speed	19,5 knots
Speed with ice thickness up to 1,5 m	5,5 knots
Ice-breaking capability:	Up to 2.1m in floe ice when navigating stern-first.

Such vessels have high passability and maneuverability, using the principle of Double Acting Tanker, (DAT), which allows to overcome hummocks and thick ice areas. The required number of vessels is evaluated in further analyses depending on the distance to the chosen markets. To identify the required number of vessels two markets are considered: European and Asian. For calculations it assumed that half of the year LNG carriers go to European market (during the winter navigation season) and half of the year to Asian (Japan). It is estimated that 13 LNG carriers are required for the transportation during the maximum liquefaction capacity of the LNG plant for the 1st phase of Shtokman field development (see Appendix 1).

7. Evaluation of iceberg hazards

7.1 Icebergs' location and distribution

One of the main challenges while attempting to operate in the Kara and Barents Seas is the icebergs existence. These large pieces of fresh-water glacial ice can damage offshore platforms, floating structures, subsea production equipment and pipelines. All these items are critical for developing most fields in the Russian Arctic shelf. A correct estimation of the iceberg occurrence is the key factor for sustainable and safe development of hydrocarbon fields in the Arctic since an underestimation of the threat will increase the risk of damage or even destruction during operation, while overestimation will result in higher capital expenditure.

Russian scientists have performed systematic iceberg observations within the periods 1949–1992 and 2002–2005. Based on these observations, Statoil has estimated that about 880 icebergs have been within the Shtokman region within the last 100 years (Eik, K., Gudmestad, O. T., 2010). In general, there is more research obtained and data available on the Barents Sea than for the Kara Sea. Therefore, evaluation of the Kara Sea iceberg hazards is currently more critical. However, there is always a significant uncertainty in this estimate due to limitations in the surveillance capabilities and effects of future climate changes.

In the current chapter possible iceberg locations are analyzed as well as the mitigation measures to prevent the impact from the ice load.

A lot of attention has recently been paid to comprehensive studies of icebergs using oceanographic expeditions, ice reconnaissance flights, satellite observations.

It has been already mentioned in Chapter 2 that there are several regions of iceberg formation in the considered area. Icebergs are formed by calving from the Arctic glaciers and there are certain regions where these processes take place. The total annual iceberg outflux from the Euro-Asian archipelagos is estimated as 6.3 km^3, contributions from different islands and their locations in the Barents and Kara Seas are shown in Table 17 and Fig. 18. Being aware of volumes of iceberg outflux would enable one to assess both the number of icebergs calved in a region and possible trends for the future.

Table 17. Glaciation of archipelagos in the Barents and Kara seas (Abramov, D. V., 1996)

Region	Island area, km^2	Area of glaciers		Vol. of ice km^3	Length of glacial shores		Annual iceberg outflux, km^3
		km^2	%		km	%	
Svalbard	60874	35106	57,7	10360	1028	19,9	1,65
Franz Josef Land	1634	13735	85,1	2250	2650	51,2	2,26
Novaya Zemlya	82600	24416	29,6	6800	666	12,9	2,00
Severnaya Zemlya	36766	18325	49,8	5500	501	9,7	0,35
Total	181874	91582		24910	4845		6,26

The maximum depth of the seabed with gouging was found to be 60 m in the central part of the Kara Sea in the year 2013 (see Fig. 18).

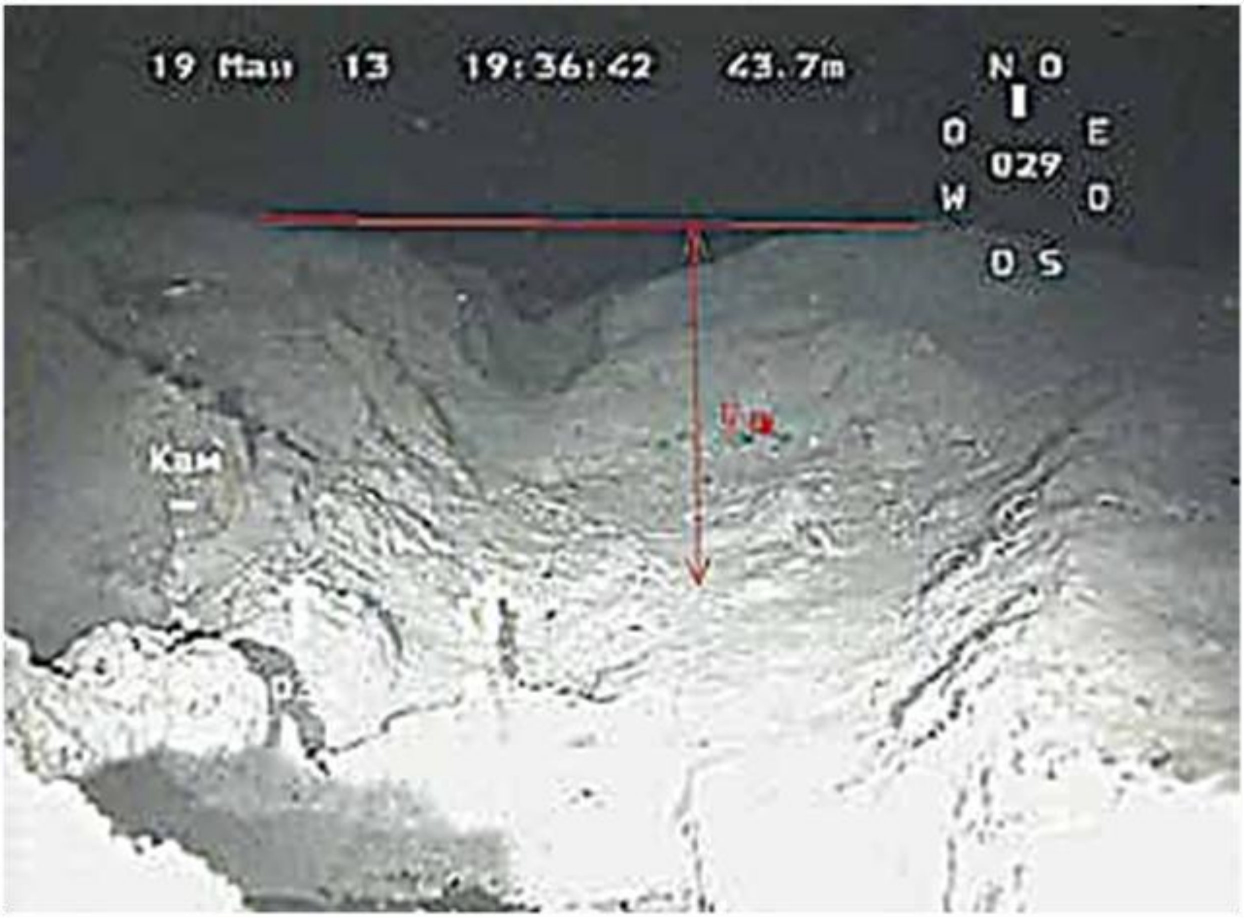

Fig. 18. Seabed gouging by icebergs in the Kara Sea (Shishkin et al., 2014)

It should be noted that assessments made by different authors might vary considerably, which points out the complexity of the task and lack of field measurements. In addition, the current situation might be slightly different from the provided data due to climate change during the past decades. However, it allows us to generally oversee the sources and figures of icebergs' calving to identify the scale of hazard and compare different origins.

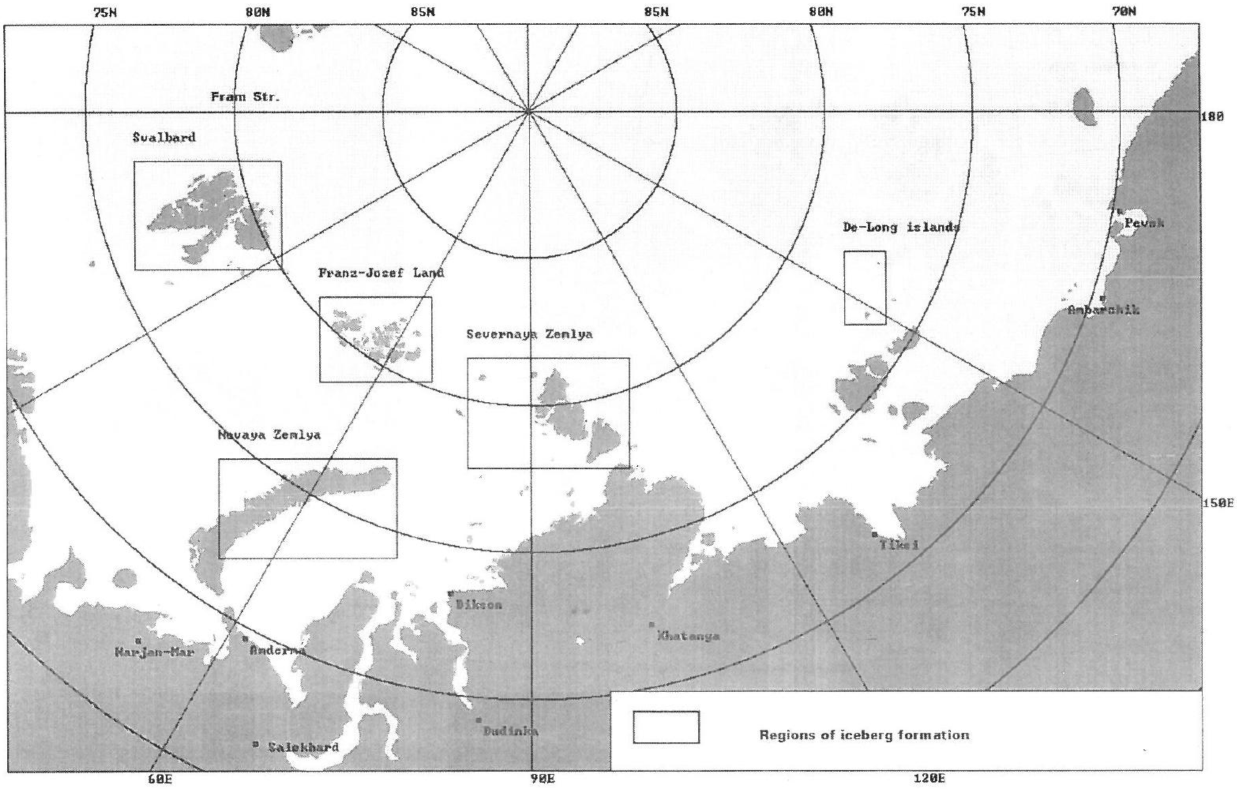

Fig. 19. Regions of iceberg formation (Abramov, D. V., 1996)

From the chart shown above (Fig. 19) it is clear that most of the Novaya Zemlya archipelago, particularly its northern part, can present the origin for iceberg formation.

The following Fig. 20 illustrates a more precise picture of the Novaya Zemlya archipelago with specific iceberg generating glaciers.

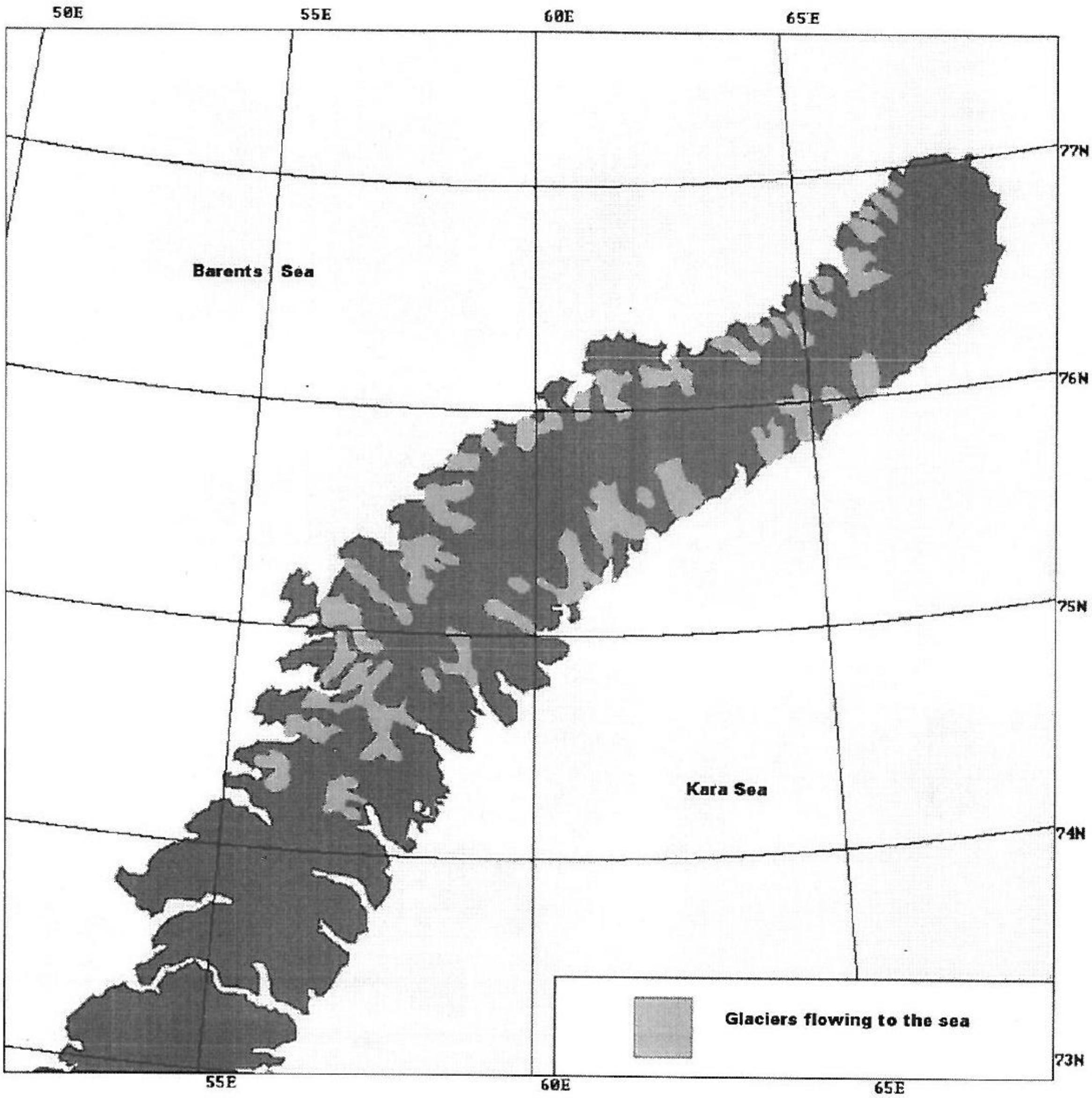

Fig. 20. Glaciers flowing to the sea from Novaya Zemlya (Abramov, D. V., 1996).

The current map is extremely important when considering the locations for pipeline shore crossing to be able to avoid places of glacier existence. Thus, the shore crossing point should be south of the 74° N latitude.

Fig. 3 and 4 also emphasize that icebergs could mostly be formed on the northern part of the archipelago where most of the glaciers reach the seas. Thereafter, it supports the decision to locate the infrastructure of the settlement, the terminal and equipment on the southern part of the Novaya Zemlya in Belushya Guba (see Fig. 21).

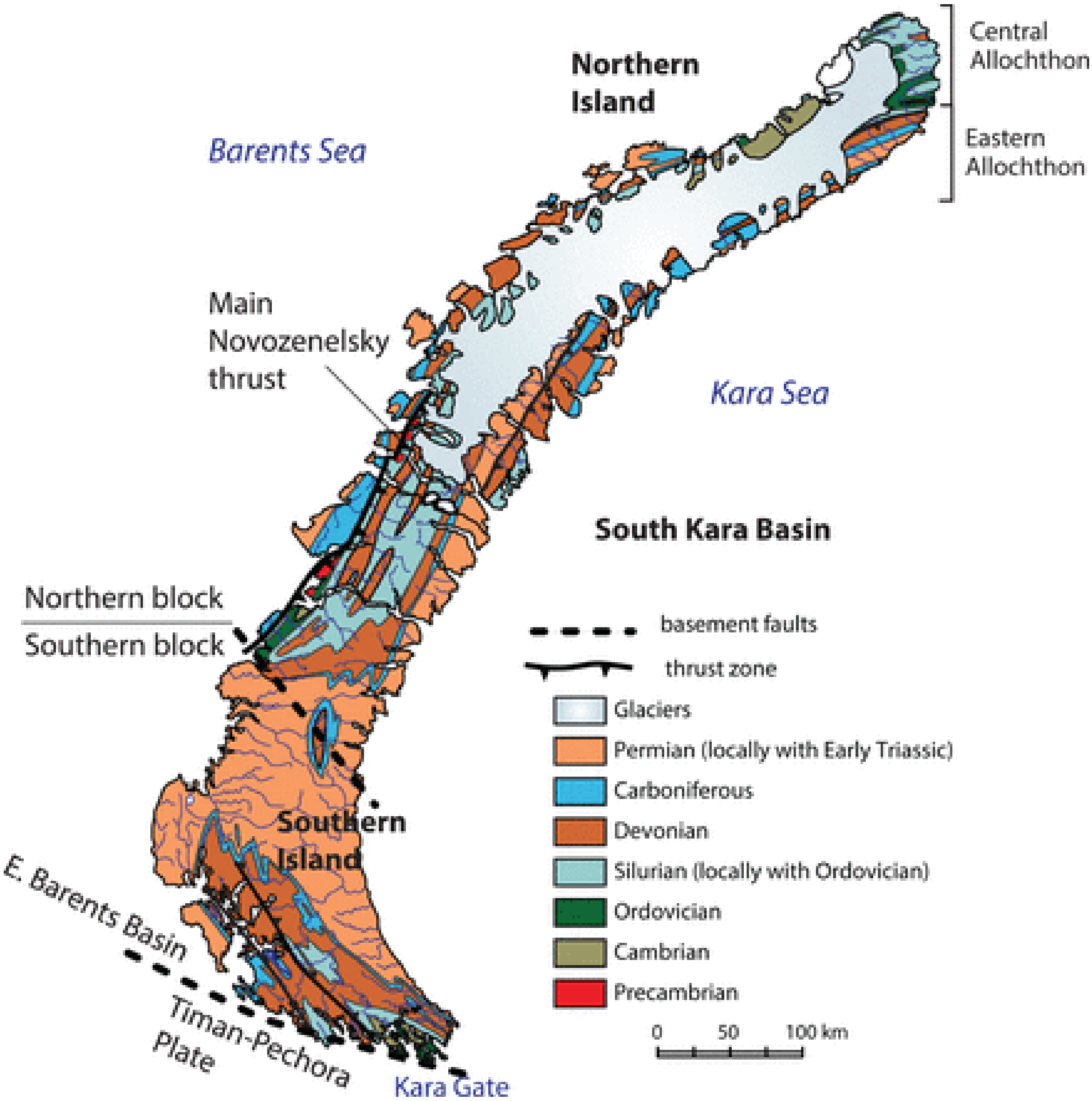

Fig. 21. Geological map of Novaya Zemlya (Toro J. et al., 2016)

Another significant task is to analyze the distribution pattern of the icebergs in the considered region to select the pipeline route and place infrastructure within the least possible iceberg occurrence area.

Therefore, monthly and annual distributions of icebergs in the Barents and Kara Seas were analyzed.

Based on the multi-year series of observation data, the results were specified for each 100x100 km cell and plotted on charts by the Abramov, D. V. (1996) and other editors of Atlas of Arctic icebergs. According to the research the highest number of icebergs occurred in the southern part of the Kara Sea along the Yuzhny Island of Novaya Zemlya in March and August. However, in March the area of possible iceberg existence is larger along the coast, therefore, this month is considered as the extreme case. The charts below (Fig. 22 and 23) provide the maximum numbers of icebergs in March, as well as the probability of their occurrence in the given area.

The charts of occurrence probabilities of icebergs were plotted using the relationship

$$P = 100 \times \frac{m}{n},$$

where P- probability of iceberg occurrence, %;

m – number of years when the iceberg occurred in the given cell in the given period of time;

n – total number of years of observations for the given cell.

Fig. 22 illustrates that icebergs can spread as low as to Kara Strait and Vuygach Island along the Novaya Zemlya. That is why one cannot completely avoid the areas of possible iceberg occurrence while designing the pipeline route from the Kara Sea hydrocarbon fields to the archipelago. However, areas of the least probability of iceberg existence should be identified as well as additional ice management measures should be considered.

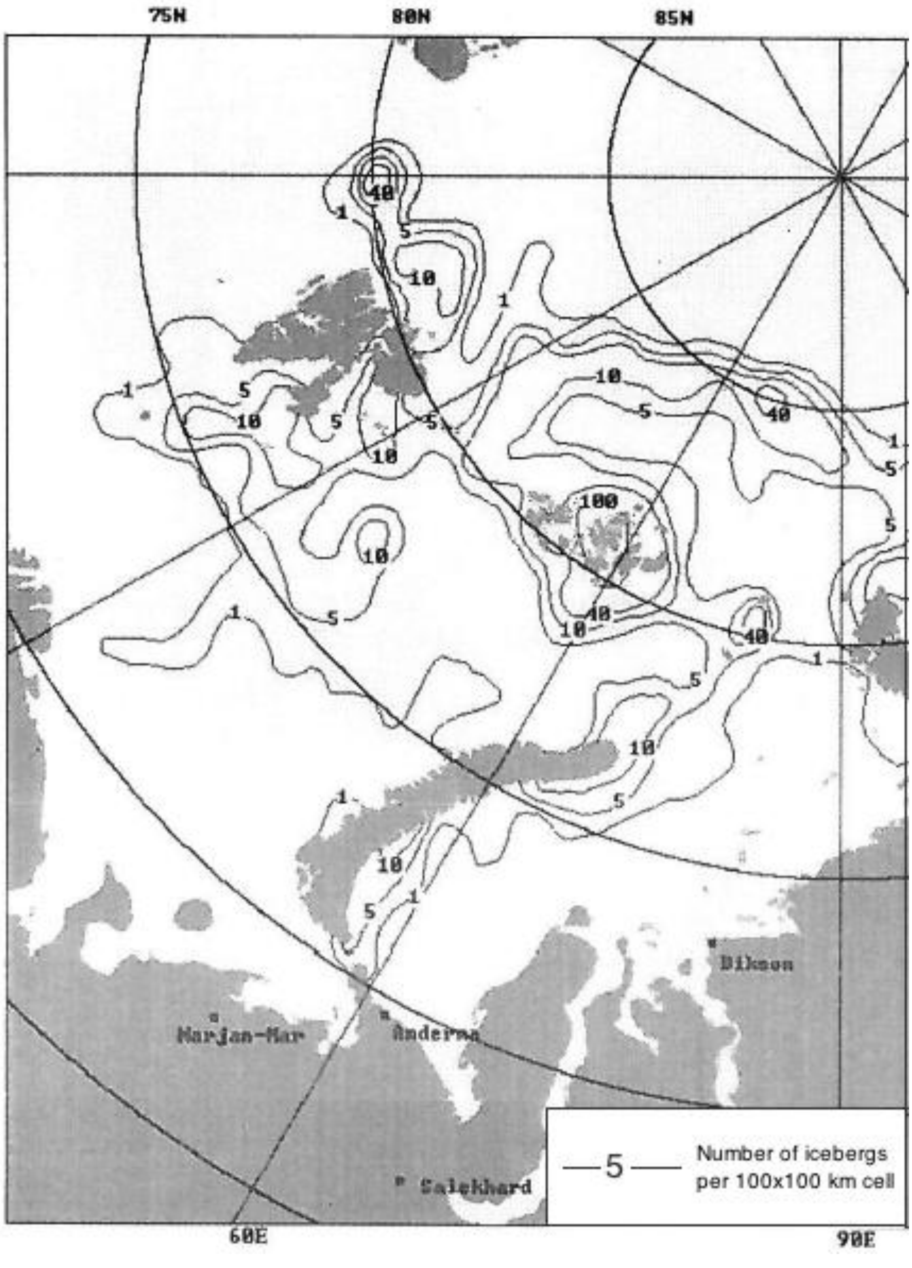

Fig. 22. Monthly Maximum number of icebergs in March (Abramov, D.V., 1996)

According to Fig.s 22 and 23 it is quite safe to reach the shore towards the Belushya Guba from the western side of the archipelago as there is a very low probability of iceberg existence. For the eastern side we can identify the location where low probability curves are closest to the archipelago in order to reach the shore somewhere in that area.

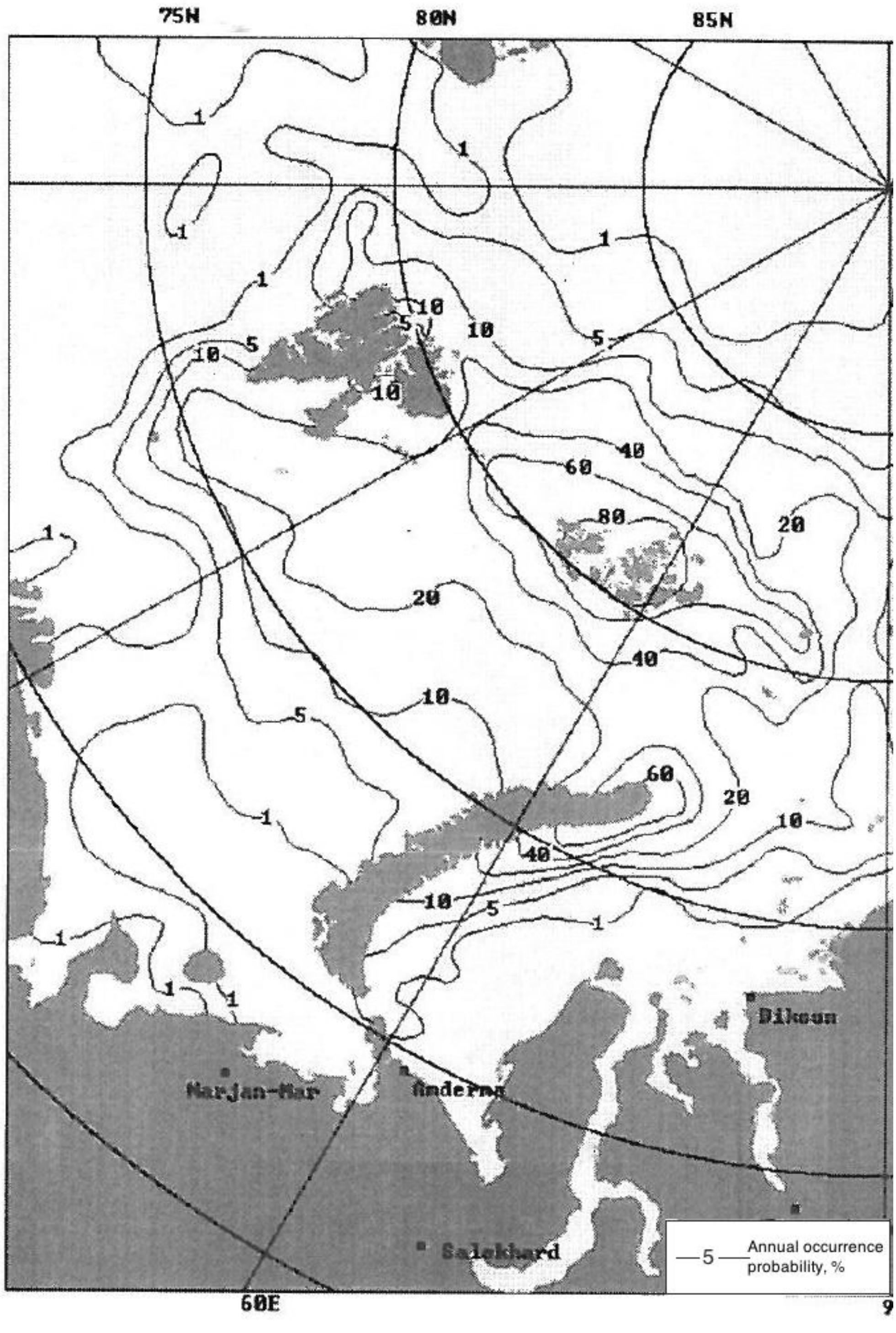

Fig. 23. Annual probability of occurrence of icebergs (Abramov, D.V., 1996)

It is also necessary to analyze the bathymetry of the regions near the shore and compare the draught of the icebergs located in the Kara and Barents seas with water depths in the chosen area to come up with the most appropriate type of landfall design and protection for the pipeline as well as ice management methods. It is particularly relevant for the Kara Sea.

Parameters of the Icebergs located in the Kara and Barents Seas were given in Table 7 (Chapter 2). According to the provided data, maximum observed iceberg draught in the area was 137 m, however, most of the icebergs were detected using the surveillance tools and the icebergs' underwater dimensions could only be assumed.

Next Fig. 24 and 25 illustrate possible approaching routes for the pipelines from the Kara and Barents seas, respectevely. The routes are suggested taking into account previous analyzes of icebergs occurrence, bathymetry data, locations of glaciers and distance to Belushya Guba.

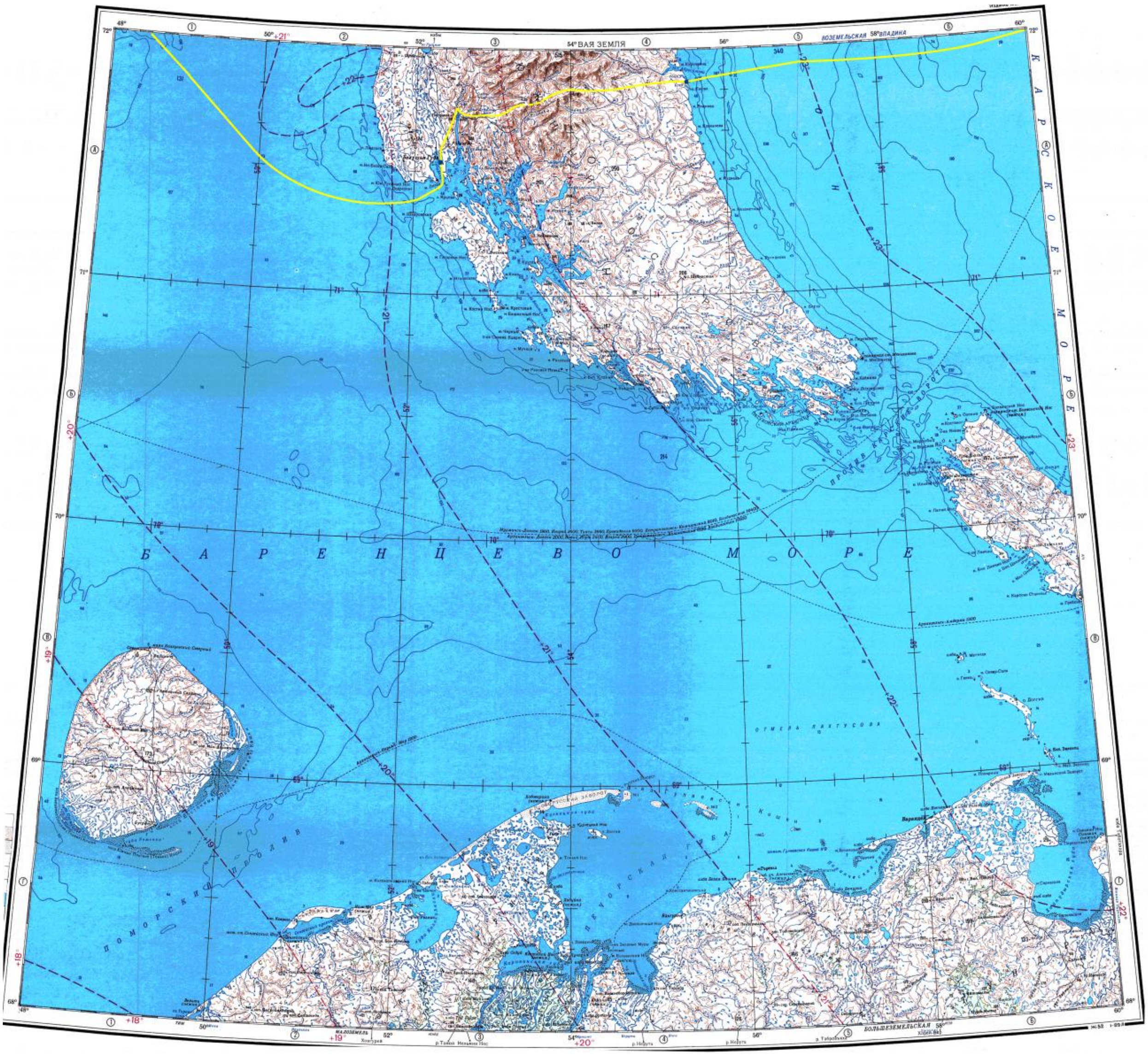

Fig. 24. Suggested pipeline route near the shore lines (10 km in 1cm) (loadmap.net)

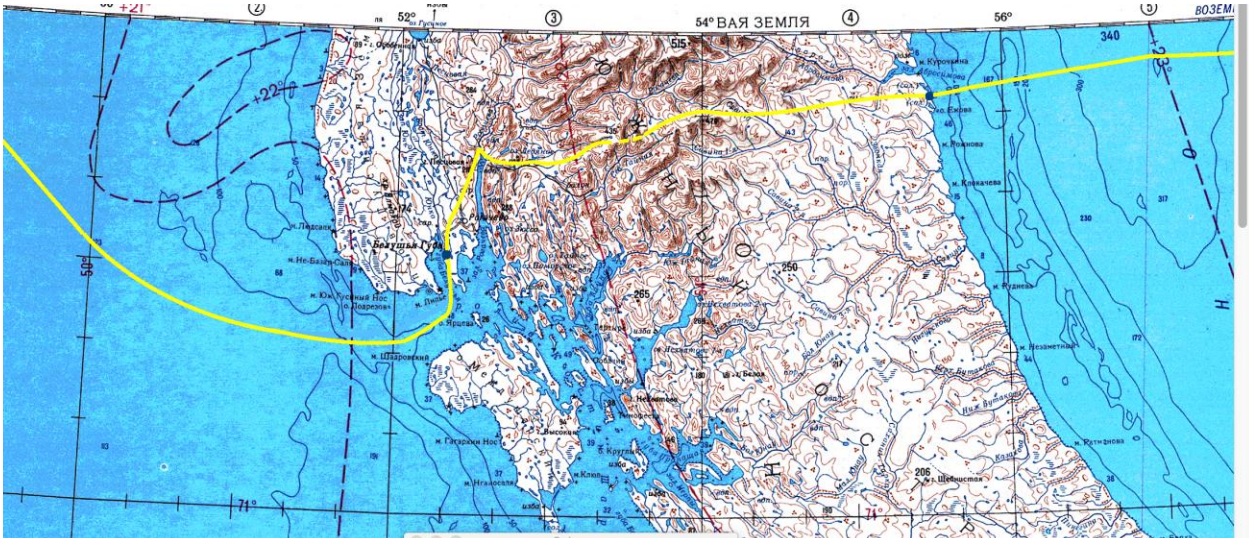

Fig. 25. Suggested pipeline routes near the shore lines (http://loadmap.net)

It is considered reasonable to place the pipeline where 100 m water depth comes closest to the shore to have the least zone and, therefore, the least probability of iceberg reaching the pipeline at the sea bottom. The map shows that the distance is about 5 km before the depth reaches 100 m water depth. In addition, it might be possible to design a tunnel under that 5 km area to secure the pipeline. Further pipeline trajectory towards Leningradskoye field follows a deep trench to ensure the route with no icebergs' grounding.

7.2 Ice management

Ice and Iceberg management (IM) has two primary aims: to ensure safety of people, installations and operations (with respect to ice hazards) and to maximize operational efficiency by minimizing downtime or delays due to ice (Edmond C., et al., 2011).

IM activities iclude:

- ice and iceberg surveillance;
- potential ice threat assessment and alert level determination, tracking and forecasting;
- physical management of the threat;

In ice management it is critical to ensure that lessons learned from experience are effectively implemented.

Surveillance includes the following tasks: detection and characterization of sea ice and icebergs, tracking of identified threats and forecasting of ice conditions. Detection of sea ice and icebergs combines remote sensing (satellites mainly), aerial survey (helicopters or airplanes) and ship observations using ice marine radars and visual observations. Satellite images provide regular data on ice boundaries and general conditions. State-of-the-art satellite radars have low sensitivity to adverse weather conditions and each potential threat is always double checked by either ship observations or aerial reconnaissance.

The Threat and Alert task concerns the assessment of hazard potential consequences with and without physical management, defining the necessary level of alert and informing relevant parties on the alert. The system assists the management personnel in taking the right decision at the right time based on pre-established procedures.

The concept of ice alert colors is a common solution in such cases. An ice Alert Color is determined by the type of ice hazard as well as the associated hazard arrival period.

- Green represents normal operations, when no specific action is required;
- Yellow represents an early warning. An ice threat has been identified within the "general surveillance zone";
- Orange indicates that an ice threat has entered the physical management zone; ice breaking and iceberg towing become a priority. The production site is prepared to initiate Planned Disconnection.
- Red indicates a requirement to stop field production and starting depressurization (trigger Planned Disconnection procedure) in order to prepare for disconnection; forecasted ice and weather conditions are such that ice hazard loads may exceed operational limits in the future; final floating platform (FP) release may be delayed until 15 minutes before impact;
- Black indicates a need for final disconnection of the FP; ice hazard is about to enter the exclusion zone. As an additional safety barrier, some installations have capabilities of performing an emergency disconnect (Gudmestad et al., 2009). This is of importance in scenarios where icebergs are not detected by the surveillance system but still are visible from the installation during the very last minutes before an impact. Technically, this implies that the installation release all moorings and risers immediately and starts to drift with winds and waves. It is assumed that this can be done within less than 15 min. Such disconnections may lead to significant damages to equipment and it may take long time before a reconnection. (Edmond C., et al., 2011, Eik, K., Gudmestad, O. T., 2010);

The Ice Alert Color (IAC) valid at any time is displayed in all facilities and vessels in the field. Any change to the IAC is reported to onshore operations and logistics centers.

Physical management is the prevention of iceberg impacts and the reduction of sea ice loads by performing ice breaking (Edmond C., et al., 2011).

Common physical sea ice management operations include breaking up ice floes to target level, assisting the FP during ice vaning, ice drift reversals, disconnection and reconnection, and providing aid during emergency, evacuation and rescue operations in ice conditions. Typical physical ice management scheme, illustrated in Fig.26., is performed by two icebreakers, one being more powerful than the other:

- The most powerful icebreaker breaks the incoming ice in circles or lengthy loops, with longitudinal axis in direction of ice drift.
- The second icebreaker breaks the smaller floes further or clears ice using the wake of azimuth thrusters.

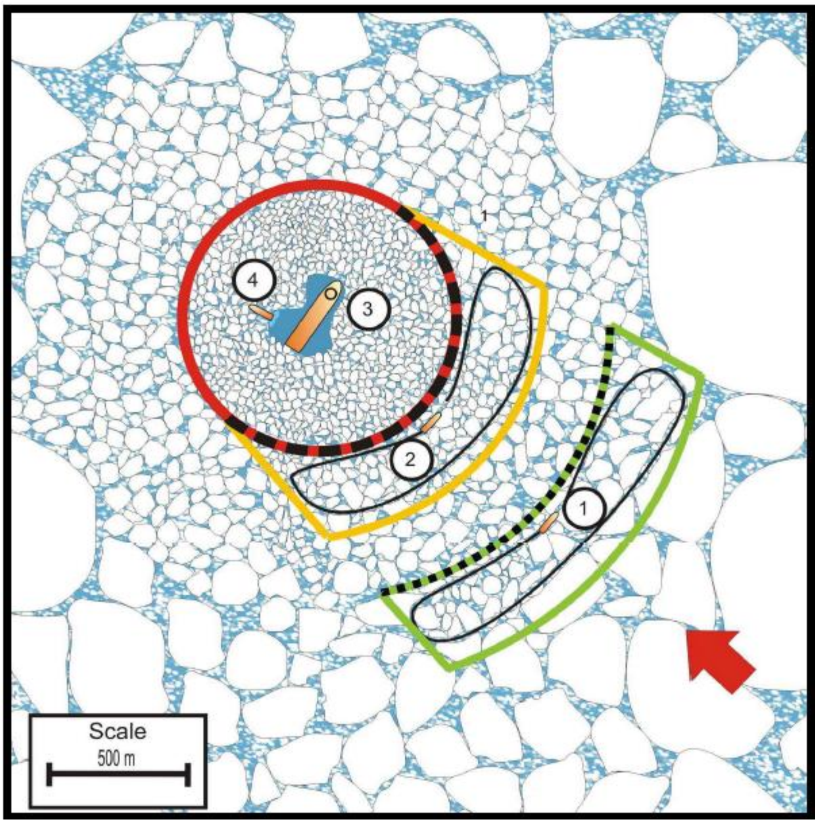

Fig. 26. Example of physical ice management using two vessels (Edmond C., et al., 2011)

Iceberg physical management involves deflection of icebergs, which is obtained by single or dual towing with lines or nets, implementation of water jets, propeller wash, deflection by use of water cannon, etc. Method selection depends on a number of factors such as iceberg size, shape, available time and available vessels. However, the single vessel tow is usually the preferred method in most of the tows while the other methods are used if the first attempt fails (Eik, K., Gudmestad, O. T., 2010). Examples of icebergs towing or pushing using single vessel are given in Fig. 27. Such techniques have been extensively used in open seas, particularly in Newfoundland, Canada. However, additional techniques should be developed for icebergs entrained in sea ice for Russian arctic regions.

Therefore, ice expeditions are frequently performed in Russia in the Northern Barents Sea and in the Kara Sea under the supervision of the Arctic and Antarctic Research Institute (AARI). Rosneft Company has also conducted a successful iceberg towing expedition in the Kara Sea in 2016 (www.rosneft.ru). With the help of such expeditions the iceberg database is increased as well as new techniques and ice management methods are tested in the actual physical environment.

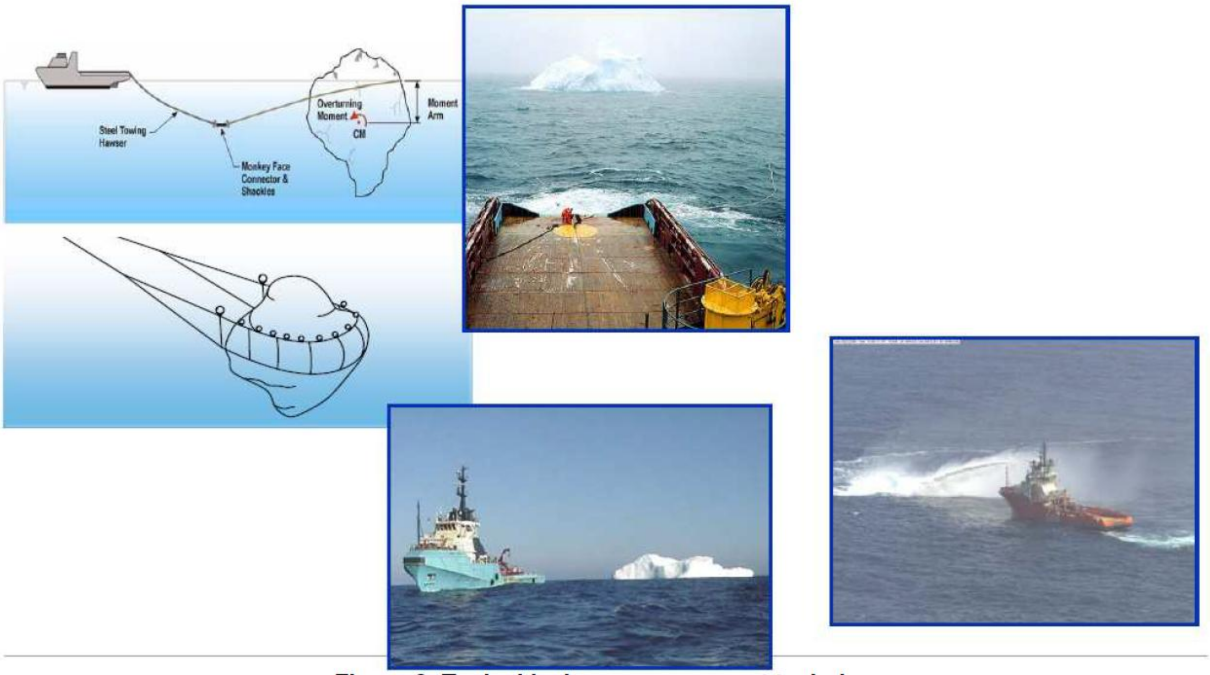

Fig. 27. Typical iceberg management techniques (left side towing of iceberg using tow line or net, right side pushing of iceberg using water jet) (Edmond C., et al., 2011)

It is important to define the objectives of ice management for each stage of the development (installation, drilling, operation).

The installation stage covers the transportation and placing subsea production systems and umbilicals, flowlines and risers, offshore installation, trunk pipelines laying, pre-commissioning and commissioning activities. The purpose of IM during this stage is to warn of hazardous sea ice conditions and icebergs in the area. During the installation phase, IM allows to detect and forecast ice and large icebergs. The ice detection is very important at this stage due to possible delays in the beginning of installation activities due to the ice presence and subsequent losses of money for the project. Ice detection is performed using remote sensing and aerial survey techniques.

The primary objectives of IM for drilling stage are to:

– Ensure drilling rig safety from hazards related to icebergs (including iceberg physical management);
– Warn drilling rig personnel of hazardous sea ice arrival (no sea ice physical management is foreseen);
– Ensure safety of marine operations in ice and icebergs infested waters.

Production stage is the longest phase of the project development, therefore, the possibility of iceberg occurrence increases with the longer time. To prevent any destructions of the equipment and ensure environmental safety a lot of efforts should be put into precise ice management activities.

First, if production infrastructure includes floating platforms the following barriers should be considered:

- Hull design should withstand sea ice loads and iceberg loads;
- Prevent interaction between mooring lines and icebergs;
- Disconnection capability of the platform, flowlines and umbilicals.

For the subsea equipment in an iceberg environment the adequate protection is to lower the wellheads and manifolds into the seabed using different protective methods.

Pipelines and flowlines in the shallow areas where there is a possibility of iceberg occurrence should also be buried into the seabed or put into the tunnels. It is also critical to be able to stop the production and empty the pipelines to prevent hydrocarbon spill in case when there is no other alternative.

In addition, to improve operability and reduce the number of possible production disruptions, physical sea ice management should be carried using support vessels during the whole production stage.

The primary objectives of IM during this stage are to:

- Ensure infrastructure safety from sea ice and iceberg hazards by proper surveillance;
- Reduce production downtime due to sea ice and icebergs by performing physical management
- Ensure safety and efficiency of marine operations in ice conditions (route planning, iceberg avoidance, assistance for load transfers, etc.)
- Assist during emergency, disconnection/re –connection, evacuation and rescue operations in ice conditions.

One of the main most important points when planning the Ice Management for the project is to identify the IM Zones.

For Shtokman project, the following ice management zones around the production site were identified (Edmond C., et al., 2011):

- The general surveillance zone (GSZ), where satellite images and aerial monitoring are used to identify potential ice threats;
- The Threat Assessment Zone (TAZ), where a scouting icebreaker will confirm ice threats to the infrastructure and associated operations, breaking those threats that can be broken, assess the extent to which the identified ice threats can be otherwise managed or towed;
- The Ice Drift Corridor is defined as the area within which ice threats have a significant probability of reaching the Emergency Disconnection Zone (EDZ) (or the stop of production zone in case of the pipeline);
- The Physical Management Zone is designed to prevent ice threats from crossing the Planned Disconnection Limit (PDL) situated about 6 hours from the infrastructure;
- The EDC is designed to defend the Emergency Disconnection Limit (EDL) situated about 15 minutes from structures.

Sizes of ice management zones and therefore periods for actions might vary for each project due to various drift speeds of icebergs. Fig. 28 below illustrates the IM zones for protecting the floating structure.

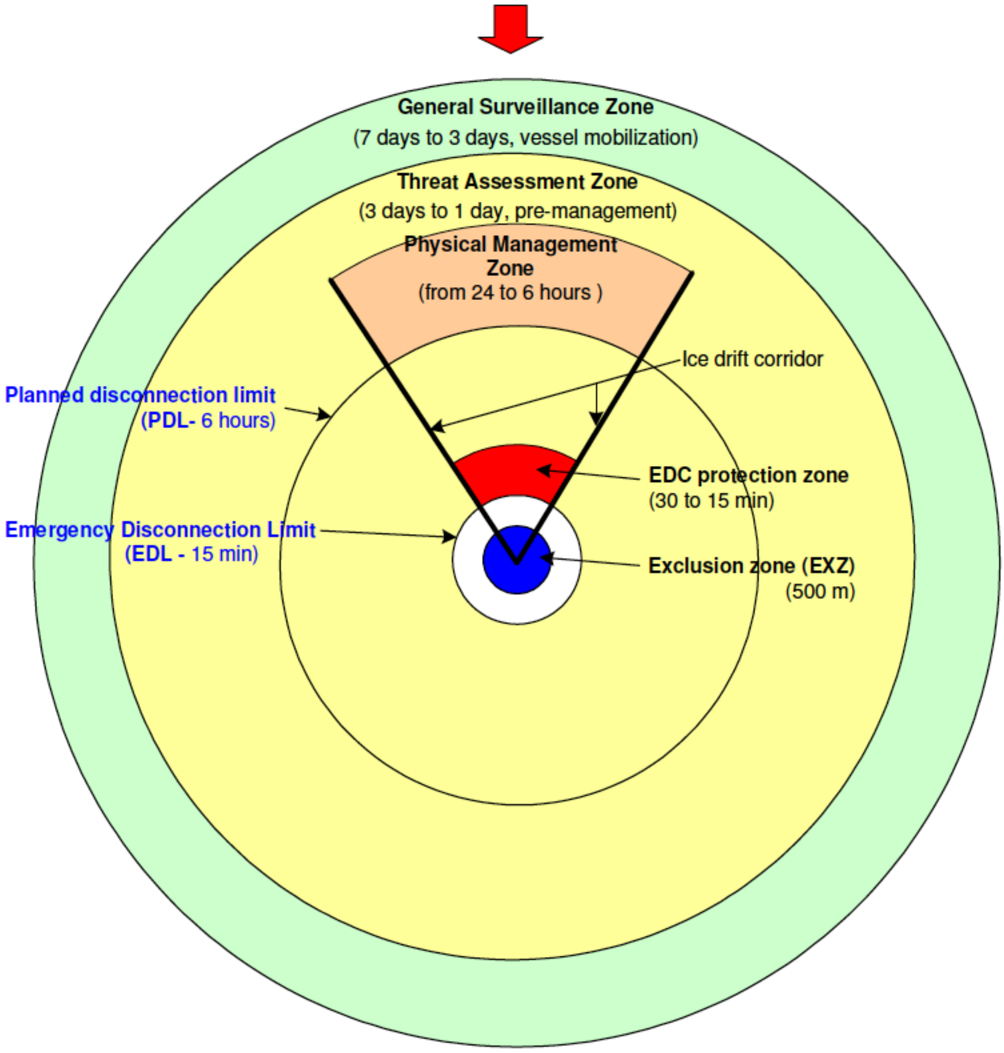

Fig. 28. Surveillance and Management zones (Edmond C., et al., 2011)

Event tree application

There are various techniques to prevent and forecast different scenarios for unwanted events. The accident progression is best analyzed by an inductive method and the most commonly used method is the event tree analysis. An event tree is a logic tree diagram that starts from a basic initiating event and provides a systematic coverage of the sequence of event propagation to its potential outcomes or consequences.

Commonly, a number of safety functions, or barriers, are provided to stop or mitigate the consequences of potential accidental events. The safety functions may generally comprise technical equipment, human interventions, emergency procedures etc. The consequences of the accidental event are determined by how the accident progression is affected by subsequent failure or operation of the safety functions, by human errors made in responding to the accidental event, and by various factors such as weather conditions and time of the day (Eik, K., Gudmestad, O. T., 2010).

Each event in the tree will be conditional on the occurrence of the previous events in the chain. The outcomes of each event are assumed to be binary (true or false) but may also include multiple outcomes.

In the current study it is proposed to model the operation of an offshore pipeline installation as such a system and the occurrence of icebergs as accidental events. The event tree analysis can be carried out in six steps (Eik, K., Gudmestad, O. T., 2010):

1. Identification of initiating event

The initiating event was chosen as an event where an iceberg is entering the ice monitoring zone. It was discussed in the previous section that the size of such a zone depends on the quality and range of devices used for iceberg detection as well as the expected and observed drifting speeds of icebergs. One of the most commonly used instruments for this case is the marine radar. In the previous studies it was found out that average distance between radar and iceberg during the first detection might be about 28 km while maximum distance goes up to 87 km (Eik, K., Gudmestad, O. T., 2010). The initiating event may, therefore, be stated, for example, as "An iceberg is observed 40 km or closer to the installation".

2. Identification of the safety functions that are designed to deal with the initiating event

In the event tree approach the ice management system may serve as a safety function.

The first step in the ice management system will be to locate the icebergs. The probability of detection (POD) will be a function of the quality of the detection system and the time the icebergs spend within the ice monitoring zone.

The next step in the ice management system will be to deflect the threatening icebergs from colliding with the protected objects. Typical methods for iceberg deflection were described above.

If the physical iceberg management fails, some installations, rigs or pipe laying vessels may have the possibility to stop the operations, disconnect and escape the site. For a disconnectable floating concept, guarantee for successful disconnection can never be given. The ability to disconnect is therefore considered as a last safety function.

3. Construction of the event tree

The event tree is constructed with binary outcomes. The statements express that the safety functions fail. At each branch there is a certain probability for two possible outcomes. The sum of the probabilities at one branch shall always be equal to one. An illustration of an event tree for an iceberg-structure collision is provided in Fig. 10.

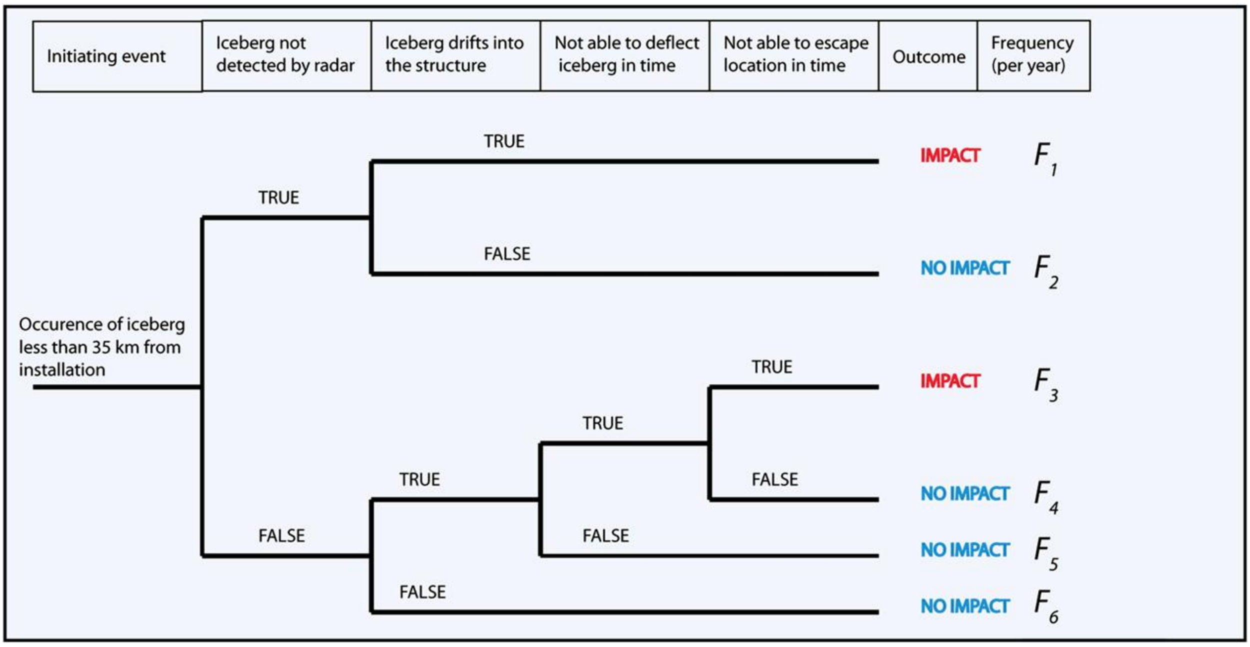

Fig. 29. Illustration of an event tree for iceberg-structure collision (Eik, K., Gudmestad, O. T., 2010)

Since this illustration is intended only to demonstrate the event tree philosophy, failure probabilities are not included. For offshore installations, one typical requirement is that the installation shall remain its structural integrity after accidental events occurring with annual probability of 10^{-4} or less (Eik, K., Gudmestad, O. T., 2010). One way to document that such a requirement is fulfilled with respect to iceberg collisions will be to show that the sum of the frequencies F_1 and F_3 in Fig. 29 is lower than 10^{-4}. If one considers a system without any sort of ice management systems, all frequencies F_3 to F_6 will be zero and the annual probability of collision will be F_1. If F_1 ends up being higher than acceptable, one should introduce physical iceberg management as a next step and the frequency of collisions will be reduced. If the probability for collision still is unacceptable, another mean to prevent collision will be to include disconnection and escape capabilities and one ends up with the system illustrated in Fig. 29 (Eik, K., Gudmestad, O. T., 2010).

4. Description of the resulting accident sequences

If any impact between iceberg and structure would result in loss of structural integrity, the event tree could have been used as it is. However, since some installations may withstand loads from smaller icebergs, it is not sufficient only to distinguish between an impact versus no impact. The one way of dealing with this is to combine the event tree model with results from a physical iceberg drift model.

From the physical drift model information regarding iceberg mass and drift velocity might be available making it possible to calculate the kinetic energy of the iceberg when it collides with the structure.

5. Calculation of probabilities/frequencies for the identified consequences

The main challenge when using the event tree model is to establish reliable probabilities for the various events. In order to establish statistics regarding frequencies of the events and sequences in the event tree, realistic iceberg drift trajectories are required. These trajectories must include all relevant information for iceberg detection and physical iceberg management. Therefore, in addition to iceberg positions, the trajectories should include parameters such as wave height, wind speed, current speed, iceberg shape and size at each time step.

According to the (Eik, K. & Gudmestad, O. T., 2010) iceberg drift may be modelled by balancing the forces with the product of mass and accelerations in accordance with Newton's 2nd law:

$$m\frac{d\overrightarrow{V_i}}{dt} = -mf\vec{k} \times \overrightarrow{V_i} + \overrightarrow{F_a} + \overrightarrow{F_w} + \overrightarrow{F_{wd}} + \overrightarrow{F_{si}} + \overrightarrow{F_p}$$

where

$$m = m_0(1 + C_m);$$

m_0 - the physical mass;

C_m - the coefficient of the added mass;

V_i - the local velocity of the iceberg;

f - the Coriolis parameter;

k - the unit vector in vertical direction;

F_a and F_w - air and water drag, respectively;

F_{wd} – the mean wave drift force;

F_{si} - the sea ice drag;

F_p - the horizontal gradient force exerted by the water on the volume that the iceberg displaces.

The current iceberg drift model can be applied to generate iceberg drift trajectories. The model is capable of performing historical iceberg drift simulations (hindcast) within the period January 1987 to December 1992.

With respect to iceberg detection, it is obvious that a 100% probability of detection (POD) cannot be guaranteed. Due to this, a statistical description of the quality of the detection systems is required. When a system consists of comprehensive detection tools, which include satellite images, upward looking sonar's, enhanced marine radars, surveillance flights etc., the POD obviously increases.

However, the following example is provided for using just the marine radars. With respect to radar detection, there are a number of parameters that influence the detection capabilities; such as sea states, distance to target, size and shape of the target, precipitation and operator skills.

As it is not feasible to include all the dependencies in a statistical model, it is necessary to identify the most important factors and describe them as accurately as possible. One of the ways to express the POD for an iceberg with waterline length L, is to use the cumulative probability of a normal distribution with mean $6 \cdot H_s$ and standard deviation $1.8 \cdot H_s$, where H_s is the significant wave height in a stationary sea state:

$$POD\ (L|H_s) = F_N(L,\ m = 6H_s,\ s = 1.8Hs)$$

Following Fig. 30 illustrates the POD for different wave heights depending on the iceberg sizes (Eik, K., Gudmestad, O. T., 2010).

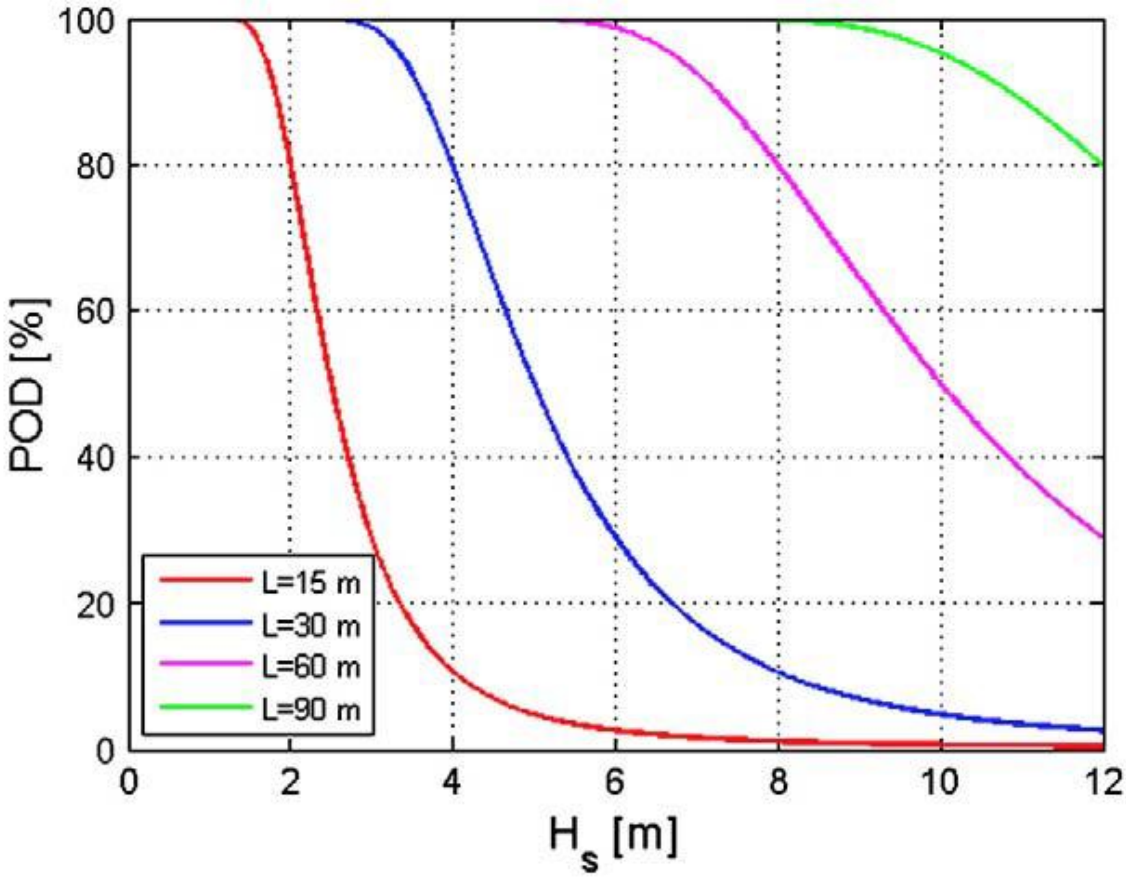

Fig. 30. Probability of detection (POD) from a marine radar given significant wave height, Hs and iceberg length, L (Eik, K., Gudmestad, O. T., 2010)

6. Compilation and presentation of the results from the analysis

The purpose of introducing the event tree model is to identify statistically and economically the effect of various iceberg management systems. By using the event tree combined with a physical iceberg drift model one ends up with various frequencies for interactions between the structure and icebergs depending on the iceberg management systems that are considered.

Therefore, by using the probability of successful offshore disconnection, the distributions for successful iceberg detection and successful iceberg deflection together with trajectories from the physical iceberg drift model, it then possible to fill in the probabilities for the various sequences in the event tree.

Following Fig. 31 shows the results for event tree analyses carried out by (Eik, K. & Gudmestad, O. T., 2010) for Shtokman region. It is important to note that the provided event tree includes probabilities for an installation with a “standard Grand Banks” iceberg management system and capabilities both for planned disconnections and emergency disconnection.

Mathematically, the probability for an iceberg-structure impact when the iceberg trajectory goes through the collision zone will be expressed as (for provided scenario):

$$P_{impact}(H_s,L,T)=[1-P_{detection}(Hs,L)][1-P_{EDC}]+P_{det}(H_s,L)[1-P_{tow}(Hs,L,T)]\times[1-P_{disc}],$$

where P_{EDC} is the probability of a successful emergency disconnection.

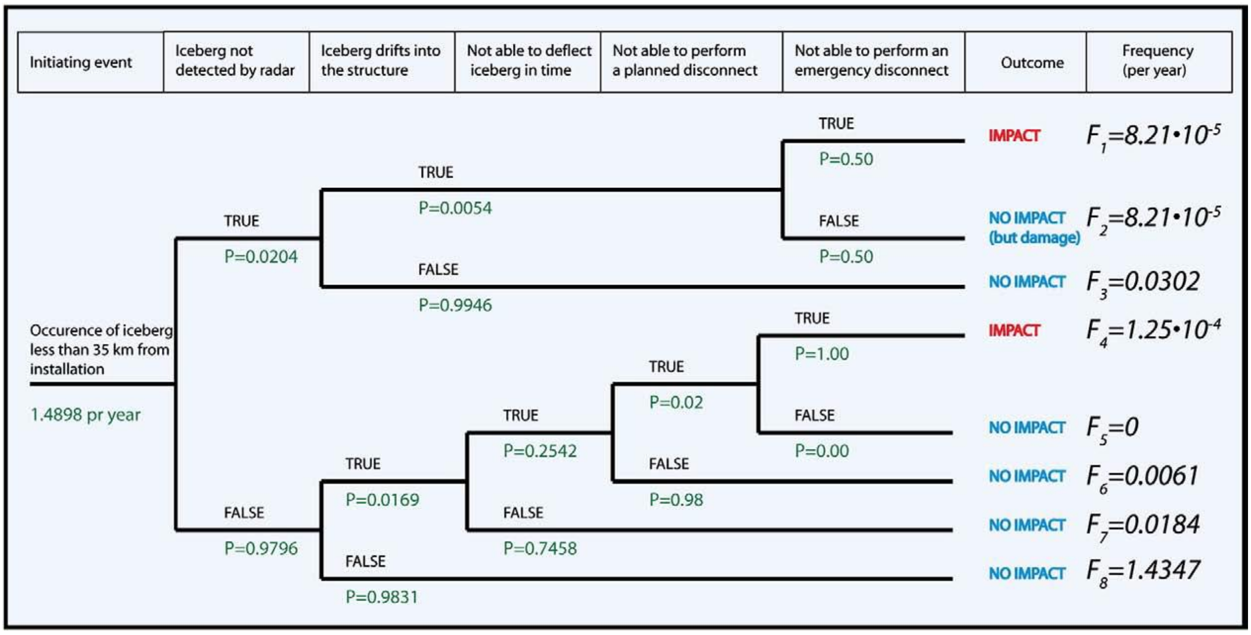

Fig. 31. Event tree for Shtokman region using probabilities for an installation with a “Standard Grand Banks” iceberg management system and capabilities both for planned disconnections and emergency disconnection.

The risk in the project is reduced when applying each additional phase of the ice management system but it will never disappear completely.

Further, prospects and efficiency of using different ice management systems can be evaluated by applying Expected Monetary Value (EMV) methodology. A method to include the risk in the economical assessment of the project is to calculate the statistical number representing the risk with the calculated income at each phase and thereby arrive at EMV (Zolotukhin A., 2011):

$$EMV = NPV \text{ x } Chance,$$

Where

NPV - Net Present Value, mln. $;

Chance (in our case) – obtained (required) probability of collision avoidance.

If the following expression is true:

$$NPV*C \geq (1-C)*Exepences,$$

then the Ice Management system can be considered as efficient.

Preliminary conclusion

The summarized data on the iceberg occurrence allows identifying the appropriate route for the subsea pipelines in the Kara Sea to the shore and mitigate the risks of possible infrastructure damages by icebergs.

The proposed ice management procedure reduces the possibility of iceberg impact on the facility as well as provides a proper plan on how to act during the iceberg hazards.

The philosophy of the event tree analysis and algorithm for its construction were considered for iceberg hazard scenarios. Previous studies carried out by Eik, K. & Gudmestad, O. T. (2010) for Shtokman field region have proven the applicability of the suggested methodology for evaluations of the effects of iceberg management measures.

Similar analysis is required for the Kara Sea region to evaluate the feasibility of the iceberg management activities and further operations.

In addition, it is reasonable to carry out more precise analyzes with additional physical and mathematical iceberg drifting models to evaluate hazard scenarios. It is also important to focus on development of the oceanographic modeling and iceberg detection modeling. Subsequent Arctic expeditions are also critical to study the icebergs' drifting patterns, collect data and perform physical ice management tests to ensure safe and sustainable deflection of icebergs and, therefore, development of hydrocarbon fields.

8. Production technologies for suggested fields

As for any offshore project, the feasibility of suggested concept highly depends on the choice of production facilities. In order to make a reliable assessment a lot of parameters should be taken into consideration, these include metocean conditions, geology, environment, remoteness, state-of-the-art engineering, etc. In addition, Russian Arctic is one of the most challenging areas for operation and the management team must handle extreme conditions in a region, which is environmentally sensitive, ecologically fragile, extremely remote, and with little or no infrastructure.

A number of concepts have been used or proposed for installation in freezing sea areas. The primary objective of these concepts is to maximize environmental safety and minimize the loads imposed on the foundations, mooring systems by the ice, and to avoid equipment damages by large masses of ice.

The screening of the production concepts for chosen fields in the Barents and Kara Seas is shown in Fig. 32. It is based on existing Arctic offshore practices, where each concept is suitable for certain conditions.

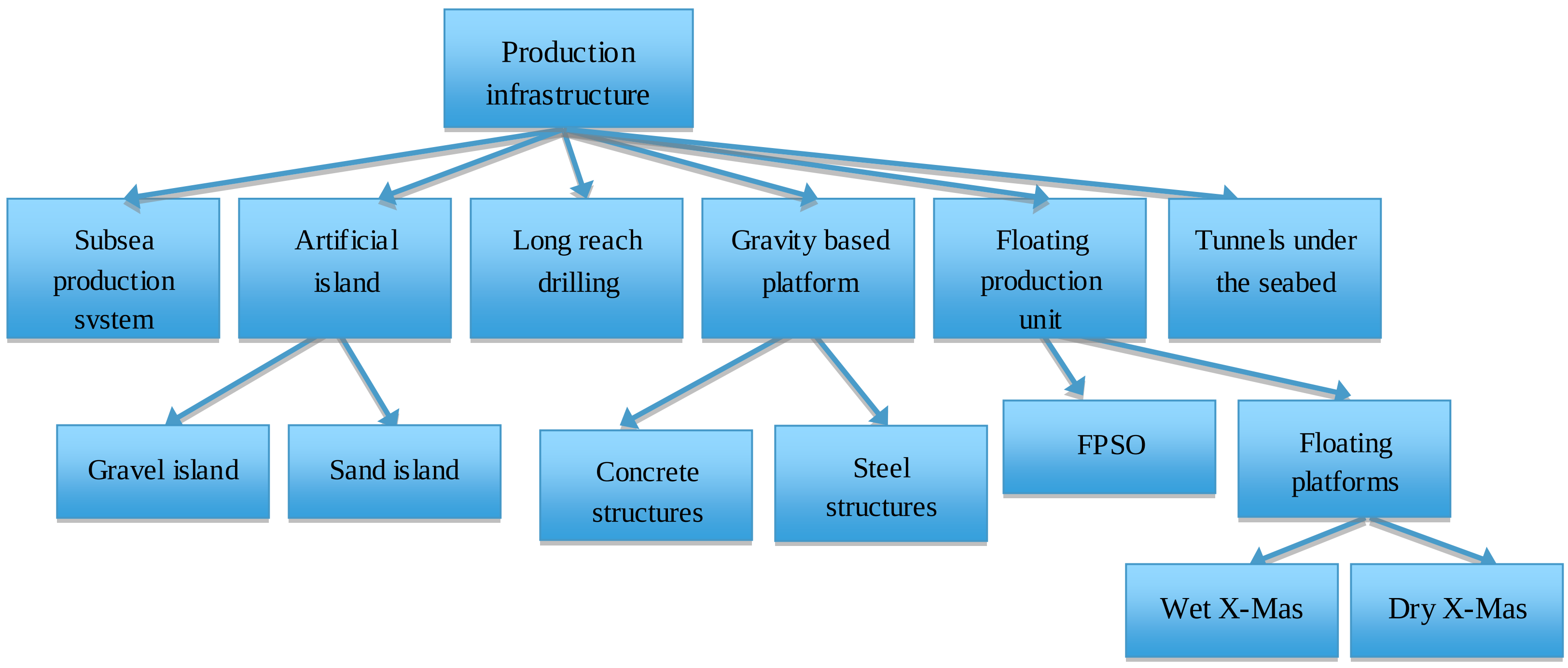

Fig. 32. Screening for production facilities

Advanced drilling technologies, such as Extended Reach Drilling (ERD), present possible options for Arctic offshore oil and gas development. The Sakhalin I project has broken several records with its extended reach drilling using the Yastreb drilling rig. Being the most powerful land rig in the world it has drilled more than 20 extended reach wells into the Sea of Okhotsk. Current wells have horizontal sections of more than 10 kilometers (Barnes, 2011). British Petroleum is also developing the Liberty field in the Beaufort Sea outer continental shelf using extended reach drilling from the Endicott satellite island.

Due to remoteness of the considered fields in the Barents and Kara Seas Extended Reach Drilling does not seem as a technologically viable option.

An artificial island is also a possible structure for drilling or production facilities in relatively shallow waters, typically 10 m or less. The concept involves dumping rock or dredged material at the location and building up the deposit until it is sufficiently high above sea level. Artificial islands are constructed in the Beaufort Sea and in the North Caspian Sea. With the depth limitation and relatively low resistance to tidal erosion, artificial islands would not be very applicable for the considered fields. Additionally, the pumping of large amounts of dredged material might cause a temporary runoff water contamination outcome (Barnes, 2011).

Gravity based structures (GBS) differ by the foundation material. Concrete gravity base structures have several advantages for the Arctic and extreme locations. These include the capability to support large topsides weights, presenting a clean profile to any ice flow, material strength and stability, and the internal oil storage capability. Gravity based platforms have been employed on the Grand Banks, offshore Sakhalin, the Beaufort Sea, the Cook Inlet, Bohai Bay and the Pechora Sea.

Steel platforms are not as frequently installed in ice conditions due to the complex and high loads that could develop if large ice slabs became trapped between the platform legs. LukOil Company has developed the Kalingrad D6 field in the Baltic Sea using two interconnected steel jackets. To reduce the risk of ice slabs being trapped between the legs, there is no cross bracing at the water line. The platforms stand in 25 - 35 m water depth and were designed to stand the loads imposed by 0,3 m thick ice. It is also significant that closeness of the Baltic Sea provides considerably small currents in the area (Barnes, 2011).

A variety of gravity based structure designs are possible, ranging from massive vertical cylinders to more tapered profiles. The researchers found that in areas of multi-year ice, water depths of about 80 meters (250 feet) would likely be an upper limit for the technical feasibility of installing these structures and that limit would go down to 65 meters (200 feet) in areas where the seafloor foundation properties are weak (Bailey A., 2009).

Thus, with water depths of up to 350 meters for considered fields in the Barents Sea and up to 165 meters in the Kara Sea GBS structures are not suitable with up-to-date economical efficiency and technological feasibility.

Floating Production Storage and Offloading (FPSO) is a different approach for an installation in an ice- and iceberg-affected region that is not subject to significant sheet ice. Ice management systems are critical in this case. A semi-rigid floater concept, with a floating platform moored in place under tension, might operate year-round in first-year ice conditions but would need to be able to disconnect to move away in the event of high ice loads. Examples of existing Arctic projects with

FPSO employment include Canadian White Rose and Terra Nova fields. Areas are characterized by the water depths between 90 m and 100 m, seasonal presence of floating sea ice, ranging in thickness from 0,5 m to 1,5 m. The FPSO's turrets for both projects are designed to allow the facility to disconnect from the subsea drill centres and move in the event of an emergency. For mentioned depths there is a potential risk of the wells to be damaged by the keels of large icebergs. For this reason, subsea equipment has been completed in "glory holes" below the seabed to protect it from ice scour. In addition, flowlines and pipelines are also buried to protect them from icebergs' impact (www.offshore-technology.com).

One of the main concepts for developing the Shtokman field presented by the Shtokman Development AG Company includes the Floating Production Unit (FPU) facility (see Fig. 33). According to the concept a number of subsea templates are linked to a floating production unit and natural gas is transported to an onshore processing and LNG terminal at Teriberka 600 km away from the field (www.shtokman.ru).

FPU differs from the FPSO, as there is no storage capacity in the current unit. Its main purpose is gas compression and separation of water and before produced hydrocarbons are being transported to the shore via subsea pipelines in a two phase system.

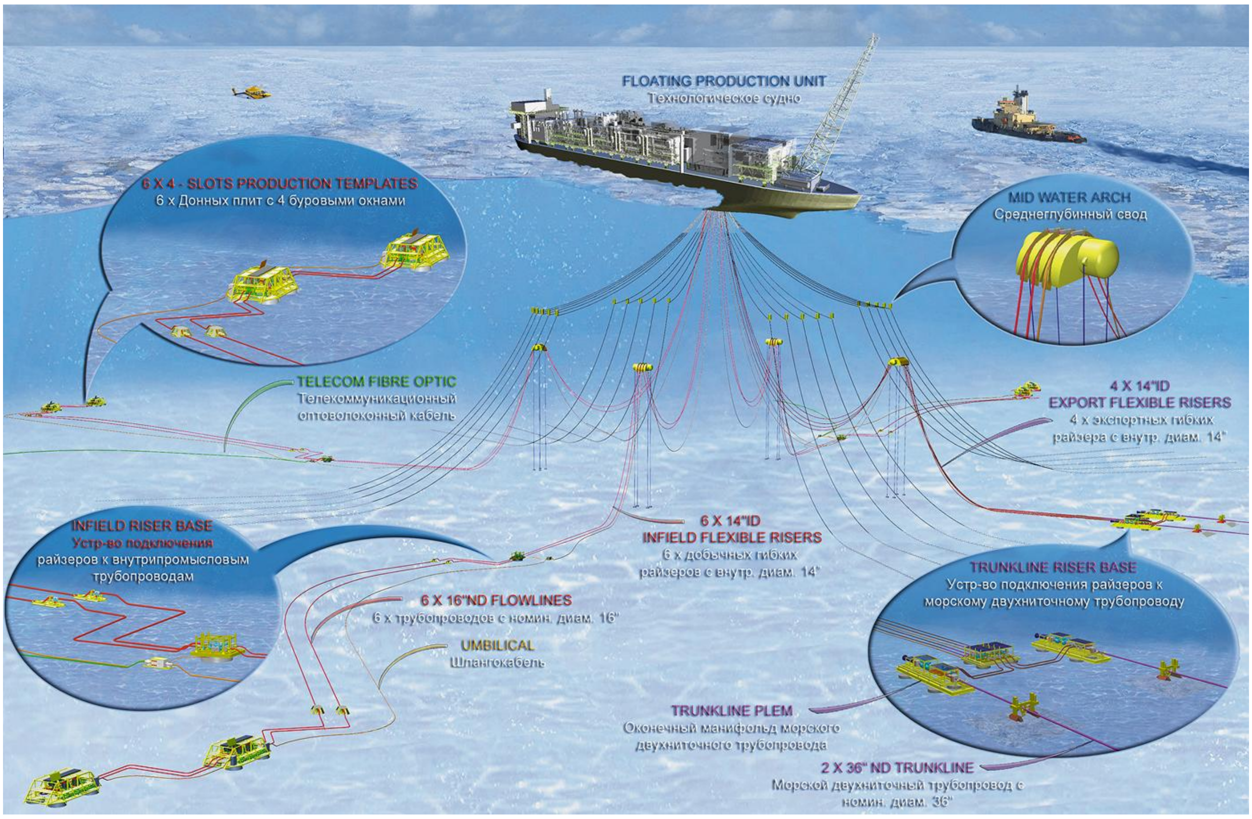

Fig. 33. Shtokman gas condensate field development concept (http://expo2012.inconnect.ru).

There are several concepts based on subsea tunnels and caverns for offshore field development to provide future alternatives for infrastructure in the harsh conditions. One of the concepts provided by Grøv E. et. al (2013) consists of 2 or 3 parallel tunnels coming from an onshore site to a base station at the low point. From the base station, parallel tunnels are bored by TBMs to the location of large production caverns with drilling and operation facilities. One of the tunnels has a transportation purpose for typical container size loads, and another one (in a two-tunnel model) is for relocation of staff and serves for escape and evacuation in emergency cases. In the case of a three-tunnel concept (see Fig. 34), additional tunnel is used as a relief tunnel for any gas emissions in abnormal situations (Grøv E. et. al, 2013).

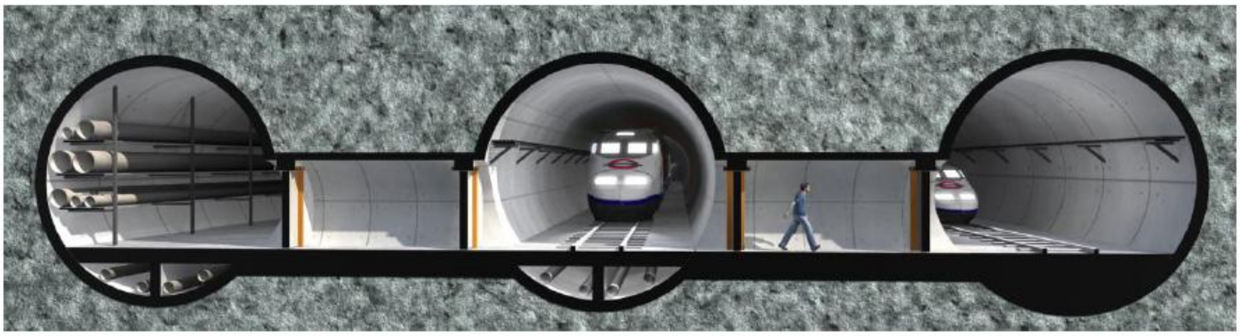

Fig. 34. Three-tunnel concept with 6,6 m outer diameters (Grøv E. et. al, 2013).

The limitation of the concept is its feasibility for large distances from offshore. Currently it is considered competitive with traditional development methods only for fields in the range of 30 kilometers from the shore. The main obstacles for the concept development include available technologies and tunneling methods (such as TBM tunneling). However, most of the complications are assumed by the authors to be within the range of technology development. Clear advantages of the idea include significant reduction of environmental risks and traditional onshore ways of field development.

Norwegian company Acona Wellpro Company in co-operation with NTNU (the Norwegian University of Science and Technology) and SINTEF (research institute located at NTNU) provided another research and concept design of a subsea tunnels, combined with directionally drilled production wells (see Fig. 35). The companies concluded that currently there are no showstoppers for their subsea tunnel concept and that it would be a possible alternative for offshore fields development with 25 - 50 km distance from the shore (Grøv E. et. al, 2013).

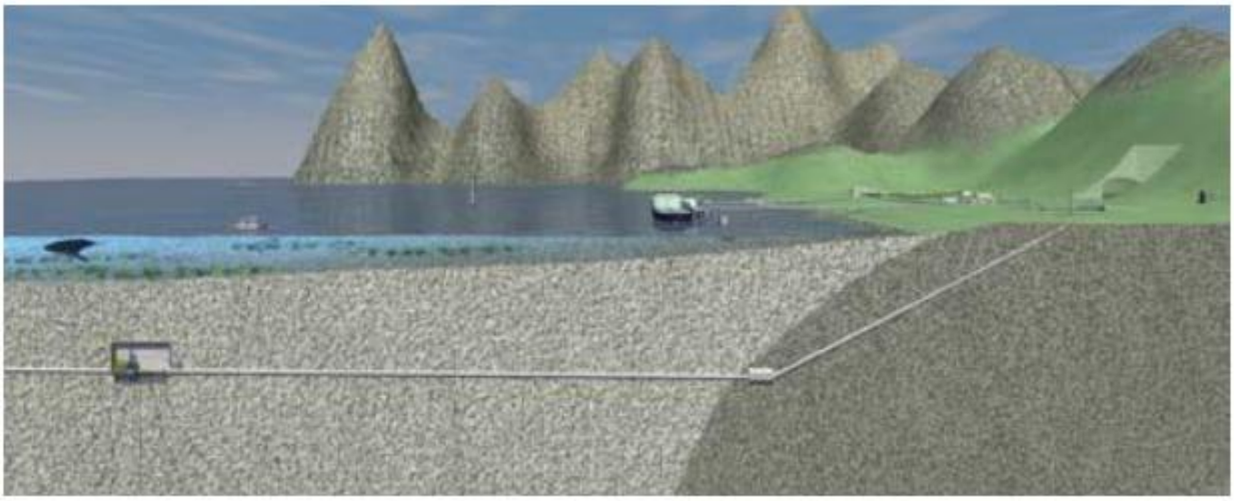

Fig. 35. Acona concept with subsea tunnels and directional drilling from caverns (Grøv E. et. al, 2013).

Throughout the cooperation of Gubkin Russian State University of Oil and Gas and University of Stavanger (Norway) another concept was created for producing the hydrocarbons from the tunnel (see Fig. 36).

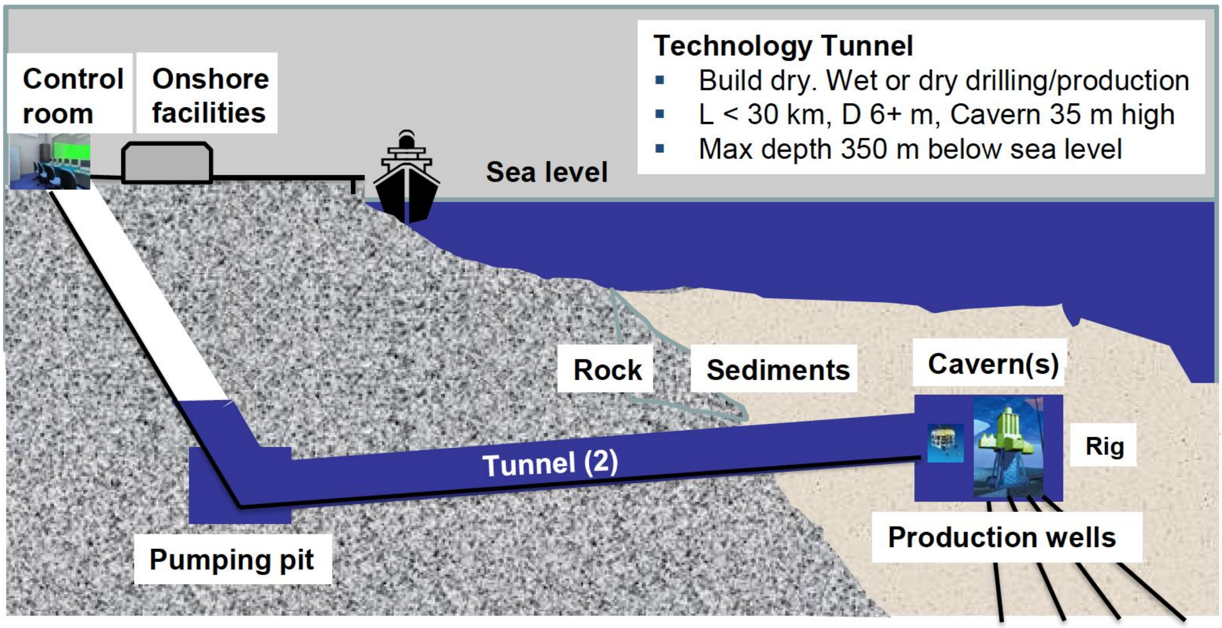

Fig. 36. Technology tunnel concept (Authors: Prof. O.T. Gudmestad, Prof. A.B. Zolotukhin, Russian MSc and PhD students A. Khrulenko. O. Bychkova, T. Mokshaev, F. Domanuyk, 2009)

The concept suggests that the tunnel might be either dry or filled with water. The distance from the shore is also limited by 30 km.

To conclude, with clear environmental and operational advantages of the tunnel concepts, there are several drawbacks, such as escape and evacuation procedures, limited distance from the shore, unclear CAPEX and reliable tunneling technologies, which introduce high risks of implementation of the considered concepts.

Subsea production system (SPS) without any floating structures is another option of hydrocarbons' production in the arctic conditions. The main advantage of such system is that it is completely autonomous. Technologies for subsea processing, separation, compression, boosting, AUV/ROV, subsea equipment, control systems and power transmissions have been developed, qualified and modernized significantly over the last 70 years. Moreover, the progress doesn't stop with new subsea technologies appearing every year on the global market. The principle of the subsea production system is shown in the following Fig. 37.

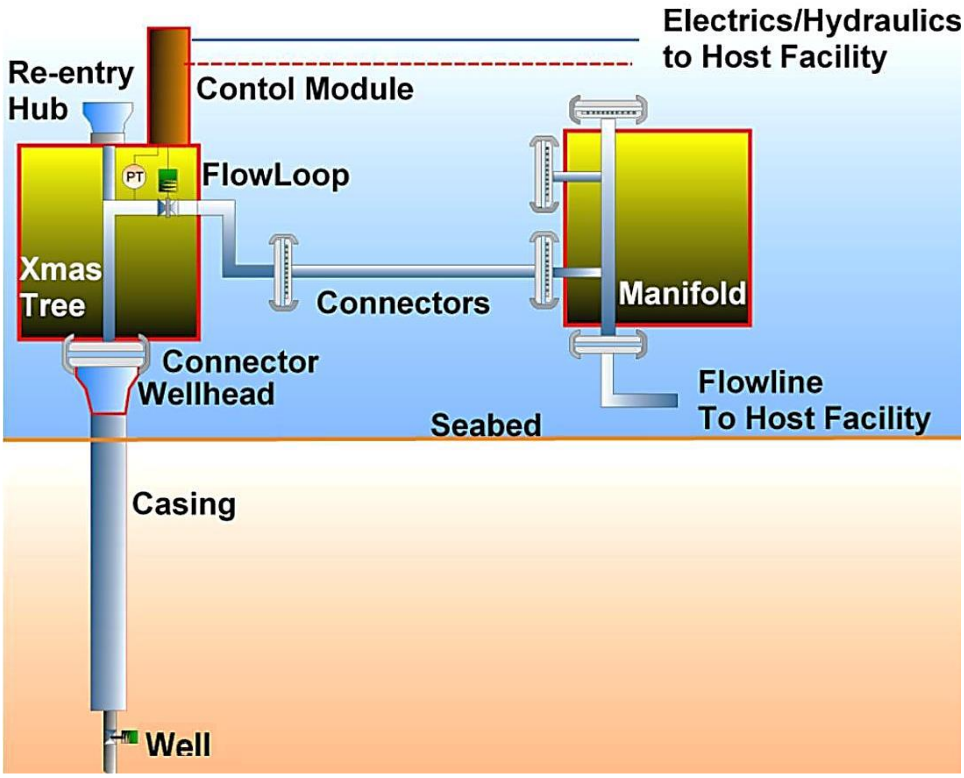

Fig. 37. The principle of subsea production system (Razhev V.E., 2016).

Complete subsea development and subsequent pipeline transportation of the produced multiphase fluid to the shore is an existing practice. This technique has been used on the Snohvit field in the sub-Arctic Barents Sea at water depths between 250 and 345 m. The pipeline to the LNG shore terminal in Melkoya Island is 143 km long. In the waters of Okhotsk Sea subsea solutions are also implemented in Sakhalin 3 project. A flow assurance design is a significant issue for this method of development due to low ambient temperatures and long distances.

All in all, subsea solutions are suitable for deep Arctic waters and large-area reservoirs. If used in more shallow waters additional protection measures have to be implemented where the iceberg scouring is possible. Depending on whether the water depth exceeds the maximum investigated ice keel depths, the wellheads should be protected in “glory holes”, for instance. SPS also appear ideal for the tie-in of subsequent and smaller fields to existing infrastructure. In addition, such systems might offer a significant decrease in CAPEX, reducing development costs.

Therefore, Shtockman, Ludlovskoye and Ledovoye gas fields in the Barents Sea could be suitable candidates for subsea development, albeit with some flow assurance challenges. The fields are located in water depths from 200 to 350 m and 360 kilometers from the Belushya Bay. Although the water depth is similar to the Snohvit field, the pipeline to the shore would be more than twice as long. Such pipeline length generates problems with significant pressure drop and liquid slugging as well as hydrates formation possibility. All these issues are subjects of further examination.

Subsea production also seems to be the most reliable concept for Leningradskoe and Rusanovskoye fields (water depth is from 80 to 165 m) in the Kara Sea. The floating production platforms are unlikely to be applied for development of these gas and condensate fields because of the harsh ice conditions and constant existence of the multiyear ice:

 the ice-free period is less than two months;

 the thickness of ice is up to 2 m.

Previous research was also conducted upon the topic and possible cross section scheme of a subsea concept for Leningradskoe and Rusanovskoe fields is shown in Fig. 38.

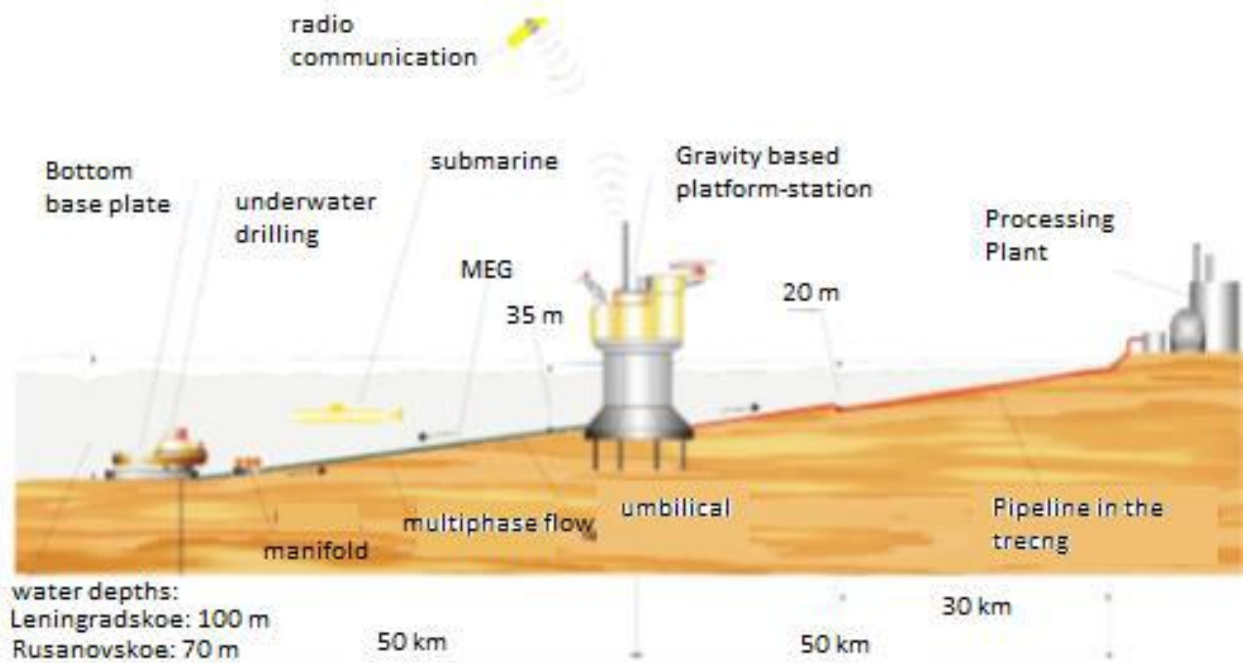

Fig. 38. A cross section scheme of a subsea concept of Leningradskoe and Rusanovskoe fields (Mirzoev D. A., 2012, Razhev V.E., 2016).

Wate depth within Rusanovskoye and Leningradskoye fields changes from 50 to 100 m and from 80 and 165 m, respectively. Due to to the average height of subsea equipment (10 m) and previous analysis on iceberg presence, it is assumed safe to locate subsea equipment without ice-resistance protection in the Kara Sea when water depths are more than 100 m. If subsea equipment is going to be placed on the parts of Leningrdaskoe field where the water depth is less than 100 m, then trenched holes are recommended. In Rusanovskoe field, it is suggested to complete the X-trees, manifolds, infield gathering systems, export pipelines, control umbilicals, power supply, and equipment in trenches and threnched holes (“glory holes”) to protect it from ice loads.

Preliminary conclusion

Provided analysis on existing production systems implemented in the Arctic conditions lead to the following suggestions:

- For the Barents Sea fields development Floating Production Unit combined with subsea production system can be employed. In addition, subsea concept might be applicable without any floating structures. The later concept might be more economically feasible and environmentally safe, however, flow assurance analyses have to be conducted to prove its reliability.
- Subsea production systems are also suggested as the most suitable production infrastructure for the Considered Kara Sea fields;

- In the Kara Sea it is also suggested to place the subsea wellheads and additional equipment in the trenched holes ("Glory holes") where water depths exceed 100 meters. It is not as relevant for the Barents Sea as waters are not so shallow in the location of the considered fields;
- Produced gas can be transported from the fields as a multiphase fluid in a single pipeline. Otherwise, gas and condensate can be transported through the separate pipelines and gas processing is required in this case. The possibility of multiphase flow will be considered in the further analyses. It is also important to consider the necessity of additional compression and pumping units for later stages of the production when reservoir pressure will not be sufficient for transporting the mixture to the shore.

To conclude, the main offshore facilities for Barents and Kara Sea fields might consist of:

- Subsea Production Systems (SPS);
- Umbilicals and Flowlines to gather production from SPS to the manifolds and transport it to the Novaya Zemlya archipelago;
- Multiphase flow trunk pipelines to the onshore facilities;
- Optical cables for communication between the SPS and the control center in Belushya Guba.

It is also important to mention that in the Arctic conditions, especially in areas with short navigation period, certain challenges occur with installation, operation and maintenance of equipment for subsea technologies. Thus, state-of-the art diving equipment has to be developed and utilized to be able to conduct all the operations in limited duration with a maximum level of reliability.

9. Pipeline design

9.1 Offshore pipeline route selection

It was mentioned before that pipeline route selection is one of the most critical issues for developing the transportation system in the Arctic. It influences the feasibility of the whole concept and depends on the combination of environmental and engineering characteristics as well as socioeconomic and geopolitical factors. A poorly chosen route can lead to delays in the project and significant cost overruns.

To finalize the decision upon pipeline routing all previous analyses should be taken into consideration:

- Environmental conditions;
- Soil conditions;
- Bathymetry of the regions and seabed characteristics;
- Characteristics of the suggested hydrocarbon fields;
- Chosen location for onshore infrastructure;
- Iceberg hazards;
- Ice management concept;
- Third party activities (ship traffic; fishing activity; dumping areas for waste, ammunition, mining activities; military exercise areas, etc.)

Further, the appropriate landfall design should be considered to ensure the reliability of the hydrocarbon transportation and reservation of the fragile environment. All listed route selection factors coincide with recommendations and requirements of DNV-OS-F101 Offshore Standard (Veritas, D. N., 2012).

According to this document, the pipeline route should be selected with due regards to safety of the public and personnel, protection of the environment, and the probability of damage to the pipe or other facilities.

For more accurate assessment of the areas along the pipeline route precise surveys should be conducted to reveal all obstructions (rock outcrops, large boulders, pock marks), topographical features (unstable slopes, mudslides, iceberg scars, sand waves, pock marks) and possible free spans as preliminary seabed preparations might be required. Therefore, comprehensive engineering analysis using state-of-the-art mapping software with 3D tools should be implemented to select the route (see Fig. 39.).

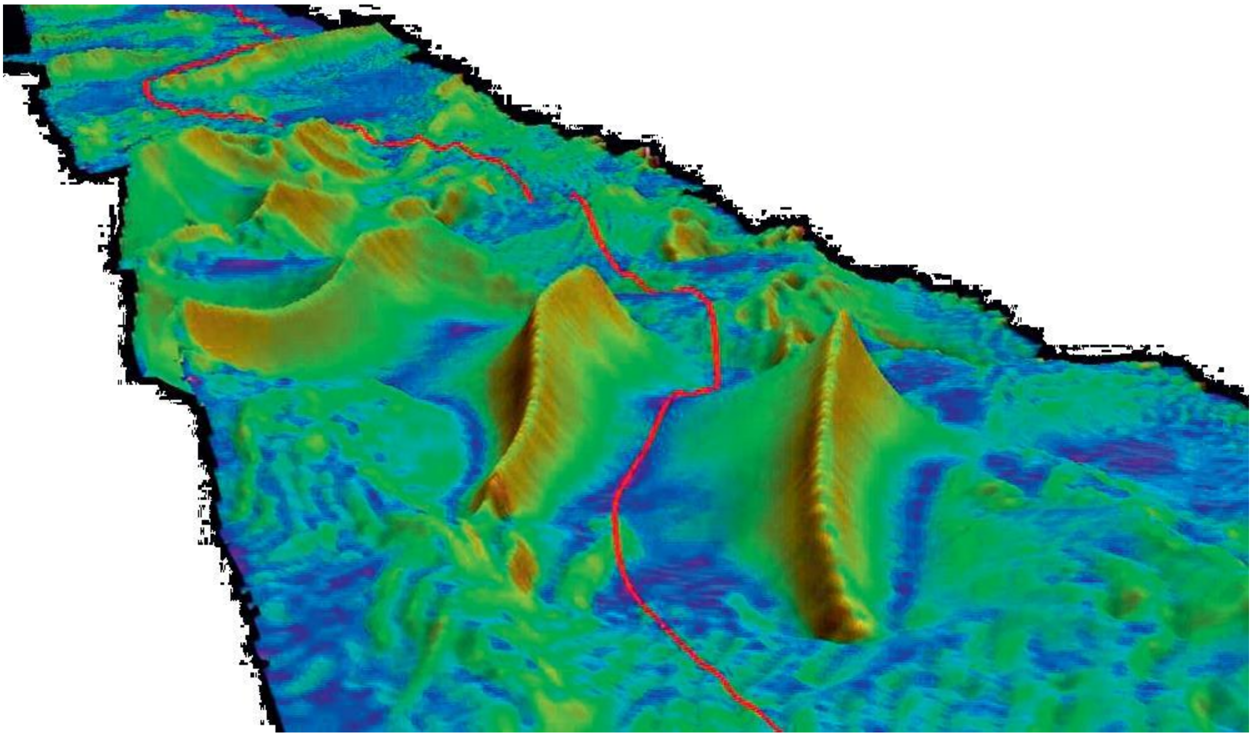

Fig. 39. Software image for pipeline route modelling (Starodubcev, 2016)

ArcGIS™ is an example of the software tool used to evaluate an optimal pipeline route. Geographic Information Systems (GIS) are used to centralize all gained data from various sources and integrate it into a database, from which the data is further modeled. GIS-based tools and processes have been extensively applied to address the challenges of optimizing pipeline route selection and route networks based on the collection, processing and analysis of spatial data (Starodubtcev A.O., 2016). Due to limited access to such tools they were not fully utilized in the current analyses. However, the results of the previous researchers will be used to compare the selected routes.

Barents and Kara Sea pipeline route selection

Belushya Bay was previously identified as the potential site for the future terminal and LNG plant. In addition, Shtokman field in the Barents Sea and Leningradskoye field in the Kara Sea were evaluated as the initial points for pipeline routes. Therefore, pipeline routes for Barents and Kara Seas were selected for further study with the due regards to previous results and discussions. Nautical maps were utilized to evaluate the routes (see Appendix 2 and 3). Scale of the used charts wouldn't allow illustrating the routes on one map, therefore, schematic trajectories are shown in the Fig. 40 and 41.

Fig. 40. Schematic pipeline route from the Shtokman field to Belushya Bay (http://wikimapia.org)

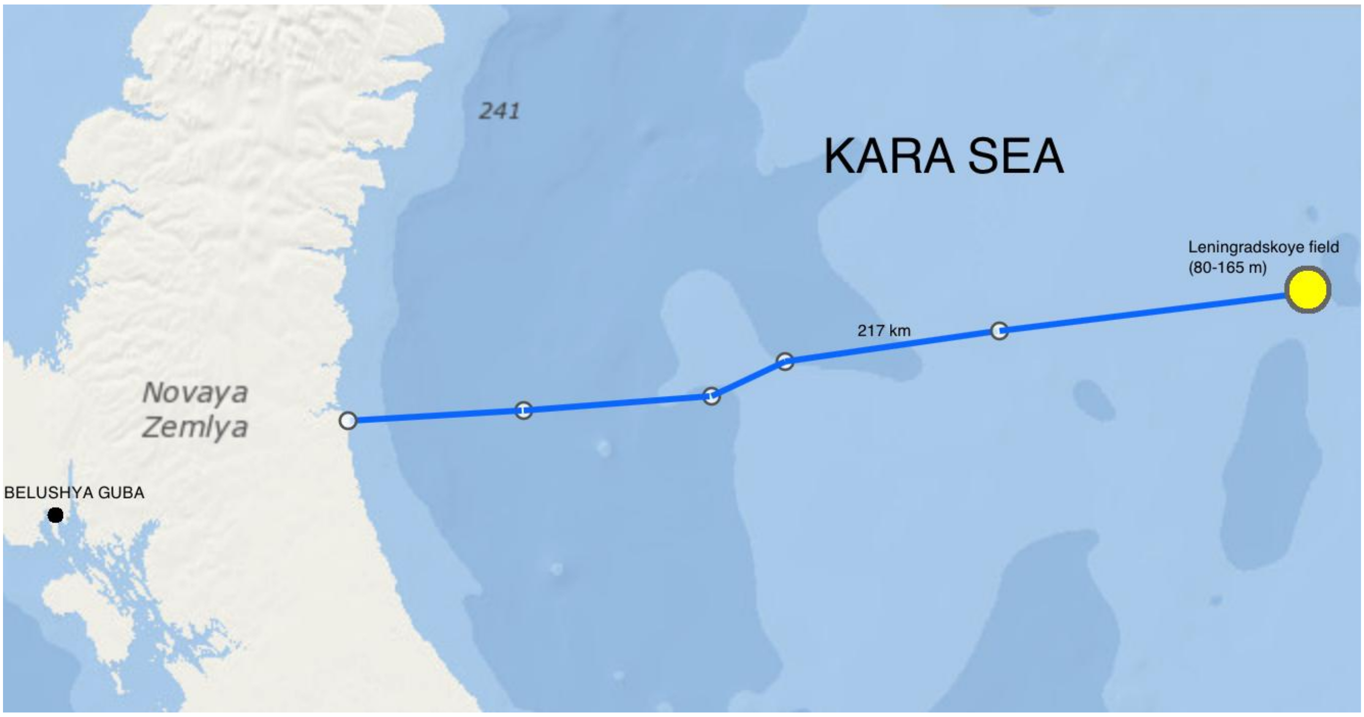

Fig. 41. Schematic pipeline route from the Leningradskoye field to Novaya Zemlya (http://wikimapia.org)

Subsea pipeline profiles from Shtokman and Leningradskoye fields are illustrated in Fig. 42. and 43. Furthermore, map with a larger scale was used to evaluate more accurate profile sections close to the shore of Novaya Zemlya from both sides. This would allow conducting more realistic flow assurance analysis as well as landfall design analysis.

Coordinates of the suggested routes:
Shtokman field – Novaya Zemlya
1. 73° 08' N 43° 53' E

2. 72° 54’ N 44° 30’ E
3. 72° 39’ N 46° 00’ E
4. 72° 30’ N 46° 40’ E
5. 72° 18’ N 47° 50’ E
6. 72° 00’ N 48° 55’ E
7. 71° 33’ N 50° 00’ E
8. 71° 23’ N 51° 19’ E
9. 71° 20’ N 51° 49’ E
10. 71° 26’ N 52° 15’ E
11. 71° 34’ N 52° 21’ E (shore crossing point at Belushya Guba)

Leningradskoye field – Novaya Zemlya

1. 72° 18' N, 65° 40' E
2. 72° 07’ N 64° 50’ E
3. 72° 06’ N 64° 00’ E
4. 72° 09’ N 63° 00’ E
5. 72° 06’ N 62° 00’ E
6. 72° 05’ N 61° 11’ E
7. 72° 03’ N 60° 20’ E
8. 71° 57’ N 59° 40’ E
9. 71° 56’ N 58° 35’ E
10. 71° 56’ 30’’ N 57° 26’ E
11. 71° 57’ N 57° 03’ E
12. 71° 52’ N 55° 30’ E (shore crossing point in Novaya Zemlya archipelago)

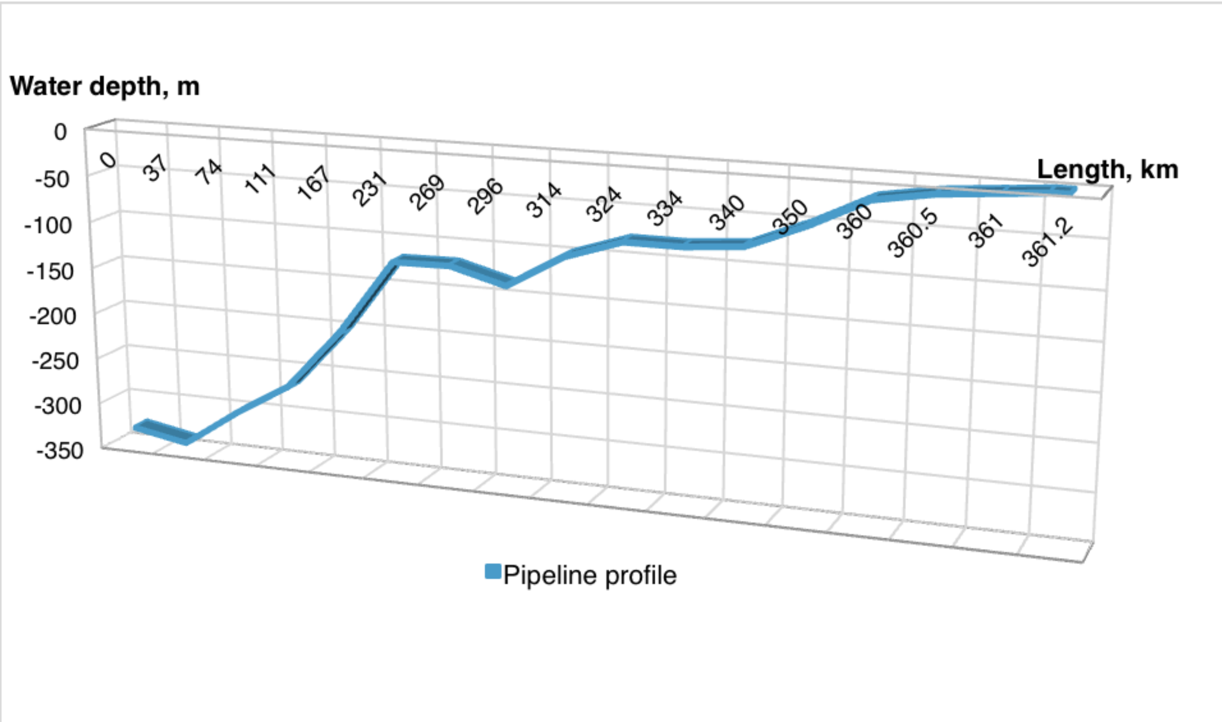

Fig. 42. Potential subsea pipeline profile from the Shtokman field to the Belushya Guba Bay

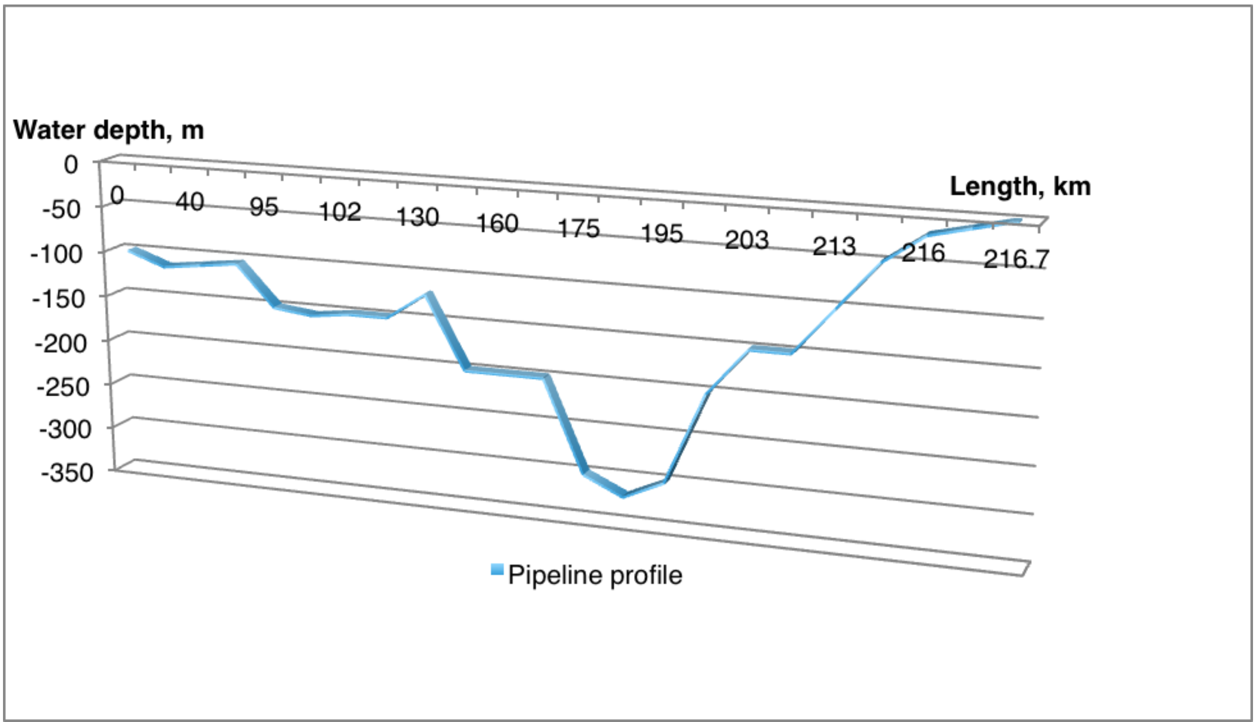

Fig. 43. Potential subsea pipeline profile from the Leningradskoye field to the Novaya Zemlya

Approximate route length from the Shtokman field to Belushya Guba is 360 kilometers and from Leningradskoye field to Novaya Zemlya's east coast – 217 km, respectively. The Fig. 42 and 43 above show that profiles are characterized by significant differences in elevations of the seabed, especially for the Kara Sea where the route crosses Novozemelnaya Trough. The maximum sea depth along the routes is 340 meters for the Barents Sea and 320 meters for the Kara Sea, respectively. All obtained values are critical for further flow assurance analysis.

As was mentioned before, similar analyses were carried out for the Barents and Kara Seas in the previous works using the ArcGIS^{TM} software. The procedure included three steps:

- The first step was to define a base requirement for pipeline route evaluation. It can include all the maps and charts that limit a pipeline routing. For provided example the map of oil and gas fields was implemented and the Shtokman field was chosen as an initial point.
- The second step was to create a discrete cost map. Different zones of the map represent different expenses for pipeline construction. In order to create the map different data and information was gathered: topography map of the seas, wind map, current map, wave map, ice concentration map, map of icebergs' frequency, ice gouging map. It is clear that the algorithm of analysis is similar to the one applied in the current research. However, using the software and digital topography maps would probably bring it to higher level of accuracy.
- The third step was to combine the cost effective discrete map with the first map of the location of the fields. Therefore, optimum route through the area could be identified. Optimization criterion for optimal route was a minimum cumulative sum of cells through whole discrete cost map.

Fig. 44 illustrates the results. The route can be compared with the previously selected one (see Fig. 40).

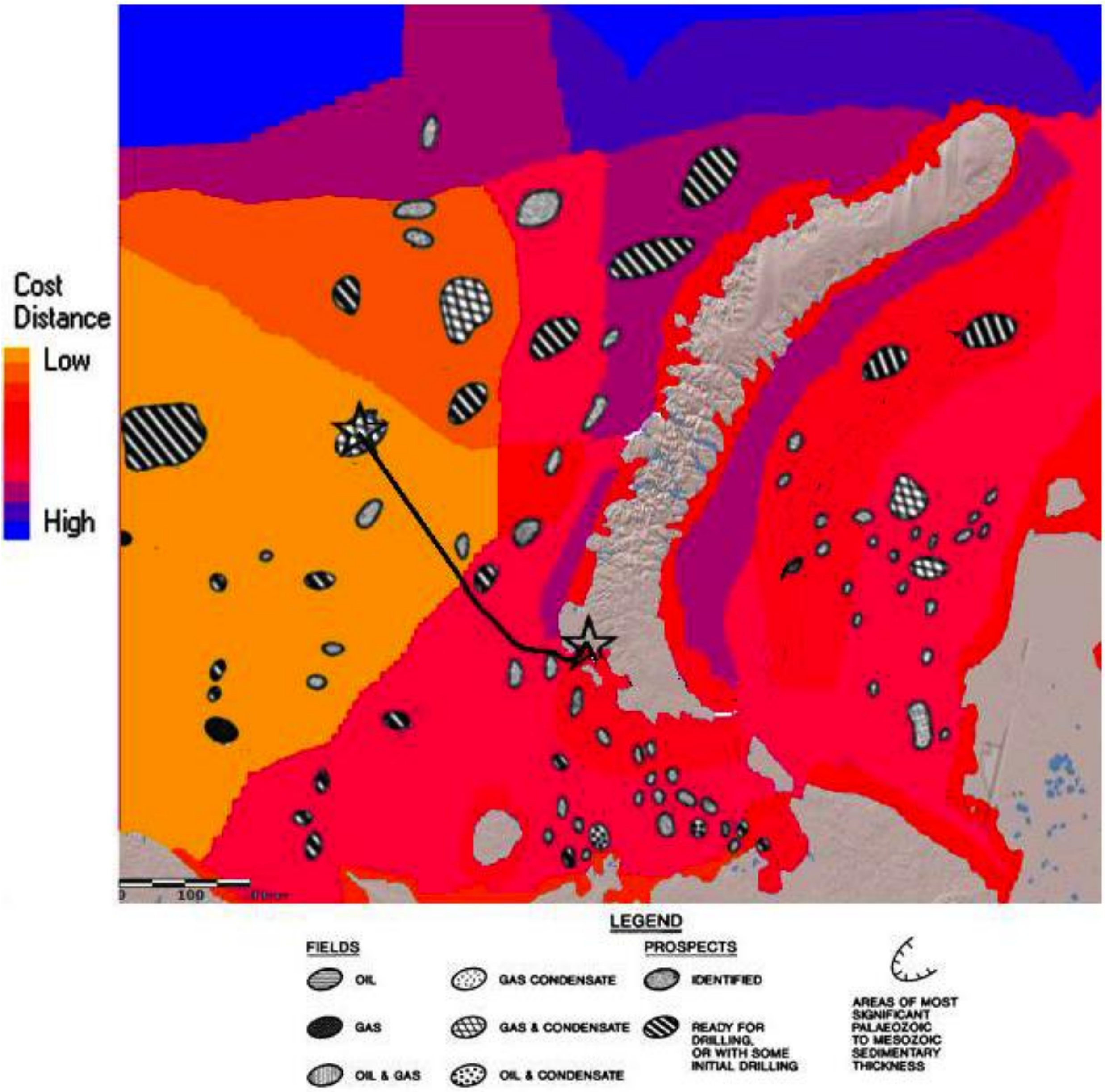

Fig. 44. Evaluation of optimum pipeline route from the Shtokman field to the Novaya Zemlya using ArcGIS™ software (Starodubtcev A.O., 2016)

The resulting route is very similar to the one obtained previously. The distances are comparable as well: about 360 and 370 kilometers, respectively. In addition, placing suggested pipeline route for the Kara Sea on the current map leads to the following results (see Fig. 45).

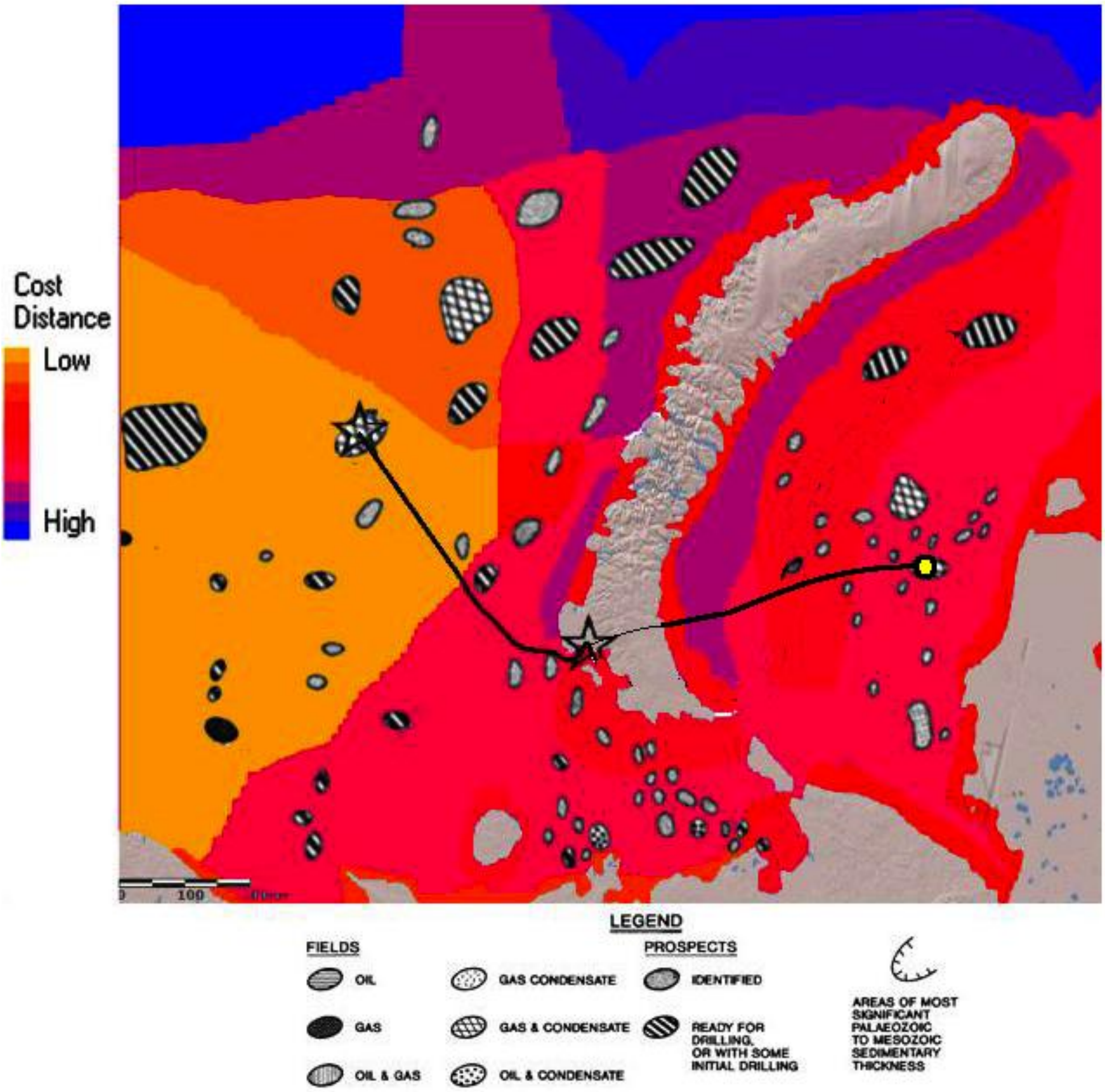

Fig. 45. Evaluation of optimum pipeline route from the Shtokman and Pobeda fields to Novaya Zemlya using ArcGIS^{TM} software (Starodubtcev A.O., 2016)

Its important to note that for the Kara Sea selected pipeline route also goes though the most cost-efficient zones except for the East Novaya Zemlya Trough. However, taking into consideration previous analysis on iceberg occurrence, it is reasonable to lay the pipe in this deep-water area. On the other hand, significant elevation differences on the short distance may lead to considerable flow assurance challenges, which have to be examined.

The onshore pipeline route through the Novaya Zemlya

It was suggested to transport the produced gas and condensate from the Kara Sea fields to the eastern coast of the Novaya Zemlya. From there the pipeline would have to cross the archipelago to reach the western side and processing facilities. Therefore, potential route was evaluated for the pipe laying from the shore crossing point on the eastern side to the Belushya Bay. Landscape elevation, water crossing areas and other aspects were taken into consideration while selecting the route. However, a tunnel construction may be required to cross the mountains for one of the sections of the pipeline (see Fig. 46).

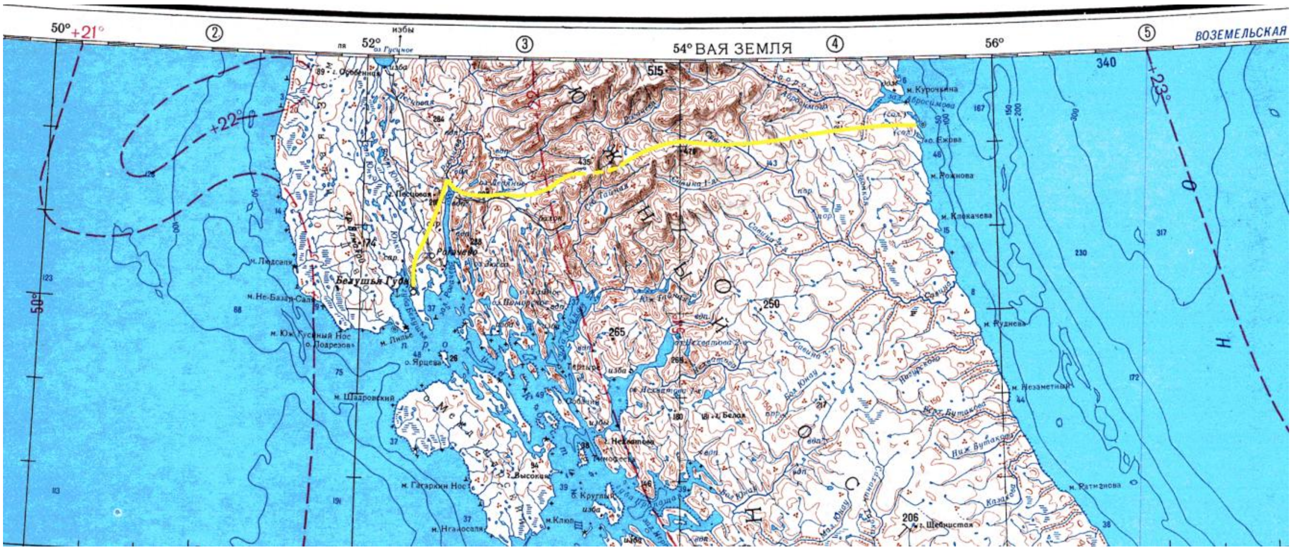

Fig. 46. Pipeline route across the Novaya Zemlya archipelago

The route length is approximately 120 km and due to very changeable landscape further analyses are required to evaluate the necessity of additional compressing stations in order to transport the produced liquid.

9.2 Flow assurance

Venturing into ever deeper and colder waters and more remote locations brings some of the greatest technical challenges to the oil and gas industry. Reliable production systems must be designed to accommodate subsea multiphase flow across long pipelines due to high intervention costs and potential for downtime.

Managing costs over extended distances introduces a number of considerable risks and reliability becomes a key concern. Characterizing and managing these risks requires detailed multidisciplinary engineering analysis and has led to the emergence of flow assurance.

Significant differences in density and viscosity of multiphase flow components make the system much more complex compared to a single-phase flow. Reynolds number commonly controls the pressure drop for a single-phase flow, whereas in a three-phase flow pipeline the pressure drop is governed by the properties of all the fluids.

Al in all, multiphase flow simulation is required for the design of subsea flowlines to provide safe and economically viable transportation from the bottom of the wells all the way to the downstream processing facility. For the current work multiphase flow simulator PIPESIM was identified as a suitable solution for modeling the flow regimes from the fields to the Novaya Zemlya Archipelago.

To start with, initial data and reservoir fluid composition were specified. The Shtokman gas and condensate field was taken as a reference for the Barents Sea, assuming possible similarity of hydrocarbon-bearing formations for considered fields in that area. Because of the lack of data for the Leningradskoye field in the Kara Sea gas properties are assumed the same as in Yamburgskoe gas and condensate field due to fields’ location in the northern part of the West Siberian oil and gas province (Razhev V.E., 2016).

Table 18. Gas composition for Shtokman and Leningradskoye fields (http://trubagaz.livejournal.com; http://biofile.ru)

Component	Barents Sea	Kara Sea
	%	
Methane	96,24	89,67
Ethane	1,33	4,39
Propane	0,37	1,64
Isobutane	0,09	-
Butane	0,1	0,74
Isopentane	0,04	-
Pentane	0,02	2,36
Hexane	0,01	-
Nitrogen	1,52	0,26
Carbon Dioxide	0,27	0,94
Helium	0,01	-

Table 19 provides the initial data for the simulations. Some of the values were calculated using the knowledge of reservoir conditions and gas properties.

Table 19. Initial data (JSC "Sevmorneftegas", 2007; Razhev E.V., 2016)

Parameter	Units	Shtokman field	Leningradskoye field
		Value	
Average wellhead temperature	°C	40	35
Max reservoir pressure	MPa	23,9	12,5
Initial reservoir temperature	°C	55	50
Max predicted wellhead pressure	MPa	16,8	10,2
Max annual production rate	bln. m^3/year	24	16
	mln. m^3/day	69	43,8
Min annual production rate	bln. m^3/year	6	-
	mln. sm3/day	17	-

Water fraction in the initial composition for both fields (for reservoir pressure and temperature) was identified using the graph provided by Gritsenko A.I. et al. (1995) (see Appendix 4). Initial water fractions for Shtokman and Leningradskoye fields equal to 0,2% and 0,15%, respectively.

The resulting phase envelopes for the considered fields are shown in Fig. 49. and 50.

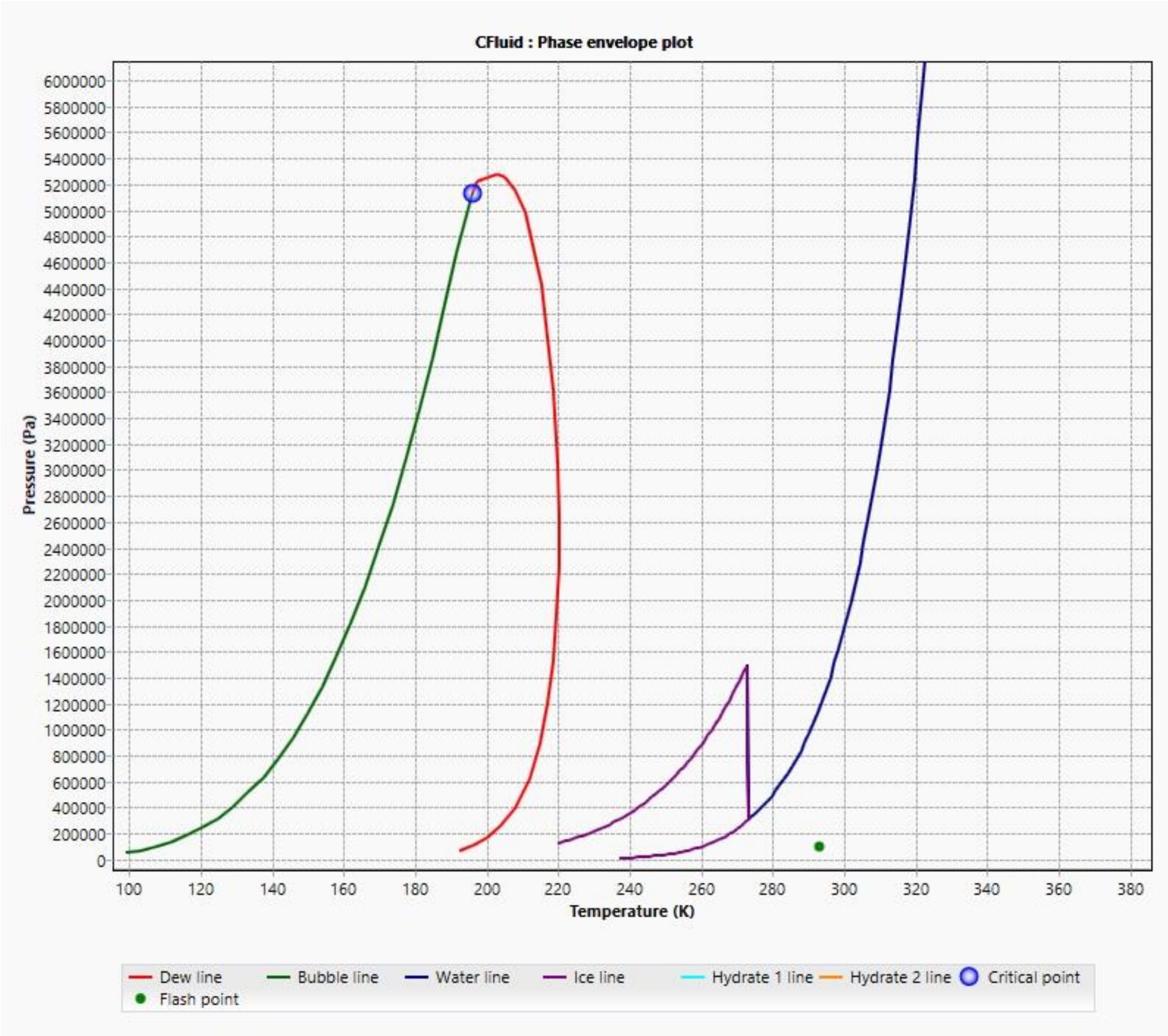

Fig. 47. Phase envelope for the Shtokman field gas composition generated by PIPESIM

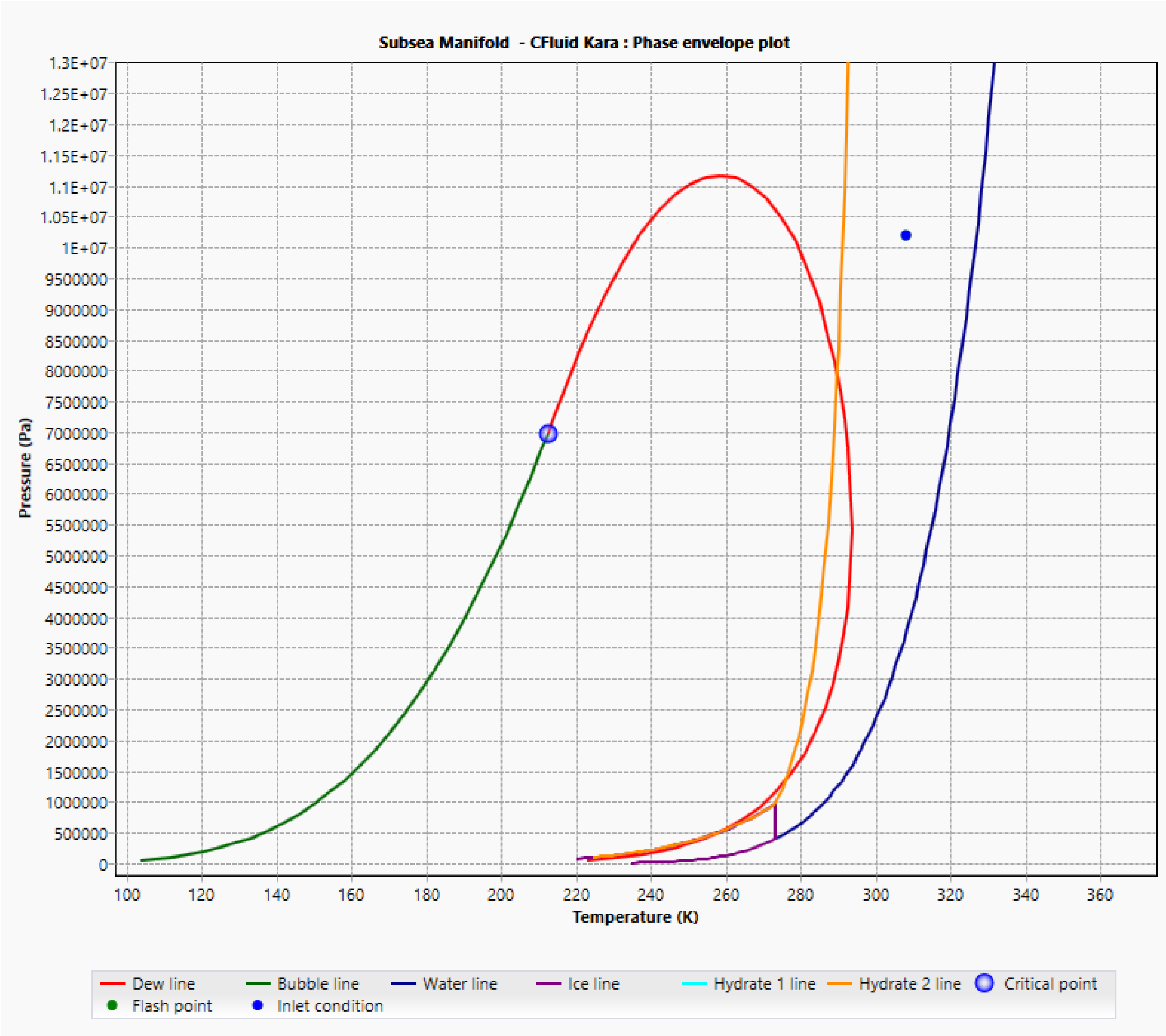

Fig. 48. Phase envelope for Leningradskoye field gas composition generated by PIPESIM

It is important to note that due to dry composition of the gas from the Shtokman field and low water content for the initial period of the production there are no hydrate lines on the diagram.

Possible pipeline routes and profiles from the Barents and Kara Seas to Novaya Zemlya were provided in the previous section. Fig. 51 once again illustrates the profiles of the pipelines.

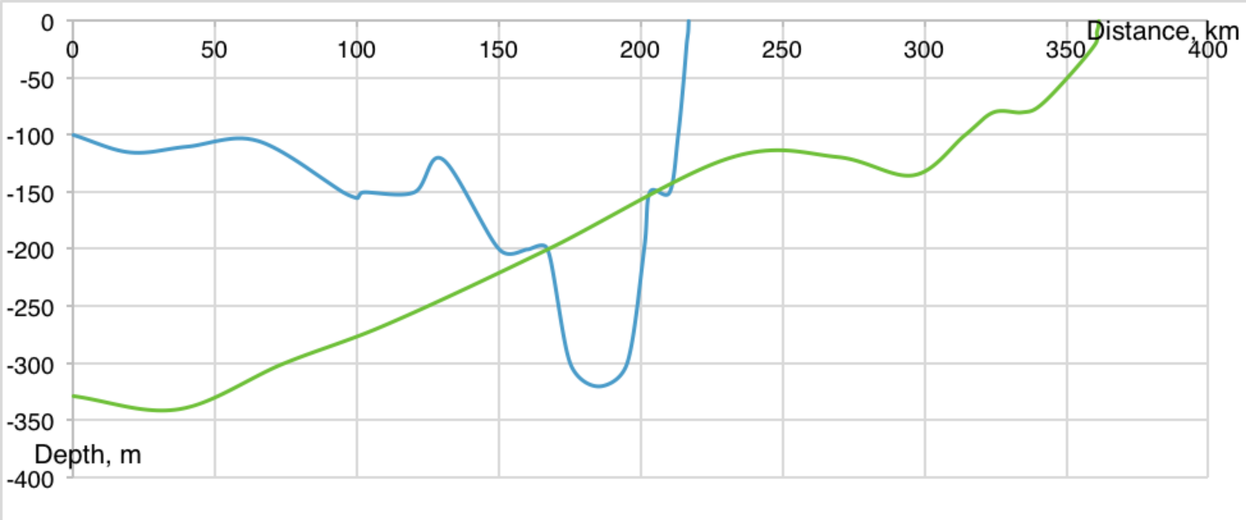

Fig. 49. Pipeline profiles for the Barents and Kara Seas (blue – Kara Sea, orange – Barents Sea)

The profiles are characterized by significant differences in elevations of the landscape and long routes of the pipes with several considerably steep sections. These parameters put additional challenges to flow assurance introducing potential spots for hydrate and plug occurrence.

Initial diameters of the pipelines were assumed to be 36 inches in accordance with Shtokman field development project (SJC "Sevmorneftegas", 2017).

Additional parameters of the pipelines are summarized in Table 20.

Table 20. Pipeline parameters and assumptions (SJC "Sevmorneftegas", 2007; PIPESIM default settings)

Parameter	Unit	Value
Pipe conductivity	W/(m*K)	45
Ground conductivity	W/(m*K)	2,5
Pipe burial depth (pipe is half buried)	m	0
Outside diameter	inch	36
	mm	914,4
Wall thickness	mm	33,5
Roughness	mm	0,0254
Soil type	Clay soil (frozen)	
Soil conductivity	W/(m*K)	2,51
Seawater gradient/current	North Sea	
Multiphase flow correlation	Beggs &Brill Original	

Pipeline insulation plays one of the key roles in flow assurance. Common offshore insulation layers were considered in the current analysis. Their characteristics are provided below in the Table 21.

Table 21. Insulation parameters (SJC “Sevmorneftegas”, 2007; http://www.engineeringtoolbox.com)

Layer	Thickness, m	Thermal conductivity, W/(m*K
1. Bitumen	0,006	0,17
2. Polypropylene	0,005	0,15
3. Concrete	0,04	1

Fig. 52 illustrates the cross section view of the simulated pipeline with all the insulation layers. The pipe is assumed to be half buried which might not be always an option.

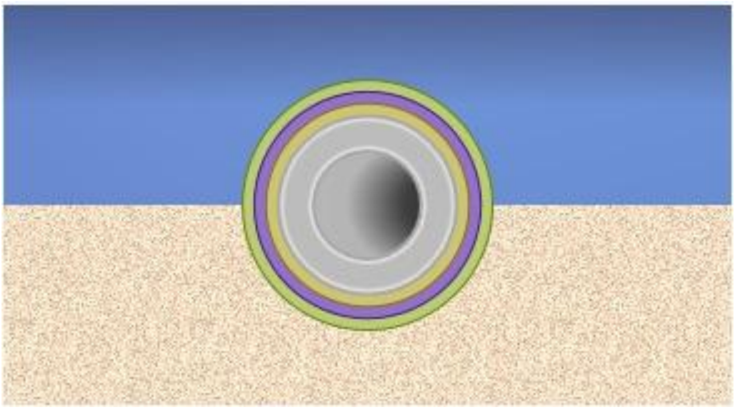

Fig. 50. Pipeline cross section view with insulation layers (PIPESIM)

The objective of the study is to analyze whether there is a possibility for multiphase fluid transportation to the Novaya Zemlya archipelago without preliminary separation and compression. Therefore, it is important to investigate how flowrate and initial pressure influence the pipeline flow regime, hold up, overall pressure loss, temperature drop and other operational parameters. For the following simulations it is assumed that wellhead pressure is equal to the manifold pressure and to the inlet pipeline pressure, respectively.

Case 1

In the first case all production capacities are transported via one trunk pipeline. Initial input data and the results are provided in the Table 22 and Fig. 53. and 54.

Table 22. Input data for the case 1.

Parameter	Unit	Barents Sea	Kara Sea
		Value	
Inlet pressure	MPa	16,8	10,2
Flowrate	bln. sm3/year	24	16
	MMsm3/day	69	43,8
Internal diameter	mm	850	850

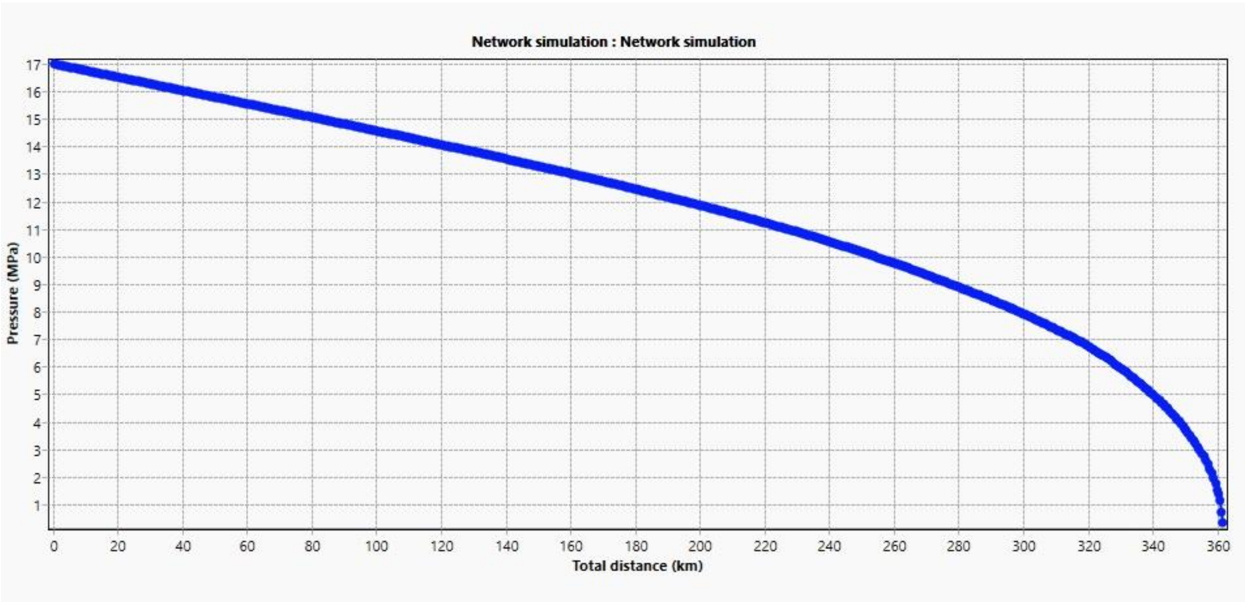

Fig. 51. Pressure distribution along the Barents Sea pipeline (69 MMsm^3/day, 36”)

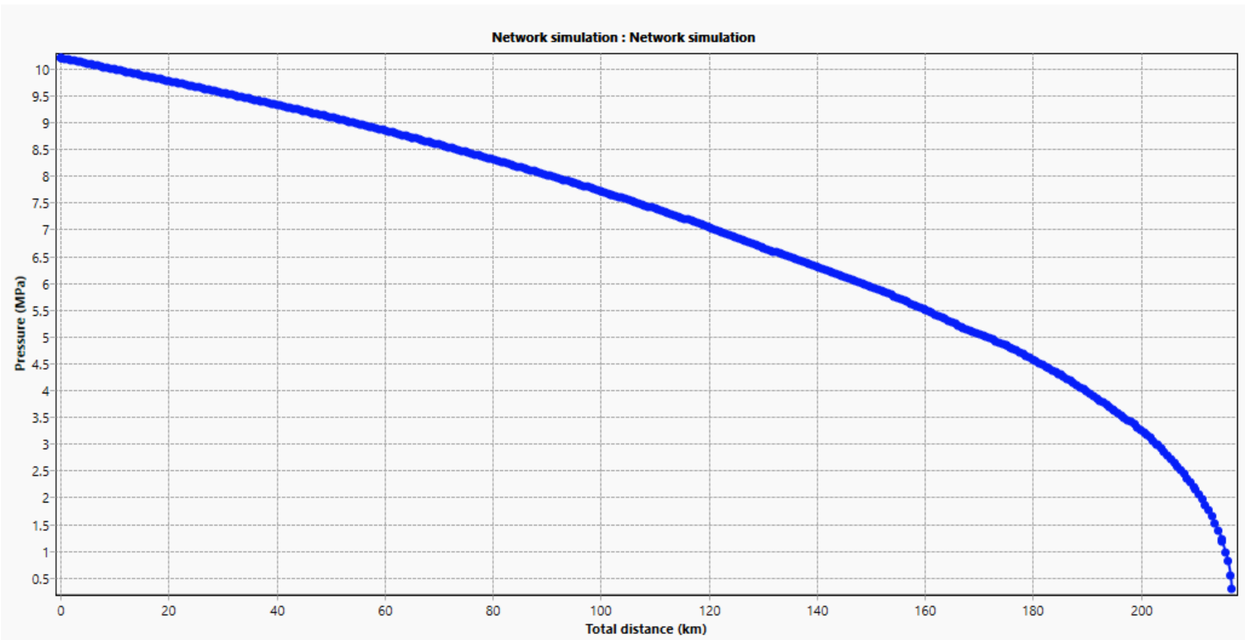

Fig. 52. Pressure distribution along the Kara Sea pipeline (43,8 MMsm^3/day, 36”)

Obtained graphs illustrate that pressure drop is very significant for both pipes. Even though the inlet pressure was assumed to be equal to the maximum wellhead pressure, it almost goes to zero after 360 and 217 kilometers respectively. Therefore, either flowrate should be decreased or initial pressure should be increased or geometrical parameters of the pipe should be changed (larger diameter can be considered). It is also necessary to note that pipeline outlet pressure is supposed to be not less than 3 - 3,5 MPa entering the processing facilities of LNG plant (SJC “Sevmorneftegaz”, 2017).

Case 2

To decrease the pressure loss pipeline diameter was enlarged to 40”.

For the Barents Sea pipeline the pressure drop was again too large and the outlet pressure was not enough for entering the processing facilities. For the Kara Sea, on the other hand, the increased pipeline diameter led to considerable decrease in pressure loss and an appropriate result was obtained (see Fig. 55).

For the Barents Sea it was chosen to divide an overall flow between two pipes with the same diameter (36 inches) to decrease the pressure loss as it might be difficult to carry out an installation of pipelines with the diameter larger than 40” in deep waters of the Barents Sea. In addition, a concrete layer would also complicate the installation process increasing the tension on the equipment. Generally, S-Lay method is applied for laying the pipes with large diameters as other pipe laying techniques such as J-lay and Reel-lay are used for smaller pipeline diameter installations. However, additional analyses are necessary to prove the suggestion.

Table 23 provides the input data and Fig. 55 and 56 show the results for considered parameters.

Table 23. Input data for case 2

Parameter	Unit	Barents Sea	Kara Sea
		Value	
Inlet pressure	MPa	16,8	10,2
Flowrate	bln. m^3/year	12	16
	mln. m^3/day	34,5	43,8
Internal diameter	mm	850	950

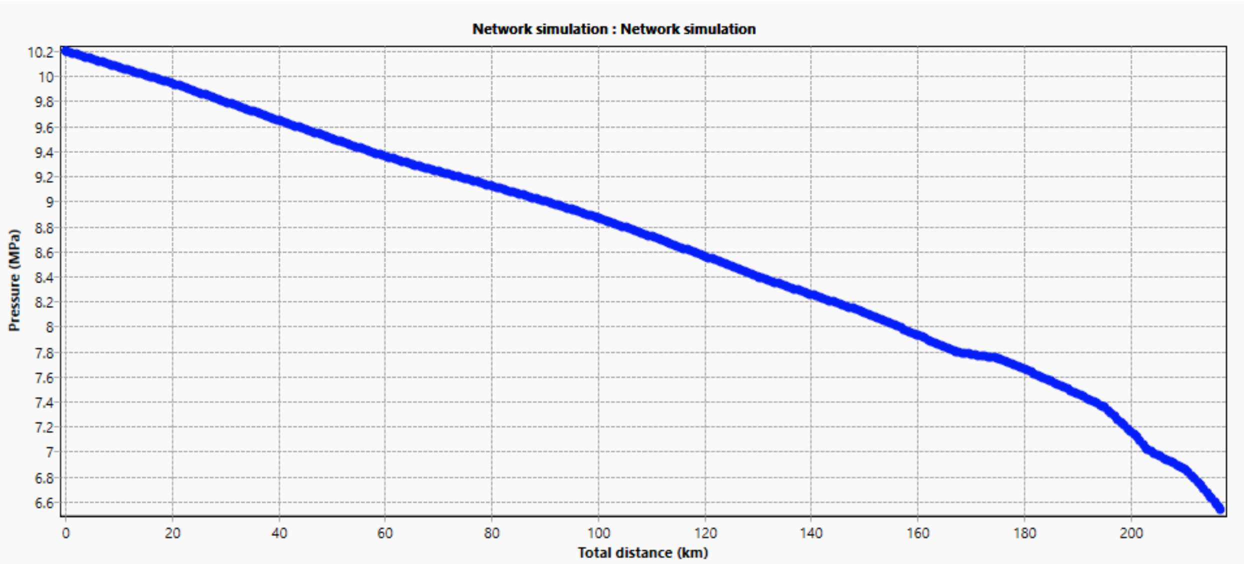

Fig. 53. Pressure distribution along the Kara Sea pipeline (43,8 MMsm^3/day, 40”)

A pressure drop of 3,7 MPa was obtained for 217 km. Therefore current diameter is suable for further analyses.

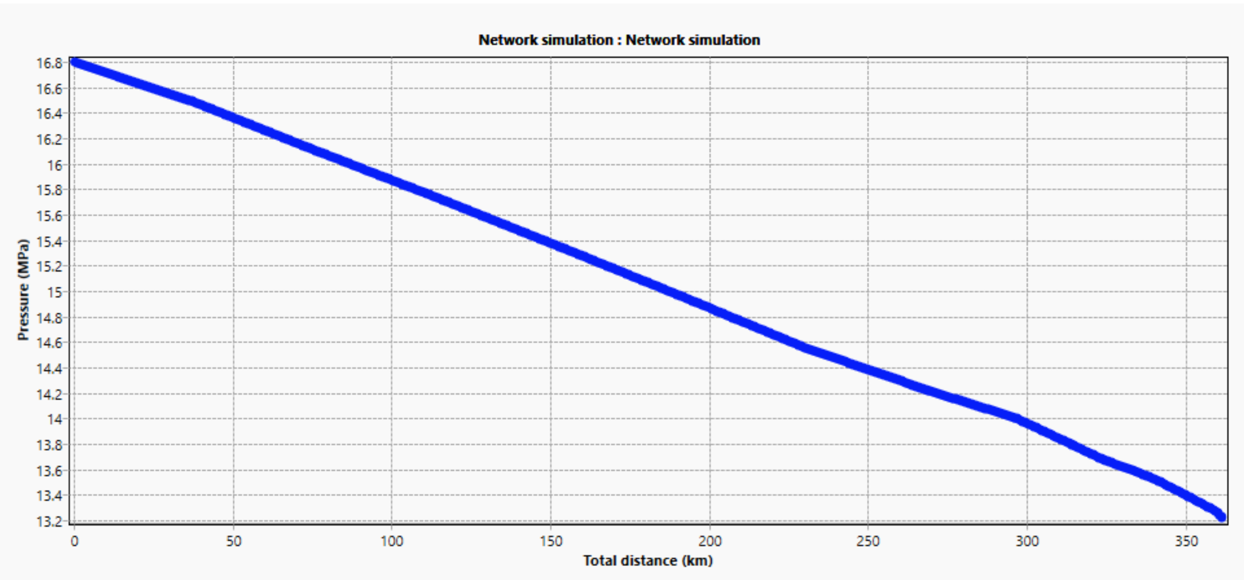

Fig. 54. Pressure distribution along the Barents Sea pipeline (34,5 MMsm^3/day, 36”)

Pressure drop from the provided graph is about 3,6 MPa, which is very sufficient for 360 km subsea pipeline. Therefore, suggested flowrate is suitable in combination with given diameter.

Furthermore, additional parameters were examined (temperature, liquid fraction holdup, fluid velocity) to evaluate possible challenges (see Fig. 57. and 58.).

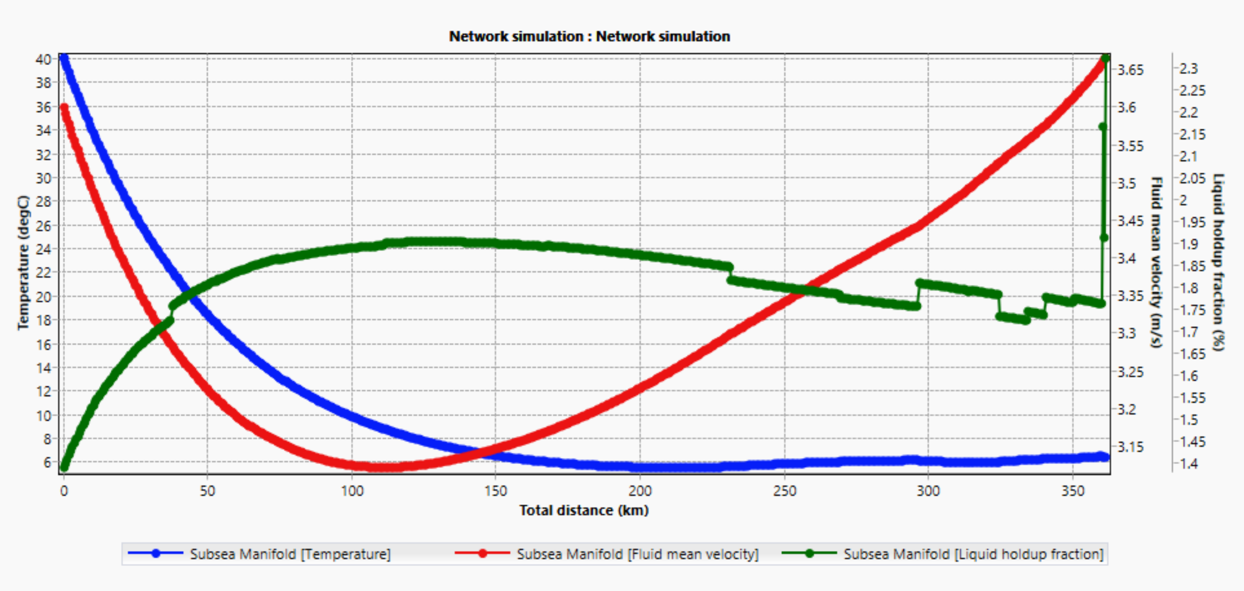

Fig. 55. Temperature, fluid mean velocity, liquid holdup fraction for the Barents Sea pipeline

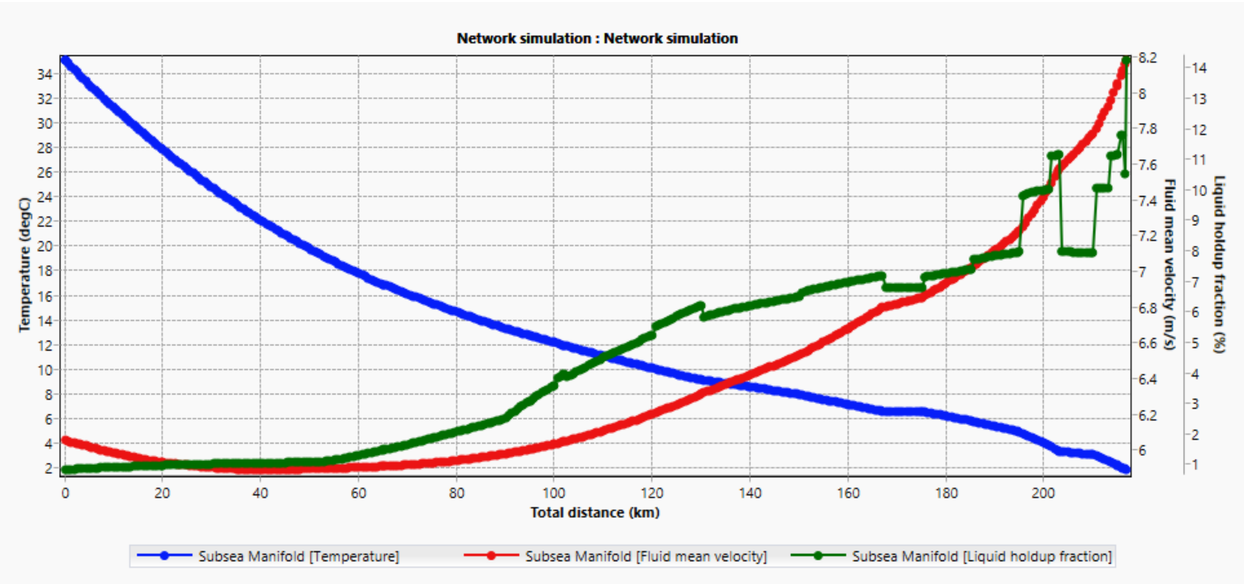

Fig. 56. Temperature, fluid velocity, liquid holdup fraction for the Kara Sea pipeline

Temperature drops are significant in both cases, going as low as 2-3 ºC. However, with provided insulation, temperature does not reach negative values, which ensures the little probability of ice plugs. Liquid holdup is more considerable in the Kara Sea pipeline, reaching 14% value, which is reasonable since gas is wet in this case. Fluid velocity in the first case experiences a drop during the first 100 kilometers and then goes back up, the difference is not as significant though and is equal to 0,5 m/s. Such behavior could be the result of temperature decrease and partial phase change from gas to liquid, which is also proved by increased liquid holdup fraction in the same section. In some cases the gas volume in the pipe decreases, and consequently the velocity might no longer be sufficient to drag the liquid up. Thus, liquid holdup might increase and slug flow regime might form at certain places (Minikeeva, A., & Gudmestad, O. T., 2013). Mean fluid velocity in the Kara Sea pipeline is smoothly increasing due to pressure losses and subsequent gas density decrease. Increasing liquid holdup fraction does not slow down the flow speed due to high fluid velocity in contrast with Barents Sea pipeline. In addition, further analyses on hydrates will be carried out to investigate whether they can potentially be formed in the pipelines in considered conditions.

Case 3

As reservoir pressure decreases throughout the lifecycle of the field it is necessary to assess when additional boosting equipment might be required for sustainable transportation. Taking into account predicted wellhead pressures and flowrates for the 1st Shtokman field development phase (see Fig. 59), pressure drop analyses were carried out for different years of production for the Barents Sea.

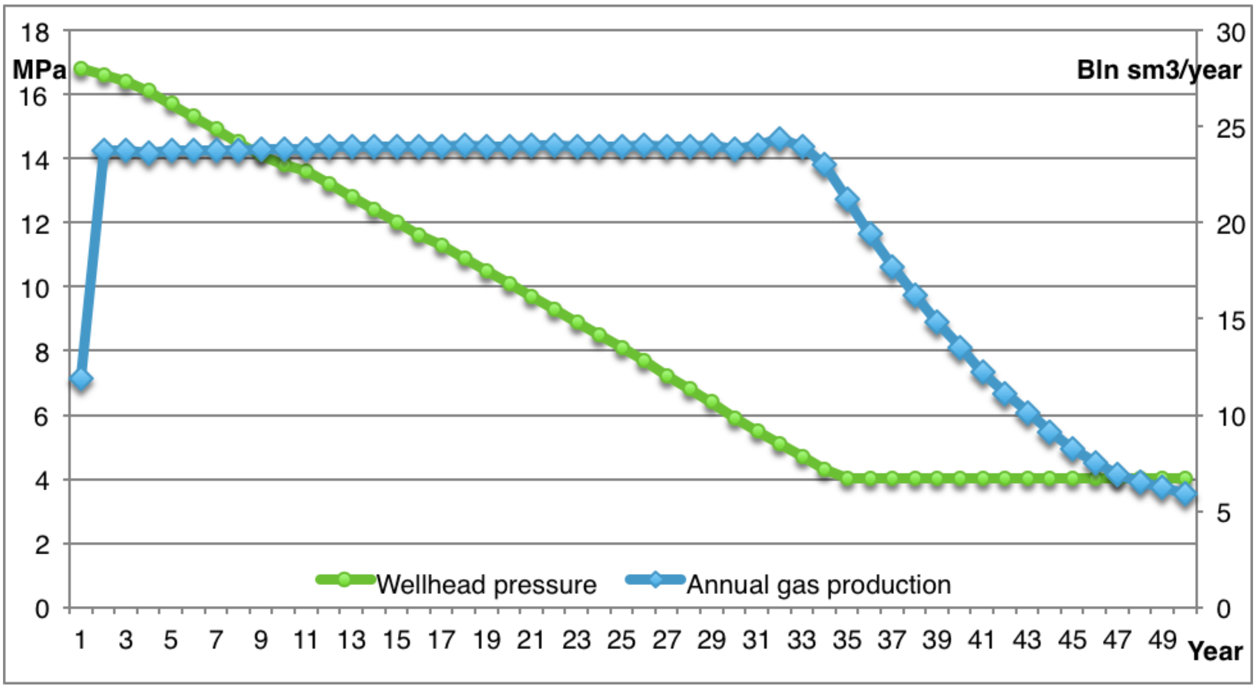

Fig. 57. Wellhead pressure and annual production throughout the lifecycle of the field ("Sevmorneftegaz", 2007).

The most valuable results are provided in the Table 24 and Fig. 60.

It is important to emphasize that composition of the fluid was assumed to be the same for the different years of production.

Table 24. Input data and results for the case 3

Year of production	Production rate, bln. sm3/year	Production rate, bln. sm3/year	Flow rate per pipe, MMsm3/d	Inlet pressure, MPa	Outlet pressure, MPa
1	11,9	11,9	16,3	16,8	15,5
2	24	24	32,9	16,6	13,0
20	24	24	32,9	10,1	3,24
21	24	24	32,9	9,7	0,97

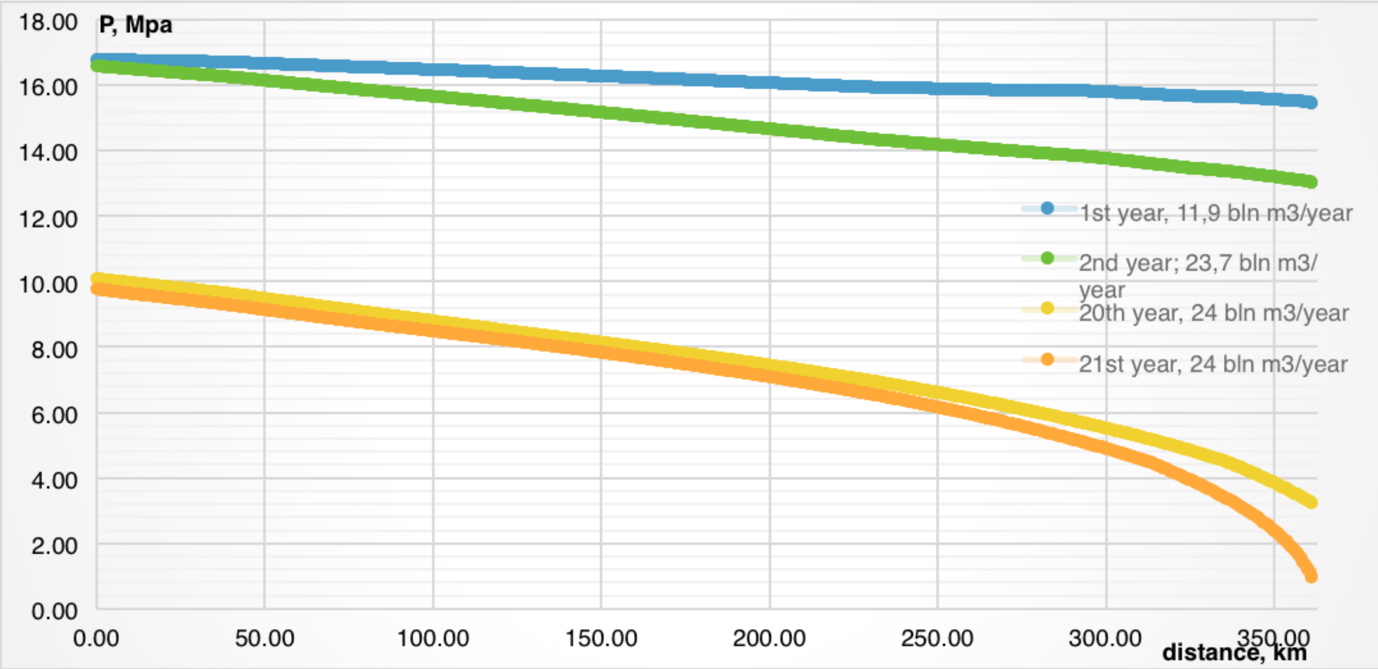

Fig. 58. Pressure distribution for different production years

The graph illustrates that in-between the 20th and 21st year of production the flow regime stops meeting the requirement for the outlet pressure. Therefore, it might be necessary to add boosting capacities when wellhead pressure will be around 10 MPa. By the end of twenty years of production period all capital expenses are supposedly paid off and it could be economically viable to install additional compressing stations. State-of-the-art technologies allow placing compressors and separators on the seabed as well as on the floating structures and additional feasibility study is required for evaluating the appropriate type.

It is also important to carry out the same analyses for the Kara Sea. However, existing amount of data and exploration level (only two exploration wells were drilled) would not make it currently as accurate.

Case 4

Another threat while dealing with multiphase flow is the hydrates formation. Gas hydrates are crystalline compounds with a snow-like consistency that occur when small gas molecules come into contact with water at or below a certain temperature. The hydrate formation temperature increases with increasing pressure, therefore, the hydrate risk is the greatest at higher pressures and lower temperatures. When hydrates form inside pipelines, they can create plugs, which obstruct the flow. In even worse scenarios, where the presence of a hydrate plug was undetected, pipeline depressurization has resulted in the plug being dislodged unexpectedly, resulting in serious injury and even fatalities. These are some of the reasons that hydrates are a serious flow assurance concern.

Hydrate forming molecules commonly include methane, ethane, propane, carbon dioxide, and hydrogen sulfide. Three hydrate crystal structures have been identified - Structures I, II, and H. The properties and characteristics of Structures I and II hydrates are precisely investigated and defined. However, research into structure H hydrates is relatively new, so the properties are still poorly evaluated. Hydrates are very likely to appear right after the choke due to Joule-Thompson cooling effects when fluid temperature drops into the hydrate formation region (Lin et al, 2005).

The following Fig. 61 shows a typical gas hydrate curve, which is very useful for subsea pipeline design and operations. On the left side of the curve is the hydrate formation region.

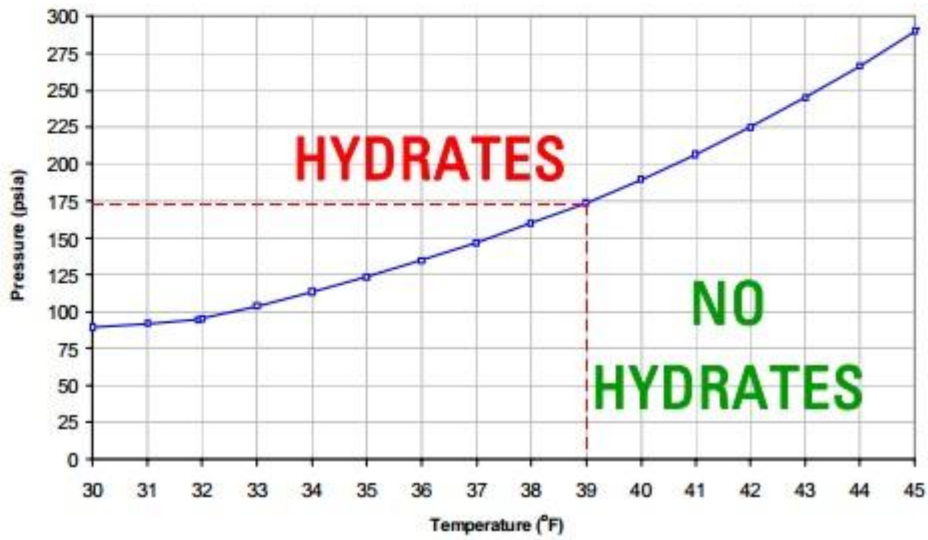

Fig. 59. Typical gas hydrate curve (PIPESIM manual)

For hydrate prevention one should stay outside of the hydrate equilibrium region. Many factors influence the hydrate curve including fluid composition, water salinity and the presence of hydrate inhibitors.

The most effective way to mitigate flow assurance risks in the pipelines is to separate all the water subsea. However, the most effective way may not be the most economical. Currently, two common strategies to mitigate hydrate formation are thermal insulation and chemical inhibitors. Both strategies can be simulated in PIPESIM. Thermal insulation provides a higher up-front capital cost, whereas chemical inhibition carries more significant operational costs.

There are several different insulation methods available in the industry:

1. "Cast-in-place" - directly cast insulation materials onto the outer surface of the pipeline. The insulation materials for this application may be a layer of homogeneous material or may consist of multiple layers.

2. "Pipe-in-pipe" - the hydrocarbon pipeline is put into another concentric pipeline. The space in-between the pipelines is normally filled with insulation material (Lin et al, 2005).

Pipe-in-pipe insulation technique is generally more effective than "Cast-in-place" but is also usually more expensive and complex in terms of installation and manufacturing.

Electric heating is another method of hydrate mitigation. It can be divided into direct electric heating and indirect electric heating. With the first method electric current flows axially through the pipe wall and directly heats the flowline. For the indirect heating, on the other hand, electric current flows through a heating element on the pipe surface and the flowline is then heated through thermal conduction (Guo, B. et al, 2013).

Electric heating is applied as both mitigation and intervention/remediation method for hydrate problems. Raising the temperature of the fluid with the given pressure would shift the conditions to the right, leaving the hydrates formation zone. Electric heating might be implemented to melt the hydrate in case of a hydrate plug formation. In this way, the hydrate will be melted much faster than using pipeline depressurization (Guo, B. et al, 2013).

Pipeline depressurization is commonly applied to remove hydrate plug in case of a long shutdown. It is reasonable that non-hydrate region can also be obtained by reducing the pressure for a given temperature and no hydrate would form in the system. In addition, if the hydrate plug is already formed in the pipeline, depressurization can be applied to melt it. It can take several weeks or even months for the hydrate plug to completely dissociate, that is why it is so important to design and operate subsea pipeline out of hydrate region. For safety reasons, it is always better to be able to depressurize the pipeline from both sides of the hydrate plug (Guo, B. et. al, 2017).

To evaluate possible hydrate formation in the considered pipelines following steps were conducted using the PIPESIM simulator.

1. Evaluation of hydrate sub-cooling temperature difference, which is the difference between the hydrate formation temperature and the flowing fluid temperature ($T_{hyd} - T_f$). If this difference is positive, then the fluid is in the hydrate formation region at that location in the system.

Following Fig. 62 and 63 show the results for considered pipelines.

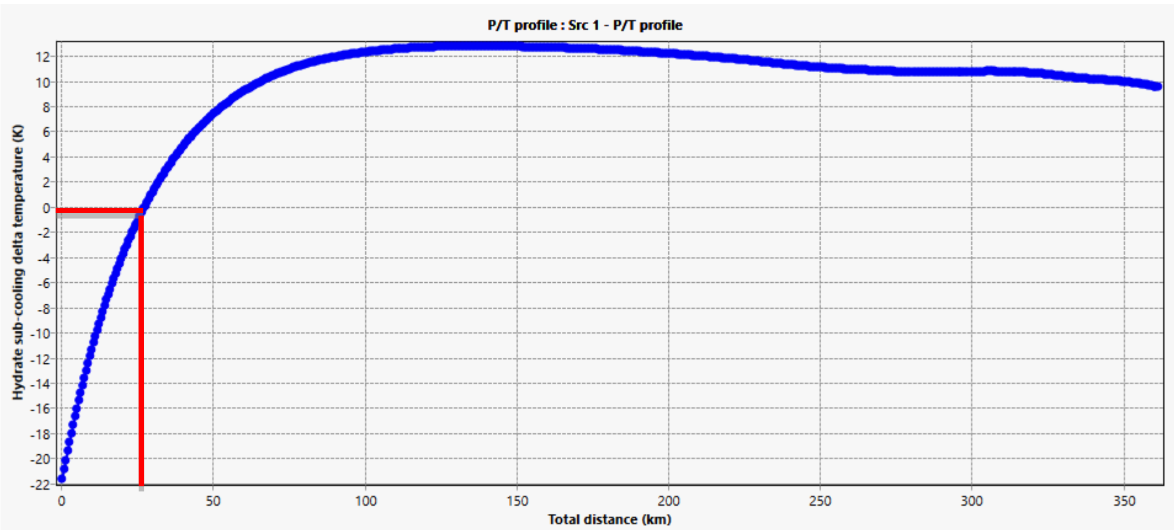

Fig. 60. Hydrate sub-cooling delta temperature for the Barents Sea pipeline

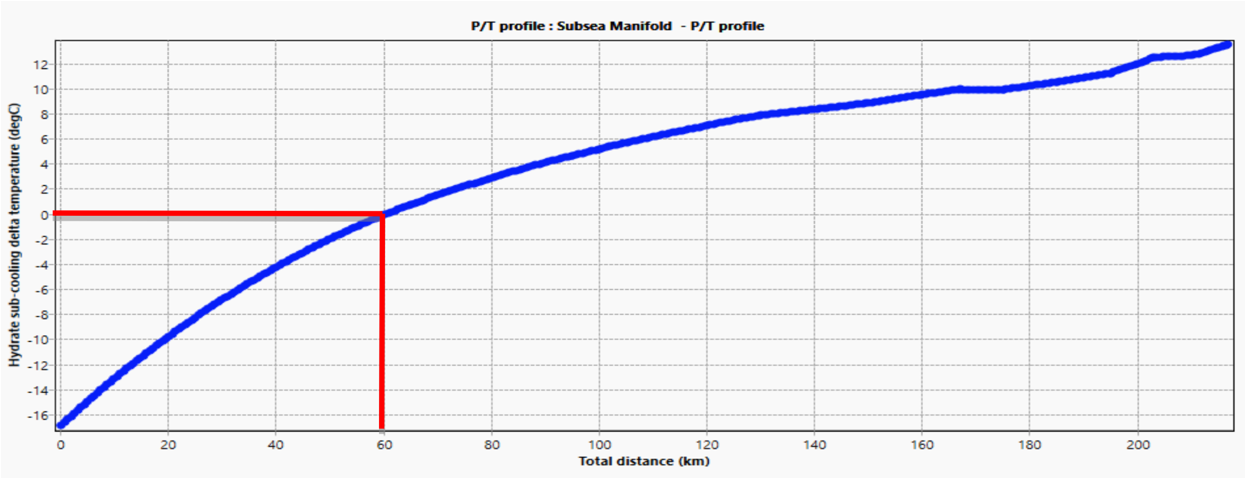

Fig. 61. Hydrate sub-cooling delta temperature for the Kara Sea pipeline

For the Barents Sea pipeline it is observed that hydrates are likely to form after just 25 km distance as the sub-cooling delta temperature goes from negative to positive values. For the Kara Sea the same situation occurs after 60 km distance. It is also noticeable that in the Barents Sea the most dangerous situation with highest delta temperature occurs around 125th kilometer of the pipeline, whereas for the Kara Sea it is at the end of the route.

Therefore, only thermal insulation is not enough to preserve the high temperature and keep the fluid conditions to the right side from the hydrate curve. The heat transfer between the fluid in the pipeline and the environment surrounding the pipeline is dependent on the temperature gradient and the thermal conductivity of the material between the two. It is not normally very efficient to use just thermal insulation to mitigate the hydrate risks in gas pipelines due to significant difference in gas and liquid densities and thermal masses, which equals to density times the heat capacity (Guo, B. et al, 2013).

To shift the hydrate curve to the left, thermodynamic inhibitors can be injected. Thermodynamic inhibitors only change the pressure and temperature conditions of hydrate formation: the hydrate formation temperature decreases or the hydrate formation pressure increases and, therefore, operating conditions can escape the hydrate occurrence zone.

Two kinds of thermodynamic inhibitors are commonly used: methanol and ethylene glycol (MEG).

Following phase envelopes (see Fig. 64 and 65) display how the calculated flowing P/T profile line intersects with the hydrate formation line to observe the hydrate risk from the phase envelope viewer.

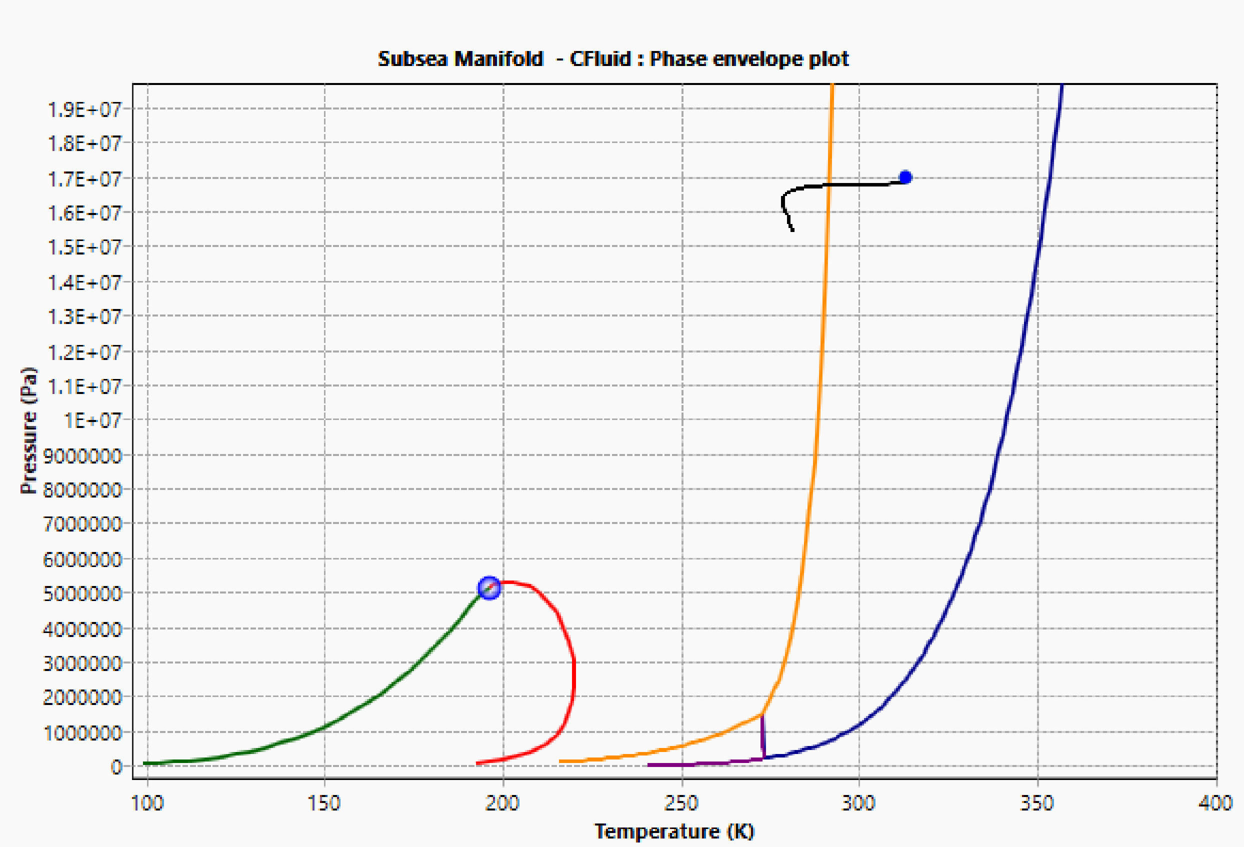

Fig. 62. Phase envelope with P/T profile for the Barents Sea

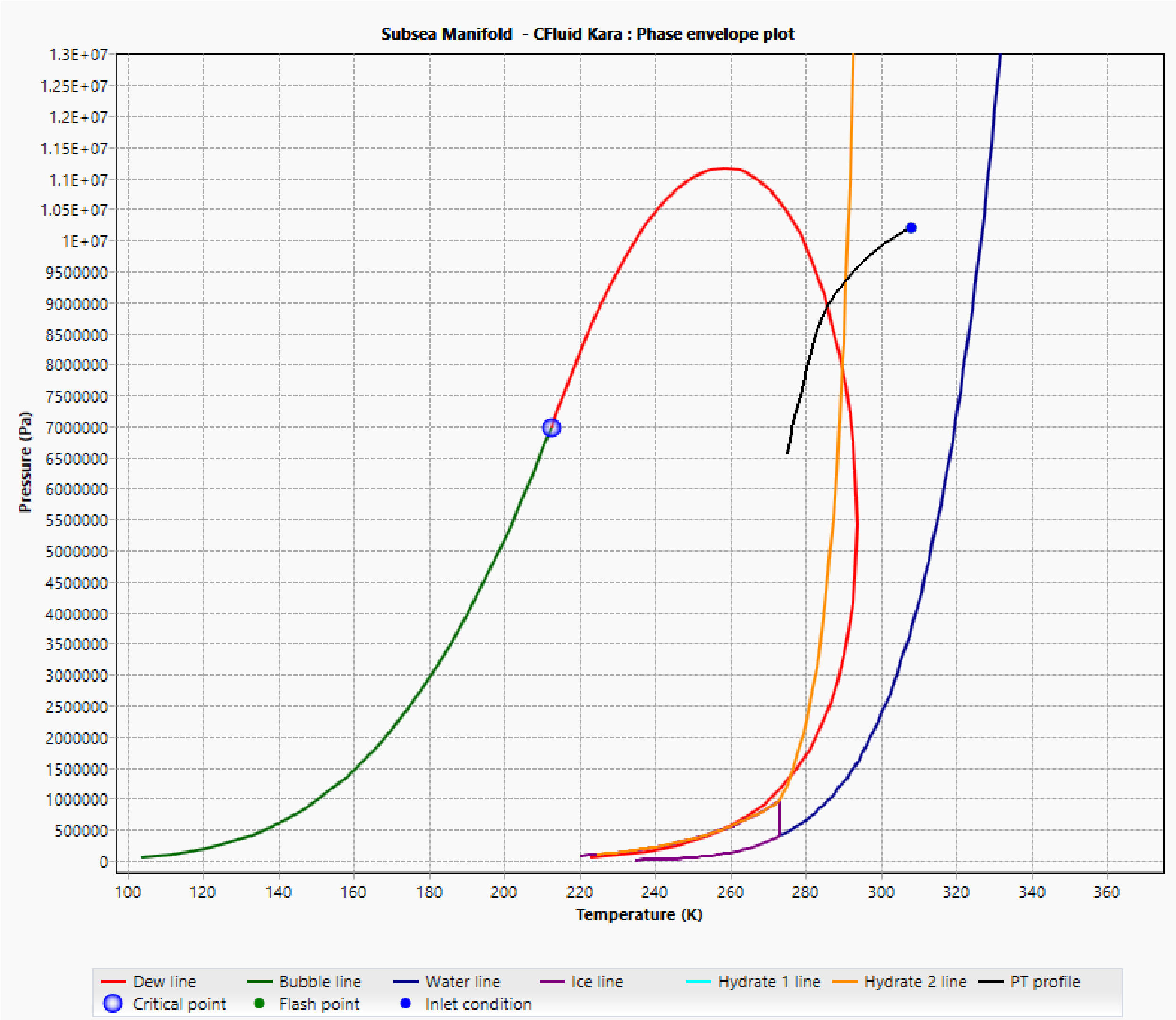

Fig. 63. Phase envelope with P/T profile for the Kara Sea

2. Required amount of inhibitor was determined for each case by simulating different injection rates of Methanol and MEG into the pipelines. Maximum Hydrate sub-cooling temperature difference was analyzed, which is the maximum value of the Hydrate sub-cooling temperature difference throughout the system for each of the cases run.

Technically, when known how much temperature needs to be reduced, the amount of inhibitor needed in the free water can be estimated using the following equation (Hammerschmidt):

$$W_i = \frac{100 \cdot M_i \cdot \Delta T_h}{(C_i + M_i \cdot \Delta T_h)},$$

where

W_i - weight percent of the inhibitor in liquid;

C_i - constant, 2335 for methanol and 2000 for MEG;

M_i - molecule weight of methanol or MEG;

ΔT_h - hydrate sub-cooling, temperature difference that has to be reduced by inhibitor.

From the provided plots (Fig. 66 and 67) the minimum required Methanol and MEG injection rates were determined to maintain the flowing fluid temperature above the hydrate formation temperature, at every point in the system (i.e. Maximum Hydrate sub-cooling temperature difference < 0).

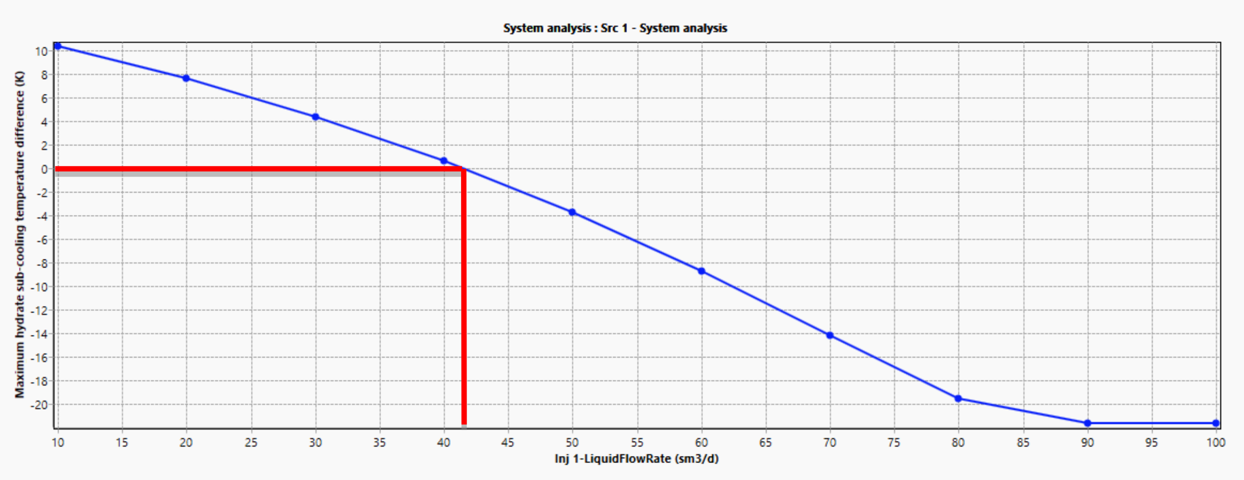

Fig. 64. System analyses for minimum required Methanol flowrate evaluation for the Barents Sea pipeline

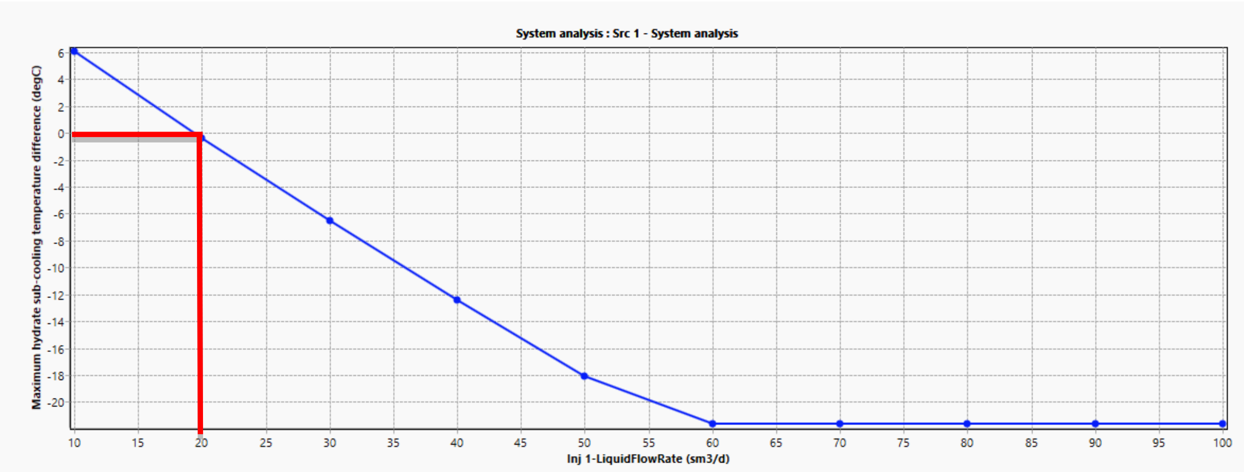

Fig. 65. System analyses for minimum required MEG flowrate evaluation for the Barents Sea pipeline

The same simulations were carried out for the Kara Sea and results are provided in the Table 25.

Table 25. Minimum required inhibitor rates for the pipelines

Parameter	Units	Value	
		Barents Sea	Kara Sea
Req. Methanol Injection Volume	Sm3/day	42	55
Req. MEG Injection Volume	Sm3/day	20	28

Required MEG flowrate is less than Methanol and it can be reasonable to use mono ethylene glycol as an inhibitor for the considered pipelines as this would require smaller diameter for injection lines. The results also emphasize that for the Kara Sea more inhibitor is needed which is the outcome of both composition and pressure/temperature distribution along the pipeline.

To check the accuracy of the results another graphs for the sub-cooling delta temperature for the Barents and Kara Sea pipelines were built after adding the required amount of inhibitor (see Fig. 68. and 69.).

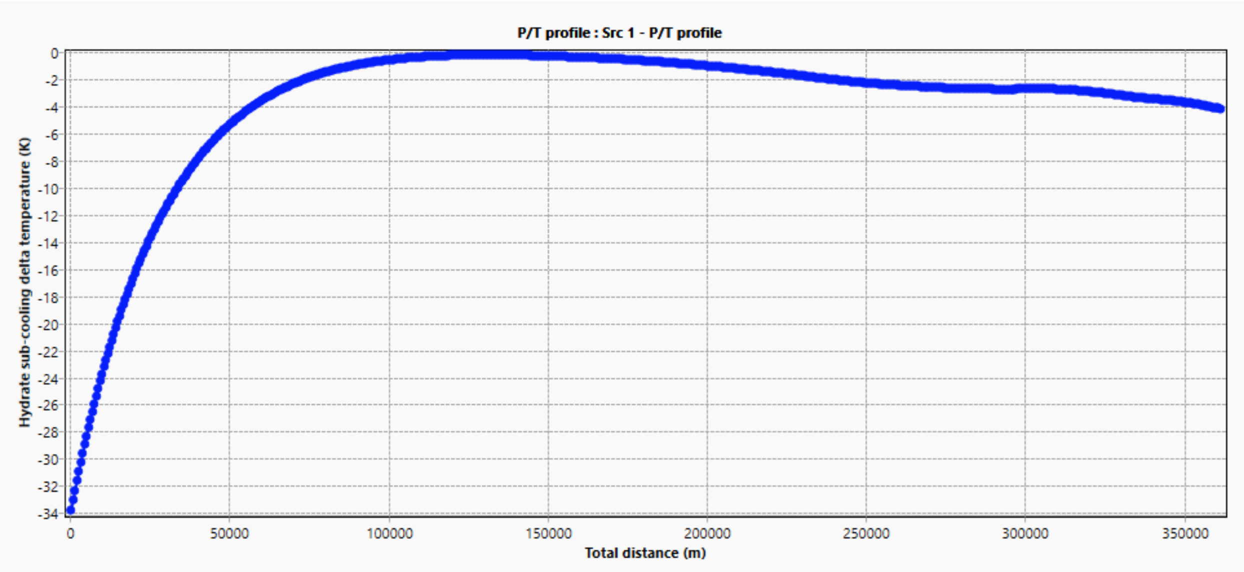

Fig. 66. Hydrate sub-cooling delta temperature for the Barents Sea pipeline after adding inhibitor

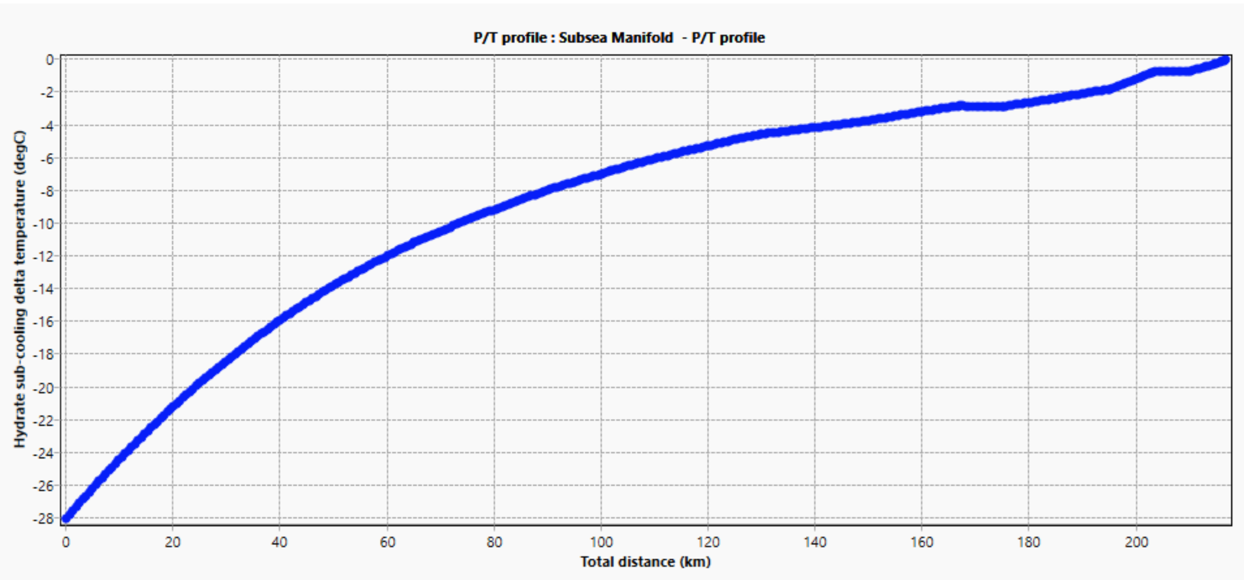

Fig. 67. Hydrate sub-cooling delta temperature for the Kara Sea pipeline after adding the inhibitor

It is observed that sub-cooling delta temperature doesn't exceed 0 degrees now, therefore, there are no preferable conditions for hydrate occurrence.

Preliminary conclusion

According to the conducted analyses in the PIPESIM simulator software, it is possible to execute the pipeline multiphase transportation of produced hydrocarbons from the Barents and Kara Seas to the Novaya Zemlya Archipelago designing two 36-inch (914 mm) pipelines for the Barents Sea and one 40" (1016 mm) pipeline for the Kara Sea. The initial pressure drop is predicted to be ca. 3,6-3,8

MPa for both cases for analyzed fluid compositions. The temperature of the fluids (for provided insulation parameters) doesn't fall below zero degrees, which is a good sign for flow assurance.

Obtained results have illustrated that additional boosting capacities might be necessary after 20 years of operation for the Barents Sea. However, if demand for natural gas will still be growing and subsequent phases of the Shtokman field will be developed, additional pressure and flowrate may eliminate the necessity of compressors and separators.

Low ambient water temperatures in the Barents and Kara Seas vary significantly from -1,7 to 7 °C influencing the flow parameters and hydrate formation analyses evaluated the possibility of hydrate occurrence in both pipelines. To insure a sustainable transportation of the multiphase fluid and prevent hydrates formation with increased water fraction, following mitigation measures were analyzed and suggested for the considered gas subsea pipelines:

- "Cast-in-place" thermal insulation;
- Continuous injection of MEG which can be recovered at the shore and recirculated after regeneration;
- Possibility of system depressurization for remediation of potential hydrate plugs.

Electric heating is not as applicable for the considered concept due to remoteness of the area and the cost of electricity production.

It is important to mention that due to the lack of commercial and geological information several assumptions have been made about the fluid properties and the topography of the seabed. It could lead to a certain slight inaccuracy in pressure loss evaluation.

Additional analyses are required for subsequent years of gas production when water content will be increased to evaluate the water accumulation along the pipelines and approximate amount of inhibitor needed in the future.

9.3 Pipeline shore crossing

9.3.1 General description

The landfall interface is a very relevant design problem for all marine pipelines, especially in the Arctic conditions. A lot of concerns and cost overruns in pipeline construction have occurred in this area. Design requires precise awareness of the complex interaction of the geological, hydrodynamic and biological factors that have formed the shore geomorphology.

Ice scour is still important in the landfall area, though the maximum scour depth and subscour deformation depth are less than in deeper waters. Ice driven by onshore winds is pushed onto the shore and may pile up to substantial heights, causing large gauges in the beach. In addition, differential bending deformation may occur in the pipeline when the permafrost starts to thaw. The pipeline is also vulnerable to the wave and sediment transport effects that make shore crossing design difficult in temperate areas, and the design may have to account for large excursions in the beach profile between winter and summer (Gudmestad et al., 1999).

Consequently, deep burial of the pipeline is required in order to protect it against scour and ice loads. It will then be below the permafrost boundary in at least some of the crossings, certainly on shore and possibly in shallow water. In addition, an extensive zone of warm weak permafrost may appear due to unknown properties of the saline permafrost, which will contribute to disturb the thermal equilibrium. One should arrange the regime of pipeline operation so that the flowing temperature is close to the temperature of surrounding permafrost. This way neither frost heave nor thaw induced differential settlement will occur. The section of a line will have to be heavily insulated to avoid wax and hydrate formation for oil and multiphase flows.

9.3.2 Methods of shoreline crossing construction

Trenching. So far, burial of the flowline in a trench on the sea floor is the most common protection from ice gouging and landfall design method in the Arctic. Strategies such as covering the flowlines and umbilicals with concrete, gravel or rock, bundling more than one line, strengthening the pipe or anchoring the pipe can be used in combination with trenching to reduce the risk of ice damage (ISO-19906, 2010).

So far, general process of arctic pipeline system construction with implementation of trenching technology includes following steps (Cowin et al., 2015):

1. Pre-fabrication of line pipe

2. Ice road construction and maintenance

3. Ice cutting and slotting

4. Trenching (dragline or a cutter-suction dredger)

5. Pipe string make-up (welding, anodes, field joints)

6. Bundle make-up

7. Bundle installation

8. Cable installation

9. Backfilling the pipeline trench

Hydrostatic testing, dewatering, pipeline integrity inspection and backfill thawing

The additional measure according to Marcellus and Palmer is to protect the mound with armour. This process forms a strong nibble mound breakwater with the pipeline under it. The breakwater has to withstand both wave action and ice action, and in most locations would need to be very heavily armoured.

In many cases rapid erosion processes and permafrost influence appears on the shore. Therefore, special techniques are used to avoid the problems where the pipeline is buried. A sheet pile wall can be used to protect the shoreline from erosion as well as cellular sheet pile construction. Using additional thermosyphons, allows preventing both erosion and permafrost thaw at the place of shore crossing. These methods are used in combination with trenching. Consideration of possible permafrost boundary profiles will be expected during the design phase as well.

Tunnelling. It is possible to set the tunnel at the depth where the pipe is completely safe from the scour. The pipelines are placed inside a submerged concrete tunnel, which acts as an underwater protecting bridge over the rocky seabed.

The tunnel usually consists of several elements depending on its total length. The cross sectional area depends on the quantity of pipes to be laid inside. The tunnel elements rest on heavy foundations, the lower parts of which are cast under water.

The tunnel elements are produced in dry docks, while the foundation work is progressed. The prefabricated tunnel elements then are towed to the installation site, water-ballasted, pulled down to the foundations, and then flooded. After this, the pull-in of the pipelines could be performed.

However, if the shore is relatively steep, a part of a tunnel called shaft is required. A number of difficulties are present in construction of the shaft, especially the method of connecting two parts of the pipeline, which meet in this shaft. There are several techniques to connect the pipeline inside the shaft:

- hyperbaric welding;
- surface tie-in.

Due to complexity, tunnels are relatively costly and the whole process of design and construction is time-consuming and demands a variety of surveys.

Horizontal directional drilling (HDD) is another option, which has been widely used for pipeline shore and river crossings, but has not been implemented for landfall construction in the Arctic yet. It is a very promising and reliable solution as it can be used for horizontal distances of several kilometres and for pipelines up to 56" in diameter (Hair, 2011).

HDD provides an economically advantageous method for installing a pipeline at required depth without the need to excavate a trench from the surface along the HDD alignment.

Thawing of unstable permafrost may be avoided by using HDD to select the formation through which the pipeline will be installed. Facilities would have to be provided at the end points of the HDD segment to secure the pipeline as it passes through the thaw unstable permafrost. This can be accomplished through the application of thermosyphons. In addition, HDD segments can be "stitched" together to allow a longer length of deep burial. The given method significantly reduces environmental impact by the elimination of above ground pipelines supported on thermal piles. Only the "hardened" HDD segment endpoints will extend above the surface.

The capability to select a deep elevation, out of the reach of scouring ice, and trenchless nature of HDD provides pipeline designers with an economical and environmentally feasible solution to a pipeline integrity threat.

Nevertheless, every technology has its restrictions. Three primary characteristics govern the feasibility of an HDD installation (Hair, 2011):

1) subsurface conditions;

2) pipe diameter;

3) drilled length.

9.3.3 Existing practices

In spite of the fact that the offshore Arctic environment imposes several unique conditions on subsea pipelines, a number of pipeline shore crossings were constructed in this harsh region and are described in the section.

<u>Northstar</u> offshore arctic pipeline (Beaufort Sea) is located in a relatively sheltered portion of the seasonal landfast ice zone. Trenching was applied for the landfall construction and two main features were taken into consideration during limit state design – seabed ice gauging and permafrost thaw subsidence. Irregular keels beneath the floating sea ice periodically contact the seabed in the Beaufort Sea shelf area and form gouges. The maximum predicted gouge depth has been estimated to be 1,1 meters (100-year return period). The minimum pipeline depth of cover (distance from original undisturbed seabed to top of pipe) was determined to be 2.2 m. Analyses indicate the Northstar pipeline may develop maximum bending strains of approximately 1.4% due to ice keel loadings. Ice-bonded permafrost is found along the Northstar offshore pipeline route in water depths less than about 1.5 meters.

Because the Northstar pipelines are operated at temperatures above the soil pore water freezing point, a thaw bulb will gradually form around the pipes. The maximum total settlement during the pipeline lifetime is predicted to be approximately 0.61 meters and calculated maximum bending strains is approximately 1.1% (Lanan et al., 2001).

<u>Oooguruk</u> offshore arctic pipeline system located in shallow water in Beaufort Sea has a thaw unstable permafrost soils near the shore.

The shore crossing and offshore gravel island flowline approaches employed a vertical sweep of straight pipes laid onto an open cut trench floor (Lanan et al., 2008). The individual flowlines separate out from the bundled configuration and the power and communication cables return to the flowline trench. The thermal design for the shore crossing transition is intended to keep the flowlines from settling and to keep the thaw-unstable permafrost along the trench frozen. The design includes thaw-stable gravel bedding beneath the flowlines, shallow-slope heatpipes (pressurized with carbon dioxide) on both sides of the flowlines, and a short length of foam sheet insulation. Frozen spoil backfill above the flowlines is expected to thaw and settle, becoming approximately level with the natural grade after several years. An oblique aerial photo of the completed shoreline transition is shown in Fig. 70.

Fig. 68. Oooguruk shore crossing (Lanan et al., 2008)

Sakhalin-2 project is a remarkable example of using a «cofferdam» (sheet pile wall) construction for the transition zone. The «cofferdam» technology was applied with cross-protective structures. The laying of pipelines is carried out using the trenching technique. Meanwhile, the pipelines are laid along the axis of the cofferdam. The special works of filling of the boulders were necessary to strengthen the shore from the thermal and abrasive impacts. Therefore, the facility serves as an obstacle to the long shore sediment transport. It is important to notice, that there is no permafrost in Sakhalin Island (Sakhalin Energy Investment Company LTD, 2005).

According to Grøv E. et al. (2013) existing today tunnels constructed from onshore into the sea for oil and gas projects exceed the lengths of 7,5 km. For instance, the Eiksund tunnel from 2007 with a length of 7.8 km and maximum depth below sea of 287 m. Plans for the future in Norway include both longer and deeper tunnels, i.e. the Rogfast tunnel with a length of 24 km at depth down to about 400 m below sea level is currently in the planning process.

9.3.4 Suggestion for Novaya Zemlya landfall design

Geologically and structurally, Novaya Zemlya is extremely complex. It is a continuation of the Ural Mountains system, is for the most part mountainous, though the southern portion of Yuzhny Island is merely hilly. The mountains, which rise at most to 1,590 m, consist of igneous and sedimentary materials, including limestone and slates. More than one-quarter of the land area, especially in the north, is permanently covered by ice, and most of the northern island, as well as part of the southern, lays in the zone of Arctic desert (Campbell, 2009).

Shore formation of the Novaya Zemlya goes under intense uplift of the islands. Abrasion and accumulative processes actively proceed on its fjord shores (Shumilova, 2012). Along the coast of Novaya Zemlya extends isolated Novozemelnaya Trench with depths of over 500 m. Fig. 71 shows the shoreline landscape of the eastern part of the Novaya Zemlya, immediately south of the Matochkin Shar.

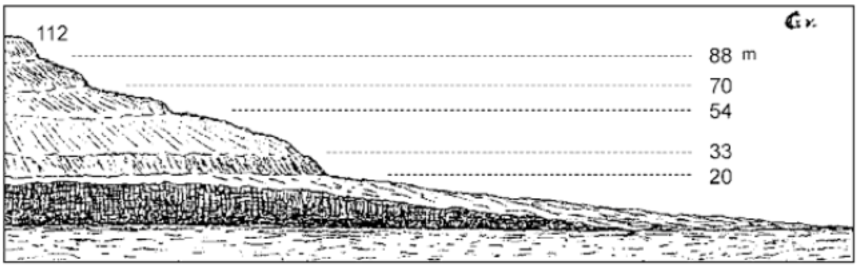

Fig. 69. East coast shoreline of the Novaya Zemlya (Zeeberg, 2002)

Earlier investigation has shown that pipeline route selection and shore approach construction method are usually influenced by a number of factors listed below.

Metocean (metrology and oceanology) parameters: data on waves, current, wind, and tidal movement. The effect of waves and current on beaches, amongst others, may lead to a retreating shoreline and exposure of a buried pipeline.

Nature of shore approach: geotechnical survey (identification of soil properties) is needed to qualify whether it is sand, clay, rocks, etc. A survey of the seabed is also required to ascertain the state of the seabed to prevent unnecessary expenses, delays or losses. Challenges of landfalls include outcropping rocks, unstable cliffs and variable shore profiles.

Social activities: shore approach construction method may have an impact on environmentally sensitive areas or disrupt commercial and daily activities.

Weather window: some of the construction methods require available weather windows for performing the work.

Ice features: existence of fast ice, ice ridges, stamukhas and icebergs can cause large loads and destructions of the pipeline.

Discussion

In order to identify the best solution for landfall construction in the Arctic following Flowchart (Fig. 72) was created according to examined practices and theoretical knowledge.

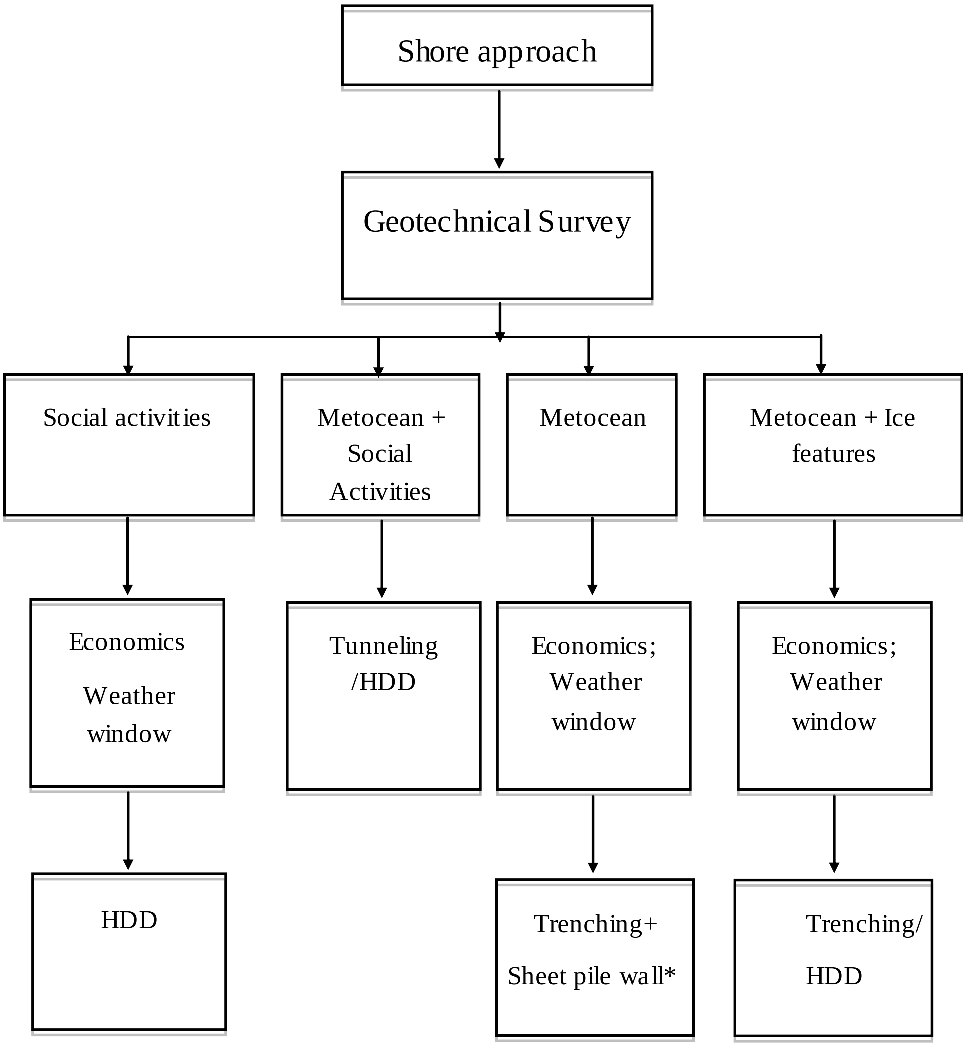

Fig. 70. Flowchart for selecting shore approach construction method

According to the provided flowchart there are two possible solutions for the Novaya Zemlya archipelago: trenching and horizontal drilling (and tunnelling if needed but being very costly option).

- First solution, being more simple, requires large operational time frame while horizontal drilling theoretically can be conducted at any season.

- On the other hand, exceptionally abrasive rock can hamper all phases of an HDD project. Frequent trips to replace worn bits and reamers can result in extended construction duration and corresponding unacceptable increases in construction cost. Moreover, HDD installation through poor quality (extensively fractured or jointed) rock can present the same problems as large grained deposits.

- Cutting a hole through such materials may cause the overlying rock to collapse creating obstructions during subsequent passes. Therefore, precise geological analysis would be needed to show the applicability of the method.

- Horizontal drilling provides extensive protection against ice gouging when for trenching additional backfilling and armouring could be necessary, which also leads to cost increase.

- With HDD method pipeline is also more protected against permafrost and shore erosion as the drilling site can be selected on favourable soils, away from patches of discontinuous permafrost or swamp.

It should also be mentioned that when considering Barents Sea shore line we can drill the HDD tunnel to about 20-25 m meter water depth eliminating the ice gouging from ice ridges and there are almost no icebergs in that area. However, the iceberg threat is presented in the Kara Sea and just horizontal drilling might be not enough to protect the pipeline from interacting with the icebergs as we move further from the coastal line. Therefore, other measures, such as trenching and the possibility to shut down the production, should be considered for safe operation.

All in all, the pipelaying is possible for the Kara Sea shore area and the horizontal drilling method looks more preferable from the scope of provided research. In spite of the lack of experience in the Arctic, the HDD methods that would be used are essentially the same as in the south, so that earlier practices and equipment is certainly applicable and a contractor does not need to learn new techniques. Nevertheless, with the specific ice features of the considered region, ice-based construction may appear highly sophisticated.

Further comprehensive geotechnical survey to identify soil formations at the potential HDD site is a vital element of HDD implementation. Especially in our case when HDD feasibility varies from excellent to unacceptable for different rock properties (David, 2005).

9.3.5. Pulling loads and stress analyses for HDD method

Pipelines installed by horizontal directional drilling (HDD) are subject to a combination of tension, bending, and external pressure. These installation loads can be more severe than operational loads and may govern drilled path design or pipe specification (Huey et al., 1996).

This is particularly true as the state-of-the-art in horizontal directional drilling is advanced to larger pipe diameters and longer drilled lengths. Current work describes methods for calculating installation loads and analysing combined stresses in steel pipe during installation. Pipe to soil frictional and fluidic drag forces are discussed. This method is taken from an engineering design guide produced specifically for HDD pipeline installation.

Analysis of a pipe that is being pulled through an underground tunnel drilled using HDD technology is conducted below.

The characteristics of the pipeline and proposed tunnel route are explained below.

<u>Assumptions</u>:

- Soil type is considered to be predominantly clay;
- Steel grade for the pipe is chosen to be X70 according to existing practices for large diameter pipes in arctic offshore and Shtokman development project solutions.
- Default diameter was set as 40 inches (1,02 m) as it was evaluated after flow assurance analysis for the Kara Sea.

Table 26. Initial data

Parameter	API		SI	
D (external diameter)	[in]	40	[m]	1,02
E (modulus of elasticity)	[psi]	2,90E+07	[MPa]	199948
Pipe steel	Grade		A steel	
μ_{soil} (friction coefficient)		0,3		
μ_{mud} (dynamic friction coefficient)	[psi]	0,05	[MPa]	0,000345
SMYS (specified minimum yield strength)	[psi]	70000	[MPa]	483
Steel density	[lb/ft3]	486,72	[kg/m3]	7800
W_s (submerged weight)	[lb/ft]	-436,2	[kg/m]	-649
Mud weight (density)	[ppg]	12	[kg/m3]	1436
Formation	Predominately clay			
R (curve radius)	[ft]	18800	[m]	5732
t (wall thickness)	[in]	1,3	[m]	0,033
Depth at point C	[ft]	328	[m]	100
ν (Poisson's ratio for steel)	[-]	0,3		

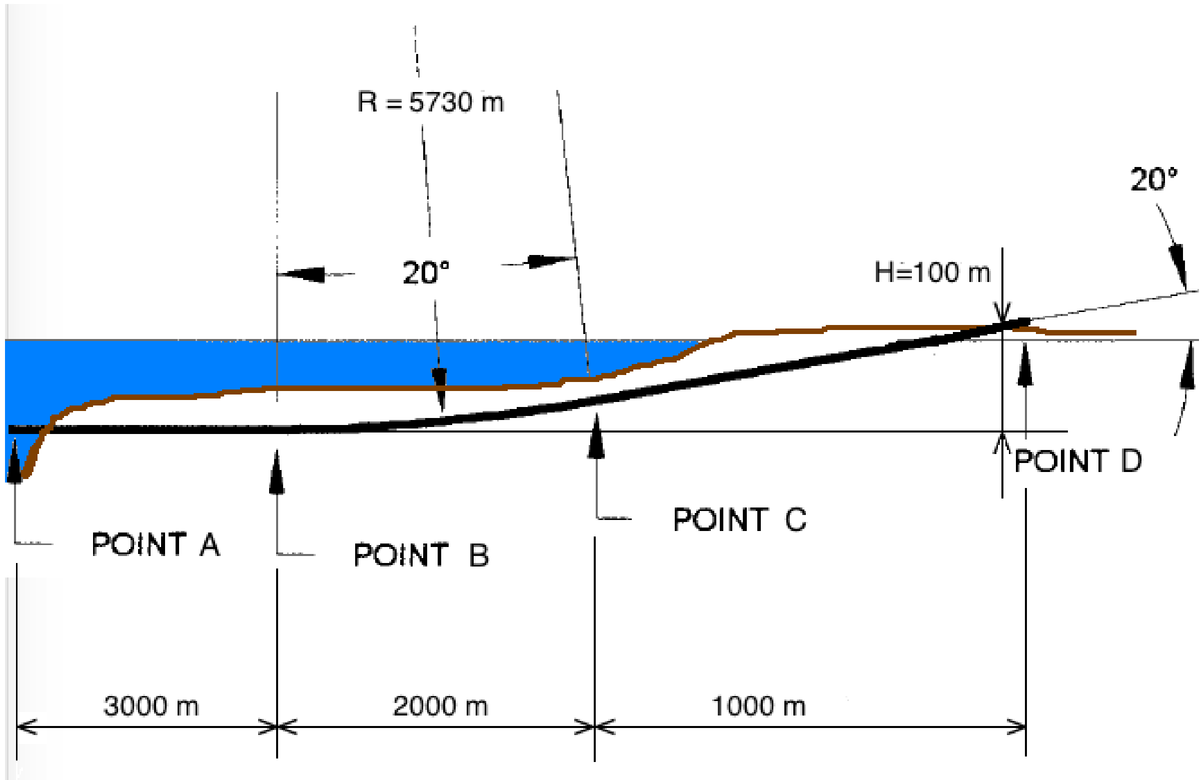

Fig. 71. Considered pipeline route trajectory for the Kara Sea (cross-section view)

The profile was divided into 3 sections: horizontal (from point A to point B), curved (from point B to point C) and inclined (from point C to point D) (see Table 27). The length was suggested in accordance with previous analysis on iceberg occurrence and pipeline routing.

Table 27. Characteristics of sections

Section	Type	Angle θ, °	Angle α, °	Length, ft	Length, m	T_2 direction
C to D	straight	20	0	3280	1000	↗
B to C	curved, R=5730 m	10	10	6560	2000	↗
A to B	straight	0	0	9840	3000	→

Installation Loads and Stresses

Pipeline properties (wall thickness, material grade) and pilot hole profiles must be selected such that the pipeline can be installed and operated without risk of damage. A pipeline installed by HDD can be examined for load and stress states. During installation the pipeline is subjected to (Huey et al., 1996):

- Tension required to pull the pipe into the pilot hole and around curved sections in the hole;
- Frictional drag due to wetted friction between pipe and wall of hole;
- Fluidic drag of pipe pulled through the viscous drilling mud trapped in the hole annulus;

- Unbalanced gravity (weight) effects of pulling the pipe into and out of a hole at different elevations;
- Bending as the pipe is forced to negotiate the curves in the hole;
- External hoop from the pressure exerted by the presence of the drilling mud in the annulus around the pipe.

The stresses and failure potential are the result of interaction of these loads. Therefore, calculation of the individual effects does not give an accurate picture of the stress limitations.

We assume that pulling load in point A is equal to zero.

Pulling loads

1) Horizontal section from point A to point B

$$\Delta T = T_B - T_A = |fric| + DRAG - W_s \cdot L \cdot \sin\theta$$

$$|fric| = W_s \cdot L \cdot \cos\theta \cdot \mu_{soil}$$

$$DRAG = 12 \cdot \pi \cdot D \cdot L \cdot \mu_{mud}$$

$$\Delta T_{BA} = fric + DRAG$$

$T_B = \Delta T_{BA} + T_A$ - pulling load at point B

Obtained results are presented in Table 28

Table 28. Pulling loads for section A-B

Parameter	Units	Value	Units	Value
|fric|	[lb]	1287597	[kN]	5730
DRAG	[lb]	741919	[kN]	3302
ΔT_{BA}	[lb]	2029516	[kN]	9031
T_B	[lb]	2029516	[kN]	9031

2) Curved section from point B to point C

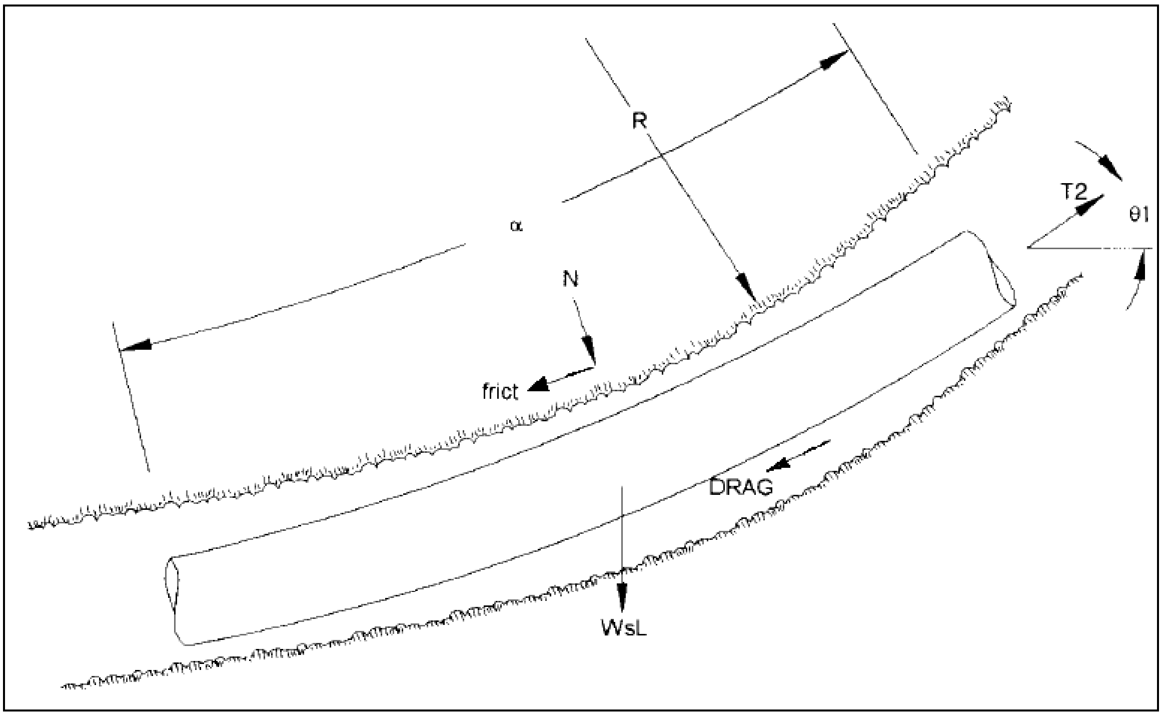

Fig. 72. Curved section model

$$h = R \cdot [1 - \cos(\alpha / 2)] = 286 ft = 87 m;$$

$$I = \pi \cdot (D - t)^3 \cdot t / 8 = 29589 \ in^4 = 0{,}0123 \ m^4;$$

Assume T_{ave} for section = 100 000 lb to start iterative solution.

$$j = (E \cdot I / T_{ave})^{1/2} = 2929 \ lb = 74 \ m;$$

$$U = 12 \cdot \frac{L_{arc}}{j} = 26{,}9$$

$$X = 3 \cdot L_{arc} - \left(\frac{j}{2}\right) \cdot \tanh\left(\frac{U}{2}\right) = 18226 \ in = 463 \ m;$$

$$Y = 18 \cdot (L_{arc})^2 - j^2 \cdot \left[1 - \frac{1}{\cosh\left(\frac{U}{2}\right)}\right] = 7{,}66 \cdot 10^8 \ in^2 = 4{,}94 \cdot 10^5 \ m^2;$$

$$N = [12 \cdot T_{ave} \cdot h - (W_s / 12) \cdot \cos\theta \cdot Y] / X = 1{,}52 \cdot 10^6 \ lb = 6779 \ kN;$$

The positive value indicates that N acting down is the reaction normal force required at the top of the hole to bend the buoyant pipe into the curvature required to match the pilot hole.

$$\Delta T_{CB} = T_C - T_B = 2 \cdot |fric| + DRAG - W_s \cdot L \cdot \sin\theta$$

$$|fric| = N \cdot \mu_{soil}$$

$$DRAG = 12 \cdot \pi \cdot D \cdot L_{arc} \cdot \mu_{mud}$$

T_C - Pull load at point C before T_{ave} assumption check.

$$T_C = \Delta T_{CB} + T_B;$$

After comparing the assumed value of T_{ave} with the value obtained from the following expression $T_{ave} = (T_C + T_B)/2$, difference higher than 4000% was received. This does not fall within an acceptable level of 10%. The subsequent iteration procedure and previous calculations lead to the following results:

Table 29. Pulling loads for section B-C

Parameter	Units	Value	Units	Value
T_{ave}	[lb]	4964277	[kN]	22091
|fric|	[lb]	689178	[kN]	3067
DRAG	[lb]	494612	[kN]	2201
ΔT_{CB}	[lb]	2369832	[kN]	10546
T_C	[lb]	4399347	[kN]	19577

<u>3) Inclined section from point C to point D</u>

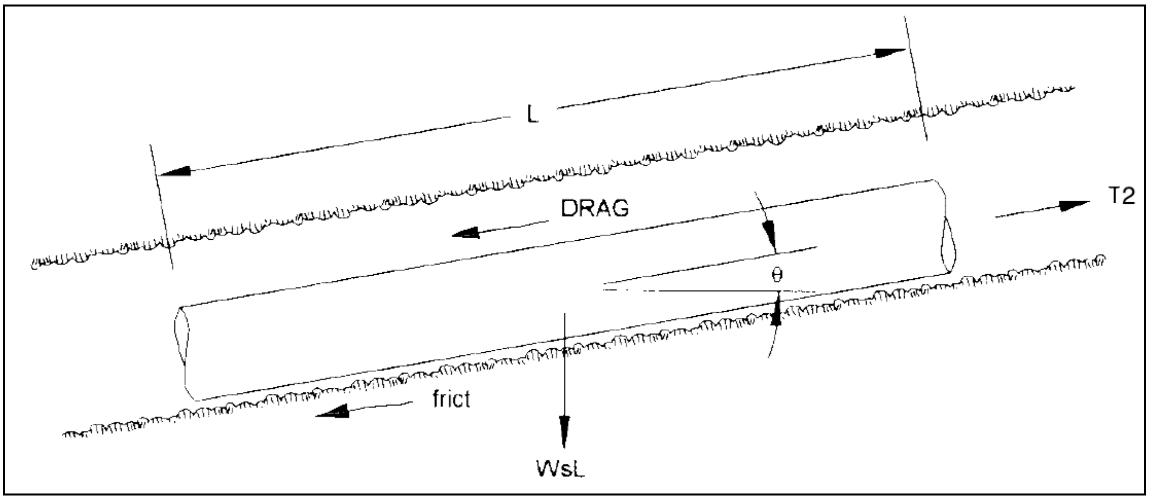

Fig. 73. Inclined section model

$$\Delta T_{DC} = T_D - T_C = |fric| + DRAG - W_s \cdot L \cdot \sin\theta$$

$$|fric| = W_s \cdot L \cdot \cos\theta \cdot \mu_{soil}$$

$$DRAG = 12 \cdot \pi \cdot D \cdot L \cdot \mu_{mud}$$

$$T_D = \Delta T_{DC} + T_C$$

Obtained results are presented in Table 29

Table 29. Pulling loads for section C-D

Parameter	Units	Value	Units	Value
|fric|	[lb]	403341	[kN]	1795
DRAG	[lb]	247306	[kN]	1101
ΔT_{DC}	[lb]	1139963	[kN]	5073
T_D	[lb]	5539310	[kN]	24650

The total pulling load T_{tot} is simply the sum of all the individual loads and is equal to the pulling load at point D:

$$T_{tot} = \Delta T_{BA} + \Delta T_{CB} + \Delta T_{DC} = T_D = 24650 \ kN.$$

Installation stress analysis

A complete analysis of the installation stresses experienced by the pipe requires stress calculations for any point where the combined stresses may possibly have maximum values. For our case, examination of the pilot hole plot shows that the most likely location for high stress due to combined loading is at point C. In this point the pipeline experiences high pulling force and, therefore, has relatively high local tension and bending stress. It is also located near the deepest point with the highest hydrostatic mud pressure.

Individual Stresses

1) At Point C

<u>Tensile stress</u>

$$f_t = \frac{T_c}{A} = 27835 \ psi = 192 \ MPa,$$

where T_C is a pulling load at point C, A is a cross sectional area of the pipe wall.

<u>Bending stress</u>

$$f_b = \frac{E \cdot D}{24 \cdot R} = 2571 \ psi = 17{,}7 \ MPa;$$

<u>External hoop stress</u>

$$f_h = \frac{\Delta p \cdot D}{2 \cdot t} = 3146 \ psi = 21{,}69 \ MPa,$$

where

$$\Delta p = \rho \cdot g \cdot h = 204 \ psi = 1{,}41 \ MPa;$$

<u>Allowable tension</u>

$$F_t = 0{,}9 \cdot SMYS = 63000 \ psi = 434 \ MPa;$$

Note that f_t = 192 MPa is less than 434 MPa, so tension is within allowable limits.

Allowable bending

$$1.\ F_b = 0{,}75 \cdot SMYS$$

for D/t < 1500000/SMYS;

$$2.\ F_b = [0{,}84 - \{1{,}74 \cdot SMYS \cdot D / (E \cdot t)\}] \cdot SMYS$$

for 1500000/SMYS < D/t < 3000000/SMYS;

$$3.\ F_b = [0{,}72 - \{0{,}58 \cdot SMYS \cdot D / (E \cdot t)\}] \cdot SMYS$$

for 3000000/SMYS < D/t < 300000.

For the considered case D/t ratio is equal to 31 and the second formula is used calculate F_b.

$$F_b = 49754\ psi = 343\ MPa;$$

Note that f_b is less than 343 MPa, so bending is within allowable limits.

Allowable elastic hoop buckling

$F_{he} = 0{,}88 \cdot E \cdot (t / D)^2 = 36956\ psi = 186\ Mpa$ (for long unstiffened cylinder);

F_{hc} (critical hoop buckling stress) is a function of F_{he} (elastic hoop buckling stress):

$$F_{hc} = F_{he} \text{ for}$$

$F_{he} < 0{,}55 \cdot SMYS$, which is true in the considered case as $0{,}55 \cdot SMYS = 38500\ psi = 265\ MPa$,

therefore,

$$F_{hc} = F_{he} = 186\ Mpa;$$

Note that $f_h = 21{,}7\ MPa$ is less than $F_{hc} / 1{,}5$, so external hoop stress is within allowable limit for buckling.

Combined load interactions

At point C.

Since all individual stress checks are acceptable, the combined load interaction checks will now be examined.

Tensile and bending

$$\frac{f_t}{0{,}9 \cdot SMYS} + f_b / F_b = 0{,}49 \le 1 \text{ (unity check);}$$

Therefore combined tensile and bending at point C is acceptable.

Tensile, bending and external hoop

$$A^2 + B^2 + 2\upsilon \cdot |A| \cdot B \le 1 ,$$

Where υ Poisson's ratio for steel:

$$A = [f_t + f_b - 0{,}5 \cdot f_h] \cdot 1{,}25 / SMYS < 1 = 0{,}515;$$

$$B = 1{,}5 \cdot f_h / F_{hc} = 0{,}175;$$

$$A^2 + B^2 + 2\upsilon \cdot |A| \cdot B = 0{,}35 \leq 1\,,$$

combined stresses at point C are acceptable.

2) The same analyses were carried out in other chosen points and the results are presented in the Table 30.

Table 30. Combined loads

Stress	Units	Point B	Point C	Point D
Tensile stress Ft	[psi]	12841	27835	35047
Tensile stress Ft	[MPa]	88,5	191,9	241,6
Tensile and Bending	[-]	0,20	0,49	0,56
Tensile and Bending & Ext Hoop	[-]	0,09	0,35	0,45

Obtained results emphasise that combined loads at all points are acceptable. However, point D suffers the highest combined loads despite of the preliminary forecast that maximum stresses would be in the point C. This can be explained by high values of tensile stress at point D (due to the length of the pipe) and curve with big radius, which reduces the bending stress at point C.

To extend the conducted analyses of our model installation stresses were evaluated for various pipeline diameters and different steel types (different SMYS) for the point D where stresses have the highest values. The results are shown in the following Fig. 76. and 77.

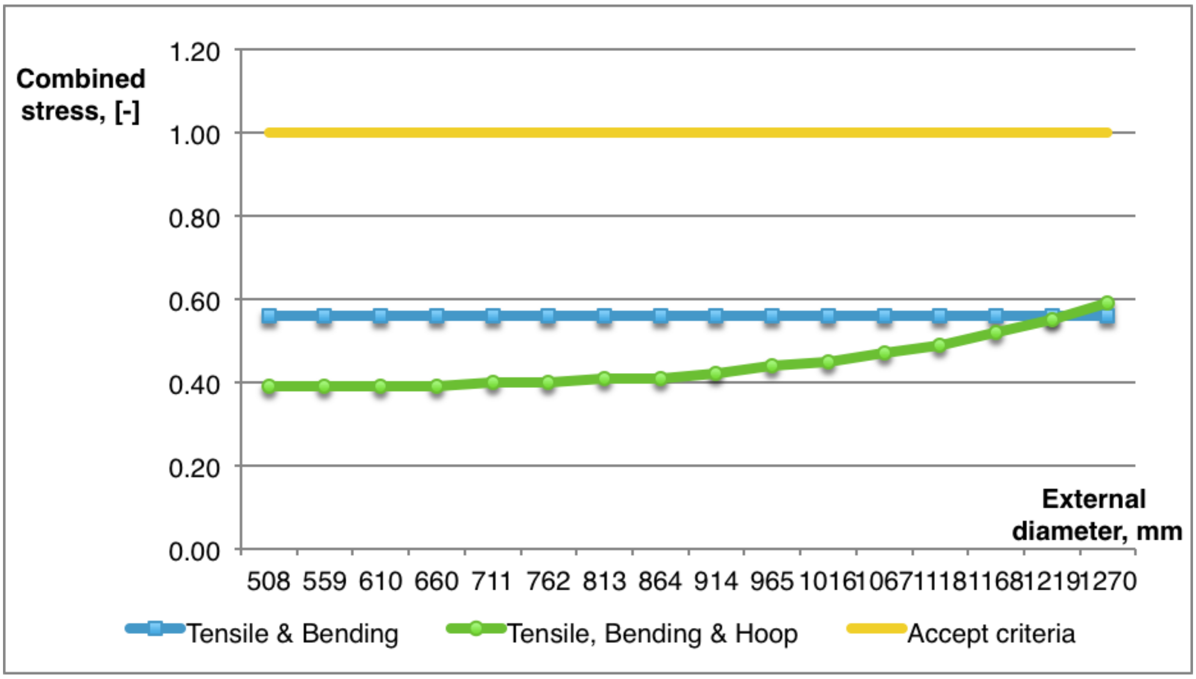

Fig. 74. Combined stresses at point D for different pipeline diameters

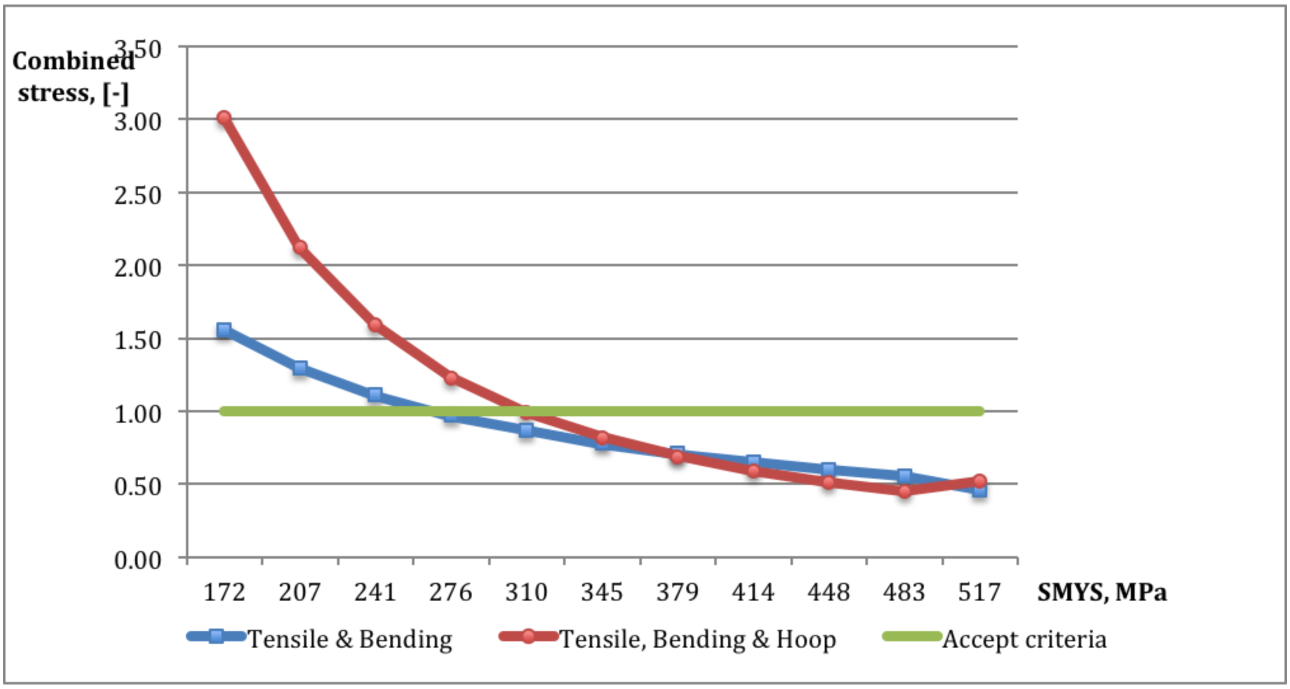

Fig. 75. Combined stresses at point D for different values of SMYS

It is observed that diameter variation doesn't have critical influence on combined stresses in considered case. Steel properties, however, have to be appropriate for such loads as we see that steels with SMYS values lower than 310 MPa do not meet acceptance criteria. Therefore, steel grades with specified minimum yield strength 310 MPa (45000 PSI) and higher should be employed.

Obtained results are significant both in terms of capacity variation of the pipeline and cost savings when choosing the steel for the pipe.

Preliminary conclusion

Pulling loads calculations and installation stress analysis for Horizontal Directional Drilling method showed that during the whole process of installation the strained state of a 5 km pipeline suggested for the Kara Sea landfall design is completely within the allowable limits at any point of the pipeline.

In addition, it is possible to chose a larger or smaller diameter for the pipeline if needed or the most economically and technically efficient type of steel as the stress values of different options were evaluated. If decided to apply the same technique of landfall construction for the Barents Sea, it would be necessary to conduct the same analysis. Meanwhile, additional design analysis of different loads is required before approving the suggestion on the type of landfall design.

10. Economic evaluation of the project

The assessment of economical feasibility and investment indicators of the suggested concept was carried out applying the method of «Cost-Benefit Analysis (CBA)». CBA is a systematic process for calculating and comparing benefits and costs of a project (Zelenovskaya, 2016). The method allows accounting for different value of money throughout the lifetime of the project implementing the discount rate. Thus, the present value of costs and benefits can be estimated for each year.

The objectives of the analysis are:

- Investigation of the economical feasibility for suggested concept for the 1st phase of Shtokman field development;
- Economical comparison of two development concepts for Shtokman field development in the Barents Sea to identify whether it is more efficient to produce the hydrocarbons using the provided transportation and production concept.

The information on costs for certain equipment, infrastructure and operations is collected from various sources, such as, development project for Shtokman gas and condensate field (SJC "Sevmorneftegaz", 2007), Korableva, M. S. (2013), experts' opinions and some other sources listed in the references.

Following major indicators of economic efficiency were calculated in the work:

1.NPV - Net Present Value of the project (in mln. $)

2.IRR – Internal rate of return (in % on investment)

3.PB - payback period (in years)

4.DPB - discounted payback period (in years)

5.BEP - Break-even price ($/1000 m3 of natural gas)

6.PI - Profitability Index (ratio)

First, the brief description of the suggested concept used for economic calculations is provided in the Table 31.

Table 31. Brief concept description

Main blocks	Concept description
Production facilities	Subsea production systems (SPS)
Transportation of produced fluid	Multiphase pipeline transportation to the Novaya Zemlya Archipelago (Belushya Bay)
Gas treatment	Onshore
Gas compression	Subsea (after 20 years of production)
Gas processing facilities	Onshore LNG plant (in Belushya Bay)
Transportation to consumers	LNG carriers

Following algorithm is used to calculate efficiency indictors:

1. Evaluation of Capital Expanses (CAPEX)

   Capital expenses directly depend on required capacities of each production, transportation, processing and infrastructure object. Expenses listed in Table 32 are evaluated for maximum annual production of 24 Bcm of gas according to production forecast of the 1st phase of Shtokman field (SJC “Sevmorneftegaz”, 2007).

Main capital expenses for the suggested concept are provided in Table 32.

Table 32. Main capital expenses

Name	Cost, mln. $
Subsea production systems	1600
Subsea pipelines	2088
LNG plant	6000
Onshore processing facilities	665
Drilling	1600
Sea terminal and bay infrastructure	1000
LNG carriers	1580
Flow assurance expenses (MEG flowlines)	360
Total CAPEX	15468

2. Revenue calculation.

$$\mathrm{Re}venue = Q \cdot P,$$

where Q – volume of the gas sold to consumers in certain year , Bcm;

P – gas price, $/1000 m3 (long term contract price for LNG was used in the current analysis).

3. Evaluation of operating expenses (OPEX)

According to Korableva, M. S. (2013) annual operating expenses include depreciation and current expenditures. Current expenditures can be estimated as a certain percent of the CAPEX. At the same time, it is also reasonable when current expenses are proportional to production rate. Therefore when estimating annual current and operating expenses both of these factors are taken into consideration. Table 33 provides the obtained values.

Table 33. Current expenses

Category	Percent from CAPEX	Average annual current expenses, mln. $
Production complex	1,2%	304,8
Subsea pipelines	1,2%	304,8
Onshore facilities	1,8%	228,6
LNG plant, sea port	4,2%	533,4
LNG tankers and service base for marine objects	3,0%	381,0
Total operational expenses	13,8%	1752,6

Overall operational expenses amounted 88,9$ per 1000 m3 of produced natural gas, which is a reasonable value for Arctic offshore fields.

4. Depreciation calculations

In the current economic model linear principle of depreciation was applied:

$$Depreciation_i = Total\ CAPEX\ /\ N,$$

where N- depreciation period (service period), years.

5. Taxes

Due to high Capital Expenses and harsh conditions, government eases tax burden on companies, which develop the Arctic offshore fields.

Property tax, for instance, is equal to 0 in this area.

Two types of taxes were estimated in the current economic model in accordance with Russian Federation Tax Code. First, Mineral Extraction Tax (MET) for considered region in the Arctic offshore is equal to 5% of tax base for the first 15 years of production (Russian Government decree No. 443-r). Meanwhile tax base for the offshore fields is equal to the revenue from produced hydrocarbons minus the transportation expenses (Chapter 26 of Russian Federation Tax Code). After 15 years of production Mineral Extraction Tax is assumed to be equal 30% from the same tax base.

Second, tax on profit is equal to 20% from the calculated profit. Accumulated tax deductions are provided in Table 34.

Table 34. Accumulated tax payments for the whole production period (50 years)

Tax name	Accumulated payment, mln. $
MET	49746
Income tax	27035
Total	76781

It is also important to mention that currently for LNG there are no export custom dues.

6. Net present value (NPV)

Net present value (NPV) of the project is the sum of the present values (PVs) of the cash flows for the considered period:

$$NPV = \sum_{i=1}^{T} \frac{Cahs\ \inf low_i - Cash\ outflow_i}{(1+d)^i},$$

where

$$Cahs\ \inf low_i = \mathrm{Re}venue_i + depriciation_i;$$
$$Cash\ Outflow_i = CAPEX_i + Taxes_i + OPEX_i;$$

i – analyzed year number;

d – discount rate, it is applied to convert the cash flows for different years into a common value to have an accurate investment forecast. The value of discount rate depends on several factors, such as:

- Opportunity cost of money;
- Erosion of purchasing power due to inflation;
- Uncertainty and risk;

For the current model the initial discount rate assumed to be equal to 12%, which is a common value for oil and gas projects.

T- considered period of the project, years.

7. Internal rate of return (IRR)

Internal rate of return refers to an average annual interest rate of the project. IRR defines such discount rate of the project when NPV would be equal to zero:

$$NPV = \sum_{i=1}^{T} \frac{Cahs\ \inf low_i - Cash\ outflow_i}{(1+IRR)^i} = 0;$$

So, the project would be acceptable only if the obtained IRR is higher than applied discount rate. In Microsoft Excel there is a special built-in function for calculating IRR.

8. Payback period (PBP) and discounted payback period (DPBP)

PBP is the period of time it takes for a project to recover the cost of initial investments.

For calculation of the DPBP discounted cash flows are used to account for different money value throughout the lifetime of the project.

9. Profitability index

Profitability index shows the relationship between the costs and benefits of a proposed project through the use of a ratio calculated as (www.investopedia.com):

$$PI = \frac{PRESENT\ VALUES\ OF\ FUTURE\ CASH\ FLOWS}{INITIAL\ INVESTMENTS} = 1 + \frac{NPV}{INITIAL\ INVESTEMENTS}$$

If PI is less than 1 the project should be rejected.

10. Break-even price (BEP)

BEP in the current case is the prize of LNG, which allows the project to financially break-even for the acceptable rate of return on capital investments (Zelenovskaya, 2016).

It is assumed that break-even point is achieved when NPV =0 with applied discount rate equal to the expected rate of return (ROR) by investor. Following formula can be applied to calculate the BEP (Zelenovskaya, 2016):

$$BEP = \frac{\dfrac{\sum_{i=1}^{T} I_i + O_i + F_i}{(1+ROR)^i}}{\sum_{i=1}^{T} \dfrac{Q_i}{(1+ROR)^i}},$$

where

Q_i - gas production/transmission/liquefaction rate in the year i, billion cubic meters (Bcm);

I_i - investment expenditures in the year i, mln. \$;

O_i - Operation and maintenance expenditures in the year i, mln. \$.

BEP can also be evaluated utilizing the “Parameter estimation” function in Excel, modifying the gas price till NPV is equal to zero.

If the obtained result for BEP is higher than expected market price of the product, then the project should be rejected.

Table 35 contains calculated investment indicators for the 1st phase of Shtokman field development project with suggested transportation and production concept.

Table 35. Investment indicators for suggested concept

Efficiency indicators	Value
NPV, mln. $	1640
PBP, years	6
DPBP, years	15
IRR (internal rate of return), %	14%
PI (profitability index)	1,16
BEP (break even price), $/1000 m3	215

It was assumed in the model that LNG is supplied to consumers through long-term contracts and the LNG price doesn't change, as it would be very difficult to forecast. Therefore, average price for long terms contracts of year 2017 for different markets was used in the calculations (www.icis.com, ycharts.com).

According to the results, all economic indicators are acceptable. Therefore, the project is economically viable. However, gas price for long-term contracts should not fall below 215$/1000m^3 for the project to be economically viable.

Second part of the analysis consists of the comparison of two technological concepts for the Shtokman gas and condensate field development.

For more accurate analyses it was assumed that all three phases of Shtokman field are being developed. It leads to higher expenses compared to previous model and maximum production rate increases as well, reaching 72 Bcm/year.

Brief outlook on the concepts and main differences are presented in Table 36:

Table 36. Compared technological concepts

Main blocks	Concept 1	Concept 2
Production facilities	Subsea production systems (SPS)	SPS, Compression platforms, Boosting platforms
Transportation of produced fluid	Multiphase pipeline transportation to the Novaya Zemlya Archipelago (Belushya Bay)	Two-phase transportation to Teriberka via subsea pipelines
Gas treatment before transportation	No (possibly on later stages)	Partial treatment on the platform
Gas compression/boosting	Subsea (after 20 years of production)	Gas-driven compressors and pumps on the platforms
Gas processing facilities	Onshore LNG plant (in Belushya Bay)	LNG plant on the main land
Transportation to consumers	LNG carriers	LNG carriers

Summary on capital expenditures for compared concepts are shown in Table 37.

Table 37. Capital expenditures for compared concepts

Name	Concept 1, mln. $	Concept 2, mln. $
Subsea production systems	2800	2100
Subsea pipelines	6264	5400
LNG plant	18000	16875
Onshore processing facilities	1995	1080
Drilling	6800	6800
Sea terminal and bay infrastructure	1000	800
LNG carriers	4740	4740
Flow assurance expenses (MEG flowlines)	1080	0
Subsea compression	1000	0
Platforms	0	9000
Total CAPEX	44178	47795

Capital expenditures for two concepts differ due to additional expenses on multiphase flow transportation and flow assurance issues for the first case and floating production units for processing and compressing of gas and pumping of the gas condensate for the second case. In addition, construction of onshore facilities in the Novaya Zemlya Archipelago is more expensive compared to inland construction for second concept due to remoteness of the archipelago. More to say, expenses on ice management are more significant in the case of existing platforms.

Obtained economic indicators for two concepts are provided in Table 38

Table 38. Economic indicators for compared concepts

Efficiency indicators	Value	
	Concept 1	Concept 2
NPV, mln. $	5440	3904
PBP (payback period), years	9	9
DPBP (discounted payback period), years	15	16
IRR (internal rate of return), %	15%	14%
PI (profitability index)	1,26	1,18
BEP (break even price), $/1000 m3	204	212

The obtained indicators point out that both concepts are economically viable. However, Concept 1 is more preferable in almost every parameter.

Preliminary conclusion

Conducted economical analyses of the investment indicators estimated economical efficiency of the suggested transportation concept for the first phase of the Shtokman gas and condensate field development in the Barents Sea. Economic indicators for 3 phases of production proved to be even more viable. Therefore, it is reasonable to assume that subsequent development of nearby fields in the Barents Sea (Ledovoye and Ludlovskoye) and considered fields in the Kara Sea (Leningradksoye, Rusanovskoye, Pobeda) would increase economical efficiency of the concept even more as common infrastructure would be utilized. However, further analyses are required to prove the statement.

In addition, two technical concepts were compared in terms of economical attractiveness for the investors. As a result, Concept 1, which amplifies installation of subsea production systems and multiphase pipeline transportation of the produced fluid to the Novaya Zemlya Archipelago, obtained better efficiency compared to Concept 2, which suggest utilizing subsea production systems, further partial processing, compression and boosting of the fluid on the platforms and subsequent two phase pipeline transportation to Teriberka (Murmansk region).

It is necessary to mention that accuracy of the economic model is limited due to lack of information on costs, changeable energy market, tax legislations and uncertainty in geological reserves of the considered field.

Conclusions

Conducted comprehensive analyses of the Arctic seas and Novaya Zemlya Archipelago environment conditions, ice features and iceberg occurrence possibilities, hydrocarbon prospects, existing arctic practices and infrastructure gave the following results:

1. Novaya Zemlya Archipelago has a suitable location and environmental features for being a transportation hub and provide necessary infrastructure for developing of Kara and Barents Sea hydrocarbon basins.
2. There is a huge hydrocarbon potential in the Kara and Barents Seas for future projects. Therefore, certain order for the development of specific hydrocarbon fields was suggested according with amount of reserves, exploration level, relative location towards the shore and technological possibility of development.
3. It was estimated that most parts of the Barents Sea are suitable for year round vessel navigation.
4. Belushya Bay has suitable bathymetry conditions, appropriate relative location towards existing hydrocarbon fields and a number of required facilities for placing the offloading terminal.
5. The specification of the LNG plant on the Belushuya Guba was estimated for the first stage of gas production from the Shtokman field:

- Required liquefaction capacity and number of trains;
- Type and number of LNG carriers;
- Required processing and treatment units for the LNG plant.

6. According to the environmental analyses pipeline system was suggested to be the optimal solution for hydrocarbons' transport from the Kara and Barents Seas oil and gas fields to the Novaya Zemlya archipelago.

Further, the pipeline transportation concept was analysed in details for the possibility of technologically sustainable and reliable application.

Appropriate pipeline routing was designed in accordance with bathymetry charts, infrastructure location, iceberg occurrence possibilities and existing ice and iceberg management technologies.

The transportation of multiphase fluid from the Shtokman and Leningradskoe fields was proved to be possible after the conducted simulations on the PIPESIM software. Therefore, it is possible to transport the products without preliminary offshore preparation and subsequent installations of floating structures.

Among existing construction methods for Arctic landfall design horizontal directional drilling was chosen to be the most preferable solution for the Novaya Zemlya shore crossing. Pulling loads and installation stress analyses showed that there are no significant limitations for the pipeline installation.

Economical evaluation of the project led to the positive results for investment indicators for suggested concept and proved it to be economically competitive compared to previous projects.

There are still uncertainties and possible inaccuracy in obtained results due to the lack of data and uncovered issues. However, while conducting current thesis a lot of previous research works were taken into account to provide reliable and accurate results.

At the same time subsequent investigations are thoroughly needed to advance the feasibility of the concept in such areas as:

- Pipeline on-bottom stability
- Iceberg drift modelling;
- Thermal modeling of the pipe’s impact on the surrounding soil and permafrost
- Risk analyses of all the problematic areas is highly important for the topic development to account for main hazards and uncertainties and come up with mitigation measures.

In addition more data from exploration activities and field tests is critical for further investigation and improvement of the results accuracy. All these steps are necessary to prove the suggested solutions, ascertain, clarify and further develop the proposed concept.

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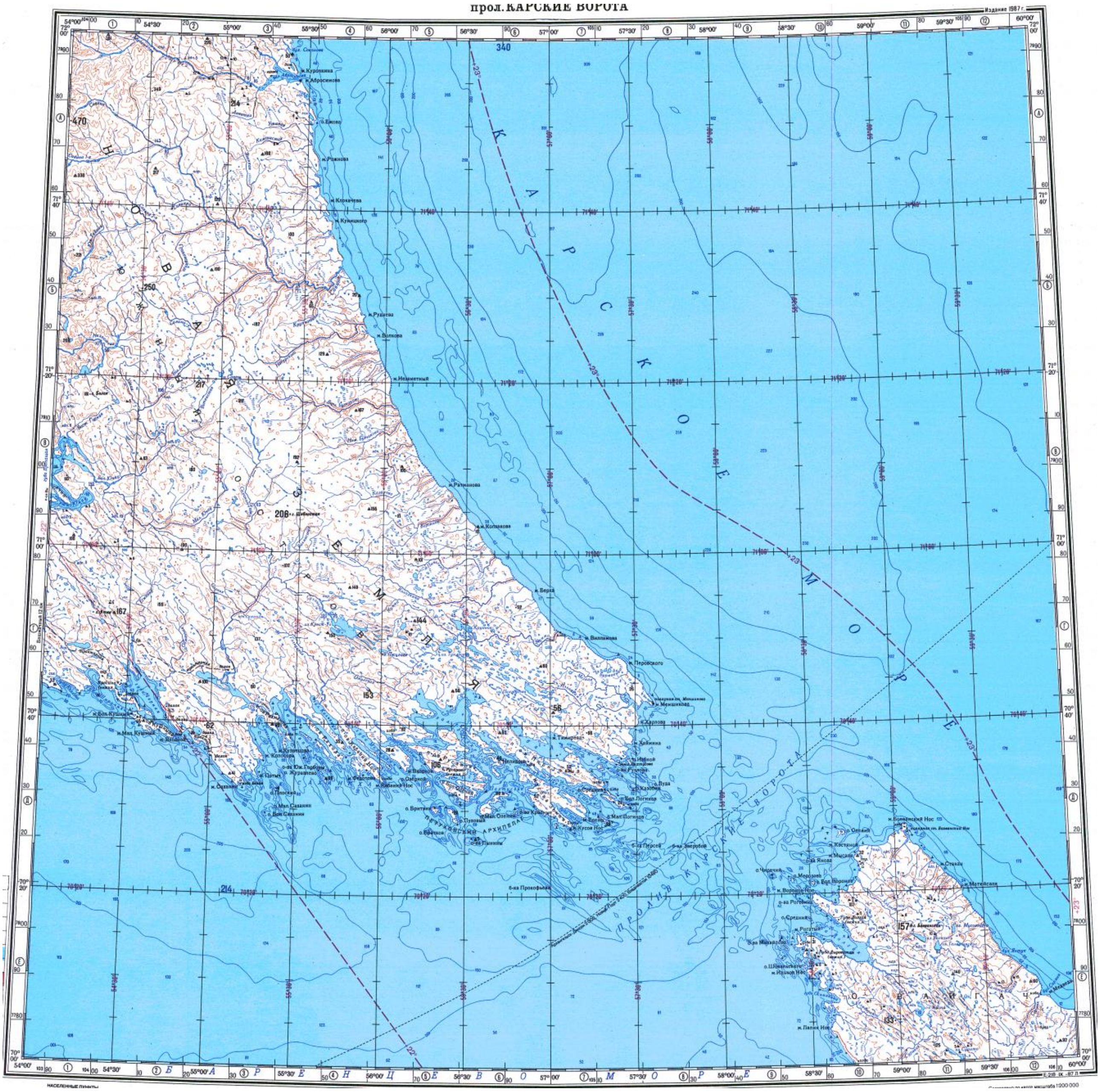
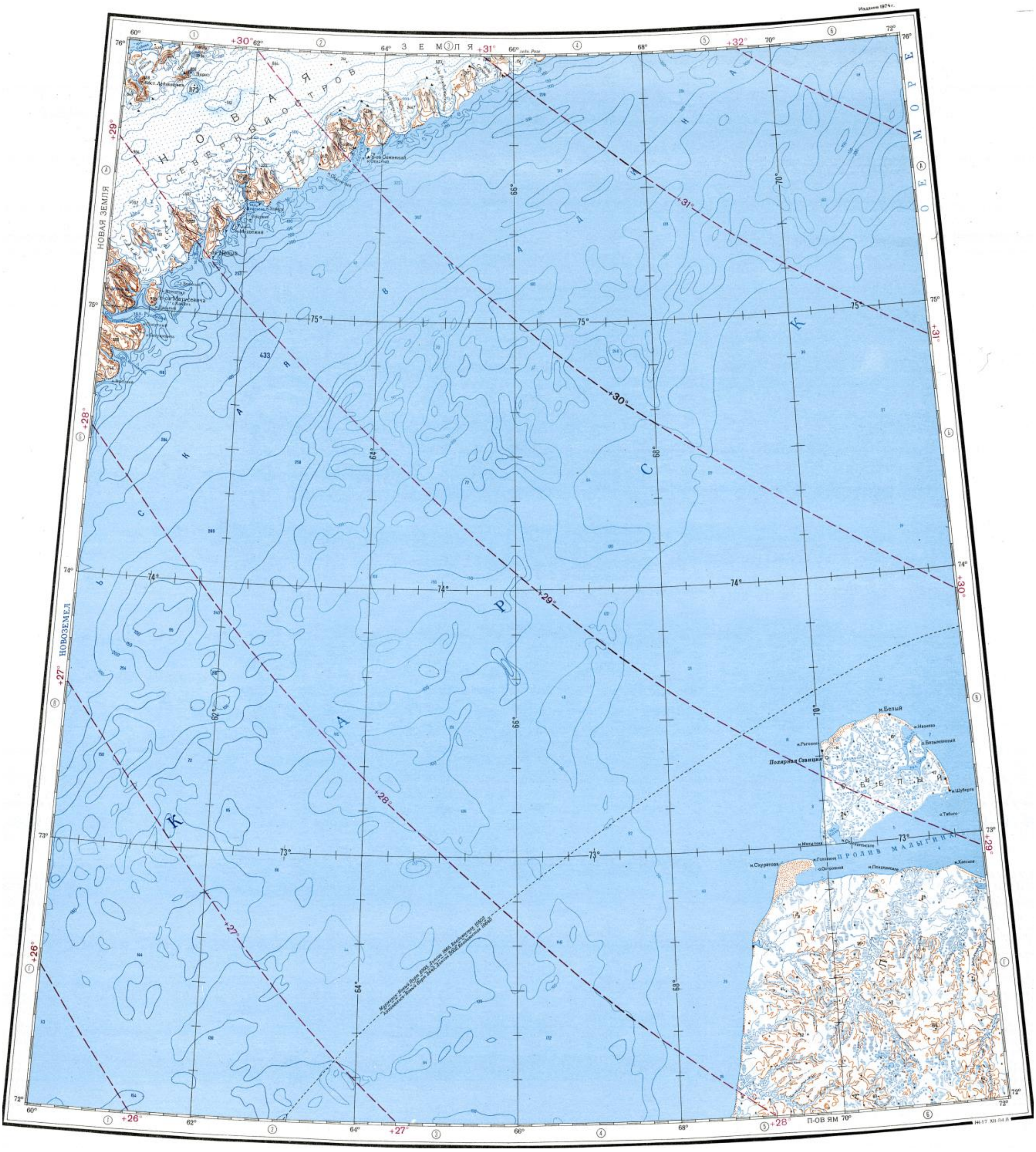
Appendix 1. Estimation of required number of LNG carriers (http://sovcomflot.ru)

Deadweight of the carrier, thousand tonnes		85
Distnace from Novaya Zemlya to Japanese regasification terminal through NSR (Shin Minato LNG terminal,) km	*summer*	5000
Distance from Novaya Zemlya to European regasification terminal through NSR), km	winter	3400
Summer Navigation Period, days		165
Winter Navigation Period, days		200
Tanker speed in the open water, km/h		36,1
Tanker speed in the ice conditions, km/h		10,2
Assumed winter Navigation (Barents Sea-Europe) speed, km/h	*half way*	23,15
	half way	10,2
Assumed summer navigation speed (Kara Sea-Japan) km/h	*half way*	23,2
	half way	10,2
Travelling time (one way), hours	*summer*	353,09
	winter	240,10
Travelling time (way back), hours	*summer*	353,09
	winter	240,10
Loading/offloading time, hours		15,00
Full time required for both ways, hours	*summer*	736,18
	winter	510,20
Numer of journeys	*summer*	5,4
	winter	9,4
	annualy	14
One carrier annual transportation capacity, mln. t		1,19
Max LNG plant capacity per year, mln. t		15
Required number on carriers		13

Appendix 2. Additional nautical maps for Kara Sea pipeline route evaluation (http://loadmap.net/)

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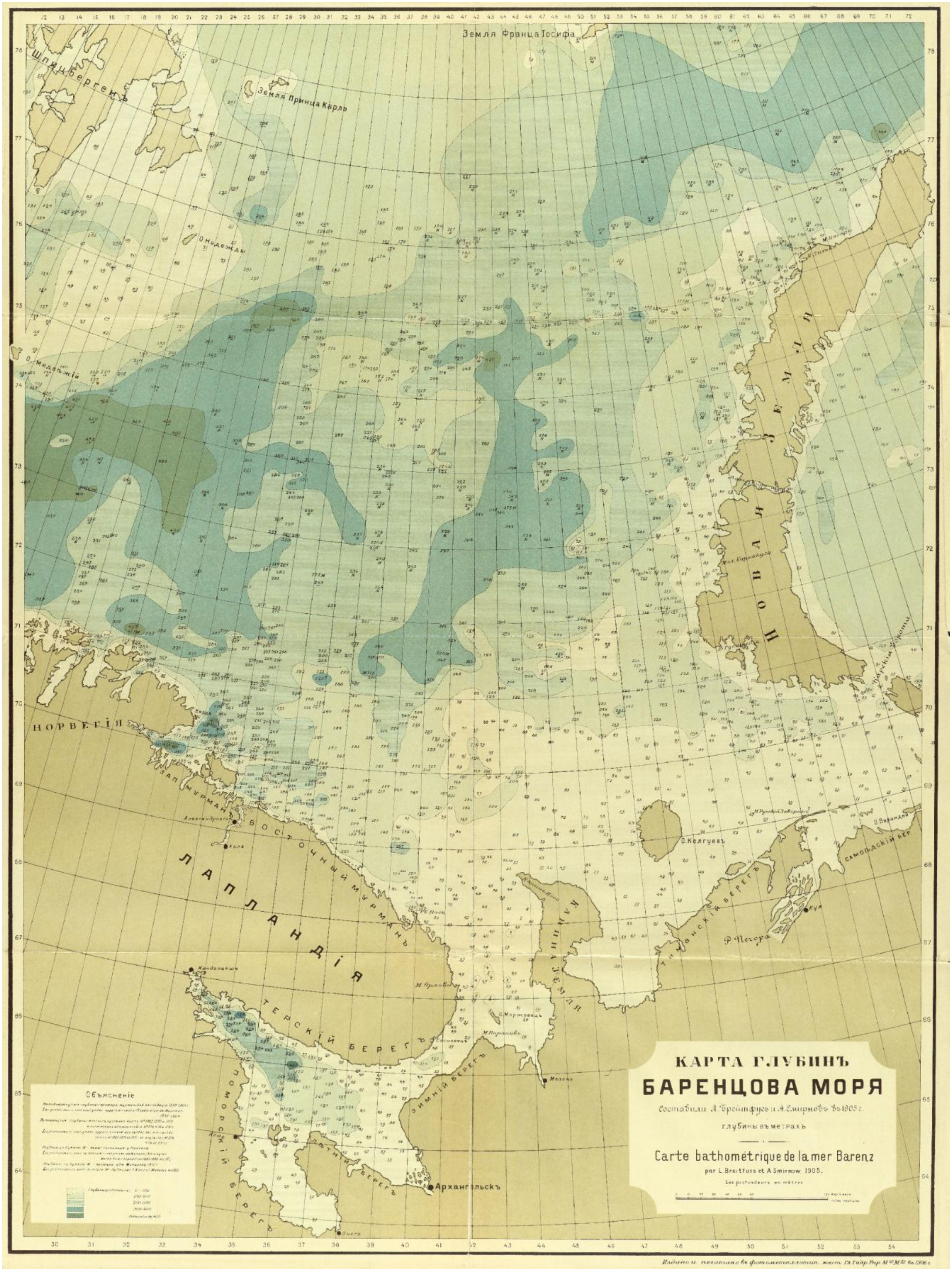
НОВОЗЕМЕЛ
П-ОВ ЯМ
ПРОЛИВ МАЛЫГИНА
433
м.Белый
Полярная Станция
Издание 1974 г.

Appendix 3. Additional nautical map for Barents Sea pipeline route evaluation (http://www.kolamap.ru; http://loadmap.net/)



Appendix 4. Estimation of water fraction (moisture content) for natural gas in reservoir conditions (Gritsenko, A. I.et al., 1995)