RUSSIAN MARITIME REGISTER OF SHIPPING

Электронный аналог печатного издания,
утвержденного 13.01.06

RULES

FOR THE CLASSIFICATION AND CONSTRUCTION OF SUBSEA PIPELINES

НД No 2-020201-006-E

Saint-Petersburg
2005

The Rules for the Classification and Construction of Subsea Pipelines of Russian Maritime Register of Shipping have been approved in accordance with the established approval procedure and come into force since the date of publication.

The Rules cover all technical aspects of design and construction of offshore subsea pipelines.

In development of the Rules experience of other classification societies has been taken into consideration.

ISBN 5-89331-064-0

CONTENTS

1 GENERAL

1.1 SCOPE OF APPLICATION

1.1.1 The present Rules for the Classification and Construction of Subsea Pipelines (hereinafter referred to as “the Rules”) cover offshore pipelines, shore crossings and sections of shore main pipelines to the isolation valve nearest to the shoreline conveying liquid, gaseous and two-phase hydrocarbons as well as other media capable of being conveyed through the pipelines.

In addition to the present Rules, Russian Maritime Register of Shipping (hereinafter referred to as “the Register”) also applies during performance of surveys the Guidelines for Technical Supervision of Industrial Safety of Industrial Objects and Facilities, and rules and regulations of the national supervisory bodies.

1.1.2 In each particular case, based on special survey agreement, scope of surveys to be carried by the Register shall be decided with the pipeline owner, operating organization and agreed upon, if necessary, with the national supervisory bodies.

An agreement shall be made between the pipeline owner and the operating organization on allocation of responsibilities for safety.

1.1.3 The present Rules do not cover the hoses and free spanning pipelines. Hoses shall comply with the requirements of Section 6, Part VIII “Systems and Piping” of the Rules for the Classification and Construction of Sea-Going Ships. Additional requirements may be imposed on the hoses within the subsea pipelines depending on the application.

1.1.4 The requirements contained in the Rules cover documentation, certification, design, materials, manufacture, welding, laying methods, strength, sea ground stability, testing, operation, service repairs and safety assessment of subsea pipelines.

1.1.5 The Rules are applicable to single pipelines, pipeline bundles and pipeline bundles encased within a carrier pipe.

1.1.6 The Rules may be applied to existing pipelines built without the Register supervision for the purpose of carrying out survey of technical condition and confirming the possibility of their further service.

1.1.7 The Register may approve, as an alternative, the design that does not comply with the requirements of the Rules but is suited for the intended service or impose more stringent requirements thereon.

1.1.8 In case referred to in 1.1.6, the Register may require special tests to be conducted during construction, and reduce the intervals between periodical surveys or extend the scope of such surveys in service.

1.1.9 The Register may approve subsea pipelines built in compliance with other rules, regulations or standards alternatively or additionally to the present Rules. Pipelines under construction shall be brought to conformity with the requirements of the present Rules within the time period agreed upon with the Register.

1.1.10 The requirements of the Rules are applicable to subsea pipelines laid by section towing with subsequent immersion to the seabed, by section reeling from a pipe-laying vessel, seabed pull with subsequent joining of pipe strings on a shore site, by free immersion and from floating supports; dropping from the ice; laid to the seabed by buoyant stingers; laid by *J*-method.

1.2 DEFINITIONS AND EXPLANATIONS

Atmospheric zone means the part of the pipeline above the splash zone.

Burying depth means difference between the level of the pipeline top and the natural level of the sea ground.

Pressure burst means an incidental pressure caused by a disturbance of steady flow in the pipeline system not exceeding the design pressure by more than 10 per cent.

Splash zone height means the vertical distance between the upper limit and the lower limit of splash zone.

Sea depth means the vertical distance measured from the seabed to the average water level plus the total height of astronomical and storm tides.

Excessive pressure means a difference between two absolute pressures, namely: outside hydrostatic and internal pressures.

Free span of pipeline means the pipeline length not touching the seabed or supporting facilities.

Permissible stresses mean the total maximum stresses in the pipeline (longitudinal, hoop and tangential) permitted by standards.

Burying of pipeline means placing of a subsea pipeline below the natural level of the sea ground.

Splash zone means external surfaces of the pipeline system that are periodically in and out of the water by the influence of waves and tides.

Test pressure means a rated pressure applied to the pipeline during testing before its commissioning.

Leak test means a hydraulic pressure testing that ascertains absence of the conveyed product leakage.

Strength test means a hydraulic pressure testing that ascertains structural strength of the pipeline.

Minimum yield stress means the minimum yield stress specified in the certificate or standard, under which the pipes are supplied. It is assumed in calculations that the total elongation will not exceed 0,2 per cent at the minimum yield stress.

Pipe nominal diameter means an outside pipe diameter specified in the standard, under which the pipes are supplied.

Nominal pipe wall thickness means the pipe wall thickness specified in the standard, under which the pipes are supplied.

Pipeline negative buoyancy means a force directed downwards and equal to the weight of the pipeline structure in the air minus the weight of the water displaced by the pipeline submerged volume.

Subsea pipeline means the part of the pipeline system, which is located below the water level, including the pipeline itself, corrosion protection system of the pipeline components providing transfer of conveyed media under given operational conditions.

Pipeline installation means a set of operations related to manufacture, laying and burying, if any, of a subsea pipeline.

Design pressure means the pressure assumed as a permanent maximum pressure by the conveyed medium on the pipeline during operation, for which the pipeline system is designed.

Stinger means a device placed on the stern of the pipe-laying vessel or barge and intended to form a flat curve of the pipeline axis with *S*-lay and to reduce bending stresses in the pipeline during laying.

Riser means a part of the pipeline or hose connecting subsea and above-water pipelines.

Conveyed media mean liquid, gaseous and two-phase hydrocarbons capable of being conveyed through pipelines.

Pipe-burying machines mean machines intended for burying of the pipelines, preliminarily laid on the seabed, into the sea ground by means of hydraulic diffusion, hydraulic milling, hydromechanical, plunger and other types of devices, as well as by dredgers.

Pipe-layer (pipe-laying vessel) means the special-purpose vessel intended for laying of subsea pipelines.

Laying of a pipeline by seabed pull means the operation consisting of the preliminary assembly of the pipeline on the site, either of its full length or with successive joining of pipe strings and seabed pull, using different pulling devices and equipment.

Pipeline laying by reeling means pipeline laying from a pipe-laying vessel with preliminary winding on the special reel.

Pipeline laying by directional drilling means the combination of directional drilling operations and laying of subsea pipeline.

Pipeline laying by *J*-method means pipeline laying by free immersion on the seabed, using a sloped or vertical frame at sea depths more than 300 m. It consists of two stages: at the first stage the pipeline is lowered from a pipe-laying vessel vertically (or almost vertically) with joining pipe strings until the pipeline comes in contact with the seabed; at the second stage the pipeline bending occurs and the pipeline is laid on the seabed while the pipe-laying vessel is moving.

Pipeline laying by *S*-method means pipeline laying by free immersion on the seabed, in the course of which the pipeline section between the point of contact with the seabed and the stinger takes form of the *S*-curve.

Weight coating (ballasting coating) means the coating applied on the pipeline to provide its negative buoyancy and protection against the mechanical damages.

1.3 CLASSIFICATION

1.3.1 The class notation assigned by the Register to the subsea pipeline consists of the character of classification, additional distinguishing marks and descriptive notations defining its purpose and structure.

1.3.2 The character of classification assigned by the Register to the pipeline consists of the following distinguishing marks: ПТ✪, ПТ★, or ПТ$\underline{✪}$.

Depending on the supervisory body, under which supervision the pipeline has been constructed, the character of classification is established as follows:

.1 subsea pipelines constructed in accordance with the Register rules and under supervision of the Register, are assigned a class notation with the character of classification ПТ✪;

.2 subsea pipelines constructed in accordance with the rules and under supervision of the supervisory body recognized by the Register are assigned a class notation with the character of classification ПТ★;

.3 subsea pipelines constructed without supervision of the supervisory body recognized by the Register are assigned a class notation with the character of classification ПТ$\underline{✪}$.

1.3.3 Descriptive notations defining the purpose of the pipeline are added to the character of classification:

gas pipeline;

oil pipeline;

chemical pipeline;

water pipeline.

1.3.4 Additional characteristics are added to the character of classification:

geographical area;

the maximum allowable working pressure (in MPa);

the maximum allowable temperature of the conveyed medium (°C).

For example: ПТ✪ oil pipeline, Baltic Sea, 12 MPa, 90 °C.

1.3.5 The Register may assign a class to the subsea pipeline on completion of its construction and assign or renew a class of the pipeline in service.

1.3.6 Assignment of the Register class to the subsea pipeline means confirmation of the pipeline compliance with the applicable requirements of the Rules, and acceptance of the pipeline under supervision for the specified period of time with performance of all surveys required by the Register to confirm the appropriate class.

1.3.7 Confirmation of class means confirmation by the Register of compliance of the pipeline technical condition with the class assigned and extension of the Register supervision for the set period of time.

1.3.8 Class of pipeline is generally assigned or renewed by the Register for 5 years, however, in sound cases the Register may assign or renew a class for a lesser period.

1.3.9 In case the subsea pipeline is not submitted to a mandatory survey within the prescribed time period, or it has not been submitted to survey after repair, or structural alterations not agreed with the Register have been made thereon, or the pipeline has been repaired without the Register supervision, the Classification Certificate ceases its validity, which results in suspension of class.

1.3.10 Withdrawal of class means termination of the Register supervision, and reinstatement of class is subject to a special consideration by the Register.

1.3.11 The Register may withdraw the class or refuse to perform supervision in cases when the pipeline owner or an operating organization regularly break the Rules, as well as in cases when the Party, which has made a survey agreement with the Register, violates it.

1.3.12 Materials and products used shall be subject to necessary surveys and tests during manufacture in the order and to the extent specified by the Register.

1.4 SCOPE OF SURVEYS

1.4.1 General.

1.4.1.1 The scope of surveys and classification covers the following stages of activities:

review and approval of technical documentation;

survey of materials and products intended for construction and repair of pipelines;

supervision during construction and repair of subsea pipelines;

surveys of subsea pipelines in service;

assignment, confirmation, renewal and reinstatement of the class, making appropriate entries and issue of the Register documents.

1.4.1.2 Any alterations made on the part of builders and owners in respect of the pipeline materials and structures, to which the requirements of the Rules apply, shall be approved by the Register before they are put into service.

1.4.1.3 Controversial issues arising during surveys may be transferred by the pipeline owners directly to the Register Head Office.

1.4.2 Survey of materials and products.

1.4.2.1 Materials and products shall be manufactured in accordance with the technical documentation approved by the Register.

During surveys the Register may check compliance with structural, technological and manufacturing standards and processes, which are not regulated by the Rules, but which influence the fulfillment of the requirements of the Rules.

1.4.2.2 Materials, products and manufacturing processes that are new or submitted to survey for the first time shall be approved by the Register. Specimens of materials and products or new manufacturing processes shall be tested according to the program and in the scope agreed with the Register subsequent to their technical documentation being approved by the Register.

1.4.2.3 The Register may perform supervision during manufacture of materials and products in the following forms:

survey by a Surveyor;

survey by an enterprise recognized by the Register;

survey in the form of the documentation approval by the Register;

survey on behalf of the Register.

The form of survey is selected by the Register when an agreement on technical supervision is made by the Register.

1.4.2.4 During survey materials and products shall be subjected to necessary tests according to the procedures and within the scope prescribed by the Register. The materials and products shall be provided with the documents specified by the Register and, where necessary, the brands confirming the fact of their survey, and marking enabling to determine their compliance with the above documents.

1.4.3 Technical supervision during construction, operation and repair of subsea pipelines.

1.4.3.1 Supervision during construction of subsea pipelines is performed by Surveyors to the Register in compliance with the technical documentation approved by the Register. The scope of inspections, measurements and tests to be conducted during supervision is established by the Register with respect to the specific conditions for the pipeline.

1.4.3.2 During operation of the subsea pipeline their owners shall keep the terms of periodical and other surveys prescribed by the Register and properly prepare the pipeline for the surveys.

1.4.3.3 Pipeline owners shall notify the Register of emergencies and repairs of the pipeline and pipeline components covered by the requirements of the Rules that have taken place between the surveys.

1.4.3.4 Where the new components covered by the requirements of the Rules have been installed on the pipeline during its operation or repair, the provisions of 1.4.2, 1.4.3.1 to 1.4.3.3 shall be applied.

1.4.4 Types and frequency of surveys.

1.4.4.1 Pipelines are subject to the following surveys:

initial survey performed under supervision of the Register during construction of the subsea pipeline for issuing of the appropriate certificates;

initial survey of subsea pipelines constructed under supervision of another classification society or another competent organization;

special surveys for renewal of class and issue of the appropriate certificates that are generally performed with five-year intervals of the subsea pipeline operation;

intermediate surveys for confirmation of the appropriate certificates;

mandatory annual surveys for confirmation of the certificate validity, which are performed every calendar year with not more than ± 3 months before or after each anniversary date of the special survey;

occasional surveys after accidents, repairs an in other necessary cases.

1.4.4.2 Initial survey is performed with the aim to assign an appropriate class to the subsea pipeline that is initially submitted to the Register for classification. The subsea pipelines that were earlier classed by the Register, but which class was cancelled by whatever reason, are also subject to initial survey. Initial survey includes thorough examination, inspections, tests and measurements, the scope of which is specified by the Register in each case depending on the environmental conditions of the pipeline operation, age of the pipeline, measures of its protection, technical condition of the pipeline, coatings, fittings, etc.

1.4.4.3 Subject to initial survey are the subsea pipelines constructed not in accordance with the Register rules, without supervision of the Register or an organization authorized by the Register to work on its behalf. In such cases, initial survey means thorough and overall survey, which shall be performed, where necessary, together with testing of the pipelines and components with the aim to confirm their compliance with the requirements of the Rules. Where documents issued for the subsea pipeline by an organization recognized by the Register are available, initial survey is performed within the scope of periodical survey. In case the required technical documentation is not available to the full extent, the survey program may be extended for the components, the documentation on which is missing.

1.4.4.4 Surveys performed during construction of subsea pipelines aim at verifying compliance of the materials, components and manufacturing processes with the requirements of the technical design and detailed design documentation on the subsea pipeline. The scope of survey is subject to special consideration by the Register in each particular case.

The date of the pipeline survey upon completion of construction is the date of actual completion of the survey and issue of the Classification Certificate for Subsea Pipeline.

1.4.4.5 Periodical survey means thorough survey, which is performed, where necessary, together with testing of pipelines, fittings, pump and compressor units and aimed at making sure that they are in a satisfactory condition and meet the requirements of the Rules, as well as at renewing of the appropriate certificates. Periodical surveys are performed at regular intervals established by the Register.

1.4.4.6 Mandatory annual survey means survey of the subsea pipeline, including fittings, pump and compressor units, other components, in the scope adequate to confirm that the pipeline and its components keep complying with the requirements of the Rules, its class being thus confirmed.

Mandatory annual surveys shall be performed every year within three months before and after the anniversary date.

1.4.4.7 During annual surveys of pipelines their testing in operation by applying a pressure and temperature and using the limit parameters of the pumps and compressors shall be combined with testing in operation of their pump and compressor stations, shut-off and safety valves, remote-operated drives.

1.4.4.8 Intermediate surveys of the subsea pipeline shall be carried out between periodical surveys within the terms specified by the Register.

1.4.4.9 Occasional surveys of the subsea pipelines or their individual components are performed upon submission for survey in all cases other than initial and periodical surveys. Occasional survey is carried out to evaluate significance of the detected defects or damages after an accident, including those that result in pipeline leaks, spillage of fluids and emissions of gaseous substances conveyed.

The scope and procedure of the surveys are defined by the Register on the basis of the survey purpose, age and technical condition of the subsea pipeline.

1.4.4.10 Occasional survey after an accident aims at identifying the type and nature of the damage, scope of work to be done for elimination of the accident consequences and at determining a possibility and conditions of retainment of class after elimination of the consequences.

1.4.5 Documents issued by the Register upon completion of the survey.

1.4.5.1 The Register documents are issued upon confirmation of the satisfactory assessment of the technical condition of the item of supervision made during surveys and tests.

1.4.5.2 The document that confirms compliance with the requirements of the Rules for the Classification and Construction of Subsea Pipelines is a Classification Certificate.

1.4.5.3 Other documents (reports, protocols, records, log books, etc.) may be issued by the Register in the course of supervision of subsea pipelines.

1.4.5.4 The Register may recognize fully or partially the documents of other classification societies, supervisory bodies and other organizations.

1.4.5.5 The Classification Certificate becomes invalid in the following cases:

upon expiry;

in case the subsea pipeline and its components are not submitted for periodical survey within the specified time with regard to the delays provided for periodical surveys in the present Rules;

after repair conducted without the Register supervision or replacement of the components covered by the present Rules;

in case the subsea pipeline is not in fit technical condition providing its safety;

when the pipeline is used for the purpose and under operational conditions different from those indicated in the class notation.

1.5 TECHNICAL DOCUMENTATION

1.5.1 Prior to commencement of the subsea pipeline construction, technical documentation, which allows ascertaining that the requirements of the Register Rules for this subsea pipeline are met, shall be submitted to the Register for review.

The scope of the technical documentation is specified in 1.5.2 to 1.5.11.

1.5.2 General:

specification;

drawings (diagrams) of pipeline routing;

list of components and equipment with indication of the main technical characteristics, manufacturer and approval by the Register or another competent body.

1.5.3 Documentation for pipes.

1.5.3.1 The technical documentation to be submitted shall contain the dimensions, materials, technique and procedure for pipe welding. To be presented are:

drawings of pipe edge preparation for welding;

drawings of pipeline sections;

drawings of pipe strings (where pipes are laid in bundles);

procedure for pipe welding;

types and scope of tests;

methods and scope of non-destructive testing.

1.5.3.2 The following information and calculations shall be submitted together with the drawings:

description of the laying method of the subsea pipeline on the seabed;

necessary information for determination of external loads (forces and moments) due to wind, currents, water, ice and other parameters to be taken into account in the pipeline strength analysis;

calculation of the pipe wall nominal thickness for appropriate load combinations;

results of the required model tests, which may be used for confirmation or more accurate definition of substantiation and calculations;

pipeline strength calculations during laying.

1.5.4 Documentation on weights used for the pipeline ballasting:

.1 calculation of buoyancy (buoyant force) of the undersea pipeline;

.2 arrangement plan of ballast weight;
.3 design drawings of the ballast weight construction;
.4 ballasting calculations for the subsea pipeline when using concrete coated pipes.
1.5.5 Documentation on fittings and their drives:
.1 arrangement plan for shut-off and safety fittings;
.2 test reports for fittings that confirm their suitability for the media to be conveyed and anticipated operational conditions;
.3 diagram of the pipeline fittings remote control;
.4 design drawings of drives.
1.5.6 Documentation on shore crossings:
.1 description of the subsea pipeline run to the shore;
.2 design drawings of shore crossing.
1.5.7 Documentation on laying the pipeline on the seabed:
.1 description of a method for laying the pipeline on the seabed (above the sea ground, into the trench, into the trench with subsequent backfilling);
.2 laying process flow sheet;
.3 design drawing of the trench;
.4 calculations of underwater earthwork operations in trench digging;
.5 calculations of underwater earthwork operations in trench backfilling.
1.5.8 Documentation on alarm systems:
.1 diagram of the alarm system that keeps under control conveyed medium characteristics, pump and compressor parameters; shut-off valve position;
.2 certificates for instrumentation, sound and light sources for instruments and other components of the alarm system.
1.5.9 Documentation on corrosion-resistant protection:
.1 substantiation for selection of the pipeline corrosion-resistant coating;
.2 scheme of the pipeline corrosion-resistant coating;
.3 instructions on preparation of the pipeline surface and application of protective coatings;
.4 cathodic protection scheme (anode arrangement);
.5 determination of anode weight.
1.5.10 Documentation on automation of subsea pipeline operation.
The amount of documentation on automatic devices and automation systems is subject to special consideration by the Register in each particular case.
1.5.11 Where new components that are significantly different from the original ones and that are covered by the requirements of the present Rules are mounted on the subsea pipeline in operation, it is necessary to submit to the Register for review and approval the additional technical documentation for new products in the scope required for the subsea pipeline under construction.
1.5.12 In cases referred to in 1.3.6, the amount of technical documentation to be submitted to the Register is subject to special consideration by the Register in each particular case.

1.5.13 The standards for individual materials and products agreed upon with the Register may substitute an appropriate part of the technical documentation.

1.5.14 Prior to their implementation, amendments made in the technical documentation approved by the Register and dealt with the components and structures covered by the requirements of the Rules shall be submitted to the Register for approval.

1.5.15 The technical documentation submitted to the Register for review and approval shall be prepared in such a way or supplied with such additional information that it enables to make sure that the requirements of the Rules are met.

1.5.16 The calculations necessary for determination of the parameters and values regulated by the present Rules shall be made in compliance with the provisions of the present Rules or according to the procedures agreed upon with the Register. The procedures and methods used for calculations shall provide an adequate accuracy of the problem solution. Computer-aided calculations shall be made in accordance with the programs having a Type Approval Certificate. The Register may require performance of check calculations with the aid of any programme. The Register does not check the correctness of computing operations in calculations. The basic regulations regarding approval of the computer-aided calculation programmes and the calculation procedures are given in 12.2, Part II "Technical Documentation" of the Rules for Technical Supervision during Construction of Ships and Manufacture of Materials and Products for Ships".

1.5.17 Standards and normative documents on materials and products shall be agreed upon for the period of their validity. When revising the standards and normative documents, they shall be verified to take account of the requirements of the current rules and regulations of the Register.

1.5.18 The Register approval of the technical documentation is valid for a period of six years. Upon expiry of this term or in case where the interval between the date of approval and commencement of the pipeline construction exceeds three years, the documentation shall be verified and updated to take account of the amendments to the Register rules.

1.5.19 Approval of technical documentation is acknowledged by putting on it the appropriate stamps of the Register. The approval of the documentation by the Register does not relate to the elements and structures contained therein, to which the requirements of the Rules are not applicable.

2 LOADS ACTING ON SUBSEA PIPELINES

2.1 Design loads acting on the subsea pipeline shall take into consideration operating conditions, test loads and loads during the pipeline assembly. Each type of loads defined in 2.2 to 2.8 shall be multiplied by significance factor γ. The values of factors are given in Table 2.1.

Table 2.1

Significance factors of load components γ

Type of load	γ
Weight of pipeline and auxiliary structures	1,1
Internal pressure:	
for gas pipelines	1,1
for oil- and petroleum product pipelines	1,15
External water pressure with regard to water level changes due to tides and waves	1,1
Covering ground pressure in case the pipeline is layed in a trench	1,4
Pipeline icing in case the products with temperature below zero are transported	1,4
Seismic forces	1,1
Current force	1,1
Wave force	1,15
Wind force	1,1
Temperature action	1,0

2.2 Design operational pressure in the pipeline p_0, in Pa, is determined by the formula

$$p_0 = \max(p_i + p_{e1}, p_i + p_{e2}) + \Delta p \tag{2.2-1}$$

where p_i = internal working pressure in the pipeline, in Pa, is determined in accordance with the pipeline design specification. In calculations the internal pressure is taken with the "plus", external pressure – with the "minus";

p_{e1}, p_{e2} = external hydrostatic pressure on the pipeline, in Pa, is determined from the formulae:

$$p_{e1} = \rho_w g\left(d_{\max} + \frac{h_w}{2}\right), \tag{2.2-2}$$

$$p_{e2} = \rho_w g\left(d_{\min} + \frac{h_w}{2}\right);$$

ρ_w = sea water density, in kg/m^3;

g = acceleration of gravity, in m/s^2;

$d_{\max}$, $d_{\min}$ = the highest and the lowest still water levels, in m, taking into account tides and bottom water sets, and determined as a result of the long-term period of observations;

h_w = design wave height on the pipeline design section determined as a result of the long-term period of observations;

Δp = full pressure of a hydraulic impact in the pipeline, in Pa, which is used only for the pipelines, in which a probability of hydraulic impact occurrence exists due to operational conditions, determined from the formula

$$\Delta p = V_{int} \sqrt{\frac{\rho_{int} E t_c K}{E t_c + D_{int} K}} \qquad (2.2\text{-}3)$$

where D_{int} = internal diameter of the pipe, in mm;
t_c = wall thickness of the pipe, in mm;
E = Young's modulus of the pipe material, in Pa;
K = bulk modulus of the conveyed gas or petroleum product, in Pa;
ρ_{int} = density of the conveyed gas or petroleum product, in kg/m^3;
V_{int} = velocity of the conveyed gas or petroleum product, in m/s.

Where special structural measures for reduction of hydraulic impact (such, as limitation of the shut-down speed for fittings, special devices for protection of the linear pipeline section against transient processes, etc.), the Δp value may be reduced in calculations by the value agreed upon with the Register.

2.3 The axial force due to temperature fluctuations shall take account of the loads arising from the changes in the pipeline length under the effect of temperature changes. Temperature difference in the pipe wall metal shall be assumed equal to the difference between the maximum and the minimum possible wall temperatures during operation and laying. The maximum and the minimum temperatures of pipeline walls during operation shall be determined depending on the environmental temperature, conveyed medium temperature, intensity of thermal interface between the pipeline and the environment.

2.4 The total linear load due to weight forces shall take into account weight of pipes, protective coatings, concrete coatings and ballast, different pipeline components (anodes, fittings, T-joints, etc.), conveyed medium, buoyancy forces. Besides, where a pipeline is laid into a trench, it is necessary to take account of a backfilling ground pressure. In case the pipeline is laid on the ground, and the temperature of the conveyed medium may be below zero, in buoyancy force calculations the possible icing of the pipelines shall be considered.

2.5 Linear loads: horizontal $F_{c,g}$, vertical $F_{c,v}$ and total F_c due to current, in N/m, are determined from the formulae:

$$F_{c,g} = c_x \frac{\rho_w V_c^2}{2} D_a, \qquad (2.5\text{-}1)$$

$$F_{c,v} = c_z \frac{\rho_w V_c^2}{2} D_a, \qquad (2.5\text{-}2)$$

$$F_c = \sqrt{F_{c,g}^2 + F_{c,v}^2} \qquad (2.5\text{-}3)$$

where V_c = design current velocity at the depth of the pipeline installation, in m/s;
ρ_w = sea water density, in kg/m^3;

c_x = pipeline resistance factor determined from Fig. 2.5-1.

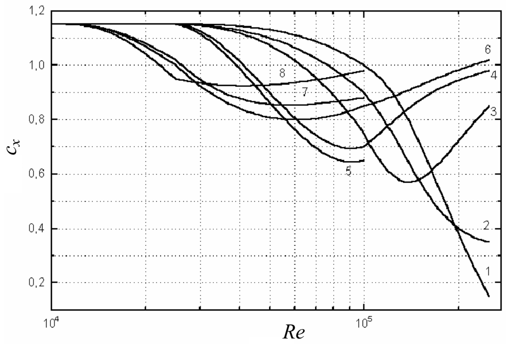

Fig. 2.5-1 Dependence of c_x factor from the Reynolds number and relative roughness of the pipeline surface:
1 – $k = 0$; 2 – $k = 5{,}0 \cdot 10^{-4}$; 3 – $k = 2{,}0 \cdot 10^{-3}$; 4 – $k = 40 \cdot 10^{-3}$; 5 – $k = 5{,}0 \cdot 10^{-3}$;
6 – $k = 5{,}0 \cdot 10^{-3}$; 7 – $k = 9{,}0 \cdot 10^{-3}$; 8 – $k = 2{,}0 \cdot 10^{-2}$

$c_x = c_x(k, Re)$

where $k = k_0/D_a$ is the pipeline roughness factor;

k_0 = roughness ridge value, m;

Re = Reynolds number.

$$Re = \frac{V_c D_a}{\nu};$$

D_a = pipeline outside diameter, in m;

$\nu = 1{,}2 \cdot 10^{-6}$, in m^2/s, is seawater kinematic viscosity;

c_z = factor for on-bottom pipeline assumed equal to 0,8.

For pipelines laid at the distance d from the seabed, factors c_x and c_z are calculated according to the diagram in Fig. 2.5-2.

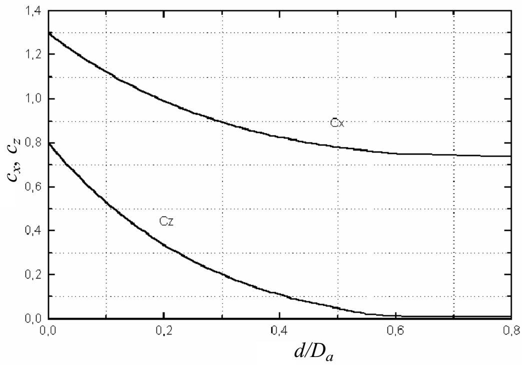

Fig. 2.5-2 Factors c_x and c_z depending on the relative distance of the pipeline from the seabed d/D_a

2.6 Linear wave load on the pipeline is calculated as superposition of resistance forces $F_{w,s}$ and inertia forces $F_{w,i}$, in N/m:

$$F_{w,s} = c_d \frac{\rho_w V_w |V_w|}{2} D_a \,,$$

$$F_{w,i} = c_i \frac{\rho_w a_w}{2} D_a^2 \,. \tag{2.6-1}$$

Design velocities and accelerations of the wave flow of the water particles at the pipeline level are calculated in accordance with the procedure for determination of environmental parameters for design of sea pipeline section.

The total wave linear load F_w, in N/m, is determined by the formula

$$F_w = \sqrt{F_{w,s}^2 + F_{w,i}^2} \,. \tag{2.6-2}$$

The vertical wave linear load $F_{w,v}$, in N/m, is determined by the formula

$$F_{w,v} = c_v \frac{\rho_w V_w^{\,2}}{2} D_a \,. \tag{2.6-3}$$

Factors c_d, c_i and c_v are determined depending on the Reynolds number and the pipeline relative surface roughness k.

2.7 Linear wave loads F_s, in N/m, due to wave impacts on the pipeline surface, for a pipeline section crossing or close to the water surface are determined by the formula

$$F_s = 1{,}6\, \rho_w V_{w,s}^2 D_a \tag{2.7}$$

where $V_{w,s}$ = a design velocity of the water particles in the surface wave, in m/s.

2.8 Linear wind loads F_{wd}, in N/m, for the pipeline sections at a distance z, in m, above the still water level are determined by the formula

$$F_{wd} = 0{,}23\, \rho_a V_{wd}^2 z^{0,2} D_a \tag{2.8}$$

where ρ_a = air density, in kg/m^3;
V_{wd} = design wind velocity, in m/s.

2.9 Pipelines laid on the seabed in freezing seas with intensive exaration of the seabed by ice shall be protected against the ice effects by burying into the sea ground. The burying depth (distance from the seabed surface to the upper point of the pipe with regard to insulation) is determined on the basis of field studies of the ice gouging depth or statistical modeling, provided sufficient initial data are available; it may also be assumed in the first approximation according to Table 2 of Annex 1.

2.10 Pipeline sections in water areas with seasonal movement of sea ground caused by intensive river flow and specific environmental features (e.g., fast ice) shall be buried in the sea ground for the depth determined by the formula

$$h = h_{max} + \Delta h \qquad (2.10)$$

where h_{max} = the maximum depth of the seasonal movement of sea ground determined from the results of field studies of the pipeline section continuously during 5 years;

Δh = 1 m or according to Table 2 of Annex 1.

2.11 Loads during the pipeline assembly under keeping of standard environmental conditions (wind, waves, water and air temperatures) and assembly procedure are determined depending on the laying procedure and environmental conditions.

2.12 Seismic resistance of the pipeline at the design stage shall be checked by a spectral method for an earthquake with probability once in 1000 years. The maximum stresses in the pipe shall not exceed the yield stress of the material. The calculation scheme shall take into consideration the insulation weight, conveyed medium ballast and virtual masses of entrained water.

3 STRENGTH OF SUBSEA PIPELINES

3.1 GENERAL

3.1.1 Strength calculations of the subsea pipelines shall be based on the classical or semi-empirical procedures that take into consideration material resistance parameters of the deformed pipe and actual loads acting on the pipe.

3.2 DETERMINATION OF THE PIPELINE WALL THICKNESS

3.2.1 Selection of the subsea pipeline wall thickness, which is one of the most important design stages, shall be based on the necessity to ensure the pipeline strength (stability) and required safety level. The calculations shall be made for the most unfavorable combination of possible loads.

3.2.2 The wall thickness of the pipeline is determined based on the following conditions:

local strength of the pipeline characterized by the maximum values of hoop stresses;

adequate local buckling of the pipeline.

3.2.3 The wall thickness t_c of the pipeline, in mm, based on local strength calculations, is determined by the formula

$$t_c = \frac{p_0 D_a}{2\varphi\sigma} + c_1 + c_2 \qquad (3.2.3)$$

where p_0 = design (operational) pressure in the pipeline determined in accordance with 2.2;
D_a = outer diameter of the pipe, in mm;
σ = permissible stresses of the pipe material (refer to 3.2.5), in MPa;
φ = strength factor determined depending on the pipe welding method (refer to 3.2.4);
c_1 = corrosion allowance (refer to 7.2.4 and 7.2.5), in mm;
c_2 = manufacture tolerance, in mm.

3.2.4 Strength factor φ is taken equal to one for seamless pipes and approved welded pipes recognized as being equivalent to seamless pipes.

For other welded pipes the value of strength factor is subject to special consideration by the Register in each particular case.

3.2.5 Permissible stress σ shall be taken equal to the least of the following values:

$\sigma = R_e/n_y$,
$\sigma = R_m/n_t$

where R_e = the minimum value of yield stress of the pipe metal;
R_m = the minimum value of tensile strength of the pipe metal;
n_y = strength factor in terms of yield stress of the pipe metal;
n_t = strength factor in terms of the tensile strength of the pipe metal.

The values of n_y and n_t are given in Table 3.2.5.

Table 3.2.5

Strength factors for subsea pipelines

Underwater section	Shore and offshore sections in protected area*
n_y = 1,5 n_t = 2,6	n_y = 1,7 n_t = 2,7
Notes: 1. The protected area of the offshore pipeline area is parts of the main pipeline from the shore compressor stations to the shoreline and further along the seabed at a distance not less than 500 m. 2. On agreement with the Register factors n_y and n_t may be reduced in making overall and local strength calculations, having regard to the particular local conditions in the area of pipeline laying and geometry of pipeline position on the sea ground.	

3.2.6 The maximum total stresses caused by the internal and external pressures, longitudinal forces, as well as external loads referred to in Section 2 with regard to the pipelines out-of-roundness shall not exceed permissible stresses:

$$\sigma_{max} = \sqrt{\sigma_x^2 + \sigma_h^2 - \sigma_x\sigma_h + 3\tau} \leqslant k_\sigma R_e \qquad (3.2.6)$$

where σ_x =total longitudinal stresses;
σ_h =total hoop stresses;
τ = tangential (shear) stresses.

k_σ is taken equal to 0,8 for normal operational conditions and to 0,95 for short-term loads during construction and hydraulic tests.

3.2.7 In general case, the wall thickness of the subsea pipeline shall be sufficient, having regard to all loads arising during assembly, laying, hydraulic tests and operation of the pipeline.

3.3 SUBSEA PIPELINE CALCULATIONS FOR STRENGTH (BUCKLING) UNDER THE EFFECT OF HYDROSTATIC PRESSURE

3.3.1 Along with the calculations for the internal pressure effect, the subsea pipeline shall be mandatory subjected to strength calculations in terms of outside hydrostatic pressure p_e (refer to 2.2) capable to cause buckling of the pipeline wall at certain depths or cause hoop compressive stresses in excess of the permissible values (refer to 3.2.6).

3.3.2 Strength calculations of subsea pipelines for pure buckling shall be made for the most unfavorable conditions, i.e. for the minimum possible internal pressure and the maximum hydrostatic pressure:

generally the minimum internal pressure takes place during construction and drying of the pipeline internal surface after hydraulic tests (in such cases, it will be equal to the atmospheric pressure or even less where vacuum is used for drying);

the maximum water depth corresponds to the maximum hydrostatic pressure, taking into account the tides and bottom water sets, seasonal and many-year fluctuations of the sea level.

In strength and local stability analysis of the pipeline cross-section against outside hydrostatic pressure, an internal pressure in the pipeline shall be assumed equal to 1 MPa.

3.3.3 The value of the critical outside pressure to the pipeline p_e, in MPa, that causes buckling of the cross-section but does not initiate plastic deformations in the pipe wall (so called elastic buckling) may be determined by the formula

$$p_e = \frac{2E}{1-\nu^2}\left(\frac{t_c}{D_a}\right)^3 \qquad (3.3.3)$$

where E =Young's modulus of the material, in MPa;
ν = Poisson's ratio;
D_a = outside diameter of the pipe, in mm;
t_c = wall thickness of the pipe, in mm.

3.3.4 Depending on elastic and plastic properties of the pipe material and with certain relationship between the pipe diameter and wall thickness, the level of hoop compressive stresses may reach the yield stress with an increase of the external load even before buckling occurs. The value of buckling pressure p_y , in MPa, is determined by the following formula:

$$p_y = 2R_e \frac{t_c}{D_{int}} \tag{3.3.4}$$

where D_{int} = internal diameter of the pipe, in mm;
t_c = wall thickness of the pipe, in mm;
R_e = yield stress of the pipe material, in MPa.

3.3.5 The bearing capacity of the subsea pipeline cross-section for pure buckling under the external pressure may be checked by the following calculation:

$$p_c = \frac{p_y\, p_e}{(p_y^2 + p_e^2)^{½}} \tag{3.3.5-1}$$

where critical loads in connection with elastic and plastic buckling are determined from dependencies (3.3.3) and (3.3.4). Formula (3.3.5-1) is valid for the conditions when $15 < D_a/t_c < 45$ and initial (based on manufacture allowance) out-of-roundness does not exceed 0,5 per cent.

Out-of-roundness is determined by the formula

$$U = \frac{D_{a\max} - D_{a\min}}{D_a}. \tag{3.3.5-2}$$

The permissible total out-of-roundness, including the initial one, shall not exceed 1,0 per cent.

3.4 SUBSEA PIPELINE ANALYSIS FOR LOCAL BUCKLING

3.4.1 Local buckling means buckling of the pipe initial shape in the form of breaking or distortion under the external hydrostatic pressure, longitudinal forces and bending moment.

3.4.2 Analysis of the subsea pipeline for buckling under the loads referred to in 3.4.1 is made according to the following inequality:

$$\left(\frac{p_0}{p_c}\right)^{k_1} + \left(\frac{M}{M_c}\right)^{k_2} + \left(\frac{T}{T_c}\right)^{k_1} \leqslant \frac{1}{n_c} \tag{3.4.2-1}$$

where p_c = critical pressure, which causes local buckling of the pipe and is determined by Formula (3.3.5-1);
M_c = critical bending moment determined by the formula

$$M_c = (D_{int} + t_c)^2 t_c R_e; \tag{3.4.2-2}$$

T_c = critical longitudinal force that may be determined by the formula

$$T_c = \pi(D_{int} + t_c) t_c R_e; \tag{3.4.2-3}$$

p_0 = design operational pressure acting in the subsea pipeline (refer to 2.2);
M = design bending moment with regard to lateral forces due to waves, wind, current and bending moments during pipeline laying by various methods;
T = design longitudinal force with regard to longitudinal forces during pipeline laying by different methods (refer to 8.4);
p_c, M_c and T_c = bearing capacity of the pipeline regarding separate types of acting loads, rated values of individual force factors, provided there are no other types of loads;
D_{int}, t_c, R_e, refer to 3.3.4;
n_c = safety factor;
k_1, k_2, k_3 = factors determined experimentally on the pipe specimens under the combined loads, using the procedure approved by the Register. Where inequality 3.4.2-1 is met with $k_1 = k_2 = k_3 = 1$, no more exact determination is further required.

Safety factor n_c is taken equal to 1,2 and may be reduced on agreement with the Register after performance of experiments on the pipe specimens.

It is necessary to take into consideration in the calculations that when the pipeline is laid at sea depths more than 1000 m with bending strain being fully controlled, the permissible bending strain shall not exceed 0,15 per cent, and the critical value of bending strain at such depths shall not exceed 0,4 per cent.

3.4.3 In the calculations of subsea pipelines for stability (buckling), the value of yield stress in compression under the combined effect of bending and compression shall be taken equal to 0,9 of the minimum pipe material yield stress.

3.5 SUBSEA PIPELINE ANALYSIS FOR PROPAGATION BUCKLING

3.5.1 Propagation buckling means propagation of the local buckling of the undersea pipeline cross-section along the pipeline route. Propagation buckling occurs when the external hydrostatic pressure at large depths exceeds the critical value p_p.

3.5.2 The critical value of hydrostatic pressure p_p, in MPa, at which propagation buckling may occur is determined by the formula

$$p_p = 24R_e\left(\frac{t_c}{D_a}\right)^{2,4} \tag{3.5.2}$$

where t_c = wall thickness of the pipe, in mm;
D_a = outside diameter of the pipe, in mm;
R_e = yield strength of the pipe material, in MPa.

Where the hydrostatic pressure acting on the subsea pipeline or its segment exceeds the critical value, special arrangements shall be taken to avoid propagation buckling.

3.5.3 In order to prevent occurrence of propagation buckling (for subsea pipeline protection) the following measures may be taken:

increase in wall thickness of the pipeline along with increase of the sea depth;

provison of buckle arrestors.

3.6 SUBSEA PIPELINE ANALYSIS FOR FATIGUE

3.6.1 Pipeline strength shall be analysed against the fatigue criterion on the basis of the linear cumulative damage rule:

$$\sum_{i=1}^{m} \frac{n_i(\Delta\sigma_i)}{N_i(\Delta\sigma_i)} \leqslant \frac{1}{n_f} \qquad (3.6.1)$$

where m = number of stress blocks;
$n_i(\Delta\sigma_i)$ = number of stress cycles in each stress block;
$N_i(\Delta\sigma_i)$ = appropriate points on the pipe material fatigue curve in each stress block;
$\Delta\sigma_i$ = change in stresses during a stress cycle to be determined as an algebraic difference of the highest and the lowest stresses during a cycle;
n_f = safety factor equal to 10.

3.6.2 Fatigue strength assessment shall take into account asymmetric nature of cycle stress and two-dimensional stress of the pipe material.

3.6.3 The pipe material fatigue curve may be obtained by means of special tests or taken from an applicable international or national standard (such as GOST 25859-83).

3.6.4 The following shall be taken into consideration in fatigue analysis:
operational cycles of pressure fluctuations between start and stop;
stress cycles during repeated pressure tests;
stress cycles caused by constraint of temperature deformation in operation;
vibration caused by vortex separation due to underwater currents.

4 MATERIALS

4.1 Materials and products used in manufacture and installation of the subsea pipeline systems are subject to survey by the Register in compliance with the procedure and in the scope established by the requirements of Part XIII "Materials" of the Rules for the Classification and Construction of Sea-Going Ships.

4.2 Process requirements for materials and products containing all the information necessary for order, manufacture and acceptance of the products shall be submitted to the Register for approval in the form of specifications attached to the technical design.

4.3 Materials and products used for the subsea pipeline systems shall comply with the requirements of the appropriate national or international standards recognized by the Register. In case of differences between these standards and the requirements of Part XIII "Materials" of the Rules for the Classification and Construction of Sea-Going Ships, as well as those of Part XII of the Rules for the Classification, Construction and Equipment of Mobile Offshore Drilling Units (MODU) and Fixed Offshore Platforms (FOP)[1] one shall be guided by more stringent requirements.

[1] Hereinafter referred to as "the MODU/FOP Rules".

4.4 Materials for the pipelines conveying media with high hydrogen sulphide content are subject to special consideration by the Register. Scope of the tests and requirements for materials shall be agreed with the Register in each particular case, based on the specific operational conditions.

5 WELDING

5.1 In performance of welding operations on the pipelines and products for the subsea pipeline systems the requirements of Part XIV "Welding" of the Rules for the Classification and Construction of Sea-Going Ships and Part XIII "Welding" of the MODU/FOP Rules shall be met.

5.2 Welding consumables used in manufacture of the subsea pipeline systems shall be tested and approved by the Register in compliance with the requirements of Section 4, Part XIV "Welding" of the Rules for the Classification and Construction of Sea-Going Ships, as well as those of Chapter 4.2, Part XIII "Welding" of the MODU/FOP Rules. The level of the requirements imposed on weld metal and welded joints shall be assigned not lower than the relevant requirements for the base metal. One shall be guided by the requirements of the Register rules or appropriate national standards on manufacture of welding consumables in case they are more stringent than the requirements for the base metal.

5.3 Process requirements for manufacture of welded structures for the subsea pipeline shall comply with the provisions of Section 2, Part XIII "Welding" of the MODU/FOP Rules.

5.4 Welders certified by the Register to weld subsea pipelines and components for the subsea pipeline systems shall be qualified in accordance with the requirements of Section 5, Part XIV "Welding" of the Rules for the Classification and Construction of Sea-Going Ships.

5.5 Approval of welding procedures used in manufacture of the subsea pipeline systems shall comply with the requirements of Section 6, Part XIV "Welding" of the Rules for the Classification and Construction of Sea-Going Ships. Pre-production welding tests to be conducted under production conditions on full-scale product specimens shall be the principal type of the tests. Welding procedure tests shall be normally supplemented by tests during production conducted according to the procedure and in the scope approved by the Register.

5.6 The requirements for inspection of welded joints of the subsea pipeline structures shall be set having regard to the provisions of Section 3, Part XIII "Welding" of the MODU/FOP Rules.

6 BALLASTING OF SUBSEA PIPELINES

6.1 GENERAL

6.1.1 Ballasting of the subsea pipeline is required for positive buoyancy compensation and for ensurance of stability on the sea ground by creating resistance to horizontal and vertical displacements caused by current forces and hydrostatic pressure ejection, as well as for protection against impacts during transportation, assembly and in operation.

6.1.2 Ballasting of subsea pipelines may be performed using continuous bulk concrete and asphalt concrete coatings applied on the insulation as well as by placing single cast iron, reinforced concrete and concrete weights.

6.1.3 Split hinged or split saddle-shaped weights made of cast iron and reinforced concrete as well as other constructions approved by the Register may be used as single weights.

6.1.4 Pipeline weight including weight of the pipes, insulation, weight coating lining, if any, weights, etc. shall ensure the weight force sufficient for creating negative buoyancy to the pipeline. The value of this force shall be equal to the difference between the pipeline weight with all components and coatings in the air, and the weight of the water displaced by the pipeline.

6.1.5 Calculation of ballasting for the pipeline for conveying hydrocarbons shall be made irrespective of the purpose (type of the conveyed medium) and environmental conditions in the area of the pipeline route as for the empty pipeline. Weight of the product conveyed is neglected.

6.1.6 Calculation of the ballast required and spacing between the single ballast weights shall be made based on the conditions for creating negative buoyancy to the pipeline, displacement resistance due to current, natural curvature during laying, pipeline curvature on the seabed.

6.2 CONTINUOUS WEIGHT COATINGS

6.2.1 Concrete coating.

6.2.1.1 Design, calculation of principal parameters and application procedure of continuous concrete weight coating shall be based on the national state and branch standards, international standards related to concrete structures, such as Eurocode No. 2 (Design of concrete structures), EN 10080 (Steel for the reinforcement of concrete).

6.2.1.2 Initial parameters for the continuous weight coating are:

specific weight/weight in water;

coating thickness;
density;
compression strength;
water absorption;
impact strength;
bending strength (flexibility).

6.2.1.3 The minimum thickness of the continuous coating shall be not less than 40 mm.

6.2.2 Raw materials for concrete making.

6.2.2.1 Properties and technical characteristics of raw materials for coating (cement, aggregates, reinforcement, water, etc.) shall comply with a performance specification, passport data and purchase specification.

6.2.2.2 Cement. Cement of domestic grades 300 and 400 and other cement grades meeting the requirements of EN 197, BS 12, ASTM-C-150, DIN 1164 or other international or national standards and regulations may be used for the concrete weight coating.

6.2.2.3 Concrete aggregates shall comply with the requirements of the national standards or regulations used in manufacture of the continuous concrete coatings.

The aggregates shall not contain harmful constituents in such quantities that could affect the concrete strength, for example, in pipeline bending or cause corrosion of reinforcing materials in case of water permeability of the concrete.

Use of aggregates with alkali-sensitive constituents is strictly forbidden.

The maximum grain size and grading[1] curve of the aggregate shall comply with EN 206, ASTM C-33 or other recognized standards.

The maximum grain size of gravel, iron or barium ore used as aggregates shall not exceed 10 mm.

6.2.2.4 Water for mixing concrete shall not contain harmful constituents in such quantities that could impair cement (concrete) curing, stiffening and strength or cause corrosion of reinforcing materials. Fresh water is normally used for concrete mixing.

6.2.3 Reinforced concrete coating.

6.2.3.1 Concrete. Composition of the concrete, aggregate and water (refer to 6.2.2.1 to 6.2.2.4) shall be such that all the requirements for properties of stiffened and cured concrete, including its consistency, bulk density, strength and durability, as well as reinforcement protection against corrosion, are met.

Concrete shall comply with the following requirements:
the minimum bulk density after curing shall be 2200 kg/m^3;
water absorption does not exceed 5 per cent;

---

[1] Grading, grain-size analysis means the combination of methods for measurement of grain sizes in various media.

durability at the operating temperature is equal to the lifetime of the subsea pipeline;

the minimum compression strength in a month after curing is 40 MPa.

The compression strength of the concrete shall be determined by standard test procedures (e.g., in accordance with EN 206, ASTM C-42, BS 1881 or the national standards) applied to test specimens made from the batches cut from the concrete coated pipes (e.g., according to BS 4019, BS 6089).

6.2.3.2 Reinforcement. Steel reinforcement for the reinforced concrete shall consist of cylindrical cages mounted of resistance welded longitudinal and hooped mild steel reinforcement or other reinforcement as required by the procedure approved by the Register. Steel reinforcement may be applied in the form of thin bars, reinforcing mesh or helical reinforcement.

Diameter, surface condition, strength characteristics and marking of steel reinforcements shall comply with the requirements of international and national standards (e.g., EN 10080, BS 4482 and BS 4483, DIN 488).

Recommendations on size and setting of steel reinforcements are given in Table 6.2.3.2-1.

Table 6.2.3.2-1

Recommended diameters of reinforcement

Geometrical parameters	Longitudinal reinforcement	Hooped reinforcement	Reinforcement type
Bar diameter, in mm Bar distance (spacing), in mm Percentage of coating sectional area	3 to 8 75 to 400 0,1 to 0,2	5 to 12 75 to 150 0,45 to 1,0	Welded cage
Bar diameter, in mm Bar distance (spacing), in mm Percentage of coating sectional area	2 to 4 50 to 300 min 0,08	2 to 4,0 65 to 100 min 0,4	Wire mesh
Alternative reinforcement materials, such as glass fiber may be used if they provide equivalent effective reinforcing.			

Diameters of steel bars for reinforcement in the form of cages shall be not less than 6 mm. The minimum spacing between hooped bars shall be 120 mm. The minimum cross-sectional area of longitudinal and hooped bars shall be 0,5 per cent and 0,08 per cent of the coating sectional area, respectively.

If a helical reinforcing mesh is used, the required number of layers depends on the concrete thickness and is determined from Table 6.2.3.2-2.

Table 6.2.3.2-2

Recommended number of layers of helical reinforcing mesh

Concrete thickness, in mm	Number of layers
0 — 60	1
61 — 100	2
101 — 140	3
>140	4

6.2.4 Composite coatings.

6.2.4.1 On agreement with the Register, asphalt- or bitumen-based coatings may be used as weight coatings of the subsea pipelines.

6.2.4.2 In an asphalt mastic-based weight coating use may be made of the aggregates in the form of glass fiber and heavy-weight particles. The volume weight of such coatings shall be at least 2,5 t/m^3.

6.2.4.3 An asphalt mastic-based weight coating shall be applied on the pipeline surface in hot state at temperature not higher than 140 °C. Upon application of the compound a layer of glass reinforced plastic is wound thereon, then the coating is pressed with pneumatic hammers and cooled down to the environmental temperature.

7 CORROSION PROTECTION

7.1 GENERAL

7.1.1 The entire external and internal surface of the subsea pipeline shall be protected with the corrosion-resistant coating. The type of the protective coating shall be selected depending on the pipeline structure and adopted method of laying. Elastic and strong coatings shall be used in cases where the pipeline is laid from a pipe-laying vessel by *S*- or *J*-method as well as by towing afloat with subsequent flooding. Where the pipeline is laid by seabed pull, the coating shall be strong enough to prevent damage from friction against the sea ground, which may be rocky. The coating shall be applied in factory conditions, on special site or on board a pipe-laying vessel.

7.1.2 An insulating corrosion-resistant coating shall comply with the specification requirements during the entire lifetime of the pipeline in terms of the following properties: breaking strength, elongation at the operational temperature, impact strength, adhesion to steel, the maximum area of sag in seawater, resistance to fouling, resistance to indentation.

7.1.3 The requirements for insulation of welded joints, reinforcement assemblies and fittings shall not be lower than those for the pipe insulation.

Insulation of connections of electrochemical protection devices and instrumentation, as well as insulation restored in damaged areas shall provide reliable protection of the pipe metal against corrosion.

7.1.4 Special arrangements shall be made to prevent mechanical damages to the protective insulating coating during transportation, handling operations and storage of pipes.

7.1.5 It shall be taken into consideration in design of corrosion protection that the metal, in the areas where the continuity of the protective (oxide) film or corrosion-resistant insulating coating is broken, has much more negative potential (becomes an anode) than the rest of the surface (cathode), and therefore deteriorates much more than the pipeline without any protective coating. The same processes might occur between the subsea pipeline sections that are covered and not covered with ground (sludge).

7.2 PROTECTION AGAINST INTERNAL CORROSION

7.2.1 For steel subsea pipelines transferring the corrosive conveyed media, arrangements shall be made to protect the internal surface of the pipeline against corrosion. Referred to such arrangements are:

increase of the pipe wall thickness with regard to corrosion allowance;

application of the corrosion-resistant pipe materials, such as stainless steels and alloys;

application of the corrosion-resistant coating on the internal surface of the pipes;

pre-treatment of hydrocarbons before transportation in order to remove water or other substances contributing to corrosion;

inhibition.

7.2.2 The method of corrosion protection selected shall be consistent with the pipeline operating conditions and comply with the requirements of the performance specification. Calculation results confirming the efficiency of the protection shall be approved by the Register.

7.2.3 The wall thickness of subsea pipelines shall be increased with regard to corrosion wear to compensate the loss of the pipeline strength resulting from the wall thinning due to overall uniform corrosion.

7.2.4 A necessity of introduction of the corrosion allowance and its value are based on consideration of the following factors:

design lifetime of the pipeline, corrosion activity of the conveyed medium and operating conditions;

suggested type of corrosion;

efficiency of additional measures on the pipeline protection to mitigate the corrosion processes, e.g., by chemical treatment of the conveyed media, coatings, etc.;

sensitivity of the internal corrosion instruments, frequency of inspections and checks;

consequences of accidental leakage of the conveyed media, reliability and safety requirements;

efficiency of the pipeline pressure monitoring system, etc.

7.2.5 The minimum corrosion allowance for carbon steel pipelines conveying non-aggressive media shall be at least 1 mm. For pipelines conveying the corrosive media, in particular liquid and gaseous hydrocarbons, likely to contain water, corrosion allowance shall be minimum 3 mm. For subsea pipelines made of stainless steel and alloys no corrosion allowance is required.

7.2.6 The following parameters shall be taken into consideration in case of using the pipelines made of stainless steel and alloys:

strength properties;

manufacturability, including weldability;

corrosion resistance.

7.2.7 When selecting corrosion-resistant coating, the following factors shall be taken into account:

chemical compatibility with hydrocarbons to be conveyed and with other substances, including probability of inhibition (refer to 7.2.8), likely to be contacted during assembly, laying and operation;

resistance to erosion effect of the conveyed media and to mechanical damages during cleaning of the internal surface of pipelines;

resistance to quick decompression;

availability of the reliable quality control systems of the basic coating of pipes and coating in the area of field joint.

7.2.8 For temporary protection of the internal surface against corrosion during storage, transportation and prior to filling, use shall be made of plugs and sockets, application of protective grease and wax, chemical treatment against fouling.

7.3 PROTECTION AGAINST EXTERNAL CORROSION

7.3.1 Coatings.

7.3.1.1 In order to protect the subsea pipeline against external corrosion, a corrosion-resistant insulating coating (normally multilayer) shall be applied. Where necessary, the external coating shall have an outside layer for protection against mechanical damage during tie-in operations and laying in/on hard sea ground. Field joint (weld) shall be protected with one- or multilayer coating.

7.3.1.2 The external coating shall be selected based on consideration of the following factors:

water permeability, solubility of gases and salts, adhesion, porosity, etc;

physical (mechanical), chemical and biological resistance, its diminution during storage and operation;

compatibility of the coating application, including areas of field joints, with construction, assembly and repair in field conditions;

compatibility with a concrete coating, if any;

compatibility with cathodic protection;

compliance with the requirements for insulating coating in case of performance as the latter;

adherence to occupational safety and health requirements with regard to harmful conditions of preparation, application and conditioning.

7.3.1.3 Physical and mechanical properties of the coating shall be given in the purchase specification. Referred to such properties are:

the maximum and the minimum thicknesses;

density;

adhesion;

tensile stresses and elongation;

impact strength;

cathodic resistance;

transverse resistivity;

bending;

thermal conductivity;

electrical resistance;

wear resistance;

resistance to hydrostatic pressure;

curing behaviour.

7.3.1.4 Manufacturing specification for coating shall contain the following:

coating material (specification for material of the coating to be applied, including certificates for material property tests);

surface preparation (manufacturer's technical requirements for surface preparation class prior to coating application);

coating application (application process with indication of main parameter values: air temperature and relative humidity, pipe surface temperature, application time, dry and wet layer thickness of the coating; material consumption; time of the coating layer drying and its total conditioning depending on the air temperature, etc.);

inspection and testing (specification for the coating to be applied, including certificates of tests to determine the coating parameters referred to in 7.3.1.3 above);

coating repairing process;

transportation and storage of coated pipes (guidelines and instructions on transportation and storage of pipes).

7.3.1.5 Pipe surface preparation prior to coating application shall include: elimination of defects (weld leveling, rounding of sharp edges to a radius not less than 2 mm), cleaning from oil and other contaminants, as well as from slag and corrosion products.

Oil and other contaminants shall be removed with white spirit and water-based washing solutions. Scale and corrosion products shall be removed with the aid of abrasive-jet blasting units with subsequent removal of dust.

Coating shall be applied not later than in 4 hours after abrasive-jet blasting in the open air and not later than in 24 hours in enclosed spaces.

7.3.1.6 All coatings shall be subjected to inspections and tests, including:
visual examination;
thickness measurement;
determination of coating integrity;
adhesion tests of separate pipes.

7.3.2 Special coatings for riser and shore crossing.

7.3.2.1 Specifity of corrosion protection of pipeline risers and shore crossings is associated with the water level fluctuations and the splash zone (refer to 1.2).

Adverse corrosive conditions occur in the zone above the lowest water level possible under astronomical conditions where the pipeline is intermittently wetted due to change of the water level, waves and splashes of water (splash zone).

Particularly adverse corrosion conditions occur in transportation of heated fluids, such as oil or petroleum products.

In the splash zone the protective coating may be exposed to mechanical damages caused by hydrodynamic effects or floating facilities. Accessibility for inspections (examinations) and maintenance in the splash zone is limited.

In the atmospheric zone (i.e. above the splash zone) mechanical damages of pipeline is less probable. Furthermore, there is better accessibility for inspections (examinations) and maintenance.

In the submerged zone and in the splash zone below the lowest water level possible under astronomical conditions, an adequately designed cathodic protection system is capable to prevent corrosion in any damaged areas of the protective coating. In the tidal zone, cathodic protection is inefficient.

For each specific riser or shore crossing, the division into corrosion protection zones is dependent on structural peculiarities of the riser or shore crossing, platform or single-point berth operated with the riser, and prevailing environmental conditions.

For each of the above zones, different types of corrosion-resistant coating may be used, provided they are compatible.

7.3.2.2 Physical and mechanical properties of the protective coatings listed in 7.3.1.3 meet the requirements for protective coatings of risers and shore crossings in the appropriate zones defined in 7.3.2.1.

7.3.2.3 Copper alloy-based external coatings may be simultaneously used both for protection against corrosion and fouling, especially in the transition area from the underwater area to the splash area. In order to attain adequate efficiency, metallic materials with anti-fouling properties shall be electrically isolated from the cathodic protection system.

7.3.2.4 Manufacturing specification for riser and shore crossing coatings shall contain all the information listed in 7.3.1.4.

7.3.3 Field joint coatings.

7.3.3.1 For pipes with concrete coating or thermally insulated coating, the field joint coating has a multi-layer structure made up of corrosion-resistant protective coating and filling material. The latter shall provide a smooth transition of the field joint coating to the pipeline basic coating.

For thermally insulated pipelines, risers and shore crossings, the filling material shall have the adequate insulating properties.

7.3.3.2 In selection of the field joint coating, the same requirements shall be met as those set forth in 7.3.1.2, 7.3.1.3, 7.3.1.5, 7.3.1.6 and 7.3.2.1. It is, however, necessary to take into account that welded seams are much susceptible to corrosion attacks. Therefore, prior to welding field joints, special attention shall be paid to proper selection of welding consumable, strict adherence to the welding procedure, careful control of weld quality. It is preferable that multi-layer cold coatings be used for protection of field joints.

7.3.3.3 All field joint coating work shall be carried out in accordance with the qualified procedure. The manufacturing specification shall contain the following items:

filling material;

surface preparation;

coating application;

filling material application;

inspections and testing;

repairs.

7.3.3.4 Coating parameters shall be contained in the design specification.

7.3.4 Cathodic protecion.

7.3.4.1 Along with an external coating, cathodic protection is a mandatory integral part of the corrosion protection system of a pipeline in seawater or a clayed mug. Cathodic protection protects the pipeline against corrosion destruction in places of its defects or damages to the coating, including field joints, occurring during operation. Cathodic protection consists in connecting a negative pole of a direct current external source to the pipeline to be protected, and the positive one to a specially provided external artificial insoluble or marginally soluble anode. This makes anode areas (areas where the coating is damaged) of corrosion macro- and microcells on the pipeline surface cathodic, which results in full cessation of pipeline corrosion or sharply reduces its intensity.

7.3.4.2 Technical documentation on cathodic protection system shall be kept during the entire lifetime of the pipeline and contain the following:

layout drawing of the cathodic protection stations, including the location of all test points;

specifications and data sheets of all the necessary equipment, i.e. transformer supports, electric cables and their protective devices, test points, etc.;

specifications for installation of the cathodic protection system;

specifications for start-up and acceptance tests;

operating and maintenance instructions for the cathodic protection system.

7.3.4.3 In order to provide adequate cathodic protection, a carbon steel subsea pipeline shall have a protection potential between $-0{,}90$ and $-1{,}1$V measured relative to a silver/silver chlorine/seawater (Ag/AgCl/seawater) reference electrode. These potentials relate to saline mud and seawater with salinity within 32 to 38 per cent. Under anaerobic conditions, e.g., saline seabed mud, and a possibility of microbiologically assisted corrosion, a protection potential value shall be assumed equal to – 0,90 V. For protection of stainless steel, a polarized potential more negative than – 0,55 V shall be used.

7.3.4.4 Such negative potentials may cause detrimental secondary effects, including hydrogen-induced cracking and corrosion fatigue of the pipeline base material and welds. Therefore cathode and anode potentials of corrosion couples in the cathodic protection system shall be close to each other (practically the same). The negative limit of the potential shall be specified in the technical documentation.

7.3.4.5 In order to measure the potential between the pipeline surface and seawater, the following types of reference electrodes may be used:

saturated calomel (KCl);

saturated copper-sulfate;

silver-silver chloride/seawater (Ag/AgCl/seawater);

high-purity zinc (minimum 99,9 per cent of zinc with iron content not exceeding 0,0014 per cent) alloy/seawater;

anode zinc alloy/seawater.

7.3.4.6 The following basic conditions shall be taken into consideration for the design of the cathodic protection system:

characteristics of the subsea pipeline to be protected (diameter, wall thickness, length, laying method and conditions of the pipeline placing on the seabed, temperature profile along the whole length of the pipeline, type and thickness of the protective coating, corrosion, thermal insulation, mechanical protection, presence, type and thickness of the weight coating, fastenings, joint components, fittings and their protective coatings, etc.);

existing or proposed installation of pipelines, platforms and other hydraulic structures in close proximity to or crossing (at another level) the subsea pipeline route;

presence of pipe bends, risers and clamps;

environmental conditions;

design lifetime of the pipeline;

required value of protection potential;

accessibility for repairs;

statistical data on operation of the cathodic protection system under similar conditions (prototype data);

availability of electric power;

safety requirements;

applicable codes (standards);

risk assessment.

7.3.4.7 Where necessary, in addition to the data referred to in 7.3.4.6 above, the following environmental parameters shall be evaluated in field (operational) conditions:

temperature;

seawater resistivity;

seawater velocity;

pH-value;

water depth along the pipeline route;

chemical composition of water, particularly oxygen content;

hydrogen sulphide content in seawater;

presence of stray currents.

7.3.4.8 The current density required to protect the surface of steel pipelines during the whole lifetime is one of the main parameters to be defined when designing the cathodic protection system. Three values of current density are important:

initial, mean and final (steady) values, which refer to the current density required to polarize the pipeline within a reasonable time period (within 1 to 2 months);

the current density necessary to maintain the polarization;

the current density necessary for an eventual depolarization, which may occur, for example, after a heavy storm.

7.3.4.9 The selection of the current density may be based on experience from the similar pipelines in the same environment or on field (operational) measurements in the same areas with consideration of the following:

the basic calculation of electrochemical protection shall be made for steady polarization conditions when protective insulating properties of main salt deposits on the polarized surface become stable;

the coating is considered efficient where 50 per cent of the protective current density for the particular area provide the design lifetime of the pipeline 30 years;

initial current density required shall be equal to 10 per cent of the protective current density;

the current density demand is normally not constant with time;

for bare areas of steel pipelines in seawater the current density requirements may decrease due to the formation of insoluble calcium carbonate deposits and other compounds that provide additional corrosion protection;

the current density demands may increase with time because as the coating deteriorates the bare areas increases and, along with this, the conductivity of the coating, the current of the cathodic stations and the potential (however, the value of the maximum protection potential shall not exceed –1,2 V relative to the copper-sulfate reference electrode due to a reason referred to in 7.3.3.2) will also increase.

7.3.4.10 Use of impressed current cathodic protection systems is limited by the following:

possible lack of an external source of power;

considerable wall thickness of the pipeline;

length of the subsea pipeline;

value of the pipeline insulation resistance at the end of the design lifetime (in order to provide efficient cathodic protection, insulation coating shall have high specific resistance);

necessity of equipment of the shore cathodic stations;

necessity of existence of the expensive stationary test points throughout the whole length of the pipeline spaced 1,0 to 1,5 km apart for intermittent monitoring of the potential over the entire length of the pipeline aiming to supervise the efficiency of the cathodic protection system;

possible requirement for cathodic protection monitoring system on the pipeline.

7.3.4.11 The cathodic protection system of subsea pipelines may be provided with one or two cathodic protection stations located on one or both ends of the pipeline. The cathodic protection system shall not be used unless a cathodic protection specialist is controlling its operation after assembly.

7.3.4.12 The anode materials for the cathodic protection system may be mixed oxides, activated titanium and platinized niobium, tantalum or titanium, platinum-tantalum alloys, niobium or titanium alloys, including platinized titanium alloy, highly-conductive metal with the oxide coating layer, lead-silver alloys (lead with addition of 1 to 2 per cent of silver).

7.3.4.13 Selection of the type of rectifier for a cathodic station shall be based on the current and voltage values, which are determined by the calculation during design. Rectifiers shall be of a constant current and potential controlled type, and manually controlled, except for the special applications. Cables shall be provided with insulation suitable for marine environment and an external jacket for adequate protection against mechanical damages. The electrical connection between the anode and anode cable shall be watertight and mechanically sound.

7.3.4.14 The calculation of the cathodic protection system parameters consists in verification of its capability to properly protect the pipeline against corrosion throughout its length, taking into consideration that not more than two cathodic protection stations installed on both ends of the pipeline may be provided. The cathodic protection system shall be designed and based on the following conditions:

cathodic protection calculation results shall specify the end values of the following values and parameters: total protective current and design voltage; type, number and lifetime of anodes; types and cross-sections of cables; anode line circuits; type of cathodic protection stations;

the cathodic protection calculation is based on the condition that the recommended arrangement of anodes shall provide equal distribution of potentials on the surface protected;

cathodic protection system shall be calculated for two stages of its operation: for a period of cathodic deposit to be formed on the surface to be protected and for operational period.

Where, due to shielding by other components of the system, some areas are not adequately protected, and installation of additional external anodes is not possible, use of a combined protection by cathodic protection system and sacrificial anode system is allowed.

It shall be taken into account that distribution of potentials is different for impressed current protection and sacrificial anode protection system is different: in the first case the anode potential is more positive, in the second case – negative.

The transformer-rectifier current output shall be at least 25 per cent over the current required for the protection of the pipeline during its entire lifetime.

7.3.4.15 The cathodic protection system shall be buried on-shore or placed on the seabed.

The anodes shall have sufficiently low electrical insulation resistance in the electrolyte (seawater) to provide low electrical resistance in the current circuit of the cathodic protection in order that the output voltage of the transformer-rectifier at the maximum current output does not exceed 50 V for safety reasons.

The total anode material weight shall be greater than the anode material consumed during the design lifetime at the maximum current output of the transformer-rectifier.

7.3.4.16 In case of inert composite anodes (e.g., platinized titanium anodes), the anode operating voltage shall be lower than the breakdown voltage of the external anode layer.

In all cases, the distance of the anode from the pipeline shall be selected minimum in order that the protective potential of the pipeline section close to the anode is higher than the negative limit of the protective potential (refer to 7.3.3.1).

The anode current density shall be lower than the maximum current density of the relevant anode material recommended by the manufacturer.

7.3.4.17 Where the cathodic protection system is used for protection of subsea pipelines and risers, the requirements for electrical insulation from adjacent structures (platforms, pipe racks) shall be met (use of insulating flanges). The same applies to the pipeline section where it comes out of the sea to the shore.

7.3.4.18 Electrochemical protection shall be put into operation not later than during 10 days after the date of completion of the pipeline laying.

7.3.5 Sacrificial anode system.

7.3.5.1 Sacrificial anode system consists in connection of the protected pipeline metal to the sacrificial anode metal that have more negative potential in seawater, due to which cathodic polarization current appears. A sacrificial anode in this protection system is the main element. The sacrificial anode system is normally designed for the entire lifetime of the subsea pipeline.

7.3.5.2 The design documentation on sacrificial anodes systems shall contain the following:

specification, drawings and data sheets for the manufacturer of sacrificial anodes and the electrochemical test results;

calculation of anodes weight and mass;

calculation of sacrificial anode resistance;

calculation of the area to be protected and the required current;

specification, drawings and data sheets for sacrificial anode installation;

method of sacrificial anode attachment.

7.3.5.3 In selection of materials for sacrificial anode manufacture, preference shall be given to alloys having the following parameters:

high utilization factor of soluble metal;

low anode polarizability;

stability of electrochemical characteristics in time;

absence of conditions for formation of anode solution products and films on the sacrificial anode surface.

Sacrificial anodes are manufactured of two types of materials: aluminium or zinc alloys that passed full-scale tests and meet the requirements of the specification for materials for manufacture of anodes, which is an integral part of the technical design. Each alloy may have different chemical compositions.

7.3.5.4 The following considerations shall be taken into account in selection of the sacrificial anode material:

sacrificial anode exposure conditions if immersed in seawater or in saline mud;

sacrificial anode chemical composition;

temperature;

method and procedure of manufacture.

Besides, the following shall be remembered:

conventionally cast zinc alloys may not be used in seawater at an anode operational temperature in excess of 500 °C;

account shall be taken of the effect on the environment of the metal alloy components solved in the electrolyte.

Based on the combination of positive properties, the best sacrificial anodes are those made of aluminium alloys; zinc alloys shall be used to prevent hydrogen depolarization. Aluminium alloys for manufacture of sacrificial anodes shall contain activating alloying additions limiting or preventing formation of an oxide surface layer.

7.3.5.5 Sacrificial anodes for subsea pipelines may be manufactured as blanks and have trapezoidal, cylindrical or U-shaped form or be of the bracelet type, however on agreement with the Register other types may be also considered.

Sacrificial anodes of bracelet type shall be provided with suitable steel inserts to facilitate the assembly and tightening of the bracelet halves or segments around the pipe. Sacrificial anodes of the bracelet type are mounted on the pipe in such a way as to avoid their mechanical damages during handling and laying of the pipeline.

For the pipelines with a continuous weight coating, sacrificial anodes have normally a thickness equal to the coating thickness. For pipelines and risers with thermal insulation, sacrificial anodes shall be designed so as to limit the sacrificial anode heating and thus to improve electrochemical efficiency, i.e. anodes shall be installed on the outside of the coating. The spacing between the serial sacrificial anodes shall be determined by calculation and it normally shall not exceed 150 m.

7.3.5.6 The dimensions of the sacrificial anodes shall be selected based on the following parameters:

outside diameter of the pipeline;

thickness of the external corrosion-resistant protective coating;

correspondence of the sacrificial anodes to the pipeline laying method;

thickness of the weight coating (concrete or reinforced concrete), if any.

For subsea pipelines without a continuous weight coating or with the outside diameter of the bracelet greater than the external diameter of the pipeline with a continuous weight coating, both ends of the sacrificial anodes of the bracelet type shall be tapered to the pipeline external surface or the weight coating.

7.3.5.7 The sacrificial anodes shall be installed on the pipes in such a way as to avoid any slippage during pipe laying and to maintain a reliable electrical connection to the pipeline. Different methods of the sacrificial anode assembly may be used, subject to approval by the Register. A typical method used for the assembly of sacrificial anodes of the half-shell bracelet type is fastening of the two halves of each sacrificial anode around the pipe by welding together the coupling strip inserts or by bolting together two halves of sacrificial anode of the bracelet type.

7.3.5.8 In order to provide electrical continuity between the sacrificial anode and the pipeline, it is necessary to have two connecting cables for each sacrificial anode. Installation of aluminium and zinc sacrificial anodes shall be carried out by welding of both ends of the anode core to the object (pipe or structure) to be protected when making pipeline field sections on the shore site in places specified in the design documentation. A necessity of use of the doublers is subject to the special consideration by the Register. Aluminium sacrificial anodes shall be welded to the top of the pipeline. The protruding ends of the sacrificial anode inserts of strip steel shall be bent to the same side at a right angle. The bent ends of the inserts shall be welded to the pipeline.

In order to make a connection between a lead wire (drain cable) and a steel pipe, use may be made of fusion thermite welding, soft soldering and brazing, manual argon-arc welding or condenser energy-storage welding. The welding procedure shall be qualified to check the mechanical strength and the electrical continuity of the connection and to verify that the welding process does not affect the mechanical properties of the carbon steel pipe, and that it does not induce any cracks in the pipeline wall.

Welding of aluminium sacrificial anode cores on field welds of the pipeline is not allowed. Welding shall be done at a distance of 150 mm from other welds.

7.3.5.9 Sacrificial anodes of the bracelet type shall be installed in accordance with the established procedure. The anodes shall be properly tightened around the pipes and installed in such a way as to avoid any damage to the pipe protective coating under the anode. Where a connection cable is used, each anode shall be connected to the pipe by at least four attachments, preferably two for each half of the anode. Connection welds shall be placed at least 150 mm from any other welds. At the points of the cable-to-pipe connections, the corrosion-resistant protective coating shall be carefully resurfaced.

After each installation of sacrificial anode the circuit continuity shall be checked by a suitable technique. In case of double welding of the anode inserts on the pipe walls or through doublers, two attachments for each half of the anode may be used.

Steel reinforcing of reinforced concrete weight coating shall not be in electrical contact with a pipe or anodes.

7.3.5.10 In exceptional cases, underwater installation of anodes may be performed, using either mechanical fixing devices or welding connections. Connections may be welded only using a hyperbaric welding method.

Welding of sacrificial anodes to the pipe walls without a hyperbaric chamber is not permitted either. It may only be used on parts of the pipeline system where cracks and defects would not be significant, i.e. of doublers, anode inserts and supports.

7.3.5.11 Continuous distribution of potentials on the entire surface of the subsea pipeline over the entire length shall be provided during the whole lifetime of the pipeline. The minimum and the maximum values of protection potentials for seawater are shown in Table 7.3.5.11. The given potentials are valid for seawater with salinity 32 to 38 pro mil at a temperature between 5 and 25 °C.

Table 7.3.5.11

Values of protection potentials for subsea pipelines

Probe electrode	Minimum protection potential, V	Maximum protection potential, V
Saturated copper-sulphate	– 0,95	– 1,10
Silver chloride	– 0,90	– 1,05
Zinc	+ 0,15	0,00

8 PIPELINE ASSEMBLY AND TESTING

8.1 GENERAL

8.1.1 Installation, assembly and commissioning of subsea pipelines shall be carried out with due regard to risk analysis that includes identification of possible hazards, failures, accidents, severity of consequences, using such well-known methods of risk analysis as FMEA, HAZOP, etc. (see Appendix III).

8.1.2 Prior to assembly, laying and commissioning of subsea pipelines, the following documents shall be submitted to the Register for approval.

8.1.2.1 Process documentation for assembly, laying, inspection, acceptance tests shall be shall be submitted containing detailed information on the equipment, devices, instrumentation to be used, their characteristics and reflecting all stages of work to be done in execution of the processes.

8.1.2.2 Appropriate procedures shall be developed subject to approval by the Register for all types of work on assembly of subsea pipelines, in particular:

storage, transport and handling of pipes;
alignment;
welding;
visual examination and non-destructive testing;
external coating;
repairs;
dismantling and recovery;
towing;
tie-in of pipeline strings.

The procedures shall contain restrictions connected with environmental conditions in area of the pipeline route.

8.1.2.3 Products and materials for subsea pipelines shall be handled in full compliance with the established procedures. Identification of materials and application monitoring shall be maintained throughout all work stages. Rejected materials shall be clearly identified, marked and separated from all other materials, All supplied materials shall be checked for their compliance with the certificates.

8.1.2.4 Prior to commissioning of the subsea pipeline, all monitor systems shall be checked, and essential equipment (welding equipment, positioning systems, tensioning machinery, etc.) shall be surveyed by the Register.

8.2 PIPELINE ROUTING

8.2.1 Before assembly and installation of the pipeline, additional studies may be required if:

the period of time since the initial survey to commencement of assembly work is rather extended;

significant changes in sea ground conditions is likely to have occurred;

the expected pipeline route is in areas exposed to hazardous effects, e.g., seismically dangerous;

new units, facilities, pipelines, etc are present in the area.

8.2.2 The following may be required in seabed preparation prior to the pipeline laying:

to remove possible obstructions from the route and prevent potential hazards interfering with the pipeline operations;

to take measures to prevent the negative effects of the unstable sea ground, sand waves, erosion processes, etc. on the pipeline;

to take measures with regard to the areas of the pipeline route crossing with the pipelines and cables;

to take measures to prevent undesirable process of any sea ground erosion resulting in the pipeline sagging.

8.2.3 Prior to commencement of assembly and laying of the subsea pipeline in the sea ground, calculations shall be made to determine the underwater trench profile. A trench shall be excavated with a sufficiently smooth profile to minimize the possibility of damages to the coating of sacrificial anode system and pipeline itself.

8.2.4 Before laying the pipeline in a preliminarily excavated trench, the contractor with participation of a Surveyor to the Register shall check invert levels of the trench longitudinal profile. Excess in the trench bottom depth shall not exceed 0,5 m. The pipeline shall be prepared for laying by completion of an underwater trench excavation.

8.2.5 Prior to the subsea pipeline laying, checking calculations of strength and stresses in the pipeline to be layed shall be made, having regard to actual current velocities, sea depth and profiles of release device.

Laying of the pipeline on the seabed for subsequent burying thereof is allowed only on condition that preliminary checking measurements and calculations show that bending radii of the pipeline will be not less than the minimum permissible values based on strength requirements.

A concrete-coated pipeline may be laid after the concrete is cured to the design strength.

8.2.6 All preparation work of pipelines and cable crossings shall be carried out in compliance with a specification detailing the measures taken to avoid any damage to crossing installations.

The specification shall contain the requirements for:
the minimum distance between the existing installation and the pipeline;
co-ordinates of crossing;
marking of the pipeline route;
position and orientation of existing installations on both sides;
lay-out and profile of crossing;
anchoring of the pipeline and its structures;
installation of bearing structures (supports) or gravel beds;
measures to prevent erosion of the pipeline structural elements;
monitoring;
tolerances;
any other requirements for pipeline structure.

8.3 MARINE OPERATIONS FOR PIPELINE LAYING

8.3.1 The requirements of this Chapter are applicable to pipe-laying vessels and barges performing the pipeline laying on the seabed. The pipe-laying vessel shall be classed with the Register. The vessel shall be fitted with all necessary systems, arrangements and equipment for pipe-laying operations with regard to provision of the adequate safety. The basic requirements for the vessel shall be given in the specification and cover the following:
anchors, anchor chains, wire cables and anchor winches;
anchoring systems;
positioning and supervision equipment;
dynamic positioning equipment and reference system;
alarm systems;
seaworthiness of the vessel in the region;
cranes;
pipeline assembly equipment.

8.3.2 A maintenance manual for all systems and equipment to provide safety of operations shall be available on board the ship. Prior to operation the vessel and systems shall be surveyed by the Register.

8.3.3 For anchoring of the pipe-laying vessel it is necessary to have a layout chart of anchoring systems. The pipe-laying vessel shall operate in strict compliance with the layout chart of anchors providing the required forces on the tensioners. The anchor layout chart shall contain the following information:
expected pipeline route and laying corridor;
location of existing pipelines and installations;
prohibited anchoring zones;
position of each anchor and cable touch down point;

vessel position for running each anchor and working position of the vessel when the anchor running is completed;

anchor handling with regard to weather limitations.

8.3.4 The minimum clearances shall be specified between the anchors, anchor chains (ropes) and any existing fixed structures of subsea installations, pipelines or cables.

8.3.5 Requirements shall be specified for the positioning system and its accuracy for each type of the vessel and appropriate environmental conditions. The accuracy of the horizontal surface positioning systems shall be consistent with the requirements for the permissible deviations of the pipeline centerline in the process of laying. In order to monitor the positioning, the appropriate monitoring systems shall be developed, reference points shall be established.

8.3.6 Positioning systems shall have the minimum 100 per cent redundancy to avoid errors in positioning. Documentation showing that the positioning system is capable of operating within the specified limits of accuracy shall be available for familiarization prior to commencement of the pipeline laying operations.

8.3.7 A vessel using a dynamic positioning system for station keeping and location purposes shall meet the IMO requirements (Guidelines for Vessels with Dynamic Positioning Systems).

8.3.8 Prior to commencement of assembly operations, the dynamic positioning system shall be tested to ensure that all control devices operate within the prescribed limits of accuracy. The remote control system of propellers shall be tested in operation with the reference system, as well as in different failure modes.

Monitoring, alarm and back-up systems shall be tested in accordance with the established test procedures. The tests shall be witnessed by a Surveyor to the Register.

8.4 METHODS OF PIPELINE LAYING ON SEABED

8.4.1 Subsea pipelines may be laid on the seabed, using different methods, namely: seabed pull, pipeline towing, laying from the pipe-laying barge or vessel, lowering from ice using directional drilling.

8.4.2 Selection of the laying method is dictated by environmental conditions, sea depth, seabed shape, sea ground soil properties, time period when the sea is covered with ice, type of the medium conveyed, pipeline diameter.

8.4.3 The pipeline laying procedure includes its movement to the cross-section and lowering to the seabed. Subsea pipeline lay patterns differ in location of the installation site, methods of pipeline movement and its lowering to the seabed.

For laying of the pipeline on the seabed one of the following patterns may be used:

.1 seabed pull of the pipeline with the preliminary full-length assembly on the site;

.2 seabed pull of the pipeline with successive tie-in operations;

.3 pipeline lowering by free immersion with preliminary assembly in cross-section;

.4 pipeline lowering by free immersion with towing of the pipe strings, their assembly and pipeline turn;

.5 pipeline lowering by free immersion with towing of the pipe strings, butt welding between strings above water;

.6 pipeline lowering with the aid of floating supports;

.7 pipeline laying using directional drilling.

The methods referred to in 8.4.3.1, 8.4.3.2, 8.4.3.4 and 8.4.3.5 are limited by weather conditions. Moreover, the patterns indicated in 8.4.3.1 and 8.4.3.2 may be used only for short runs.

8.4.4 Pipeline laying by seabed pull.

8.4.4.1 The laying procedures referred to in 8.4.3.1 and 8.4.3.2 may be used for short runs of pipelines of all diameters under fairly favorable weather conditions (sea state 3 to 4, current velocity under 0,5 m/s). This laying procedure shall be preferably used for gas pipelines; for oil pipelines – at relatively big depths and high current velocities.

8.4.4.2 The pipeline laying procedure by pulling consists in assembly (welding) of the pipes on the site, stretching the pipeline in line and pulling it over the seabed using winches, tractors or tugs. The pipeline head is sealed before pulling with a tight plug, and a frame for securing a pulling rope is welded thereto. Depending on the environmental conditions of the region for pipeline laying, pipeline structures, availability of pulling facilities, the entire pipeline or its sections are pulled.

8.4.4.3 The condition for using the pulling method is a flexible (natural) radius curvature even on one side of the pipeline. Pulling of a large-diameter pipeline is possible in case of bent inserts but with a limited pulling force.

Selection of one of the two pulling procedures is governed by the relief of the seabed and the shore where the site is located, power of the pulling facilities, design and number of lowering equipment.

8.4.5 Pipeline laying by towing above water.

8.4.5.1 Pipeline laying by towing above water may be used only under favorable weather conditions with low current and wind velocities, with sea state under 2 – 3. The limit length of towed pipe sections shall not exceed 3000 m. The procedure is more acceptable in open water. In justified cases, towing may be used in the water partially covered with ice. It shall be noted that manoeuvring freedom of the towing vessel is substantially restricted.

8.4.5.2 Where towing procedure is used, the documentation shall be developed for the following processes:

assembly of pipe stringers on shore;

ballast control during tow;

pipe stringer positioning during tow and installation;

deballasting control;

tie-in;

use of safe measuring and navigation equipment with regard to weather restrictions.

8.4.5.3 During tow the following main parameters shall be monitored and maintained within the calculated limits:

pulling force;

towing speed;

water depth;

bending radius;

pipeline floating conditions.

The selected towing route shall be free of any obstructions, which may have influence on the pipeline pull. Any environmental restrictions shall be observed.

8.4.6 Pipeline laying from a pipe-laying barge.

8.4.6.1 Pipeline laying from a pipe-laying barge may be used in the regions with a long-term period without ice. Laying speed may be 5 to 8 km per day. The advantage of pipeline laying from a barge is that the barge is an independent system, which upon arrival is ready to start pipe-laying operations.

8.4.6.2 The disadvantage of the pipe-laying procedure from the barge is insufficient accuracy of its positioning: a barge shall not deviate more than 1 to 2 meters to prevent pipeline bending in excess of the permissible value. In such circumstances a need arises in many mooring lines. In case of ice, anchors shall be continuously moved by special vessels for laying out the anchors (dynamic positioning system). In case of ice, it is difficult to keep the barge in the fixed position.

8.4.6.3 Prior to the pipeline-laying activities, pipe-laying barge and equipment used in the laying process shall be surveyed by a Surveyor to the Register.

8.4.6.4 During laying the following shall be monitored:

anchor cable loads;

roller loads;

pipe tension at each tensioner;

total tension;

stinger tip depth and stinger angle;

water depth;

tension of winches during abandonment and recovery of the pipeline;

environmental conditions.

8.4.6.5 An approved process documentation shall be available on board to be used in case of:

buckles;

damage to weight coating;

damage to corrosion-resistant coating.

8.4.7 Pipeline laying from a pipe-laying vessel (or a pipe-laying barge) using a reel.

8.4.7.1 Pipeline laying from a pipe-laying vessel (barge) using a reel is possible only in free water conditions. The system is highly efficient (approximately 2 – 4 km/hour), which is the main advantage in construction of pipeline systems in the regions with short-term periods without ice. The procedure allows laying pipelines with the maximum diameter up to 400 mm at sea depths to 600 m.

8.4.7.2 Pipeline is laid by off-reeling from a reel installed on a barge or vessel without tension. A reel may be placed on board vessel in different ways, i.e. vertically, horizontally, on deck, on the bow, amidships, etc. Use of a reel allows laying the pipeline practically without interruptions. *S*- or *J*-methods may be used in such pipeline laying.

8.4.7.3 Only not concrete-coated pipelines may be constructed with the aid of a reel. Negative buoyancy is provided using pipes with a big wall thickness, which results in a number of advantages: a possibility to apply strong tension and increase of the working pressure. The maximum longitudinal stresses are observed in the pipeline turn nearest to the core. Stresses in the pipeline are controlled by the pipeline tension and frame angle.

8.4.7.4 On-reeling shall be carried out in a dock. Prior to on-reeling, pipe stringers up to 1 km long are welded, x-rayed and insulated by an epoxy coating.

The capacity of the reel with a diameter of side flanges 17 m, and core 12 m in diameter and 5 m in width shall be:

with pipe diameter 100 mm – 64 km;

with pipe diameter 250 mm – 11 km;

with pipe diameter 300 mm – 7 km.

A necessity of on-reeling of the pipe stringer and subsequent off-reeling cause residual out-of-roundness and helicity in the pipe. Therefore it is efficient to lay pipelines by off-reeling only in construction of inter-field and main pipelines, as well as of small-diameter field pipelines.

8.4.7.5 For pipeline laying by reeling, it is necessary to make calculations and work out the following procedures:

loading out of the reel;

tension control;

installation and/or joining of pipe stringers;

abandonment and recovery of the pipeline.

In some cases, additional information may be required.

8.4.7.6 For storage of flexible pipes on reels, the following parameters shall be considered:

the reel radius shall be not less than the minimum bending radius of the flexible pipe;

the reel shall accommodate the whole length of the flexible pipe, including end fittings and accessories;

the structure of the reel including foundations and bearings shall be capable of supporting the weight of the flexible pipe.

For steel pipelines consideration shall be given to plastic deformation during on- and off-reeling.

8.4.8 Laying of subsea pipelines using stingers.

8.4.8.1 This procedure suggests use of a stinger to form a flat curve of the pipeline axis and reduction of bending stresses during laying. In lowering from the stinger the pipeline forms *S*- or *J*-shaped curve.

8.4.8.2 Laying of pipelines by *S*-method allows using the pipes up to 1200 mm in diameter at a sea depth to 750 m.

8.4.8.3 Stresses in the pipeline during laying depend on the curvature radius of a stinger and angle of pipeline transition from the stinger, tensioning pull and depth of laying, strength characteristics of the pipeline material, its diameter and buoyancy. Stability of the pipe-laying vessel in the fixed position is ensured with the aid of anchoring system or dynamic positioning system.

8.4.8.4 It shall be noted that laying of the pipeline using the *S*-method causes the substantial bending stresses and strains in the pipeline. A combined action of bending and hydrostatic pressure results in buckling of pipes that limits their installation by the *S*-method at big depths. Successive bending of the pipeline on the convex and concave parts of the *S*-curve may cause the residual plastic deformations. This requires increase of the stinger length, power of the barge anchoring system and pipeline tension, limitation of the pipeline weight. The maximum tension of the pipeline in this case may be about 3000 kN.

8.4.8.5 Application of the *J*-method allows installing pipelines at big depths (1000 to 3000 m) but its use at small depths is limited. Combination of *S*- and *J*-methods is normally used in practice.

8.4.9 Laying of subsea pipelines using directional (horizontal) drilling.

8.4.9.1 Directional (horizontal) drilling may be used in laying subsea pipelines with pipe diameters up to 1220 mm for transition through small water obstructions (up to 1500 m).

8.4.9.2 Pipeline laying using such method does not depend on the season, ice cover and condition of the water surface. With this method of laying the pipeline is placed well below the seabed, which makes it totally safe as regards mechanical damages by anchors, big ice formations, etc.

8.5 SUBSEA PIPELINE TESTING BY PRESSURE

8.5.1 General.

8.5.1.1 After assembly and after any work that may damage the pipeline (trenching, burying, repairs), a pressure test shall be carried out.

8.5.1.2 The pressure test may generally be divided into two parts: a leak test and a strength test. The leak test shall be carried out after the strength test.

8.5.2 Documentation.

The pressure test shall be described in a test program or procedure, which is subject to approval prior to testing. The documentation shall contain the following.

8.5.2.1 Operating instructions, including:
pipeline flooding (e.g. type and number of pigs);
method and rate of pressurizing;
equipment/sections to be isolated during a holding period;
method and rate of pressure relief;
dewatering and removal of the test medium;
internal drying of pipeline, if applicable;
emergency and safety procedures and precautions.

8.5.2.2 Equipment and systems:
description of the pipeline section to be tested (dimensions, valves, pumps, etc.);
description of the test medium, including possible use of chemical additives;
specification of instrumentation and measuring devices (temperature, pressure, flow rate), including their location and connection;
description of calibration and marking of equipment;
distribution of temperature measuring devices along the length of the pipeline.

8.5.2.3 Calculations:
temperature and other environment influence on pressure, including estimation of the sensitivity of the test medium temperature due to variations of the seawater temperature;
"pressure-volume" assumption diagram.

8.5.3 Safety measures.

The test area shall be surrounded with warning signboards displayed in order to prevent unauthorized personnel from entering during the pressure test.

8.5.4 Strength test.

The strength test is carried out to verify that the pipeline integrity is sufficient to operate at the design pressure with a specified safety margin.

The strength test may also be used to verify the uprating to a higher operating pressure for a pipeline in operation.

The strength test pressure shall not be less than 125 per cent of the design pressure.

The test pressure during a strength test shall be held for not less than two hours. If a pressure drop during the holding period is less than 1 per cent/hour, the strength test is acceptable.

8.5.5 Leak test.

The leak test is carried out to verify that the pipeline is free of leakage.

The leak test pressure shall not be less than 110 per cent of the design pressure. The test pressure shall depend on the lowest water level possible under astronomical conditions.

The pressurizing of the pipeline section shall be followed by a stabilization period before a holding period starts. During the holding period the pressure shall be recorded at least every 30 minutes. In case pressure recovery or a pressure relief is needed, the leak test is interrupted and shall be repeated after a new stabilization period.

The maximum allowable pressure variation during a leak test is $\pm 0,2$ per cent of the test pressure. If the pressure variation caused by tidal or temperature influence can be documented, an additional variation corresponding to $\pm 0,4$ per cent of the test pressure may be accepted. Temperature instruments shall be located close to the pipeline.

8.5.6 Test medium.

The test medium shall normally be filtered fresh water or filtered seawater, which, in order to avoid internal corrosion in the pipeline, may be chemically treated. Hydrocarbon liquids or other suitable liquids may also be used as the test medium.

8.5.7 Pipeline flooding and pressurizing.

8.5.7.1 During flooding of the test section, precautions shall be taken to limit the air inclusion to less than $\pm 0,2$ per cent of the total filling volume.

8.5.7.2 During pressurizing of the test section, the added volume and corresponding pressure shall be recorded at least every 15 minutes (or more frequently).

8.5.7.3 Air inclusion measurement in the test section shall be carried out during initial pressurization. This may be done by establishing a "pressure-volume" diagram based on the pressure and volume values measured during the pressurization.

8.5.8 Conservation of the test section.

In order to avoid internal corrosion, conservation of the test section shall be done after the pressure test. Inert gas or inhibited water may be used for the purpose.

8.5.9 Dewatering and drying.

Disposal of inhibited water requires permission from the national authorities, as it may be associated with the environmental hazards. Where drying is required, in order to prevent internal corrosion or hydrate formation, the detailed description of the procedure shall be submitted to the Register for approval.

9 MAINTENANCE, INSPECTIONS AND REPAIR

9.1 MAINTENANCE AND INSPECTIONS

9.1.1 The involvement of the Register in periodic inspections is based on the quality of maintenance and inspections of the pipeline system carried out by the owner of the pipeline.

The Register shall be notified of any occurrences, which may affect safe operation of the pipeline, including planned repairs.

9.1.2 Inspection and maintenance program.

The owner of the pipeline system establishes the inspection procedure and maintenance program where frequency and content of inspections and maintenance are described.

The document containing the above provisions shall be submitted to the Register in triplicate prior to putting the pipeline into operation.

9.1.3 Periodical inspections.

9.1.3.1 For confirmation of the pipeline operation license, the pipeline shall be periodically inspected. It is the responsibility of the owner to carry out the pipeline inspections. The owner shall notify the Register about the terms, method and extent of the inspection. A Surveyor to the Register may witness the inspection.

Inspections shall be carried out by an organization involved in underwater inspections, which is recognized by the Register.

9.1.3.2 The basic requirements for inspections and evaluation of their results are set forth in 9.1.4 and 9.1.5.

9.1.3.3 Periodical inspections aimed at extending validity of the pipeline operation license may require interruption in operation of the pipeline system.

The extent and frequency of such inspections depend on the condition of the pipeline system and are subject to consideration by the Register in each particular case.

9.1.4 Frequency of periodical inspections.

The frequency of periodical inspections depends on the following factors:

design concept of the pipeline system;

inspection and maintenance program;

expected level of corrosion, erosion wear;

aquatic medium activity in the vicinity of the pipeline route;

stability of the seabed and pipeline free spans;

environmental conditions;

consequences of failures occurred;

previous inspections and maintenance program.

For subsea gas and oil pipelines an inspection shall be carried out once a year.

9.1.5 Findings during periodical inspections.

9.1.5.1 In order to assess the condition and assure further safe operation of the pipeline, as well as to plan maintenance and repairs, the periodical inspections shall comprise the following operations:

inspection of the free spans location;

inspection of condition of the exposed pipeline areas;

assessment of pipeline deformations, their damages and the conveyed medium leaks;

inspection of underwater electronic sensors and other devices for monitoring the conveyed medium leaks;

measurements of the pipe wall thicknesses;

checking of coating integrity;
checking of cathodic protection condition;
checking of possible lateral and vertical displacements.

9.1.5.2 For periodical inspections of risers, the following items apply, in addition to those listed under 9.5.1:

inspection of clamps and bolts;
inspection of flanges condition;
assessment of marine fouling.

9.1.5.3 The periodical inspection of manholes/mudholes on shore or on the drilling platform shall also cover the following items:

compartments;
door locking devices;
isolation and safety valves;
fittings and instrumentation.

9.1.5.4 Pipeline fittings and accessories of the pipeline system shall be inspected for possible leaks and serviceability.

9.1.6 Records of periodical inspection results.

9.1.6.1 The owner bears full responsibility to submit to the Register the results of periodical inspections of the subsea pipeline condition.

The report shall contain description of the pipeline condition as regards corrosion, location of free spans, with indication of the exposed parts and displacements.

9.1.6.2 Drawn up reports of periodical inspections shall be registered and submitted to the Register upon request.

9.1.7 Modification.

Modification of the existing pipeline system is subject to approval by the Register. All documentation with calculations and explanations shall be submitted to the Register in triplicate prior to commencement of modification work and shall contain the following information:

description of modification;
assessment of the environmental influence in performance of modification;
list of equipment to be used during modification;
quality control and acceptance criteria.

9.2 REPAIR

9.2.1 Documentation.

9.2.1.1 Any repair to be carried out on the pipeline system under construction or in operation shall be described in the procedure, which shall be submitted in triplicate to the Register for approval.

9.2.1.2 The description of the repair procedure shall include the following:
type of damages to be repaired;
welding technique to be used, welding procedure specification and preliminary assessment of its compliance with the technical requirements;
conditions of repair;
list of tools and equipment to be used during preparation, repair and post-repair work;
detailed description of the preparation of the repair area;
detailed description of the repair procedure;
detailed description of the post-repair activities, including tests, pressurization and acceptance criteria;
safety requirements.

9.2.2 Repair procedure.

9.2.2.1 Any repair shall be carried out only under the favorable environmental conditions.

9.2.2.2 The pipeline shall be repaired in compliance with the technical requirements for its construction and operational procedure. A necessity of performance of the pressure test following the repair shall be considered in each particular case.

No pressure test is required after the repair, in which no more than two repair welds are made, provided the extent of non-destructive testing is increased. In such case, in addition to visual examination, 100 per cent radiographic inspection, ultrasonic inspection or magnetic particle inspection is required.

9.2.3 Repair of pipeline constructions.

9.2.3.1 Pipeline or pipes with defects or damages not within the specification requirements shall be repaired. The pipeline system shall be repaired prior to the pressure test.

Damages to be mandatory repaired include:
outside damages of pipes;
damages of the corrosion-resistant coating, weight coating or anodes of the corrosion protection system;
welding defects;
deformation and buckling of the pipeline;
damages of field joints;
damages due to corrosion;
damages of fittings, monitoring equipment, manholes/mudholes, etc.;
damages of anchor stays, supports and clamps.

9.2.3.2 Outside damages of the pipe section are removed by grinding. The minimum wall thickness shall be within the tolerance limits.

9.2.3.3 Unacceptable welding defects detected during non-destructive testing or by visual examination shall be repaired by rewelding of the defective area.

Welding of outside defects is permitted, only provided the pipeline stability during repair is ensured. Internal defects shall be repaired with subsequent welding of the defective area in compliance with 5.5.3.

Repairs shall be carried out by the qualified personnel having permission for work (refer to 5.3). Upon completion of the repair, welding quality shall be checked by non-destructive testing methods.

9.2.3.4 Corrosion areas may be repaired only after their examination for defects and assessment of their condition for compliance with the specification requirements.

Erosion section repairs shall be carried out by the same methods.

9.2.3.5 Buckling or other major deformation damage shall be repaired by the total cutting out of the damaged portion with subsequent replacement thereof.

9.2.3.6 A decision on carrying out a repair shall not be made before identification of the corrosion defects.

9.2.4 Repair of pipeline system without interruption of its operation.

9.2.4.1 Repairs on the pipeline resulting in a temporary interruption of its operation are allowed only subject to the special consideration by the Register. Any such repair shall result in a restored pipeline serviceability or serviceability acceptable for the remaining lifetime of the pipeline.

9.2.4.2 Damages to the pipeline resulting in a temporary interruption of its operation are as follows:

damages due to corrosion;

damages of the weights or corrosion-resistant coatings;

damages in the corrosion protection system;

damages due to external impact;

damages due to erosion.

9.2.4.3 Reductions of wall thickness detected during examination of the pipeline for defects shall be assessed by the methods recognized by the Register.

9.2.5 Repairs of the damaged areas shall be carried out by the partial replacement of the damaged pipeline section or by cutting out of the section with a spool piece. Other repair methods, such as installation of bolted clamps may be used upon the special consideration by the Register.

Repair of cracks by welding is permitted in cases when the cause is known or cracks are restricted to the small areas.

Repair by grinding for elimination of small surface defects is allowed, provided the minimum wall thickness remains within the specified limits.

9.2.6 Special safety measures shall be taken in case of welding or thermal cutting of the pipelines intended for conveying fire-hazardous and explosive substances.

10 SAFETY ASSESSMENT

10.1 SCOPE OF APPLICATION

10.1.1 For the purpose of this Section the objects of safety assessment are:
subsea field oil, condensate and gas pipelines;
subsea main oil, condensate, gas and oil product pipelines;
subsea distribution oil product and gas pipelines.
10.1.2 This Section does not apply to hoses and free floating pipelines.
10.1.3 This Section covers the accidents of the following kinds:
extreme hydrometeorological conditions;
seismicity;
leakages;
explosions;
fires;
combinations of these accidents;
other possible accidents.

10.2 TERMS, DEFINITIONS AND EXPLANATIONS

10.2.1 The main terms, definitions and explanations relating to general terminology of the present Rules are given in Section 1 (refer to 1.2).

10.2.2 For the purpose of this Section of the Rules, the following additional definitions are used.

A c c i d e n t means a hazardous technogenic accident that causes at an object, certain area or water area a threat to the human life and health and results in destruction of buildings, structures, equipment and transport means, in manufacturing or transport process irregularity, or environmental damage.

A c c i d e n t o n t h e p i p e l i n e means an accident on the pipeline route involving the emission or spillage under pressure of hazardous chemical or fire-hazardous substances and resulting in occurrence of technogenic emergency. Hereinafter, only an occurrence will be considered that might result in abnormal ingress of the conveyed hazardous substance (oil, oil products, condensate and gas) in the environment.

R i s k a n a l y s i s means a process of hazard identification and assessment of risk for individuals or groups of population, property or the environment. The risk analysis means use of all available information for hazard identification (detection) and assessment of risk of a certain event defined earlier (accident and emergencies involved) caused by these hazards.

F r e e - f a i l u r e o p e r a t i o n means capability of an item (object) to retain its serviceability during the specified period of time or until the completion of a certain work without forced breaks, e.g. for repairs.

S a f e t y i n e m e r g e n c y s i t u a t i o n s means condition of population protection, objects of national economy and environment against hazards in emergency situations.

H a z a r d i d e n t i f i c a t i o n means a process of hazard identification, recognition of its existence, as well as determination of hazard characteristics.

A c c i d e n t i n i t i a t i n g e v e n t means depressurization of the pipeline system conveying hazardous substances.

W o r k i n g o r d e r means a condition of an object, at which it complies with all the requirements of the normative and technical and/or design documentation.

C a t a s t r o p h e means an event (accident) of a mass disaster nature, extraordinary in its consequences, resulting in the pipeline destruction, loss of lives or considerable damage to environment.

F a i l u r e c r i t e r i o n o f s u b s e a p i p e l i n e means an indication or a combination of indications of the pipeline operable condition disturbance as specified in the normative and design documentation.

Quantitative risk indications are as follows:

i n d i v i d u a l r i s k means a frequency of individual injury as a result of affecting hazard factors under consideration;

c o l l e c t i v e r i s k means an expected number of fatalities resulting from the possible accidents during a certain period of time;

p o t e n t i a l t e r r i t o r i a l r i s k means spatial frequency distribution of materialization of a negative effect of a certain level;

s o c i e t a l r i s k means dependence of frequency of events (F), during which a number of people suffered at a certain level in excess of the number determined (N).

R e l i a b i l i t y means a property of an object to retain with the time within the specified limits the values of the parameters characterizing capability to fulfill the required functions within the specified operating conditions and application conditions, maintenance, storage and transport.

H a z a r d means an objectively existing possibility (probability) of a negative effect on the society, individual, environment, which can result in a loss or damage impairing the condition and giving undesirable dynamics or parameters to their development.

H a z a r d o f t e c h n o g e n i c n a t u r e means a condition specific to the technical system, industrial or transport object that realizes in the form of striking the environment when it occurs or in the form of the direct or indirect damage to an individual and environment during normal operation of the objects.

F a i l u r e means malfunction in serviceability of the object.

R i s k a s s e s s m e n t means a process of an extent of risk identification of a considered hazard to the health of individual, property or environment. Risk assessment includes the analysis of frequency of the risk occurrence, analysis of consequences and combination of both.

D a m a g e means disturbance of the conveyed order of the object, with the serviceable condition being maintained.

A c c e p t a b l e r i s k means the risk, which level is permissible and substantiated based on economic and social considerations. The risk of an industrial object (subsea pipeline) operation is acceptable, provided its magnitude is so insignificant that the society is prepared to run the risk to benefit from the object operation.

S e r v i c e a b l e c o n d i t i o n means a condition of an object, at which values of all the parameters that characterize a capability to fulfill the specified functions are in line with the normative and technical documentation.

R i s k (r i s k d e g r e e) means a potential hazard of losses (combination of frequency or probability and consequences of a certain hazardous event) due to the specific character of some natural phenomena and various kinds of human activities.

A c c i d e n t s c e n a r i o means a complete and formalized description of the following events: accident initiation phase, accident process and emergency situation, losses in accident, including specific quantitative characteristics of the accident events, their space-time parameters and causal relationship.

T e c h n o g e n i c e m e r g e n c y s i t u a t i o n means a condition where, as a result of occurrence of the technogenic emergency situation source at the object, in certain area or water area, normal conditions of life and activities of people are disturbed, their lives and health are threatened, damage is done to the national economy and environment.

10.3 BASIC PRINCIPLES

10.3.1 For purpose of this Section, the subsea pipeline is treated as an object of high risk, entire lack of correct and fairly full statistical data on accidents of subsea pipelines, causes of the accidents, accident initiation conditions, consequences being taken into account. That may be explained by an extremely wide spectrum of factors determining the accidents.

10.3.2 The safety control system under consideration is based on the assumption that design, calculations, manufacture, construction, operation and maintenance of the subsea pipeline comply with all the requirements of the Register normative documents.

10.3.3 Safety assessment shall be made at the conceptual design stage.

10.3.4 For safety assessment a designer shall submit the following information:

environmental conditions;

functions and specifics of the pipeline operation;

drawings of the pipeline route, ballasting, underwater trenches, sacrificial anode arrangement, shore crossing structures, etc.;

calculations of ballasting, pipeline wall thickness, effectiveness of corrosion protection, weight of sacrificial anodes, etc.;

list and description of basic arrangements aiming at reducing probability of accidents;

confirmation based on calculations that consequences of extreme environmental conditions and accident effects meet the adequate safety criteria considered in this Section.

10.3.5 There exist several safety concepts based on the following principles or combinations thereof:

principle of unconditional priority of safety and health of people as compared to any other items of conditions and life quality of society members;

principle of an acceptable hazard and risk, in compliance with which the low permissible and upper desirable safety levels, and an acceptable safety level and risk within this range are established, having regard to the social and economical factors;

principle of the minimum hazard, in compliance with which the risk level is established as low as reasonably practicable;

principle of successive approximation to the absolute safety.

10.3.6 The ALARP (“as low as reasonably practicable”) concept that allows using “to foresee and to prevent” is adopted in the present Rules similar to the rules of most of the countries. This is a dominating concept that governs the relations in the area of industrial safety.

10.3.7 Risk analysis is part of a system approach to solving the problems of prevention or reduction of the hazard associated with a pipeline. Risk control includes collection and analysis of information on industrial safety, risk analysis (hazard analysis) and safety monitoring. Risk analysis is the main link in provision of safety; it is based on the information collected and defines the measures on monitoring of the subsea pipeline safety.

10.3.8 Safety assessment of the subsea pipeline shall be made based on the fact that the designer has selected the most favorable design solution meeting the basic principles of safety. The result of this assessment shall confirm that correct decisions were made at an early stage, which would not result later in a necessity of making significant modifications in design and construction due to underestimation of the safety requirements.

10.3.9 Safety assessment of the subsea pipeline shall demonstrate an adequately low probability of financial losses and societal risk. Safety assessment shall result in confirmation of the fact that the subsea pipeline complies with the assessments made at the conceptual design stage and the criteria of sufficient (acceptable) safety.

10.4 BASIC REQUIREMENTS FOR RISK ANALYSIS

10.4.1 Risk analysis is a part of industrial object safety declaration, safety expertise, safety economic analysis using a criterion "cost – safety – profit" and other types of the safety analysis and assessment of industrial objects and regions, on which territory technogenic emergency situations are likely to occur.

10.4.2 Risk analysis is an effective means that permits to determine approaches to hazard and risk detection, to take measures for development of objective decisions on acceptable risk level, to specify the requirements and recommendations on the safety control.

10.4.3 The process of risk analysis shall contain:

planning and organization of work;

identification of hazards;

risk assessment;

elaboration of recommendations on reduction of risk levels (risk control).

Appropriate documentation shall be prepared for every stage of the risk analysis.

10.4.4 Planning and organization of work.

10.4.4.1 At the stage of work planning it is necessary:

to describe the reasons that caused the necessity of the risk analysis;

to choose the system to be analyzed and to review it in detail;

to select the risk analysis performers;

to identify sources of information on the system safety;

to assess limitations of the initial data, financial resources affecting the scope and completeness of risk analysis;

to define the final target of the risk analysis;

to select the risk analysis technique;

to substantiate the acceptable risk criterion.

10.4.4.2 Selection of the risk analysis performers substantially affects the quality of the risk analysis. Specialists from the appropriate design organization and the Register representatives shall be included in the team.

10.4.4.3 Life cycle of a hazardous object, and the subsea pipeline as such, consists of design stages (with regard to environmental conditions of the pipeline route region), commissioning, operation and modification, and decommissioning. The particular targets of risk analysis shall be defined for each of the above stages.

10.4.4.4 When choosing the risk analysis technique, it is necessary to take into account the complexity of the processes under consideration, completeness of the initial data submitted and qualification of the experts involved in the risk analysis. Preference shall be given to more simple and easily understandable techniques as compared to more complicated techniques but not ultimately clear and not properly supported methodologically.

10.4.4.5 Selection of the acceptable risk criteria is governed by the techniques used for the risk analysis, completeness of necessary information, potentials and targets of the analysis to be made. The acceptable risk criteria may be based on the normative and legal documentation or they may be established at the risk analysis planning stage or specified more exactly in the course of obtaining analysis results. The main requirement for choosing the risk criterion is its validity and certainty.

10.4.5 Hazard identification.

10.4.5.1 The main task of hazard identification is definition and full description of all possible hazards for the particular pipeline system. Detection of the hazards existing for the particular industrial object is made on the basis of the information on the given object operation, expertise data and operation experience of the similar systems.

The importance of this analysis stage lies in the fact that the hazards not detected at the identification stage will not be later considered and not taken into account.

10.4.5.2 The initial stage of identification consists in the preliminary analysis of hazards. The aim of the preliminary analysis is detection of the most hazardous subsystems (units). For the subsea pipelines considered in this Section the hazard criterion at this stage is presence of hazardous substances and their mixtures in the pipelines, potentiality of their uncontrolled outflow (outburst), potentiality of ignition (explosion) source occurrence and external (technogenic and natural) impacts.

10.4.5.3 For the purpose of identification, analysis and control of the hazards associated with the subsea pipelines, regular and thorough recording of accidents shall be maintained aiming at minimizing the consequences of such accidents. The most hazardous accidents are damages and faults caused by the pipeline leakages due to breaks and fractures in the base metal of pipes and welds, corrosion wormholes, joint leakages, pipe wall thinning down to impermissible values, etc.

10.4.5.4 Information on the subsea pipeline accidents shall contain description of conditions at the beginning of the accident and measures of fighting against the accident taken to eliminate its consequences; information on development of accidents; physical and statistical models, etc.

10.4.5.5 The preliminary analysis of hazard identification permits to determine what components of the pipeline system require more careful analysis and what components are of lesser interest in terms of safety.

10.4.5.6 As a result of hazard identification, a list of undesirable events causing an accident is compiled. Hazard identification is completed with determination of further activities, namely:

whether or not to stop the further analysis because of hazard insignificance;

whether to make more thorough risk analysis;

elaborate recommendations on reduction of the hazard level.

10.4.6 Risk assessment.

10.4.6.1 At the stage of the risk analysis the hazards detected in the course of identification shall be analyzed in terms of their compliance with the acceptable risk criteria. In so doing, the acceptable risk criteria and assessment results may be shown qualitatively as a text (tables) or quantitatively by calculation of risk indications (see Appendix 2).

10.4.6.2 When selecting the form for presentation of the risk assessment results, one shall bear in mind that use of complicated and expensive calculations often gives a risk value, the accuracy of which for sophisticated engineering systems, to which subsea pipelines refer, is not high even in case of availability of all necessary information. In such case, performance of the complete qualitative risk assessment is more useful for the purpose of comparison of various hazard sources or analysis of the safety measures taken (e.g., when laying the subsea pipeline on the seabed) than for making a conclusion on the degree of subsea pipeline safety.

In risk assessment the priority shall be given to the qualitative engineering methods for risk analysis based on the approved procedures, special auxiliary materials (e.g., detailed methodological guides) and practical experience of the experts. Along with that, qualitative methods for risk assessment may be very useful, and sometimes they are the only acceptable ones, e.g. for comparison of hazards of different origin and for illustration of the results.

10.4.6.3 Risk assessment includes the event frequency analysis, analysis of consequences of the events revealed and analysis of the result uncertainties. Where the event consequences are insignificant or their frequency is fairly low, it is sufficient to assess one of the above parameters.

For the purpose of the event frequency analysis and assessment, the following approaches are normally used:

statistical data on accidents and reliability of the subsea pipeline similar to the type considered are used;

logic methods of event tree analysis or fault tree analysis are applied;

expert appraisal with consideration of the opinions of specialists in the area of subsea pipelines is performed.

10.4.6.4 The important condition for risk assessment is availability of the necessary information. It is recommended that in practice use shall be made of the expert appraisals and risk ranking methods in case of statistical data lack. Where such approach is used, the events under consideration are subdivided by a probability, severity of consequences and risk into several groups, e.g. with high, intermediate, low and insignificant risk degree. Normally the high risk degree is considered to be unacceptable, the intermediate degree requires a complex of measures to be taken for reduction of risk, the low degree is recognized to be acceptable and insignificant degree is neglected (see Appendix 2).

10.4.6.5 The analysis of the accident consequences includes assessment of impacts on people, property and environment. Consequences shall be predicted through assessment of physical and chemical effects of undesirable events (fires, explosions, emissions of toxic substances). For these purposes, use shall be made of the accident models and criteria on the subsea pipeline damages.

10.4.6.6 In risk assessment uncertainty and accuracy of the results shall be analyzed. The main causes of uncertainties are insufficient information on reliability of the equipment and components used, and a human factor, as well as assumptions made in the accident models. Analysis of uncertainties is transmission of the initial parameter uncertainties and assumptions used in risk assessment into result uncertainties. The causes of uncertainty shall be identified and presented in the results.

10.4.7 Recommendations on risk reduction.

10.4.7.1 The final stage of the risk analysis is elaboration of recommendations on risk reduction (risk control).

Risk may be reduced due to measures either of technical or organizational nature. In selection of the measures most important is general assessment of their efficiency for risk reduction. During operation of the subsea pipeline organizational arrangements may, in a number of cases, compensate a limited possibility to take major technical measures on reduction of hazard. When measures on risk reduction are developed, account shall be taken of possible limitations of the resources (both financial and material). Therefore it is primarily necessary to elaborate simple recommendations and measures that require less expenses and that work for the future.

10.4.7.2 In all cases, the measures that reduce a probability of an accident shall prevail over the measures that reduce accident consequences. Thus, selection of technical and organizational measures to reduce a hazard has the following priorities:

measures that reduce probability of accident occurrence including:

measures that reduce probability of fault occurrence;

measures that reduce probability of fault development into accident;

measures that reduce severity of the accident consequences;

measures that provide, for example, selection of an appropriate pipe wall thickness, corrosion protection, etc. in the process of the pipeline design;

measures related to accident prevention and monitoring;

measures dealing with organization, equipment and readiness of emergency services.

With equal possibility to implement the recommendations elaborate, priority shall be given to the accident prevention measures.

10.5 METHODS OF RISK ANALYSIS

10.5.1 Methods of risk analysis shall be selected, having regard to the purpose of the analysis, acceptable risk criteria, type of the system to be analyzed and hazard nature, availability of resources, experience and qualification of the personnel performing the analysis, availability of the required and reliable information, and other factors.

10.5.2 Methods of risk analysis shall meet the following requirements:

to be scientifically supported and consistent with the system under consideration;

to give the results in such a form that allows understanding of the risk nature in the best possible way and finding out the most effective ways for the risk reduction;

to be easily repeatable and verified.

10.5.3 Generally one or several methods of risk analysis described below shall be used at the hazard identification stage:

checklist;

"What-if …?";

combination of checklist and "What-if" analysis;

hazard and serviceability analysis;

failure type and consequences analysis;

failure and event tree analysis;

appropriate equivalent methods.

Brief information on the above methods is given in Appendix 3.

10.5.4 Guidelines for selection of the risk analysis methods at different stages of activities and subsea pipeline operation (design, routing, commissioning and decommissioning, operation, modification) are shown in Table 10.5.4.

The methods may be used individually or in combination. Qualitative methods may include quantitative risk criteria, based mainly on the expert appraisals, using such hazard ranking matrices, as "probability – severity of consequences" (see Appendix 2). Complete quantitative risk analysis may include all the methods listed.

Table 10.5.4

Guidelines for selection of risk analysis methods

Method	Stages of activities and functioning				
	Design	Arrangement and routing	Commissioning/ decommissioning	Operation	Modification
"What-if" analysis	+	0	++	++	+
Checklist method	+	0	+	++	+
Hazard and serviceability analysis	++	0	+	+	++
Failure type and consequences analysis	++	0	+	+	++
Failure and event tree analysis	++	0	+	+	++
Quantitative risk analysis	++	++	0	+	++
The following designations have been adopted for methods: 0 = least suitable; + = recommended; ++ = the most suitable.					

RECOMMENDATIONS ON PROVISION OF RELIABILITY AND SAFETY OF SUBSEA PIPELINES ON SEA GROUND

1 GENERAL

1.1 At the current level of technical development of subsea pipeline systems a probability of their damage during construction and operation due to various causes may not be excluded.

Referred to the main causes may be:

pipeline vibration and movement under the effect of hydrodynamic factors;

physical damages of subsea pipelines and their coatings by anchors, trawls, scrapers, vessel keels, ice formations, etc.;

external and internal corrosion (refer to Section 7);

improper ballasting of the pipeline (refer to Section 6);

weld defects of the pipeline base metal;

subsea pipeline buckling on the sea ground (refer to Section 3);

pipeline sagging in the area of the sea ground movement;

inadequate monitoring of the subsea pipeline condition during construction and operation (refer to Section 9).

The types of subsea pipeline damages are breaks and cracks on the pipe base metal and on welds, through corrosion flaws, joint leakages, thinning of the pipe wall to unacceptable limits in places of abrasion against the sea ground, high corrosive wear, dents, discontinuity of protective coatings, etc. The most severe consequences of the subsea pipeline damages are leakages and emergency spills of oil and oil products, condensate, gases and liquefied gases in case of seal failure.

1.1.1 Sea ground may be washed out under the pipeline due to erosion processes caused by waves and currents, seabed shape changes, which may result in the pipeline sagging at long distances. An opposite phenomenon — covering of the pipelines laid on the seabed or in a trench without backfilling — may take place due to the same causes. Under the effect of sand (movable) soil erosion, the pipeline may go deeper into the seabed, self-deepening will occur, and its stability in the sea ground will improve.

For the pipeline laying on the stiff and rocky sea ground, underwater currents may cause the lateral movement of the pipeline and excessive bending stresses.

Flow of the pipeline laid on the seabed creates pressurized area behind the pipeline (in the direction of the flow). Shear stresses in this area as compared with adjacent areas are higher. Sea ground erosion becomes more intensive in the pipeline laying area due to the differential pressure.

1.1.2 In the area of the sea ground erosion below the pipeline, significant static stresses act on the pipeline due to the internal pressure, its own weight, drag force, hydrostatic pressure, and dynamic stresses due to alternating hydrodynamic forces that cause pipeline oscillations (vibration).

1.1.3 One of the causes of the sea ground erosion in the pipeline laying area may be the action of the heavy water flows produced by a running vessel propeller in shallow water. The danger of such effect increases with reduction in depth under the vessel bottom and increase in vessel engine power.

1.1.4 A significant danger for subsea pipelines, especially in shallow water areas and in the areas with considerable fluctuations of the water level are physical damages to pipelines and their coatings by anchors, vessel keels, trawls, scrapers, ice formations and other objects.

1.1.5 Most dangerous for subsea pipelines in the regions, water areas of which are covered with ice during long periods of the year, are ice formations. They are characterized by large diversity, variability of properties and can exist in different forms, such as: level ice, ice with ice brash beneath, hummocks, grounded hummocks, icebergs. Different types of ice formations affect the pipeline structures during assembly and operation in different way.

Ice formation may be subdivided in terms of fast and drifting level ice thickness into four categories, namely: light — up to 30 cm, medium — up to 100 cm, heavy — up to 200 cm and very heavy — over 200 cm. Then all prospective oil- and gas sea areas in Russia may be subdivided into five categories (refer to Table 1). It should be noted that ice fields of the same thickness in the seas of Russia are observed far from being everywhere.

Analysis of seasonal changes in traveltime and morphological parameters of ice cover in the water areas of oil and gas deposits in the Arctic and the Far East seas of Russia shows that there exists nothing similar in the world practice.

1.1.6 Special place among dynamic phenomena that take place in the sea ice cover is taken by large ice formations, which in interaction with the seabed, may result in its exaration by hummocks, grounded hummocks and less frequently by icebergs.

Probability of seabed exaration by ice formations, possibility of occurrence of concentrated additional loads on the subsea pipelines under the effect of grounded hummocks and icebergs settled on the sea ground may have a determining influence on selection of pipeline routes, pipeline structure, burying depth in the seabed, seasonal periods for pipeline assembly, and, most importantly, on safety of construction and operation.

1.1.7 The phenomenon of the seabed erosion by melt water plunge pools is not ordinary process. Plunge pools are craters formed in shallow areas of the seabed. River and melt water flowing to the fast ice surface when snow is thawing

Table 1

Classification of prospective oil- and gas sea areas in Russia

Water area	The Caspian and the Baltic Seas, the Sea of Azov and the Black Sea basin, south-western shelf of Sakhalin Island	South-western part of the Barents Sea	South-eastern part of the Barents Sea, north-eastern shelf of Sakhalin Island	Coastal shallow water of the Kara Sea	Shelf of the Kara Sea
Sea depths, m	30 — 200	70 — 330	15 — 100	0 — 10	50 — 150
Ice conditions	Light	Light, medium	Medium, heavy	Very heavy	Very heavy
Average ice period duration, months	0 — 2	0 — 2	3 — 9	9 — 10	9 — 10

penetrate through scours under the ice and flow very fast vertically down. Due to inertia forces and gravitation flows of this water are vortexed and wash out plunge pools in the seabed for several meters in depth.

Wash-out plunge pools themselves are not dangerous for the subsea pipeline but through stripping the pipeline they cause hazardous sagging of the pipeline and situate conditions for pipeline vulnerability due to hummock and grounded hammock backbones, and in case of open water, due to anchors and other foreign objects.

1.1.8 Big areas of the Arctic seas are located under frozen sea grounds with different geocryological conditions. In case of pipelines conveying hydrocarbons at a temperature higher than temperatures of frozen sea grounds, the latter start to melt and settle. It can result in pipeline stripping accompanied by occurrence of additional stresses in the pipe and other associated negative phenomena.

In order to prevent the above phenomena, a feasibility study shall precede the selection of the pipeline burying depth in the frozen sea ground, and additional protective measures shall be taken. Referred to such measures may be, for example, application of pipes with thick insulation (up to several centimeters thick) covered with a protective metal jacket. In case of short lengths of frozen sea grounds, a possibility of the pipeline engineering protection may be considered that provides combined laying in one trench of the main piping and a tracer line of a small diameter that has a negative temperature.

2 PROTECTION OF SUBSEA PIPELINES AGAINST HYDRODYNAMIC AND MECHANICAL EFFECTS

2.1 General.

2.1.1 In order to protect the subsea pipelines against damages and to ensure fail-safe operation, use may be made of various methods, most of which shall be developed at the pre-conceptual and conceptual design stages. Referred to such methods may be: redundancy, restrictions on the minimum permissible distance between the parallel pipelines, laying in a trench with subsequent backfilling, in case the last operation is provided in the design specification.

2.2 Redundancy.

2.2.1 Redundancy of the subsea pipeline suggests installation of a booster pipeline parallel to the main pipeline. Redundancy is an efficient and at the same time expensive method to provide fail-safe transfer of the conveyed medium in the pipelines. Therefore the expediency of redundancy shall be supported by thorough economic feasibility study.

2.2.2 In case of a single subsea line, provision shall be made for redundancy where the length of the subsea pipeline (or a subsea section of a land pipeline) is more than 75 m.

For multi-line subsea pipeline, irrespective of its length, a necessity of redundancy depends on the pipeline purpose and particular conditions of the project.

2.3 Distance between the parallel pipelines.

2.3.1 The correct selection of a distance between the pipelines laid in parallel provides to a considerable extent safety of the subsea pipeline operation and uninterrupted transfer of conveyed media. The distance between the parallel pipelines shall be determined based on the conditions, under which an accident or catastrophe of one pipeline does not cause failure of the nearest parallel pipeline.

2.3.2 In general case, the distance between the parallel subsea pipelines shall be specified based on geological and hydrological conditions, methods of digging underwater trenches, if any, convenience of laying pipelines therein, safety of the pipeline in case of an accident. In all cases, the minimum distance between the parallel subsea pipelines shall be:

for gas pipelines buried in the seabed:

30 m at diameters to 1000 mm inclusive;

50 m at diameters over 1000 m.

for gas pipelines laid on the seabed:

100 m at all diameters.

For oil- and oil product pipelines these distances may be the same as for gas pipelines; they may be reduced subject to adequate substantiation and the Register agreement.

2.4 Pipeline burying in a trench with subsequent backfilling.

2.4.1 An efficient protection measure of the subsea pipeline against a destructive effect of waves, currents, storms, ice formations, physical damages by anchors, trawls, scrapers, etc. is burying of the pipeline in a trench with subsequent backfilling. This is a labor-consuming and expensive arrangement that requires performance of big volume of underwater earthwork.

2.4.2 A necessity of the pipeline burying and burying depth are dictated by hydrogeological conditions of the region, probability of the pipeline damage under external and internal effects, economic considerations.

In shallow water, especially where a probability of ice formation occurrence exists, pipeline burying is mandatory. Pipelines may be laid without burying and backfilling only at large depths; however, burying is also required in the coastal areas. Depths from 25 to 30 m and over may be considered to be fairly safe. Smaller depths are subject to special consideration. Most reliable will be a decision that is based on the most thorough investigation of the pipeline routing area for each particular case.

2.4.3 Burying of pipelines in the seabed shall be normally done by laying them in preliminarily dug or washed-out trenches. Underwater rocks shall be normally exploded. The designed trench profile is normally assumed to be a trapezium. The requirements for trench construction and selection of main geometrical parameters (slope grade, trench width, distance between the pipe side and a communication cable, etc.), having regard to a free passage for a diver for the pipeline inspection after laying of the pipeline in the trench, sediments, pipeline diameters and burying depth, shall be specified in the technical design.

2.4.4 In certain circumstances, pipelines may be buried after laying them on the seabed with the aid of pipe burying vessels or other special mechanisms. Pipe burying vessels shall be used where pipeline can be preliminarily laid following the natural contour of the seabed with acceptable bending radii and where there are no underwater rocks.

2.4.5 In case of ice cover in shallow water, a trench may be dug by a mechanism operating through openings in the ice.

2.4.6 The increase of the trench depth requires a substantial increase of power inputs. Therefore deep trenches shall be dug using several passages. Digging of more narrow trenches with strengthening of their walls by temporary baffles to prevent their fall may be an alternative.

2.4.7 Pipelines laid in trenches are backfilled with a soil to the design reference marks selected so as to protect the pipeline against the physical damages. Having been laid in the trench and tested before backfilling, the pipeline shall be inspected by a diver.

The following shall be determined in the course of the diver's inspection:

local soil erosion, pipeline sagging and displacements in relation to the design route, deviation from the design reference marks;

damages to external corrosion-resistant coatings;

breaks in solid weight coatings and correct arrangement of weights on the pipeline.

The defective places found are marked with buoys, and measures are taken to eliminate the defects.

2.4.8 Upon laying, subsea pipelines are backfilled to the design reference marks indicated in the design specification. The thickness of the sea ground layer above the pipeline shall be not less than the design value or shall exceed it by not more than 20 cm.

The method of trench backfilling shall be chosen depending on the season of the year (whether it is winter or summer), trench depth, water depth, current velocity and earthwork to be done.

Where the local sea ground in terms of its mechanical-and-physical properties is not suitable for backfilling, it shall be substituted by a specially brought soil. Sometimes, under special conditions where drifting sand currents occur, a sanding-up phenomenon can be used for trench backfilling (refer to 1.1.1), as well as for plunge pool self-filling (refer to 1.1.7), which allows considerable decreasing of the earthwork cost.

2.4.9 In exceptional cases, where the subsea pipeline burying is not economically feasible, and the length of the subsea pipeline is relatively small, bags filled with sand or stones, or mattresses of various types may be put above the pipeline or it is covered with polymer boards, reinforced concrete slabs, or combinations of the above methods are used.

2.4.10 For safety reasons the pipeline route is sometimes transferred to the area with more favorable conditions for pipeline construction and operation although it may result in increase of the pipeline length and cost. The decision on the pipeline transfer shall be economically proved.

2.4.11 In all cases, to determine the subsea pipeline routing and the required burying depth, comprehensive investigation of the suggested area for the pipeline installation shall be conducted. Such investigation shall include thorough studies of the seabed relief, depths, composition of the sea ground, statistical data on winds, waves, currents, local changes in seabed shape, duration of ice coverage period, ice cover dynamics, especially of large ice formations. It is also necessary to know local features, such as presence of frozen sea grounds under the seabed, probability of a thermal action of the product conveyed through the pipeline on the frozen sea grounds, formation of plunge pools in the seabed, etc.

2.4.12 There does not exist a strict regulation of the pipeline burying depth, and it cannot basically exist. An issue of each pipeline protection and its safe operation shall be decided in each particular case individually based on investigation of the situation in the area of the pipeline route. The more thorough investigation is conducted, the more exactly the burying depth of the pipeline will be determined and the safer its operation will be.

Some generalized recommendations on burying depths of subsea pipelines in the sea ground are given in Table 2 below. Where no more reliable data are available, these recommendations may be used at earlier stages of the subsea pipeline design.

Table 2

Recommendations on selection of pipeline burying depth

Nos.	Prevailing external factor affecting the pipeline	Burying depth	Remarks
1.	Large ice formations	The burying depth shall be determined by the maximum depth of exaration furrow plus 0,4 m	Recommendation does not allow for extreme cases
2.	Seabed plunge pools	The burying depth shall be equal to the height of plunge pool plus 1,0 m	
3.	Frozen sea grounds	Where pipelines for conveying hydrocarbons at a temperature higher than the surrounding frozen sea grounds are laid, their burying depth shall be selected based on the calculation made using numerical methods that would allow to exclude melting and settling process capable to result in pipeline stripping	
4.	Sea ground erosion by currents, waves, flows from operating vessel's propellers	The burying depth shall be determined by the maximum possible height of the washed-out sea ground plus 1,0 m	
5.	Currents and waves	Where rocks penetrate the seabed, the burying depth shall be the sum equal to the pipeline diameter plus 0,5 m	
6.	Horizontal displacements	Where currents and waves shall be taken into account, the burying depth shall be selected so as to exclude the dangerous horizontal displacements	
7.	Anchoring of marine engineering facilities	The burying depth in the area of possible anchoring of vessels or other engineering facilities shall be assumed equal to 2,5 m	Use of trawls, scrapers and other objects towed along the seabed shall be taken into consideration separately
8.	Ecological water purity	Where pipelines are laid below the seabed of fresh water lakes and basins, their burying depth shall be based on the conditions that totally exclude loss of the water purity in the lakes and basins	
9.	Problems with burying	Where it is impossible to provide the required burying depth, the pipeline route shall be transferred to the area with more favorable conditions for the pipeline construction and operation	
10.	Large ice formations	In the areas with large ice formations, at depths from 25 m and over, the burying depth may be assumed equal to zero (laying on the seabed). Where depths are less, this issue shall be considered in each particular case	Recommendation does not allow for extreme cases

INDICES OF RISK ANALYSIS

1 GENERAL PROVISIONS AND CHARACTERISTICS

1.1 Risk is an inevitable and multi-dimensional factor associated with industrial activities. Actually risk is a measure of hazard. The aim of risk control is to prevent and to reduce the number of injured people and fatalities, destructions of material objects, loss of property and harmful effects on the environment. In order to control risks, it is necessary to conduct their thorough analysis and assessment. Risk analysis is a means to identify existing hazards, to determine levels of risks of identified undesirable events (in terms of frequency and consequences) and to develop recommendations on risk reduction in case its acceptable level is exceeded.

1.2 Risk analysis may be quantitative and qualitative. In case of quantitative analysis, the results are obtained by calculation of risk indices. In case of qualitative analysis, the results are presented in the form of the text analysis, tables, charts or by using qualitative (engineering) methods of hazard analysis and the expert appraisals.

1.3 The risk concept is used for measurement of the hazard and is normally applied to an individual or a group of people (attending personnel, population), property (material objects, ownership) or to the environment.

Along with the risk concept, use is made of a risk degree or risk level concept. The degree of risk of accidents with an engineering system, such as the subsea pipeline, is determined based on the analysis of all indices of risks found in analysis of undesirable events, e.g., events associated with leakage of pipelines and equipment, failures of warning (alarms) and monitoring systems, errors of attending personnel, unfavorable weather conditions, consequences of various mechanical impacts, etc.

1.4 Based on the principal cause of risk occurrence, risks are subdivided as follows:

natural risks mean risks associated with the natural disaster, such as earthquakes, floodings, storms, tornados, etc.;

engineering risks mean risks associated with the hazards caused by a technical object (subsea pipeline);

environmental risks mean risks associated with the environmental pollution;

financial risks mean risks associated with the hazard of losses resulted from financial and economic activities.

1.5 From the viewpoint of risk concept application in technical safety analysis and control, most important are:

individual risk means the risk, to which an individual is exposed;

potential territorial risk means spatial frequency distribution of materialization of a negative effect of a certain level;

societal risk means dependence of frequency of events, during which a number of people suffered at a certain level in excess of the number determined;

potential lose of life (PLL) means an expected number of fatalities resulted from possible accidents during a certain period of time;

acceptable risk means a degree of an individual risk, which the society as whole is prepared to accept for obtaining certain benefits resulted from its activities;

negligible risk means the maximum risk established by regulating authorities, above which measures shall be taken for elimination thereof.

In other sectors, e.g., in insurance activities, the above classification of risks may be different.

2 INDIVIDUAL RISK

2.1 Individual risk means a probability (frequency) of individual injury as a result of affecting hazard factors under consideration:

$$R = P(A) . \tag{1}$$

In case of technical hazards, individual risk is basically determined by a potential risk (or its territorial distribution) and probability of presence of an individual in the area of likely action of hazardous factors. Individual risk is determined in many respects by qualification and skills of an individual to act in a hazardous situation and individual's protectability. Individual risk determines to a significant degree other important risk categories, such as potential territorial risk.

2.2 Individual risk is normally measured by a probability of one fatality a year. Risk of injuries, diseases, disability, etc. may be assessed in a similar way. According to the MODU/FOP Rules (2000 edition), the value of individual risk a year

$$R_{ik} = \sum_{i=1}^{i=m} Q_i Q_{ik} Q_{ik}^p \tag{2}$$

where Q_i = recurrence of the i-th situation (event) under consideration;
Q_{ik} = probability of materialization for the i-th branch of an event tree (risk of accident);
Q_{ik}^p = assumed probability of striking an individual in materialization of the i-th branch of an event tree;
n = number of branches of the event tree;
k = coefficient consistent with the certain kind of an accident.

2.3 The total risk a year under various effects, e.g., earthquakes fires, explosions, etc., may be determined as a sum R for separate effects:

$$\sum R = \sum_{k=1}^{k=m} R_{ik} \tag{3}$$

where m = the number of striking factors considered.

2.4 Analysis of individual risk is normally not made based on individual risk of an individual. Made more frequently is assessment of individual risk for groups of people characterized by approximately the same time of staying in different hazardous zones and use similar protection means. Individual risk of attending personnel and population of surrounding areas is normally considered.

3 POTENTIAL TERRITORIAL RISK

3.1 Potential territorial risk means spatial frequency distribution of materialization of a negative effect of a certain level.

$$R(x, y) = P(x, y) \tag{4}$$

where x, y = rectangular coordinates.

Potential territorial risk is a complex measure of risk characterizing a hazardous object, i.e. the pipeline and surrounding area in the case considered. The measure does not depend on the fact where the affected object (e.g., an individual) is located in the space. It is considered that probability of location of the affected object is equal to 1, if, for example, the individual stays at the considered point of the space during the whole period of the time investigated. Potential risk does not depend on the fact whether a hazardous object is in a crowded or inhabited area; it may vary in a wide range.

3.2 Potential risk is a potential for the maximum possible risk for particular affected objects that are located at the considered point of the space. It is important in practice to know the distribution of potential risk for individual sources of danger and for separate accident scenarios.

3.3 By an accident scenario is meant the full and formalized description of the following events: an accident initiation phase, an accident initiating event, an accident process and an extraordinary situation, including specific quantitative characteristics of accident events, their space-time parameters and causal relationship.

3.4 Potential risk is normally an intermediate measure of a hazard used for assessment of individual and societal risks. Distribution of potential risk and distribution of attending personnel and population in the considered area allow obtaining the qualitative assessment of societal risk for population. To do that, it is necessary to determine the number of affected people in each accident from each source of hazard and then to determine the dependence of the frequency of events F, in which more people suffered to some extent than the N number obtained (societal risk).

4 SOCIETAL RISK

4.1 Societal risk characterizes the scale of possible accidents and catastrophes. It is determined by a function called FN-curve. Depending on the purpose of the analysis N may mean either the total number of people affected or the number of fatalities or some other indicator of severity of consequences.

The criterion of the acceptable degree of risk is determined in such case not by the number for an individual event but a curve plotted for different scenarios.

4.2 A general approach to determine the acceptable risk is use of two curves. In such case, FN-curves of societal risk of fatalities are assessed in logarithmic coordinates. The area between these curves defines the intermediate degree of risk. The issue regarding how to reduce it shall be decided based on specific features of the subsea pipeline operation and local conditions by agreement with the Register and administrative authorities of the local government.

The example of plotting FN-curves is given in the MODU/FOB Rules (2000 edition).

4.3 Assumed as variable N may be property or environmental damage, then own FN-curves that will serve as a measure of insurance or environmental damage can be plotted.

5 POTENTIAL LOSS OF LIFE (PLL)

5.1 Potential loss of life (PLL) is an integral measure of a hazard. It determines the scale of expected consequences of potential accidents for people:

$$R_N = P(A)N \tag{5}$$

where N = total number of people exposed to potential negative effect.

Potential loss of life actually determines the expected number of facilities resulted from an accident on the territory under consideration during a certain period of time.

5.2 Individual risk and potential loss of life may be transferred into economic and financial categories under certain conditions.

In order to make environmental safety analysis dependence between the area of the contaminated surface and frequency of accidents may serve a measure of the environmental risk. For insurance purposes, such risk indication as statistically expected damage in value terms (the value determined by the product of the accident frequency by the damage) is important.

METHODS OF RISK ANALYSIS

The principal methods recommended for application in risk analysis are given in this Appendix.

1 Checklist and "What-if" methods or their combination refer to a group of qualitative hazard assessment procedures based on studying compliance of the operating conditions of the object (the subsea pipeline) with industrial safety requirements in force.

1.1 The checklist is a method for identification of compliance with the existing standards. It is simple for use at any design, construction, operation and accident situation stage, and allows quick identification of the minimum permissible degree of hazard.

1.2 The checklist method is drawn up, where necessary, for specific situations and is used, for example, for assessment of correctness of marine operations, solution of the problems that require careful attention.

1.3 The checklist method is very effective in the process of management of standard emergency situations. The result of the checklist method is a list of questions and answers regarding compliance of the object (the subsea pipeline) with safety requirements and instruction on safety provision. An example of drawing up of the checklist for the analysis of accident situation is given in the MODU/FOP Rules (2000 edition).

1.4 The checklist method differs from the "What-if" method in more complete presentation of the initial data and results of safety violation consequences.

1.5 The "What-if" method uses the questions beginning with "What-if" and considers the development of a situation after these words. The compilers of an analysis shall be very cautious and adequately realistic in order to avoid improbable scenarios of the event development in emergency situations.

1.6 The "What-if" method may be used during design, modernization or operation of the subsea pipeline. It results in a list of danger zones that are potential for accidents and the methods supposed for accident avoidance and prevention.

1.7 The above methods are fairly simple (especially if provided with auxiliary forms, unified forms that facilitate analysis in practice and presentation of the results), inexpensive (results may be obtained by one person during one day) and most effective in studying well-known objects with a minor risk of major accidents.

2 Failure Mode and Effect Analysis (FMEA) is used for qualitative safety assessment of engineering systems and is applied in determination of single types of failures causing or contributing to occurrence of an accident. The specific feature of this method is consideration of each engineering system part (the pipeline component) or an individual component as if it were defective (type and cause of failure), and the possible effect of failure on the engineering system (the subsea pipeline).

2.1 At the design stage of the subsea pipeline FMEA may be used to determine the necessity of additional safety measures or their reduction. In modernization of the subsea pipeline, FMEA permits to determine their influence on the existing structures and equipment. The method may be applied during operation of the pipeline for identification of single failures likely to result in severe consequences.

2.2 Subjectivity of FMEA method requires involvement of at least two experts in its application, competent in issues of the pipeline transport processes and the equipment used. The method of analysis of failure types and consequences may be used together with other methods of hazard identification, e.g., HAZOP.

2.3 Failure Mode, Effects and Critical Analysis (FMECA) is similar to FMEA but, different from that method, it allows obtaining quantitative results due to the fact that each type of failure is ranked with regard to two criticality components – probability (or frequency) and severity of failure consequences. The concept of criticality is close to the risk concept and therefore may be used in quantitative analysis of accident risk. Selection of criticality parameters is necessary for development and instructions and priorities of safety measures.

2.4 FMECA results are presented in the form of tables with a full list of equipment and components, types and causes of possible failures, frequency, consequences, criticality, failure detection means (alarms, monitoring devices, etc.) and recommendations on hazard mitigation.

2.5 The following criteria may be considered in terms of severity of consequences:

catastrophic — results in fatalities, causes significant damage to industrial objects and residential buildings, and irreplaceable damage to the environment;

critical (non-critical) failure — threatens (does not threaten) human life, loss of objects, environment;

failure with negligible consequences — a failure which refers, in terms of its consequences, to none of the above three categories.

2.6 Recommended indices of the level and criticality criteria in terms of probability and severity of consequences of failure (event) are shown in the table. Four groups of affected objects to which damage may be caused by an accident, are selected for the analysis, namely: attending personnel, population, environment, material objects — the pipeline itself, equipment, completing components and buildings (industrial and residential) of the nearest inhabited localities. The criteria used in the Table may be applied for ranking hazards and assessment of an extent of risk for the whole industrial object (the subsea pipeline). In the case under consideration, rank A corresponds to the highest (unacceptable) risk degree that requires immediate safety measures to be taken. Ranks B and C correspond to the intermediate risk degrees, and rank D to the safest conditions.

Depending on the hazard rank:

A — thorough detailed risk analysis is mandatory, special safety measures are required for reduction of risk;

B — detailed risk analysis is desirable, safety measures are required;

C — risk analysis and safety measures are recommended;

D — no risk analysis and safety measures are required.

In risk analysis, consideration shall be given to contribution of risks of industrial object (the subsea pipeline) component failures to the joint risk of an accident.

Table

“Probability – severity of consequences” matrix

Expected frequency of occurrence (I/year)		Severity of consequences			Failure with negligible consequences
		Catastrophic failure	Critical failure	Non-critical failure	
Frequent failure	> 1	A	A	A	C
Probable failure	$1 — 10^{-2}$	A	A	B	C
Possible failure	$10^{-2} — 10^{-4}$	A	B	B	C
Infrequent failure	$10^{-4} — 10^{-6}$	A	B	C	D
Practically unlikely failure	$< 10^{-6}$	B	C	C	D

2.7 FMEA and FMECA methods may be successfully used for analyzing sophisticated engineering system designs or during modernization of hazardous facilities, to which the subsea pipelines directly refer. The analysis with application of such methods is normally made by a team of 3 to 7 people during several days or weeks.

2.8 Quantitative determination of contributions to risks consists of several stages based on statistics of accidents. The mathematical formulation of quantitative determination of contributions to risks includes different statistical models (refer to the MODU/FOP Rules (2000 edition)). The formula of full probability in quantitative determination of contributions to risks as indicated in the Rules has a form:

$$KOP_k = = \sum_{i=1}^{i=n} Q_i Q_{ik}$$

where Q_i = recurrence for the i-th situation (case) under consideration;

Q_{ik} = probability of materialization for the i-th branch of an event tree (risk of an accident);

k = consistent with the certain kind of an accident.

3 Hazard and Operability Study (HAZOP) investigates the effect of deviations of technical parameters (pressure, temperature, etc.) from normal operating conditions from the viewpoint of hazard occurrence. HAZOP method may be used in design, modernization and operation of the subsea pipelines. In terms of complexity and quality of the results, the HAZOP method is consistent with the FMEA and FMECA methods.

3.1 In the course of analysis possible deviations in operation and their causes are identified, and a list of instructions, recommended alterations, proposals or actions to improve safety or operability aimed to prevent the deviations is compiled for each subsea pipeline and its equipment.

3.2 Key words, such as "no", "more", "less", "as well as", "another", "other than", "opposite to", etc. are used to characterize deviations. The key words help to reveal all possible deviations. The concrete combinations of the words with technical parameters are determined by specifics of the media conveyed through the pipelines and appropriate conditions. The approximate combinations of key words are as follows:

"NO" — no direct supply of the conveyed medium when it shall take place according to the process;

"MORE" ("LESS") — increase (reduction) in values of operational variables in comparison with the specified values (pressure, throughput, temperature, etc.);

"AS WELL AS" — new components included (air, water, impurities);

"ANOTHER" — condition different from normal operation (start-up, stop, etc.);

"OTHER THAN" — total change of the process, contingency, destruction, depressurization, etc.;

"OPPOSITE TO" — logic opposition to intention, backflow of the conveyed medium.

3.3 The HAZOP-method results are presented on special flow sheets (tables). The degree of hazard may be determined quantitatively by assessment of probability and severity of consequences of the accident under consideration, using criticality criteria similar to FMECA method (refer to Table).

In addition to identification of hazards and their ranking, the HAZOP method similar to FMECA permits to clear up uncertainties and inaccuracies in safety instructions and to improve them. Efficiency and effectiveness of the method depend to a considerable extent on complexity and length of the subsea pipeline, qualification of experts. The disadvantages of HAZOP and FMECA methods are associated with difficulties of their use for analysis of combinations of events causing an accident.

4 Logic and graphic methods of "failure and event trees" analysis.

4.1 "Failure and event trees" analysis methods are logic and graphic methods used to reveal cause-effect relations between the events.

4.2 Fault tree analysis (FTA) permits to detect combinations of equipment and component failures, personnel errors and external (technogenic, natural) effects causing the main event, i.e. an accident. Occurrence and development of major accidents are normally characterized by a combination of accidental local events occurring with different frequency at different stages of the accident. The FTA method is used for analysis of likely causes of accident occurrence and calculation of frequency based on the knowledge of initial event frequencies.

4.3 The Event Tree Analysis (ETA) is an algorithm of plotting sequence of events resulted from the main event (accident). The ETA method is used for analysis of accident development. The event tree is materialized in the form of risk distribution diagram. The plotting of the event tree starts from categories of accidents suggested by logic and information available aimed at compiling a priority list of risks.

The frequency of each scenario of accident development is determined by multiplying the frequency of an accident by the probability of the final event, e.g., accidents with leakage of the subsea pipeline conveying explosive and fire-hazardous medium, which can develop both with or without ignition depending on the particular conditions.

Fault and event tree techniques are labor consuming and are mainly used for analysis of designs or revamping of sophisticated engineering systems, to which subsea pipelines refer.

5 Quantitative methods of risk analysis are characterized by calculation of risk indices given in Appendix 3. They can include one or several of the above methods or use their results. Performance of the quantitative analysis requires high qualification of personnel, big volume of information on accidents, adequate reliability of equipment, consideration of specific features of the locality, weather conditions, time of staying people in the area close to a hazardous object, population density in the neighboring regions and other factors.

5.1 The efficiency of the quantitative risk analysis becomes mainly apparent:

at object design and installation stages;

in safety assessment of the objects which have equipment of the same type, e.g., main piping;

in case where complex evaluation of accident impact on people, environment and material objects is necessary;

in development of a list of priority measures on protection of the hazardous object (the subsea pipeline).

5.2 The disadvantages of the quantitative risk analysis are as follows: fairly low accuracy of the results obtained; therefore use of quantitative indices (in particular, probability of accident occurrence) as the safety criteria for complicated industrial objects, to which the subsea pipelines refer, is not always justified.

Российский морской регистр судоходства
Правила классификации и постройки
морских подводных трубопроводов
2005 г.

Russian Maritime Register of Shipping
Rules for the Classification and Construction
of Subsea Pipelines
2005

The edition is prepared
by Russian Maritime Register of Shipping
8, Dvortsovaya Naberezhnaya,
191186, St. Petersburg,
Russian Federation
Tel.: +7(812) 312-89-59
Fax: +7(812) 312-89-86