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The concept of developing HP/HT Silurian and Lower Devonian age deposits of Prirazlomnoye field

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Abstract

As more attention is paid to the exploration and production of oil and gas resources offshore, Russian companies keep looking for new fields to increase the hydrocarbons production in the Arctic. The development of the Silurian and Lower Devonian age deposits is the next step to increase the profitability of the IRGBS (Ice Resistant Gravity Based Structure) Prirazlomnaya, the first project in the Russian Arctic. Silurian and Devonian deposits underlay below the production deposits (Permian age), the depth of deposits varies from 4 to 6 km, the optimal drilling site is located about 2—3 km from IRGBS Prirazlomnaya. The exploratory well PH-5 stopped drilling on the depth 4460 m because of the ice conditions. According to exploratory drilling, the Silurian and Lower Devonian age deposits are characterized by high pressure and high temperature (HPHT). In the present moment, the project of developing Silurian and Lower Devonian deposits is on the pre-feed studying. There are 3 ways to develop deposits: to drill and produce oil from the IRGBS Prirazlomnaya, to install a mini—platform or to use subsea production systems with tie—in to the platform.

The basic concept is to drill and develop deposits from the IRGBS Prirazlomnaya. However, many challenges and insoluble problems were found on the pre—feed studying. Although CAPEX of drilling and production from IRGBS Prirazlomnaya is less in comparison with alternative concepts, the cumulative production does not reach maximum value. Therefore, the concept of using subsea production systems with tie—in to IRGBS Prirazlomnaya becomes the next possible option.

Arctic region brings the following challenges: extreme weather conditions such as cold temperatures and storms; the scarce and distant infrastructure, which affects the transfer personnel and equipment; a short ice-free season that limits operational flexibility and introduces the need for an effective ice-monitoring plan; prolonged periods of darkness and daylight; oil spill response planning. The oils from Permian

and HP/HT Silurian and Lower Devonian deposits have to be blended to protect the processing and offloading facilities of IRGBS Prirazlomnaya due to different properties (viscosity, density, etc.). A serious risk is damage from ice ridges through either direct contact or upper sediments movements. Thus, trenching of pipelines and glory holes for protection of subsea production systems and pipelines is necessary to ensure uninterrupted production process in the Pechora Sea.

The utilization of associated gas is a crucial problem for all offshore projects. 150 million m3 of associated gas was produced with oil in 2017; some amount of gas was converted to energy for domestic needs, and some was flared. The production from Silurian and Devonian deposits increases the total amount of associated gas up to 20 %. In this Master thesis, it is considered that after the processing facilities of IRGBS Prirazlomnaya, all associated gas will be pumped to Silurian and Lower Devonian deposits to maintain reservoir pressure.

Based on consideration of possible technical solutions, potential challenges and economic evaluation the conclusions will be given.

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In addition, I would like to thank Gazprom Neft Shelf for providing necessary information and for the knowledge I gained, working there. I sincerely appreciate wise advises and support of my coordinator in the company — Ivan Kradinov.

Content

List of symbols:

Latin characters:

A — Square;

A_{a1} — Wind projection area;

A_w — Current protection area ;

a — Temperature expansion coefficient;

afab — Fabrication factor;

B— Single keel breadth;

c — Cohesion;

C_i — Keel rubble cohesion;

C_{dw} — Drag coefficient;

C — External Temperature;

D —Pipeline diameter;

d — Scour depth;

D (1;1L;3f;3fm) — Devonian deposits;

E_s— Elasticity modulus;

F_b— Buoyancy;

F_{pipe} — Force on the pipe;

F_i— Force due to drifting ice;

f — Total lateral force;

F_{dw} — Current drag;

$F_c cos\alpha_k$ — Horizontal passive friction;

$F_c sin\alpha_k$ — Vertical passive friction;

F_{li} — Level ice reaction;

F_{dw} — Drag force due to the wind;

F_{dc} — Drag force to due current;

h_i — Ice thickness;

q_u— Vertical ultimate drag;

R_k — Radius of a circular feed loop;

r_c — Radius of a well;

S(1;2) — Silurian deposits;

T_b — Ridge average block size;

T_e — Minimum Seawater temperature;

T_i — Pipeline Temperature;

t — Pipeline wall thickness;

t_u — Axial ultimate resistance;

u_c — Surface current speed;

v_i — Ice speed;

W — Ridge weight;

ΔW — Weight due to elevation;

Greek characters

a_k— Keel angle;

a_p— The angle of pipeline motion;

a_s— Sail angle;

a_u — Material strength factor;

β — Seabed Slope angle;

ye — Resistance strain factor;

yf — Environmental load factor;

ysc — Safety class resistance factor;

ym — Material resistance factor;

η — Keel porosity;

η_s — Sail porosity;

ε_{lc} — Limiting compressive strain

h_s — Ridge sail height;

h — Consolidated layer thickness;

h_k — Keel draught;

h_i — Maximum level ice thickness

k — formation permeability;

K_P —Passive earth pressure coefficient;

L — length of horizontal well;

M — Mobility ratio, unit fraction;

N_a — number of ridge formation per unit area;

n_p — efficiency of the stage;

p_u — Horizontal ultimate drag;

P_i — Pipeline Internal pressure;

p_c — plastic collapse pressure;

p_{el} — elastic collapse pressure;

Δp — Differential pressure

p_s — extreme value of seabed upper sediments pressure;

q_i — Ice ridge rubble internal friction angle;

Q — production rate;

value;

ε_t — Ultimate tensile strain;

ε_p — Actual strain in pipelines;

λ — distribution parametr;

μ_w — viscosity of water;

μ — Friction coefficient;

ϑ_s — Poisson ratio;

p_w — Seawater Density;

ρ_{iw} — Average keel density;

ρ_{ia} — Average sail density;

ρ_s — Seabed upper sediments density;

p_i — Ice density;

σ_h— hoop stress;

σ_l — longitudinal stress;

σ_{eq}— Von Misses equivalent stress;

φ_w— Wall friction angle;

φ — Internal friction angle;

w_k— Keel width at the sea level;

w_b — Keel width at the bottom;

List of abbreviation:

BHP	Break Horse Power;
BEP	Break-Even Price
DNV	Det Norske Veritas
DPB	Discounted Payback Period
ESP	Electric Submersible Pump
FDD	Freezing Degree—Days
FY	First Year Ice Ridge
HAZID	Hazard Identification
HP/HT	High Pressure/High Temperature
HSE	Health and Safety Executive
IRGBS	Ice Resistant Gravity Based Structure
IRR	Internal Rate of Return
ISO	International Standard Organization
LSD	Limit State Design
LRFD	Load and Resistance Factor Design;
MODU	Mobile Offshore Drilling Unit
NPV	Net Present Value
PB	Payback Period
PI	Profitability Index
SG	Specific Gravity;
SMTS	Specified Minimum Tensile Strength;
SMYS	Specified Minimum Yield Strength
SPS	Subsea Production System
TDH	Total Head Developed
ULS	Ultimate Limit State.

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Introduction

The development of the Arctic is the key purpose for the “Gazprom Neft Shelf”. Currently, the price of the oil is 80$, and due to increased competition in the global market, the main task is using high-tech equipment to increase oil and gas production.

“Gazprom Neft Shelf” is going to produce oil through IRGBS “Prirazlomnaya” facilities until 2038. However, the decreasing of production after 2024 makes company wonder about tie—in other projects to IRGBS “Prirazlomnaya” facilities.

Silurian and Devonian deposits underlay below the production deposits (Permian age), the depth of deposits varies from 4 to 6 km, the optimal drilling site is located about 2—3 km from IRGBS Prirazlomnaya. In the basic concept, it is expected to modernize IRGBS “Prirazlomnaya” to drill highly deviated wells and produce oil on depletion mode. *(Gazprom Neft, 2017).* Although, there are some circumstances to change the existing concept:

- The developing HPHT Silurian and Lower Devonian deposits on the Anatolya Titova and Romana Trebsa fields on depletion mode in the Timano-Pechorskayaya province that have a similar reservoir characteristics showed poor production performance. The reservoir pressure has sharply decreased.
- The necessity of modernization processing facilities of IRGBS Prirazlomnaya due to drilling of the extended-reach wells up to 9000 m in consideration of using invert-emulsion drilling mud.

Furthermore, there is a trend of increasing the number of developing fields with low or medium amount of resources operated by subsea production systems.

The developing concept for the Silurian and Lower Devonian age deposits with using subsea production systems and solving all technical challenges (seasonable drilling, ice ridge gouging etc.) is the aim of the Master thesis. The Bow-Tie diagram is considering the main risks of damaging pipeline from the ice ridge scouring on the potential production site of the Prirazlomnoye field.

This work presents potential solutions to the utilization of associated gas produced from the Silurian and Lower Devonian deposits and the main Permian deposits through maintaining pressure, which will significantly reduce, or perhaps eliminate gas flaring.

The artificial lift in HP/HT will be critical parameter for developing Silurian and Lower Devonian deposits when the reservoir energy will not be enough to lift the fluid. There are two widespread technologies used offshore: gas lift and ESP technologies. Due to high cost of remedial work the Dual ESP is considered in the concept with run life up to 1,7 from typical pump.

The analyze of technical possibility and economic feasibility of tie—in the HP/HT Silurian and Lower Devonian deposits to the existent processing, storing and offloading capacities of the IRGBS "Prirazlomnaya" is presented in this Master thesis.

The concept of developing HP/HT Silurian and Lower Devonian deposits can be used to other fields which has deposits with similar parameters (Dolginskoye, Varandey—More, etc.). Moreover, the Master thesis might be used for the development of future fields with low or medium resources with tie—in to the IRGBS Prirazlomnaya.

1. Environmental and Site Data on Prirazlomnoye field

Offshore seabed upper sediments conditions

The investigations have been undertaken at the Prirazlomnoye field area located in the Pechora Sea. The Russian institute AMIGE (Arctic Marine Engineering Geological Expeditions) has performed the majority of these investigations during 1994 and 2003. Characteristics of upper sediments seabed of the Prirazlomnoye field area are presented in Figure 1.1 and Table 1.1.:

- The upper sediments are very fine-grained sands with small interlayers of clay. The sands have generally been found to be very dense.
- 5 to 10 m of dark grey marine clays;
- Below these soft clays is a layer of fine marine sands that are loose to medium dense and are interbreed within thin layers of peat. These are found above;
- Clayey silts and clays with traces of sand and course material. This layer has a thickness up to 20 meters, and is found above;
- Fine-grained sands of medium dense consistency with a thickness up to 30 meters.

Table 1.1: Description of the upper sediments seabed *(Gazprom Neft, 2017)*

Depth, m	Upper sediments description	Density, kN/m^3	Water Content %	Undrained Shear Strength, kPa	Cohesion, kPa	Friction Angle, degrees
4,6	Sand	19,6	27	40	5	34
5,8	Clay	18,4	37	74-36	59-33	34
13,5	Loam	17,4	45	36-46	33-42	34
15,2	Loam	18,6	27	46	42	34
16,4	Loam	18	30	97	78	34
21,5	Sand	19,9	21	-	5	35,5

Seabed permafrost

Offshore permafrost conditions have been found to be discontinuous throughout the Pechora Sea. The positive seabed water temperature (+ 2 ^{0}C) on the Prirazlomnoye field led to degradation of some frozen upper sediments. These upper sediments have very low strength, and the upper sediments are prone to considerable thaw settlement and consolidation. Due to the degradation on the Prirazlomnoye field area, frozen upper sediments were not encountered in the northern part of the area where it is planned to install templates. *(Gazprom Neft, 2017).*

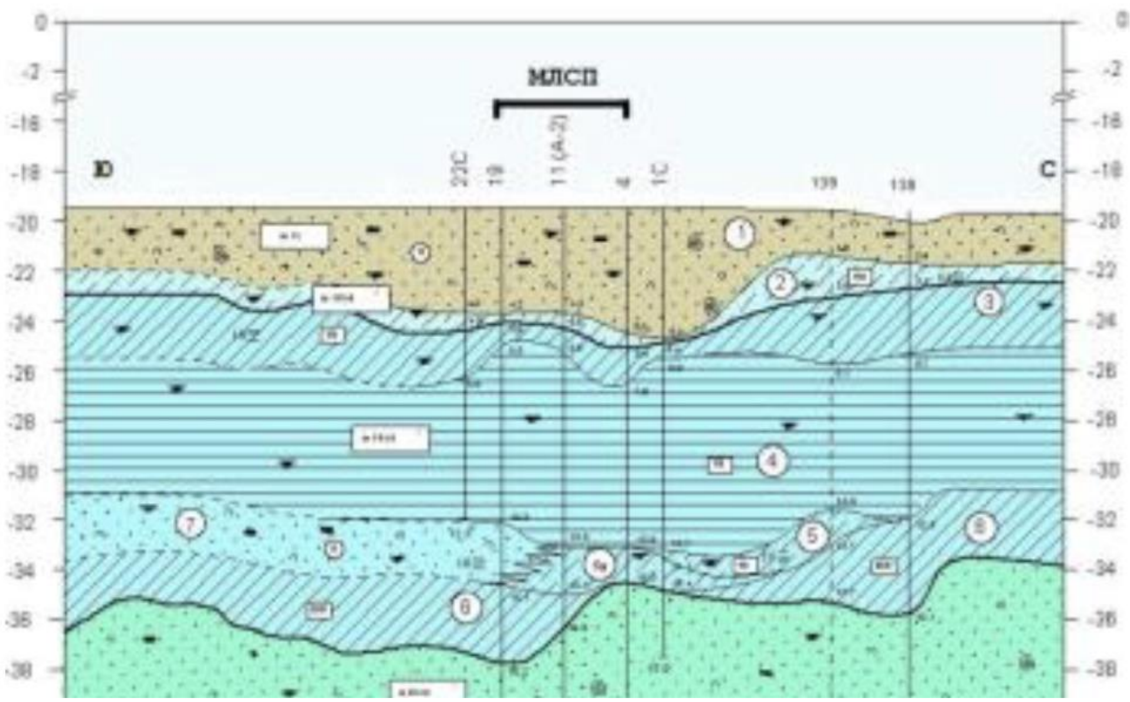


Fig. 1.1 Seabed upper sediments condition on Prirazlomnoye field *(Gazprom-Neft, 2017)*

Stability of Bottom Sediment

At a depth of up to 20 meters, hydrodynamical processes are dependent on both currents and waves. The coefficient of stability characterizes the stability of the seabed upper sediments. It is represented by the ratio of the critical velocity (velocity of erosion). The velocity at a depth of 1-2 meters above the sea bottom is about 30-40 cm/s. The coefficient of stability for the Pechora Sea upper sediments may be assumed 0.4—0.5. The calculated wave current velocity for a 5 m wave is 49 cm/s, and the stability coefficient is 0.14. It is above the critical rate for the considered seabed upper sediments, in this way an increase of the hydrodynamic processes during storms and intensive rework of the seabed upper sediments might be expected *(Gazprom Neft, 2017).*

Metocean Conditions

The meteorological conditions are the results of the northern latitude, geographical position of the area, specific features of atmospheric circulation and radiation balance. Winter is generally severe, with low air temperature, frequent strong winds, snowstorms and intensive snow falls. Summer is generally short and cold. The average annual air temperature on the Prirazlomnoye field area is around -5,8 ^{0}C. Negative air temperatures are observed over 8 months' period from October to June. The minimum temperature recorded was -44 ^{0}C. In the period June—September, the air temperature remains positive with a maximum—recorded temperature of + 32 ^{0}C.

Wind

The Prirazlomnoye field area is relatively windy. The monthly average of wind speed during the summer is 5 m/s and during winter months is 7m/s. Constant conditions occur very rarely. Wind speeds of over 15 m/s are attained most frequently in February (4%) and are infrequent during the summer (0,5%). Maximum speed is 26 m/s, with gusts of up to 38 m/s. The predominant wind direction depends on the season and the atmospheric circulation patterns. See Table 1.2.

Table 1.2 Wind in the area near the Prirazlomnoye field *(The Northern Office for Hydrometeorology and Environmental Monitoring, 2018)*

Period	N	NE	E	SE	S	SW	W	NW
December	5	6	14	10	13	38	9	5
July	17	25	11	7	5	5	14	16

Wind Waves

Waves generated on the Prirazlomnoye oil field area are induced by local winds and are often combined with waves coming from the open water. Stormy northwestern winds generally induce extreme waves. These situations generally occur when deep cyclones cross the central part of the Barents Sea in westward and southwestward directions. In the area near Prirazlomnoye field (Varandey meteorological station), wind waves of 6.1 m height will occur with 3% confidence level during the summer and 7.5 m waves during autumn for a 1 in 50 year return period.

Sea Level and Tides

Tides dominate the sea level oscillations in the Pechora Sea area. They are semi-diurnal and mixed semi-diurnal. Tidal levels in average syzygy and quadrature, and extreme concerning the conventional zero level is as follows:

- Mean syzygy +70 cm
- Mean quadrature -75 cm
- Maximum high water +95 cm
- Minimum low water – 105 cm

Under storm conditions, long waves may cause level elevation comparable to (or even greater) the tidal variation. Nonperiodical level oscillations with recurrence once in 50 years are +150 and -160 cm, and the combined level oscillation is +240 and -255 cm.

Current

Tidal current is the main cause of water dynamic in the region. Calculations allow evaluation of the maximum current speed. The currents are calculated to be as follows:

- Tidal current 70 cm/s
- Non-periodic/wind-induced current 106 cm/s
- Combined 134 cm/s

Offshore Ice conditions

Based on observations that started in 1881, icebergs have never been observed in the central part of the Pechora Sea. (Table 1.3). The average width of the landfast ice is 2,5 km. In cold years it may reach 15 km, in warm years the maximum observed depth was 1,8 km. The landfast ice zone during extreme years extends 10-15 km offshore, reaching depths at 12-15 m. Landfast ice thickness is on average 110 cm a minimum observed of 79 cm and a maximum of 158 cm. Snow accumulates on the landfast ice with an average depth of 30 cm, a minimum of 15 cm and a maximum of 64 cm.

Table 1.3 Ice formation at the Prirazlomnoye field

Open water season 145 days		
No icebergs		
The average time of the ice formation	**The earliest date of ice formation**	**The latest date of ice formation**
2 November	14 October	25 December
The average time of the open water season start	**The earliest date of open water season start**	**The latest date of open water season start**
29 May	5 April	13 July
The average width of fast ice	**The width of fast ice in the warmest year**	**The width of fast ice in the coldest year**
2,5 km	1,8 km	15 km

The ice conditions in the Arctic on the 5-7 November based on AARI (Arctic and Antarctic Research Institute) is shown in the Figure 1.2.

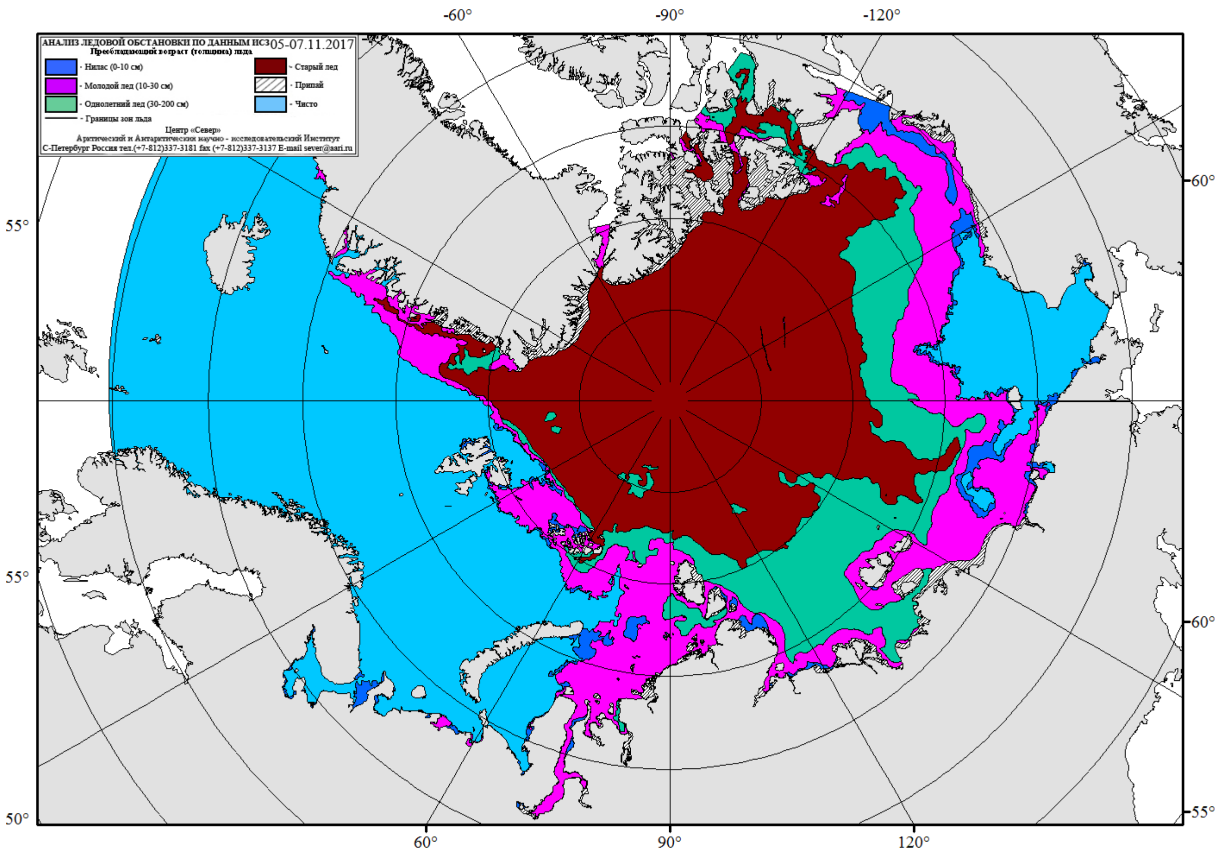


Fig. 1.2 Ice conditions in the Arctic 05-07.11.2017

(http://www.aari.ru/odata/_d0015.php?lang=0&mod=1&yy=2017)

Fast ice is not steady, and fracturing occurs very often during the winter. This may lead to the formation of hummock fields with as much as 60-80% of the sea surface being covered by ridges. The shear zone is situated between the landfast and the drift ice zones and is characterized by the most intensive ice field interactions. A significant amount of ice ridges and Stamukhas are formed in the shear zones.

Ice Ridges

The Prirazlomnoye field area is ice covered between November and June (almost 220 days) and the ice thickness is typically up 1.4 m. The depth in the area of Prirazlomnoye field is 19-20 meters. Ice scouring of the seabed is a widespread process in the Arctic seas. The ice scouring is a phenomenon, which occurs when ice ridge moves while in contact with the seabed. The most often ice ridge gouging occurs on the depth from 10 to 25 meters. There are different types of ice ridges, but only first—year ice ridge scouring is present in the Pechora Sea. Thus, there are 3 critical parameters that should be anticipated on the Prirazlomnoye field area given the water depth, the anticipated seabed upper sediments and ice conditions.

The frequency of ice ridges increases from the shore to the external fast ice boundary and from the west to the east. The maximum ridge height of 4,6 m was observed in the southern part of the Pechora Sea *(Golovin et al., 1996).* The consolidated ridge layer thickness is twice as large as that for level ice thickness. The maximum ice ridge parameters have been estimated based on the morphology of sail parts of the pressure ridges *(Gudoshnikov, 1997).*

The parameters are as following:

— Maximum sail height – 3,6 m;

— Consolidated part thickness- 3,5 m;

— Maximum keel depth – 22,5 m

— Ridge thickness- 30,0 m

Grounded hummocks usually form at the edge of the fast ice. They are located at water depths of 7-15 m. As mentioned by Spichkin & Egorov (1995) Stamukha were not observed at water depths exceeding 20 m. Very often, Stamukha forms a chain at the same place from year to year. In the Pechora Sea, they are located mainly near the Matveev and Dolgy Islands and along the southern extremity of Novaya Zemlya. Stamukha consists mostly of ice blocks that are not consolidated. The sail height can reach 7-12 m while the length can be hundreds of meters. The prevailing length is 30-150m. Seabed scouring is therefore possible in the water depth up to 20 m

Drifting Ice

Zubakin (1997) by analysis of observation on the wind—driven and tidal ice drift in the Pechora Sea obtained the statistical estimations of wind—driven ice drift. The main conclusions of their analysis are as follows:

— The most expected wind—driven ice drift velocity is 15-20 cm/s

— The wind—driven drift velocities with a periodicity once in 5 years is about 100 cm/s and 1 once in 50 years is more than 120 cm/s.
— Most dangerous are west rhombus winds (SW—W—NW) that cause eastern ice drift with maximum velocities.
— The maximum drift velocity is 60-70 cm/s. The mean one is about 40-50 cm/s.
— Summarize maximum drift velocity is about 140-150 cm/s.

Sea Ice Extension

The seasonal variation of the sea ice extension is very high with a maximum southern extension in March and a minimum extension in September.

The water depth represents the main factor when considering the exploitation of offshore hydrocarbons as the feasibility of both drilling and field development is depending on the water depth. The ice in the Pechora Sea poses restrictions determined by the sea-bottom structures. Any use of subsea equipment will be hampered by lack of access for drilling or maintenance during ice season. Furthermore, such equipment must be trenched at depths where ice cannot cause damage. Trenching is required in water depths up to 15—25 m where ice-ridges occur.

2. Evaluation of capacities of IRGBS “Prirazlomnaya” for tie—in Silurian and the Lower Devonian deposits

2.1 General information about IRGBS “Prirazlomnaya” and Prirazlomnoye field

The Prirazlomnoye oil field is located in the central part of the Pechora Sea. The distance from IRGBS “Prirazlomnaya” to the shoreline is 60 km. The closest city is Narayan—mar that is located approximately 230 km away from the IRGBS “Prirazlomnaya”. The “Gazprom Neft Shelf” has a development license.

The following parameters characterize the Prirazlomnoye oil field:

- Extractable oil reserves composed of 79 million tons of oil without including reserves from Silurian and Lower Devonian deposits;
- Water depth varies from 19 to 21 meters;
- The main pay zone formation is found at a depth of 2350 -2550 meters (Permian age);
- The oil density ranges at approximately 955 kg/m^3
- Assumed amount of wells includes 19 production wells, 16 injection wells, and 1 slurry well.
- On 14th of June 2018 more than 7,5 million tons were produced from Prirazlomnoye field;
- The production from the field is carried out from the ice-resistant gravity-based structure (IRGBS);
- Structure is capable of carrying out the following operations: Drilling, Production, Processing, Offloading and Storing.
- The oil comes to a specially constructed ice resistant shuttle tankers (IRST) named as “Mikhail Ulyanov” and “Kirill Lavrov.” The deadweight for both tankers is equal to 70000 tons.

To accelerate payback period (PBP) of the project, the 3—D seismic was made. The Gazprom—Neft RDC (Research and Development Center) distinguished 6 perspective deposits of Silurian—Devonian age with HP/HT characteristics and located on the depth 3500—6000 meters: S1 - reef, S2 - biostream, D1 - bio stream, D1l - reservoir, D3f reef, D3fm reef. See Fig 2.1.

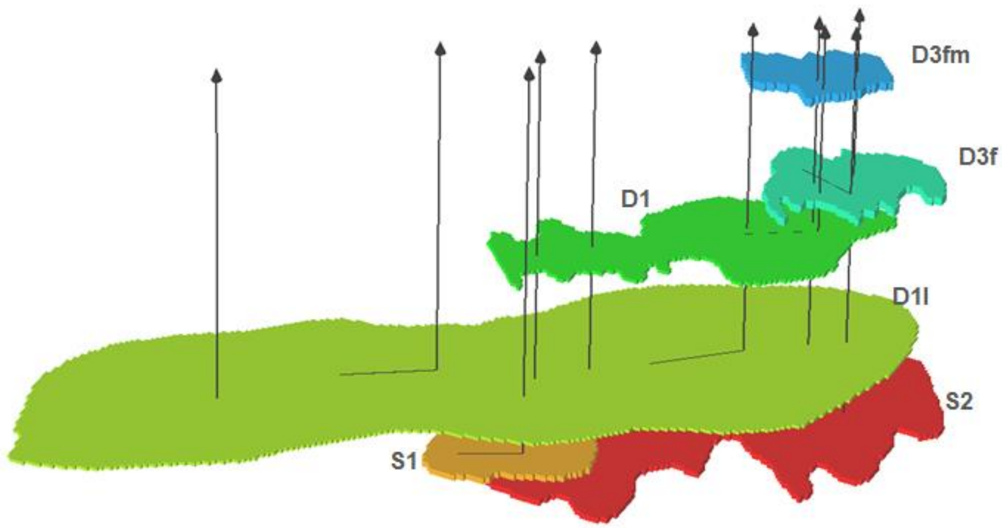


Fig. 2.1 The six most promising traps of Silurian—Devonian age *(Gazprom-Neft, 2017)*

The estimated reserves distribution P10, P50, P90 is presented on the Figure 2.2. *(Gazprom Neft, 2017).*

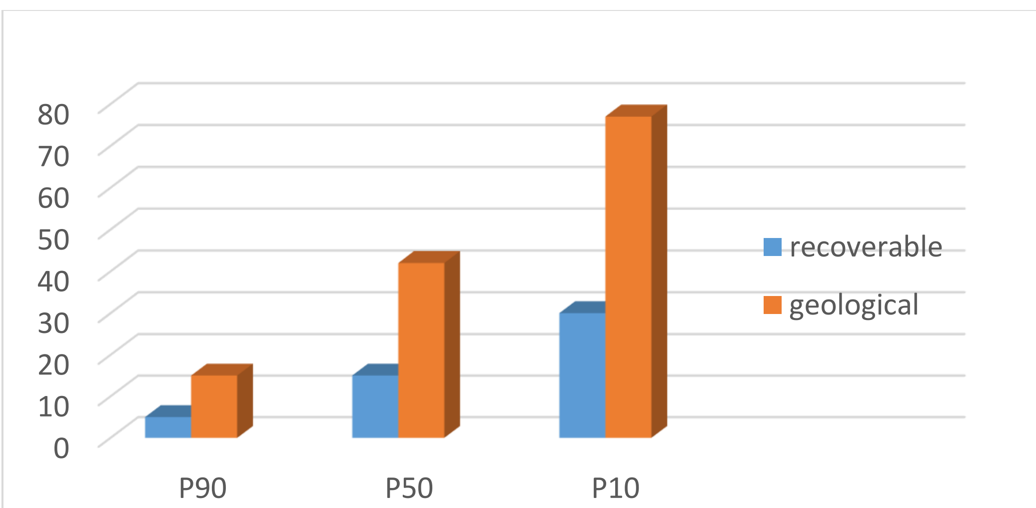


Fig. 2.2 Estimated reserves distribution *(Gazprom Neft, 2017)*

The data about the number of geological prospecting works made on 14 June 2018 is shown in Table 2.1.

Table 2.1 Name of works made on the Silurian and Devonian deposits *(Gazprom Neft, 2017)*

Year	Name of work, results
2014	Reprocessing and reinterpretation of previous seismic surveys by using sophisticated technologies
2015	Gazprom-neft NTC selected 6 of the most promising deposits and a probabilistic estimate of recoverable resources of 15 million tons
2015	"Gazprom-neft NTC - Tyumen" carried out a preliminary design project for the implementation of the 3D Seismic Survey
2018	3D Seismic Survey

The conclusions from the works made on the Silurian and Devonian deposits on 15 June 2018:

- High Pressure/High Temperature characterizes the reservoir properties, and the traps are laying at about 3500—6000 meters depth;
- The distance between the Prirazlomnaya platform and the anticipated and the most favorable drilling site is 2500 m. The depth along the route from the site to the platform is 20 m;
- Extractable oil reserves are estimated to be 18 million tons of oil;
- The storage, processing and offloading capacity of Prirazlomnaya are going to be usedused for developing these deposits;
- The estimated period for development is 15 years;
- The IRGBS “Prirazlomnaya” is capable of working until 2060 (it is assumed that the oil production finishes in 2038, therefore after this year processing, storing and offloading capacities will be free).

To calculate cumulative production from the wells, it is necessary to estimate production forecast for each well. Information about the properties of the deposits is limited to PH-5 exploratory well drilled in 1995. Due to the ice conditions, the flow test was not accomplished. Thus, the 8 fields—analogs with same deposits in Timan—Pechora province were chosen to estimate fluid characteristics . See Table 2.2.

Table 2.2 Analogs of Silurian-Devonian deposits of Prirazlomnoye field in Timan-Pechora province *(Gazprom Neft, 2017)*

<table>
<tr><td>D3fm</td><td>Object 1</td><td rowspan="2">Passed (Nenets Autonomous District)
Pashshorskoye (Nenets Autonomous District)
Sredne-Kharyaga (Nenets Autonomous District)
Hosoltinskoye (Nenets Autonomous District)</td></tr>
<tr><td>D3f</td><td>Object 2</td></tr>
<tr><td>D1</td><td>Object 3</td><td rowspan="2">Named of Anatolia Titova (Nenets Autonomous District)
Named of Roman Trebs (Nenets Autonomous District)
Osoyevskoye (Nenets Autonomous District)
Podverjuskoye (Nenets Autonomous District)
Hosoltinskoye (Nenets Autonomous District)</td></tr>
<tr><td>D1l</td><td>Object 4</td></tr>
<tr><td>S2</td><td>Object 5</td><td rowspan="2">Named of Anatolia Titova (Nenets Autonomous District)
Named of Roman Trebs (Nenets Autonomous District)
Osoyevskoye (Nenets Autonomous District)
Hosoltinskoye (Nenets Autonomous District)</td></tr>
<tr><td>S1 f</td><td>Object 6</td></tr>
</table>

The results of a probabilistic assessment of the prospective resources (geological) of the Prirazlomnoye field are shown in Table 2.3.

Table 2.3 Results of a probabilistic assessment of the prospective resources of the Prirazlomnoye field

Deposit	Probability	Ground bed, m	Oil Net Pay, m	Productivity factor, unit fraction	Oil saturation coefficient, unit fraction	Density, g/sm3	Initial oil in place, thousands. t
D3fm	P50	3 300	100	0,09	0,8	0,8	2 000
D3f	P50	3 500	150	0,09	0,8	0,8	3 000
D1	P50	3 800	230	0,08	0,8	0,8	7 000
D1l	P50	4 400	200	0,08	0,8	0,8	28 000
S2	P50	5 200	150	0,07	0,79	0,81	500
S1	P50	6000	220	0,07	0,79	0,81	1 500

IRGBS “Prirazlomnaya” was built specifically for developing Permian and Carboniferous age deposits of Prirazlomnoye field. It ensures the performance of all technological operation: drilling wells, production, storage, offloading, generation of thermal and electric energy. Thus, the subsea development concepts for shallow water with tie back of subsea wells need to evaluate possibility of tie—in Silurian and Lower Devonian deposits to storage, processing and offloading capacities of IRGBS “Prirazlomnaya”.

2.2 Production and utilization of associated gas

In the basic concept, it was supposed to develop Silurian and Lower Devonian deposits on depletion mode (Figure 2.3.). However, the developing HPHT Silurian and Lower Devonian deposits of fields—analogs in Timan—Pechora province (named of Anatolya Titova and named of Romana Trebsa) on depletion mode showed poor production performance. The reservoir pressure has reduced in 2 years at the fields—analogs that led to a sharp decrease in well production rates. Thus, in order to keep production at a given level, it is necessary to use methods of maintaining reservoir pressure, such as water injection, gas injection or combined methods.

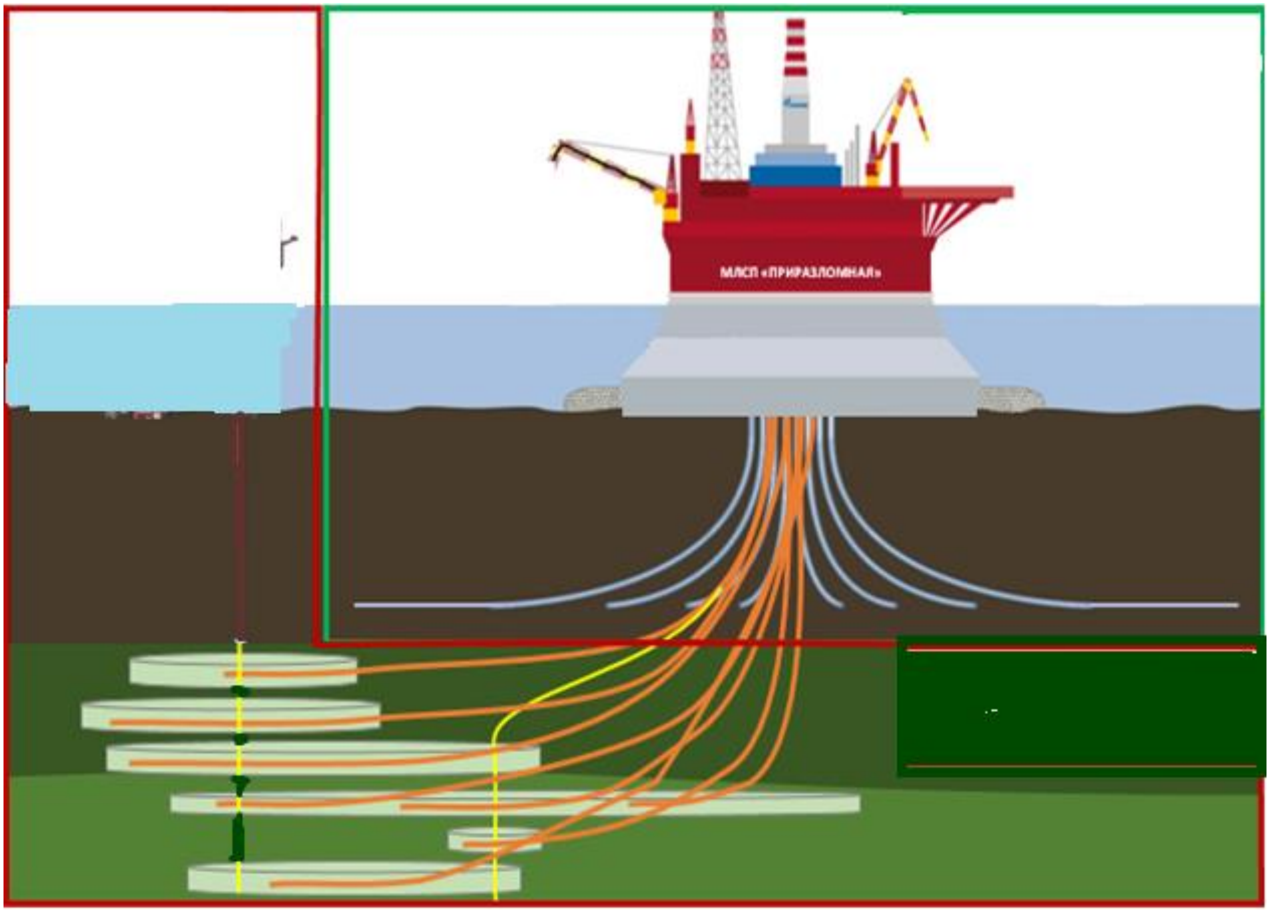


Fig. 2.3 The basic concept of producing wells on depletion mode

The development of the field is expected to be carried out using horizontal wells. To calculate the projected production rate of a horizontal well, it is necessary to apply the model to account for:

— the ellipsoidal form of the drainage zone of the formation;

— inequality of horizontal and vertical permeability of the formation;

— Imperfection of the formation exposing of the pay zone.

In the practice of operating horizontal wells, there is a formula (the S. Joshi equation) for estimating the production rate:

$$Q = \frac{2\pi k h \Delta p}{\mu[\ln(\frac{a+\sqrt{a^2-(L/2)^2}}{L/2}) + \frac{h}{L}\ln(\frac{h}{2r_c\pi})]} \quad (2.1)$$

Where $a = \frac{L}{2}\sqrt{\frac{1}{2}+\sqrt{\frac{1}{4}+(\frac{2R_k}{L})^4}}$ — semi major axis of drainage.

The increasing oil production due to tie—in Silurian and Lower Devonian deposits by using SPS to the IRGBS "Prirazlomnaya" processing and offloading systems is presented in Figure 2.4.The cumulative production based on exponential—type of distribution amounted to 13, 298 million tons of oil.

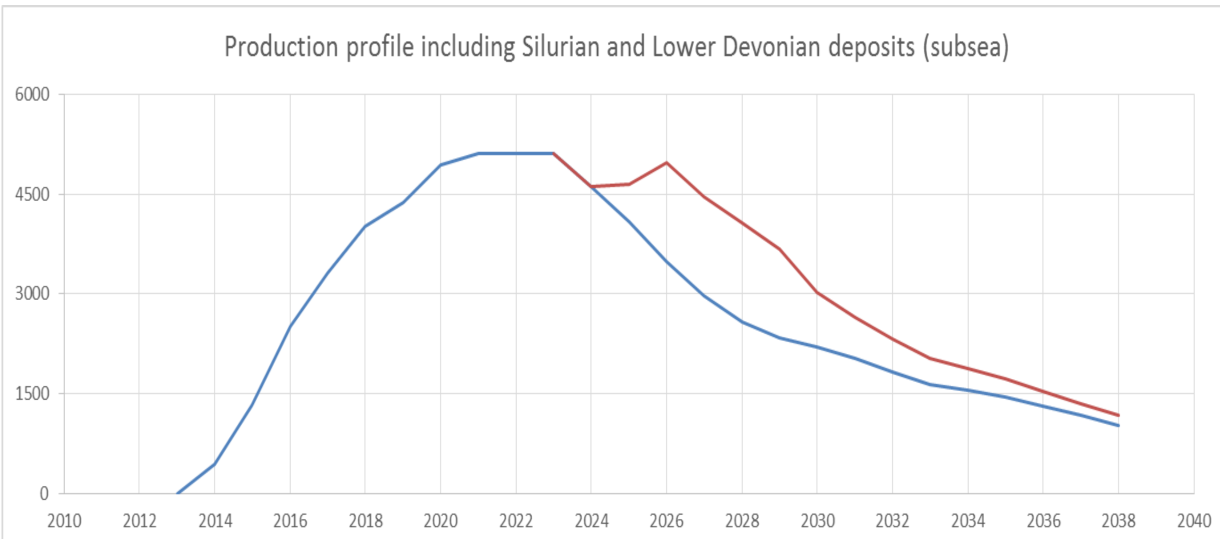


Fig. 2.4 Production profile including Silurian and Lower Devonian deposits

Injection should improve recovery and thereupon sweeps support, depending on the geometry, layering and aquifer size. The recovery factor becomes typically 15-45%.

In the project development, the most important is the justification of the location of the injection wells, in view of limited information from exploratory drilling; it is assumed that the injection will be carried out in the D1 deposit with the largest recoverable reserves.

The production strategy in this Master thesis includes 8 production wells and 2 injection wells, the distribution of wells according to deposits: D3fm reef — 1 production well; D3f reef — 1 production well; D1 — 1 production well and 1 injection well; D1l — 3 production wells and 1 injection well. S1 — 1 production well; S2 —1 production well.

Gas Injection

150 million m3 of gas will be produced in 2018, some of which will be converted to energy for domestic needs, and some will be flared. The possible tie—in of Silurian and Lower Devonian deposits lead to an increase of associated petroleum gas production up to 20 % per annum. See Figure 2.5.

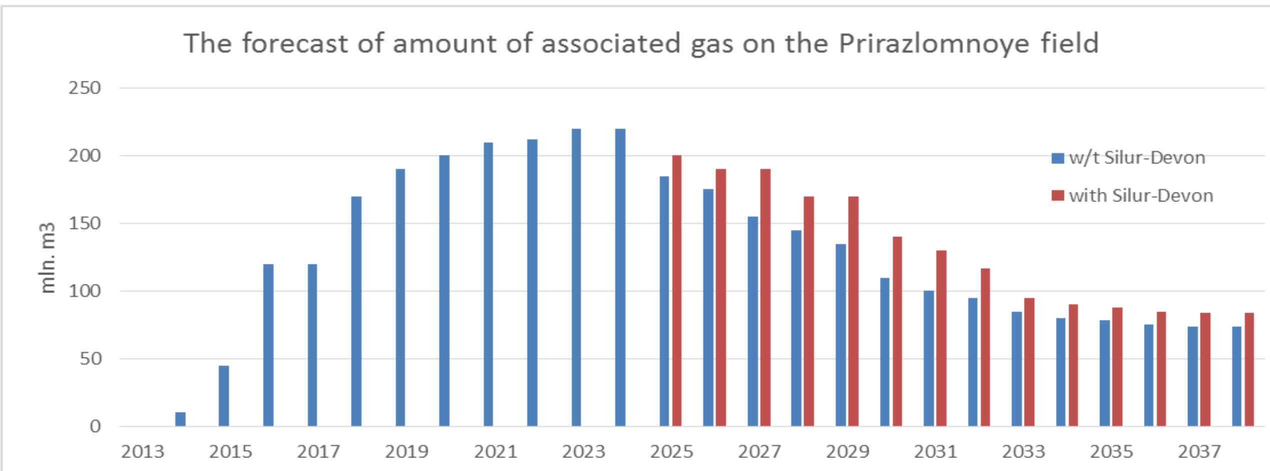


Fig. 2.5 The forecast of associated gas on the IRGBS " Prirazlomnaya"

There is about 100 m2 of free space on the IRGBS "Prirazlomnaya" in this way it is enough to install compressors for gas injection. The injection of treated associated gas produced from the Silurian and Lower Devonian deposits and the main Permian deposits will significantly reduce, or perhaps eliminate gas flaring.

The hydrocarbon gas could be utilized at the injection medium in non-miscible mode; the impact on sweep efficiencies varies with the prevailing situation (Figure 2.6). Gas, due to its low viscosity, will always have higher mobility than oil, usually resulting in poor volumetric sweep efficiency due to viscous fingering. On the other hand, due to lower interfacial tension between gas and oil, the residual oil saturation after gas flooding tends to be lower than for water flooding *(Gudmestad et al, 2010).*

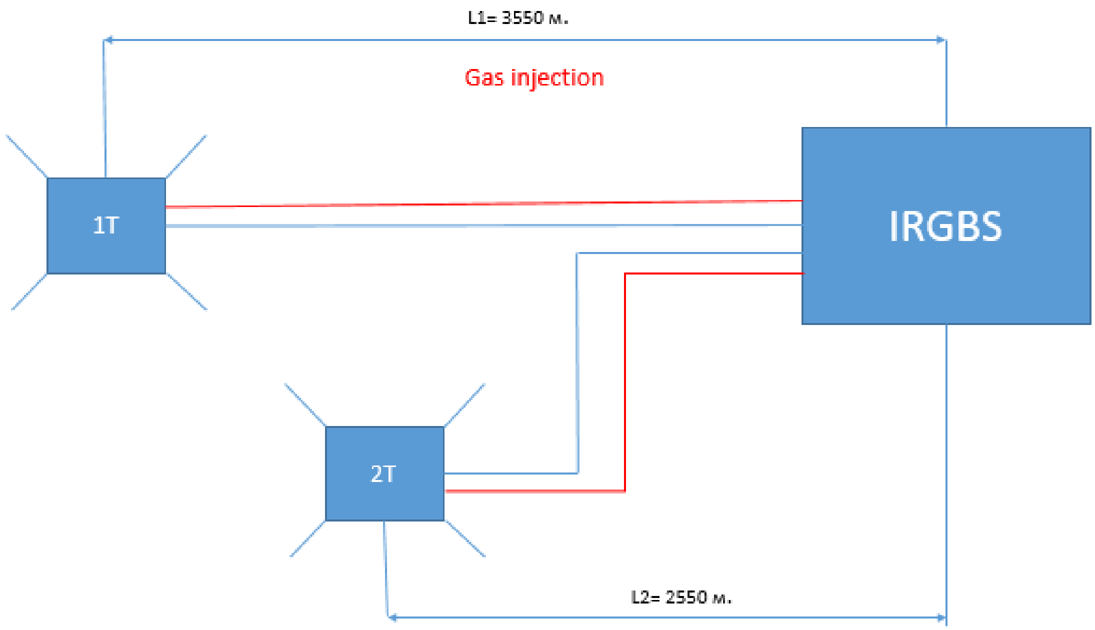


Fig. 2.6 Possible Scheme of developing deposits with Gas Injection

Also, gravity plays a big part in the context of gas flooding. Oil has a much higher density than the gas. This implies that if gas is injected below the flanks of the oil zone, gravity will move the gas very rapidly to the ceiling of the structure, resulting in very poor volumetric sweep efficiency between injector and producer. However, if oil exists above the producer well, a secondary gas cap can displace the attic oil toward the producer well, thereby increasing recovery. The applicability of technology is shown in Figure 2.7.

EOR Method	Gravity (°API)	Viscosity (cp)	Composition
Nitrogen and flue gas	> 35 ↗ 48 ↗	< 0.4 ↘ 0.2 ↘	High percent of C_1 to C_7
Hydrocarbon	> 23 ↗ 41 ↗	< 3 ↘ 0.5 ↘	High percent of C_2 to C_7
CO_2	> 22 ↗ 36 ↗ [a]	< 10 ↘ 1.5 ↘	High percent of C_5 to C_{12}
Immiscible gases	> 12	< 600	NC

Fig. 2.7 Field of applicability of gas methods ***(Zolotukhin et al, 2000)***

If gas is injected in the structural high and the reservoir has a reasonable dip, a secondary gas cap can form, and gravity can serve to stabilize the descending gas – oil contact, allowing for good volumetric sweep efficiency. As soon as, the contact is so close to the perforation of the producer that the mobility difference overrides the gravity forces and destabilizes the contact, resulting in gas fingering into the perforation *(Gudmestad et al, 2010).*

As shown in Figure 2.8, down-dip gas injection (a) results in forming the secondary gas cap and in favorable displacement scenario, while up-dip gas injection (b) leads to an overriding gas process that deteriorates the reservoir performance *(Zolotukhin et al, 2000)*.

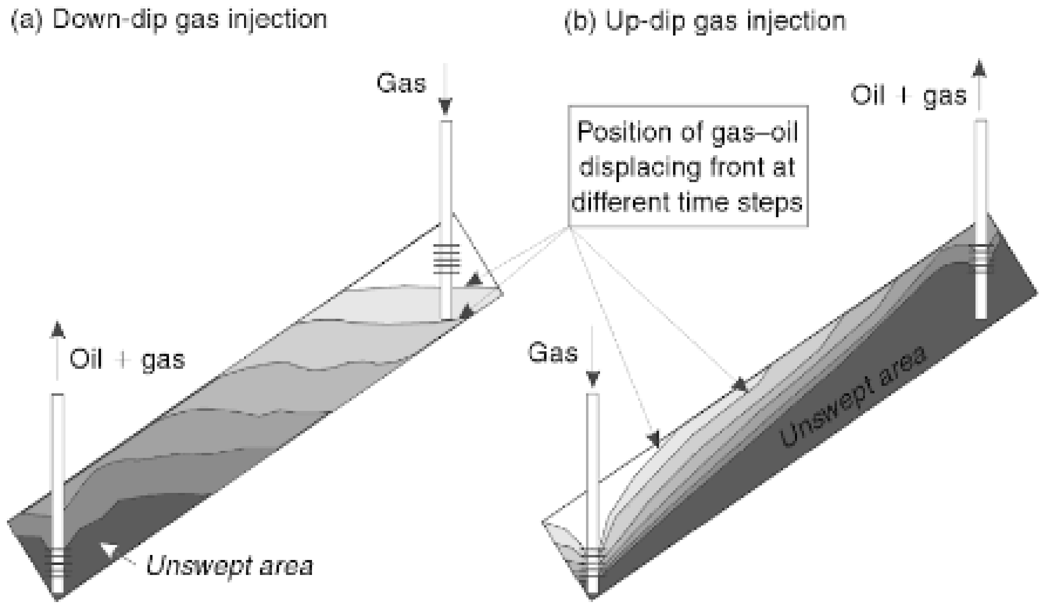


Fig. 2.8 Effect of gas injection ***(Zolotukhin et al, 2000)***

The pumping of treated associated gas from the Silurian and Lower Devonian deposits and the main Permian deposits through injection wells significantly reduce, or perhaps eliminate gas flaring.

Water Injection

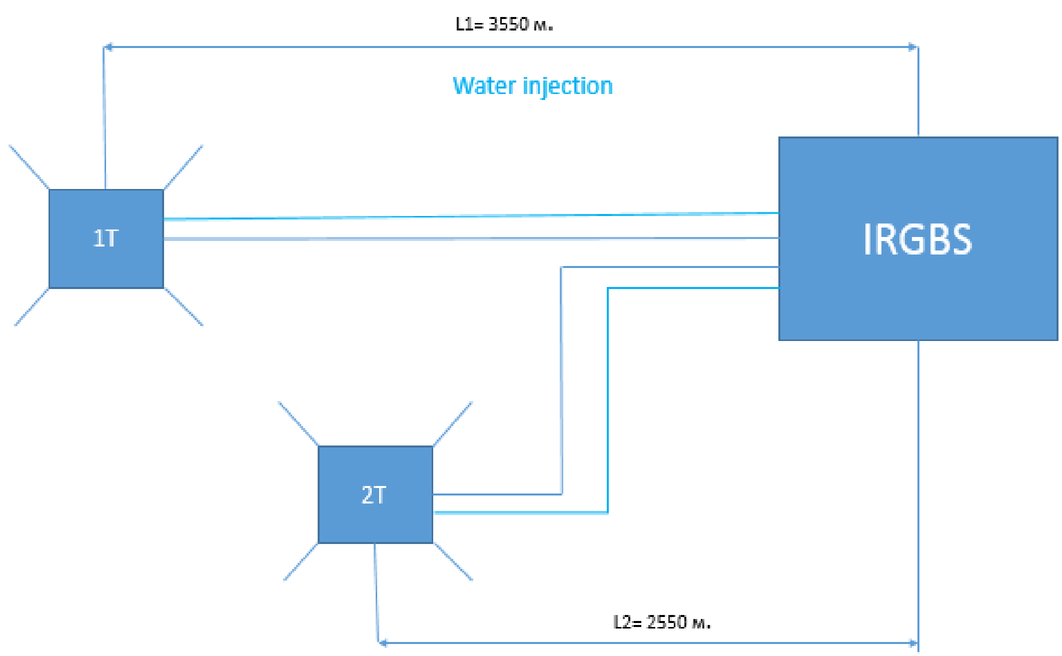


Fig. 2.9 Possible scheme of developing deposits with water Injection

Water injection is the most conventional choice of injection fluid due to the abundance and cost. Its efficiency as a displacing medium is dependent on how large reservoir volumes it contracts (volumetric sweep efficiency) and how much of the contacted oil it can mobilize (microscopic sweep efficiency). The mobility ratio is a major determinant of water flooding efficiency. See Figure 2.9

Mobility ratio is defined here as the ratio of mobility of the displacing (water and gas) and displaced (oil) fluids at the end-point relative phase permeability.

$$M = \frac{k_{rw} * \mu_0}{\mu_w * k_{ro}} \quad (2.2)$$

Conventional (primary and secondary) methods of oil recovery usually result in less than 45% of the recoverable resources. The major portion of petroleum remains in place. This unrecovered quantity depends on the complexity of reservoir conditions and the field development strategy. Economics can constrain the selection of a high-recovery strategy, that is, the added expenditures need justification through added revenues at an acceptable rate of return *(Gudmestad et al, 2010).*

The comparison of cumulative production of Silurian and Lower Devonian depositsdepending on the method of maintain reservoir pressure is presented in the Figure 2.10.

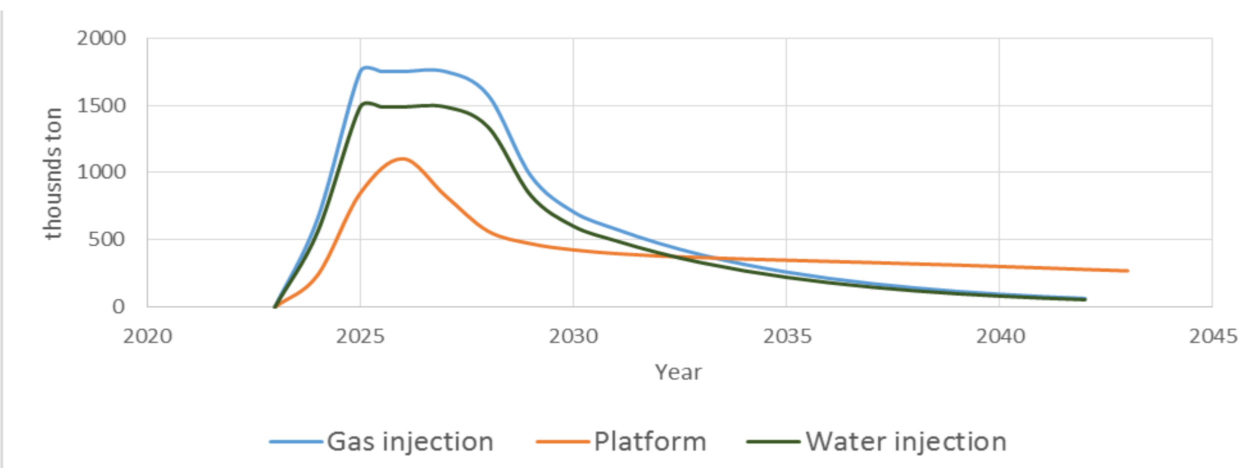


Fig. 2.10 Production profiles of Silurian and Lower Devonian deposits on different development modes

2.3 The storage and offloading capacities on the IRGBS "Prirazlomnaya"

The oil is stored in the platform in special tanks, which are located under the top side of IRGBS "Prirazlomnaya". There are twelve tanks with total storing capacity equal to 160 thousand cubic meters (See Fig.2.11) *(Gazprom-neft, 2017).* Preventing the formation of the dangerous gaseous mixture, Gazprom Neft Shelf stores the oil in the tanks in combination with water. Thus it allows to replace all oxygen from the tanks and to mitigate the probability of explosion *(Gazprom-neft, 2017).* The offloading system is presented by two "CUPON" systems, which are located in opposite sides – southwest and northeast. The offloading system includes fast disconnection in the case of an emergency that allows eliminating oil spills to the open water (*Subbotin, 2015*). The offloading system is an important part of stable transportation of the oil from IRGBS "Prirazlomnaya".

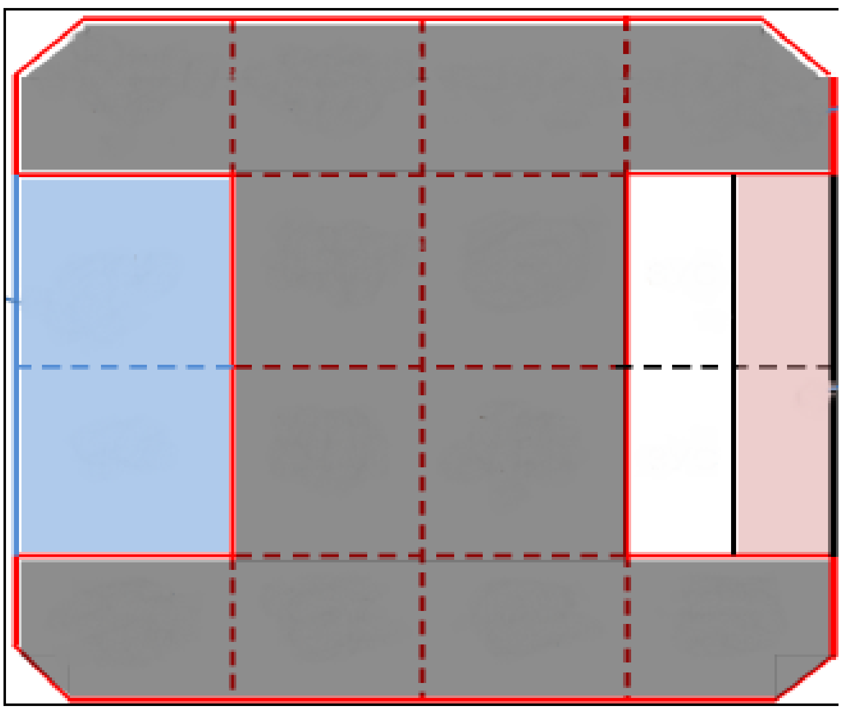


Fig. 2.11 Oil tanks arrangement on the IRGBS "Prirazlomnaya." *(Subbotin, 2015)*

The "CUPON" offloading system includes the following parts (Figure 2.12): Crane; Pipes; Special hose passing equipment; Controlling and monitoring system during offloading operations.

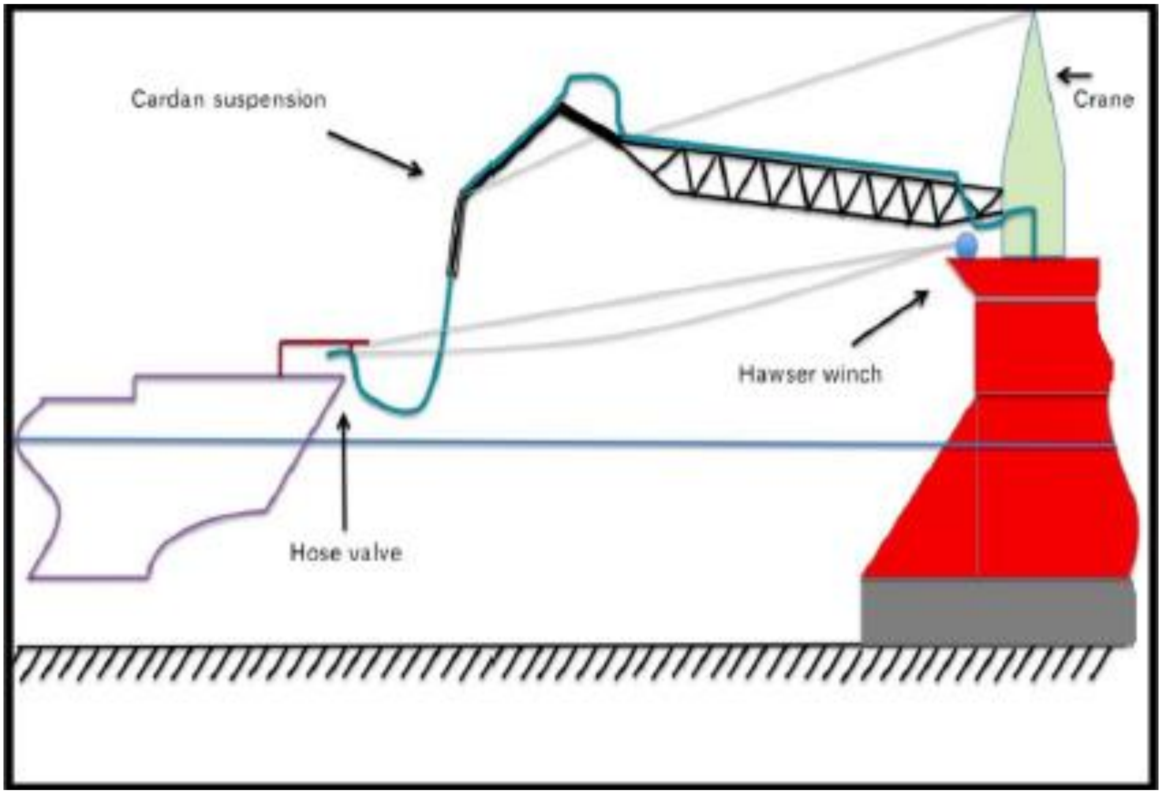


Fig. 2.12 The scheme of the "CUPON" system *(Subbotin, 2015)*

At a peak offloading rates, pumps at the IRGBS "Prirazlomnaya" may reach 8750 m3/h (*Gazprom neft, 2017)* what might be required at the peak oil production at the platform. The production from the main pay zone is going to decrease after 2024. Thus, there is no restriction in tie—in Silurian and Lower Devonian deposits with additional oil to the offloading capacities of IRGBS "Prirazlomnaya".

2.4. The processing capacities on the IRGBS "Prirazlomnaya."

Considering the oil production curve presented in Figure 2.3, it is obvious that there are three phases of oil production on the Prirazlomnoye field. The peak level of oil production at the Prirazlomnoye field without the amount of oil from Silurian and Lower Devonian is expected in 2021 and will be about 4,8 million tons of oil per year. After 2024, oil production in the following years will gradually decline (*Gazprom neft, 2017).* However, this declinaton does not mean that the processing facilities will become free to connect deposits with additional oil, due to increased water cut in the wells, which will lead to a general increase in fluid production on the IRGBS "Prirazlomnaya". Until 2027 the volume of liquid will increase, then until 2037 it will be stable.

Considering the processing capacity of the IRGBS "Prirazlomnaya", it should be noted that it is more expedient to attach incoming oil from the Silurian and Lower Devonian deposits to the second stage of separation, since the processing capacity at this stage is higher than at the first stage. Most of the water is separated in the first separation stage and then injected into wells to increase reservoir pressure. Thus, after each stage of the separation, there are various technological capacities. The maximum volume of liquid that can be attached to the preparation system in the first and second separation stages is shown in Figure 2.13.

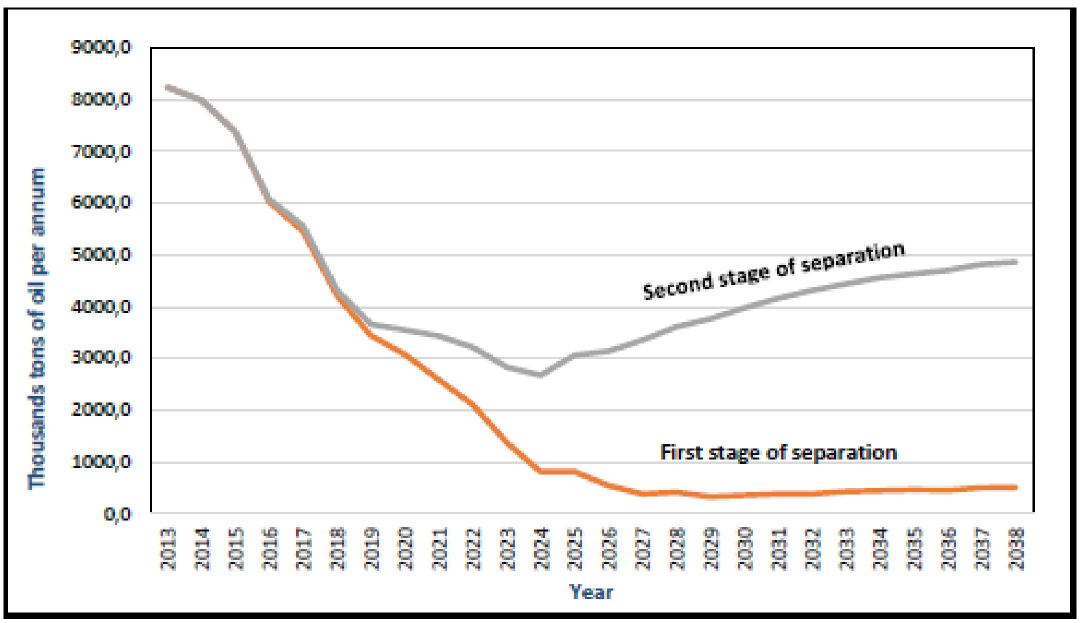


Fig. 2.13 The maximum volume of liquid that can be attached to the preparation system in the first and second separation stages *(Gazprom-neft, 2017).*

2.5 The perspectives of the application of development concept using SPS in the Pechora Sea

The gained experience from the production with use of subsea production systems on Silurian and Lower Devonian age deposits with tie—in to IRGBS

Prirazlomnaya will be used to develop the future projects in the Pechora Sea: Dolginskoye, Varandey-More, and others.

Dolginskoye field is located 25 km from the IRGBS “Prirazlomnaya” and the production will start over in 2028. See Figure 2.14.

Fig. 2.14. Fields in Pechora sea *(*The internet portal of the fuel and energy complex, *2011)*

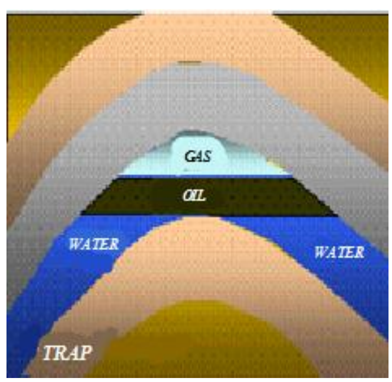
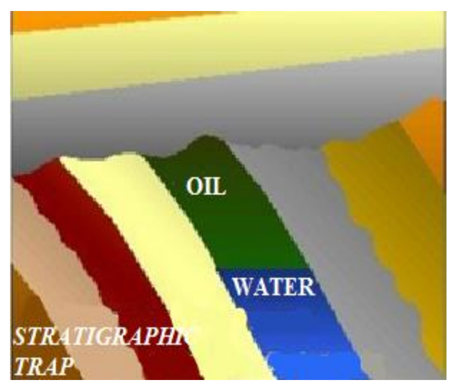
There are five oil-bearing complexes are distinguished in Dolginskoye field:

- Silurian-Lower Devonian carbonate;
- Middle Devonian terrigenous;
- Upper Devonian—Lower Carboniferous;
- Permian—Carboniferous carbonate;
- Lower Triassic terrigenous.

Dolginskoye field regarding recoverable oil reserves belongs to large deposits. Recoverable oil reserves by categories C1 + C2 - 235.8 million tons (C1 - 0.9 million tons).

The prolific oil indication has already anticipated in the Silurian and Devonian age deposits of Dolginskoye field and the knowledge about tie—in to the existing infrastructure (IRGBS “Prirazlomnaya”) aid to make the project more economically attractive regardless of whether the deposit will be developed with IRGBS “Prirazlomnaya” or separately. The comparative characteristics of the Silurian and Lower Devonian deposits of Dolginskoye versus the Silurian and Lower Devonian deposits of Prirazlomnoye fields are presented in Table 2.4.

Table 2.4. The comparative characteristics of the Silurian and Lower Devonian deposits of Dolginskoye and Prirazlomnoye fields *(Gazprom Neft, 2017)*

Field	Prirazlomnoye field	Dolginskoye field
Geology	Traditional structural traps 	Unstructured traps 
reservoir properties forecast	Primary carbonates (not exposed to weathering). Porosity up to 2%. Area of all traps 56 km2	Zone of improved reservoirs due to weathering processes. Porosity up to 11%. Area of all traps 100 km2
Estimated geological reserves of Silurian-Devonian deposits (P50)	41 million ton	371 million ton

2.6 Necessary steps to address the main challenges associated with tie—in deposits to the infrastructure of IRGBS "Prirazlomnaya"

The development of Silurian and Lower Devonian deposits increases the cumulative production on Prirazlomnoye field up to 13,298 million tonns. The calculation was done based on S. Joshi equation. However, the IRGBS was built specifically for the implementation of the developing Permian and Carboniferous age deposits of Prirazlomnoye field. Evaluation of the existing infrastructure of IRGBS " Prirazlomnaya" showed that after 2024 there are no restrictions on the connection of deposits to the offloading and storage capacities of IRGBS Prirazlomnaya. . However, the processing system needs to be upgraded due to increasing water cut in the wells and a lack of free volumes on the first stage of separation. Considering the processing capacity of the IRGBS "Prirazlomnaya", it should be noted that it is more expedient to attach incoming oil from the Silurian and Lower Devonian deposits to the second stage of separation, since the processing capacity at this stage is higher than at the first stage.

In the basic concept, it was supposed to develop Silurian and Lower Devonian deposits on depletion mode. However, the absence of maintains reservoir pressure does not allow to keep the production at a given level. The international practices used offshore of maintaining pressure through gas injection proved to be very successful and effect of implementation was estimated which allow reducing gas flaring.

There are many fields in the Pechora Sea which is on pre—feed stage. Thus, the subsea development concept for shallow water with tie back of subsea deposits to processing and offloading facilities of IRGBS "Prirazlomnaya" will be used to develop fields with low resources with using existing infrastructure.

The challenges in the implementation of the concept with using of SPS are:

— The protection of pipeline and subsea production systems from ice gouging;

— Seasonable drilling;

— The limited experience of using subsea production systems ;

— Periodical inspections for the integrity and reliability of the subsea production systems and the pipelines located below the ice;

— The necessary of implementation of artificial lift systems with increased run life in the HP/HT wells;

— The utilization of additional volume of gas.

The concept of development of the field with tie—in to the platform with using SPS in the Arctic is presented in Figure 2.15.

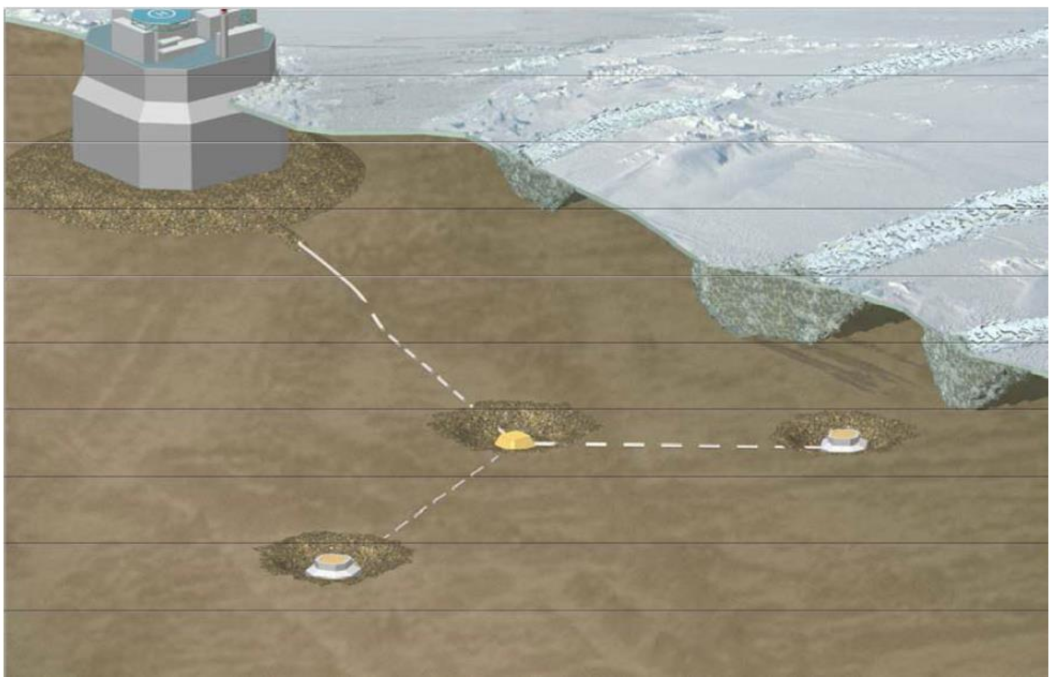


Fig. 2.15 Subsea production systems in the Pechora Sea ***(Vershinin et al., 2009)***

3. Challenges related to the development of HP/HT reservoirs in the Arctic

3.1 Arctic seasonable HP/HT drilling limits.

Arctic offshore drilling operations should be limited to periods when the drilling rig and its associated system are capable of working and cleaning up a spill in Arctic conditions. It should be highlighted that, in the case of HP/HT, this period should include the time required to control a blowout by drilling a relief well to intercept the well involved in the blowout and bring it under control. *(The PEW charitable trusts, 2013).*

The average open water season in the Prirazlomnoye field is about 145 days. If a well blowout occurs, it may take about 60 days on average to complete a relief well. The drilling on Prirazlomnoye field should be limited to approximately 85 days during a 145-day open-water season because oil spill response techniques are more successful during summer. Oil spill response techniques are substantially less effective during periods of broken ice, periods of fall ice freeze-up, and when oil is trapped under the ice *(The PEW charitable trusts, 2013).* The arctic seasonable drilling limits for the Beaufort Sea, which has more severe climate, are shown in Figure 3.1

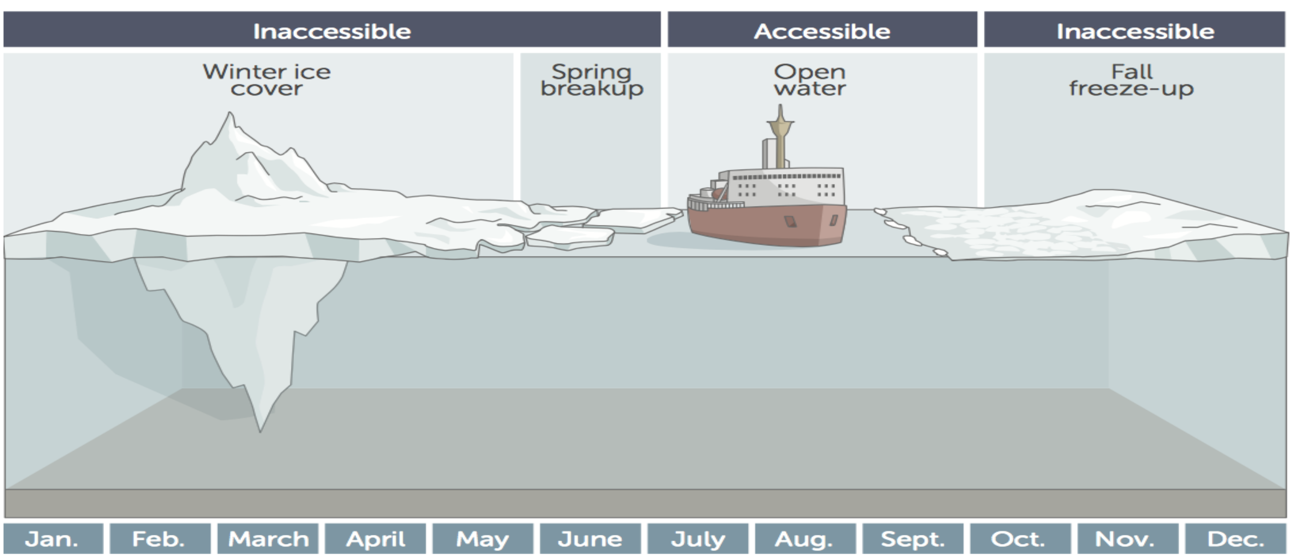


Fig. 3.1 Arctic seasonal drilling limits *(The PEW charitable trusts, 2013)*

Figure 3.2 shows the approximate operating limits for mechanical oil removal and burning of spilled oil under various considerations of ice and weather conditions for Arctic projects.

Limiting Factor	Ice Coverage						Wind			Wave Height			Visibility		
Conditions	Oil spilled on top of ice or among ice					Oil spilled under solid ice	0-20 mph	21-35 mph	>35 mph	<3 ft.	3-6 ft.	>6 ft.	High	Mod-erate*	Low†
	<10%	11%-30%	31%-70%	>70%	Solid ice 100%										
Mechanical recovery with no ice management	○	×	×	×	✓	×	✓	○	×	✓	○	×	✓	○	×
Mechanical recovery with ice management	✓	○	×	×	✓	×	✓	○	×	✓	○	×	✓	○	×
In-situ burning	✓	○	×	○	✓	×	✓	×	×	✓	○	×	✓	○	×

Fig. 3.2 Seasonal constraints to clean up Arctic oil spill *(The PEW charitable trusts, 2013)*

Drilling rig selection is a critical step for Arctic oil and gas exploration. MODUs working in Arctic waters, even in summer, require icebreaker support for ice management and must be capable of transiting thick first-year ice. Arctic drillship design must include a hull shape that *(The PEW charitable trusts, 2013):*

- Minimizes ice loads, or the weight and stress of ice against a vessel;
- Prevents ice accumulation in the 'moon pool' area (where drilling equipment passes through, typically located in the center of the MODU);
- Prevents ice damage to propulsion systems;
- Safely transits ice-infested water;
- Works up to 15000 psi.

The HSE management system in the company should be based on the principles of accident prevention. At the same time, the company must develop emergency response plans that provide readiness for unexpected events.

The basic principles of Norwegian companies, which are the trendsetters, regulate the plans for emergency preparedness and response to oil spills *(Ahmed Osman, 2015)*. The Emergency Response Plan (ERP) for the Arctic should be based on these principles:

- Saving lives shall be given the highest priority.
- Emergency preparedness analysis shall be risk-based and form the basis for performance standards and emergency response plans.
- Emergency response plans, resources and incident management capabilities shall be available to respond to incidents and emergencies.
- Preparedness measures shall be robust to handle unforeseen consequences, emergency response, and incident management capabilities shall be maintained through systematic training.

Drilling season extension.

Urycheva (2013) mentioned, the permissible ice thickness for drilling operations using the new Arctic Jack-Up rig is 0.54 m. The new arctic Jack-Up with the drill string protected inside the platform legs can withstand ice loads during operations. . However, if a significant rubble accumulation occurs the Jack-Up may be stuck in the ice. Based on the information from this work, the acceptable ice thickness during drilling is suggested to be limited by 0.3 m. Thus, this thickness is a critical parameter in order to begin preparing for demobilization, which takes approximately one week.

Estimation of freezing degree-days for the Pechora Sea based on Heat Equation, Zubov Formula and Lebedev Formula, is presented in Table 3.1

Table 3.1 The estimation of freezing degree-days *(Urycheva, 2013)*

FDD	Heat equation	Zubov formula	Lebedev formula
For h_i=0.3 m	69	300	215
For h_i=0.54 m	192	702	594

The measurements from the Varandey Meteorological station, which is located 25 km from the expected subsea production modules, are used to give a general understanding of how the drilling season could be extended. (yellow mark – the duration of target thickness (0.3 m) formation, red mark – the duration of design ice thickness (0.5 m)). See Table 3.2.

Table 3.2 Ice growth calculations

Date	Time interval, days	Air Temperature, C	FDD, C day	Ice growth, m
31.10	2	0,3	-	-
1.11	1	-4,7	2,9	0,02
5.11	4	-8,5	29,7	0,1
7.11	2	-6,2	38,5	0,11
8.11	1	0,2	38,5	0,14
12.11	4	-6	55,3	0,16
14.11	2	-11,3	74,3	0,16
15.11	1	-4	76,5	0,16
19.11	4	-1,8	76,5	0,16
21.11	2	-2,1	77,1	0,17
22.11	1	-5,7	81	0,17
26.11	4	-18	145,8	0,24
28.11	2	-21,2	184,6	0,27
29.11	1	-26,2	209	0,29
3.12	4	-7,6	232,2	0,31
5.12	2	-14,4	257,4	0,33
6.12	1	-10,7	266	0,34
10.12	4	-14,9	318	0,38
12.12	2	-27,8	370	0,41

13.12	1	-19,4	388,3	0,42
24.12	11	-6	505,4	0,49
26.12	2	-17,1	536	0,51
27.12	1	-18	552,2	0,52
29.12	3	-17,3	598,7	0,54
10.1	12	-23,2	855,5	0,67

Over the past years, weather conditions have allowed to extend the drilling season to 5 weeks after the ice began to form, thus remaining 5 to safely leave the site until a critical ice thickness is formed. It should also be mentioned that due to the icebreaking capabilities of the jack-up hull the jack-up could be on location earlier in the summer. That will allow an extended operational season. The Figure 3.3 represents the extending of drilling season.

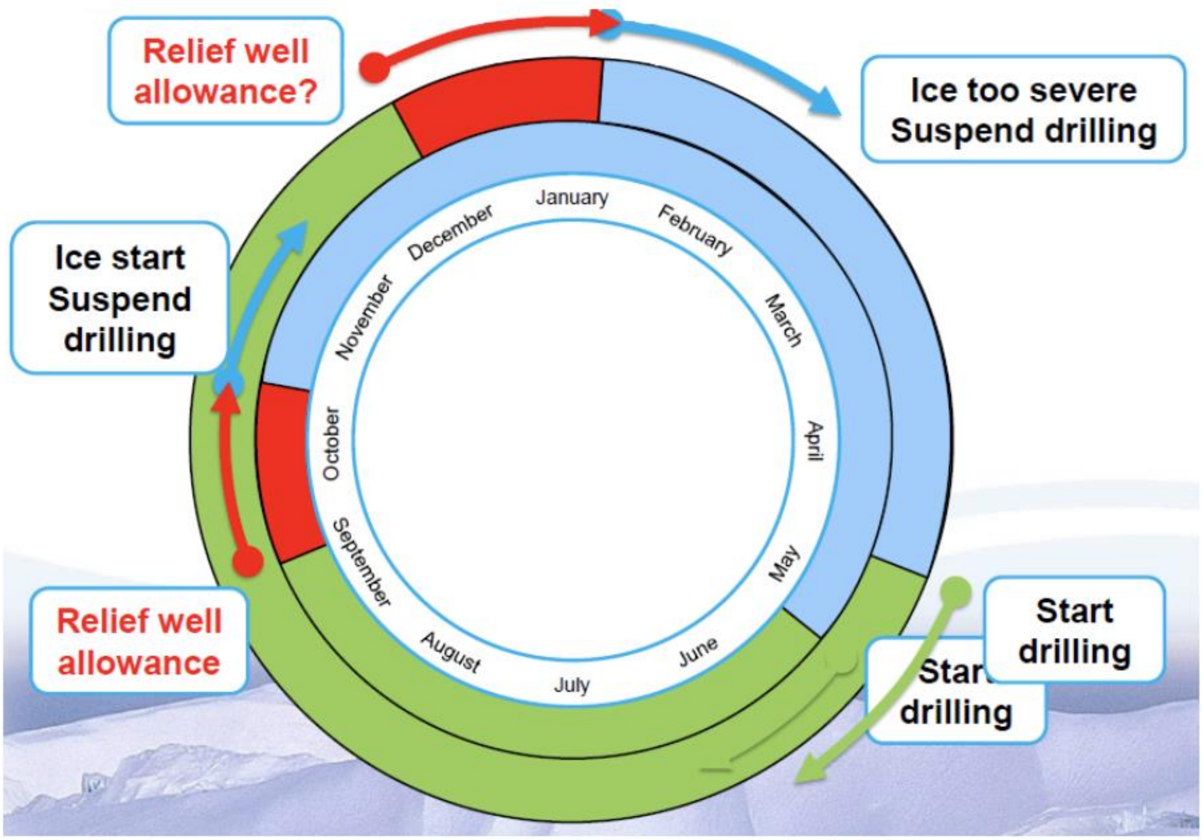


Fig. 3.3 Extended drilling season *(Urycheva, 2013)*

Jack-up day rates for Arctic region increased, and presently they are close to

600,000 USD/day for some areas. This leads to a huge increase of well construction costs in Arctic and Sub-Arctic - from 50 million USD in the Norwegian Barents Sea to 250 million USD for East Greenland (Urycheva M., 2013).

3.2 Ice ridge and strudel gouging

Strudel is the German word for 'whirlpool.' Strudel scour describes a situation when a large volume of freshwater during spring melt flows onto a pack of ice and drains through a hole or crack in the ice, creating a severe whirlpool down to the seabed where the water pressure can wash layers of the seabed away, creating a hole more than 3 meter deep. *(The PEW charitable trusts, 2013)*.See Figure 3.4.

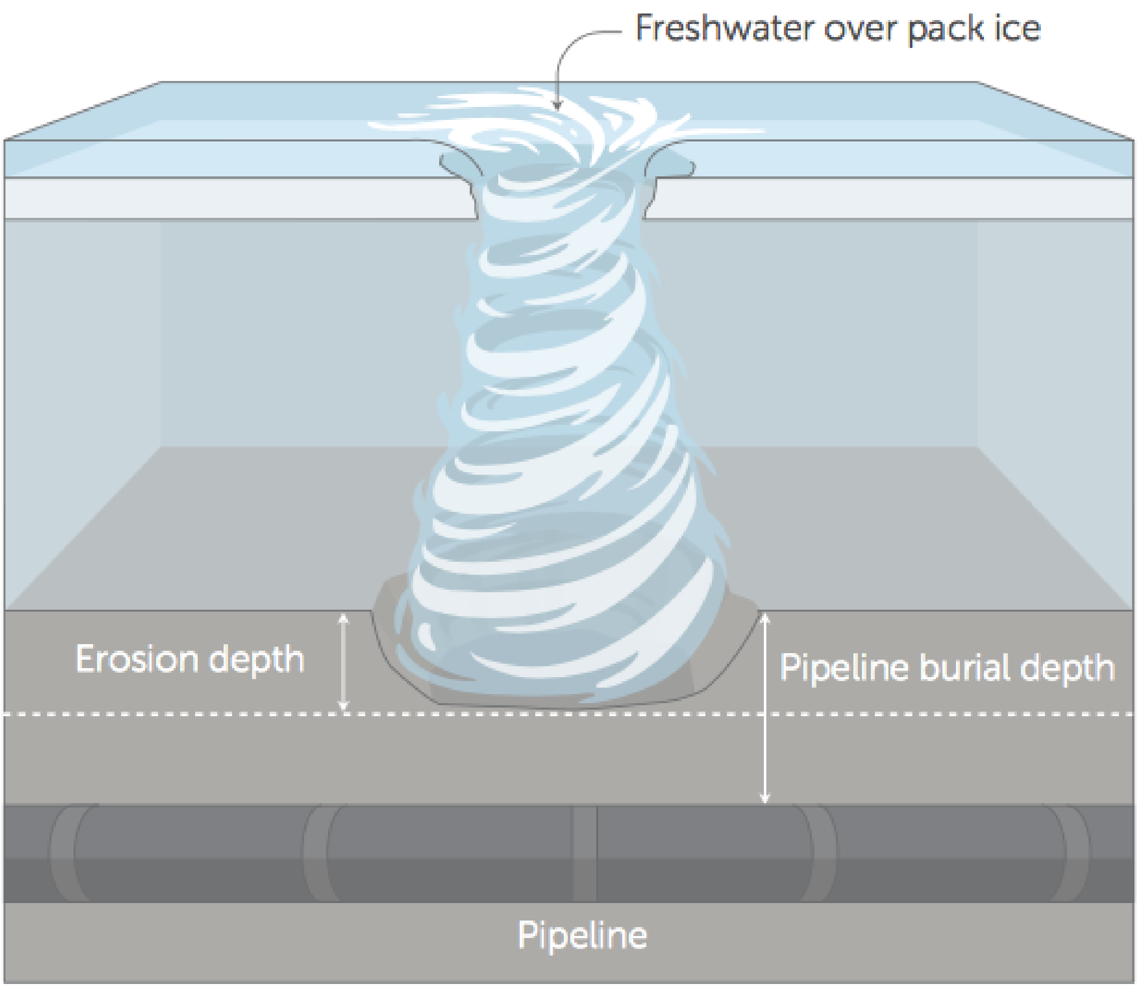


Fig. 3.4 Strudel scouring *(The PEW charitable trusts, 2013)*

Ice scouring of the seabed is a widespread feature in the Arctic seas. The ice scouring is a phenomenon, which occurs when ice ridge moves while in contact with the seabed. The scour may take the form of a long linear furrow following a relatively straight line *(Clark et al., 1998)*. See Figure 3.5.

Ice scour depth has economical importance due to the possibility of damaging to pipelines and subsea production systems. The main method of pipeline protection from ice ridge impact is the trenching.

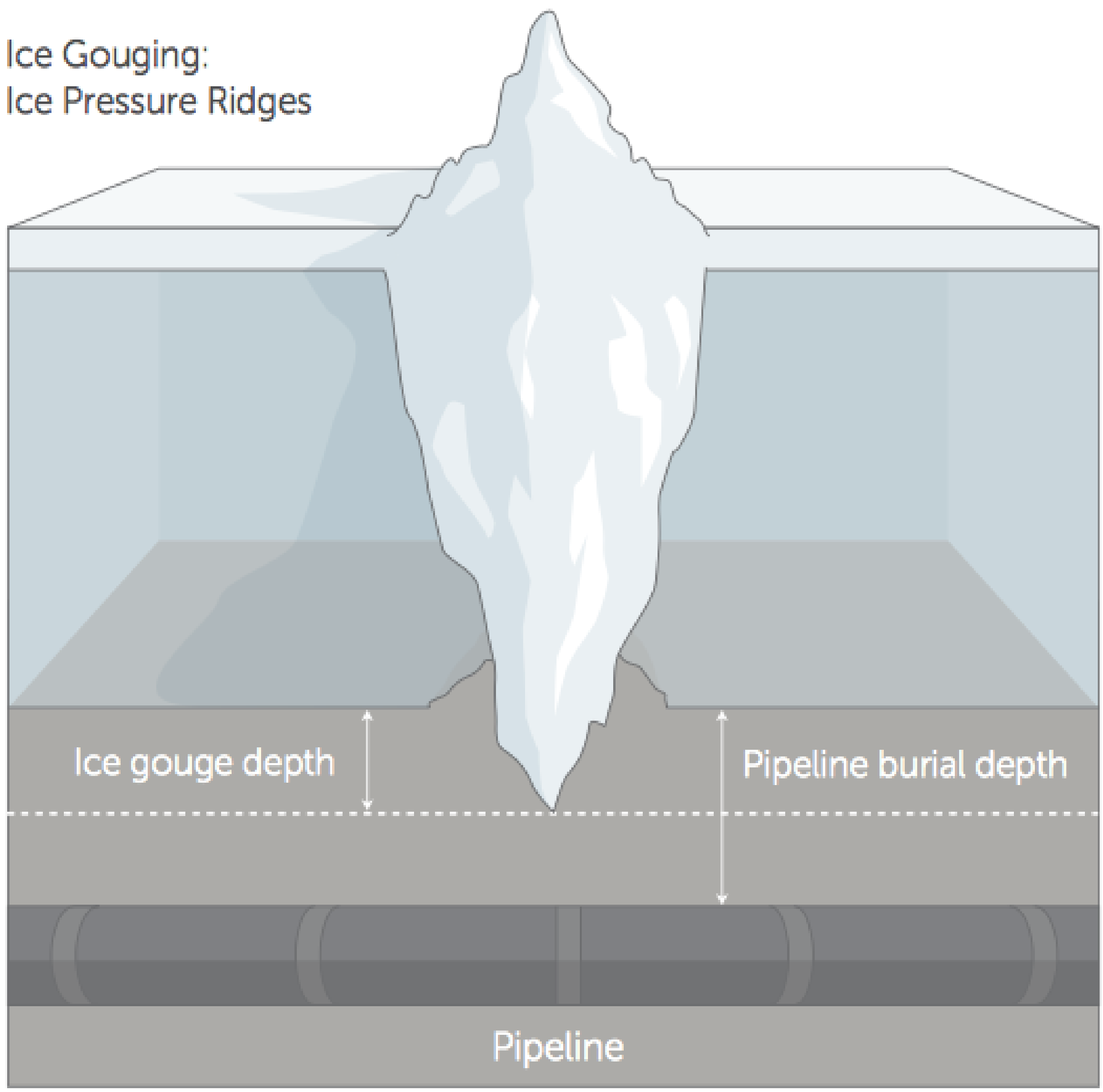


Fig. 3.5 Ice ridge or Stamukha scouring *(The PEW charitable trusts, 2013)*

The procedure for calculating the maximum burial depths along the route of a pipeline from the IRGBS “Prirazlomnaya” and subsea production system is presented in the Master thesis based on the Force model and Bow-Tie diagram for evaluation and prevention of the most likely risk that could happen — the pipeline damage in the stages of installation and operation.

Besides, the risk of substantial subgouge deformation have to be evaluated before trenching a pipeline because of in some cases extend the effect of ice ridge gouging more than twice of initial gouge depth, depending on the type and seabed upper sediments density.

In this Master thesis, the main attention is paid to the first—year (FY) ice ridge, not to the multi-year ice ridge, due to its relevancy in the Pechora Sea. FY ice ridges are sophisticated ice features with a wide variability of sizes and shapes. As a rule, a large amount of chaotic conglomeration of broken ice below the waterline—a keel, a sail, formed by smaller ice rubble accumulation above the sea level. Part of the ridge, close to waterline is consolidated and has a greater thickness than the ice level.ISO 19906 recommends a typical cross-section of FY ice ridge. See Figure 3.6.

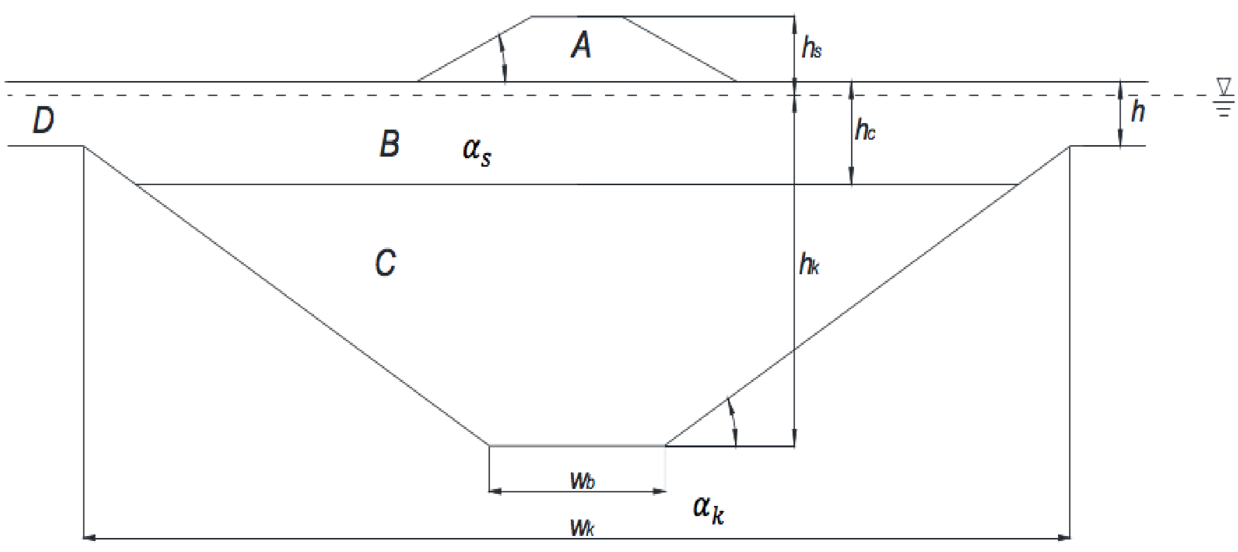


Fig. 3.6 Scheme of FY ice ridge ***(Vershinin et al., 2009)***

The following parameters have a large value for calculations:

— Keel depth;

— Keel angle;

— Width of a keel;

— Keel porosity.

Ratio of parameters for FY ice ridge and Stamukha in the Pechora Sea is presented in Table 3.3.

Table. 3.3 Ice ridge and Stamukha parameters in the Pechora Sea *(Vershinin et al, 2009)*

FY ice ridge model	Stamukha model
$h_K=4{,}5H_s$; $W_s=6H_s$ $W_k=17H_s$ $\alpha_s=18$ $\alpha_k=25$	$h_k=3{,}4H_S$ $W_s=11H_S$ $\alpha_s=27$ $\alpha_k=41$

Gudoshnikov et al. (1997) created probability model of the sail height distribution in the Pechora Sea by using Gamma-distribution:

$$f(x) = \frac{\lambda^{\alpha}}{\Gamma(\alpha)} x^{\alpha-1} e^{-\lambda x}, x > 0 \ (3.1)$$

$$f(x) = 0, x < 0$$

$$\mathrm{M}(\xi) = \frac{\alpha}{\lambda}; D(\xi) = \frac{\alpha}{\lambda^2}$$

Where α and λ represent distribution parameters; M(ξ) and D(ξ) represent the average and dispersion, respectively. For the maximum sail height estimation over the area A, km^2, the following relationship has been suggested $P_c(h) = 1/N_A A$, where $N_A=1{,}56*\mu^2$ — a number of ridge formations per the unit of area. Gudoshnikov et. al (1997) evaluates 1,56 coefficient for Prirazlomnoye field area in Pechora Sea. The probability of a number of ridges formation per unit of area is shown in Figure 3.7

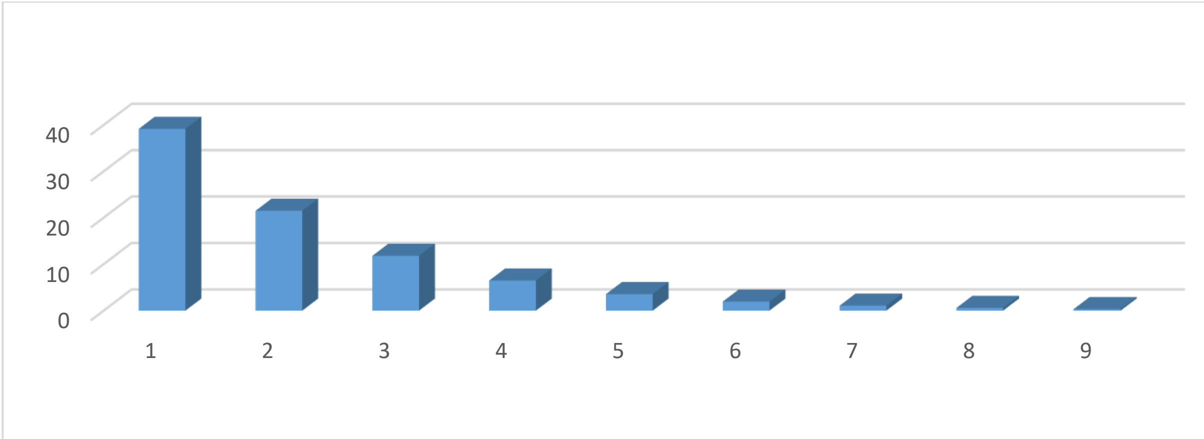


Fig. 3.7 Probability of some ridge formations per the unit of area. (Gudoshnikov, 1997)

Two suggestions that have been proposed imply that the maximum keel depths that may be expected in the Pechora Sea are about 20-22 m found at water depths of about 25 m and the ice scouring is more severe in the shallow water.

The data regarding the FY ice ridge on the Prirazlomnoye field based on information from the Prirazlomnaya-96 expedition *(Gudoshnikov et. al, 1997)* and characteristics of seabed upper sediments is presented *(Gazprom Neft, 2017)* in Table 3.4.

Table 3.4 Initial data

Factor	Symbol	Unit	Value
Seabed data			
Wall friction angle	φ_w	degrees	0,49
Internal friction angle	φ	degrees	0,59
Cohesion	c	kPa	5
Friction	μ_p	-	0,5
Friction coefficient	μ	-	0,5
Seabed upper sediments density	ρ_s	kg/m^3	1998
Elasticity modulus	E_s	MPa	8000

Poisson ratio	ϑ_s	-	0,34
Seabed slope	-	degree	1
Ice Data			
Maximum level ice thickness (100-year value)	h_i	m	1,4
Ice speed	v_i	m/s	0,34
Ridge sail height	h_s	m	3,6
Consolidated layer thickness	h	m	3,5
Keel angle	a_k	degrees	25
Sail angle	a_s	degrees	18
Single keel breadth	B	m	21,6
Ice density	p_i	kg/m^3	900
Ridge average block size	T_b	m	0,3
Sail porosity	η_s	-	0,07
Poisson ration	v_i	-	0,34
Ice ridge rubble internal friction angle	q_i	degrees	20
Keel rubble cohesion	C_i	kPa	15
Seawater data			
Minimum temperature	T_e	C	
Density	p_w	kg/m^3	1030
Drag coefficient	C_{dw}	-	0,9
Surface current speed	u_c	m/s	1.35

Burial depth evaluation

Vershinin et al. (2007) distinguish two general scenarios of ice ridge scouring: the separate ridge, which is represented by a single ice feature floating in the ice and large ice field that confines the ridge.

Vershinin et. al (2007) have established several design models, determining the behavior of ice ridges when contact with seabed upper sediments occurs.

The first design model when the ice ridge has a rigid constraint with the drifting ice fields, and only one degree of freedom is available. In this Master thesis, the first design model will be evaluated. The model corresponds to the maximum gouge depth assessment and is feasible for thick ice sheets and soft upper sediments that can be plowed deep without significant response.

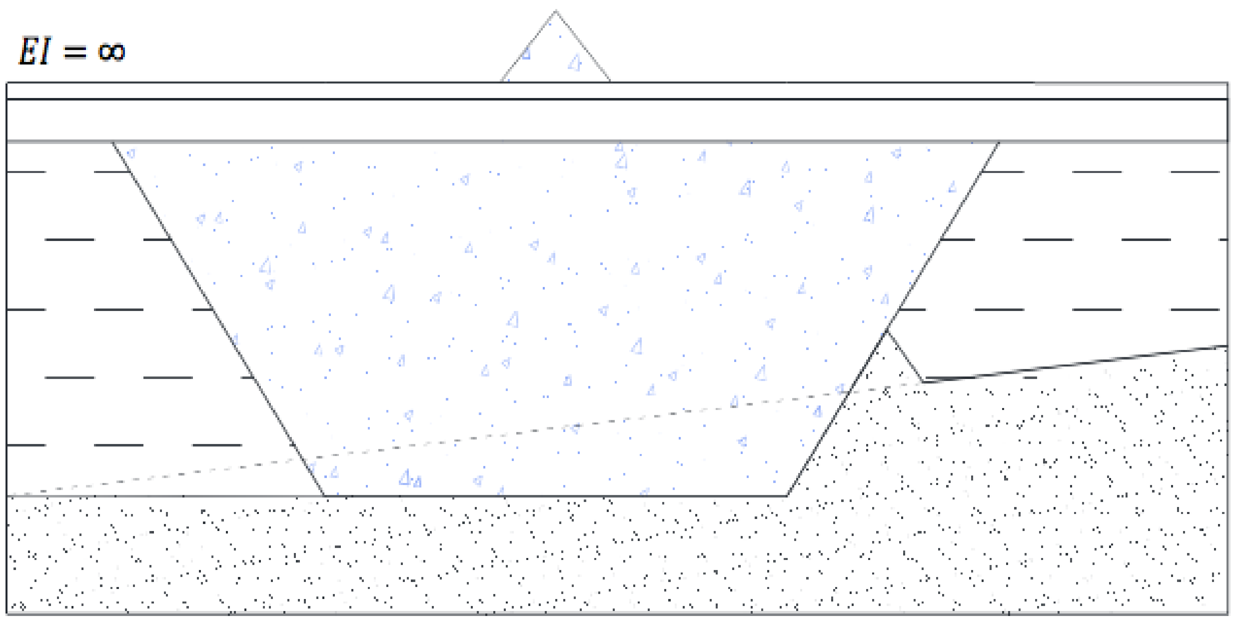


Fig. 3.8 Design scheme for the scouring process modeling *(Duplenskiy, 2012)*

With this assumption, the force model can be implemented to calculate the burial depth. The aim is to estimate the thickness of the seabed upper sediments that ice ridge may scour. There are some assumptions in the first design model:

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

— Ridge keel bottom has infinite strength; it is not destroying with contact with seabed;

— The substantial surface of the ice restricts the ridge's upward motion.

Seabed upper sediments behavior with ice ridge contact

Vershinin et al. (2007) have described several experiments at different scales regarding upper sediments behavior above the gouge bottom. The first stage is described by the compaction of the seabed upper sediments and its transition into the limit state. Once the maximum load is applied, the ridge starts to displace the upper sediments. The movement of two wedges, proceeding in a plastic flow mode, represents these deformations. It is limited by a constant height, dependent on the keel breadth and depth, which is accounted in models for scour depth determination. Dead wedges are moving in a united assembly with the keel (Figure 3.9), being considered motionless concerning it. The sliding of the upper sediments, therefore, occurs in the bound of a dead wedge and overriding prism.

With that, the seabed upper sediments type should be accounted as it plays an important role in both related processes: the scouring and the pipeline response. The Mohr-Coulomb theory governs the upper sediments shear failure envelope as the function of upper sediments cohesion, the angle of internal friction and normal stress applied, which provides an important outcome for stronger sand: its strength is substantially larger in the condition of the certain confinement. Thus, it is expected that sand resists against deep scouring are high. *(Vershinin et al., 2007).*

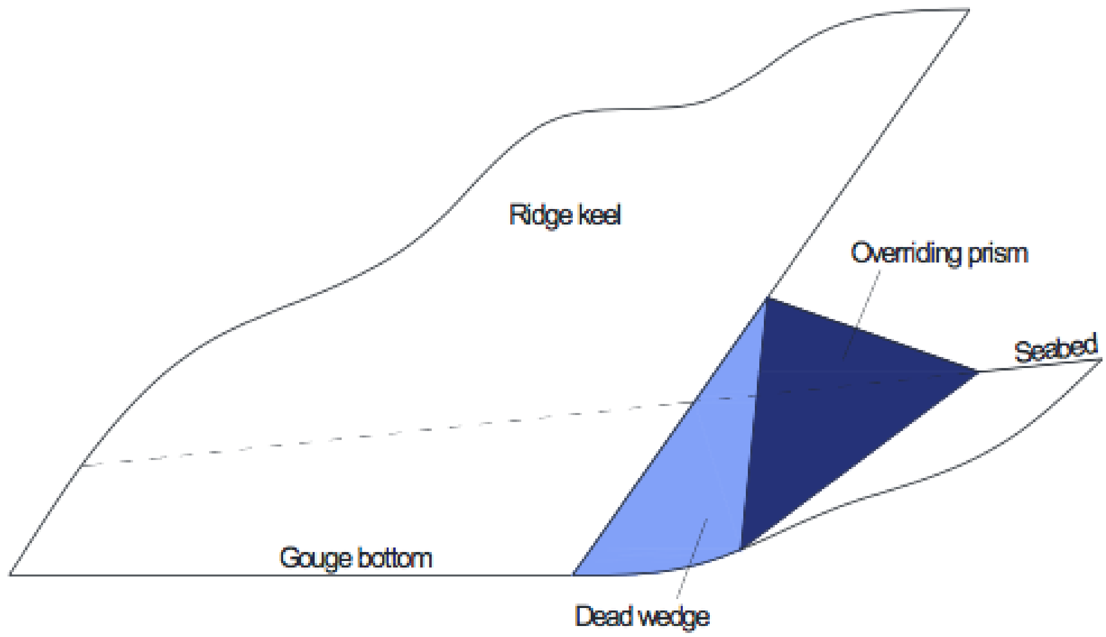


Fig 3.9 Behavior of upper sediments subjected to the scouring by the ridge keel *(Duplenskiy, 2012)*

Force scouring model

The first design model is based on the expectations that the friction forces are depended on the scour depth. The more the seabed upper sediments in the front face the greater is the friction. At the maximum scour depth, the resistant forces are in balance with drag force (Figure 3.10). In addition to that, the behavior of the ice ridge keel interacting with upper sediments is determined by the attack angle. If the vertical downforce is applied, the ridge elevation could be eliminated. *(Vershinin et al., 2007).*

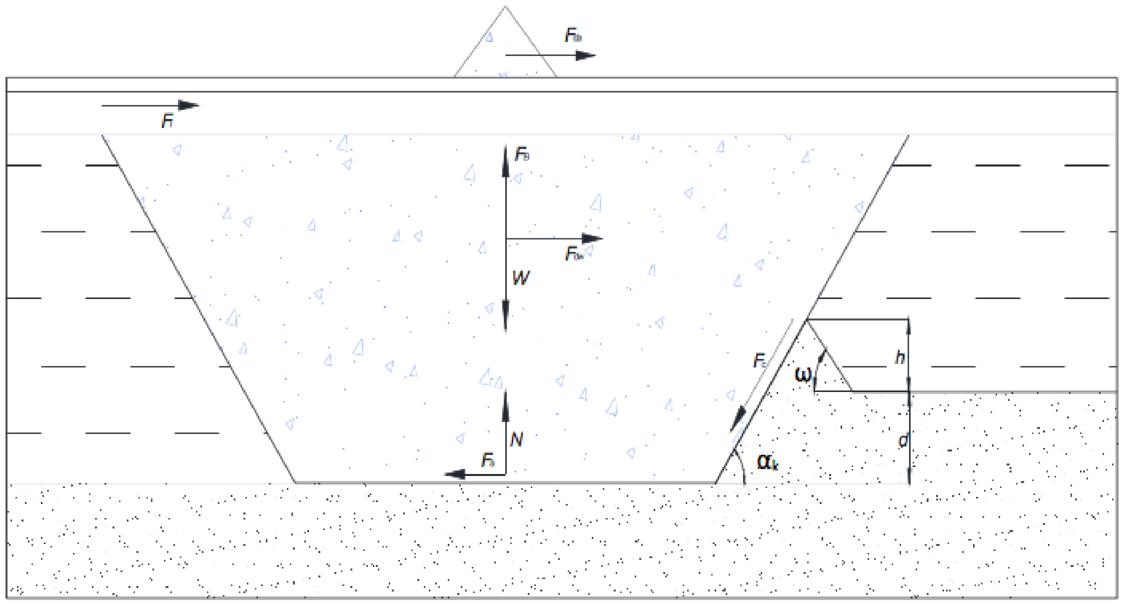


Fig 3.10 Force system on the ice ridge *(Duplenskiy, 2012)*

As it was mentioned the critical gouge depth is relevant when the following force system exists in equilibrium *(Choi and et. all, 2002):*

Horizontal direction:

$$F_{da} + F_{dw} + F_i - F_a - F_c \cos a_k = 0 \text{ (3.2)}$$

Vertical direction:

$$F_b - W - F_C \sin a_k + N = 0 \text{ (3.3)}$$

Drag force from the wind:

Generally, frontal and top wind force components push the ice. Regarding the ice ridge confined to the level, ice this component:

$$F_{da} = \frac{1}{2}\rho_a C_{da} A_{a1} u_a^2 + C_{sa}\rho_a A_{a2} u_a^2 \text{ (3.4)}$$

The projection areas are given by:

$$A_{a1} = \left(h_s - \frac{\rho_w - \rho_i}{\rho_w} h_i\right) \text{ (3.5)}$$

$$A_{a2} = w_k B \text{ (3.6)}$$

Drag force from the current:

As it acting only transversally, its value is determined by the single component:

$$F_{da} = \frac{1}{2}\rho_w C_w A_w u_c^2 \text{ (3.7)}$$

The effective area of current influence is:

$$A_w = \left(h_k - \frac{\rho_i}{\rho_w} h_i\right) B \text{ (3.8)}$$

Weight:

To estimate the weight of the ridge density, heterogeneity, and the shape particularities have to be taken into account.

$$W = \rho_{iw} B g \left[\frac{\rho_{ia}}{\rho_{iw}} (h_s - \frac{\rho_w - \rho_i}{\rho_w} h)^2 cota_s + \frac{\rho_i}{\rho_w} h w_k + \frac{1}{2} (w_k + w_b)(h_k - \frac{\rho_i}{\rho_w} h)\right] \text{ (3.9)}$$

This equation implies that the ridge weight dependency on minimum dimensional parameters such as the consolidated layer thickness and the sail height.

Buoyancy force:

On the analogy regarding the weight equation, buoyancy forces affect the ridge keel trapeze and the subsea consolidated layer part as follows:

$$F_b = \rho_w \nabla g = \rho_w g B \left[\frac{1}{2} (w_k + w_b) \left(h_k - \frac{\rho_i}{\rho_w} h\right) + \frac{\rho_i}{\rho_w} h w_k\right] \text{ (3.10)}$$

Ice force:

The ice limit state before ridging governs the maximum horizontal force in the condition of the limited ice strength (in MN):

$$F_i = 0{,}43 \cdot 4{,}059 \cdot B^{0{,}622} \cdot h_i^{0{,}628} \text{ (3.11)}$$

Passive friction force:

To calculate the upper sediments resistance force, the passive earth pressure theory is applied. The earth pressure normally acts to the slant surface of the ridge keel and causes additional friction, depending on the wall friction angle.

Front resistance:

$$F_c = \mu P cos(\varphi_w) \text{ (3.12)}$$

The upper sediments pressure force in front of the ridge:

$$P_f = \frac{1}{2} K_p \rho_s g (h' + d)^2 B + 2c\sqrt{K_p} \text{ (3.13)}$$

Where c is upper sediments cohesion and Kp is the passive earth pressure coefficient *(Vershinin, 2007):*

$$K_p = \frac{cos\varphi^2}{cos\varphi_w\left[1-\sqrt{\frac{\sin(\varphi+\varphi_W)\sin(\varphi+\beta)}{\cos(\varphi_W)\cos(\beta)}}^2\right]} \quad (3.14)$$

$$h' = \sqrt{\frac{d^2cot\varphi}{cot\varphi+\frac{d}{3B}cot\varphi cot\beta}} \quad (3.15)$$

$$P_s = \frac{1}{6}K_p\rho_s g d^2 w_b(w_b + d \cdot cot\alpha_k) \quad (3.16)$$

For horizontal one:

$$F_{cx} = F_c cosa_k = \mu \cdot P_f cos\varphi_w \cdot cos\alpha_k + \mu \cdot P_s \cdot cos\varphi_w \quad (3.17)$$

For vertical one:

$$F_{cy} = F_c sina_k = \mu P_f cos\varphi_w sin\alpha_k \quad (3.18)$$

Active friction force

This force is a function of upper sediments reaction:

$$F_a = \mu \cdot N \quad (3.19)$$

The reaction force from the equation:

$$N = W - F_b + F_{cy} = F_{cy} \quad (3.20)$$

Substituting into

$$F_{da} + F_{dw} + F_i - \mu F_{cy} - F_{cx} = 0 \quad (3.21)$$

Replacing all forces with outlined formulas, the quadric equation with respect to the gouge depth d is derived and solved in Maple. The results are given below in Table 3.5 and the procedure of calculations in Matlab is given in Appendix 1.

Table 3.5 Results based on Force model

Force Component	Unit	Value (Sand)
Ridge keel macro porosity, μ	-	0,27
Average keel density, ρ_{iw}	kg/m³	933,65
Average sail density, ρ_{ia}	kg/m³	837,09
Wind projection area, A_{a1}	m²	74,60
Wind projection area, A_{a2}	m²	1900,26
Current protection area, A_w	m²	463,24
Keel draught, h_k	m	22,5
Keel width at the sea level, w_k	m	87,98
Keel width at the bottom, w_b	m	9,98
Drag force due to the wind, F_{dw}	MN	0,06
Drag force to due current, F_{dc}	MN	0,39
Ridge weight, W	MN	252,6
Buoyancy, F_b	MN	262,8
Force due to drifting ice, F_i	MN	13,32
Passive earth pressure coefficient, K_P	-	12,28
Scour width, B	m	21,6
Scour depth, d	m	1,62

3.3 Pipelines with the fluid from HP/HT wells and Subgouging

HP/HT fields in the world

Many companies in the world face with challenges of developing high— pressure, high— temperature reserves (HP/HT). See Figure 3.11.

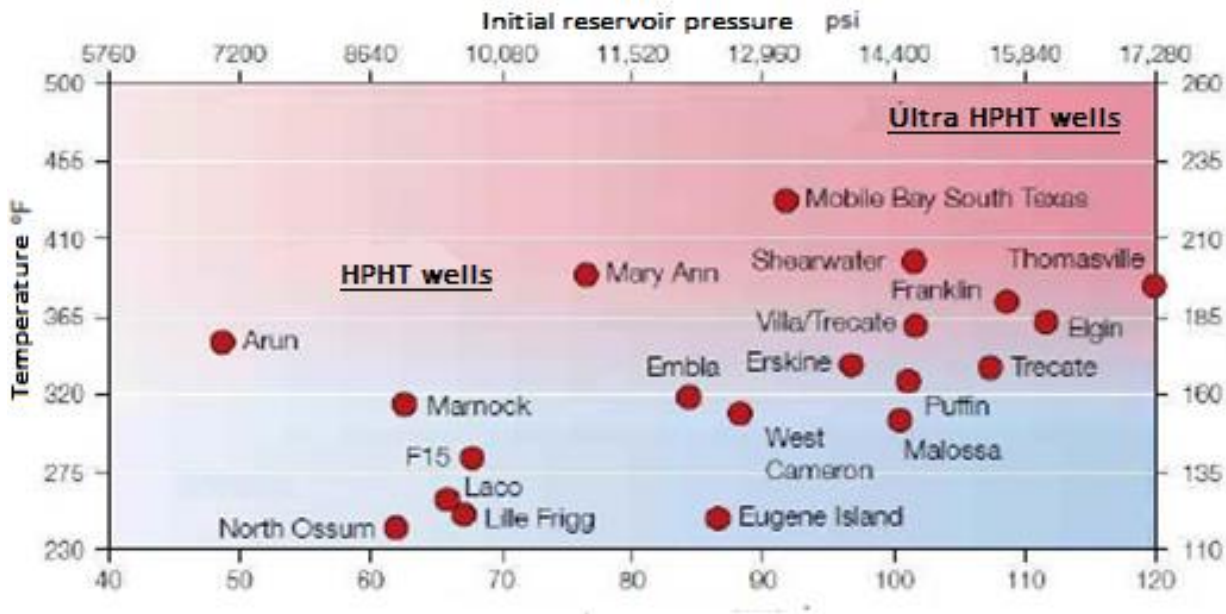


Fig. 3.11 The HP/HT fields in the world

HP/HT reservoirs are at the frontier of development. They pose technical, safety, and environmental challenges, for which a considerable effort in technology development has been mobilized. The classification of the HP/HT fields varies from country to country and often different parameters are taken as a definition. See Figure 3.12.

	Temperature °C (°F)	Pressure MPa (psi)	Notes
United Kingdom	150 (300)	69 (10000)	1
Norwegian Petroleum Directorate (NPD)	150	69	2
Society of Petroleum Engineers (SPE)	>150	(>10000)	3

Notes
1 The UK defines temperature and pressure based on reservoir conditions.
2 The NPD define the pressure as the wellhead shut in pressure.
3 The SPE defines HP as a well requiring pressure control equipment with a rated working pressure in excess of 10,000 psi or where the maximum anticipated pore pressure of any porous formation to be drilled through exceeds a hydrostatic gradient of 0.8 psi/ft.

Fig. 3.12 Classification of an HP/HT development *(Marsh and et. al, 2010)*

Information about the properties of the Silurian and Lower Devonian deposits is limited to PH-5 exploratory well. The drilling of the well was stopped on the 4463 meters due to the ice conditions and showed abnormally high values of the pressure

(73,1 MPa). Thus, inflow of light oil from Silurian and Lower Devonian deposits was obtained. Consequently, the deposits can be classified as HP/HT. The pressure distribution in the Permian deposits and the possible distribution in the Silurian and Devonian deposits is shown on Figure 3.13.

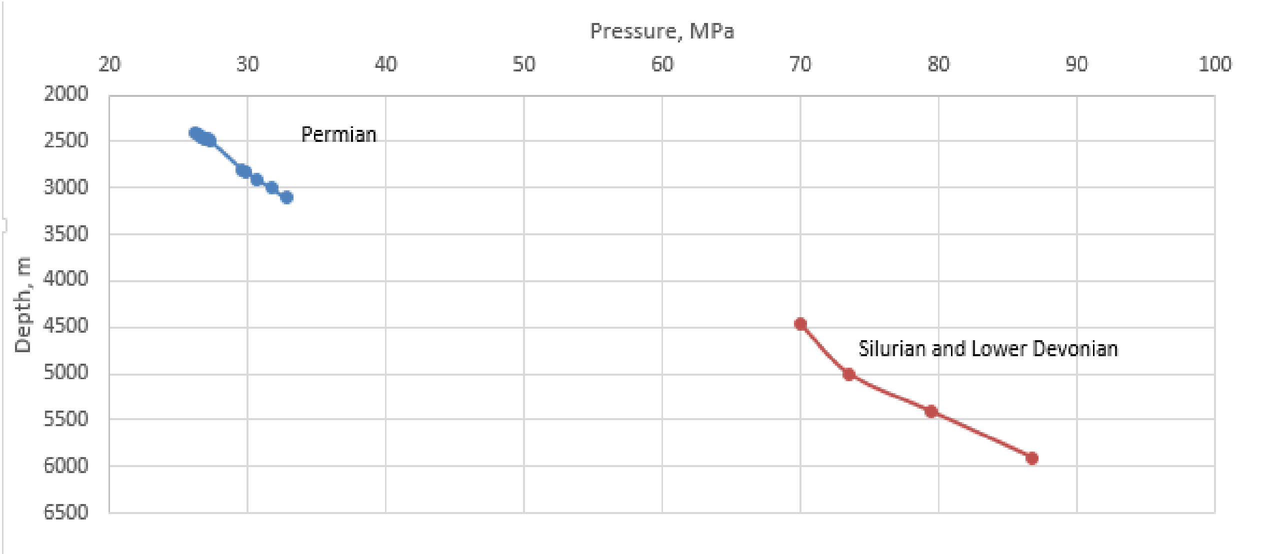


Fig. 3.13 The pressure distribution on the Prirazlomnoye field based on data from exploratory well PH5+possible distribution in S1,S2

The materials requirements for dealing with subsea HP/HT developments require special consideration. Issues include Corrosion; Cracking; Mechanical properties of the material; De-rating of SMYS at elevated temperatures; Pressure management; Temperature management; Equipment qualification; Cost materials; Cooling spools; Materials for more extreme future development. *(Marsh and et. al, 2010)*

The important recommendation for developing Silurian and Lower Devonian deposits are following:

- Like an operator of HP/HT field, Gazprom has different philosophies towards materials for HP/HT developments, and the chosen materials range from carbon steel to super duplex stainless steel and nickel alloys.
- The duplex type stainless steels can offer excellent corrosion resistance and mechanical strength, especially 25% Cr super duplex.

- Carbon steel suffers regarding corrosion resistance, even with corrosion inhibition, as inhibition becomes problematic at elevated temperatures.

Seabed upper sediments—pipeline interaction model

Substantial subgouge deformation in some cases extends the effect more than twice of initial gouge depth, depending on the type and upper sediments density.

Due to lack of information about Silurian and Lower Devonian deposits, there are several assumptions about the size, pipeline pressure and temperature:

— The diameter of the pipe is 406 mm, and the wall thickness is 18, 2 mm (typical case).

— The internal pressure in the pipeline is 32 MPa and equal to the pressure at the wellhead based on information from exploratory drilling. Friction losses in the well are neglected. Thus, the pressure at the wellhead is equal to the difference in reservoir pressure and hydrostatic pressure.

— It considers the behavior of pipeline characteristics at different temperatures. (60 C, 90 C, 120 C).

In this particular ice- seabed upper sediments interaction(Fig. 3.14), the zone two is in the critical state, where the upper sediments is deformed plastically. Subgouge upper sediments deformation transmits substantial loading to the buried pipeline, able to stress it beyond the allowable strength *(Palmer, 1996).*

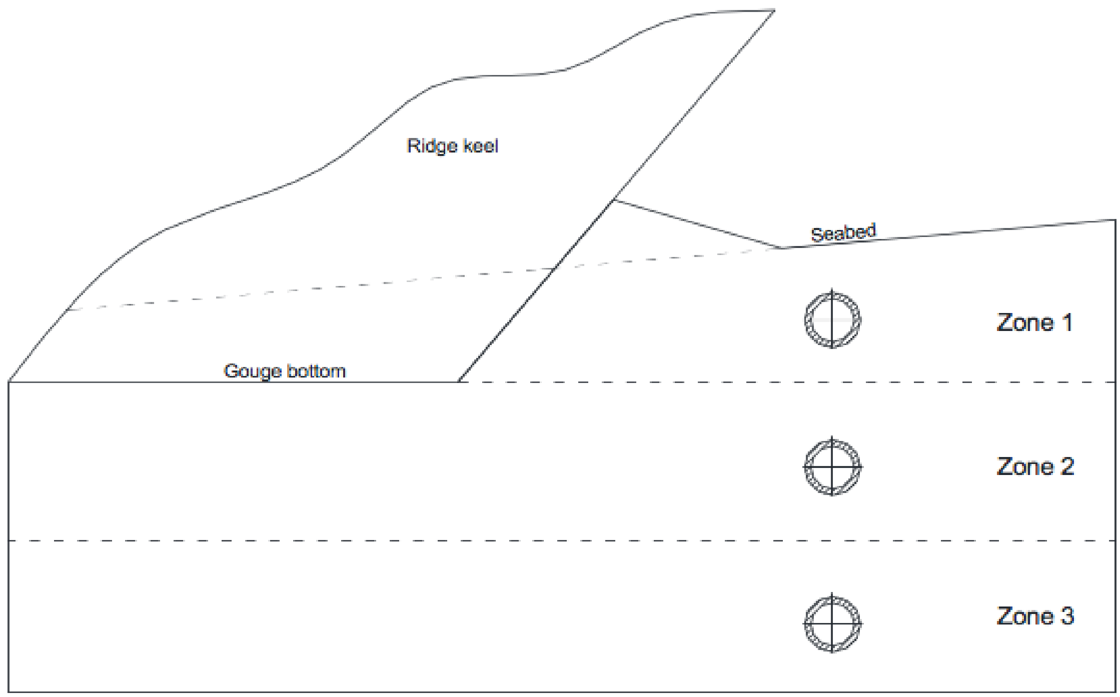


Fig. 3.14 Ice- upper sediments interaction scenario *(Duplenskiy, 2012)*

Initial data for HP/HT pipeline taking into account the recommendations for different fluid temperature in the pipeline is presented in Table 3.6.

Table 3.6 Initial data for Subgouging calculations X65

Parameter	Unit	Value		
Pipeline Internal pressure, P_i	MPa	32		
Pipeline Temperature, T_i	C	60	90	120
Pipeline diameter, D	m	0,406		
Pipeline wall thickness, t	m	0,0182		
Poisson ratio for steel, v		0,3		
Elasticity modulus for steel, E	MPa	207000		
Temperature expansion coefficient, a		$1{,}15\ 10^{-7}$		
External Temperature, T_e	C	1		
SMYS	MPa	Depends on temperature		
SMTS	MPa	Depends on temperature		

Resistance strain factor, ye		3,3
Environmental load factor, yf		1,3
Material strength factor, au		0,96
Safety class resistance factor, ysc		1,308
Material resistance factor, ym		1,15
Fabrication factor, afab		0,85

In the calculation, the maximum scour depth is 1,62 m. However, in the prediction of Vershinin et all. (2007) the gouge depth is estimated from 0 to 1,3 m. in the most severe case. Thus, the maximum scour depth can be reduced to an acceptable level.

The force of pipeline segments is calculated from the following equation.

$$F_i + F_{dw} + F_{da} - F_c cos\alpha - F_{pipe} cos\alpha_k = 0 \text{ (3.23)}$$

$$F_{pipe} = \frac{F_i + F_{dw} + F_{da} - F_c cos\alpha - \mu(F_c sin\alpha_k + F_u + \Delta W)}{cos\alpha_k - \mu sin\alpha_k}$$

The forces influencing the pipeline from ice ridge for different scour depth are presented in Table 3.7.

Table 3.7 Forces on the pipeline from the ice ridge for different scour depth

Parameter	Unit	Value		
Scour depth,d	m	0	1	1,3
Ice force, F_i	MN	13,23		
Wind drag, F_{da}		0,06		
Current drag, F_{dw}		0,4		
Horizontal passive friction, $F_c cos\alpha_k$		0	2,3	5,68
Vertical passive friction, $F_c sin\alpha_k$		0	0,8	1,94
Level ice reaction, F_{li}		0	1	2,4
Weight due to elevation, ΔW		0	0,66	1,61
Force on the pipe, F_{pipe}		22,23	16,48	8,2

To protect the pipeline from additional load, it must be in zone 2. Thus, a burial level should ensure that the pipeline will be protected from unfavorable stresses *(Vitali et al., 2004).* The model involves an idealization of the subgouge deformation: the seabed upper sediments moves within the gouge breadth B, applying the lateral load f on the pipe, and remains stationary outside it, resisting the pipeline transverse motion.

The deeper the pipeline is trenched, the less is the relative displacement. If large relative displacement occurs, the seabed upper sediments loads reach steady ultimate values p_u, q_u and t_u. *(Vitali et al.,2004).*

The general ultimate axial upper sediments resistance is

$$\tau_u = \frac{\pi D}{2}(\rho_S Hg + \frac{N}{Bw_b}(1+K_0)tan\varphi + \pi D\alpha c \quad (3.24)$$

Where a — is the adhesion factor, depending on the undrained shear strength. See Figure 3.15

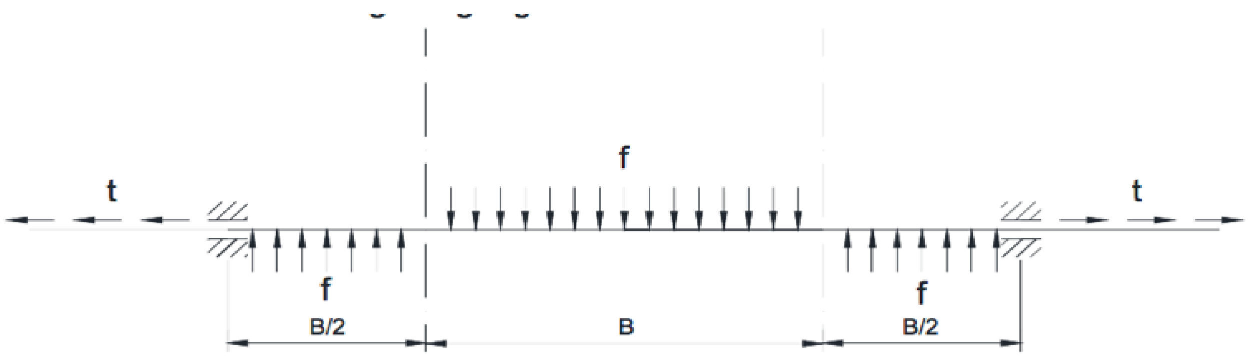


Fig 3.15 Proposed beam model *(Duplenskiy S., 2012)*

$$pu = s_u * N * D = \left(\rho_S Hg + \frac{N}{Bw_b}\right) N_{qh}D + cN_{ch}D (3.25)$$

The condition of critical relative deformation should be satisfied by the following equation: $y_u = 0{,}03H$. (Figure 3.16).

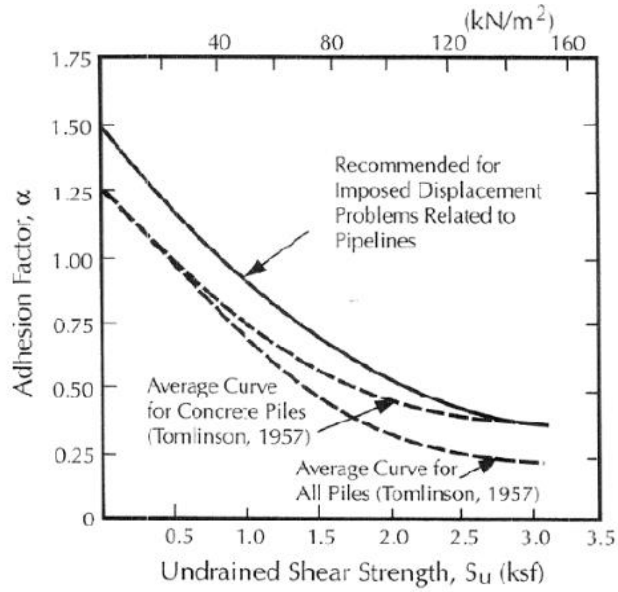


Fig. 3.16 Adhesion factors plotted as a function of the undrained shear strength *(Vitali et al, 2004)*

The horizontal bearing capacity factors N_{qh} are represented as a function of H/D, based on the model of Hansen. Since the angle of internal friction is relevant for original sand. (Figure 3.17).

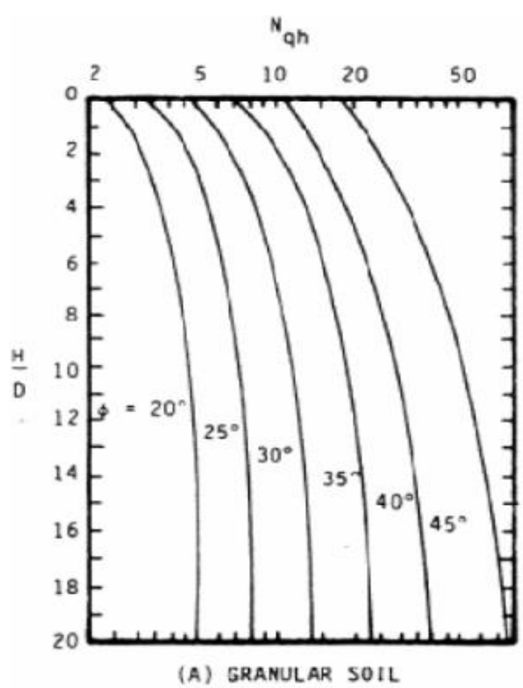


Fig. 3.17 Horizontal bearing capacity factors for granular upper sediments *(Hansen, 1961)*

The vertical transverse ultimate force has an unsymmetrical response to the direction of the upper sediments motion: defining deferent relations for upward and downward resistance.

Evident that the downward upper sediments drag is much greater than upward. Nearly the same relations are used to estimate the ultimate vertical upper sediments forces for sand. (Figure 3.18). The vertical uplift factors $N_{qv} and\ N_{cv}$ are shown below *(Vitali et al., 2004):*

$$q_u = s_u ND = \left(\rho_S Hg + \frac{N}{Bw_b}\right) N_{qv} D + cN_{qv} D \text{ such as } \varphi = 36 \quad (3.26)$$

The ultimate forces (both axial and transverse) are greater for the deeper trenched pipeline. The deeper the pipeline is trenched, the greater relative upper sediments-pipeline displacements should take place for the ultimate drag equations applicability. The closer to the seabed, the more significant the vertical movements are. Simultaneously, making a comparison of bearing capacity and uplift factors, the values of vertical forces themselves are one order less than horizontal ones (Vitali et al.,2004).

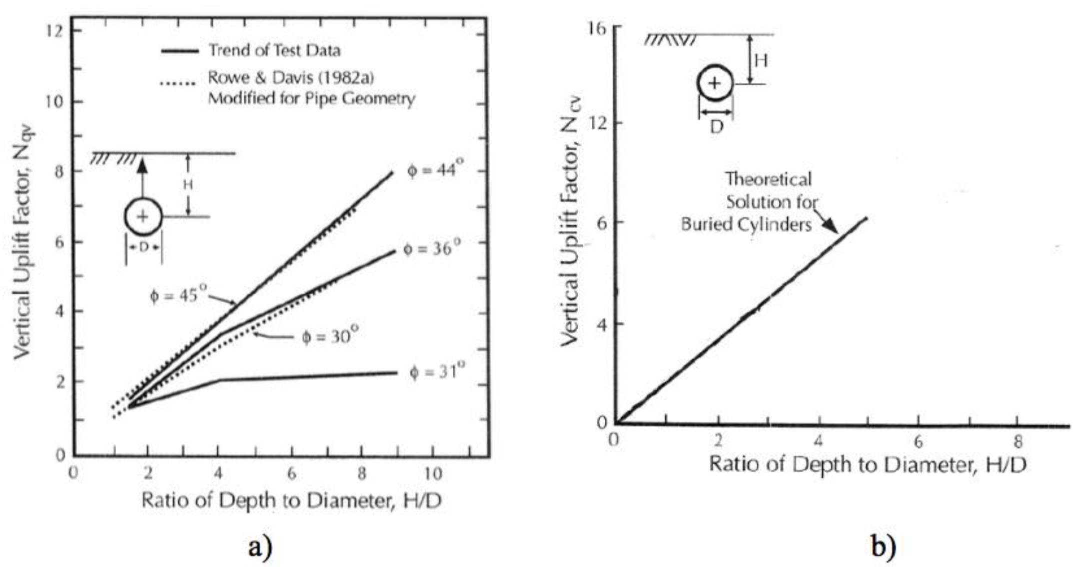


Fig. 3.18 Vertical uplift factors for sand strength *(Vitali et al, 2004)*

Both vertical and horizontal transverse force's components might be united into a single lateral force per unit length f.

$$f = \sqrt{p^2 + q^2} \quad (3.27)$$

The angle to the horizontal, determining the direction of the pipeline movement is also the desired value and could obtain from (Vitali et al.,2004):

$$tan\alpha_p = \frac{q_u}{p_u} \quad (3.28)$$

The values of parameters required for subsequent analysis are shown in Table 3.8.

Table 3.8 Parameters of upper sediments impact on the pipeline at the gouge base

Parameter	Unit	Value
		Sand
Axial ultimate resistance, t_u	KN/m	18,3
Horizontal ultimate drag, p_u		68,3
Vertical ultimate drag, q_u		6,21
Total lateral force, f		68,6
The angle of pipeline motion, a_p	degrees	9

The pipeline is designed for 30 years, and following the practice of limit state design the reliability criterions established below should meet:

- LRFD SLS: The annual probability of Von Misses stresses occurrence exceeding 90% of yield strength should be equal or less than 10^{-1}
- LRFD ULS: The annual probability of excessive compressive/tensile strains should not exceed 10^{-2}
- LRFD ULS: Plastic collapse annual probability for direct ridge keel accidental contact with the pipe should not exceed 10^{-4}.

SLS Stress

The DNV governs the following expression for the equivalent stress calculations (DNV, 2007):

$$\sigma_{eq} = \sqrt{\sigma_h^2 + \sigma_l^2 - \sigma_h \sigma_l} \quad (3.29)$$

Where the hoop stress is given as a function of internal operating pressure p_i, obtained

$$\sigma_h = \frac{p_i(D-t)}{2t} \quad (3.30)$$

The axial force and the moment due to the pipeline bending influence the longitudinal stress:

$$\sigma_l = \frac{T'}{A} \pm \frac{M}{W_S} \quad (3.31)$$

Here T' is an axial force, A – a cross-sectional area of the pipe; M – bending moment, W_s – sectional modulus. The sign $\pm$ is explained by the compression and tension in upper and lower sections of the pipe.

For a pipeline with thin wall:

$$A = \pi dt \ and \ W_s = \frac{I}{y} = \frac{\pi(D^4-d^4)2}{64D} = \frac{\pi(D^4-d^4)}{32D} \quad (3.32)$$

Bending moment:

Longitudinal stress proportionally depends on the bending moment, which appears to be varied along the considered section of the pipe.

In the critical case when the tension is maximum, the moment is $M = \frac{fL^2}{32}$ (Figure 3.19).

The axial force, acting on the pipeline is proposed to be represented by the function of several components. The pipeline is put into operation and goes to the stressed state due to increased temperature and pressure:

$$T = -\frac{\pi d^2}{4} p_i(1-2\vartheta) - \pi dtE\alpha(T_i - T_e) \quad (3.33)$$

The first term is pipeline expansion due to pressure increase, which is explained by the end cap and Poisson's effects. Here ϑ- Poisson's ratio. The second term is an expansion due to the temperature. Here t – characteristic wall thickness of the pipe, E – the elasticity modulus; - thermal expansion coefficient and $(T_i - T_e)$- temperature difference between the surrounding water and the pipeline. In steel pipelines the temperature term dominates, therefore the force is always compressive and negative (Palmer, 1996).

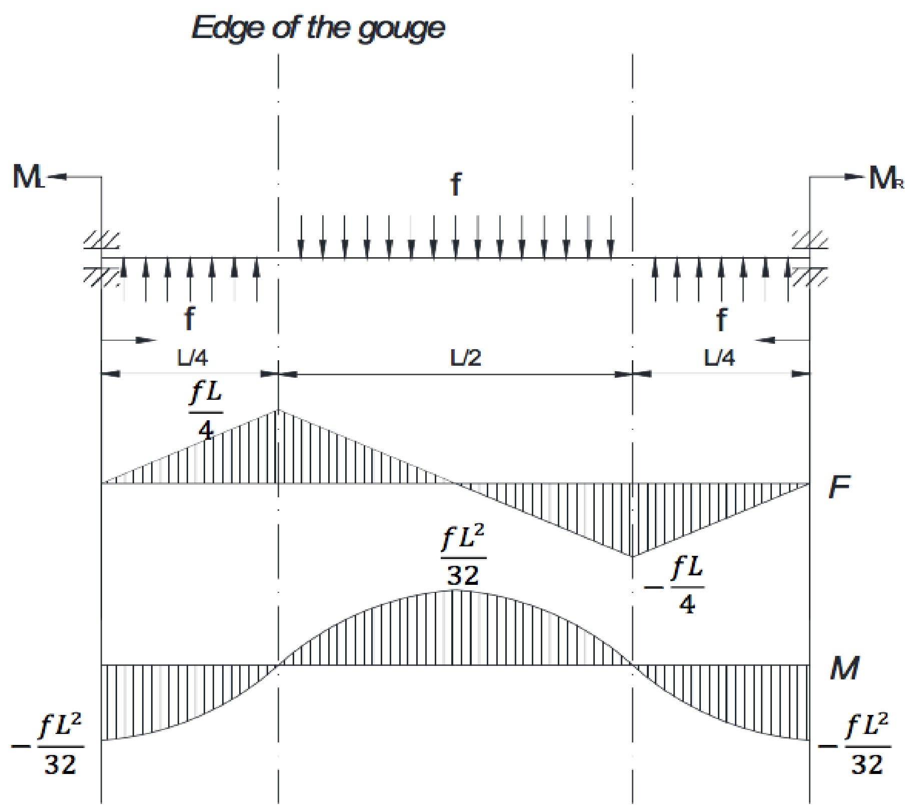


Fig. 3.19 Pipeline bending force and moment areas *(Duplenskiy, 2012)*

However, after gouging, the pipeline is dragged, and the axial force becomes tensile. The change in tension induces the additional axial strain. Under the assumption that the pipeline displacements are small compared to scour width B, and the behavior of the pipeline is dominated by the interaction between the effective axial force and the lateral force, Palmer proposed the following equation *(Palmer, 2000)*, which easily could be solved for T':

$$\frac{f^2B^2}{24(T')^2} = \frac{(T'-T)B}{S} + \frac{(T'-T)^2}{2T_uS} \quad (3.34)$$

Where S is the elastic rigidity: $S = \pi dtE$

Although the pipeline embedment below the maximum scour depth reduces the ridge actions, stronger upper sediments apply the forces able to cause stresses far beyond the steel yield strength, unless the upper sediments are very week indeed. Granular upper sediments independently on their cohesion values transmit huge loading, since their shear strength could be huge regarding normal stress from the ridge.

Relation, accounting yielding at the certain point:

$$\varepsilon_p = \frac{\sigma_l}{E}\left[1 + A\left(\frac{\sigma_l}{\sigma_Y}\right)^{n-1}\right] \quad (3.35)$$

Where $A = 0{,}005\left(\frac{E}{\sigma_Y}\right) - 1$

$$n = \frac{log\left[\frac{(\varepsilon_t - \frac{\sigma_t}{E})}{0{,}005 - \frac{\sigma_y}{E}}\right]}{\log\left(\frac{\sigma_t}{\sigma_y}\right)} \quad (3.36)$$

Here σ_y - SMYS; σ_t - SMTS; ε_t - ultimate tensile strain, corresponding to SMTS. The best practice shows the good performance of the 13% Cr in the case of HP/HT. The obtained maximum stresses for sandy sea bottom, and the dependence of SMYS and SMTS from Temperature for Corrosive resistant alloy (CRA), 13% Cr are shown in Table 3.9.

Table 3.9 Stresses in the pipeline regarding scouring and temperature dependence of limits states for CRA, 13% Cr

Parameters		Unit	Value		
Temperature		C	60	90	120
Pipeline SMYS		MPa	435	410	440
Pipeline STMS			522	507	490
Hoop stress			340,92		
Longitudinal stress	Tensile		5020	5000	4980
	Compressive		-4570	-4590	-4610
Maximum Von Misses equivalent stresses			4860	4840	4820
Limiting compressive strain			0,030	0,030	0,030
Square A			0,88	0,92	0,95
Actual strain in pipelines			$5,25*10^{21}$	$2,32*10^{21}$	$1,05*10^{21}$

Although the pipeline embedment below the maximum scour depth reduces the ridge action, stronger upper sediments apply the forces able to cause stresses far beyond the yield strength. From the top of the seabed level – the original sand should be used to minimize the penetration into the upper sediments. Also, the wall thickness should be increased to withstand stresses from ice gouging.

ULS collapse

Once the pipeline is embedded into the upper sediments, the collapse criterion might be checked for the external overpressure, caused by vertical and horizontal upper sediments action. It is proposed to refer to DNV code to check whether the upper sediments pressure is small enough for the pipeline to withstand the buckling. The stability against collapse is met if the following condition is satisfied *(DNV, 2007):*

$$p_s - p_i \leq \frac{p_c}{\gamma_m \gamma_{sc}} \quad (3.37)$$

Where the safety class factor γ_{sc} is 1,308. The collapse pressure p_c could be outlined as a root of the following equation:

$$(p_s - p_i)\left(p_c^2 - p_p^2\right) = p_c \cdot p_{ei} \cdot p_p \cdot f_0 \frac{D}{t} \quad (3.38)$$

Where $p_{el}\, and\, p_p$ are elastic and plastic collapse pressures respectively, f_0 - constructional ovalisation

$$p_{el} = \frac{2E\left(\frac{t}{D}\right)^3}{1-\vartheta^2} \quad (3.39)$$

$$p_p = f_y \alpha_{fab} \frac{2t}{D} \quad (3.40)$$

The calculations shown in the project provide the extreme value of seabed upper sediments pressure: $p_s = 63{,}69\ MPa$, which is possibile to occur only in the case of direct contact with the ice ridge. The collapse, therefore, is unlikely to occur if the pipeline somewhat buried into the upper sediments.

3.4. Subsea Production Systems protection in the Arctic

The developing concept for the Silurian and Lower Devonian age deposits with using subsea production systems is the main purpose of this Master thesis. The SPS may be an attractive supplement to the development on IRGBS “Prirazlomnoye” as it largely reduces uncertainties associated with ice loads etc. It is necessary to install two 5 — slots templates for SPS to effectively development of Silurian and Lower Devonian deposits. Optimal sites for the installation of SPS are located directly at a distance of 2550 and 3550 meters. See the Figure 3.20.

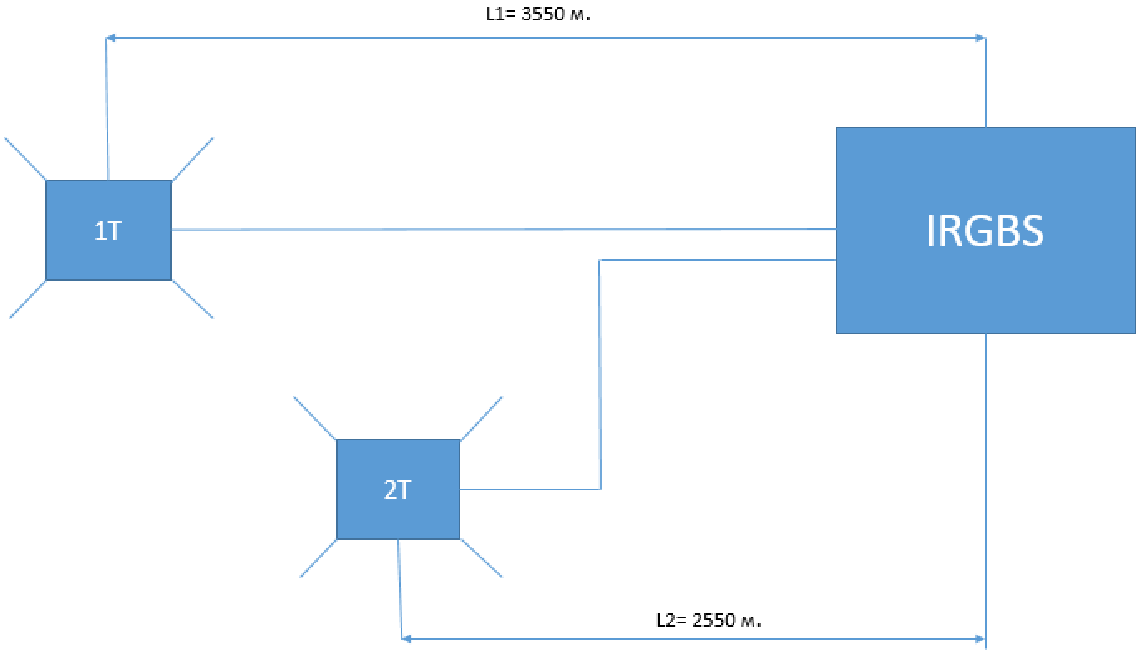


Figure 3.20 The possible scheme with 5-slots templates for development Silurian and Lower Devonian deposits

Gudmestad (2005) mentioned that subsea development concepts for shallow Arctic waters might include fixed production units with possible tie back of subsea wells and reviewed subsea development versus surface development for different Arctic conditions; the potential areas of this application are the North Eastern Barents Sea (including the Pechora Sea) and the Kara Sea.

Previously, applying the scouring dynamics, upper sediments and environmental conditions-, the maximum gouge depth was estimated to be 1,62 m. To protect subsea modules, both passive and active protective solutions are used. Passive protection implies that the interaction between the ice and the elements of the subsea system is avoided. In the same time, active protection implies that the subsea system may experience the direct or indirect action from the ice. Thus, the system must be designed in such a way as to withstand the load.

Experience

There exists limited experience with the use of subsea technology in ice-covered waters. The caisson-protected subsea templates have been used in Alaska

(Fig. 3.21). In the areas where ice gouging is evident, the wellhead and the Xmas tree was required to be placed in a glory hole such that the top of the Xmas tree was below the deepest gouge in the area. Typical glory hole dimensions were 6 m in diameter and up to 12 m deep.

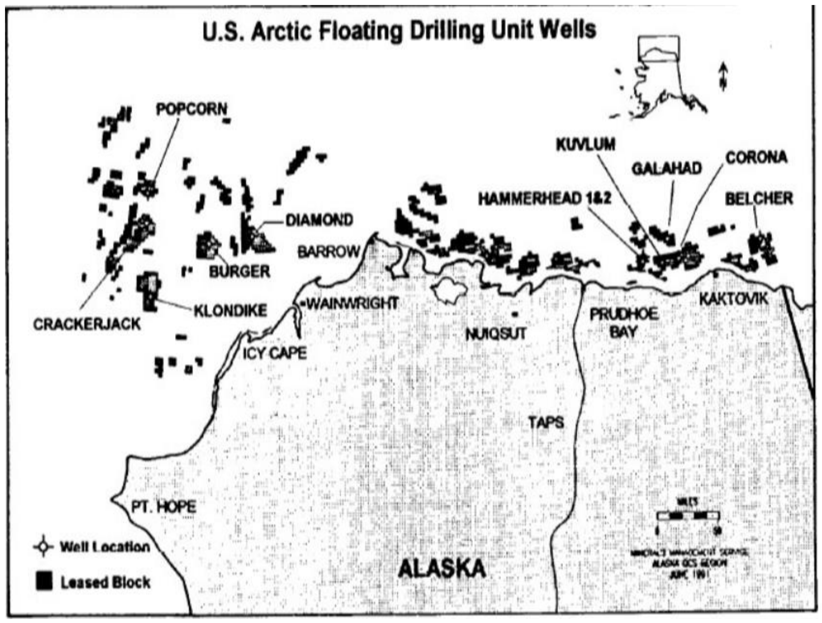


Fig. 3.21 U.S. Arctic Drilling Unit Wells *(Regg, 1993)*

Another subsea wellhead (wet) with some pipeline connectors was used at Drake point in Canadian High Arctic at about 80 m water depth, off the Melville Island. However, this field only operated four days for testing. The wellhead was abandoned in 1996.

Under sub-Arctic conditions, the subsea technology is presently used on the Grand Banks in the central part of the Jeanne d'Arc basin, approximately 350 km east south-east St. John's, Newfoundland (Figure 3.22). Two fields are being developed there with the use of subsea technology: The Terra Nova in 90 - 100 m water depth and the White Rose in 120 m water depth. Drifting icebergs characterize the ice conditions at the Grand Banks while incursion of sea ice is a seasonal event, averaging approximately 40 days every three years. The Terra Nova Project Development comprises four drill centers, and several wells are clustered in each drill center.

Fig. 3.22 Subsea field developments on Grand Banks

(http://www.suncor.com/about-us/exploration-and-production/east-coast-canada/terra-nova)

Active protective solutions

External Barriers: Rock berms or structures are placed around the wellhead and Xmas tree to protect by either blocking or grounding the icebergs. Whereas External Barriers are considered to be technically viable, the associated costs were considered prohibitive. *(Gudmestad, 2005).*

Open Glory Hole: The Open Glory Hole protection method is compatible with the system, which involves clustering of several wellheads in one location. To ensure a safe elevation for the top of the structure, one needs to assess the behavior of the scouring ice keel as it approaches the "open hole." However, the keel may pitch and dive into the open hole as illustrated in Figure 3.23.

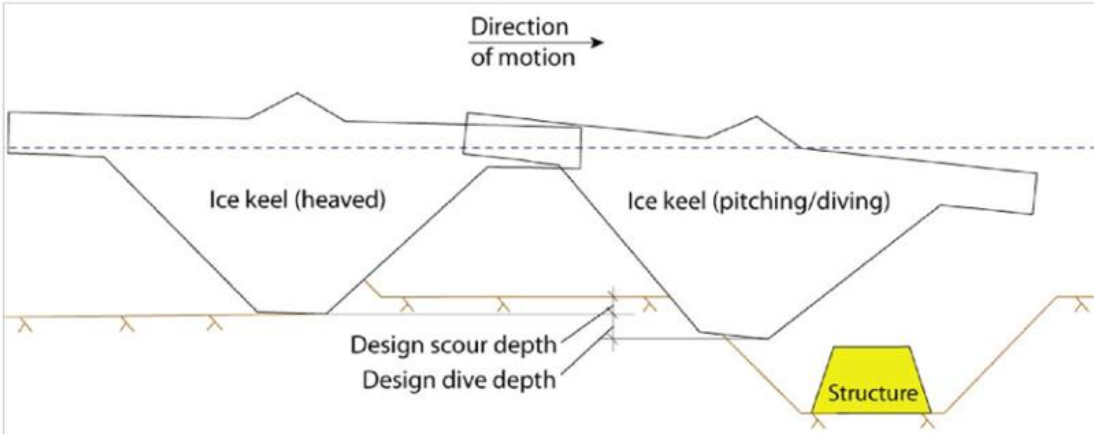


Fig. 3.23 Keel is diving in the open hole scenario *(Gudmestad, 2005)*

Cased Glory Hole (silo): This method involves placing the wellhead and Xmas tree steel or concrete silo typically 8 m in diameter. Installation would normally be carried out from a drilling rig (Figure 3.24). The silo is installed before the commencement of drilling operations. The silo has a weak point at the predetermined elevation below sea level. In the case of ice ridge impact, the silo is sheared at the weak point, and the upper part of the silo is sacrificed, leaving the lower part of the silo, the wellhead and the Xmas tree intact. The Cased Glory Hole is particularly suited to single wellheads. The Silo Cased Glory Hole is particularly suited to single wellheads. *(Gudmestad, 2005).*

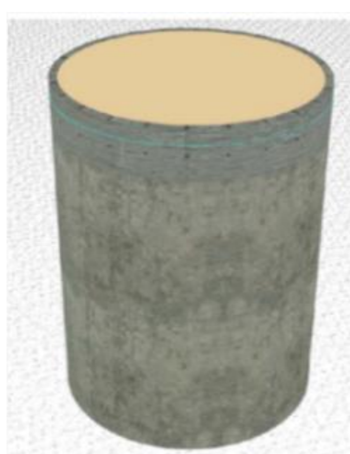


Figure 3.24 Cased Glory Hole (Silo with sacrificial upper part) *(Gudmestad, 2005)*

Cased Glory Hole (caisson): This method involves a seabed level Xmas tree with the wellhead situated below the ice ridge scour line (Figure 3.28). Installation is carried out from the drilling rig. There is a weak point in the wellbore casing above the wellhead. In the case of iceberg impact, the upper wellbore casing and the Xmas tree are sacrificed. The Caisson Cased Glory Hole may also be used to multi-well centers. *(Gudmestad, 2005).*

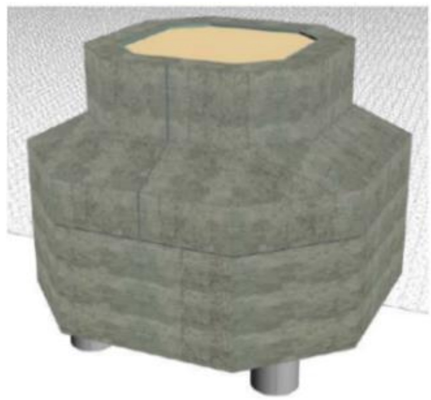


Figure 3.25 Cased Glory Hole (Caisson) *(Gudmestad, 2005)*

Any subsea installation in the shallow water, which is prone to interaction with ice keels, may yield to the formation of the permanently grounded Stamukha. In principle, this scenario shall be avoided unless the equipment will be specially designed for it. The protection method evaluation shall go hand-in-hand with the selection of the overall template concept.

3.5. Necessary steps to address the main challenges in the Arctic conditions. Launch of the Silurian and Lower Devonian deposits development

The oil and gas resources in the Arctic are estimated as one—fifth of the undiscovered oil and gas resources in the world. That is the reason why many of the major oil and gas companies have been involved in exploration activities in the Arctic. However, the Arctic has a unique environment distinguished by the presence of ice and its general remoteness.

Arctic offshore drilling operations should be limited to periods when the drilling rig and its associated system are capable of working and cleaning up a spill in

Arctic conditions in case such problems occur. Urycheva (2013) mentioned, the permissible ice thickness for drilling operations using the new Arctic Jack-Up rig is 0.54 m. Over the past years, weather conditions have allowed to extend the drilling season to 4-5 weeks after the ice began to form, thus remaining four more weeks to safely leave the site until a critical ice thickness is formed. The drilling from new Arctic Jack-Up rig allows putting two wells on production per one season (180 days). Thus, two new Arctic Jack-Up rigs allow completing all drilling operation to the Silurian and Lower Devonian deposits in 3 years. See Table 3.10.

Table 3.10 Possible distribution of launching of wells per annum

<table>
<tr><td colspan="3">2024</td><td colspan="3">2025</td><td>2026</td><td>Parameters</td></tr>
<tr><td colspan="3">Template</td><td colspan="3">Template</td><td>Template</td><td rowspan="2">Drilling with using</td></tr>
<tr><td colspan="2">1</td><td>2</td><td>1</td><td colspan="2">2</td><td>1</td></tr>
<tr><td>1</td><td></td><td>2</td><td>2</td><td>1</td><td></td><td>2</td><td>Number of production wells</td></tr>
<tr><td></td><td>1</td><td></td><td></td><td></td><td>1</td><td></td><td>Number of injection wells</td></tr>
</table>

The theoretical model, based on the force equilibrium has been introduced regarding design ridge scouring assessment. Involving the scouring dynamics, upper sediments and environmental conditions-, the maximum gouge depth has been assessed to 1,62 m. Under the assumption that the keel strength is limited and the keel fractures before it ploughs maximum depth (1,62); the forces distribution with gouge depth (1,3) is reflected in this Master thesis. The chapter gives a comprehensive analysis of the ice ridge implications on the pipeline, trenched in the nearshore area, and its influence on the integral pipeline design concept.

The analysis of the subsystem "Soil Pipeline" was based on the introduced model of the loaded pipeline subjected to multidirectional loads in terms of both:

operational and seabed scouring considerations. When the ridge scours the seabed above the pipeline, it bends horizontally towards the ridge movement direction and vertically downwards. Following the limit state criterions (ULS, SLS, ALS), it was concluded that the pipeline is safe below the estimated gouge, if certain mechanical properties of soil backfilling are performed, which attractive from economic reasons.

The distribution of estimated upper sediments volumes required per m trenched is presented in the Figure 3.26 During construction of the pipeline system, given the short operating windows, it is important to realize that the entire section of pipeline laid in the season, should be buried in the same season. Avoiding potential damage from ice to the pipeline system during construction requires a trenching system and operation with high reliability and minimized risk of downtime *(Berg and et al., 2012).*

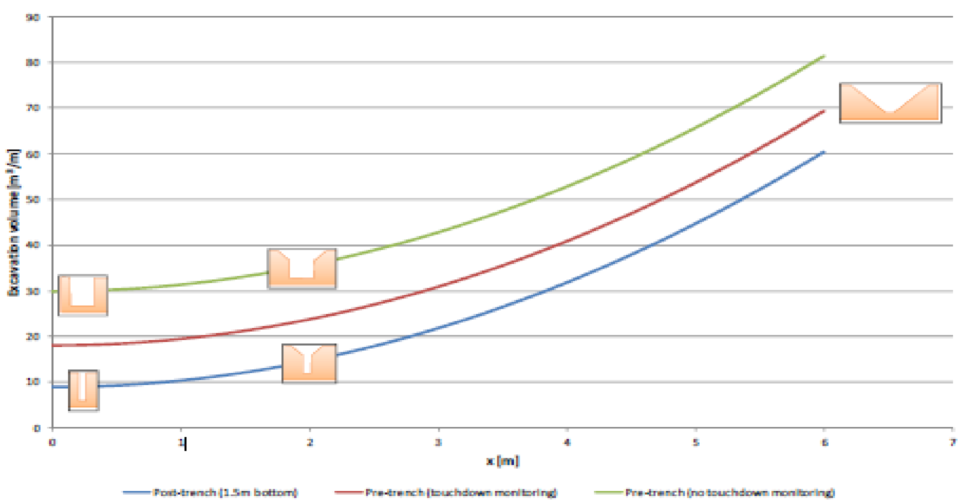


Figure 3.26 Excavation volume *(Berg and et al., 2012)*

Various protection methods can be used depending on the overall template design parameters, bathymetry and ice conditions. According to the Chapter 1, the level of ice thickness up is to 1.2 m, ice season duration 4 – 6 months, variable ice coverage, only first-year ice ridges in the Pechora Sea, thereby the cased glory hole (silo), and cased glory hole (caisson) is suitable for Silurian and Lower Devonian deposits.

Safe and efficient operations are a priority while conducting business. The company believes that all accidents can be avoided, and therefore company ambition is always to achieve zero personal injuries and zero harm to the environment. The recent major incidents in the oil and gas industry are clear examples of the need to have an effective emergency management system in place, to ensure that the effects on people and the environment are minimized.

4. Artificial lift in the HP/HT wells

4.1 Justification of putting on the artificial lift into the HP/HT well

Maximizing the use of natural energy in a reservoir is critical to any production installation.

The project of developing Permian and Carboniferous deposits of Prirazlomnoye field includes 19 production wells, 16 injection wells, and 1 slurry well. The production well on the Prirazlomnaya platform is equipped with an H1100N ESP with an optimal rate 1600 m^3/day (Figure 4.1). The primary purpose of the wellhead is to provide a hanging point and pressure seals for casing strings that extend from the bottom of the hole sections to the surface pressure monitoring equipment, which is designed for a pressure of 21 MPa and is equipped with fountains and a hydraulically actuated latch. *(Gazprom-Neft, 2017).*

The upper completion is comprised of tubing and shut-off valve, and it is possible to automatically/manually control the emergency shutdown system (ESD) of valves and hydraulic valves. Taps at the wellhead were installed to inject scale inhibitors into well. *(Andreev, 2017).*

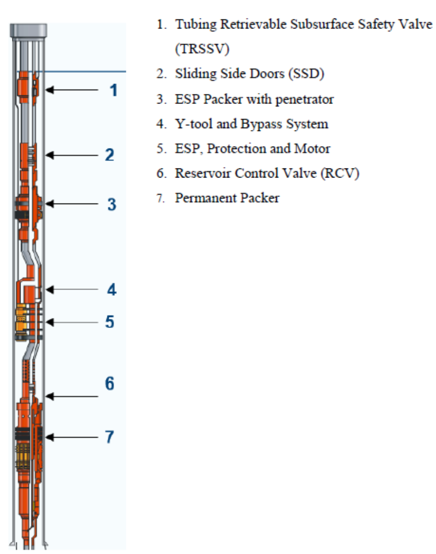


Figure 4.1 The upper completion of Prirazlomnoye oil field *(Gazprom-Neft, 2017)*

In the basic concept of developing Silurian and Lower Devonian deposits, the artificial lift is not provided for the wells. Though the developing HP/HT Silurian and Lower Devonian deposits of fields—analogs (named of Anatolya Titova and named of Romana Trebsa) showed the necessity of using artificial lift over time.

In the Master thesis, the option to lift oil first 5 years with using natural energy of HP/HT reservoir with gas injection is considered. If reservoir energy is too low for natural flow, or when the desired production rate is greater than the reservoir energy can deliver, it is expected to put the well on some form of artificial lift.

4.2 Criteria for choosing the optimal artificial lift system for HP/HT wells.

As of 2018, there are 70% of oil wells on offshore are equipped some form of an artificial lift according to Rushmore Reviews. See Figure 4.2.

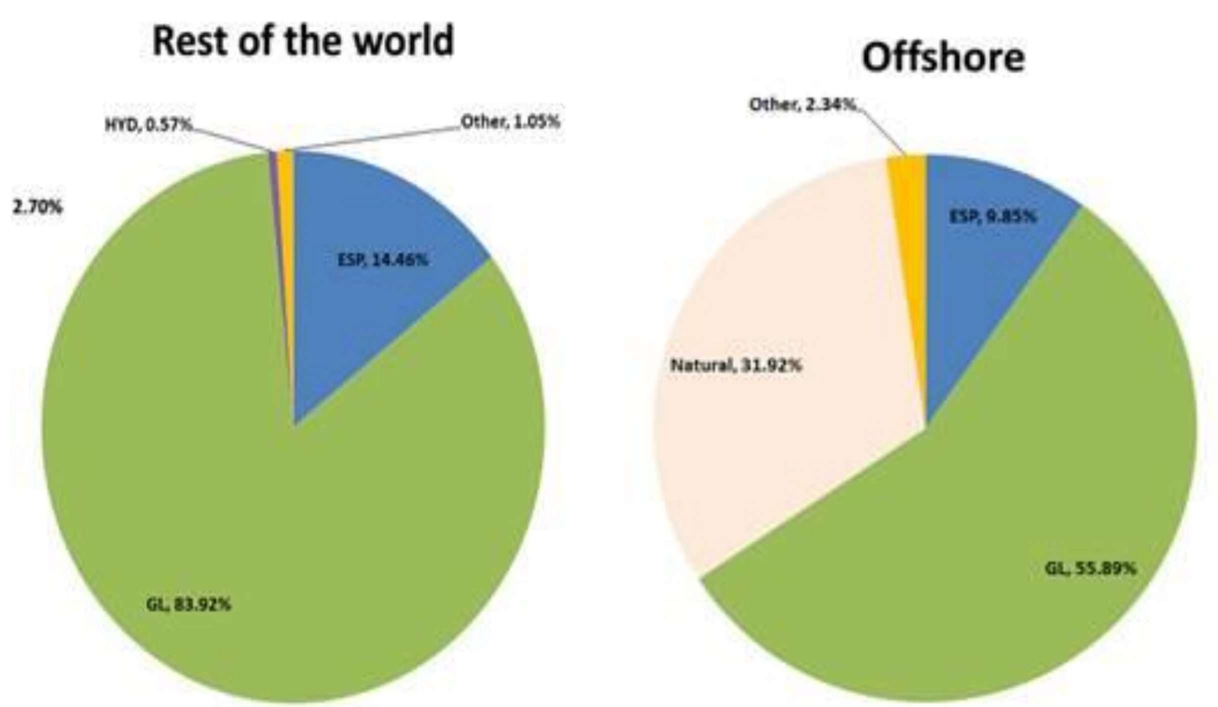


Fig. 4.2. The distribution of artificial system in the world *(Rushmore Review, 2018)*

In most cases, when choosing the optimal artificial lift system, the equipment with the best available experience is best suited, or which is already used for wells with similar conditions. Furthermore, the equipment and services have to be available from vendors. In view of the substantial costs of servicing wells and high well rates, it is necessary to consider both artificial lift systems: gas lift and ESP (Electric Submersible Pump). There are several factors which influencethe choice of optimal artificial lift system: experience of working with this type of artificial lift, run life and energy costs.

The use of charts with focus on the range of depth and rate when lift can operate allows estimating advantages and disadvantages of the systems. Geological data about Silurian and Lower Devonian deposits are limited by 3D seismic and the PH-5 exploratory well drilled by BHP Group in 1995, which showed abnormally high pressure (HPHT), drilling was stopped due to ice conditions at a depth of 4,463 meters with a reservoir pressure of 73.1 MPa. The viscosity, sand production, gas was estimated based on fields—analogs. Thus, it is only possible to estimate prudently the type of artificial lift.

4.3 Electric Submersible Pump

Electric Submersible Pump (ESP) system includes an electric motor and centrifugal pump unit run on a production string. ESP connected back to the surface control mechanism and transformer via an electric power cable. See Figure 4.3.

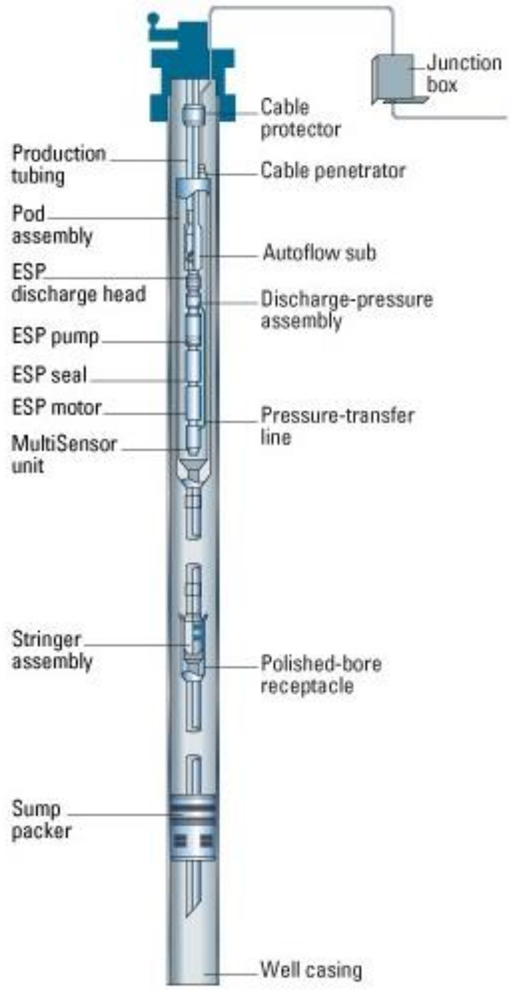


Figure 4.3 Typical ESP (aoghs.org)

The downhole components are suspended from the production tubing above the well perforations. The motor is located on the bottom of the work string; above the motor are the seal section, the intake and the pump. The power cable is attached to the top of the motor.

The ESP is a multistage centrifugal pump. The shaft is connected to the seal-chamber section and motor. It transmits the rotary motion from the motor to the impellers of the pump stage. The shaft and impellers are keyed, and the key transmits the torque load to the impeller.

The stages are stacked in series to increase the pressure to that calculated for the desired flow rate. The flow path is shown in the Figure 4.4.

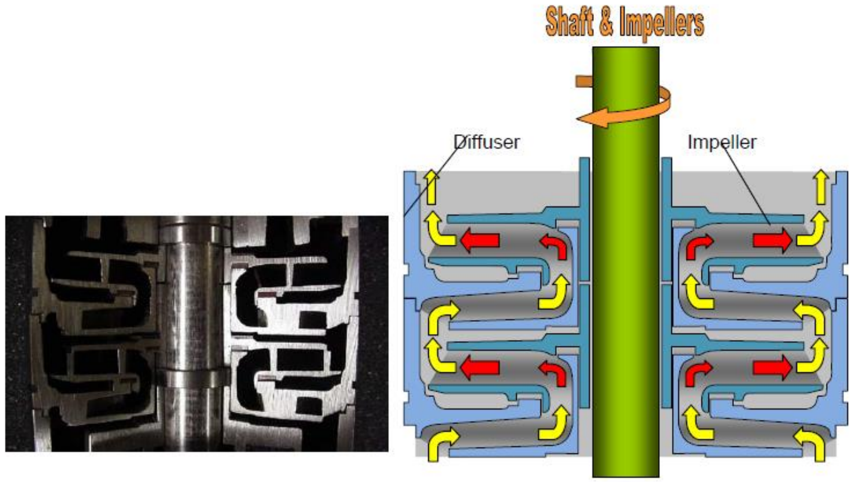


Figure 4.4 Shaft with the rotating impellers attached ***(Knut U, 2009)***

The vendors give the pump performance characteristics by 1 stage at 50-Hz power. A typical performance graph is shown in Figure 4.5. The head, brake horsepower (BHP), and efficiency of the stage are plotted against flow rate on the x-axis. Pump efficiency is given by:

$$n_p = \frac{[Q \times TDH \times SG]}{(C \times BHP)}$$

Where: Q= flow rate; TDH = Total Head Developed; SG= Specific gravity; BHP= Break horsepower; C= constant = 6, 75 (when Q=m3/d and TDH = m).

The head/flow curve shows the head or lift, measured in meters, which can be produced by one stage because of the head is independent of the fluid SG, the pump produces the same head on all fluids. The highlighted area on the graph is the manufacturer's recommended operating range. The graph was plotted in Novomet software based on estimated flow rate (Joshi equation) and characteristics of fluid on Silurian and Lower Devonian deposits.

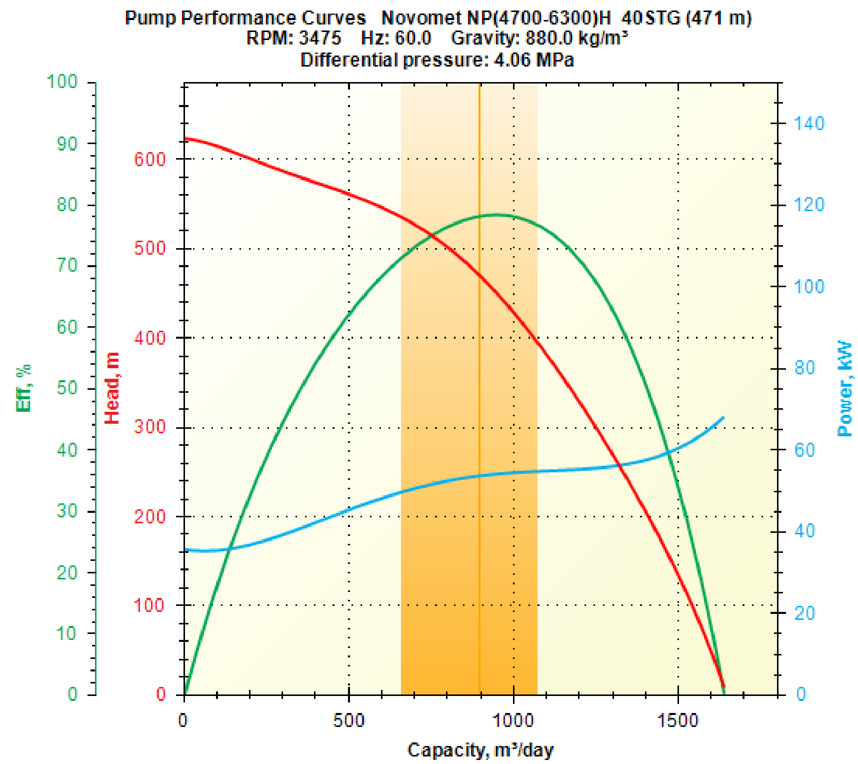


Figure 4.5 Pump curves for the head necessary, efficiency, and BHP for the HP/HT well

ESP run lives depend on numerous variables: equipment, operation, and operating environment. A combination of these factors can produce significant variation in ESP survival times, as presented in Figure 4.6.

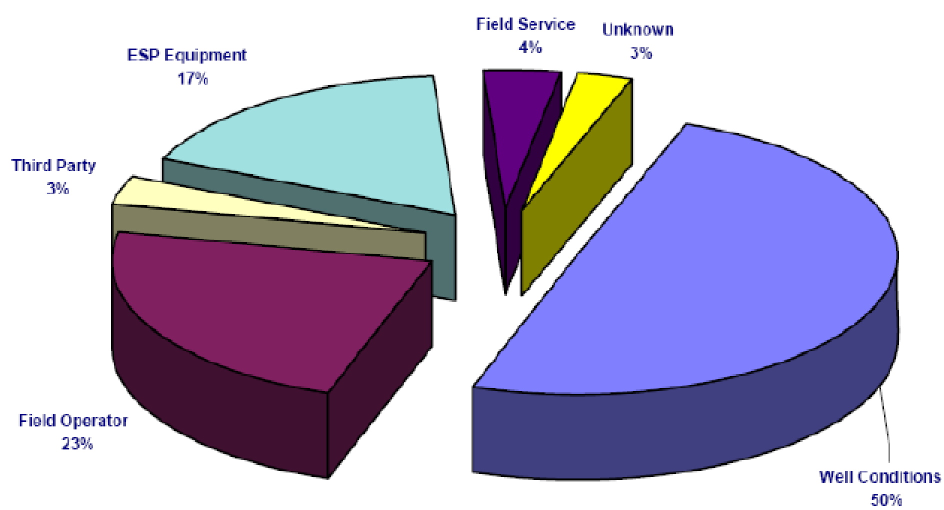


Figure 4.6 Factors acting on ESP run life *(Zerrouki, et al., 2006)*

The reliability model for ESPs is described as the "bathtub" concept (Figure 4.7) and uses three stages in the life of an ESP:

- Stage one: Infant mortality ESP (fails to start at installation).
- Stage two: In-service failures (Operational issues).
- Stage three: Wear out (Failure due to pump wear out).

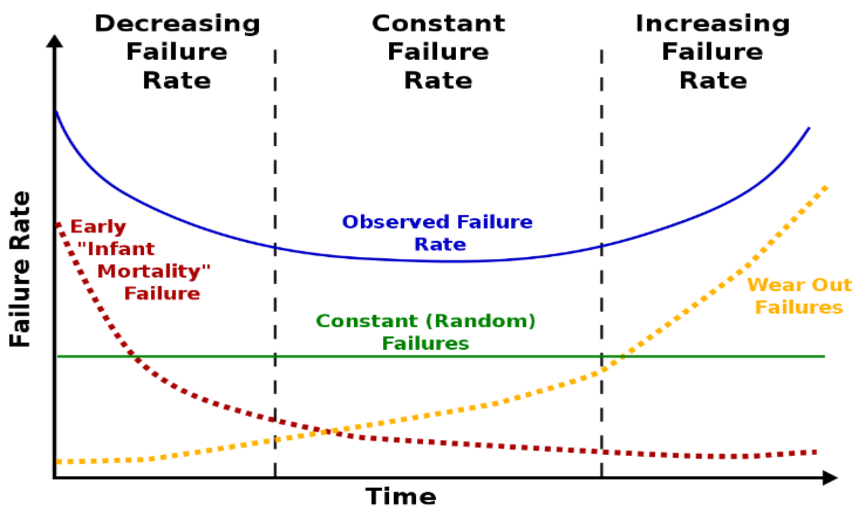


Figure 4.7 Bathtub concept

4.4 Gas Lift

Gas lift is the process of injecting gas in the annulus between tubing and casing where it will enter the tubing via a gas-lift valve located in a side pocket. The gas will then reduce the weight of the produced fluid column, which will lower the bottom hole pressure. Reservoir fluid will then experience lower resistance to flow, resulting in increased flow rates and increased production. See Figure 4.8.

Gas lift is the artificial lift method that most closely resembles the natural flow process. The only major requirements are a supply of pressurized injection gas. Normally, the lift gas is supplied from other producing wells, separated from the oil, run through a gas compressor and pumped in the annulus at high pressure. The gas from the producing well is then recovered again, recompressed and re-injected. However, the gas compressing process is power consuming and expensive (Knut U, 2009).

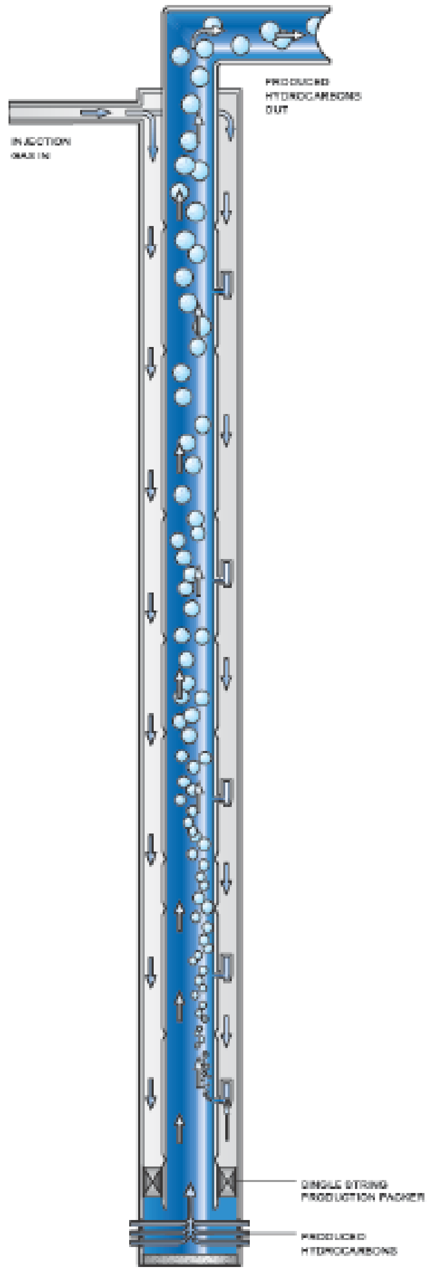


Figure 4.8 Typical Gas Lift System *(http://www.bakerhughesdirect.com).*

4.5 The comparative analysis of the two artificial lift systems

Nowadays, there are two artificial methods, which are operating offshore: ESP and gas lift, the main advantages and disadvantages of these lifting systems in Table 4.1. Much of the selection process can be accomplished with depth rate charts and this extensive set of tables of artificial lift capabilities.

Table 4.1 Advantages and disadvantages of ESP and gas lift

ESP		Gas Lift	
Advantages	Disadvantages	Advantages	Disadvantages
Lift high volume	Sensitive Electric cable	Handles large volume in high-PI wells.	Not efficient in lifting small fields or one well leases.
Corrosion and scale treatment easy to perform.	High voltages are necessary.	The power source can be remotely located	Gas freezing and hydrate problems
Simple to operate	Expensive to change equipment to match declining well capability.	Lifting gassy wells is no problem.	Cannot effectively produce deep wells to abandonment
Easy to install downhole pressure sensor for telemetering	The system in depth limited because of cable cost.	Easy to obtain downhole pressure and gradients.	Some difficulty in analyzing properly without engineering supervision
Availability of different sizes.	Gas and solids production are problems	Sometimes serviceable with wireline unit.	Casing must withstand lift pressure.

Consideration of reservoir characteristics and location are examples of what will fall in to this category. If the well was expected to decline rapidly, it would not be wise to choose a high volume method that will only be required for a short time. See Table 4.2

Table 4.2 Design considerations and overall Comparisons

Consideration /System	ESP	Gas lift
Capital cost details	Relatively low capital cost if electric power is available. Costs increase as horsepower increases.	Well, gas lift equipment cost low, but compression cost may be high.
Downhole Equipment	Requires proper cable in addition to motor, pumps, seals, etc. Good design plus good operating practices essential.	Good valve design and spacing essential. Moderate cost for well equipment (valves and mandrels).
Operating Efficiency	Good for high-rate wells Efficiency can vary from 40% in a low-rate well to 60% in a high-rate.	Fair. Increases for wells that require small injection GLRs. Low for wells requiring high GLRs. Typically 20%, but range from 5 to 30%.
Flexibility of system	Poor for a fixed speed. Requires careful design. Variable speed drive provides better flexibility.	Excellent. Gas injection rate varied to change rates. The tubing needs to be sized correctly.
Miscellaneous problems	Requires a highly reliable electric power system. The system is very sensitive to changes downhole or in fluid properties.	A highly reliable compressor with 95+% runtime required. Gas must be properly dehydrated to avoid gas freezing.

Operating costs	Repair costs often high.	Well costs low. Compression cost varies depending on fuel cost and compressor maintenance.
System reliability	Varies. Excellent for ideal lift cases.	Excellent if compression system properly designed and maintained.
Savage value	Fair. Some trade-in value.	Fair. Some market for good used compressors and mandrels/valves.
System total	Simple to design but requires good rate data. The system is not forgiving. Each well is an individual producer with a common electrical system.	An adequate volume, high Pressure, dry, noncorrosive, and clean gas supply source are needed throughout the entire life. System approach needed. Low backpressure beneficial.

4.6 The possible artificial lift design into the HP/HT wells

In the Master thesis, the option to lift oil first 5 years with using natural energy of HP/HT reservoir with gas injection is considered. It is assumed that the reservoir pressure in 5 years will not be enough to lift the fluid in the way implementation of artificial lift is obligated.

Gazprom-Neft has tremendous experience of using ESP with different head-capacity characteristics in Russia. Gazprom-Neft Shelf has been using the ESP on the Prirazlomnoye field since 2013; nowadays 9 wells are equipped by ESP. Thus, the accumulated experience, evaluated production rate and the absence of the need for modernization of the processing system for the needs of gas lift lead to decision that the ESP is optimal solution. The run life will be a critical problem in developing the reservoir with subsea modules in the Arctic because of operational expenditure in a period of reservoir production life (15 years). The implementation of DUAL ESPs allows to reduce well remedial works. The mean time to failure of this pump in this master thesis is equal to 1.7 run-life of the typical pump (1850 days). See Figure 4.9.

Well	Natural	Run life of new pump	Run life 3 repair
PS1	1850	1850	1850
PW1	1850	1850	1850
IS2	1850	1850	1850
PW2	1850	1850	1850
PS3	1850	1850	1850
PW3	1850	1850	1850
PS4	1850	1850	1850
IW4	1850	1850	1850
PS5	1850	1850	1850
PS6	1850	1850	1850

Figure 4.9 Failure interval

DUAL ESP consists from two separate systems, one upper and one lower. Only one ESP system operates at the time. While one works, the other pump is used as a backup until it stops or is shut down voluntarily. Dual ESP lift systems enable cost-effective production in applications where rig availability may be at a premium and where the cost of workover affects the overall profitability of the well. See Figure 4.10.

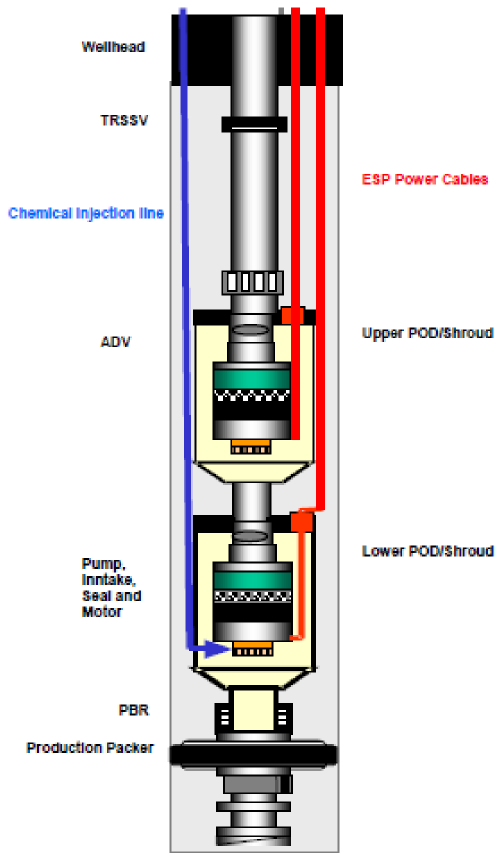


Figure 4.10 The possible design of Dual ESP system design for the HP/HT wells *(Knut U, 2009)*

In this concept, there are two assumptions that the run life of injection well is equal to run life of production well and the tubing has excellent strength performance and anticorrosion steel to withstand the destroying loads from the fluid during 5 years. The possible distribution of time of well remedial works is shown in the Figure 4.11.

Well	Production Start-up	ESP	1 repair	2 repair
PS1	15.10.2024	08.11.2029	02.12.2034	26.12.2039
PW1	15.10.2024	08.11.2029	02.12.2034	26.12.2039
IS2	15.10.2024	08.11.2029	02.12.2034	26.12.2039
PW2	15.10.2024	08.11.2029	02.12.2034	26.12.2039
PS3	15.10.2025	08.11.2029	02.12.2034	26.12.2039
PW3	15.10.2025	08.11.2030	02.12.2035	25.12.2040
PS4	15.10.2025	08.11.2030	02.12.2035	25.12.2040
IW4	15.10.2025	08.11.2030	02.12.2035	25.12.2040
PS5	15.10.2026	08.11.2030	02.12.2035	25.12.2040
PS6	05.10.2026	08.11.2030	02.12.2035	25.12.2040

Figure 4.11 The time of remedial works

An example of a possible technical solution for the integrated development of Prirazlomnoye field with the tie—in subsea production systems to IRGBS "Prirazlomnaya" is shown in Figure 4.12. The surface controller provides power to the ESP motor and protects the downhole ESP components. Motor controller designs vary in complexity from the very simple and basic to the very sophisticated, which offers numerous options to enhance the methods of control, protection, and monitoring of the operation.

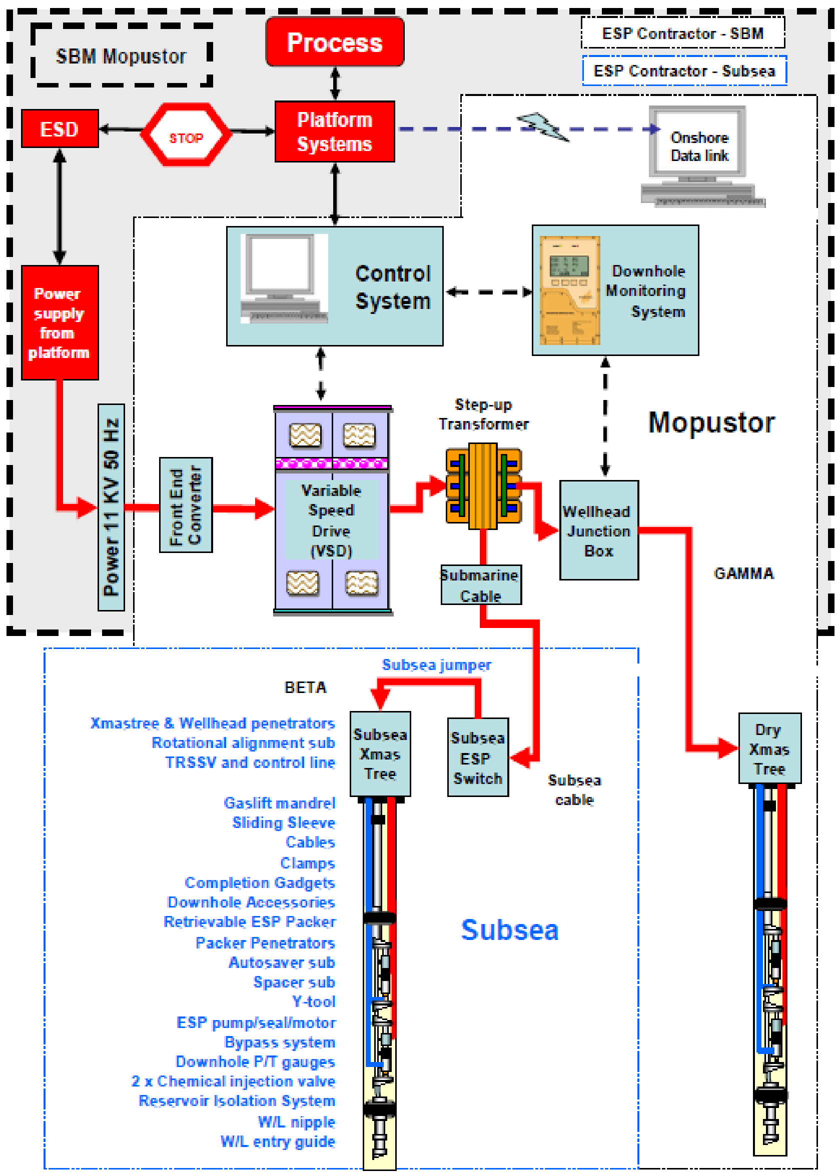


Figure 4.12 The possible artificial lift system for developing Prirazlomnoye field including Silurian and Lower Devonian deposits

5. Economic evaluation of the project

«Cost-Benefit Analysis (CBA)» was used to estimate the economic feasibility and investment indicators of the proposed concept. This method allows to calculate costs and benefits of the project and to compare them *(Zelenovskaya, 2016).* The method allows accounting for the different value of money throughout the lifetime of the project implementing the discount rate. Thus, the present value of costs and benefits are estimated for each year.

The objective of the analysis is to investigate economic feasibility of proposed concept for the development of Silurian and Lower Devonian deposits of Prirazlomnoye field with the use of subsea production units.

The information on costs for certain equipment, infrastructure and operations is gathered from different sources: development project for Silurian and Lower Devonian deposits *(Gazprom Neft, 2017)*, experts' opinions and some other sources listed in the references.

The brief description of the suggested concept and processes used for economic calculations is provided in Table 5.1.

Table 5.1 The concept description

Main blocks	Concept description
Production facilities	Subsea production system
Transportation of produced fluid	Multiphase pipeline transportation to the IRGBS Prirazlomnaya
Oil Treatment	IRGBS Prirazlomnaya
Oil Offloading	IRGBS Prirazlomnaya
Transportation to consumers	Tankers

To calculate above mentioned efficiency indicators the following algorithm is applied:

Evaluation of Capital Expenses (CAPEX)

Capital expenses depend on required capacities of each production, transportation, processing and infrastructure object. Expenses for suggested concept are evaluated for maximum annual production of 1,7 million tons of oil production forecast of Silurian and Lower Devonian deposits of Prirazlomnoye field *(Gazprom Neft, 2017)*. Capital expenses for the suggested concept are provided in Table 5.2.

Table 5.2 CAPEX

Name	Number	Cost, mln $	Total cost, mln $
Subsea production systems	2	109	220
Subsea pipelines	1	100	100
Flow assurance expenses	1	50	50
Trenching of pipeline	1	20	20
Drilling	10	40	400
ESP	8	4	32
Modernization of the platform	1	10	10
Total CAPEX			832 mln

Revenue calculation

Revenue = Q*P;

Where Q – the volume of the oil sold to consumers in a certain year, barrels;

P – Oil price, $/1 barrel (long-term contract oil price was used in the current analysis).

Evaluation of operating expenses (OPEX)

Overall operational expenses are amounted to 30 $ per barrel of produced oil, which is a reasonable value for Arctic offshore fields.

Depreciation calculations

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

Depreciation = Total CAPEX/N,

Where N- depreciation (service period), years;

Taxes

Due to high capital costs and harsh conditions, the government reduces the tax burden on companies that develop Arctic shelf deposits. In accordance with the Tax Code of the Russian Federation in the current economic model, two types of taxes were taken into account. First, the mineral extraction tax (MET) for the area of the Arctic shelf in question is 5% of the tax base for the first 15 years of production (Government Decree No. 443-r). Meanwhile, the tax base for offshore fields is equal to the revenue from hydrocarbons produced, minus transportation costs (Chapter 26 of the Tax Code of the Russian Federation). After 15 years of production, the mineral extraction tax is considered equal to 30% of the same tax base. Secondly, the profit tax is 20% of the estimated profit. Accumulated tax deductions are provided in Table 5.3.

Table 5.3 Taxes

Tax name	Accumulated payment, mln $
MET	15
Income Tax	10
Total	25

It should be mentioned that in this concept all associated gas from the main Permian deposits and Silurian and Lower Devonian deposits is injected through injection well to the Silurian and Lower Devonian deposits. This way, the taxes for flaring gas is avoided.

Net Present Value

Net present value (NPV) of the project is the sum of the present values (PV) of the discounted cash flows for the reviewed period;

$$NPV = \sum_{i=0}^{T} \frac{Cashs\ inflow_i - Cash\ outflow_i}{(1+d)^i}$$

$$where$$

$$Cashs\ inflow_i = Revenue_i + depriciation_i;$$

$$Cash\ outflow_i = CAPEX_i + Taxes_i + OPEX_i;$$

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:

— The opportunity cost of money;

— Uncertainty and risk;

For the current model, the initial discount rate is assumed to be equal to 12%, which is a common value for oil and gas projects. T- a considered period of the project, years.

The internal rate of return (IRR)

The internal rate of return refers to the average annual percentage rate of the project. The IRR determines such a project discount rate, where the NPV is equal to zero:

$$NPV = \sum_{k=0}^{n} \frac{Cash\ inflow_i - Cash\ outflow_i}{(1+IRR)^i} = 0$$

As a result, the project would be acceptable only if the obtained IRR is higher than applied discount rate.

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

PBP is the period that requires a project to recover the cost of the initial investment. To calculate DPBP, discounted cash flows are used to account for different monetary values throughout the project lifecycle.

Profitability index

Profitability index is used to show the relationship between the costs and benefits of a proposed project using a ratio calculated as:

$$PI = \frac{present\ values\ of\ future\ cash\ flows}{initial\ investments} = 1 + \frac{NPV}{Initial\ investments}$$

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

Break-even price (BEP)

It is considered that the breakeven price is reached when the Net Present Value is equal to 0 with the established discount rate equal to the expected rate of return (ROR) by the investor. The following formula can be used to calculate the break-even price (breakeven price-BEP) *(Zelenovskaya, 2016):*

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

Where

Q_i — oil production rate in year i, barrrels;

I_i—investment expenditures in year i, mln $;

O_i — Operation and maintenance expenditure 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 the expected market price of the product, then the project should be rejected.

Table 5-4 presents calculated investment indicators for the development Silurian and Lower Devonian deposits.

Table 5.4 Investment indicators for Basic concept and SPS

	Basic concept	Subsea
Efficiency indicators	Value	Value
Oil price per barrel,$	80	80
Total production, mln.t.	10,50	13,60
Total production, mln. b.	76,98	99,69
Revenue, mln $	6158,36	7 975,37
CAPEX, mln $	739,70	850,00
OPEX, mln $	2 309,38	2 990,76
Taxes, mln $	50,00	25,00
Depreciation, mln $	52,84	60,71
Cash inflow, mln $	6 211,19	8 036,08
Cash outflow, mln $	3 099,08	3 865,76
Discount rate %	12	12
NPV, mln $	636,80	853,33
PBP, years	13	10
IRR, %	24	32
PI	1,21	1,50

According to the results, all economic indicators are acceptable. Therefore, the project is economically viable. However, oil price for long-term contracts should not fall below 40 $/barrel for the project to be economically viable.

6. Risk analysis for the ice gouging

The gained experience from the production with using subsea production systems will be used to develop the future projects in the Pechora Sea: Dolginskoye, Varandey-More, and others. Thus all risks should be evaluated. This work presents the qualitative analysis methods and Bow-Tie diagram for evaluation and prevention of the most likely risk that could happen – the pipeline damage in the stages of installation and operation.

Risk matrix

The risk matrix is the typical qualitative analysis method that shows the probability of occurrence of different consequences and the acceptance criteria for different situations (Figure 8.1). The qualitative method considers four aspects where risk can occur: health and safety of human life, environment, assets, and reputation *(Ong, 2017).*

Table 6.1 Risk evaluation

1	4	6	10	12	25
Low Risk (Acceptable)		Medium Risk (Tolerable)		High Risk (Intolerable)	
Number of effective barriers in place for all threats					
1		2		3	
Number of one effective barrier (recovery measures) in place for each identified consequence					
1		1		2	
Number of effective control in place for each barrier failure/decay mode					
0		1		1	

The risk of pipeline damage will cause environmental, safety and reputations problems. The risk is staying in BE column. This accident will cause oil leakage, which will stop production from the Silurian and Lower Devonian deposits; also, it will tend to lose of the pipeline, which tends to stop developing of those deposits due to the price of repairing trenching pipeline, which is almost 90 % of building a new pipeline. Moreover, it may cause an oil spill that can destroy the sensitive environment in the Arctic and the reputation of Gazprom Neft. The dependence of likelihood and severity of consequences can be seen in Figure 6.2. *(Ong, 2017).*

					Increasing Severity of Consequences >				
			People		Minor injury	Loss time accident	Single or few serious injuries	Single or few fatalities	Many fatalities (> 5)
			Assets		Minor damage	Significant damage	Severe damage	Major damage	Catastrophic damage
	Min-Max	Median			1	2	3	4	5
Increasing Likelihood >	> 1	10	Frequent	E	E1	E2	E3	E4	E5
	10^{-2} - 1	10^{-1}	Probable	D	D1	D2	D3	D4	D5
	10^{-4} - 10^{-2}	10^{-3}	Unlikely	C	C1	C2	C3	C4	C5
	10^{-6} - 10^{-4}	10^{-5}	Very unlikely	B	B1	B2	B3	B4	B5
	<10^{-6}	10^{-7}	Extremely unlikely	A	A1	A2	A3	A4	A5

Fig. 6.1 Risk matrix *(Ong, 2017)*

Health and Safety:

The damage of pipeline will not be critical to the health or safety of human life. Thus the risk stays in BA column. The consequences can be classified as A – minor injury; B – uncomfortable; C – single or few serious injuries; D – single or few fatalities; E – many fatalities (Figure 6.2).

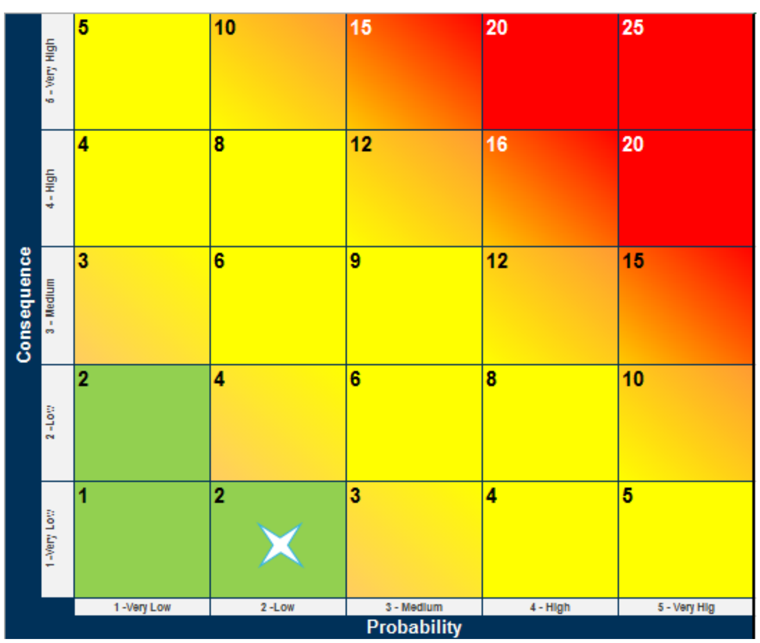


Figure 6.2 Risk for Health and Safety of People

Environment:

The leakage of the damaged pipeline will be able to lead to the oil spill and therefore destroy the sensitive ecosystem of the Arctic. In the Arctic, there are several limits for mechanical oil removal and burning of spilled oil, depending of ice conditions. Furthermore, the accident may stop all activity in the Arctic (production, exploration, and drilling). The risk moves from BA to BD, which is unacceptable. The consequences can be classified as A – no obvious effect; B – a little change of environment, but will recover soon; C – a few sea animals die; D – polluted, some sea animals die; E – badly polluted (Figure 6.3).

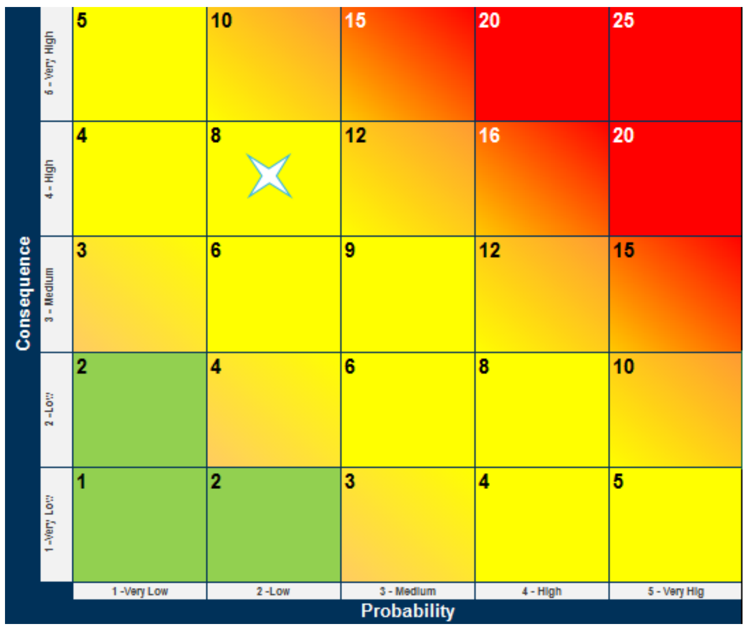


Figure 6.3. Risk for Environment

Assets

The leakage of damaged pipeline stops the production and repairing operation would be needed, but the cost of repairing of trenching pipelines in Arctic conditions are the same as laying a new pipeline. Thus the risk stays in BE column, which is unacceptable. The consequences can be classified as A – minor damage; B – significant damage; C – severe damage; D – major damage; E – catastrophic damage (Figure 6.4).

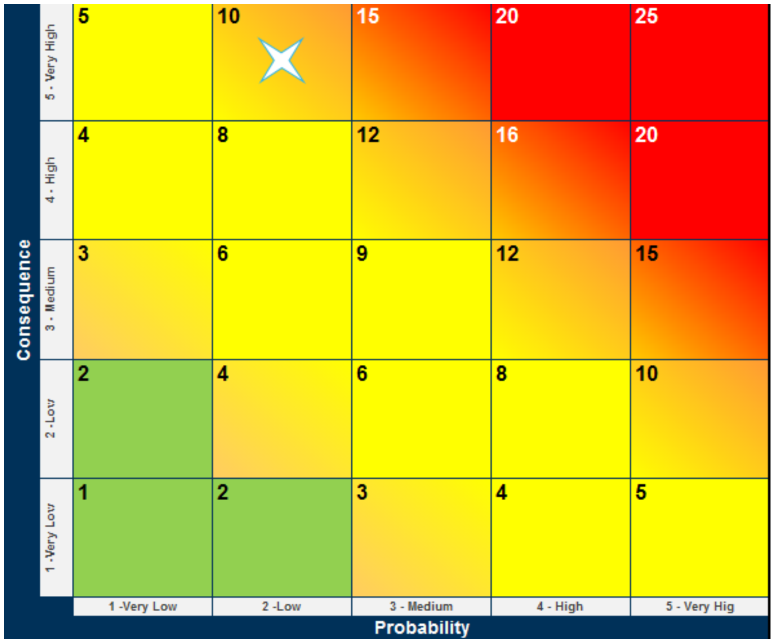


Figure 6.4. Risk for Assets

Reputation:

The oil production in the Arctic is important for Russia. Also, the Arctic is home to many spices and nature is extremely sensitive. Thus, all Russian activity in the Arctic is closely followed by many ecological and political organizations. Any damages of the pipeline will cause a big economic loss, and it could stop all cooperation with Russian companies in the Arctic. Thus, the risk stays in the BD column, which is unacceptable. The consequences can be classified as A – no obvious effect; B – Slightly bad reputation; C – bad reputation cause some economic loss; D – bad reputation, cause a big economic loss; E – fame, company goes bankrupt (Figure 6.5).

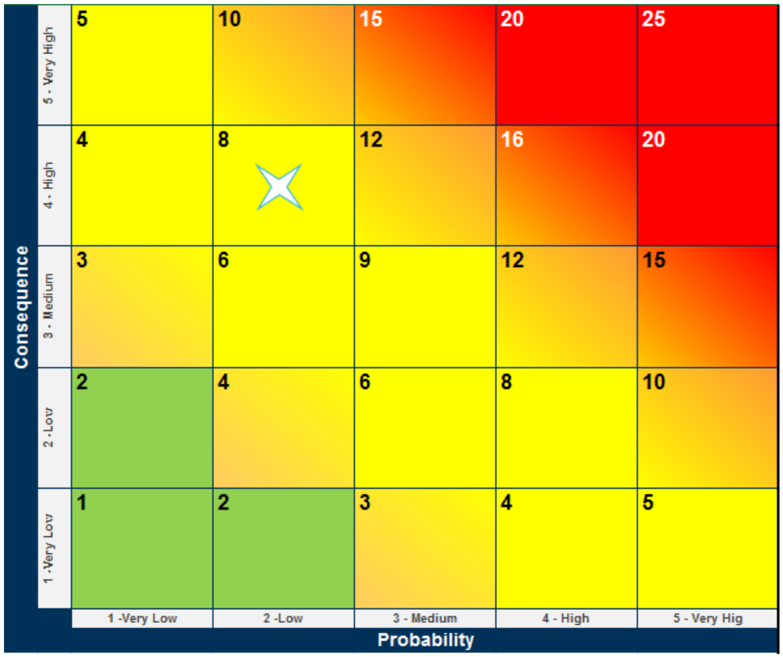


Figure 6.5. Risk for reputation of the company

Hazard identification (HAZID):

The purpose of Bow-Tie Analysis (BTA) is to identify threats and add available barriers to prevent the hazard or to avoid the bad consequence of hazard. Bow-Tie is a practical way to implement the risk management *(Ong, 2017)*.

Hazard Identification and Risk Analysis (HIRA) is a collective term that encompasses all activities involved in identifying hazards and evaluating risk at facilities, throughout their life cycle, to make certain that the risks of employees, the public, or the environment are consistently controlled within the organization's risk tolerance. The Bow—Tie diagram is in Appendix 2.

Conclusion

Gazprom Neft Shelf has several projects to improve the profitability of the Prirazlomnaya platform. One of such projects is the development of the Silurian and Lower Devonian deposits of the Prirazlomnoye field.

Initially, it was planned to drill and subsequently develop deposits from the platform. However, such concept was not economically and technically profitable for a number of reasons. In the Master thesis, the concept of development of Silurian and Lower Devonian deposits with the use of subsea production system was considered.

In the proposed concept it is considered to develop Silurian and Lower Devonian deposits with tie—in subsea to the IRGBS " Prirazlomnaya". There are 2 questions that should be answered: Is it possible to use processing, offloading and storing capacities of IRGBS Prirazlomnaya; How to solve challenges of installation and operation of SPS and pipelines in the severe climate?

To assess the effectiveness of this concept, the hydrometeorological conditions of the research area, the Prirazlomnoye field, were analyzed. The analysis of the region was carried out. The paper considers the main indicators that will influence the successful implementation of the concept, such as the characteristics of the upper seabed sediments and the ice conditions at the site of the installation of subsea production modules and the trenching of the pipeline.

To analyze the possibility of tie—in the Silurian and the Lower Devonian deposits it is necessary to know the oil properties, reservoir properties and cumulative production. However, information about the properties of the deposits is limited to PH-5 exploratory well, in which due to the ice conditions the flow test was not accomplished in 1995. Thus, to calculate the cumulative production the 8 fields—analogs with similar HP/HT Silurian And Lower Devonian deposits in Timan—Pechora province were chosen. The profile of production based on Joshi equation shows the increase of the production on the Prirazlomnaya field up to 13,28 million tons of oil equivalent. The increasing of production will not be critical for offloading and storage system because at a peak offloading rates, pumps at the IRGBS “Prirazlomnaya” may reach 8750 m3/h what might be required at the peak oil production at the platform. The processing facilities will become free to connect fields or deposits with additional oil. Considering the processing capacity of the IRGBS “Prirazlomnaya”, it should be noted that it is more expedient to attach incoming oil from the Silurian and Lower Devonian deposits to the second stage of separation. The concept of tie—in deposits with SPS will be first step to use the IRGBS Prirazlomnaya like a “hub” for future fields in the Pechora Sea (Varandey More, Dolginskoye etc.).

Severe climatic conditions in the Arctic create additional challenges and uncertainties, among which: ice gouging, which poses a threat to the pipeline and subsea units; the drilling time is limited by ice conditions; complexity of infrastructure inspection; utilization of associated gas; modernization of the processing system due to different physical and chemical properties of oil; high reservoir pressure and temperature.

This work presents the procedure for choosing the optimum depth for trenching the pipeline along the route between the platform and the sites where templates will be installed. A theoretical model based on force balance was introduced with respect to the estimation of ice gouging. The maximum depth of the ice gouging was 1.62 m. The subgouging analysis for HP/HT pipelines shown in the project provides the extreme value of seabed upper sediments pressure: $p_s = 63{,}69\, MPa$, which is possibile to occur only in the case of direct contact with the ice ridge.

Subsea production units for the development of the Silurian and Lower Devonian deposits will include two 5-slot bottom templates for drilling wells, which will be connected to the IRGBS “Prirazlomnaya”. Placing the templates below the seabed means that direct contact with the ice keel should be completely eliminated or greatly reduced.

In the Master thesis, there are three methods of maintaining pressure by water injection, gas or combined injection of water with gas. When injecting gas, it is assumed that all additional volumes from the Permian deposits and the Silurian and Lower Devonian deposits will be injected into Silurian and Devonian deposits.

Maximizing the use of natural energy in a reservoir is critical to any production installation. In the Master thesis, the option when injection of the gas, HP/HT characteristics of the reservoir will allow lifting oil first 5 years without any kind of artificial lift. When reservoir energy is too low for natural flow it is expected to put ESPs into the wells. However, run life will be a critical issue when developing a field with subsea production modules in the Arctic due to operating costs. The putting Dual ESPs into the wells will increase run life and time between repairs. Hence, possible distribution of remedial works for life cycle of the project was built.

The economic feasibility and investment indicators of the proposed concept were assessed using the "Cost-benefit analysis (CBA)" method. Results showed the economic profitability of the project to develop the Silurian and Lower Devonian deposits of the Prirazlomnoye field with the use of subsea production units versus production from the IRGBS “Prirazlomnaya”.

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Appendix 1 (The estimation of gouge depth)

> ***Ice gouging*** :

> $W := 2.52 \cdot 10^8$:

> $Fb := 2.62 \cdot 10^8$:

> $Fi := 13.232 \cdot 10^6$:

> $Fda := 0.598 \cdot 10^5$:

> $Fdw := 0.389 \cdot 10^6$:

> $Kp := 12.2797$:

> $ps := 1998$:

> $g := 9.81$:

> $wb := 9.985$:

> $ct := 1.734$:

> $nuu := 0.5$:

> $ak := 0.523$:

> $qw := 0.49$:

> $q := 0.5931$:

> $z := 0.0175$:

> $pa := 1.3$:

> $Cda := 0.9$:

> $wk := 87.975$:

>

> $Pfd := \frac{1}{2} \cdot Kp \cdot ps \cdot g \cdot (d + 0.635\, d)^2 \cdot B$

$$Pfd := 6.948827290\, 10^6\, d^2$$

> $Psd := \frac{1}{6} \cdot Kp \cdot ps \cdot g \cdot d^2 \cdot wb \cdot \left(wb + \frac{d \cdot ct}{2} \right)$

$$Psd := 4.005429268\, 10^5\, d^2\, (9.985 + 0.8670000000\, d)$$

> $Fcxd := nuu \cdot Pfd \cdot \cos(qw) \cdot \cos(ak) + nuu \cdot Psd \cdot \cos(qw)$

$$Fcxd := 2.655795555\, 10^6\, d^2 + 1.767060928\, 10^5\, d^2\, (9.985 + 0.8670000000\, d)$$

> $Fcyd := nuu \cdot Pfd \cdot \cos(qw) \cdot \sin(ak)$

$$Fcyd := 1.531204710\,10^6\,d^2$$

> $Nd := Fcyd$

$$Nd := 1.531204710\,10^6\,d^2$$

> $Fad := nuu \cdot Nd$

$$Fad := 7.656023550\,10^5\,d^2$$

> $solve(Fda + Fdw + Fi - Fad - Fcxd = 0, d)$

$$1.587433132,\ -1.665732952,\ -33.77069936$$

> ***Energetic equation***

$$Energetic\ equation$$

> $Cdw := 0.9 :$

> $pw := 1030 :$

> $Aw := 463, 241 :$

> $uc := 1.35 :$

> $vi := 0.6 :$

> $Aa1 := 74.599 :$

> $Aa2 := 1900.26 :$

> $ua := 38 :$

> $Csa := 0.001 :$

> $hi := 1.2 :$

> $Ek := 1.5 \cdot 10^7 :$

> $WorkCD := \frac{1}{2} \cdot Cdw \cdot pw \cdot Aw \cdot \left(uc - \frac{1}{L} \cdot (L - x) \cdot vi \right)$

> $l := int(WorkCD, x = 0..L)$

$$l := 1.609503750\,10^5\,L + 139.0500000\,(463., 241.)\,L$$

> $WorkWD := \frac{1}{2} \cdot pa \cdot Cda \cdot Aa1 \cdot \left(ua - \frac{(L-x)}{L} \cdot vi \right)^2 + Csa \cdot pa \cdot Aa2 \cdot \left(ua - \frac{(L-x)}{L} \cdot vi \right)^2 :$

> $ll := int(WorkWD, x = 0..L)$

$$ll := 65538.13545\,L$$

> $WorkIDF := \frac{x}{L} \cdot 0.43 \cdot 4.059 \cdot B^{0.622} \cdot hi^{0.628} \cdot 10^6 :$

> $lll := int(WorkIDF, x = 0..L)$

$$lll := 6.616275290\,10^6\,L$$

> $Kp1 := 13.27:$

> $C1 := 1.79:$

> $aaa := solve\left(\frac{nuu}{B^2 \cdot pw} \cdot \frac{1}{2} \cdot Kp1 \cdot ps \cdot B \cdot (1 + C1 \cdot \tan(z))^2 \cdot (1 + 0.691)^2 \cdot (x \cdot \tan(z) - y)^2 - y = 0, x\right):$

> $xy1 := aaa[1]:$

> $xy := \frac{1000}{17} \cdot y + \frac{10000}{289} \cdot 10^{0.5} \cdot y^{0.5}:$

> $yx := \frac{500}{289} + \frac{17}{1000} \cdot x - \frac{1}{289} \cdot (250000 + 4913 \cdot x)^{0.5}:$

> $yL := \frac{500}{289} + \frac{17}{1000} \cdot L - \frac{1}{289} \cdot (250000 + 4913 \cdot L)^{0.5}:$

>

> $Pf1x := \frac{1}{2} \cdot Kp1 \cdot ps \cdot g \cdot ((1.691 \cdot (x \cdot \tan(z) - yx))) \cdot (1 + C1 \cdot \tan(z))^2 \cdot B:$

> $Pf2y := \frac{1}{2} \cdot Kp1 \cdot ps \cdot g \cdot ((1.691 \cdot (xy \cdot \tan(z) - y))) \cdot (1 + C1 \cdot \tan(z))^2 \cdot B:$

> $Psx := \frac{1}{6} \cdot Kp1 \cdot ps \cdot g \cdot \cot(z) \cdot (x \cdot \tan(z) - yx)^3:$

> $Wprx := nuu \cdot Pf1x \cdot \cos(qw) \cdot \cos(ak) + nuu \cdot Psx \cdot \cos(qw):$

> $llll := int(Wprx, x = 0 ..L):$

> $Wpry := nuu \cdot Pf2y \cdot \cos(qw) \cdot \sin(ak):$

> $lllll := int(Wpry, y = 0 ..yL):$

> $Ep := \frac{pw \cdot g \cdot B \cdot wk \cdot yL^2}{2}:$

> $ki := 2.55 \cdot 10^6:$

> $Epi := \frac{ki \cdot yL^2}{2}:$

> $War := nuu \cdot (pw \cdot g \cdot B \cdot wk \cdot yx + ki \cdot yx + nuu \cdot Pf1x \cdot \cos(qw) \cdot \sin(ak)):$

> $llllll := int(War, x = 0 ..L):$

> $ura := solve(Ek + int(WorkCD, x = 0 .. L) + int(WorkWD, x = 0 ..L) + int(WorkIDF, x = 0 ..L) = int(War, x = 0 ..L) + int(Wpry, y = 0 ..yL) + int(Wprx, x = 0 ..L) + Ep + Epi, L):$

> $L777 := ura[1]$

$$L777 := 138.6005587$$

> $d777 := L777 \cdot \tan(z) - \frac{500}{289} - \frac{17}{1000} \cdot L777 + \frac{1}{289} \cdot (250000 + 4913 \cdot L777)^{0.5}$

$$d777 := 1.678041601$$

Appendix 2 (Bow-Tie diagram for ice gouging)